Adopted
Revenue Requirements
Analysis

2007-2008

Seattle City Light
December 2006

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Chapter 1

Introduction

1.1 The Adopted Rates

The 2007-2008 Adopted Rate Design Report contains the rates needed to collect sufficient revenues from customers so that City Light can provide for its operations, maintenance and capital needs as well as meet its financial policies, most recently articulated by the City Council in Resolution 30761 in May 2005. The 2007-2008 Budget adopted by the City Council is the basis for the 2007-2008 adopted rates. The Budget identifies the activities and resources necessary to achieve City Light's mission, i.e., "exceed our customers' expectations in producing and delivering environmentally responsible, safe, low cost and reliable power."

As stated in Section 2 of Resolution 30933 of November 20, 2006, "The [rate review] process is generally comprised of three steps [revenue requirement, cost of service and rate design], which are described below. While the documentation of each of the steps is done separately, the documents are the basis of a single complete rate proposal made by the Mayor, reviewed by the public, and reviewed and acted upon by the Seattle City Council."

The three steps in the rate process are as follows:

- **Revenue Requirements Analysis (RRA)**
  The first step estimates and documents the amount of revenue required to meet operating and maintenance expenses and to satisfy the Department's financial policies.

- **Cost of Service and Cost Allocation (COSACAR)**
  The cost of serving each customer class is analyzed in the Cost of Service and Cost Allocation Report, which determines the share of the total revenue requirement to be collected from each class.

- **Rate Design Report**
  The third step of the process is the design of rate schedules that recover the required amount of revenue from each rate group, as determined by the cost allocation procedure. The structure, components and relationships among the components of each rate schedule are determined in this step.

1.2 Organization of the 2007-2008 Revenue Requirements Analysis

Chapter 2 of this RRA discusses the major reasons for the change in revenue requirements between the forecast for 2006 and projections for 2007 and 2008.

Chapter 3 describes net power costs and the forecast of energy sales to customers. This chapter reviews the sources of energy for the utility, including both owned generation and purchased power contacts. It also includes discussions of transmission and wheeling expenses and revenues, water-for-power expenses and other power-related expenses and revenues that do not reflect purchases and sales of energy. A discussion of the net revenue or expense resulting from short-term wholesale market transactions and the uncertainty associated with these transactions is also included.

Chapter 4 deals with the operation and maintenance expenses of the utility other than the power-related costs discussed in Chapter 3. Operation and maintenance costs include distribution, customer accounting and advisory, direct conservation and administration and general expenses. Chapter 4 also reviews sources of revenue other than sales of energy to customers and other utilities. These revenues, which include interest earnings and miscellaneous revenues, help to reduce the revenue required from customers because they are sources of additional funds. This chapter also reviews credits to base rates, uncollectible accounts, and taxes.

Chapter 5 describes the utility's capital requirements. This chapter discusses major initiatives in the Department's Capital Improvement Program (CIP), Conservation Implementation Plan and other capital requirements. The RRA forecast classifies CIP expenditures according to functional categories: generation, transmission, distribution, and general plant.

Chapter 6 analyzes the factors affecting reliance on debt, details the computation of the amount of debt issued and describes the trend in the utility's debt service and debt accumulation. It also discusses how the utility's financial policies determine the relative mix of funding to pay for capital requirements. Funding sources include: 1) proceeds from operations, which include retail energy sales, wholesale power and power–related revenue, and miscellaneous revenue from property rentals, service charges, late payment fees, etc.; 2) proceeds from debt issues and other borrowing; and 3) contributions in aid of construction, capital grants, federal agency funding for conservation programs and customer payments for conservation.

Chapter 7 presents the methodology used in unbundling the Department's costs into the various functional components that reflect its major lines of business. The two primary functional categories are energy and retail services. Energy is further subdivided into subcategories of power, conservation and long-distance transmission. Within retail services, the major subcategories are distribution, customer accounts and services, and low-income assistance. Functionalized revenue requirements serve as inputs to the Cost of Service Model, which allocates them by customer class based on marginal cost of service.

This RRA also includes appendices. Appendix 1 presents the financial statements, including the Flow of Funds (Table 1.02), Net Earnings (Table 1.04) and Balance Sheet (Table 1.05) statements prepared for this rate period by the Department's Financial

Planning Model (FPM). It details the revenue and expenditure forecasts used to calculate the revenue required from retail customers to support City Light's operations and plant and meet the utility's financial guidelines, and includes the underlying load-resource balance of the utility. Appendix 2 provides an explanation of the power resource forecast. This forecast provides inputs to the forecast of wholesale sales and purchases, providing ranges of data that reflect the uncertainty associated with resource availability. Appendix 3 provides calculation details of tables in Chapter 2.

A goal of this rate-setting process has been to establish stable rates for the period 2007-2008. City Light first determined the revenue requirements for each calendar year. However, revenue requirements over these two years differed significantly, largely in the expectation of receiving less net wholesale revenue in 2008. To facilitate stable rates, City Light averaged the revenue requirements for the two-year period, which resulted in an average rate decrease of 8.4%[1]. City Light then prepared its forecast using the retail rates determined by averaged revenue requirements. Therefore, the revenue requirements discussed in this analysis are the result of the averaged retail rates for 2007-2008. The revenue requirements presented in the Cost of Service and Cost Allocation Report and the Rate Design Report differ slightly from those contained in the financial forecast described in this RRA since they were used to determine the average retail rate for 2007-2008. The adopted rates for 2007 and 2008 meet the financial policy objectives in each of these two years.

[1] It should be noted that the average rate decrease of 8.4% is not the same as the change in average revenue per MWh from 2006 to 2007-2008 which is analyzed in this RRA. The rate decrease of 8.4% is based on a comparison of revenues from customer classes with and without a rate change assuming 2007-2008 energy consumption in both cases; and the revenue requirement allocated to customers includes adjustments for power factor charges, rate discounts, credits for customer own-transformation, and assumed additional revenues from network customers outside the downtown network in 2008. The change in average revenue per MWh, on the other hand, assumes estimates of revenues and expenses for 2006, as well as 2006 customer consumption, as the base from which 2007-2008 changes are calculated; and the revenue requirements described for that purpose are net of the adjustments mentioned.

Chapter 2

Summary of Changes in Revenue Requirements

2.1 Introduction

This chapter presents a summary of changes in revenue requirements underlying the rate adjustments to take effect on January 1, 2007. After reviewing the Department's rate proposal and considering the Mayor's recommendations, the City Council passed Ordinance 122282 on November 20, 2006, establishing rates for calendar years 2007 and 2008. The revenue requirements forecast underlying the 2007-2008 rates allows for a decrease of 8.4% in the average rates to be paid by retail customers, while using conservative hydro-system assumptions and satisfying all City Light financial policies.

Resolution 30761, which establishes financial policies for City Light, requires City Light to use a "flow of funds" approach (like cash flow) in discussing its revenue requirement forecast. This shows how revenue available for debt service and the capital program are calculated and demonstrates that the Department expects to meet its targets for debt service coverage and revenues available for the capital program.

Section 2.2 describes how the revenue requirements are determined using the flow-of-funds format. Section 2.3 identifies the major sources of change between the forecast for 2006 and the 2007-2008 revenue requirements.

2.2 How Revenue Requirements Are Determined

The object of the Revenue Requirements Analysis is to determine the amount of revenue from customers that must be collected by the Department in a given calendar year to cover operating costs in that year and meet financial policies prescribed by Resolution 30761.

Operating costs and capital expenditure levels are set during the biennial budget process. Levels of expenditure are set so that Seattle City Light will have the staff and financial resources necessary to support key activities and projects. The amount of revenue required from customers is calculated after operations and maintenance expenses, capital expenditures, other sources of revenue, and cash balances required by financial policy are projected.

Table 2.1 shows the flow of funds in the financial forecast. City Light has set rates so that expected revenues from customers will total $530.8 million in 2007 and $542.5 million in 2008. At that level, revenues from customers plus wholesale power and other expected sources of revenue will be sufficient to pay for City Light's operations, debt service and taxes, and also meet its financial policy targets. These targets, and their level of expected achievement for the 2006-2008 period, are shown in the third section of Table 2.2.

Table 2.1

City Light's Flow of Funds
(All Dollar Figures in Millions)

	2006	2007	2008
Revenue from Customers	$566.1	$530.8	$542.5
Power and Power-Related Revenue	215.2	265.6	223.4
Other Revenue	13.5	14.1	15.2
Total Revenue	$794.8	$810.4	$781.1
Power Costs	$363.3	$365.7	$345.2
Nonpower O&M	123.8	128.2	129.9
Other Costs (Net)	16.4	8.3	19.9
Total Costs Before Debt Service	$503.4	$502.3	$495.0
Revenue Available for Debt Service	$291.4	$308.1	$286.1
First Lien Debt Service	$128.2	$128.2	$128.2
Second Lien Debt Service	7.9	8.3	8.8
Repayment of Sound Transit Loan	5.6	4.4	0.0
City Taxes	34.9	32.9	33.5
Other Uses of Funds	2.1	-3.8	2.5
Net Revenue Available for the Capital Program	$112.7	$138.0	$113.1

Note: Data sources and calculations used in this table are documented in Appendix 3

2.3 Changes in Revenue Requirements in 2007 and 2008

Table 2.2 presents a summary of changes in the revenue requirements forecast and its implications for meeting financial targets. It identifies the changes in each of five major categories of revenue requirements: net power, non-power operations and maintenance, debt service expense, other costs minus other revenues and additional revenue required to meet financial policy targets. Forecasts of the components of each of these categories are discussed in more detail in Chapters 3 through 6. Projected revenue requirements in 2007 and 2008 will be compared with revenue requirements in the forecast for 2006 and the reasons for changes between the two forecasts will be explained. The forecast for 2006 reflects historical trends in costs and revenues and known adjustments to the trends.

Table 2.2

Summary of Revenue Requirements 2006-2008
(All Dollar Figures in Millions Except Where Noted)

	Average Retail Revenue per MWh			Change from 2006 to 2008	
	2006	2007	2008	$ or MWh	%
Total Revenue Requirement	$566.1	$530.8	$542.5	-$23.6	-4.2%
Sales (MWh)	9,324,653	9,496,232	9,677,386	352,733	3.8%
Average Retail Revenue per MWh ($/MWh)	$60.71	$55.89	$56.06	-$4.65	-7.7%
Annual % Change in Avg. Retail Revenue per MWh		-7.9%	0.3%		

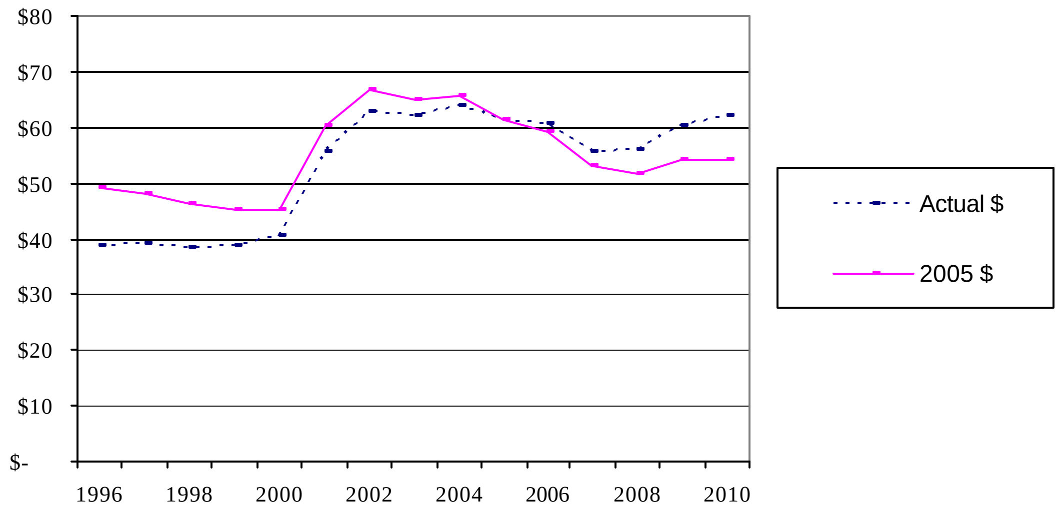
	Revenue Requirements			Change from 2006 to 2008	
	2006	2007	2008	$	%
Net Power Costs	$145.2	$97.2	$118.8	-$26.4	-18.2%
Other O&M Costs	$123.8	$128.2	$129.9	$6.1	5.0%
Debt Service	$141.7	$140.9	$137.0	-$4.8	-3.4%
Other Costs Minus Other Revenues	$42.8	$26.3	$43.8	$1.0	2.3%
Add'l Revenue Required to Meet Financial Policy Targets	$112.7	$138.0	$113.1	$0.4	0.3%
Total Revenue Requirement	$566.1	$530.8	$542.5	-$23.6	-4.2%

	Financial Policy Targets			
	2006	2007	2008	Target
Debt Service Coverage	2.14	2.26	2.09	2.00
Probability of Revenue for Capital	94.0%	96.0%	95.0%	95.0%
Long-Term Debt as % Capitalization	72.9%	67.1%	63.1%	60% by 2010
Minimum Operating Cash Balance	$116.1	$76.9	$30.0	$30.0
Operating Contingency Reserve	$25.0	$25.0	$25.0	$25.0

Note: Data sources and calculations used in this table are documented in Appendix 3

The Total Revenue Requirement is projected to decrease from $566.1 million in 2006 to $542.5 million in 2008, or by $23.6 million. The average retail revenue per MWh is projected to decline by about 7.7% from 2006 to 2008. Historical and forecasted average retail revenue is shown in Figure 2.1. The projected decrease is a result of the combined effects of revenue from customers declining by 4.2% at the same time that energy sales are expected to grow by 3.8%.

Figure 2.1
Average Retail Revenue in $/MWh



2.3.1 Net Power Costs

Net power costs are projected to decrease by $26.4 million from 2006 to 2008, an 18.2% decrease. The primary causes of this decrease are lower expenses for power purchased under long-term contracts excluding purchases from the Bonneville Power Administration (BPA), higher net revenues from short term wholesale power transactions and higher transmission revenues, which more than offset an increase in expenses for Bonneville power purchases.

- The forecast reflects the discontinuation of the Klamath Falls contract in July 2006, lowering purchased power costs by $23.9 million.
- In 2008 Lucky Peak purchased power expenses will decrease by $4.5 million when the debt service component of this contract is completely paid off.
- Net revenues from short-term wholesale surplus energy sales, because of their volatility, have a substantially different impact on revenue requirements in 2007 and 2008. They increase $52.5 million in 2007 but in 2008 drop back to a level that is only $12.7 million higher than the amount projected for 2006.
- Transmission revenues are estimated to be $3.4 million higher.
- These reductions in net power costs more than offset an $11.8 million increase in BPA power costs.

2.3.2 Non-Power O&M Costs

Non-power operating and maintenance expenses include costs related to distribution, customer accounting and advisory, conservation and administration and general costs.

Expenses in this category are projected to grow by $6.1 million from 2006 to 2008, a 5.0% increase.

- The largest portion of this growth will be in the administrative and general (A&G) expense category, which is projected to grow by $5.2 million or 10.9%. A&G cost is increasing primarily due to higher projected labor and labor benefits costs, City services cost allocations and significant increases in Seattle Municipal Tower rental rates charged to all City Departments. The A&G forecast also provides resources for improving security at City Light facilities to prevent unauthorized access and criminal activities that could cause significant system damage, power outages, and other related disruptions to the electrical system.
- Total distribution O&M expense is projected to increase by $0.5 million or 1.1%. By refocusing existing resources (about $3.2 million in 2007 and $4.4 million in 2008), City Light plans to increase its preventative tree trimming effort, which will improve service reliability and facilitate better customer service by reducing outages in both frequency and duration. This forecast allows City Light to catch up on tree trimming that was deferred by budget cuts in the early 2000s.
- All other categories are projected to increase at or below the rate of inflation for the rate period.

2.3.3 Debt Service Expense

Debt service expense is expected to decrease by $4.8 million or 3.4% from 2006 to 2008. This reflects increased funding of capital expenditures from current revenue as a result of more stringent financial policies, lower capital improvement program expenditures in years 2002 to 2004, and liquidation of the Bond Reserve Fund, which was replaced with a surety bond in 2005.

2.3.4 Other Cost Minus Other Revenues

There are a number of changes in revenues and expenses not included in the three major categories of revenue requirements, the net effect of which is to increase revenue requirements by $1.0 million between 2006 and 2008.

- Interest Income decreases by $3.2 million due to lower interest-earning cash balances.
- Other Revenues increase by $1.7 million mainly due to increases in account service charges and pole attachment rental fees that will take effect in 2007 when new customer retail rates take effect.
- Taxes and Contract Payments decrease by $0.9 million.

2.3.5 Additional Revenue Required to Meet Financial Targets

Revenue required to meet financial targets is expected to increase by $25.4 million from 2006 to 2007, then decrease by $25.0 million from 2007 to 2008. The financial policy that drives revenue required to meet financial targets during the rate period is that City

Light must have 95% confidence that current revenue is available to support capital requirements. This means that all other financial policies will be met or exceeded as well. Table 2.2 shows that City Light's debt service coverage is expected to be 2.26 in 2007 and 2.09 in 2008, which exceeds the minimum financial policy target of 2.0. Operating cash balances and contingency reserves are also projected to meet or exceed financial guidelines. Minimum operating cash balances are projected to be $76.9 million in 2007 and $30 million in 2008. In addition, the balance to be maintained in the operating contingency reserve is set at $25 million in both years, as stipulated by City Council resolution.

Chapter 3

Loads, Resources, Power Costs and Other Power-Related Revenue

3.1 Introduction

Chapter 1 indicated that one part of City Light's revenue requirements is Net Power Costs. Net Power costs equal Gross Power Costs less Gross Power Revenue and less Other Power-Related Revenues. This chapter presents critical details concerning Gross Power Costs, Gross Power Revenue from wholesale power sales, and power-related revenue from sources other than sale of power on the wholesale market. It also presents detailed information on transmission and wheeling costs and revenues.

Section 3.2 presents the forecast of retail loads, losses, power used in production, and other energy obligations, such as contractual obligations and seasonal exchange obligations. The total retail load, though, is the largest determinant of the amount of power resources required (accounting for 94 percent of the total Seattle system load) and reflects the load that is the billing quantity used to compute retail revenue.

Section 3.3 presents data on Power Supply available to meet total energy obligations. The current sources are City Light-owned hydro facilities, long-term purchase contracts, and short-term wholesale market purchases. This section also presents information on Power Costs. These costs cover Generation (production at City Light-owned hydro facilities), Purchased Power (both long-term purchase contracts and short-term purchases), Transmission (services provided by City Light), and Wheeling (transmission services purchased from others).

Section 3.4 presents data on revenue from short-term wholesale power sales, presented both gross and net of purchases of short-term wholesale energy. This section presents the forecast methodology used to project these revenues under conditions of uncertainty with regard to load, energy prices and water conditions. It also provides information regarding the sources of data for these projections, and describes how these projections are related to the Department's financial policies.

Section 3.5 presents information on other power-related revenues and revenue from transmission and related services.

3.2 Load Forecast

The load forecast reflects the projected demand from all customers in the utility's service area over the period 2006 to 2027. The forecast incorporates expected trends in the economic and demographic characteristics of the service area.

Table 3.1 presents three kinds of load data as well as system peak demand. The top part of the table shows projections of the expected values for use of MWh by type of retail customer plus the amount of energy used by the Department for its own use at its generation stations and energy losses suffered in serving retail customers. Total sales to customers account for 94 to 95 percent of total system load. The second portion of the table presents expected values for MWh sales by major customer rate classes. The third portion of the table adds MWh data on other obligations the Department has for energy as well as amounts of energy expected to be available to sell on the wholesale market creating the total expected energy to be disposed. The bottom portion of the table presents the system peak demand (MW).

The table presents data currently in the model for the years 2006 through 2016. The expected value of Seattle System Load is forecast to increase at an annual average rate of 0.9 percent from 2006 to 2016. This forecast assumes the continuation of conservation throughout the forecast horizon. The conservation program is discussed in Chapter 5.

There is, of course, uncertainty in the annual forecasts. Due to weather and business conditions, usage of power can vary significantly from year to year. Section 3.4 of this chapter will discuss how the uncertainty associated with the generation and usage of power and the price at which it can be purchased and sold in the short-term wholesale power market is handled in the Financial Planning Model.

Residential load, which currently accounts for about 33 percent of total energy sales to customers, is expected to increase at an annual average rate of 0.6 percent over the 2006-2016 period, mostly as a result of the growth in multi-family dwellings.[2] Very little increase is expected in the number of single-family dwellings. The average household size is projected to decline as a result of the increase in the proportion of multi-family housing units, which normally house smaller households.

Commercial and government customers account for about 53 percent of total energy sales to customers, a share that is projected to increase as a result of the rapid growth in these sectors. Commercial load is projected to increase at an annual average rate of 1.2 percent over the 2006-2016 period and government load growth is projected at 1.6 percent. Diversification in the local economy has helped to mitigate the impact of variations in Boeing employment levels, but these are still capable of causing fluctuations in the demand for energy in City Light's service area.

Industrial customers currently account for about 14 percent of total energy sales to customers in the service area, a share that is expected to slightly diminish over the next several years due to slower projected load growth than that of the other customer classes.

[2] There is a small difference in the residential load in the top and middle sections of Table 3.1. This difference is caused by different ways to distribute the total retail load for the two different purposes. The difference is not materially significant.

Table 3.1
System Load by Type of Use, Sales by Rate Class, and Disposition of Energy, MWH

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Seattle System Load (MWh)	9,861,410	10,042,294	10,236,300	10,345,567	10,460,494	10,527,036	10,626,442	10,653,479	10,690,615	10,724,324	10,802,962
Sales by Type											
Energy Sales to Customers	9,324,653	9,496,232	9,677,386	9,783,960	9,892,995	9,956,104	10,047,364	10,076,086	10,111,310	10,143,299	10,214,813
Residential	3,125,307	3,179,516	3,246,443	3,273,752	3,280,524	3,284,482	3,297,747	3,291,870	3,294,429	3,296,814	3,307,779
Commercial	3,876,631	3,939,847	4,020,724	4,081,665	4,157,924	4,200,844	4,255,067	4,281,075	4,306,330	4,329,376	4,372,897
Governmental	1,050,644	1,094,408	1,118,458	1,136,636	1,160,635	1,174,727	1,194,054	1,203,699	1,210,600	1,217,255	1,226,238
Industrial	1,272,071	1,282,461	1,291,761	1,291,907	1,293,913	1,296,051	1,300,496	1,299,443	1,299,951	1,299,854	1,307,899
Own Use + Losses	536,757	546,062	558,914	561,607	567,499	570,932	579,078	577,393	579,305	581,025	588,149
Sales by Rate Class											
Sales to Customers	9,324,653	9,496,232	9,677,386	9,783,960	9,892,995	9,956,104	10,047,364	10,076,086	10,111,310	10,143,299	10,214,813
Residential Service	3,118,337	3,172,459	3,239,278	3,266,543	3,273,303	3,277,255	3,290,499	3,284,631	3,287,187	3,289,568	3,300,515
Small General Service	1,180,812	1,203,007	1,228,236	1,247,281	1,271,266	1,284,926	1,302,349	1,310,784	1,318,722	1,325,970	1,339,230
Medium General Service	2,302,982	2,351,396	2,399,253	2,435,545	2,482,191	2,510,060	2,546,162	2,564,234	2,580,526	2,595,114	2,620,665
Large General Service	1,492,548	1,520,705	1,548,099	1,566,605	1,590,396	1,603,824	1,621,966	1,629,959	1,637,298	1,644,026	1,659,124
High Demand General Service	1,135,059	1,153,750	1,167,605	1,173,071	1,180,923	1,185,124	1,191,472	1,191,562	1,192,662	1,193,707	1,200,363
Street and Flood Lights	94,915	94,915	94,915	94,915	94,915	94,915	94,915	94,915	94,915	94,915	94,915
Disposal of Energy											
Seattle System Load	9,861,410	10,042,294	10,236,300	10,345,567	10,460,494	10,527,036	10,626,442	10,653,479	10,690,615	10,724,324	10,802,962
Article 49 Sales to PO County	370,022	370,024	371,037	369,997	369,978	369,978	370,845	369,990	369,998	369,997	371,017
Other Obligations	160,966	173,402	169,387	169,270	209,099	207,713	206,335	205,321	204,884	204,822	204,184
Sales to Power Market	3,597,031	4,276,431	4,057,276	4,025,004	4,007,483	3,941,359	3,872,953	3,820,966	3,785,728	3,750,900	3,725,837
Expected Energy Disposed	13,989,430	14,862,150	14,833,999	14,909,837	15,047,056	15,046,087	15,076,574	15,049,756	15,051,225	15,050,043	15,103,999
Peak Demand (MW)	2,026	2,063	2,098	2,126	2,149	2,163	2,178	2,189	2,197	2,204	2,214

Industrial load is expected to increase at an average annual rate of only 0.3 percent over the period 2006 through 2016. The number of large industrial customers in the utility's service area is expected to remain largely unchanged, but industrial output is expected to increase in response to local and national economic growth. Each one of the major industrial sectors is dominated by a small number of large firms.

The forecast of own use of energy is based on historical consumption and currently accounts for about 0.3 percent of total system load. This amount, equivalent to about 3.5 average MW annually, is anticipated to remain virtually unchanged in the forecast years.

The load forecast must also incorporate an estimate of losses, i.e., the energy lost in the transmission and distribution system during the process of delivering power from the generating sources to the customers. (These losses are combined with own use in Table 3.1). The assumption in the forecast is that losses will be equal to 5.1 percent of total system load. Losses in the past have fluctuated around this number.

The second portion of Table 3.1 shows annual projected consumption by customer class. Though not in this table, the annual load forecast is disaggregated into monthly load projections by rate classes using historical data on monthly profiles. A monthly revenue model predicts energy sales to customers by month and by rate class and is an integral part of the financial planning model.

In addition to retail sales and own use, the Department has several other, small, obligations to deliver energy. The third portion of Table 3.1 indicates the required wholesale sales per Article 49 of a contract with Pend Oreille County PUD. There also are some exchanges of energy with City Light's obligations to other utilities listed under Other Obligations. At this time, under expected water conditions, the Department will have a surplus, on an annual basis, of energy after all the preceding uses and obligations of energy are considered. The surplus in the past and the expected surplus in the future are available for sale to the wholesale power market.

The forecast of energy sales described above reflects the total number of megawatt hours demanded by customers in each year. Demand for electricity varies by time of day, day of the week and season of the year. The Department must be capable of meeting the highest quantity demanded by its customers at each moment and thus must have the distribution capacity and the power required during the peak period, which normally occurs in the winter. The forecast of energy required in the 16-hour peak period of each winter is shown at the bottom of Table 3.1. The units are in average megawatts during the 16-hour period for the winter beginning the year listed. This peak period is defined as the 16 hours of highest consecutive load in the month of January.

3.3 Power Supply

City Light derives energy to supply its obligations from two main sources: its own hydro facilities and long-term purchase contracts. Short-term and spot market wholesale purchases are also used. This section focuses on power supply and includes pertinent details about cost considerations.

3.3.1 Owned Hydroelectric Resources

For planning purposes, City Light assumes that energy available from its hydro resources in any planning year will be equal to the average that would be realized under water conditions that can be expected to be exceeded 57% of the time. This amount is calculated by taking the average of the outputs of 2001 scenarios run by a simulation model that produces a range of results that reflect forecast assumptions about uncertainty with regard to water conditions. The methodology for developing this projection of generation is described in section 3.4 of this chapter. FPM Table 1.09, in Appendix 1, shows City Light's actual generation for past years and projected levels for future years. Currently City Light owns seven hydroelectric projects. Expected generation from these hydro resources is about 726 average MW in 2006.

All resources built after passage of the Federal Power Act of 1920 must be licensed by the Federal Energy Regulatory Commission (FERC). Cedar Falls, built in 1905, is the only hydro project owned by City Light that is not licensed by FERC.

The following paragraphs describe the Department's owned resources.

3.3.2 Boundary

The Boundary Project is located on the Pend Oreille River in northeastern Washington near the Canadian and Idaho borders, approximately 250 miles from Seattle. The plant was placed in service in 1967. It has a one-hour peak capability of 1,005 MW and expected energy output of 3.9 million MWh under expected water conditions. The Boundary Project is operated under a Federal Energy Regulatory Commission (FERC) license which expires on October 1, 2011. The Department plans to apply for renewal of its Boundary license. The most recent FERC-mandated independent safety inspection in August 2000 concluded that the dam facilities were in good condition.

The Boundary Project's FERC license requires that up to 48 MW of the Boundary Project's capacity be assigned, at cost, to Public Utility District No. 1 of Pend Oreille County (Pend Oreille PUD). The energy delivered to the Pend Oreille PUD equals the PUD's average load factor multiplied by the capacity assigned. Due to Pend Oreille PUD's increasing loads and other contractual requirements, the amount of Boundary Project power assigned to Pend Oreille PUD increased to the maximum allowable associated with 48 MW of capacity in August 2005.

3.3.3 Skagit

Ross, Diablo, and Gorge Projects are located on the Skagit River. These projects taken together produce 2.3 million MWh under projected water conditions. These three projects are operated as a single system. Ross Dam is a major water storage reservoir.

Water released from Ross Dam flows through the Diablo and Gorge projects, located downstream from Ross Dam. The Federal Energy Regulatory Commission approved the Department's application to relicense the Skagit projects in 1995. The first license for these projects was issued in 1927. The conditions for the new license include some restrictions on the stream flows to protect fish populations as well as mitigation measures to ensure the preservation of wildlife habitat and historical sites and the maintenance of recreation facilities. These measures are known collectively as the Skagit Mitigation package. They are the result of agreements with state and federal regulatory agencies, native tribes, and other interveners to deal with fisheries, wildlife, erosion control, archeology, historic buildings, recreation and visual quality. The Skagit Mitigation package includes expenditures over the thirty-year life of the new license. There are three kinds of expenditures in this package: (1) operation and maintenance expenditures, capital expenditures, and (3) payments to other entities. Each of these costs is treated differently.

Operation and maintenance expenditures associated with the Skagit Mitigation package are included in the forecast of operation and maintenance expenses. They include the operation and maintenance of fish ponds and ladders, elk habitat improvement and monitoring, wildlife research and education projects, vegetation management, a part-time gardener, some staff positions for wildlife and fisheries management, and costs of maintaining historic properties in the area.

Capital expenditures for the Skagit Mitigation package are for acquisition of land for wildlife habitat, a research center, a greenhouse, an Environmental Education Center, rehabilitation of the Gorge Inn, and other items. The capital expenditures are included as part of the Department's Capital Improvement Program, described in Chapter 5, and are part of the generation CIP expenditures shown in FPM Table 1.03 of Appendix 1.

Payments to other entities include payments to a Tribal Activity Fund, payments for a Recreation Program Endowment Fund, contributions to upgrade and rehabilitate recreation areas (such as trails, overlooks, and boat ramps) and payments to the U.S. Forest Service to enhance wildlife habitat and fish populations. The largest part of these payments ends by the year 2010. These payments are deferred and amortized over the 30-year life of the new license. The payments are neither part of operation and maintenance expenses nor of the capital program. They are identified as deferred costs because they are spread over a number of years. They are shown as part of Deferred Costs in the top portion of FPM Table 1.03 in Appendix 1. They are included in the total funds used by the Department and affect the revenue required in future years through their impact on borrowing. The amortization of these payments, which may be seen in FPM Table 1.04, has no impact on revenue required but affects net earnings.

3.3.4 Cedar Falls/Newhalem

Cedar Falls and Newhalem Projects together provide 10.6 average MW of expected energy. These projects were built in 1905 and 1921 respectively. The Newhalem Project was enhanced in 1970. There is no large expenditure in the current Capital

Improvements Program (CIP) for the enhancement of plant and equipment for these plants.

3.3.5 South Fork of the Tolt

The South Fork of the Tolt Project came on line in November 1995. This project uses the hydroelectric potential of the Seattle Water Department municipal water supply dam, located northeast of Carnation. Under expected water conditions it provides 6.5 average MW.

3.3.6 Purchased Resources

City Light has several long-term contracts to buy power from other utilities. Data are presented in Table 3.3, below, along with related discussion. In 2005, City Light purchased approximately 50 percent of its total available system energy from long-term contracts. Several contracts specify the amounts of energy that City Light will buy from these utilities over the year. Others provide City Light a share of the output from resources in exchange for sharing costs. The largest purchase is from the Bonneville Power Administration (BPA). This contract contains provisions for buying both a fixed amount and also a share of output. Under expected water conditions in 2007, for example, BPA will provide about 82 percent of the 7.4 million MWh of total long-term purchased power. The following sections describe existing firm power contracts, including a brief mention of resources whose contracts have ended recently.

3.3.7 Bonneville Power Administration

Bonneville markets power from 30 federal hydroelectric projects, from several non-federally-owned hydroelectric and thermal projects in the Pacific Northwest and from various contractual rights with installed peak generating capacity of 24,080 MW and a firm energy capability of approximately 8,500 average MW (the “Federal System”). These 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 approximately 45 percent of the region’s energy requirements. Bonneville’s transmission system includes over 15,000 circuit miles of transmission lines, provides about 75 percent 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 ten million. Bonneville sells electric power at cost-based wholesale rates to about 130 utility and governmental customers in the Pacific Northwest. Bonneville also sells power directly to three industrial customers in the region. Bonneville is required by law to give preference to government-owned utilities and to residential customers in the Northwest region in its wholesale power sales.

A Block and Slice Power Sales Agreement with Bonneville provides for purchases of power by City Light over the ten-year period beginning October 1, 2001. Under the contract, power is delivered in two forms: a shaped block (the “Block) and a Slice.

Through the Block product, power is delivered to the Department in stipulated monthly amounts. The original contract provided for delivery of 163.8 average MW annually as a Block for the period from October 1, 2001 through September 30, 2006, and 278.2 average MW from October 1, 2006 through September 30, 2011. The amount of Block power available to the Department has been reduced by 41 average MW since the inception of the contract, pursuant to agreements with Bonneville through which Bonneville purchases energy savings realized by the Department's conservation programs. The Department's entitlement to Block power is reduced by the amount of savings purchased. Through December 31, 2005, the Department has received nearly $44.2 million in payments from Bonneville for conservation savings and expects to receive an additional $4 million in 2006.

Under the Slice product, the Department receives a fixed 4.6676 percent of the actual output of the Federal System and pays the same percentage of the actual costs of the system. Payments for the Slice product are subject to an annual true-up adjustment to reflect actual costs. Power available under the Slice product varies with water conditions, federal generating capabilities and fish and wildlife restoration requirements. Under the most recent estimates of the capability of the Federal System, energy available to the Department through the Slice product is expected to average 443 MW over all water conditions. Under critical water conditions, the slice product provides 334 average MW of energy. The revenue requirement forecast assumes water conditions that would be exceeded 57% of the time, and this results in a Slice product forecast of 433 average MW in 2007 and 429 average MW in 2008.

BPA CRACs and Slice True-Up

Bonneville's Record of Decision established fees and charges for the first five years of the contract effective October 1, 2001. Bonneville's Record of Decision also included a Cost Recovery Adjustment Clause (CRAC) which authorized Bonneville to increase its power rates under certain stipulated conditions in the first five years of the contract.

The second five years of the ten-year contract began October 1, 2006. Final decisions on base rates and initial CRACs to be applied to those base rates were announced in the summer of 2006. No CRACs are currently proposed.

In addition to paying rates that include the CRAC adjustments, the Department also makes or receives a Slice true-up payment to reconcile the difference between actual Slice costs and the estimates on which the Slice Load-Based CRAC were based. The Department paid $10.4 million in 2003, received a Slice true-up credit of $6.4 million in 2004, paid $2.1 million in 2005 and $8.9 million in 2006 and expects to make a true-up payment of $11.5 million in 2007. Recently, BPA and Slice customers reached a settlement over questions of Slice costs in the first several years of the contract. BPA will return payments, plus interest, because Slice customers paid more than final cost calculations indicated were appropriate. City Light will receive a credit of about $5.4 million.

BPA Block Purchases

The Department and BPA negotiated revisions to the delivery of Block power in light of several amendments to the initial contract that called for the Department to provide conservation savings. Additionally, starting in October 2006, the second five-year block of the ten-year contract, the Department contracted to increase its take of BPA Block power. Table 3.2 indicates the monthly average MW of Block power through the year 2008. The amounts each month are currently contracted to stay the same as in 2008 through September 2011.

Table 3.2
BPA Block Power by Month (MW)

	2001	2002	2003	2004	2005	2006	2007	2008
Jan		221	215	222	222	222	380	380
Feb		218	211	218	218	173	373	373
Mar		218	212	219	219	219	372	372
Apr		162	109	132	139	133	105	75
May		67	0	0	0	0	0	0
Jun		0	0	0	0	0	0	0
Jul		42	51	0	0	0	126	126
Aug		95	111	0	0	114	238	238
Sep		177	208	215	119	215	360	360
Oct	219	212	219	219	154	275	230	230
Nov	218	211	218	218	124	371	371	371
Dec	216	209	216	216	127	371	371	371

Average Cost of BPA Power

The unit cost of power purchased under the Bonneville contract in 2005 was $30.36 per MWh based on expenses booked that year and MWh received. City Light's projections of future expenses for BPA power are based on Bonneville's new rates effective October 1, 2006 and Bonneville's current forecast of CRAC adjustments and Slice true-up payments through September 30, 2011. City Light's financial forecast assumes that the rates in effect in the twelve months ending September 30, 2009 will continue through the remainder of the contract period.

3.3.8 Energy Northwest (formerly known as the Washington Public Power Supply System)

The City is a member of Energy Northwest, a municipal corporation and joint operating agency organized under State law that currently has, as members, ten public utility districts and three municipalities, all located within the State. Energy Northwest has the authority to acquire, construct and operate plants, works and facilities for the generation and transmission of electric power.

Energy Northwest was engaged in the construction of five nuclear generating facilities termed Projects Nos. 1, 2, 3, 4, and 5. Project No. 2 was placed in commercial operation in December 1984 and the other projects were terminated in the 1980s. Pursuant to separate Net Billing Agreements with Energy Northwest and Bonneville with respect to Projects Nos. 1, 2 and 3 (the "Net Billed Projects"), City Light is obligated unconditionally to pay Energy Northwest its pro rata share of the total annual costs of the Net Billed Projects, including debt service. The payments are required to be made whether or not construction is completed, delayed or terminated, or operation is suspended or curtailed. Payment by Bonneville to Energy Northwest of City Light's share of its total annual cost of the Net Billed Projects is made by a crediting arrangement whereby Bonneville credits against amounts that the Department owes Bonneville for the purchase of wholesale power an amount equal to City Light's share of the total annual cost of each Net Billed Project. The agreements provide that the Department purchase from Energy Northwest and, in turn, assign to Bonneville a maximum of 8.605 percent, 7.193 percent and 5.043 percent of the capability of Projects Nos. 1 and 2 and Energy Northwest's ownership share of Project No. 3, respectively. The Department's respective shares may be increased by not more than 25 percent upon default of other public agency participants. To the extent that City Light's share of such annual costs exceeds amounts owed by City Light to Bonneville, Bonneville is obligated, after certain assignment procedures, to pay the amount of such excess to City Light as reimbursement or to Energy Northwest directly, but only from funds legally available for that purpose.

Under the Net Billing Agreements, City Light's electric revenue requirements are not affected directly by the cost of completion or termination of the Net Billed Projects, but such revenue requirements may be affected to the extent that the costs of such Projects result in increases in the wholesale power rates of Bonneville. Bonneville has been paying principal of and interest on Project No. 1 revenue bonds since 1980, on Project No. 2 revenue bonds since 1977 and on Project No. 3 revenue bonds since 1982. Bonneville, in projecting its revenue requirements and wholesale power rates, includes in its estimate the principal of and interest on those bonds issued and projected to be issued and Energy Northwest's operating expenses for the Net Billed Projects.

3.3.9 Klamath Falls Cogeneration Project

An agreement with the City of Klamath Falls, Oregon, provided for the purchase of energy and capacity from Klamath Falls Cogeneration Project, a 500 MW cogeneration facility consisting of a combined-cycle combustion turbine fueled by natural gas. Under the contract, City Light received 100 MW of capacity from the project for the five-year period ending in July 2006. Energy generation in 2005 was 581,497 MWh. City Light decided not to renew this contract because anticipated costs of output exceeded expected market prices.

3.3.10 Lucky Peak Hydroelectric Power Plant

The Lucky Peak Hydroelectric Power Plant (Lucky Peak) 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 rated capability of the three generating units at the plant is 101 MW.

Energy generation in 2005 was 226,256 MWh. Since generation is concentrated in the summer months, the plant has no peak capability during City Light's winter peak period.

City Light entered into a 50-year power purchase and sales contract in 1984 with the Districts under which City Light will purchase all energy generated by Lucky Peak, in exchange for payment of costs associated with the plant and royalty payments to the Districts. City Light also signed a transmission services agreement with Idaho Power Company (Idaho Power) to provide for transmission of power from Lucky Peak to a point of interconnection with the Bonneville system. City Light sold the actual net output of the plant for the period from May 1, 2003, through November 30, 2004, at a price equal to the Dow Jones Mid-Columbia index plus $3.25 per MWh. City Light sold the actual output of the plant in calendar year 2005 at a price of $52 per MWh. City Light has sold the output again, in calendar year 2006, at a contract price of $78.75/MWh multiplied by stipulated monthly factors for high load and low load hours (ranging from a low of 0.66 for low load hours in April and May to a high of 1.34 for high load hours in August).

3.3.11 Priest Rapids Hydroelectric Plant

Under an agreement effective through October 31, 2005, City Light received eight percent of the output of the Priest Rapids Development (Priest Rapids). The Priest Rapids Development and the Wanapum Development jointly constitute the Priest Rapids Project, which is owned and operated by Public Utility District No. 2 of Grant County (Grant PUD). The Priest Rapids Development has an installed capacity of 855 MW. City Light's share of Priest rapids generation in 2005 was 288,329 MWh.

In 1995, certain Idaho and Snake River cooperatives filed a complaint with FERC in which they sought entitlement to allocation of power from Priest Rapids under any new license. FERC ruled in 1998 that, effective November 1, 2005, 70 percent of the Priest Rapids Project's output would be allocated to the licensee. The remaining 30 percent would be available for sale pursuant to market-based principles to entities in the broad seven-state Northwest region, while giving certain Idaho cooperatives and the current power purchasers a priority right. FERC also issued an order permitting any entity, not just Grant PUD or another Washington public agency, to file a competing license application. These proceedings could impact the amount of power generated at Priest Rapids and City Light's allocation of power upon expiration of the current contract.

Contracts executed in 2002 with Grant PUD provide for the allocation of power and other benefits from the Priest Rapids and Wanapum Developments to City light over the period from November 1, 2005, through the end of the new FERC license period. Under the terms of these contracts the Department will purchase a share of the firm and non-firm power allocated to Grant PUD that is surplus to the PUD's load requirements. The amount of power available from Grant PUD under these provisions will decline over time as the PUD's load, and therefore its claim on the 70 percent of the Priest Rapids Project's output that is allocable to the PUD, increases. In addition, the Department has contracted, for the first four years of the contract, to receive a share of the net revenue derived from the sale of the 30 percent share of the Priest Rapids Project's output that will be sold pursuant to market-based principles in the seven-state Northwest region under the terms of the FERC order. The Yakama Indian Nation has filed a petition with FERC challenging the new contracts signed by Grant PUD.

3.3.12 Grand Coulee Project Hydroelectric Authority

City Light, in conjunction with the City of Tacoma, Department of Public Utilities, Light Division (Tacoma), has power purchase agreements with three Columbia Basin irrigation districts for 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 and have a total installed capacity of approximately 129 MW. 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. In 2005 the Department received 249,331 MWh from the project.

3.3.13 Box Canyon Hydroelectric Plant

City Light previously purchased power from the Box Canyon Hydroelectric Plant (Box Canyon) owned and operated by Pend Oreille PUD. The purchase contract, which ended August 1, 2005, provided the Department with 25,874 MWh of energy in 2005.

3.3.14 West Point Sewage Treatment Plant Cogeneration

In 1982, the Municipality of Metropolitan Seattle ("Metro," now part of King County) and City Light executed a contract for the purchase of the electrical output of a cogeneration plant located at the County's West Point Sewage Treatment Plant. The Department's contract with Metro expired on August 31, 2003 but was extended through September 2004. Metro plans to supply most of its own requirements for electrical power from an expanded cogeneration plant at West Point and is likely to rely on the Department only for back-up power. The Department does not now expect to purchase power from Metro.

3.3.15 Wind Generation

An October 2001 agreement with PacifiCorp Power Marketing provides for City Light's purchase of wind-generated energy and associated environmental attributes (such as offsets or emission reduction credits) primarily from the State Line Wind Project in eastern Washington and Oregon. Under the agreement, City Light received wind energy with an aggregate maximum delivery rate of 50 MW per hour from January 1, 2002, through July 31, 2002, 100 MW per hour from August 1, 2002, through December 31, 2003, and 125 MW per hour from January 1, 2004, through June 30, 2004. From July 1, 2004, through the end of the contract on December 31, 2021, the maximum delivery rate will be 175 MW per hour. Energy delivered under the contract is expected to average about 30 percent of the maximum delivery rate. In 2001, City Light also entered into a ten-year agreement to purchase integration and exchange services from PacifiCorp and a

20-year agreement to sell integration and exchange services to PPM. City Light has not sold these services to PPM since the beginning of 2004, however, because all of the State Line Wind Project's energy is now fully subscribed to purchasers under long-term contracts, including Seattle, so there is no longer any surplus available for PPM. City Light received 327,302 MWh of wind energy under the PPM contract in 2005.

3.3.16 High Ross

In 1984, an agreement was reached between the Province of British Columbia and the City under which British Columbia provides City Light with power equivalent to that which would have resulted from an addition to the height of Ross Dam. The agreement was ratified through a treaty between Canada and the United States in 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 cost 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. City Light received 310,246 MWh of energy from this resource in 2005.

3.3.17 Seasonal Exchange

In addition to its firm power contracts, City Light has seasonal exchange contracts with other utilities, which allow both utilities to shape resources to fit the demand from their customers. These exchanges usually involve exchanges of energy, and sometimes cash payments, resulting in costs or revenue to City Light. Other utilities (especially those in the Southwest) have load or resource profiles that are the reverse of City Light's, with peak demand in the summer. Therefore, exchange agreements with these utilities are beneficial to both parties. At this time, only one seasonal exchange agreement, with the Northern California Power Authority (effective 1995), remains in effect.

3.3.18 Selected Power Summary Data

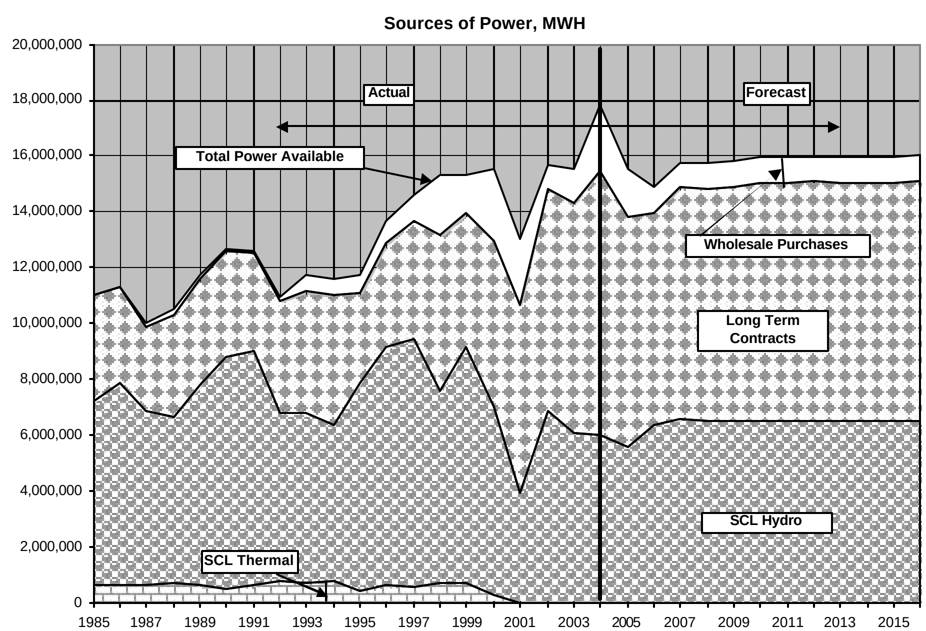
Power Data

Table 3.3 presents projections through 2016 of expected energy from the various energy sources. Figure 3.1 presents a summary of those data with twenty years of history. The historical data indicate there is significant volatility in the output of City Light hydro facilities. Several of the long-term contracts also subject City Light to taking shares of output from hydro facilities whose energy output fluctuates with water availability. Section 3.4 of this chapter presents information on revenue from wholesale power sales. As indicated above, a critical aspect of that revenue is that it is variable for several reasons, one of which is variability in output from hydro resources. Data regarding the future in Table 3.3 and Figure 3.1 represent expected values of output within a range of uncertainty.

Table 3.3
Sources of Power, MW

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total Energy Available	13,989,430	14,862,149	14,834,001	14,909,837	15,047,056	15,046,086	15,076,575	15,049,755	15,051,225	15,050,042	15,103,999
SCL Generation, Total	6,362,486	6,564,968	6,536,322	6,515,602	6,517,299	6,515,198	6,522,583	6,514,838	6,516,171	6,515,602	6,535,349
Total Purchases	7,626,944	8,297,181	8,297,679	8,394,235	8,529,757	8,530,888	8,553,992	8,534,917	8,535,054	8,534,440	8,568,650
Long Term Contracts	6,712,387	7,421,181	7,406,950	7,507,615	7,628,146	7,624,439	7,639,527	7,617,747	7,615,058	7,610,589	7,630,900
BPA	5,153,629	6,070,558	6,055,430	6,034,951	6,033,686	6,033,736	6,048,777	6,035,871	6,035,815	6,034,951	6,053,351
Box Canyon	0	0	0	0	0	0	0	0	0	0	0
Priest Rapids	19,226	19,805	19,805	144,215	265,234	261,904	260,038	254,259	250,994	247,189	245,285
High Ross Contract	310,246	310,246	310,246	308,747	309,318	309,138	309,768	308,317	308,437	308,747	310,947
Grand Coulee	234,322	240,018	240,018	240,018	240,018	240,018	240,018	240,018	240,018	240,018	240,018
Lucky Peak	275,083	288,857	288,970	288,857	288,857	288,857	288,970	288,857	288,857	288,857	288,970
Klamath Falls	231,160	0	0	0	0	0	0	0	0	0	0
Wind Resources	380,025	382,985	383,771	382,895	383,075	382,828	383,880	383,012	383,005	382,895	383,593
Seasonal Exchange Received	108,696	108,712	108,710	107,932	107,958	107,958	108,076	107,413	107,932	107,932	108,736
Purchases from Power Market	914,557	876,000	890,729	886,620	901,611	906,449	914,465	917,170	919,996	923,851	937,750

Figure 3.1



Energy Cost Data

Power costs include the costs of energy production (generation), purchased power, other power-related costs such as control and dispatch, transmission (provided by City Light), and wheeling (transmission services provided by others, primarily Bonneville). Table 3.4 presents the costs of energy for 2006 through 2016. This table also includes Seattle retail load and Total System requirements that include Seattle retail load, losses, energy sold on wholesale markets and other energy obligations as indicated in Table 3.1. Figure 3.2 illustrates twenty years of history and the forecast of power costs associated with the data in Table 3.4. This figure shows clearly the unprecedented explosion of costs for wholesale purchases in 2001 associated with the meltdown of the wholesale power market in California. Figure 3.3 illustrates net power costs as the residual of total power costs less offsetting revenue.

Figure 3.4 illustrates the net unit cost per MWh for power. Two versions of net cost per MWh are presented. One version is derived by dividing the total net cost of power illustrated in Figure 3.4 by Seattle retail sales. Retail sales, though a large fraction of the total amount of power handled in order to serve the retail sales, are still only a fraction of all MWh disposed (retail sales, losses, wholesale market sales, serving other obligations). Hence the other version of cost per MWh is derived by dividing total net costs by total MWh. This version of net cost per MWh is, of course, lower than the unit net cost based only on service to retail sales. In both cases it is clear there was a surge in unit costs of energy from the wholesale market when the California experiment in wholesale energy markets failed.

Figure 3.5 illustrates the cost per MWh of power from different elements. The net total cost of power in Figure 3.5 is the same as net total cost in Figure 3.4. Average short-term wholesale market cost equals cost of short-term wholesale purchases divided by MWh of purchases from the short-term wholesale market. Average cost of long-term contracts and seasonal exchange equal their cost divided by MWh from those sources. The other cost or offsetting revenue per MWh elements equal their costs in Table 3.4 divided by total MWh. Figure 3.5 truncates the ordinate to emphasize the costs in the deeper history and in the forecast. It is obvious that the cost per MWh for short-term wholesale market purchases surged off the figure in 2000 and 2001.

3.3.19 Transmission and Wheeling Costs

Table 3.5 summarizes the forecast of costs for City Light's own transmission services and costs for purchases of transmission services purchased from others (i.e., wheeling). Figure 3.6 illustrates these transmission and wheeling costs along with twenty years of history. Table 1.11 in Appendix 1 presents the forecast for these expenses in slightly more detail.

The Department operates 656 miles of transmission facilities. The principal transmission line transmits power from the Skagit Project to City Light's service area. In 1994, City light signed an agreement with Bonneville for the acquisition of ownership rights to 160

Table 3.4
Energy Cost Data ($1,000)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Wholesale Market Purchases [1]	54,897	51,500	46,949	33,832	36,447	38,190	40,322	44,156	49,873	49,782	57,217
Other Power Related Purchases:											
Bonneville [2]	161,548	184,514	173,341	173,109	173,111	174,965	182,919	182,712	182,718	184,687	193,819
Priest Rapids	1,551	1,629	1,629	2,293	3,803	3,748	3,709	3,630	3,567	3,513	3,473
GCPHA	3,400	4,017	4,122	4,046	4,560	4,397	4,153	4,190	4,227	4,266	4,305
High Ross	13,281	13,391	13,399	13,398	13,405	13,413	13,421	13,429	13,437	13,446	13,454
Lucky Peak [3]	15,570	16,863	11,114	5,177	5,258	5,350	5,480	5,613	5,750	5,889	6,032
Klamath Falls	23,915	0	0	0	0	0	0	0	0	0	0
State Line Wind Project	14,624	15,222	15,240	14,954	14,954	14,954	15,005	14,965	14,965	14,965	15,006
Integration/Exch of Wind Resources	4,781	4,961	5,031	5,068	5,138	5,225	2,824	2,893	2,963	3,035	3,109
Seasonal Exchange Received	2,885	2,941	3,004	3,073	3,151	3,241	3,331	3,428	3,529	3,638	3,751
Power Related Wholesale Purchases [4]	534	548	563	578	-926	-1,029	-1,106	-1,222	-1,443	-1,404	-1,600
BPA Billing Credits [5]	-3,066	-3,044	-3,004	-3,230	-3,313	-3,407	-3,407	-3,407	-3,407	-3,407	-3,407
SUBTOTAL	239,023	241,042	224,440	218,464	219,141	220,856	226,331	226,230	226,307	228,627	237,942
Production:											
Hydro Projects [6]	19,419	21,109	21,722	21,243	21,802	22,390	23,926	24,538	25,173	25,831	26,515
Other Production Costs [7]	7,708	7,908	8,122	8,341	8,549	8,772	8,991	9,216	9,446	9,682	9,924
Subtotal	27,127	29,017	29,843	29,584	30,352	31,162	32,917	33,754	34,619	35,513	36,439
Transmission & Wheeling:											
Transmission	5,777	5,861	5,958	6,126	6,277	6,437	6,595	6,757	6,923	7,093	7,268
Wheeling	37,867	39,862	39,589	41,560	42,617	43,671	44,735	45,821	46,934	48,074	49,242
SUBTOTAL	43,644	45,723	45,547	47,686	48,894	50,108	51,330	52,578	53,857	55,168	56,510
Total Power Supply & Trans. Expense	364,691	367,282	346,779	329,567	334,834	340,315	350,899	356,718	364,656	369,089	388,108
Minus Offsetting Power & Trans. Revenue:	223,369	273,798	231,682	163,060	169,682	173,697	171,379	186,015	208,745	201,026	226,704
Wholesale Power Sales	192,007	241,099	196,747	136,903	143,030	147,818	148,923	163,028	185,238	176,962	202,057
Other Power Sales [8]	29,495	29,423	29,649	21,920	22,265	21,318	17,738	18,112	18,509	18,920	19,352
Transmission Sales	1,868	3,276	5,286	4,237	4,388	4,561	4,718	4,874	4,998	5,144	5,295
Net Cost of Power [9]	141,322	93,485	115,097	166,507	165,152	166,618	179,519	170,704	155,911	168,063	161,404
Total Energy Requirement (MWh) [10]	13,989,430	14,862,150	14,833,999	14,909,837	15,047,056	15,046,087	15,076,574	15,049,756	15,051,225	15,050,043	15,103,999
Seattle System Load (MWH) [11]	9,861,410	10,042,294	10,236,300	10,345,567	10,460,494	10,527,036	10,626,442	10,653,479	10,690,615	10,724,324	10,802,962
Average Cost for Total Energy ($/MWh) [12]	$ 10.10	$ 6.29	$ 7.76	$ 11.17	$ 10.98	$ 11.07	$ 11.91	$ 11.34	$ 10.36	$ 11.17	$ 10.69
Average Cost, Seattle System ($/MWh) [13]	$ 14.33	$ 9.31	$ 11.24	$ 16.09	$ 15.79	$ 15.83	$ 16.89	$ 16.02	$ 14.58	$ 15.67	$ 14.94

(1) Purchases to compensate for low water conditions and to make up the difference between loads and resources. Excludes wheeling costs.

(2) From 2003 through 2006 the forecast assumes the CRAC adjustments projected by Bonneville. Effective October 1, 2006, Block purchases from Bonneville will increase by 114.4 MW under the terms of the power sales contract.

(3) The cost of power from the Lucky Peak Project decreases in 2008 and 2009 as the bonds issued to finance construction of the Project are retired.

(4) Includes: (a) Basis, Storage & Load Factoring, Ross Overdraft contract, etc, (b) Encroachment on Box Canyon, (c) Entitl/Supp Capacity, (d) Interchange Received [Exludes Deferred Expenses]

(5) Billing credits received from Bonneville for the South Fork Tolt Project.

(6) Includes operations and maintenance costs plus Water for Power costs

(7) (a) Control & Dispatch, (b) Greenhouse Gas Mitigation, (c) Other Energy Costs

(8) Includes sales to Pend Oreille PUD under Article 49 of the Boundary Project license, seasonal exchange delivered, and other energy credits.

(9) Net Power Costs in Table 2.2 in Chapter 2 include amortization of the following items: BPA payments for conservation, High Ross expenditures, relicensing mitigation, Puget Stillwater Substation, Puget intertie. See Table 1.04 in the FPM output tables in Appendix 1. Amortization of BPA payments for conservation are large negative numbers through 2011.

The sum of these, tied to the table above, equal:	-3,845	-3,752	-3,691	-3,600	-3,542	-2,164	2,810	2,884	2,967	3,059	3,164
Net Power Costs adjusted for these values equal:	145,167	97,236	118,788	170,107	168,694	168,782	176,710	167,820	152,945	165,004	158,240

(10) Total retail load plus energy for wholesale sales, losses, and other energy obligations

(11) Total retail load

(12) Average cost of power supplied for all purposes after recognizing the net revenue or cost from wholesale power sales and purchases.

(13) Average cost of power supplied to service area customers after recognizing the net revenue or cost from wholesale power sales and purchases.

Figure 3.2

Costs of Power Supply ($1,000)

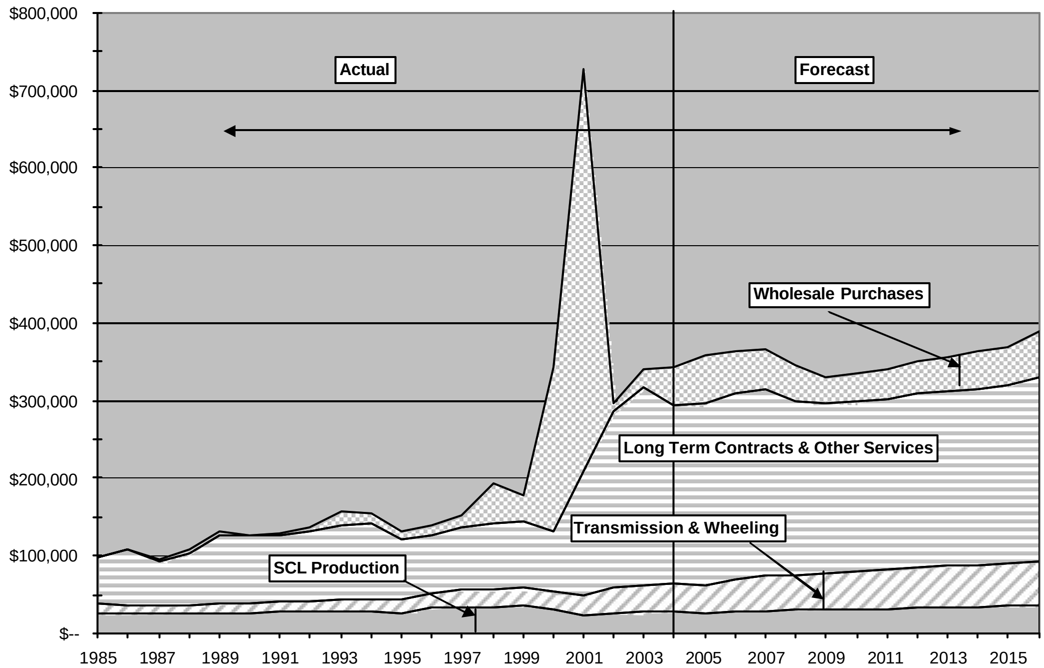


Figure 3.3

Net Power Costs, $1,000

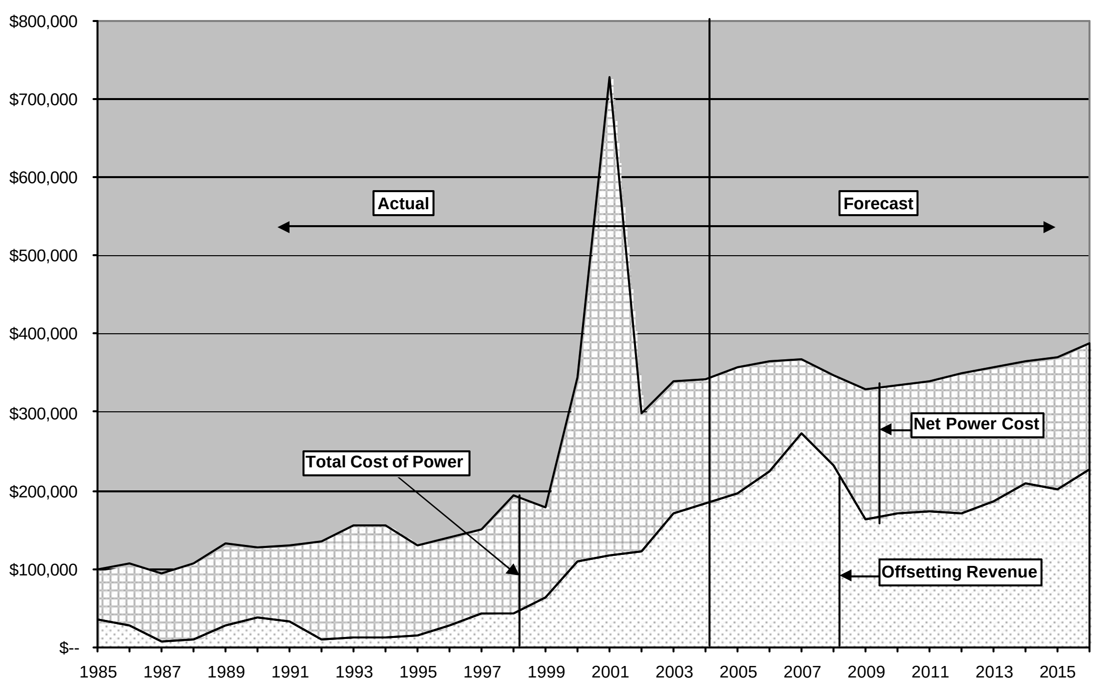


Figure 3.4

Net Power Cost for All Power and for Seattle Retail Load, $/MWh

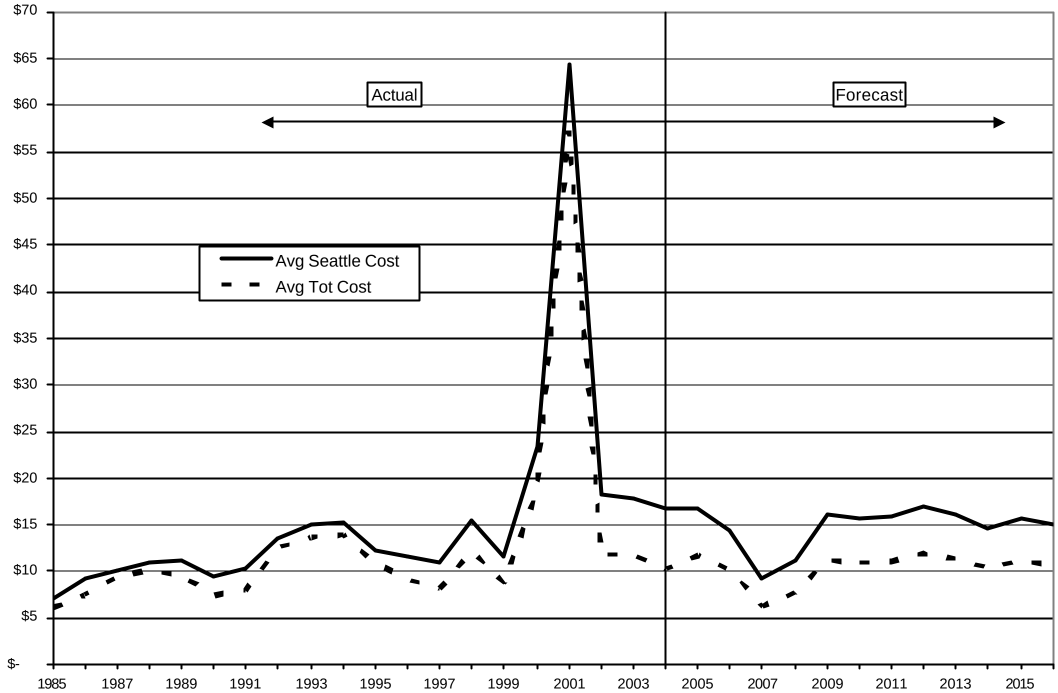


Figure 3.5

Net Power Costs by Element, $/MWh

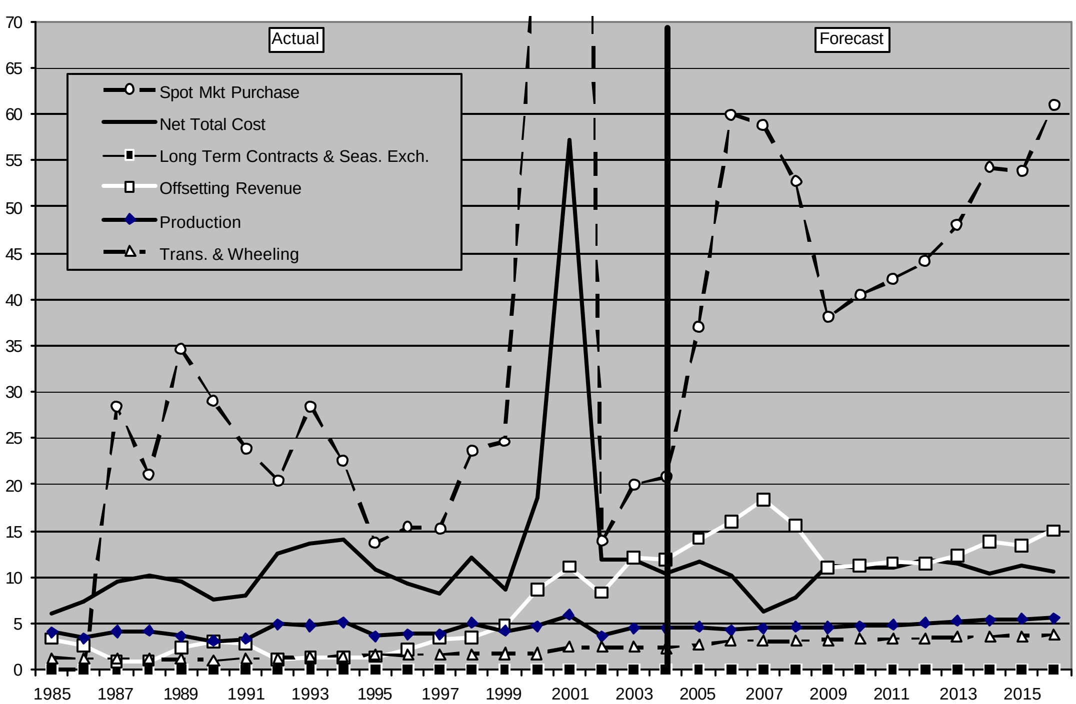
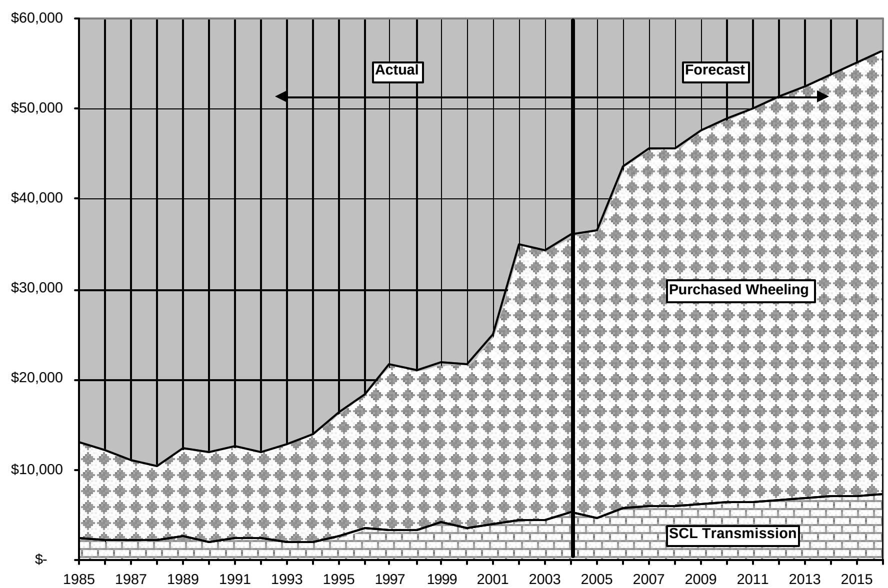


Table 3.5
Costs of Transmission and Wheeling, $1,000

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
City Light Transmission	5,777	5,861	5,958	6,126	6,277	6,437	6,595	6,757	6,923	7,093	7,268
Wheeling Expenses from Others for:	37,867	39,862	39,589	41,560	42,617	43,671	44,735	45,821	46,934	48,074	49,242
Centralia	-	-	-	-	-	-	-	-	-	-	-
Boundary	18,681	18,786	18,786	19,722	20,223	20,723	21,228	21,744	22,272	22,813	23,367
South Fork Tolt	332	375	385	404	415	425	435	446	457	468	479
Box Canyon to Seattle	-	-	-	-	-	-	-	-	-	-	-
Entl/Supp Capacity	-	-	-	-	-	-	-	-	-	-	-
Priest Rapids	1,281	1,289	1,289	1,353	1,387	1,422	1,456	1,492	1,528	1,565	1,603
CSPE	-	-	-	-	-	-	-	-	-	-	-
Grand Coulee (BPA)	1,263	1,270	1,270	1,334	1,368	1,401	1,436	1,470	1,506	1,543	1,580
Grand Coulee (Local)	1,507	1,023	965	1,013	1,039	1,065	1,091	1,117	1,145	1,172	1,201
Lucky Peak (BPA)	1,805	1,815	1,815	1,905	1,954	2,002	2,051	2,101	2,152	2,204	2,258
Lucky Peak (Local)	117	1,031	1,231	1,292	1,325	1,358	1,391	1,424	1,459	1,494	1,531
Wind Resources	409	684	719	754	773	793	812	832	852	872	894
NCPA Exchange	650	653	653	686	703	721	738	756	775	793	813
BPA Firm Power	11,731	11,797	11,797	12,385	12,700	13,014	13,331	13,655	13,986	14,326	14,674
Other Wheeling Purchases	90	1,138	678	712	730	748	766	785	804	823	843

Figure 3.6

Wheeling and Transmission Costs, $1,000



MW of transmission capability over Bonneville's share of the Third AC Intertie, which connects the Northwest region with California and the Southwest. The benefits from this investment include avoidance of Bonneville's transmission charges associated with power sales and exchanges over the Intertie and the ability to enter into long-term firm contracts with out-of-state utilities.[3]

In compliance with FERC Order 2000, Bonneville and nine investor-owned utilities in the Northwest have made various filings with FERC regarding the formation of a regional transmission organization (RTO) that would assume operational responsibility for transmission facilities in the Pacific Northwest under standardized, FERC-jurisdictional tariffs. However, the effort to implement the proposed RTO lost momentum when it became apparent that the framework proposed for the RTO was incompatible with FERC's proposed Standard Market Design. Discussions continue on the principles that will guide future efforts to form an RTO. City Light has joined other regional utilities in questioning whether the framework embodied in the originally proposed RTO was appropriate for the Northwest region. A new organization, the "ColumbiaGrid Corporation" has been formed for the purpose of analysis and planning in the areas of transmission reliability, expansion and planning, and market oversight. City Light is part of this organization, along with other regional Control Area Operators. The annual O&M costs associated with ColumbiaGrid are covered by the member organizations. City Light's share is currently 9.8% of the total. As new members join, the percentage share will change. The Purchased Power Budget for 2007-2008 includes about $500,000 each year for planning and development work with ColumbiaGrid.

Contracts with Bonneville provide City Light with 1,962 MW of transmission capacity under a point-to-point (PTP) transmission service agreement for the period from October 1, 2001, through July 31, 2025. City Light's rights under the current PTP contract are expected to be preserved under any new regional transmission organization. However, the rates that will apply to services provided by an RTO are uncertain, as are the rates likely to be charged by Bonneville if the formation of a regional system is delayed or abandoned. In its financial forecast, the Department has assumed that wheeling costs will increase by 4.5% percent from 2006 through 2008, growing from $37.9 million in 2006 to $39.6 million in 2008.

Power supplied to the Department by BC Hydro under the High Ross Agreement is transmitted over Bonneville's lines under a second PTP transmission service agreement extending through 2005. The High Ross PTP contract was assigned to BC Hydro in 1999. BC Hydro in turn reassigned the contract to the British Columbia Power Exchange Corporation (Powerex). Under the assignment agreement provisions, Powerex pays Bonneville directly for all costs associated with the PTP contract. The previous BPA point-to-point agreement for transmission service necessary for the delivery of High Ross replacement power was extended for a 30-year period just prior to the end of 2005. SCL

[3] Oregon attempted to gain revenue for the state coffers and dilute this benefit of ownership by imposing taxes on revenue generated by sales of transmission services. But, eventually, the Oregon Legislature resolved the matter by enacting legislation that retroactively exempted tangible property and intangible property rights in or related to the Pacific Northwest AC Intertie from *ad valorum* property taxation.

and Powerex also signed an Assignment Agreement for the same term. The Department also transmits power under contracts with Idaho Power for the transmission of power from the Lucky Peak Project, with Avista for transmission of power from the Grand Coulee Project Hydroelectric Authority, with Puget Sound Energy for transmission of power from the Cedar Falls and South Fork Tolt Projects, and with other utilities. Additional purchases of transmission on a non-firm basis may be required in the future in order to accommodate the Department's sales of power in the wholesale market during the spring runoff.

Removing the effects of inflation, direct transmission expenses excluding payments to BPA for the Third AC Intertie have moved up and down within a range of $3.0-$5.0 million since the mid-1990's, trending closer to the upper end of that range during the past few years. These expenses are projected to total $5.1 million in 2006 with gradual upward movement to $5.4 million by 2008. Intertie O&M expenses paid to BPA totaled $0.3 million in 2005. They are projected to be about $0.5 million in 2006, then decrease to about $0.4 million in 2007 and 2008.

3.3.20 Other Power Costs

Other power costs include operating expenses for the system control center, power marketing activities, greenhouse gas mitigation, green tag purchases and the Skagit Environmental Endowment. In 2005, Other Power Costs totaled $7.8 million. They are projected to rise from $7.7 million in 2006 to $7.9 in 2007 and $8.1 million in 2008. This information is displayed in total, as Other Production costs, in Table 3.4. These costs are also displayed in more detail in Table 1.10 in Appendix 1.

3.4 Net Wholesale Revenue

Previous sections of this chapter have included brief descriptions of short-term wholesale purchases and sales, since these are a component of net power costs. This section provides a more detailed explanation of the methodology used in forecasting these revenues and expenses.

A key feature of this part of the forecast is that it takes into account the uncertainty associated with short-term wholesale revenues and expenses, using a stochastic approach to modeling them. This is a departure from recent past practice, at least back to the 1980's. From that time up until the 2000-2001 energy crisis, net wholesale revenue was forecast as a point forecast of a single expected value rather than as a range of possible outcomes. The deregulation of the wholesale energy market that began in the late 1990's and the resulting increased volatility in market prices that reached a peak during the 2000-2001 energy crises made the Department aware that it needed to better account for the uncertainty of wholesale power transactions in its financial forecast. A new method of modeling that uncertainty was developed, as described below.

Changes to City Light's financial policies also warranted an update to its forecast methodology to reflect uncertainty in wholesale power revenue. In particular, the new policies include the requirement that City Light generate sufficient annual operating revenue to achieve 95% confidence of having operating funds available for capital expenditures after all operating expenses, including debt service. In order to be able to forecast the revenue required at this 95% confidence level, City Light needed to model the uncertainty in its forecast of wholesale revenue.

In modeling the uncertainty associated with wholesale revenue in its forecast, the Department has developed ranges of values for each of the major factors that create uncertainty in these revenues. These ranges of values are based primarily on recent historical trends but in certain cases also on longer-term historical trends.

There are three types of uncertainty associated with net wholesale revenue. The first type of uncertainty is load uncertainty, which is a function of customer demand for electricity. Load uncertainty is an important component of the overall uncertainty in net wholesale revenue because increases in load decrease the amount of surplus energy generated or purchased by the Department that is available to sell in the short-term wholesale market. Unanticipated increases in load can also increase the amount of energy that the Department needs to purchase in the short-term wholesale market if those increases occur at times when the Department does not have sufficient resources to cover the increased demand.

The second type of uncertainty is generation resource uncertainty, which is a function of weather conditions and their impact on snow-pack, stream-flows and water stored behind the dams at the Department's hydroelectric generating facilities and those of its suppliers under long-term power purchase contracts. Resource availability will also vary slightly from year to year due to changes in the Department's planned operations for these resources, which include planned outages for maintenance and changes in operating schedules in order to comply with environmental regulations such as federally mandated fish flow requirements. The third type of uncertainty is price uncertainty, which is a function of several factors that influence wholesale market prices for electricity in the Pacific Northwest, the most important of which are water conditions and wholesale market prices for natural gas.

In order to model the uncertainty associated with expected values, the forecast model assumes ranges of uncertainty around three important components of the load forecast: base load, load used for heating residences and buildings, and load used for cooling residences and buildings. All of this data is broken out by months of the year and by light load hours and heavy load hours within each month. This breakout is important because of the significant differences in prices between each of these times. This data is input to a Monte Carlo simulation model that is run 2001 times in order to provide a statistically accurate sample size and the ability to scale the results across 2000 intervals. The annual output of this process is both an expected value (the mean or average result across all of the scenarios) and an overall range of uncertainty that reflects the combined effects of all of the uncertainty factors used as inputs to the model, which are further described below.

Power resources are modeled by taking the outputs of a model used by Power Management to develop its operating plan and scaling those resources back by 2.5%. In other words, we assume that, on the average, only 97.5% of the engineering estimates of resources forecasted by Power Management are actually realized. If the Department were to use the engineering estimates as given, that would be equivalent to assuming average water conditions. The Department believes that assuming average water conditions creates undesirable levels of financial risk. The outputs of Power Management's resource forecast model are the outputs of a Monte Carlo simulation model that also runs 2001 scenarios that produces ranges of outputs around expected values for each of the resources. In addition to being broken out by resource, this data is also broken out by months of the year as well as by light load hours and heavy load hours.

Using all of the outputs from Power Management as inputs, the financial forecast essentially imports the ranges of uncertainty used by Power Management, adjusted by 97.5% scaling, which makes the ranges slightly narrower. The average generation calculated under this scaled down distribution is exceeded by the generation under 57% of the scenarios run by Power Management. This is equivalent, in terms of the impact on hydro generation resource output, to assuming water conditions that will be exceeded 57% of the time ("57% exceedence") rather than assuming average water conditions. The data sources and assumptions that Power Management uses in projecting resources and the uncertainty associated with those resources are described in Appendix 2.

The price forecast for wholesale energy is developed using the most recent long-term forecast from Global Energy Decisions, which is currently the Spring 2006 forecast (the forecast is produced twice a year, in Spring and Fall). Global Energy Decisions (GED) produces electricity and gas price forecasts for the entire Western Electricity Coordinating Council (WECC) area, which includes 14 states in the western U.S. as well as the western regions of Canada and Mexico. GED also produces forecasts for several sub-regions within the WECC, including the Pacific Northwest.

As inputs to its forecast of wholesale revenue, City Light uses Global Energy's Pacific Northwest electricity price and Pacific Northwest Coastal gas price forecasts. The City Light forecast of wholesale revenue stochastically forecasts electricity prices by making use of a ratio known to the energy community as the "market heat rate" which is the price of electricity divided by the price of natural gas. The market heat rate depends upon the amount of natural gas used to generate electricity. This, in turn, is a function of water available for hydro generation and the electrical energy used by WECC customers, which, in turn, depends upon base load, heating load and cooling load, similar to the City Light service area but on a much larger scale.

The market heat rate increases as the amount of natural gas used for electric generation increases. The market heat rate can fall to very low levels when no natural gas is being used for electrical generation, but it can also reach very high levels when the demand for electricity exceeds the capability of all generation in the WECC area. City Light recognizes the random nature of deviations in the major elements that determine the market heat rate and uses this to calculate the deviations in the market heat rate from the expected values forecast by GED.

City Light then calculates market prices for natural gas in a similar manner, by looking at the major elements that cause deviations from the expected values projected by GED. This calculation also recognizes that there is a correlation between the price of natural gas and the amount of natural gas used for electrical generation. For example, as water available for hydro generation in the WECC decreases, the market heat rate goes up, and this in turn drives up the price of natural gas. City Light then uses its forecast of gas prices to calculate electricity prices, by multiplying the price of gas times the market heat rate.

There is currently significant volatility in the price of natural gas and not all of the drivers of that volatility are completely transparent. For example, although we know that hurricanes in the Gulf of Mexico and changes in world oil prices have impacts on gas prices, we are not at this time able to quantify those impacts. Therefore, gas prices should be considered the greatest source of uncertainty in City Light's forecast of wholesale electricity prices.

3.5 Other Power-Related Revenue and Transmission Revenue

In addition to the revenues that it earns from retail energy sales and sales of surplus energy in the short-term wholesale power market, the Department earns revenues from a variety of power-related products and services. In 2005 these revenues totaled $23.3 million. They are expected to grow to $29.4 million in 2007 and $29.6 million in 2008. In addition, the Department earns revenue from sales of transmission capacity and related services. In 2005 this revenue totaled $4.5 million. It is projected at $3.3 million in 2007 and $5.3 million in 2008.

3.5.1 BPA Funding for Conservation

The Bonneville Power Administration currently provides two types of funding for City Light's conservation programs. The first type of funding is a "Conservation and Renewables Credit". The power sales contract with Bonneville that took effect on October 2001 provides a credit of $0.50 per MWh against the amounts payable under Bonneville's rate schedules for investments in conservation and renewable resources. In 2005, credits totaling $2.0 million were applied against the cost of power from Bonneville. The forecast projects these credits to be $2.1 million in 2006, then grow to $2.2 million annually in 2007 and 2008. These credits have an immediate impact on revenue requirements because they reduce the amount of power purchases required in the period to which they apply.

The second type of funding that Bonneville provides to the Department, pursuant to "Conservation Augmentation" agreements signed in 2002 and 2003, is direct funding totaling $48.2 million for conservation savings to be achieved between October 1, 2001 and September 30, 2006. This funding is being deferred and amortized into revenue every month over the remaining life of the current power contact with Bonneville, which ends on September 30, 2011. It reduces revenue requirements at the time that funds are received from Bonneville and it has a delayed, upward impact on net income, but no impact on revenue requirements, at the time that it is amortized as revenue. In 2006-2008 annual amortization of this revenue from BPA is $5.3 million.

3.5.2 Sales from Priest Rapids

On November 1, 2005, in compliance with a 1998 FERC ruling, 30 percent of the output of the Priest Rapids Project was offered for sale pursuant to market-based principles to entities in the seven-state northwest region. Under the terms of contracts entered into with Grant County PUD in 2002, the Department has contracted to receive a share of the profits derived from the sale of the 30 percent share of Priest Rapids' output. Revenues of $1.7 million were generated by the Department's share in 2005, during the last two months of the year. $8.8 million in revenue from a full year of sales is projected for 2006. City Light must decide on a year-by year basis whether to take its share in revenue, rather than power. City Light has elected to do this for 2007 and the financial forecast here presumes a similar decision for 2008. Thus the financial forecast has approximately the same amount of revenue from this source in 2007 and 2008 as in 2006.

3.5.3 Article 49 Sales to Pend Oreille County

Part of Boundary Dam output cannot be used to serve the customers in the Seattle service area because it must be sold to Pend Oreille County. According to Article 49 of the original license issued by the Federal Energy Regulatory Commission (FERC) for the Boundary Project, part of the generation at this site must be made available to Pend Oreille County Public Utility District (PUD) No. 1 to meet its load growth. Pend Oreille County PUD is withdrawing currently about 28 average MW per year from Boundary. This withdrawal increased to its maximum amount of 41.3 average MW in the year 2005. Revenues from these sales to Pend Oreille County totaled $1.3 million in 2005. These are projected to increase to $1.5 million in 2006 and $1.6 million in 2007 and 2008.

3.5.4 Seasonal Exchange

In addition to its firm power contracts, City Light enters into seasonal exchange contracts with other utilities which allow it to shape its resources to fit the demand from its customers. As discussed in Section 3.3 of this chapter, these exchanges can produce either costs or revenue to City Light. City Light usually has surplus energy during the summer while its heaviest load is in the winter. Other utilities (especially those in the Southwest) have load or resource profiles that are different from City Light's, with peak demand in the summer. Therefore, exchange agreements with these utilities are beneficial to both parties. These seasonal exchange contracts usually result in exchanges of energy and no cash payments, but they provide for cash payments if a utility cannot deliver energy at the times specified in the agreements. If the exchange is a non-cash transaction, it only affects net income, but if it is settled in cash it affects both net income and revenue requirements. If it is settled in cash it is accounted for as a short-term sale or purchase rather than a seasonal exchange transaction. On a planning basis, revenue and expenses for the seasonal exchange are assumed to be equal. However, in actual practice, revenue and expenses are not equal.

In the past, City Light valued each exchange at its average cost of power for the month that the first half of the transaction occurred. In 2006, in accordance with financial Accounting Standard (FAS) 153, City Light began recording these transactions at market prices. This accounting change is currently pending approval by Council with the expectation that it will be approved prior to 2006 year-end.

Currently, City Light has a seasonal exchange agreement only with the Northern California Power Authority (NCPA). Revenue associated with exchange energy delivered to NCPA in 2005 totaled $0.3 million, while expenses associated with exchange energy received were only $33,000. These expenses and revenues were much less than had been projected for 2005 because NCPA decided to keep most of the energy that had been delivered to it, settling those transactions in cash, which resulted in their being accounted for as short-term sales rather than exchanges. Seasonal exchange revenues and expenses are projected at levels closer to those of 2003 and 2004, which were not cashed out: $2.9 million in 2006 and 2007 and $3.0 million in 2008.

3.5.5 Basis Sales

Basis sales are transactions that occur on the sale side of a basis trade. Basis trades are paired power purchase and sale transactions at different locations at the same time at prices based on the difference in market value of energy at two locations (e.g., Mid-Columbia and COB). These types of trades may occur at any location where City Light has access to transmission services. In 2003, because it was economically advantageous to do so, City Light engaged in a significant volume of basis trades. Basis sales that year totaled $15.9 million and basis purchases totaled $13.4 million. By 2005, basis sales dropped to $1.0 million and basis purchases fell to $0.5 million. These transactions are projected to stay at about those levels through 2008.

3.5.6 Reserve Capacity Sales

City Light sells utilities, power marketers and other entities that purchase power from the Bonneville Power Administration the right to purchase reserve capacity, enabling them to meet their required reserves (i.e., the requirement that a utility have capacity at its disposal that exceeds its expected peak demand by a certain percentage). Revenue from these sales totaled $5.4 million 2005, up from just $1.6 million in 2003. The forecast assumes that there will be continued strong demand for this product, and these revenues are projected to grow to $6.4 million by 2008. These sales are included in the "Other Services" line of Table 1.07 in Appendix 1.

3.5.7 Green Tag Revenues

City Light is able to unbundle the environmental attributes from renewable energy purchases, such as purchases of wind power from State Line Wind Project, and sell those environmental attributes as green tags. This is a relatively new market that City Light, in conjunction with the environmental community, the government and other utilities, is trying to develop in order to encourage development of renewable resources. In 2005, the Department earned $0.8 million in revenues from green tag sales. Earnings from these sales are highly variable; therefore, the forecast conservatively projects them to be just $0.2 million in 2007 and $0.3 million in 2008. These sales are included in the "Other Services" line of Table 1.07 in Appendix 1.

3.5.8 BC Hydro Seven Mile Encroachment on Boundary Dam

The High Ross Treaty allowed BC Hydro to raise Seven-Mile Reservoir, which reduced the output at Boundary Dam due to encroachment on the tailrace. Until March 2004, BC Hydro returned the energy that would have otherwise been generated at Boundary Dam if Seven-Mile Reservoir had not been raised. From March 2004, forward, BC Hydro has been paying City Light for these losses at the Mid-Columbia rate. Pursuant to terms of the "Agreement for Boundary Generating Station Tailwater Encroachment Losses Caused by Seven Mile Generating Station" dated February 2, 1990, the amount of return is calculated hourly by the Boundary Encroachment Monitoring System. The prices used to forecast these payments are based on Global Energy Decisions' price forecast. Payments actually received in 2005 totaled $0.8 million. They are projected at $0.6 million in 2007 and $0.5 million in 2008.

3.5.9 Miscellaneous Other Power-Related Services

The forecast also assumes that City Light's power marketing group will find additional ways of generating about $0.5 million new power-related revenue in 2007 and $0.6 million 2008. This revenue is also included in the "Other Services" line of Table 1.07 in Appendix 1.

3.5.10 Miscellaneous Transmission Revenue

Under its Point-to-Point transmission service agreements with BPA and others, City Light is permitted to market its unused capacity. Resale price cannot exceed the cost of transmission but can be discounted at the discretion of the reseller. The revenue from this source has been quite variable over the years because it depends on both City Light's transmission surplus as well as its marketing effort. Since 2005, City Light senior management has emphasized the importance of this resource and encouraged more creative marketing. City Light earned $4.2 million of miscellaneous transmission revenue in 2005, more than double the average of the prior two years. The forecast assumes that the Department will continue making strong efforts to market this service, Revenue from this service is projected at $3.0 million in 2007 and $5.0 million in 2008.

3.5.11 Transmission Sales to North Mountain Substation, Snohomish County PUD

City Light has three contracts with Snohomish County PUD (SNOPUD) for North Mountain Substation: an Operations and Maintenance Agreement, a Power Transfer Agreement, and a Telecommunications Agreement. These contracts reimburse City Light for expenditures made to operate and maintain the substation and pay for transmission of power to SNOPUD over City Light's Skagit Transmission Lines. These revenues are projected at $0.3 million annually in 2007 and 2008.

Chapter 4

Non-Power Expenses, Other Revenues, Low-Income Customer Rate Assistance and Non-Cash Expenses

4.1 Introduction

This chapter presents the forecast of non-power operating and maintenance expenses, taxes, other revenues, other non-operating income and expenses, assistance for low-income customers and non-cash expenses. The methodology used in forecasting non-power O&M expenses is explained in Section 4.2. The major components of the non-power O&M forecast are presented in Section 4.3. This section discusses major drivers of the non-power O&M forecast. Sections 4.4 and 4.5 present the forecast of taxes and other revenues, respectively. Section 4.6 explains the forecast of non-operating income and expenses and 4.7 discusses low-income customer rate assistance. Section 4.8 discusses non-cash expenses, i.e., depreciation and amortization.

4.2 Forecast Methodology

This chapter presents the forecast of revenue required for non-power operating and maintenance expenses for categories including distribution, conservation, customer accounting and advisory services, and administration and general expenses. Non-power operating and maintenance expenses directly affect revenue requirements in the year in which they are incurred. Neither depreciation of capital investments nor the amortization of deferred O&M expenditures[4], which are non-cash expenses, are included.

In projecting these costs, a baseline forecast was developed based on past experience. The baseline forecast was then adjusted to account for changes anticipated in the forecast period from 2006 to 2010.

4.3 Major Components of Non-Power O&M Expense

Non-power O&M expense, excluding deferred expenses and amortization, is expected to increase from $123.8 million in 2006 to $129.9 million in 2008 or by $6.1 million (5.0%). Table 4.1 shows the forecast of expenses for distribution, conservation, customer accounting and service, and administration and general through 2010. The area of largest increase is projected in administration and general expense, which is increasing by $5.2 million or 10.9%, which is well above the rate of inflation for the period. Administration and general expense is largely comprised of labor, so the increase in labor benefits impacts this category markedly. In addition, the allocation of rents and City services to

[4] Deferred O&M expenditures such as conservation and environmental mitigation costs are treated like capital expenditures and are amortized over time. For more detail see Chapter 5.

all City departments has increased significantly and these costs are a part of this forecast. Distribution and customer accounting and service expenses are growing less than the rate of inflation (2% to 3%), while conservation direct expenses are growing with inflation. New initiatives in these areas will be accommodated by completion of O&M activities and refocusing of existing resources on higher priority work. The forecast of each major category of expense is discussed below.

Table 4.I
Distribution, Conservation, Customer Accounting and Service, and A&G
(Millions of Dollars)

	2006	2007	2008	2009	2010
Distribution	$42.3	$40.2	$42.8	$42.4	$43.5
Conservation	$2.4	$2.4	$2.5	$2.6	$2.6
Customer Accounting	$31.3	$31.7	$31.6	$30.1	$30.9
Administration	$47.8	$54.0	$53.0	$51.4	$52.7
Total	$123.8	$128.2	$129.9	$126.5	$129.7

Note: the amounts in this table exclude depreciation and amortization, which are non-cash expenses.

Distribution Expenses. Total distribution O&M expense is projected to increase from $42.3 million in 2006 to $42.8 million in 2008, or by 1.1%. Distribution expenses include the direct expenses of operating and maintaining substations, power lines, line transformers, poles, service connections, meters, and streetlights. Distribution expenses have been gradually increasing by more than the rate of inflation over the past few years and that trend is expected to continue. This is due in part to efforts being undertaken to improve system reliability, such as increasing the level of expenditure for tree trimming. It also reflects O&M expenditures required to plan and maintain large interagency projects requiring City Light distribution infrastructure, such as Sound transit, relocation of equipment on the Alaskan Way viaduct, and the development of South Lake Union. Several key initiatives for 2007 and 2008 are discussed below.

- **Tree Trimming**. During the forecast period, City Light plans to catch up on deferred maintenance of distribution assets, which jeopardizes system reliability and customer service. About $3.2 million in 2007 and $4.4 million in 2008 is added for tree trimming. These funds will improve service reliability and facilitate better customer service by reducing outages in both frequency and duration. Historically, funding has been provided to perform routine area-by-area tree trimming on a three- to four-year trimming cycle. Budget cuts in the early 2000's eliminated much of the funding for preventative tree trimming. Consequently, tree-related service outages have increased in the last four years.

- **Apprenticeship Program**. In anticipation of the need for more skilled electrical workers to meet customer needs, additional funds for the Apprenticeship Program are included in the revenue requirements. Washington State Apprenticeship Standards require that apprentices have 144 hours of specialized academic instruction provided by community colleges. These increased revenue requirements will cover increases in community college fees. In addition, City Light plans to hire approximately 30 additional apprentices in 2007-2008, bringing the total to 100. These additional apprentices are needed to meet City Light's future needs for skilled electrical workers. About $400,000 each year is included in the revenue requirements for 2007 and 2008.

Conservation Direct Expenses. Conservation direct expenses are projected to increase from $2.4 million in 2006 to $2.5 million in 2008 or by 5.4%. Conservation direct expenses include costs for administration, planning, marketing, and customer services for the conservation programs net of regional funding for the Lighting Design Lab. City Light expects to receive around $0.3 million annually in operating grants for the Lab, as it has for the past few years.

Deferred conservation expenditures are costs that City Light invests in energy efficiency measures (currently 7 aMW annually) in our customers' homes or businesses. The level of conservation investment is approved during the 2007-2008 Budget process. Deferred expenditures are treated like capital expenses and are discussed in more detail in Section 5.5. These expenditures impact revenue requirements over time through debt service coverage and current revenue available for capital requirements. Amortization of deferred conservation expenditures, which is a non-cash expense, is discussed in Section 4.8 of this chapter.

Customer Accounting and Service. Customer accounting and service expenses are projected to increase from $31.3 million in 2006 to $31.6 million by 2008 or by 1.1%. These expenses include the direct expenses for reading meters, billing customers, providing information to customers, and maintaining customer records. They also include the costs to administer rate relief programs for low-income customers. (See Section 4.7.) Several key initiatives for the rate period are discussed below.

- **Improved Customer Service Process**. The customer service forecast includes about $1.2 million in the 2007-2008 rate period for the Customer Electrical Service Implementation Process (CESIP). This project will fund consultant services and two IT technical support positions. CESIP will focus on process improvements to clarify roles and responsibilities for existing customer service and operational staff, and technology enhancements to communicate, track and report progress of electric service installations to customers. Funds are also included in the capital forecast for information technology in the General Plant category (see Chapter 6).

- **Uncollectible Accounts**. The utility will reduce the age and amount of active receivables on residential accounts to reduce annual write-offs by 6% through active collection efforts. Uncollectible accounts are projected to decrease from $7.4 million in 2006 to $4.9 million in 2008, decreasing by $2.5 million or 34%.

Administration and General Expenses. Administration and general expenses (A&G) include the direct expenses for administration, planning, office supplies, building rents, maintenance of general plant, services provided by the Executive Services Department, injury and damage claims, cleanup of toxic materials, and research and development.

In addition to the direct expenses noted in the above paragraph, A&G also includes amortization of vehicles and boats. This is a non-cash expense and therefore does not have any impact on the revenue requirements during the rate period. It does affect the Department's calculation of net earnings, however, and therefore also affects its debt-to-capitalization ratio. Amortization of vehicles and boats is projected to total $1.5 million annually in 2006-2008.

A share of A&G expenses is allocated to capital projects, based on the number of labor hours expended on capital projects. The allocation is expected to increase from $22.5 million in 2006 to $23.7 million in 2008 or by 5.4%. This allocation reduces A&G costs recognized as current expenses and increases capital requirements. A&G allocation will reduce revenue required from customers during the current rate period but will increase it over time through debt service expense and coverage requirements.

A&G expense (excluding A&G allocated to capital) is projected to increase steeply from $47.8 million in 2006 to $53.0 million in 2008, an increase of $5.2 million or 10.9%. The major drivers of this increase are the increasing cost of labor and benefits, office rents, City services cost allocation to all City Departments and the Duwamish Cleanup.

The following City Light initiatives are intended to support the Department's vision, mission and values. The Department intends to achieve operational excellence, which will enable the utility to improve productivity and customer delivery performance. The initiatives include activities essential to that purpose. Current funding levels support most of these activities, but several are new. New initiatives will be funded primarily by refocusing existing resources rather than by increasing total funding for administrative and general expenditures above current levels.

- **Security and Emergency Preparedness**. The purpose of the Security Improvement Program, which started in 2005, is to plan, design, and implement projects to improve the physical security of City Light's facilities so that reliability of customer service is maintained. It is intended to prevent unauthorized access and criminal activities that could cause significant system damage, power outages, and other related disruptions to the electrical system.

- **Asset Management**. A utility-wide Asset Management Plan was established during 2006 as part of the transformational reorganization. The plan includes the creation of an Asset Management Division within the Power Supply and Environmental Affairs (PSEA) and the Customer Service and Energy Delivery (CSED) business units. The Asset Management program will develop maintenance and replacement strategies that will prolong the life of assets and optimize the life cycle benefits of City Light's investment. In addition, CSED plans to establish a business planning group focused on workload planning, job estimating, job dispatching, in-service times, and job closeouts. Workload planning software (Maximo) will be funded for their use to improve maintenance management.

- **Corporate Performance**. City Light intends to implement programmatic performance measurement and reporting to improve utility performance. Resources are available to establish and hire staff to measure corporate performance through benchmarking and metrics. Performance measures established as part of the programmatic budgeting process and in accountability agreements will be the basis for management reporting by program on a regular basis. Benchmarking of these measures will be used to determine utility performance compared to industry standards.

- **Strategic Planning**. The Department will develop a Strategic Plan based on benchmarked industry practices, including issue-specific strategies responsive to SWOT and Gap analyses, consistent with the Vision, Mission and Values of City Light. The Plan will help reaffirm, redirect and identify new strategies and initiatives that will guide future decisions and investments in an effort to achieve customer service and operational excellence, a high performance work culture and financial strength.

- **Power Supply Risk Management**. An initiative intended to address financial reliability and accountability is a department-wide risk management function within the Finance Business Unit. This initiative is intended to bring City Light into conformity with industry best practices.

- **Employee Performance and Growth**. City Light must invest more in its employees to enable them to achieve customer service and operational excellence. The Adopted 2007-2008 Revenue Requirement provides resources for training, development and improved ways to recruit, hire and retain the best utility employees possible. Performance management initiatives will encourage and reward performance excellence. In addition, safety initiatives and training will emphasize "safe" as well as excellent work performance.

4.4 Taxes and Contract Payments

The Department recognizes taxes and contract payments as operating expenses. The major taxes paid by City Light are revenue taxes paid to the City of Seattle and the State of Washington. The Department also makes payments to counties in which City Light resources are located. These payments are for a variety of public services, such as fire and police protection, schools, and road maintenance. City Light also makes payments to suburban cities, as agreed in franchises negotiated with these cities. Other taxes include city and state business taxes. The forecast of taxes is presented in Table 1.13 in Appendix 1.

Total taxes and contract payments are projected to be \$62.8 million in 2006 and decrease to \$61.9 million in 2008. The major part of this category fluctuates with retail revenue.

- **State Public Utility Tax**. City Light pays state utility tax on retail revenue. Approximately 2.0% of total revenue is exempt from this tax; the tax on the remainder is 3.873%. State Public Utility tax payments are projected to decrease from $22.5 million in 2006 to $21.8 million in 2008.

- **City of Seattle Occupation Tax**. City Light pays the City of Seattle an occupation tax equal to 6.0% of retail revenue. Approximately 1.7% of retail revenue is exempt from this tax. The City occupation tax expense is projected to decrease from $34.9 million in 2006 to $33.5 million in 2008, changing with retail revenue.

- **Payments to Counties and Schools**. Payments to Whatcom County, where the Skagit Projects are located, totaled $0.8 million in 2006 and are expected increase slowly to $0.9 million by 2008. Payments to Pend Oreille County, where the Boundary project is located, totaled $1.2 million in 2006 and are expected to increase to $1.3 million by 2008. Contracts for both of these counties allow for annual increases to account for inflation and the forecast reflects this by assuming that these payments will grow by the rate of inflation.

  In addition, City Light makes payments to the Concrete School District (located in Whatcom County), which provides career counseling, bus transportation to after school events and night school, and other services to City Light staff and family members residing at the Skagit. These payments are about $0.1 million annually.

- **Payments to Suburban Cities**. City Light also 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. These payments are made to the cities in return for their agreement not to exercise their rights to establish their own municipal utilities and to acquire City Light's distribution property within their limits. Under the terms of franchise agreements signed in 1998 and 1999, City Light makes monthly payments to the cities of Shoreline, Burien, Lake forest Park and SeaTac in amounts equal to 6.0% of the revenue attributed to the energy component of rates charged to customers residing within those cities. Under a franchise agreement with the City of Tukwila, the Department paid Tukwila monthly amounts equal to 4% of total revenue billed to customers in Tukwila from March 1, 2003 through December 31, 2004 and 5% of revenue in calendar years 2005 and 2006, and will pay 6% of revenue from calendar year 2007 through the end of the franchise in 2018. Payments to suburban cities consistent with the franchises are projected to increase from around $3.0 million in 2006 to around $4.0 million 2008.

- **Other Taxes and Payments**. This forecast includes State and City business taxes not based on revenues and payments to King County for surface water management fees. The expenses are projected to increase from $250,000 in 2006 to $258,000 in 2008.

4.5 Other Revenues

In addition to operating revenue from retail sales of energy to customers in its service area and wholesale sales of power and power-related products, the Department earns operating revenue from fees and charges for a variety of services. These sources of income offset revenue requirements and reduce the required level of customer rates. These miscellaneous fees and charges are projected to be $13.5 million in 2006, increasing to $14.1 million in 2007 and $15.2 million in 2008. FPM Table 1.14 in Appendix 1 presents the annual forecast for each of these sources of revenue. Details of the forecast are discussed below.

- **Late Payment Fees.** Delinquent customer balances of $75 or more are assessed the greater of $10 or 1% per month. Revenue from these fees increased sharply in the past several years, to highs of $5.4 million annually in 2003 and 2004. Billing system problems, significant rate increases and a slower economy led to the increase in late payments. The Department has implemented a variety of measures to correct this situation, such as revising collection methods to increase their effectiveness and making improvements to the billing system. These improvements, along with the leveling off of rates and some improvement in the local economy, have been successful, reducing revenue from late payment fees to about $3.4 million in 2005. Revenues from these fees are expected decline further to around $3.1 million in 2006, then grow by inflation to about $3.2 million by 2008.

- **Revenue from Damage to Property and Equipment.** The Department bills those responsible for damage to its property and equipment, such as damage to streetlight poles, vaults, ducts, etc., for any repairs required to restore the functionality of the property or equipment. Prior to 2000, these billings were recorded as offsets to expense for property and equipment maintenance. Since that time, they have been recorded as a source of operating revenue. Revenue from damage to property and equipment is forecast to increase with inflation, from about $1.4 million in 2006.

- **Other O&M Revenues.** These revenues encompass income earned from a very broad range of billable O&M charges, including service charges, charges for inspections of meters and other technical equipment, building maintenance charges and recreational charges such as those for Skagit tours. These revenues are projected to increase from $3.8 million in 2006 to $4.0 million by 2008.

- **Property Rental Income.** Property rental income includes revenue from rental of City Light property including underground ducts and vaults, housing units at the Skagit project, and transmission and distribution rights-of-way. Property rental income is expected to increase from $1.7 million in 2006 to $1.8 million by 2008.

- **Construction Charges.** Construction charges are paid by customers for City Light services during phases of construction activity on the customer premises related to the delivery of electricity. The Department bills customers for associated accounting time, engineering work, and administrative overhead. These revenues are projected at $0.4 million annually in 2006 through 2008.

- **Transmission Attachments and Cellular Antenna Sites.** Transmission attachments and cellular sites accounted for a significant portion of the increase in revenues from miscellaneous fees and charges in late 1990's but have since leveled off. Revenues from these rentals are forecast to remain around their 2005 level of $0.6 million through 2008.

- **Pole Attachments.** Ordinance 119395, passed in March 1999, allows City Light to charge two different rates for pole attachments. Attachments billed at the traditional cost-based rates are called Class 1 attachments and a new type of attachment, billed at a market-based rate, is called a Class 2 attachment.

  - **Class 1 Pole Attachments.** Class 1 attachments typically consist of television or computer cable strung pole-to-pole and charged a cost-based rate. An increase in pole attachment rates will go into effect with new rates in 2007. Revenue is projected to increase from $0.8 million in 2006 to $1.0 million in 2007 and 2008. The number of poles on which Class 1 attachments are made and rents collected is expected to remain constant throughout the forecast period.

  - **Class 2 Pole Attachments.** Class 2 attachments are defined as "non-linear, non-wire line devices, related to advanced and competitive communication technologies, such as wireless communication antennas and remote-site cameras." Ordinance 119395 allows City Light to negotiate market-based rates for these types of attachments. At one time, the Department expected to earn significant revenue from these types of attachments and included that revenue in the forecast. However, the Department has not earned any such revenue, so the current forecast does not include it.

- **Account Change Fee.** City Light charges a fee when customers open an account. Account service revenues are estimated using a forecast of the number of account changes and the projected fees charged for changing an account. A fee increase was implemented in late 2006. As a result, these revenues are projected to increase substantially from $0.5 million in 2006 to $1.4 million in 2007 and 2008.

- **Miscellaneous Rentals.** These revenues are collected from commercial customers for rental of equipment. Miscellaneous rental income totaled less than $0.2 million in 2006. It is expected remain near that level, gradually growing with inflation.

- **Reconnect Charges and Returned Checks.** City Light charges customers for the cost of processing returned checks, making field visits to collect on delinquent bills, and reconnecting electric service. Revenues are forecast to remain near the 2006 level of $0.2 million, growing with inflation.

- **Miscellaneous Income.** Miscellaneous income includes income net of expenses for non-operating property expenses. The latter include work performed on plant that is considered surplus property because it is no longer used to generate electricity. Miscellaneous income often includes one-time receipts such as refunds or reimbursements that can vary greatly in amount, making this a difficult revenue category to forecast with any precision. The forecast projects it at about $0.8 million in 2006, growing with inflation.

4.6 Miscellaneous Non-Operating Income and Expense

Miscellaneous Non-Operating Income and Expense includes investment income, proceeds from sale of property and other income and operating fees and grants. The largest components of this forecast are income from investment income and proceeds from property sales. These revenues vary widely from year to year as can be seen in Table 4.3 below. Consequently, historical trends are not useful for forecasting purposes. Miscellaneous Non-Operating Income (Net of Expense) reduces the revenue requirement from customer rates.

Table 4.2
(Millions of Dollars)

Non-Operating Income (Net)	2006	2007	2008	2009	2010
Investment Income	$7.6	$7.1	$4.4	$2.5	$2.4
Other Income (Expense)	-$0.2	-$0.2	-$0.3	-$0.3	-$0.3
Sale of Property	$1.0	$9.5	$1.1	$1.1	$1.1
Operating Fees and Grants	$0.3	$0.3	$0.3	$0.3	$0.3
Total	$8.6	$16.7	$5.5	$3.6	$3.5

- **Investment Income.** City Light's investment income is projected to decline from $7.6 million in 2006 to $4.4 million in 2008. Investment income varies with the level of funds in cash balances. These levels vary with actual retail and wholesale sales revenues, operating expenses, capital expenditures, contributions and grants, proceeds from the sale of bonds, and cash reserves and minimum balances required to meet financial policies set by the City Council. Cash balances are projected to be $141.1 million in 2006, declining to $55 million in 2008 as excess cash over and above reserves and minimum balance amounts required by financial policies is used as a source of funding for capital expenditures during that time. (FPM Table 1.01, Appendix 1)

- **Sale of Property.** Every year, the Department sells and otherwise disposes of surplus real property. About $1.0 million is projected for 2006, $9.5 million in 2007, including $8.5 million for the sale of property located at 8th Avenue North and Roy Street in the South Lake Union area, and $1.0 million in 2008. This forecast is based on projections for 2006 through 2008 from City Light's Real Estate unit.

- **Other Income (Expense).** This category includes non-operating income or expense, including non-operating income, donations, penalties and other deductions. The expenses are projected to remain at about $300,000 annually. No non-operating income is anticipated.

- **Operating Grants.** Operating grants are any grant funds received from Federal, State or local agencies in support of City Light's operating expenses. In actuality, the amount of grants received and the purposes for which grant funding is provided can vary significantly from year to year. The only type of operating grant funding that is known with any certainty and can therefore be forecast is funding for the Lighting Design Lab that City Light receives from the Northwest Energy Efficiency Alliance. It is projected at $300,000 annually, based on historical trends.

4.7 Assistance for Low-Income Customers

The Department provides assistance to eligible low-income customers by giving rate discounts and fee waivers for trouble calls and account changes. There is also an Emergency Low-Income Assistance Program (ELIAP), which helps customers pay electricity bills. The amount of revenue not collected because of City Light rate discounts and service fee waivers is added to the revenue requirement as if the amount were either an operating expense or a deduction from operating revenue.

Assistance for low-income customers is projected to decrease by 2.5%, from $6.2 million in 2006 to $6.0 million in 2008. Table 4.2 shows the components of the forecast. Low-income program administration costs are direct expenses and are included in the O&M forecast for customer service expenses (Section 4.3, Customer Accounting and Service).

Table 4.3
(Thousands of Dollars)

Low Income Assistance	2006	2007	2008	2009	2010
Rate Discounts	$5,752.1	$5,551.0	$5,551.0	$5,965.8	$6,142.4
Trouble Calls	$1.0	$1.1	$1.1	$1.1	$1.2
Account Change	$13.8	$37.1	$37.4	$37.7	$38.0
Payments from LI Account	$242.8	$248.6	$254.4	$260.3	$266.5
Administration	$175.4	$180.0	$184.8	$189.8	$194.6
Total	$6,185.1	$6,017.8	$6,028.8	$6,454.8	$6,642.6

- **Rate Discounts.** Discounts make up the largest part of assistance for low-income customers. These discounts are available to households with incomes less than 200% of the federal poverty level or who receive Supplemental Security Income. The program is also available to customers with household incomes less than 70% of Washington State median income and who are older than 65, blind, disabled, or on medical life support equipment. Past City policy has been for customers qualifying for the low-income program to pay rates equal to 50% of rates paid by other residential customers. However, this policy was relaxed during the "energy crisis". Rate assistance customers were not given the full amount of rate increases that were necessary to compensate for the extraordinarily high costs of energy during those years. Consequently, discounted rates are now considerably less than half those of other residential customers. The Mayor and Council have decided to keep low-income rates at 40% of standard residential rates during 2007 and 2008, rather than raising them back up to 50%. The cost of these discounts is projected to be $5.8 million in 2006 and $5.6 million in 2008.

- **Service and Administrative Fee Waivers.** The Department also waives fees to low-income customers for trouble calls, account change services and account administration. The cost of these waivers is projected to increase from $190,000 in 2006 to $223,000 in 2008. Most of this increase is due to a more than doubling of account change fees, which are being increased to reflect the cost of service.

- **Emergency Low-Income Assistance Program (ELIAP).** This program was established by Ordinance 112637 in 1985. It offers last-resort help to customers who have received shutoff notices. Grants to pay up to half the past due balance (to a maximum of $200) are given when arrangements are made to pay the balance. About $250,000 in ELIAP grants are given each year.

4.8 Non-Cash Expenses

Depreciation and amortization expenses on the income statement are non-cash expenses. They represent an accounting estimate of the amount by which the value of long-lived assets is reduced through usage in a given year. The forecast of depreciation and amortization expenses is expected to increase from $89.9 in 2006 to $99.1 million in 2008, or $9.2 million (10%). Driving this growth is capital investment in prior years in City Light-owned plant and deferred expenditures (e.g., conservation measures, vehicles, and environmental mitigation expenses related to relicensing). Biennial budget decisions on the Capital Improvement Plan, Conservation Implementation Plan and environmental mitigation required to maintain licenses at the Department's generation facilities, and changes in accounting policies related to categorization and treatment of capital investments and deferred operating expenses, will impact depreciation and amortization expense in future years.

Table 4.4
(Millions of Dollars)

Non-Cash Expenses	2006	2007	2008	2009	2010
Depreciation	$81.7	$85.2	$89.2	$93.9	$99.1
Amortization	$8.2	$9.1	$9.9	$10.8	$11.6
Total	$89.9	$94.3	$99.1	$104.7	$110.7

Capital expenditures are funds that City Light invests in replacing and enhancing its own generation, transmission, substations, distribution, and general plant. These costs are depreciated or expensed over the useful lives of the investments, which vary and are set by accounting practice. The forecast of capital expenditures and related accounting policies drives the forecast of depreciation over time.

Deferred expenditures are treated like capital expenditures and are discussed in more detail in Chapter 5. These costs are amortized or expensed over their useful lives like capital expenditures. Conservation comprises the largest component of the amortization forecast in years 2007 and 2008 at $11-$12 million per year, but only $6-$7 million on a net basis, after subtracting the $5.3 million annual amortization of revenue from BPA conservation funding, which is described in Chapter 3. Deferred conservation expenditures are costs that City Light invests in energy efficiency measures in customers' homes or businesses. Conservation expenditures are amortized over 20 years. The forecast of deferred conservation expenditures is approved during the budget process and is expected to save about 7 aMW per year.

Increases or decreases in depreciation and amortization expenses may impact revenue required to meet financial policies indirectly through the debt-to-capitalization target, since it is part of the net earnings calculation, as can be seen in FPM Table 1.02 (Net Income Statement), Appendix 1. The debt-to-capitalization ratio is calculated as total debt outstanding divided by capitalization (the sum of accumulated net earnings and debt outstanding). So, for example, if City Light accelerated depreciation and amortization schedules (all things being equal), net income would go down. That would decrease accumulated net earnings and, therefore, the debt-to-capitalization percentage would go up, perhaps not allowing City Light to achieve its 60% target by 2010 unless revenues from customers were increased.

Details of the depreciation and amortization expenses can be found in FPM Table 1.04, Appendix 1.

Chapter 5

Capital Requirements

5.1 Introduction

The Department maintains long-range capital improvement and conservation implementation programs to ensure the availability of adequate supplies of power and to provide a high level of service reliability to its various customer groups. The Capital Improvement Program (CIP) for the Department forms a part of the City's Comprehensive Capital Improvement Program, which is mandated by the State's Growth Management Act. The City's biennial budget process determines the annual funding levels for both the CIP and the Conservation Implementation Program.

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 this year, requiring that new initiatives and existing projects with major changes in scope or budget provide a business case and economic analysis which justifies funding for the project. The economic analysis includes a discussion of all benefits and costs including customer service, legal and technical considerations, and 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. At the same time, expenditures for existing projects are also reviewed.

The Department's current CIP emphasizes projects that address the long-term performance and reliability of its hydroelectric generation plants, substations and distribution systems. It also includes infrastructure and customer service investments that address priority billing services and metering needs, energy efficiency, security and safety improvements at City Light facilities, and needs for computing equipment, systems, and software that have a life spanning several years. Significant investment in interagency projects such as the Alaskan Way Viaduct utility equipment relocation and Sound Transit are scheduled. The capital expenditure program was designed to meet all these requirements while keeping total expenditure levels as low as possible.

The Department's Conservation Implementation Program provides funding for investments in the residential, commercial and industrial sectors of the service territory to achieve the Department's long-term energy savings goals of 7 aMW per year. 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. Administrative costs associated with managing and evaluating the programs are part of the O&M forecast and are expensed in the year they occur.

In addition to CIP expenditures and conservation programs, capital requirements include other deferred costs. Other deferred costs result from the fact that some of the Utility's expenditures do not produce conservation or capital assets for City Light but still relate to activities that have impacts extending beyond the year these payments are made. One example is the payment to other parties (such as native tribes and the Federal Government) required under the terms of the relicensing of generation plants. These payments are not expensed in the year they are made but are amortized over several years. They are grouped with CIP and conservation because they have the same impact on revenue requirements as capital expenditures.

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 first and second-lien debt service is a component of revenue required.

Sections 5.2 and 5.3 present information on capital expenditures and the CIP forecast. Deferred conservation expenditures are reviewed in Section 5.4, and other deferred costs in Section 5.5. Section 5.6 discusses the projected funding levels of contributions in aid of construction, grants from other entities and customer fees for services. These revenue sources are included in FPM Table 1.03 in Appendix 1. The impact of CIP, Conservation and other deferred expenditures (net of contributions in aid of construction, grants and fees for service) on funding required from customer rates and borrowing is discussed in more detail in Chapter 6, Borrowing, Debt Service and Debt Accumulation.

5.2 The Forecast of Capital Requirements

Capital expenditures are projected to be $167.6 million in 2006 and $203.9 million in 2007, increasing to about $228.5 million in 2008. This represents a $60.9 million or 36% increase from 2006 to 2008. For the longer term, capital expenditures are projected to increase in real and constant dollars from 2007 to 2010. The long-term trend of CIP expenditures is shown in the following graph.

Capital Expenditures Excluding Deferred Power Charges
In Millions of Dollars

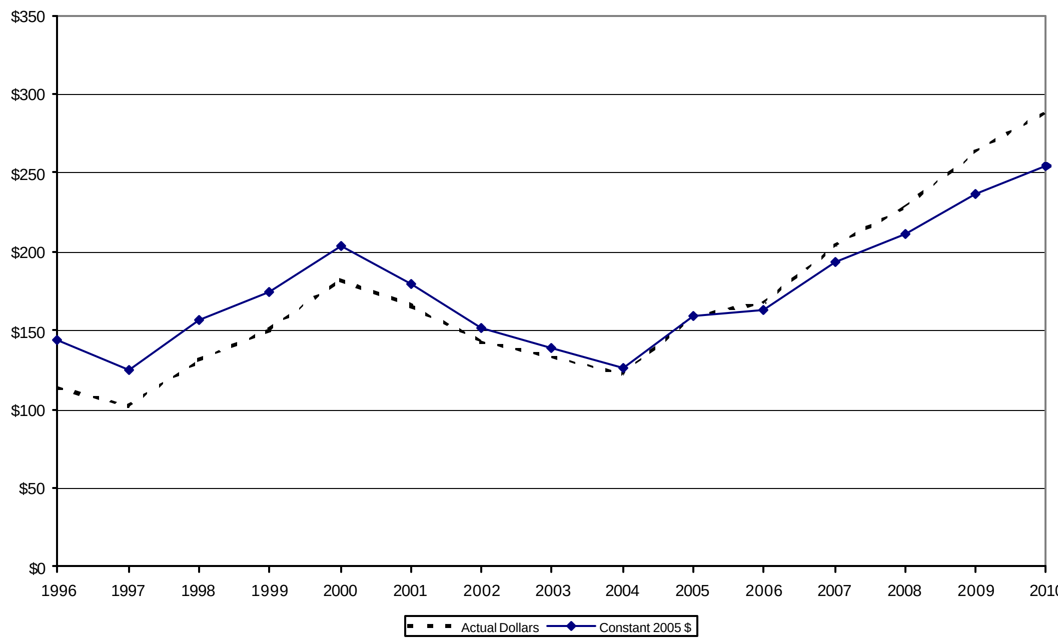


Table 5.1 shows the major components of the capital requirements forecast for years 2006-2012. Total capital requirements are projected to increase from $167.6 million in 2006 to $228.5 million in 2008, or by $60.8 million (36%). Capital improvement project expenditures are projected to grow substantially in the rate period, primarily in distribution plant. Conservation is projected to grow at the rate of inflation, while deferred High Ross charges are projected to remain fixed at $9.1 million. Deferred O&M is expected to increase due to Boundary relicensing expenditures. Components of the capital requirements forecast are discussed in sections below.

Table 5.1
Thousands of Actual Dollars

	2006	2007	2008	2009	2010	2011	2012
Capital Improvement Projects	146,102	181,716	207,745	248,502	276,674	233,483	186,753
Expenditures Not Yet Distributed	-14,610	-18,172	-20,775	-24,850	-27,667	-23,348	-18,675
Conservation	20,790	21,194	21,647	22,144	22,709	23,352	24,007
Deferred O&M Costs	6,251	10,029	10,760	8,229	8,206	7,286	1,180
Deferred High Ross Charges	9,103	9,103	9,103	9,103	9,103	9,103	9,103
Deferred Power Charges (Expenses	0	0	0	0	0	0	0
Capitalized Interest	0	0	0	0	0	0	0
Total Capital Required	167,637	203,871	228,481	263,128	289,025	249,877	202,367

5.3 Major Projects in the Capital Improvement Expenditure Forecast

The Revenue Requirements Analysis (RRA) forecast classifies CIP expenditures according to functional categories: generation, transmission, distribution and general plant. Generation plant includes facilities used to produce electricity. Typical assets would be reservoirs, dams, waterways, waterwheels, turbines, generators and accessory electrical equipment. Transmission plant refers to the poles, towers and conductors used to carry electricity from generation facilities to substations. Distribution includes substations and other distribution plant equipment as well as utility equipment relocation costs associated with transportation projects such as the Alaskan Way Viaduct and Sound Transit; these are major drivers of the CIP expenditure forecast, accounting for 25% of total CIP and 37% of distribution CIP. Substations comprise the buildings and equipment that transform electricity from the 115-KV or 230-KV levels, at which it is transported over long distances, to the 4-KV, 13-KV, or 26-KV levels at which it is delivered to the line transformers located at the premises of individual customers. Other distribution assets include the equipment used to deliver electricity from the substations through customers' meters, such as poles, underground conduits, overhead wires, line transformers, and meters. General plant includes all assets not included in the other four categories: buildings, such as the North and South Service Centers, computer equipment, office furniture and communications and mobile equipment.

The RRA forecast includes all projects individually documented in the Department's 2007-2008 CIP Budget and proposed CIP through 2012. Capital plan expenditures include loadings for benefits, transportation, and administration and general cost allocation, based on the number of labor hours estimated for the project. The RRA forecast assumes a 10% under-expenditure in CIP, and this is displayed in the line titled Expenditures Not Yet Distributed. Beyond this period the financial forecast makes provision for the expected level of spending on CIP projects required but not yet identified.

Table 5.2 presents forecast information for selected CIP projects by major capital category. It indicates relative size of the projects, points out areas of growth and characterizes trends for the forecast period 2007 to 2012. Each major expenditure category is discussed in more detail below.

Table 5.2
Selected CIP Projects
(Thousands of actual dollars)

	2006	2007	2008	Increase '06 to '08	Total CIP ('07 to '12)	Avg/Year('07 to '12)	% of Total CIP
Generation	22,556	23,290	26,295	3,739	123,505	20,584	9%
Generator and Turbine Runner	7,591	6,821	12,921	5,330	50,600	8,433	4%
Boundary Plant Improvements	5,089	3,398	3,867	(1,222)	19,524	3,254	1%
Skagit Plant Improvements	6,991	9,166	6,019	(972)	38,935	6,489	3%
Environmental Mitigation	909	818	650	(259)	3,683	614	0%
All Others	1,976	3,087	2,838	862	10,763	1,794	1%
Transmission	5,369	5,573	3,992	(1,377)	35,804	5,967	3%
Substations	11,971	7,322	12,441	470	77,277	12,880	6%
Distribution	86,917	123,941	137,227	50,310	912,808	152,135	68%
26KV Conversion	328	2,884	4,079	3,751	23,579	3,930	2%
Sound Transit	13,991	15,469	4,053	(9,938)	28,532	4,755	2%
Network Additions and Services	19,299	21,621	23,513	4,214	159,558	26,593	12%
Service Connections	14,236	13,753	13,638	(598)	84,684	14,114	6%
Capacity Additions	16,717	14,975	14,566	(2,151)	92,711	15,452	7%
Other Relocations	8,839	5,104	3,154	(5,685)	19,605	3,268	1%
Alaskan Way Viaduct	1,446	23,726	43,266	41,820	305,794	50,966	23%
Street and Floodlights	1,596	2,048	1,905	309	11,718	1,953	1%
Outage Prevention	2,235	3,360	1,757	(478)	14,957	2,493	1%
Residential Undergrounding	-	1,805	4,882	4,882	34,358	5,726	3%
Franchise Undergrounding	2,659	2,718	2,342	(317)	21,114	3,519	2%
Capacity Load Transfers	-	5,253	4,261	4,261	15,669	2,612	1%
Automated Meter Reading	-	880	1,310	1,310	7,135	1,189	1%
All Others	5,571	10,345	14,501	8,930	93,394	15,566	7%
General Plant	19,289	21,590	27,791	8,502	185,474	30,912	14%
Vehicle Replace and Add	4,273	5,555	7,654	3,381	50,723	8,454	4%
Security Improvements	1,556	2,159	2,346	790	9,320	1,553	1%
Communications Improvements	2,069	2,250	2,560	491	13,970	2,328	1%
Information Technology	9,382	9,205	12,647	3,265	89,795	14,966	7%
All Others	2,009	2,421	2,584	575	21,666	3,611	2%
TOTAL ALL PROJECTS	146,102	181,716	207,746	61,644	1,334,868	222,478	100%

Generation Plant

Generation expenditures are projected to total $123.5 million during the six-year planning period, averaging about $21 million per year and representing about 9% of planned expenditures for that period. About $50 million of total expenditures is associated with generator rebuilds and $39 million with Skagit Plant improvements.

Generator Rebuilds – Investment in System Reliability. The Department is continuing to rebuild 10 aging hydroelectric generators accounting for 70% of the utility's generating capability at the Boundary, Ross and Diablo powerhouses. Projected work at Boundary includes repair of the Unit 55 generator stator, and rewinding and refurbishing Units 51, 53, 54 and 56 generators. Work at the Ross powerhouse will include rebuilding of Generators 41, 43 and 44. Generators 31 and 32 at the Diablo powerhouse will also be rebuilt. These projects will significantly extend the economic life of the generators. Seattle City Light plans to complete all these projects by 2013.

Skagit Plant Improvements. In addition to the generator improvements described above, funds are also included to upgrade the Skagit plants – Ross, Gorge, Diablo and Newhalem. About 80% of the expenditure over the six-year period is for improvements to the Gorge and Diablo plants. In 2007 City Light plans to complete the multi-year Turbine Runner Replacement program with the replacement of the Gorge Unit-24 turbine runner. Improvements and replacements are scheduled for powerhouse and switchyard equipment and control systems, for drainage and water supply systems, roads, shop and warehouse facilities, and for security and communications systems.

Boundary Plant Improvements. Capital improvements at the Boundary Plant, beyond those mentioned above, include replacement or upgrades of safety and security installations, control, monitoring and electrical systems, rockfall guards and other plant infrastructure.

The Federal Energy Regulatory Commission (FERC) licenses all City Light hydroelectric plants except Cedar Falls, which was built before the Federal Power Act of 1920. City Light's FERC license for the Boundary project expires in 2011. The projects described in this section, together with the generator projects noted above, will contribute positively to the relicensing process, which was formally initiated near the end of 2004. A Notice of Intent to seek a new license and the Preliminary Application Document were submitted to FERC in May 2006.

Environmental Mitigation. Environmental mitigation projects are required under the terms of the license for the Skagit Project and by City Council resolution to protect endangered species in City Light generation areas.

The Skagit Mitigation projects in the CIP fund the remediation actions required to mitigate the environmental impacts of running the Skagit plants, for which FERC relicensing was completed in 1995. The license is valid for 30 years. The Skagit mitigation package includes expenditures for acquisition and management of land for wildlife habitat, an environmental learning center, and other costs associated with mitigating the environmental effects of these plants. The North Cascades Environmental Learning Center was completed in 2006. However, funds for land management related to wildlife habitat are allocated over the term of the license until 2026.

The Endangered Species Act (ESA) mitigation program was established by City Council Resolution 30272 in response to the listing of Puget Sound Chinook salmon and bull trout as threatened under the ESA in 1999. Both City Light and Seattle Public Utilities are required to carry out mitigation work in this area. City Light's responsibilities include research, watershed planning in the Skagit and Tolt River basins where the utility owns generation resources, and restoration and protection activities in those watersheds.

Transmission Plant

Transmission expenditures are projected to total $35.8 million during the six-year planning period, averaging about $6.0 million per year and representing about 3% of planned expenditures for that period. The majority of planned expenditures are intended to enhance or maintain reliability and satisfy capacity needs; these include new and rebuilt lines, new configurations and relocations, correction of 115 kV violations, replacement of transmission poles, conductors, lights, and tower structures, x-ray assessments and upgrades to cathodic protection of underground conductors.

Smaller projects include demand-driven transmission improvements such as a request by Burlington Northern Santa Fe Railway to raise three transmission lines and a request by Puget Sound Energy to reconductor the Bothell-Sammamish Line.

At Summer Falls in Western Washington, City Light proposes to build a new interconnection to Bonneville Power Administration (BPA) lines to replace the Avista transmission contract that expired in 2005. Power from Summer Falls and Main Canal requires a transmission arrangement that extends through the expiration of the contracts in 2024 and 2026, respectively. City Light, Tacoma Power and BPA will share costs associated with this project.

Substation Plant

Substation expansion and improvements are projected to cost about $77.3 million over the 2007-2012 period, averaging about $12.9 million per year and comprising about 6% of total planned expenditures. Major expenditures to construct a future substation in the South Lake Union area and a new Interbay Substation have been deferred and are now scheduled to begin in 2014 and 2015, respectively. However, City Light proposes four capital projects (one substation and three distribution) to shift load among the substations so that capacity needs in South Lake Union can be met in the near term. City Light anticipates purchasing property for a future South Lake Union substation in 2006. The Department also plans to replace breakers at two BPA substations, Covington and Maple Valley.

Distribution Plant

The Department plans to spend about $912.8 million over the 2007-2012 period on improvements and additions to the distribution system, averaging $152.1 million per year and representing about 68% of total CIP expenditures. A major portion of these expenditures will be required to relocate infrastructure and provide capacity related to a number of large local transportation projects. Projects include the development of a light rail system by Sound Transit, the construction of the South Lake Union streetcar, and utility equipment relocation associated with replacement of the Alaskan Way Viaduct. Together, those projects account for about 37% of Distribution CIP (or 25% of total CIP spending) during the six-year period. Reimbursement for these relocation costs is not expected. Investment in the downtown network distribution system is projected to reach $159.6 million over the six-year period, averaging $26.6 million per year and representing about 12% of total CIP spending during that time. Other distribution expenditures include service connections, relocations and capacity additions, conversion of the 26 kV system, and streetlight/floodlight improvements. The following discussion provides a brief summary of the major Distribution CIP projects planned for 2007-2012.

Alaskan Way Viaduct. The Alaskan Way Viaduct is part of State Route 99, serving north/south traffic through downtown Seattle. Viaduct support structures were damaged during the 2001 Nisqually Earthquake. The Washington State Department of Transportation conducted a plan and study for demolition and replacement of the viaduct. City Light has critical transmission and distribution infrastructure along the project corridor, all of which must be relocated once or twice during the project. City Light capital expenditures for this project are estimated to be $305.8 million in years 2007-2012. Costs are expected to peak in 2009 and 2010, averaging $71.2 million for each of those years.

Sound Transit. This project relocates City Light transmission and distribution facilities and provides service connections and capacity to the Sound Transit Light Rail project. Project expenditures for the six-year period 2007-2012 are expected to amount to about $28.5 million, peaking in 2007 at about $15.5 million.

Network Additions and Service. These projects provide for the improvement and expansion of the networks that serve high-density load areas (downtown, University District, First Hill), ensuring system reliability and continuity of service. The planned work includes installation, upgrading and replacement of conduits, maintenance holes, vaults, feeders, primary cables, transformers, network protectors, fire protection systems, and switch gear, as well as improvements to the network transformer monitoring system. Over the 2007-2012 period, annual expenditures are projected to average about $26.6 million.

Capacity Additions. The expenditures projected in this group of projects are for building or reconductoring line segments, replacing poles, adding cables for increased customer loads, installing new feeders, and adding underground facilities to match changing service demands in the City Light service territory. These projects are outside the network areas. Capital expenditures in this category are expected to average about $15.5 million per year over the 2007-2012 period.

Service Connections. There is a continuous need for new and enlarged service connections within the City Light service territory, outside of the network areas. Customer requests fluctuate with land use development and changing demand. Voluntary underground projects are also included in this set of capital projects. Average annual expenditures for these purposes over the six-year period are expected to amount to approximately $14.1 million.

Neighborhood and Customer Initiated Projects. City Light proposes to address neighborhood issues and customer requests. The Leschi residential underground distribution system is unreliable and needs replacement. Residential and franchise undergrounding expenditures are expected to average about $9.2 million per year over the six-year period. Lake Forest Park area feeders need rehabilitation. The Intergate East Internet Center in Tukwila requires feeder upgrades, which will be funded substantially through customer service charges.

26-kV Conversion. Conversion of both the overhead and underground distribution systems from 4 kV to 26 kV is a long-term project for the Department. The conversion provides greater capacity and reliability and allows the system to meet increased capacity demand. Total capital expenditures for the conversion are projected to average about $3.9 million per year throughout the six-year CIP.

Other Relocations. The Department frequently has to move electrical lines to accommodate projects being constructed by non-City entities. Types of projects that require relocation of electrical lines include transportation projects, street vacations, and large industrial, commercial and residential developments. Total capital expenditures for relocations are projected to average about $3.3 million per year throughout the six-year CIP. This does not include the costs of relocations for Sound Transit and the Alaskan Way Viaduct.

South Lake Union Load Transfer. Expenditures to acquire property and construct a future substation in the South Lake Union area have been deferred pending approval of Council legislation to acquire property for this purpose. The Department's load forecast indicates that a new substation may be needed by 2016. Four capital projects to meet near-term capacity requirements in the South Lake Union (SLU) area (one substation and three distribution projects) are assumed in this capital plan. They will allow City Light to shift load among the substations to accommodate SLU's growing demands. About $3.0 million in 2007 and 2008 are needed.

Streetlights and Floodlights. Lighting projects in the 2007-2012 capital plan include provision for additional customer-requested streetlights, including requests from unincorporated areas served by City Light. Lighting projects address public safety concerns in certain commercial and residential neighborhoods and major maintenance for arterial streetlights in Seattle whose ownership was transferred from the City to City Light at the end of 1999. About 72% of the lighting project cost is in the arterial streetlights category, and the majority of those expenditures will be for lights and their associated infrastructure in the downtown area. Total capital expenditures for lighting are projected to average about $2.0 million per year throughout the six-year CIP.

Automated Meter Reading. A pilot project in 2006 purchased, installed, integrated and tested a two-way radio frequency (RF) network collection system in the South Lake Union/Denny Triangle areas. This project installs AMR-equipped metering in all new buildings developed in the South Lake Union/Denny Triangle areas from 2007 onward and retrofits existing buildings beginning in 2008 until done. This project improves customer service by automating the collection of time-based consumption and billing data from customers' electric meters in the South Lake Union/Denny Triangle areas. The AMR technology will enable a wider range of billing and payment options that customers want and better response to outages by being able to see who is out and then which meters are still out as restoration begins. It is also expected to achieve cost savings from efficiencies in the metering/billing/call center business processes. Project costs are expected to average about $1.2 million annually over the period.

General Plant

Programmed expenditures of $185.5 million will support general plant improvements over the 2007-2012 period, averaging about $30.9 million per year and representing about 14% of total capital expenditures over that period. Investments in information technology account for about $89.8 million, or about 7% of the total CIP. Replacement and expansion of mobile fleet equipment, which had been deferred over the past several years, will require the expenditure of $50.7 million, or about 4% of the total CIP. The major components of General Plant CIP for the next six years are described below.

Information Technology. Planned capital projects in information technology are expected to average about $15.0 million per year over the 2007-2012 period. CIP funding is provided for the Department's customer billing systems, as well as those dedicated to information technology infrastructure, non-network area mapping, and work process management. Several new projects have been proposed to maintain or improve customer service.

- BillView software replacement in 2007 will enable City Light to continue to answer customer billing questions in a timely manner by replacing an obsolete system that is no longer supported by vendors. Total project cost is estimated at $660,000.

- Complex Billing will replace a manual billing system for City Light's largest customers in 2007 at an estimated cost of $543,000. It will allow City Light to provide its largest business customers with improved billing and presentment options, while reducing risk of costly errors in the billing process.

- Customer Electrical Service Installation Process (CESIP) enhances the current electric service installation process for all type of new and enlarged electric services. It is expected to reduce the cycle time for electric service installations for residential, commercial and industrial customers. As a result, customer satisfaction should improve because costs and schedules will be more predictable and utility revenues and credibility with customers should increase. Projected costs are $250,000 starting in 2008 and continuing throughout the six-year plan.

- City Light will initiate funding for Disaster Recovery and Business Continuity by securing IT computing system backup offsite in the event of a natural or other disaster, which will allow essential utility and customer services to continue.

Mobile Equipment Replacement/Additions. Averaging expenditures of about $8.5 million per year over the period, the Vehicle Replacement Project is dedicated to replacing and expanding City Light's heavy-duty mobile equipment fleet, as well as gradual replacement of light-duty vehicles previously leased from the City's Fleets and Facilities Department. The Utility deferred any capital replacement of vehicles during the energy crisis, which created a significant backlog of vehicles that have exceeded their useful life cycle. The Department will conduct a comprehensive review of the vehicle replacement program and establish industry standards and benchmarks for vehicle specifications and future replacement.

Communications Improvements. The major communications projects included in the 2007-2012 CIP will improve fiber optic cable and radio communications infrastructure that supports distribution, transmission and generation control systems. The annual expenditure for these projects will average about $2.3 million.

Security Improvements. The Security Improvements program plans, designs and implements projects to improve physical security of critical City Light facilities to restrict unauthorized access and criminal activities that could cause significant system damage, power outages and other disruptions to City Light's electrical system. Average expenditures for the six-year plan are about $1.6 million per year.

5.4 Deferred Conservation Program Expenditures

Conservation resource programs offer financial incentives (rebates, discounts, loans, etc.) 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 current plan anticipates expenditures of $20.7 million in 2006, $21.2 million in 2007 and $21.6 million in 2008, with growth at the rate of inflation thereafter.

In the 1980's and early 1990's, the residential sector commanded well over 50% of the programmatic conservation expenditure plan. Since the mid-1990's, this sector accounted for a smaller proportion of the total, and that is expected to continue. Because of saturation in the residential sector, City Light's conservation program has been focused primarily on the commercial sector in the past several years.

5.5 Deferred O&M Expenses – Boundary Relicensing and Mitigation

In addition to making capital expenditures for environmental mitigation as part of its CIP, City Light also defers and capitalizes certain operations and maintenance expenditures for environmental mitigation. These expenditures are for mitigation measures similar to those included in the CIP and are similarly required under the terms of Federal licenses of the Skagit, South Fork Tolt and Boundary projects and in accordance with City Council resolution to protect endangered species in City Light generation areas. They differ from the expenditures in the CIP because they are for measures on land or structures belonging to entities other than City Light and involve payments to the owners. Recipients of these payments include a variety of nonprofit organizations and governmental agencies with which City Light has entered into contracts for environmental mitigation per the terms of relicensing settlement agreements. They are projected to total $6.3 million in 2006, $10.0 million in 2007, and $10.8 million in 2008, as shown in the line for "Deferred O&M Costs" in Table 1.03 in Appendix 1.

5.6 Other Funding for Capital Expenditures

Capital expenditures are funded from three major sources: 1) contributions, grants and fees from customers and other entities related to the assets or services being acquired as a result of the capital expenditure; 2) revenue from retail customer rates and other operating revenues; and 3) proceeds from debt. The more City Light can leverage costs with other entities or collect revenues from fees for construction and connection services, the less funds are required from retail customer rates and long-term borrowing. Other funding for capital expenditures is projected to decrease from $25.2 million in 2006 to $19.0 million by 2008, or by $6.2 million (25%), largely due to the schedule of completion for the Sound Transit light rail project.

Table 5.3
(Thousands of actual dollars)

Contributions	2006	2007	2008	2009	2010	2011	2012
Contributions in aid of construction	13,870	20,692	17,418	18,818	20,374	20,988	20,100
Capital Grants - Sound Transit	11,289	5,878	1,540	1,169	938	681	636
Customer Conservation Loans	8	8	8	8	8	9	9
Total Contributions	25,166	26,578	18,966	19,995	21,320	21,678	20,745

Contributions in Aid of Construction (CIAC). Customers that install new electrical service or upgrade their existing service pay installation charges that reimburse City Light for part of the cost of equipment and hookup to the City Light system. Customers also pay the capital cost of non-standard service that they request. Examples of the latter are underground service and a second feeder. When large customers have buildings or other facilities under construction that require City Light to relocate or replace the utility's feeders or other equipment, the customers must reimburse the utility for these costs also. City Light projects CIAC to increase from $13.9 million in 2006 to $17.4 million in 2008, or by $3.5 million.

Fees for Services and Grants. When construction projects of local governments or other agencies require City Light to relocate, construct, or replace utility equipment, the local government or agency is required to reimburse the utility for its costs. Examples of this would include street widening, bridge rehabilitation or tunnel digging. The largest of these are tracked as Special Projects. Among the largest current Special Projects are Sound Transit Light Rail, the South Lake Union Streetcar and the Alaskan Way Viaduct. Seattle City Light does not expect to be reimbursed for the cost of relocating electrical equipment before and after construction for either the Viaduct or the Streetcar projects.

The Sound Transit Light Rail project requires a substantial amount of work on the City Light distribution system to support construction of the project and electric service to the light rail system. City Light expects to be reimbursed for some of this work. City Light received $8.4 million in 2005 and is expecting to receive $11.3 million in 2006, with lesser amounts forecast for succeeding years through 2012.

Sources of Funding for Conservation. The Department receives contributions from customers participating in residential weatherization and lighting programs. These are either up front payments by customers for work during the current year or repayments of loans made in prior years. Customer contributions for conservation have greatly diminished in recent years as residential home energy loans have been paid off, and they are forecast to total only $8,000 - $9,000 annually through 2012.

The primary source of funding for City Light conservation programs is Federal funding provided by the Bonneville Power Administration (BPA). This is accounted for as operating revenues and is discussed in detail in Chapter 3, Section 3.5, "Other Power-Related Revenues." BPA funding takes two forms. The first is a "Conservation & Renewables Credit" which reduces City light's expenses for power purchased from Bonneville. The second is direct grant funding, as part of BPA's "Conservation Augmentation" program.

Chapter 6

Borrowing, Debt Service and Debt Accumulation

6.1 Introduction

The amount of borrowing required to fund the capital program is determined by the size of City Light's capital requirements (net of contributions and grants) and its accounting and financial policies. The Capital Improvement Program and Conservation Implementation Program, and the amount of funding from fees for services, contributions in aid of construction, and grants from outside entities such as the Bonneville Power Administration, are discussed in detail in Chapter 5.

The size of the Department's borrowing requirements is affected by accounting policies, in addition to program requirements. Accounting principles guide decisions about which activities may be capitalized or deferred and expensed over time. For example, the decisions to defer conservation and information systems investments and to allocate a portion of administration and general expenses to capital expenditures have had a significant upward impact on capital requirements and debt over time. Similarly, accounting policies regarding how fast to depreciate and amortize capital and deferred expenditures can impact net earnings and, therefore, the Department's ability to achieve its financial debt-to-capitalization target.

To fund capital requirements, City Light mostly uses proceeds from operations, including revenue from retail customer rates, and proceeds from debt issued. Contributions and capital grants fund only a small percentage of capital expenditures. In general, higher reliance on debt to finance capital expenditures leads to lower customer rates in the near term but higher rates over the long run, as future revenue must be sufficient to meet debt service payments and coverage requirements on that debt. Conversely, lower reliance on debt causes customer rates to be higher in the near term and lower over the long run.

City Light's financial policies govern the relative mix of funding from retail customer rates, cash balances and long-term borrowing to ensure the financial stability of the utility. In the 2007-2008 revenue requirement, the financial target that drives customer rates is the financial policy that requires City Light to have 95% confidence that current revenues available for CIP are greater than zero during the rate period. In achieving that goal, all other financial policies are met. City Light expects to reach its long-term goal of 60% debt to capitalization by 2010 while also maintaining a debt service coverage ratio of at least 2.0 and a minimum operating cash balance of $30 million, in addition to the $25 million operating contingency reserve that must be maintained at all times and used only in the event of a critical shortage of operating funds due to extremely dry water conditions or other unanticipated extraordinary circumstances.

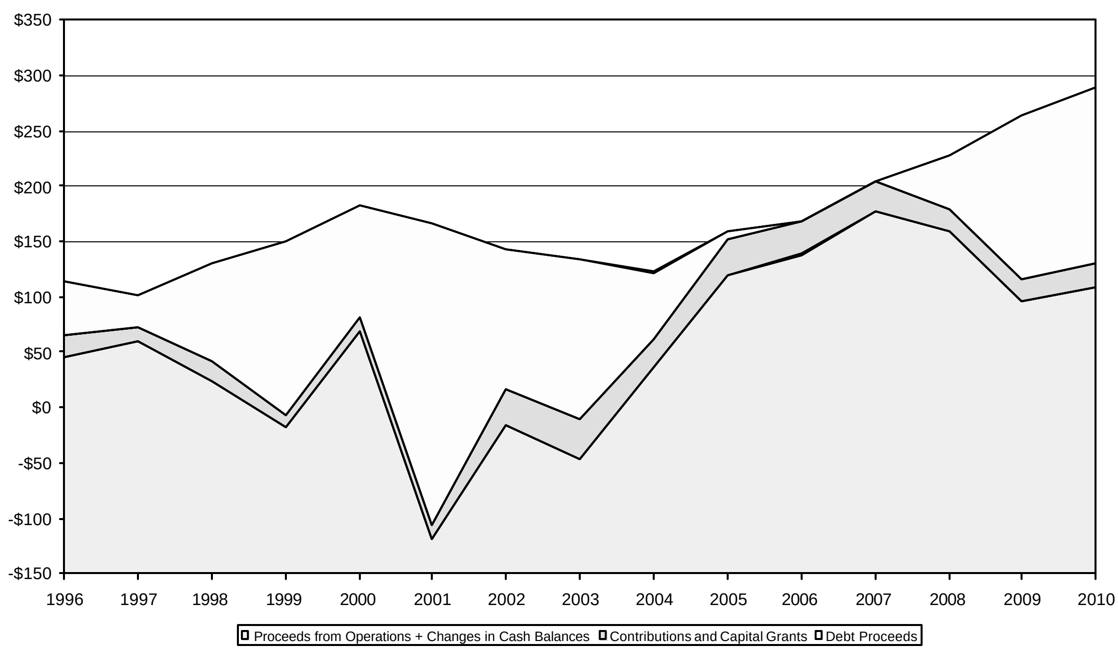
6.2 Funding for Capital Requirements

Figure 6.1 shows total capital requirements (excluding deferred power charges) for years 1996 to 2010 and the mix of funding sources from borrowing, operations, and contributions and capital fees and grants for each year. Capital requirements are projected to grow from $167.6 million in 2006 to $228.5 million by 2008, increasing by $60.9 million or 36%. The capital forecast continues to increase from 2006 through 2010 in actual and constant dollars. Growth is projected to continue at a level above the rate of inflation. Prior to 2006 actual capital expenditures were funded at a level that was on average below the rate of inflation.

Looking ahead from 2006, City Light anticipates funding a larger share of capital expenditures from operating revenues, consistent with more conservative financial policies enacted since the Energy Crisis of 2000-2001. In past years, capital expenditures were more heavily funded from debt and City Light's debt to capitalization ratio rose above prudent industry benchmarks.

Figure 6.1

Capital Expenditures Excluding Deferred Power Charges and Sources of Financing
In Millions of Current Year Dollars



6.3 Debt Issued

Total debt issued in any year is equal to total funds required for capital projects less funds available from sources other than the issuance of bonds and less (or plus) required changes in the utility's cash balances, which are governed by financial policies. In years 2006 and 2007, City Light does not anticipate issuing debt. Funding of capital requirements will primarily come from current revenues and excess cash balances that resulted from the liquidation of the Bond Reserve Fund in 2005 and from keeping customer rates near the level set in response to the energy crisis in 2001. Between 2006 and 2008, funding from operations including changes in cash balances is expected to increase from $138.4 million to $159.9 million, or by $21.5 million. Other funding for capital expenditures including contributions in aid of construction and capital fees and grants is expected to decline from $29.2 million in 2006 to $19.0 million in 2008, or by $10.3 million, due primarily to the winding down of the Sound Transit Light Rail project. City Light plans to issue about $50.0 million in debt in 2008, $148.9 million in 2009 and $160.6 million in 2010.

6.4 Debt Accumulation and Debt Expense

The change in the mix of funding sources for long-term capital expenditures, including the liquidation of the Bond Reserve Fund and lower capital expenditures in prior years (2001 to 2004) results in declining debt outstanding and debt service expense through 2008. Debt outstanding will begin to rise again in 2009 as capital expenditures increase and borrowing occurs, as can be seen in Figure 6.2. Debt service expense is expected to decrease from $141.7 in 2006 to $137.0 in 2008, or by $4.8 million (3.4%). The primary reason for the decline is that City Light will repay a note payable to Sound Transit, paying off $5.5 million in 2006 and the remaining $4.4 million in 2007. Offsetting this decrease is a $0.8 million increase in debt service on 2nd lien debt. Debt expense will begin to increase after the bond sale in 2008, which will provide funds for a growing capital program.

6.5 Debt-to-Capitalization Ratio

Figure 6.3 tracks the debt-to-capitalization ratio from 1996 to 2010. Prior to the energy crisis in 2000, City Light's debt to capitalization ratio grew from about 68% in 1997 to about 84% in 2001 and remained at that level through 2004. By keeping retail customer rates at levels implemented during the energy crisis, liquidating the Bond Reserve Fund and replacing it with a surety bond, and lowering capital investment from 2001 to 2004, City Light began to reduce its debt to capitalization ratio, bringing it down to about 78% in 2005. By pursuing more conservative financial policies that require higher contributions from operating revenues and higher cash reserves, City Light expects to reach its long-term debt to capitalization target of 60% by 2010. This reduction in the debt to capitalization ratio occurs even though debt issuance increases in 2009 and 2010 because equity capital also increases significantly during that time as a result of City Light's increased investment in capital assets.

Figure 6.2

Outstanding Long-Term Debt
In Millions of Dollars

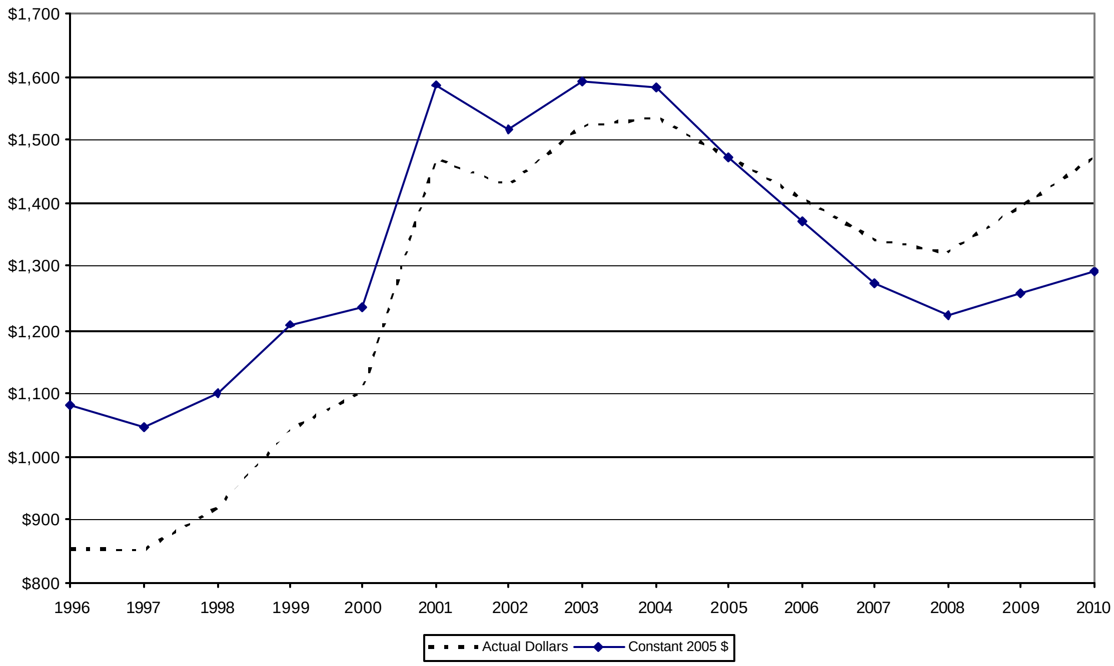
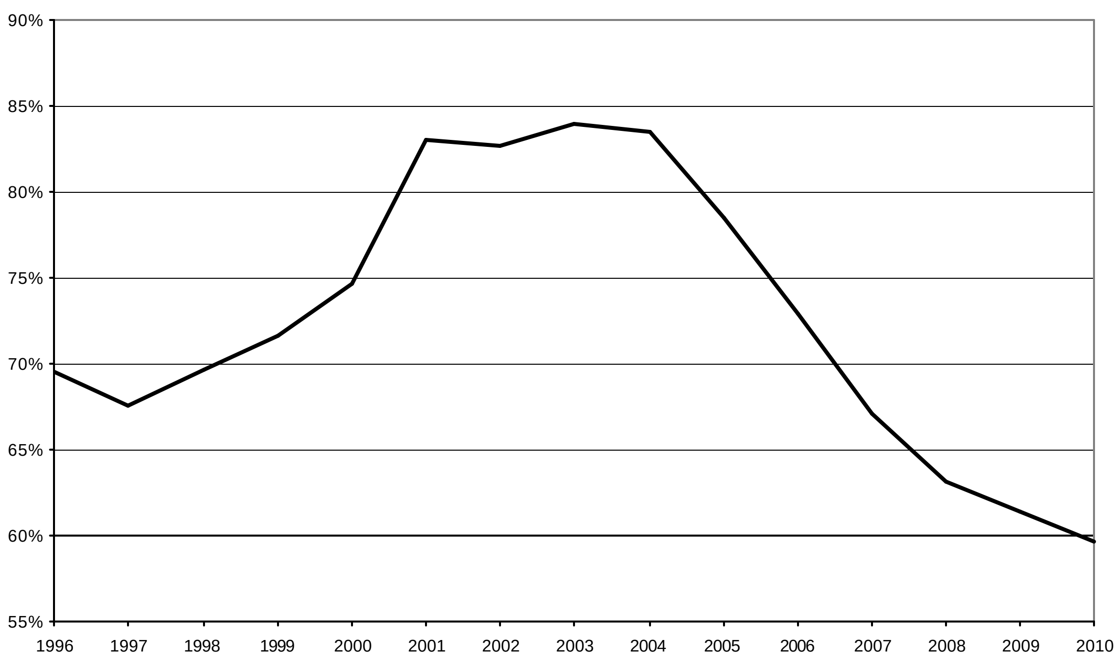


Figure 6.3

Outstanding Long-Term Debt as a % of Total Capitaliztion



6.6 Types of Debt Financing

The amount of debt issued is the difference between total capital requirements and the sum of all the funding sources described above. Debt issued may be fixed-rate first-lien debt or variable-rate second-lien debt. Miscellaneous funding sources from short-term notes and loans are also used for specific purposes from time to time.

City Light currently has two types of long-term debt outstanding: first-lien debt, consisting of long-term revenue bonds issued with fixed interest rates; and second-lien debt, issued in the form of long-term bonds paying interest at variable interest rates. The distinguishing features of these types of debt are reviewed in the following paragraphs.

First-Lien Bonds. The payment of debt service on first-lien bonds has a claim on the revenues of the Department that is subordinate only to the payment of operating and maintenance costs. This claim gives bondholders a high degree of confidence that they will receive their payments of principal and interest on the scheduled dates. Bonds issued with the same claim on revenues as outstanding first-lien bonds are said to be issued "on a parity with" the outstanding bonds. The terms "parity bonds", "first-lien bonds", and "fixed-rate bonds" are used interchangeably. City Light's first-lien bonds are issued with a fixed schedule of annual maturities. The rate of interest is fixed at the time of issue. The debt service schedule on outstanding first-lien bonds may be altered only through the issuance of bonds to refund the debt outstanding.

Second-Lien Bonds. The payment of debt service on second-lien bonds has a claim on City Light's revenue stream that is subordinate to that of first-lien bonds. City Light's second-lien bonds are similar to first-lien bonds in that they are issued with a fixed schedule of maturities, with the final maturity scheduled 25 years after the date of issuance. However, second-lien bonds differ from first-lien bonds in several important ways. The interest rate payable on second-lien bonds is not fixed at the time of issue for the entire life of the issue. When second-lien bonds are issued, an interest rate is set for an initial interest payment period, which may be as short as one week or as long as several years. At the end of the initial interest payment period, a new interest rate is set for the next interest payment period, the length of which is again determined by the issuer. This process is repeated throughout the life of the second-lien bonds. At the end of any interest payment period, the holder of the bond has the right to demand payment of principal (to "put" the bond to the issuer). If this option is exercised, the bonds will be re-marketed by the issuer's marketing agent. In addition, at the end of any interest payment period, the issuer has the right to convert the second-lien bonds to fixed-rate, first-lien debt.

Other Miscellaneous Borrowing. City Light may issue short-term bond anticipation notes (BANs) or revenue anticipation notes (RANs) before a bond sale or rate adjustment from time-to-time. The notes are repaid with bond proceeds or customer revenues. Also, City Light has borrowed from other City Departments or government agencies, such as the Sound Transit Fund, Parks Department and City cash pool. These loans are generally earmarked for a specific purpose such as a construction project or property purchase and are not the result of cash constraints. They are also relatively small in amount, unlike the RANs and BANs, which have been quite large at times, and are typically of relatively short duration, usually being repaid within a year or two.

Chapter 7

Unbundled Revenue Requirements

7.1 Introduction

The Stages of Bundling and Unbundling. The issue of bundled and unbundled revenue requirements is related to the definition of equity contained in Council rate resolutions. In the most recent resolution, the definition states that rates should fairly apportion the costs of providing service among customer groups. The following is a short history of bundled and unbundled revenue requirements.

1980s-1995/96: From the early 1980s through the 1995/96 rate review, City Light had calculated marginal costs in component pieces (energy, distribution, customer costs). However, the revenue requirements, though separated into components in terms of direct expenses (such as production, transmission and distribution), were still "bundled" in terms of indirect expenses (such as administrative expenses, depreciation and amortization, interest expense and taxes). Consequently, City Light had "bundled" the pieces in both cases to calculate one marginal cost total for each customer class and one revenue requirements total. The percentages of marginal costs by customer class determined the share of the revenue requirement that each class would pay.

1997/98: In the 1997/98 rate review, Seattle City Light separated the revenue requirements into component pieces, finding reasonable ways to allocate or assign indirect expenses to direct expense categories (often called "functions"). Such components were related to energy production and purchases, transmission, distribution, customer services, and public policy programs. It then used shares of the appropriate components of the marginal costs to allocate each component of the revenue requirements. An energy marginal cost allocator was applied to the energy-related revenue requirement (production, purchased power and transmission), a distribution marginal cost allocator was applied to the distribution-related revenue requirement, and a customer cost allocator was applied to the revenue requirement related to customer service. Conservation and low-income assistance were placed in the category called public policy programs, which was allocated to customer classes based on a total marginal cost share, consistent with what was done in the past. This placement was a policy decision made with the intent that: a) customers who might choose another energy provider could not avoid paying for conservation investments made on their behalf, thus leaving programmatic conservation measures as stranded investments to be paid for by the remaining customers; and b) the low-income assistance subsidy would not be shifted among classes. The overall methodological change was called "unbundling."

The 1997/98 unbundling procedure facilitated City Light's participation in the 1998 statewide discussion of electric utility deregulation and improved the utility's ability to explain to its customers the different services provided and the cost of providing them.

This level of unbundling is also sufficient for decisions about what to charge a customer who might want to buy retail services from City Light and energy from another provider.

2000-2002: For the 2000-2002 rate review, City Light continued to unbundle the revenue requirement more or less along the lines that were used for the 1997/98 review. Related marginal cost shares continued to be used to allocate the revenue requirement components to customer classes. Some fine-tuning was carried out to match up these shares and components. Likewise, the revenue requirement was split into more components and these were reshuffled in some cases, in order to make costs clearer or to respond to policy decisions. There were three major differences between the 1997/98 unbundling and the 2000-2002 unbundling. For the latter: 1) Conservation was included as an energy resource instead of a public policy program; 2) Transmission was divided into two parts – the long distance part, which is considered part of Energy, and the in-service-area part, which is considered part of Retail Services in the Distribution category; and 3) Streetlight/Floodlight revenue requirements were calculated based on actual expenses instead of an external model.

The decision to treat Conservation as an energy resource rather than a public policy program was the result of the addition of provisions in conservation measure contracts that require a customer who benefits from such measures but then decides to take energy from another provider to reimburse the Utility for such measures.

The separation of Transmission into two components was based on the fact that in-service-area transmission supports the distribution system, while long-distance transmission is used to bring energy to the Department's service area.

The calculation of revenue requirements to be directly assigned to Streetlight/Floodlights using actual expenses as the basis increased the overall revenue requirements for this sub-function dramatically over the 1997/98 amount. Since this was the first time lighting expenses had been calculated under the new procedures and it was not known whether the expenses would continue at the 1998 level, the effect of the change was mitigated within the unbundling process by using a five-year average for both the labor hour allocation factor and distribution expenses assigned to the function, as well as by omitting an allocation for "miscellaneous distribution" expenses.

2007/08: The unbundling of the 2007/2008 forecasted revenue requirements generally follows the same logic and procedures used for the 2000-2002 process, with two exceptions: 1) the Streetlight/Floodlight allocation is not mitigated within the unbundling process because experience over several years has shown that lighting expenses are indeed quite a bit higher than those calculated in the previously used external model; and 2) net wholesale revenues to be received by City Light are so much greater than they have been in the past that they distort actual energy costs by a significant amount; they have been removed from the unbundling process and then allocated to customer classes after all other cost of service allocations have been made.

The rationale for allocating net wholesale revenues to customer classes after other cost allocations have been determined, and in fact based on those prior allocations, is that the risk City Light faces through sales and purchases of energy in the West Coast wholesale market is borne by the utility as a whole – that is, all functions and all customer classes. City Light's participation in the wholesale market involves substantial risk because the utility's energy supply is determined by unpredictable weather conditions and by prices that are also subject to significant uncertainty. New, stricter financial policies were adopted by the City Council in 2001 and 2005 (Resolutions 30428 and 30761) with the goal of managing the risk associated with the possible wide variance of wholesale revenue and assuring the utility's financial strength over the long term by reducing its debt.

Prior to the energy crisis of 2000-2001, City Light's participation in the wholesale market was fairly small. In 2000 and 2001, purchases on that market exceeded sales by a significant amount. By 2002, however, City Light had acquired new resources and sales began to exceed purchases by a very large amount, with this situation continuing through 2005, into 2006, and through the forecast horizon. If City Light had continued with its prior policy of allocating net wholesale revenue (which was negative, i.e., an addition to power expense, in the years 1992-1995, 1998 and 2000-2001) to the purchased power function of the 2007 and 2008 unbundled revenue requirement, the expected $190 million and $150 million of net revenue in this category for the two years would have reduced the power portion of the revenue requirement by about 40% for each year. Such a reduction would disproportionately benefit energy-intensive customers through rates, to the detriment of those which are not so energy-intensive, when the financial risk of net wholesale revenues being significantly different from the forecast is really borne equally by all the utility's customers.

7.2 Overview of Unbundled Revenue Requirements

Rates are normally set to recover the revenue requirement on a calendar year basis. However, because of the Mayor's desire to establish one set of rates that would be applicable for both 2007 and 2008, the revenue requirements for each year were unbundled into functions, then the dollars in the functions were combined for the two-year period. Once average customer class rates were determined by the cost of service process, based on the combined unbundled functions, the Financial Planning Model (FPM) was re-run for 2007 and 2008 to test the results with the two-year rates. The explanation of the unbundling results that follows describes the initially separate annual revenue requirements. The final unbundled revenue requirements that tested the adequacy of the two-year rates are provided at the end of this chapter.

One aspect of the FPM which is different from previous rate reviews is that FPM Table 1.01 is designed as a Statement of Operations that shows the net revenue from retail power sales actually expected to be received by Seattle City Light ("Retail Power Sales Inside System"); in previous rate reviews that same table showed what was termed "Energy Sales Inside System at Base Rates." Revenue from base rates – the retail revenue requirement actually allocated to retail customer classes – is a little different from revenue from retail power sales now shown in Table 1.01 because the former is adjusted to take into account revenues and credits which are handled apart from retail sales in the FPM. The table below reconciles the two revenue requirement amounts.

Reconciliation of Revenue from Retail Power Sales with Allocated Revenue Requirement

	2007	2008	2007-08
Revenue from Retail Power Sales Inside System	$527,958,847	$545,531,748	$1,073,490,595
Avg. Rate ($/MWh) Before Adjustments	$55.60	$56.37	$55.99
Plus:			
Residential Low-Income Rate Discount	5,360,752	5,419,559	10,780,311
Transformer Ownership Credit	313,559	322,014	635,573
Less:			
Power Factor Charge	(2,430,956)	(2,489,006)	(4,919,962)
Credit for Network Rates-New Areas	0	(1,500,000)	(1,500,000)
Total Revenue Allocated to Retail Customer Classes	**$531,202,201**	**$547,284,314**	**$1,078,486,515**
Energy Sales to Retail Customers (MWh)	9,496,232	9,677,386	19,173,618
Avg. Rate ($/MWh) After Adjustments	$55.94	$56.55	$56.25

The residential low-income rate discount is ultimately reflected in separate low-income rate schedules that are established outside the cost of service analysis as a percentage of non-low-income residential rate schedules, based on policy direction from the City Council. The cost of service study treats the portion of the revenue requirement related to low-income residential service as a separate dollar amount to be reallocated to other customer classes.

The transformer ownership credit is incorporated as a secondary part of non-residential rate schedules. When the few customers who have provided their own transformation equipment are billed, they are first billed on rates which do not reflect that discount, then their bill is reduced by the discount.

The amount charged to customers with low power factors is also incorporated into non-residential rate schedules, as a separate charge which also appears as such on the customer's bill.

The credit for network rates in new areas is a reflection of new revenue forecasted to be received from customers located in City Light network areas that are not billed currently under higher network rates (such as First Hill and the University District). A study will be undertaken in 2007 to determine the extent to which customers in these areas should be charged network rates.

The revenue requirements below total to the revenue allocated to retail customer classes.

Functional Allocation of 2007 Revenue Requirements

	Total	Net Direct Expenses	Depreciation & Amortization Net of Capital Cont. & Grants	Interest	Admin. and General	Rev. Taxes & County Payments	Net Income
Total Energy	**$497,991,576**	**$287,136,193**	**$24,974,997**	**$23,854,475**	**$13,752,088**	**$41,073,681**	**$107,200,142**
Power	429,849,409	246,746,185	18,704,191	16,285,765	11,875,747	34,883,072	101,354,449
Conservation	17,053,942	2,122,745	3,998,844	4,969,515	811,342	1,313,292	3,838,204
Transmission-Long Distance	51,088,225	38,267,263	2,271,962	2,599,196	1,064,999	4,877,317	2,007,489
Total Retail Services	**$222,809,788**	**$65,011,046**	**$35,553,691**	**$35,844,143**	**$39,326,408**	**$19,390,279**	**$27,684,221**
Total Distribution	155,084,787	32,725,616	23,392,559	34,358,121	25,297,726	12,774,273	26,536,492
Transmission-In Service Area	*9,494,421*	*3,406,606*	*1,637,864*	*1,110,112*	*1,624,154*	*858,290*	*857,395*
Stations	*30,518,054*	*9,882,080*	*4,993,797*	*3,265,358*	*7,072,758*	*2,782,061*	*2,521,999*
Wires and Related Equipment	*78,242,821*	*11,038,111*	*9,770,836*	*22,214,934*	*11,991,004*	*6,070,232*	*17,157,703*
non-network	*55,083,413*	*9,225,743*	*6,213,863*	*14,127,814*	*10,214,879*	*4,389,499*	*10,911,616*
network	*23,159,408*	*1,812,368*	*3,556,973*	*8,087,121*	*1,776,125*	*1,680,733*	*6,246,087*
Transformers	*17,436,369*	*1,577,424*	*3,734,160*	*5,667,010*	*783,099*	*1,297,762*	*4,376,914*
non-network	*9,542,231*	*701,343*	*2,164,030*	*3,284,161*	*159,995*	*696,181*	*2,536,521*
network	*7,894,138*	*876,082*	*1,570,129*	*2,382,849*	*623,104*	*601,581*	*1,840,393*
Meters	*10,130,724*	*2,812,759*	*1,971,300*	*1,388,254*	*1,986,020*	*900,174*	*1,072,218*
Streetlights/Floodlights	*9,262,397*	*4,008,636*	*1,284,602*	*712,453*	*1,840,690*	*865,754*	*550,263*
Customer Accounts & Services	59,075,595	25,511,801	11,730,654	1,433,420	13,532,096	5,760,523	1,107,102
Low-Income Assistance	8,649,406	6,773,629	430,479	52,602	496,586	855,483	40,627
Total	**$720,801,364**	**$352,147,239**	**$60,528,688**	**$59,698,618**	**$53,078,496**	**$60,463,960**	**$134,884,363**
Load (MWh)	9,496,232						
Average Cost per MWh	$75.90	$37.08	$6.37	$6.29	$5.59	$6.37	$14.20
Percent of Total Cost	100.00%	48.85%	8.40%	8.28%	7.36%	8.39%	18.71%
Net Wholesale Revenue	(189,599,163)						
Retail Revenue Requirement	**$531,202,201**						

Functional Allocation of 2008 Revenue Requirements

	Total	Net Direct Expenses	Depreciation & Amortization Net of Capital Cont. & Grants	Interest	Admin. and General	Rev. Taxes & County Payments	Net Income
Total Energy	**$456,175,793**	**$268,884,295**	**$26,517,368**	**$22,818,793**	**$14,418,908**	**$40,627,304**	**$82,909,125**
Power	388,593,815	230,639,552	19,491,369	15,578,691	12,451,585	34,393,734	76,038,884
Conservation	18,472,758	2,188,160	4,735,720	4,753,755	850,683	1,433,531	4,510,909
Transmission-Long Distance	49,109,220	36,056,583	2,290,279	2,486,347	1,116,640	4,800,039	2,359,332
Total Retail Services	**$240,906,787**	**$65,123,653**	**$46,331,212**	**$34,287,910**	**$41,233,290**	**$21,394,413**	**$32,536,309**
Total Distribution	171,522,966	32,845,496	33,690,329	32,866,406	26,524,377	14,408,934	31,187,423
Transmission-In Service Area	*9,844,984*	*3,461,149*	*1,703,977*	*1,061,915*	*1,702,907*	*907,370*	*1,007,667*
Stations	*32,394,899*	*10,558,442*	*5,311,333*	*3,123,587*	*7,415,706*	*3,021,812*	*2,964,019*
Wires and Related Equipment	*88,990,743*	*9,896,767*	*18,039,564*	*21,250,436*	*12,572,431*	*7,066,689*	*20,164,856*
non-network	*61,554,946*	*8,030,402*	*11,472,444*	*13,514,431*	*10,710,185*	*5,003,439*	*12,824,045*
network	*27,435,797*	*1,866,365*	*6,567,120*	*7,736,005*	*1,862,247*	*2,063,250*	*7,340,811*
Transformers	*19,723,339*	*1,667,456*	*5,172,881*	*5,420,967*	*821,071*	*1,496,928*	*5,144,036*
non-network	*10,828,805*	*734,827*	*2,997,802*	*3,141,573*	*167,753*	*805,764*	*2,981,086*
network	*8,894,534*	*932,629*	*2,175,079*	*2,279,394*	*653,317*	*691,164*	*2,162,951*
Meters	*10,709,169*	*2,994,309*	*2,074,242*	*1,327,981*	*2,082,319*	*970,178*	*1,260,141*
Streetlights/Floodlights	*9,859,831*	*4,267,374*	*1,388,333*	*681,521*	*1,929,942*	*945,957*	*646,705*
Customer Accounts & Services	60,576,604	25,436,509	12,193,422	1,371,185	14,188,248	6,086,101	1,301,138
Low-Income Assistance	8,807,217	6,841,648	447,461	50,318	520,665	899,377	47,748
Total	**$697,082,580**	**$334,007,948**	**$72,848,580**	**$57,106,703**	**$55,652,198**	**$62,021,717**	**$115,445,434**
Load (MWh)	9,677,386						
Average Cost per MWh	$72.03	$34.51	$7.53	$5.90	$5.75	$6.41	$11.93
Percent of Total Cost	100.00%	47.92%	10.45%	8.19%	7.98%	8.90%	16.56%
Net Wholesale Revenue	(149,798,266)						
Retail Revenue Requirement	**$547,284,314**						

The unbundling analysis takes its primary information from the Financial Planning Model. Other information used in the analysis includes non-administrative O&M labor hours by FERC account, depreciation and amortization schedules, and work order and accounting records. The latter information is used to assign and allocate expenses to functional categories.

There are two primary categories of expense within the functionalized revenue requirement analysis. These are direct expenses and assigned/allocated expenses. Direct expense is considered to be O&M and related revenue offsets. In the case of Transmission and Distribution, direct expense is allocated to the sub-functions within these major functions. Assigned expenses include amortization, depreciation and county payments (in lieu of taxes) applied to one function. Allocated expenses are those expenses that are apportioned among multiple functions and sub-functions. Allocated expenses include general plant depreciation, contributions and grants, interest, administrative and general expense, taxes and net income. The basis for allocations is explained below.

A detailed comprehensive table of the functionalized revenue requirements is included in the appendix to this chapter.

7.3 Direct Expenses (Net)

Direct expenses are O&M expenses that are directly incurred in providing City Light's services under each functional category. In some categories they are modified by revenue offsets.

Energy Generation and Purchases

Direct generation expenses include the costs of running City Light's seven hydroelectric plants (Boundary, Ross, Diablo, Gorge, Cedar Falls, Newhalem, and South Fork of the Tolt), as well as system control and dispatch expenses. Direct purchased power expenses include City Light's costs of buying long-term power from BPA, Lucky Peak, the High Ross Contract, the Grand Coulee Project, the State Line Wind Project and other projects.

Other direct expenses and offsets in this category include:

- Basis purchases and sales (paired power purchase and sale transactions at different locations at the same time at prices based on the difference in market value of energy at two locations).

- Other power costs, such as expenses associated with City Light's automated system control center, checking the metering apparatus associated with power purchases, and contract and environmental expenses.

- Other power revenues, such as the sale of reserve capacity and green tags (environmental benefits of energy generated from green resources), sales to Pend Oreille PUD 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.

Direct Generation and Purchased Power expenses are summarized below.

Direct Expense: Power		
	2007	**2008**
Generation O&M	$20,066,153	$20,574,544
Long-Term Purchased Power	240,147,177	223,529,463
Basis Purchases	547,884	562,677
Other Power Costs	7,908,114	8,121,633
Article 49 Sales to Pend Oreille County	(1,568,000)	(1,610,300)
Sales from Priest Rapids	(8,765,424)	(8,765,424)
Seasonal Exchange Delivered	(2,941,119)	(3,004,039)
Basis Sales	(1,026,000)	(1,053,702)
Other Services	(7,622,600)	(7,715,300)
Total	$246,746,185	$230,639,552

Conservation

Conservation is treated as an energy resource by City Light. It has been City policy since 1982 to avoid new physical resource costs by funding cost-effective conservation. All customers benefit because new (higher) resource costs are avoided. Costs of installed conservation measures are amortized over 20 years; therefore, direct conservation expenses include only annual planning, management, and customer information and assistance costs. Fees received from operation of the lighting lab are netted against these expenses. Conservation direct expense amounts are shown in the following table.

Direct Expense: Conservation		
	2007	**2008**
Conservation	$2,422,745	$2,488,160
Operating Fees (Lighting Lab)	(300,000)	(300,000)
Total	$2,122,745	$2,188,160

Long-Distance Transmission

Transmission O&M expense is split between long-distance and in-service-area lines on the basis of actual 2004 expenses recorded in FERC accounts. In most cases, FERC account names indicate whether the O&M should be one or the other. However, in a few cases (e.g., supervisory and engineering, load dispatching, and other expenses related to other sub-functions), 2004 expenses had to be allocated between the two transmission components; 2004 Transmission labor hour percentages were used for this purpose. The result is that 34.9% of forecasted transmission O&M expense is allocated to long-distance transmission, while 65.1% goes to in-service-area transmission. The long-distance portion below, however, is shown net of Puget Intertie and Puget Stillwater Substation amortization, since these amounts are included in the amortization category of costs.

Direct expenses of long-distance transmission include the costs of operating and maintaining City Light's own transmission facilities, payments for the operation and maintenance of the utility's share of BPA's Third AC Intertie to the Southwest, and payments to other entities for transmitting power across their high voltage lines (called "wheeling"). These expenses are reduced by expected revenues from:

- Transmission services, which are all assigned to the long-distance sub-function because they are derived from wheeling to the North Mountain Substation of Snohomish PUD and miscellaneous wheeling.

- A portion of rental revenue for transmission line attachments and cellular antenna sites, allocated to both transmission functions by 2004 O&M percentages.

Expenses of City Light's own transmission include those associated with transmission load dispatching, switching stations, inspecting and testing lines, and engineering. City Light's long-distance transmission facilities include lines that come from the Skagit projects to the Department's service area and lines associated with Cedar Falls, Boundary the North Mountain Substation, and the South Fork Tolt plant, BPA connections, and Bothell-to-Renton lines. Wheeling payments cover transmission from the Boundary project, Lucky Peak, Grand Coulee and smaller projects across BPA lines and lines owned by other utilities.

Direct long-distance transmission expenses and revenue offsets are summarized below:

Direct Expense: Long-Distance Transmission		
	2007	**2008**
Transmission O&M	$1,900,868	$1,978,402
Wheeling	39,861,676	39,588,976
Transmission Services	(3,275,505)	(5,286,317)
Transmission Attachments & Cell Sites	(219,776)	(224,478)
Total	$38,267,263	$36,056,583

In-Service-Area Transmission

As discussed above, transmission has been separated into two components in this unbundling analysis. In-service-area transmission is included in the Retail Services category of expense.

Direct expenses of in-service-area transmission include the costs of operating and maintaining the transmission facilities associated with 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 expenses are reduced by allocated rental revenues from transmission line attachments and cellular antenna sites. Expenses of in-service-area transmission include transmission load dispatching, switching stations, inspecting and testing lines, and engineering. Direct in-service-area transmission expenses are summarized below.

Direct Expense: In-Service-Area Transmission		
	2007	**2008**
Transmission O&M	$3,817,070	$3,880,394
Transmission Attachments & Cell Sites	(410,464)	(419,245)
Total	$3,406,606	$3,461,149

Distribution

Direct distribution expenses cover the costs of operating and maintaining the Department's distribution system, i.e., the lower voltage lines and associated equipment that bring energy to homes and businesses within the utility's service area. Expenses associated with distribution load dispatching and substations, overhead and underground lines, public lighting, meters, poles, vaults, ducts and transformers are included.

In the unbundled analysis, the direct expense for Distribution is allocated among five sub-functions: Stations, Wires and Related Equipment (Wires), Transformers, Meters, and Streetlights/Floodlights (Lights). The allocation of forecasted Distribution O&M expense is carried out based on actual 2004 expenses and labor hours recorded in FERC accounts. The result is that 27.1% is allocated to Stations, 52.8% to Wires, 3.1% to Transformers, 7.0% to Meters and 10% to Lights.

Most of the Distribution FERC accounts already carry titles that relate directly to the five sub-functions. Some, however, must be allocated among the components. Load dispatching is allocated on the basis of 2004 Distribution labor hour percentages to all categories except Meters and Lights, because no load dispatching work deals with these two sub-functions. General distribution expenses in the categories of supervision and engineering, apprenticeship programs, safety, tools and miscellaneous other expenses are allocated to all sub-functions, also based on 2004 labor hours.

Two distribution sub-functions have revenue offsets to O&M expense:

- Stations: O&M expense is offset by gains on the sale of distribution substation properties.

- Wires: O&M expense is offset by property rental and damages revenue, construction charge revenue, pole attachment revenue, revenue from customers who pay a penalty for having a low power factor, additional revenue expected from network rates, and other O&M revenue (mostly for equipment maintenance).

One distribution sub-function, Transformers, includes an additional expense for transformer investment discounts. Bills for customers that own their transformers are calculated initially as if all customer transformers were owned by City Light. However, these customers receive a discount on their bill and this discount adds a direct expense to the transformer sub-function.

Direct distribution expenses and offsets are summarized below.

Direct Expense: Distribution		
	2007	**2008**
Distribution O&M-Stations	$10,908,080	$11,612,144
Gain on Sale of Distribution Assets	(1,026,000)	(1,053,702)
Subtotal Stations	$9,882,080	$10,558,442
Distribution O&M-Wires and Related Equipment	$21,208,867	$22,577,798
Property Rental Income	(1,744,200)	(1,791,293)
Revenue from Damage	(1,436,400)	(1,475,183)
Other O&M Revenue	(3,148,800)	(4,004,068)
Construction (Installation) Charge Revenue	(410,400)	(421,481)
Pole Attachment Revenue	(1,000,000)	(1,000,000)
Network Rates-New Areas	0	(1,500,000)
Power Factor Revenue	(2,430,956)	(2,489,006)
Subtotal Wires	$11,038,111	$9,896,767
Distribution O&M-Transformers	$1,263,865	$1,345,442
Credits for Customer-Owned Transformers	313,559	322,014
Subtotal Transformers	$1,577,424	$1,667,456
Distribution O&M-Meters	$2,812,759	$2,994,309
Distribution O&M-Streetlights/Floodlights	$4,008,636	$4,267,374
Total	$29,319,010	$29,384,347

Customer Accounts and Services

Direct expenses in this category cover meter reading, records and collections, uncollectible accounts, and customer information and assistance (except amounts related to conservation and low-income assistance). These expenses are reduced by revenue from late payment fees, account change fees, miscellaneous equipment rentals and reconnect charges. Customer Accounts and Services expenses are summarized below.

Direct Expense: Customer Accounts and Services		
	2007	**2008**
Customer Accounting and Advisory O&M	$30,344,824	$30,368,786
Late Payment Fees	(3,036,060)	(3,113,963)
Account Change Fee Revenue	(1,401,847)	(1,413,061)
Revenue from Miscellaneous Rentals	(170,052)	(174,415)
Revenue from Reconnect Charges	(225,064)	(230,839)
Total	$25,511,801	$25,436,509

Low-Income Assistance

The City's low-income assistance policies provide reduced electric rates, bill payment assistance, and fee waivers for qualified low-income residential customers. The direct expenses for this category include estimated O&M expenses related to low-income activities charged under Customer Accounts and Services (e.g., credit, collections and the work of customer service representatives). The O&M applicable to the low-income function is estimated based on 2004 labor hours devoted to low-income activities, as a percent (3.35%) of all labor hours in the Customer Accounts and Services function before subtraction of Conservation and Low-Income hours. Other elements of the revenue requirement included in the low-income direct expense category are revenues foregone for the rate discount and for trouble call and account change fee waivers, contributions from City Light's low-income account for bill payment assistance, and administrative costs paid by City Light to the Human Services Department. Income from late payment fees offsets the foregoing expenses. Direct low-income assistance expenses are shown below.

Direct Expense: Low-Income Assistance		
	2007	**2008**
Low-Income Assistance O&M	$1,058,125	$1,059,135
Rate Discount	5,360,752	5,419,559
Bill Payment Assistance from Low-Income Account	248,568	254,445
Trouble Call Charge Waiver	1,068	1,097
DHS Administration Payments	179,988	184,847
Account Change Fee Waiver	37,118	37,429
Late Payment Fees	(111,990)	(114,863)
Total	$6,773,629	$6,841,648

7.4 Assigned and Allocated Expenses

Depreciation

Depreciation is a gradual reduction in the book value of a physical asset. Assets are depreciated over their useful lives and the associated expense is charged against income each year. Depreciation categories in the FPM include Production Plant, Transmission

Plant, Distribution Plant, and General Plant. For future years, the projected depreciation amount includes the depreciation associated with forecasted additions to capital plant.

Depreciation amounts associated with Production, Transmission and Distribution Plant are assigned directly to these categories. Depreciation amounts related to Transmission and Distribution are further disaggregated into unbundled categories based on the 2004 depreciation provisions in City Light's accounting records.

The following table shows the breakdown of Production, Transmission and Distribution Plant depreciation.

Production, Transmission and Distribution Plant Depreciation			
	2007	**2008**	**Percent**
Production	$13,017,772	$13,531,316	23%
Transmission	3,619,009	3,761,777	6%
Long-Distance Transmission	2,114,499	2,197,915	4%
In-Service-Area Transmission	1,504,510	1,563,862	3%
Distribution	40,480,256	42,726,467	71%
Stations	4,024,645	4,247,969	7%
Wires and Related Equipment	27,224,773	28,735,450	48%
Transformers	6,420,284	6,776,540	11%
Meters	1,569,570	1,656,664	3%
Streetlights/Floodlights	1,240,984	1,309,845	2%
Total	$57,117,037	$60,019,560	100%

General Plant depreciation was allocated to Production and Purchased Power (Power), Conservation, Transmission, Distribution, Customer Accounts and Services, and Low-Income Assistance based on analysis of the items in the General Plant depreciation schedule. The following assignments or allocations were made from this schedule:

- Microwave communications equipment and Skagit general plant – assigned to Production because the microwave equipment is used generally to control generation and because the Skagit project is a series of generation facilities.

- System Control Center – allocated to Production, Purchased Power, Transmission and Distribution according to 2004 labor hour percentages.

- Customer service software (Banner and automated meter reading) – assigned to Customer Accounts and Services.

- Distribution training site, software and monitoring equipment – assigned to Distribution.

- Stores (shops and pole yards, tools, transportation equipment, materials management systems) – allocated to Production, Transmission and Distribution according to 2004 labor hour percentages.

- Office buildings and furniture, internally developed software, Summit financial system, and data processing, communications and miscellaneous equipment – allocated to all functions based on 2004 non-A&G labor hours, on the assumption that depreciation expense for these items is analogous to Administrative & General expenses, for which the non-A&G labor hour allocation procedure was also used.

General Plant depreciation amounts allocated to the principal functions are shown below.

General Plant Depreciation Allocations			
	2007	**2008**	**Percent**
Power (Production and Purchased Power)	$4,296,094	$4,465,573	15%
Conservation	169,993	176,699	1%
Transmission	1,075,584	1,118,015	4%
Long-Distance Transmission	628,438	653,229	2%
In-Service-Area Transmission	447,146	464,786	2%
Distribution	10,360,879	10,769,610	37%
Stations	1,030,104	1,070,741	4%
Wires and Related Equipment	6,968,152	7,243,042	25%
Transformers	1,643,265	1,708,091	6%
Meters	401,730	417,578	1%
Streetlights/Floodlights	317,628	330,159	1%
Customer Accounts and Services	11,730,654	12,193,422	42%
Low-Income Assistance	430,479	447,461	2%
Total	$28,063,682	$29,170,781	100%

Functionalized depreciation amounts after addition of General Plant depreciation are shown below.

Depreciation Including General Plant Allocation		
	2007	2008
Power	$17,313,866	$17,996,889
Conservation	169,993	176,699
Transmission	4,694,593	4,879,792
Long-Distance Transmission	2,742,936	2,851,144
In-Service-Area Transmission	1,951,657	2,028,649
Distribution	50,841,134	53,496,078
Stations	5,054,748	5,318,709
Wires and Related Equipment	34,192,925	35,978,492
Transformers	8,063,549	8,484,631
Meters	1,971,300	2,074,242
Streetlights/Floodlights	1,558,612	1,640,003
Customer Accounts and Services	11,730,654	12,193,422
Low-Income Assistance	430,479	447,461
Total	$85,180,719	$89,190,341

Amortization

Amortization is a gradual reduction in the book value of an intangible asset, or of an amount contributed by City Light to a tangible asset which is owned by another entity (e.g., the Puget Intertie). The value of such assets is amortized over a certain time period and the associated expense is charged against income each year. The amortization expense related to various City Light assets is assigned to related functional categories for purposes of unbundling the revenue requirements. These include:

- Power – Deferred O&M costs related to mitigation of environmental impacts associated with the 1995 relicensing of City Light's Skagit River projects and the relicensing effort currently under way for the Boundary project. The contribution to the Skagit Environmental Endowment made by City light under the terms of the High Ross Contract is also included.

  The High Ross Contract refers to the 1984 agreement between City Light and the Canadian Province of British Columbia, whereby City Light agreed not to raise the height of Ross Dam on the Skagit River (which would have flooded Canadian land) and the province agreed to provide energy to City Light in exchange for payments approximating the cost of the proposed addition to the dam. City Light's annual payments to the Province include a fixed charge of $21.8 million annually through 2020, which represents the estimated debt service costs that would have been incurred had the addition been constructed and financed with bonds. In 2000, City Light began amortizing the remaining annual $21.8 million payments over the period through 2035.

- Conservation – Costs of installed conservation measures amortized over 20 years. Examples include installations under the Home Energy Loan Program, the Low-

Income Electric Program, the Multifamily Conservation Program, the $mart Business Program, and Energy Smart Design. The costs are offset by conservation credits and payments made to City Light by BPA.

- Long-Distance Transmission – Amortization associated with the Puget Intertie, which is used to transmit the output of Cedar Falls and South Fork of the Tolt, and the Puget Stillwater Substation, which is used to transmit South Fork of the Tolt output via Puget Sound Energy facilities to City Light's service area.

Amortized expenses and offset assigned to functions are shown below.

Amortization		
	2007	**2008**
Power		
Hydro Project Mitigation	$1,042,921	$1,147,076
High Ross Contract	347,404	347,404
Conservation		
Programmatic Conservation	11,328,591	12,058,761
BPA Conservation and Renewables Credit	(2,215,000)	(2,215,000)
BPA Payments for Conservation	(5,284,740)	(5,284,740)
Long-Distance Transmission		
Puget Intertie	43,628	0
Puget Stillwater Substation	99,286	99,286
Total	$5,362,090	$6,152,787

Contributions in Aid of Construction and Grants

Customers that install new electrical service or that upgrade their existing service pay Installation Charges that reimburse City Light for part of the cost of equipment and hookup to the City Light system. Customers also pay the capital cost of non-standard service that they request. Examples of the latter are underground service and a second feeder. When large customers have buildings or other facilities under construction that require City Light to relocate or replace the utility's feeders or other equipment, the customers must also reimburse the utility for these costs. Some government agencies provide grants to cover costs of a requested project.

All forecasted contributions in 2007 and 2008 come from transmission and distribution projects. These contributions are assigned to a sub-function where appropriate, or allocated between sub-functions of a major function by percentages of forecasted depreciation in the sub-functions. Depreciation is used as the allocator because contributions are capitalized.

Contributions and Grant Revenues		
	2007	**2008**
Transmission	$927,681	$984,823
Long-Distance Transmission	613,889	660,151
In-Service-Area Transmission	313,793	324,672
Distribution	29,086,440	21,509,725
Stations	60,951	7,376
Wires and Related Equipment	24,422,089	17,938,929
Transformers	4,329,390	3,311,750
Streetlights/Floodlights	274,010	251,671
Total	$30,014,121	$22,494,548

Interest

This expense category includes interest accrued on first- and second-lien debt and amortization of debt expenses, with an offset from interest earnings. Interest was allocated to all functional categories of expense based on the book value of plant and other deferred debits in those categories as of the end of 2004. Book values include shares of General Plant in all functional categories, computed as described under Depreciation, as well as the assignment of the book value of deferred debits to a related function. The latter include assignment of: unamortized Hydro Project Relicensing, High Ross and Skagit Endowment to Production and Purchased Power (Power), unamortized programmatic conservation measures to Conservation, and unamortized Puget Intertie and Puget Stillwater Substation expenses to Long-Distance Transmission.

The book values on which interest allocations are based are shown below.

Book Values of Plant and Deferred Debits		
	2004	**Percent**
Power	$409,656,410	27.28%
Hydroelectric Plant	313,134,919	
Share of General Plant	27,901,849	
Unamortized Hydro Project Relicensing	17,544,501	
Unamortized High Ross	51,075,142	
Conservation	125,004,480	8.32%
Unamortized Conservation	124,315,502	
Share of General Plant	688,979	
Transmission		
Long-Distance Transmission	65,380,855	4.35%
Transmission Plant	58,576,170	
Share of General Plant	5,085,229	
Puget Intertie & Stillwater Substation	1,719,456	
In-Service-Area Transmission	27,924,047	1.86%
Transmission Plant	25,693,493	
Share of General Plant	2,230,554	
Distribution		
Stations	82,137,682	5.47%
Distribution Plant	75,824,296	
Share of General Plant	6,313,386	
Wires and Related Equipment	558,800,308	37.21%
Distribution Plant	515,848,986	
Share of General Plant	42,951,322	
Transformers	142,549,453	9.49%
Distribution Plant	131,592,610	
Share of General Plant	10,956,843	
Meters	34,920,513	2.33%
Distribution Plant	32,236,402	
Share of General Plant	2,684,111	
Streetlights/Floodlights	17,921,227	1.19%
Distribution Plant	16,543,740	
Share of General Plant	1,377,487	
Customer Accounts and Services	36,056,615	2.40%
Share of General Plant	36,056,615	
Low-Income Assistance	1,323,166	0.09%
Share of General Plant	1,323,166	
Total	$1,501,674,756	100.00%

Interest on debt is allocated to all functions, using the above percentages, as follows:

Interest		
	2007	**2008**
Power	$16,285,765	$15,578,691
Conservation	4,969,515	4,753,755
Transmission	3,709,308	3,548,262
Long-Distance Transmission	2,599,196	2,486,347
In-Service-Area Transmission	1,110,112	1,061,915
Distribution	33,248,009	31,804,492
Stations	3,265,358	3,123,587
Wires and Related Equipment	22,214,934	21,250,436
Transformers	5,667,010	5,420,967
Meters	1,388,254	1,327,981
Streetlights/Floodlights	712,453	681,521
Customer Accounts and Services	1,433,420	1,371,185
Low-Income Assistance	52,602	50,318
Total	$59,698,618	$57,106,703

Administrative and General

The basic Administrative and General (A&G) expense category includes administrative salaries, office supplies, outside services, property insurance, injuries and damages, employee pensions and benefits, rents, general plant maintenance and miscellaneous general expenses. A&G expense taken from the FPM is adjusted by the addition of King County surface water management fees and by subtraction of miscellaneous income. These expenses are allocated by percentages of non-A&G labor hours in each functional category in 2004.

A&G expenses allocated to the functionalized revenue requirement categories and the corresponding labor hour percentages are shown below.

Administrative and General Expense			
	2007	2008	Percent
Production and Purchased Power	$11,875,747	$12,451,585	22%
Conservation	811,342	850,683	2%
Transmission	2,689,154	2,819,547	5%
Long-Distance Transmission	1,064,999	1,116,640	2%
In-Service-Area Transmission	1,624,154	1,702,907	3%
Distribution	23,673,571	24,821,470	45%
Stations	7,072,758	7,415,706	13%
Wires and Related Equipment	11,991,004	12,572,431	23%
Transformers	783,099	821,071	1%
Meters	1,986,020	2,082,319	4%
Streetlights/Floodlights	1,840,690	1,929,942	3%
Customer Accounts and Services	13,532,096	14,188,248	25%
Low-Income Assistance	496,586	520,665	1%
Total	$53,078,496	$55,652,198	100%

Revenue Taxes and County Payments

A Public Utility tax paid to the State of Washington (3.873%), the City of Seattle's Occupation tax (6.0%), contract payments to suburban cities with which City Light has franchise agreements, and a small Renton business tax comprise the Department's tax expense. Franchise payments amount to about 6.5% of the total. In order to allocate these amounts to all revenue requirement functions, the sum of all expenses except taxes in each category is multiplied by the effective tax rate.

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.

Taxes allocated to the various functions, together with county payments assigned to the Power function, are shown below.

Revenue Taxes and County Payments		
	2007	**2008**
Power	$34,883,072	$34,393,734
Whatcom County Contract Payments	852,432	875,404
Pend Oreille County Contract Payments	1,278,139	1,315,137
Payments to Concrete School District	108,860	111,654
Revenue Taxes	32,643,641	32,091,539
Conservation	1,313,292	1,433,531
Transmission	5,735,607	5,707,409
Long-Distance Transmission	4,877,317	4,800,039
In-Service-Area Transmission	858,290	907,370
Distribution	11,915,983	13,501,564
Stations	2,782,061	3,021,812
Wires and Related Equipment	6,070,232	7,066,689
Transformers	1,297,762	1,496,928
Meters	900,174	970,178
Streetlights/Floodlights	865,754	945,957
Customer Accounts and Services	5,760,523	6,086,101
Low-Income Assistance	855,483	899,377
Total	$60,463,960	$62,021,717
Effective Tax Rate	17.22%	16.05%

Net Income

City Light's net income to be collected from retail customers is a residual after all revenues and expenses are taken into account. Net income contributes to the Utility's equity. The net income allocation procedure first assumed a 7% return on expected equity for the revenue requirement year. This is a little lower than the norm in the electric utility business for private utilities, but corresponds generally to the City's Discount Rate Policy (which, loosely speaking, could also be called the City's "Rate of Return Policy"). Then, the percentages of book values shown above under the discussion of interest expense were used as a proxy for each unbundled component's share of equity and that percentage was multiplied times the 7% return amount. The remainder of net income to be collected through the retail revenue requirement was assigned to the power component as a risk management premium due to the weather-related variability of power supply.

Allocations of net income for the forecast years are shown below.

Net Income		
	2007	**2008**
Power	$101,354,449	$76,038,884
Contribution to Equity	12,578,309	14,782,852
Risk Management Premium	88,776,141	61,256,031
Conservation	3,838,204	4,510,909
Transmission	2,864,883	3,366,999
Long-Distance Transmission	2,007,489	2,359,332
In-Service-Area Transmission	857,395	1,007,667
Distribution	25,679,097	30,179,757
Stations	2,521,999	2,964,019
Wires and Related Equipment	17,157,703	20,164,856
Transformers	4,376,914	5,144,036
Meters	1,072,218	1,260,141
Streetlights/Floodlights	550,263	646,705
Customer Accounts and Services	1,107,102	1,301,138
Low-Income Assistance	40,627	47,748
Total	$134,884,363	$115,445,434

Non-network and Network Expenses

For cost allocation purposes, two of the Distribution sub-functions, Wires and Related Equipment and Transformers, are 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). For cost allocation purposes, 85% of the network costs shown below are allocated to the downtown network; this allocation is based on historical consumption percentages. The other 15% of the network costs shown is 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.

Wires and Related Equipment

The division of the Wires and Related Equipment O&M expenses into non-network and network components is based on the analysis of 2004 distribution expenses recorded in FERC accounts. The process of distributing 2004 expenses between non-network and network components uses direct assignment where the FERC account value clearly applies to one component (e.g., maintenance of underground network equipment is assigned to the network component); and 2004 labor hours to allocate the expense where it applies to both components (e.g., supervision, load dispatching, safety programs).

Projected O&M expenses, as well as all adjustments to that expense except pole attachment revenue, are multiplied by the percentage of 2004 expenses calculated for each category (84.94% non-network and 15.06% network). Pole attachment revenue is assigned only to the non-network category.

Plant depreciation, contributions and grants, interest expense and net income are distributed between non-network and network components based on a "capital" allocator. This allocator is based on an analysis of the 1993-2004 capital additions for FERC accounts 364-367 (Poles, Towers and Fixtures; Overhead Conductors and Devices; Underground Conduit; Underground Conductors and Devices) from depreciation schedules. Additions in FERC 36664 (Underground Conduit-Network) and FERC 36764 (Network UG Conductors and Devices) are assigned to the network component, while the other FERC sub-accounts are assigned to the non-network component. Amounts in each category are summed and the resulting percentages of the total are used as the non-network/network "capital" allocator (63.60% non-network and 36.40% network).

Administrative and General expense is allocated by 2004 labor hours in the non-network and network sub-categories of the Wires and Related Equipment category (85.19% non-network and 14.81% network).

Taxes are computed for the non-network and network expense components by multiplying the expenses calculated in the processes described above by the effective tax rate.

The non-network/network breakdown of projected revenue requirements in the category of Wires and Related Equipment is shown below.

Non-network/Network Expenses: Wires and Related Equipment		
	2007	
	Non-network	**Network**
Distribution O&M-Wires and Related Equipment	$18,015,818	$3,193,049
Property Rental Income	(1,481,606)	(262,594)
Revenue from Damage	(1,220,146)	(216,254)
Other O&M Revenue	(2,674,740)	(474,060)
Construction (Installation) Charge Revenue	(348,613)	(61,787)
Pole Attachment Revenue	(1,000,000)	
Power Factor Revenue	(2,064,969)	(365,987)
Subtotal Distribution O&M	$9,225,743	$1,812,368
Plant Depreciation	21,745,339	12,447,586
Contributions and Grant Revenues	(15,531,476)	(8,890,613)
Interest	14,127,814	8,087,121
Administrative and General	10,214,879	1,776,125
Taxes	4,389,499	1,680,733
Net Income	10,911,616	6,246,087
Total	$55,083,413	$23,159,408

Non-network/Network Expenses: Wires and Related Equipment		
	2008	
	Non-network	Network
Distribution O&M-Wires and Related Equipment	$19,178,652	$3,399,145
Property Rental Income	(1,521,609)	(269,684)
Revenue from Damage	(1,253,090)	(222,093)
Other O&M Revenue	(3,401,245)	(602,823)
Construction (Installation) Charge Revenue	(358,026)	(63,455)
Pole Attachment Revenue	(1,000,000)	
New Large Loads (Networks)	(1,500,000)	
Power Factor Revenue	(2,114,280)	(374,726)
Subtotal Distribution O&M	$8,030,402	$1,866,365
Plant Depreciation	22,880,888	13,097,604
Contributions and Grant Revenues	(11,408,444)	(6,530,484)
Interest	13,514,431	7,736,005
Administrative and General	10,710,185	1,862,247
Taxes	5,003,439	2,063,250
Net Income	12,824,045	7,340,811
Total	$61,554,946	$27,435,797

Transformers

The division of Transformer O&M expenses into non-network and network components is also based on the analysis of 2004 distribution expenses recorded in FERC accounts. The process of allocating 2004 expenses between non-network and network components uses direct assignment where the FERC account value clearly applies to one component (e.g., maintenance of network underground line transformers and devices is assigned to the network component); and 2004 labor hours to allocate the expense where it applies to both components (e.g., supervision, load dispatching, safety programs).

Projected O&M expenses are multiplied by the percentage of 2004 expenses in each category (30.68% non-network and 69.32% network). The additional expense of Credits for Customer-Owned Transformers is assigned only to the non-network component because customers who receive this credit are located outside the network.

Plant depreciation, contributions and grants, interest and net income are distributed between non-network and network components based on a “capital” allocator. This allocator is based on an analysis of the 1993-2004 capital additions for FERC account 368 (Line Transformers) from depreciation schedules. Additions to FERC 36864 (Network UG Transformers-Installed Cost) are assigned to the network component, while the other FERC sub-accounts are assigned to the non-network component. Amounts in each category are summed and the resulting percentages of the total are used as the non-network/network “capital” allocator (57.95% non-network and 42.05% network).

Administrative and General expense is allocated by 2004 labor hours in the non-network and network sub-categories of the Transformer category (20.43% non-network and 79.57% network).

Taxes are computed for the non-network and network expense components by multiplying the expenses calculated in the processes described above by the effective tax rate.

The non-network/network breakdown of projected revenue requirements in the Transformer category is shown below.

Non-network/Network Expenses: Transformers		
	2007	
	Non-network	Network
Distribution O&M-Transformers	$387,784	$876,082
Credits for Customer-Owned Transformers	313,559	
Subtotal Distribution O&M	$701,343	$876,082
Plant Depreciation	4,673,010	3,390,540
Contributions and Grant Revenues	(2,508,980)	(1,820,410)
Interest	3,284,161	2,382,849
Administrative and General	159,995	623,104
Taxes	696,181	601,581
Net Income	2,536,521	1,840,393
Total	$9,542,231	$7,894,138

Non-network/Network Expenses: Transformers		
	2008	
	Non-network	Network
Distribution O&M-Transformers	$412,813	$932,629
Credits for Customer-Owned Transformers	322,014	
Subtotal Distribution O&M	$734,827	$932,629
Plant Depreciation	4,917,036	3,567,595
Contributions and Grant Revenues	(1,919,234)	(1,392,516)
Interest	3,141,573	2,279,394
Administrative and General	167,753	653,317
Taxes	805,764	691,164
Net Income	2,981,086	2,162,951
Total	$10,828,805	$8,894,534

7.5 Final Unbundled Revenue Requirements

With a few minor changes and the insertion of the retail rates to be effective for the two-year-period 2007-2008, the FPM was calculated again to verify the acceptability of the two-year results. The revised unbundled revenue requirements are shown below.

Reconciliation of Revenue from Retail Power Sales with Final Allocated Revenue Requirement

	2007	2008	2007-08
Revenue from Retail Power Sales Inside System	$530,772,704	$542,523,365	$1,073,296,069
Avg. Rate ($/MWh) Before Adjustments	$55.89	$56.06	$55.98
Plus:			
Residential Low-Income Rate Discount	5,551,017	5,551,017	11,102,034
Transformer Ownership Credit	313,559	322,014	635,573
Less:			
Power Factor Charge	(2,430,956)	(2,489,006)	(4,919,962)
Credit for Network Rates-New Areas	0	(1,500,000)	(1,500,000)
Total Revenue Allocated to Retail Customer Classes	**$534,206,324**	**$544,407,391**	**$1,078,613,715**
Energy Sales to Retail Customers (MWh)	9,496,232	9,677,386	19,173,618
Avg. Rate ($/MWh) After Adjustments	$56.25	$56.26	$56.26

Final Functional Allocation of 2007 Revenue Requirements

	Total	Net Direct Expenses	Depreciation & Amortization Net of Capital Cont. & Grants	Interest	Admin. and General	Rev. Taxes & County Payments	Net Income
Total Energy	**$499,269,145**	**$287,136,193**	**$24,974,997**	**$23,851,335**	**$14,204,718**	**$41,150,503**	**$107,951,399**
Power	431,048,214	246,746,185	18,704,191	16,283,621	12,266,620	34,948,851	102,098,747
Conservation	17,088,357	2,122,745	3,998,844	4,968,860	838,046	1,317,088	3,842,774
Transmission-Long Distance	51,132,574	38,267,263	2,271,962	2,598,854	1,100,052	4,884,564	2,009,879
Total Retail Services	**$224,536,342**	**$65,234,356**	**$35,553,691**	**$35,839,424**	**$40,620,779**	**$19,570,911**	**$27,717,181**
Total Distribution	156,044,876	32,725,616	23,392,559	34,353,598	26,130,363	12,874,654	26,568,086
Transmission-In Service Area	*9,555,240*	*3,406,606*	*1,637,864*	*1,109,966*	*1,677,611*	*864,777*	*858,416*
Stations	*30,781,021*	*9,882,080*	*4,993,797*	*3,264,928*	*7,305,548*	*2,809,666*	*2,525,002*
Wires and Related Equipment	*78,702,495*	*11,038,111*	*9,770,836*	*22,212,010*	*12,385,671*	*6,117,737*	*17,178,130*
non-network	*55,470,743*	*9,225,743*	*6,213,863*	*14,125,954*	*10,551,087*	*4,429,490*	*10,924,607*
network	*23,231,752*	*1,812,368*	*3,556,973*	*8,086,056*	*1,834,584*	*1,688,247*	*6,253,523*
Transformers	*17,470,281*	*1,577,424*	*3,734,160*	*5,666,264*	*808,874*	*1,301,434*	*4,382,125*
non-network	*9,551,105*	*701,343*	*2,164,030*	*3,283,728*	*165,261*	*697,202*	*2,539,541*
network	*7,919,175*	*876,082*	*1,570,129*	*2,382,535*	*643,612*	*604,232*	*1,842,584*
Meters	*10,205,013*	*2,812,759*	*1,971,300*	*1,388,071*	*2,051,387*	*908,002*	*1,073,495*
Streetlights/Floodlights	*9,330,828*	*4,008,636*	*1,284,602*	*712,359*	*1,901,274*	*873,039*	*550,918*
Customer Accounts & Services	59,610,769	25,543,740	11,730,654	1,433,231	13,977,485	5,817,240	1,108,420
Low-Income Assistance	8,880,696	6,965,000	430,479	52,595	512,930	879,016	40,676
Total	**$723,805,487**	**$352,370,549**	**$60,528,688**	**$59,690,759**	**$54,825,497**	**$60,721,414**	**$135,668,580**
Load (MWh)	9,496,232						
Average Cost per MWh	$76.22	$37.11	$6.37	$6.29	$5.77	$6.39	$14.29
Percent of Total Cost	100.00%	48.68%	8.36%	8.25%	7.57%	8.39%	18.74%
Net Wholesale Revenue	(189,599,163)						
Retail Revenue Requirement	**$534,206,324**						

Final Functional Allocation of 2008 Revenue Requirements

	Total	Net Direct Expenses	Depreciation & Amortization Net of Capital Cont. & Grants	Interest	Admin. and General	Rev. Taxes & County Payments	Net Income
Total Energy	**$454,663,880**	**$268,884,295**	**$26,517,368**	**$22,813,468**	**$13,966,278**	**$40,532,431**	**$81,950,040**
Power	387,161,138	230,639,552	19,491,369	15,575,055	12,060,713	34,313,030	75,081,419
Conservation	18,439,111	2,188,160	4,735,720	4,752,646	823,979	1,428,761	4,509,845
Transmission-Long Distance	49,063,631	36,056,583	2,290,279	2,485,767	1,081,587	4,790,639	2,358,776
Total Retail Services	**$239,541,777**	**$65,229,219**	**$46,331,212**	**$34,279,908**	**$39,938,921**	**$21,233,880**	**$32,528,637**
Total Distribution	170,563,271	32,845,496	33,690,329	32,858,736	25,691,740	14,296,900	31,180,069
Transmission-In Service Area	*9,783,897*	*3,461,149*	*1,703,977*	*1,061,667*	*1,649,451*	*900,225*	*1,007,429*
Stations	*32,130,639*	*10,558,442*	*5,311,333*	*3,122,858*	*7,182,917*	*2,991,768*	*2,963,320*
Wires and Related Equipment	*88,532,845*	*9,896,767*	*18,039,564*	*21,245,477*	*12,177,766*	*7,013,172*	*20,160,101*
non-network	*61,168,220*	*8,030,402*	*11,472,444*	*13,511,277*	*10,373,977*	*4,959,099*	*12,821,021*
network	*27,364,625*	*1,866,365*	*6,567,120*	*7,734,200*	*1,803,788*	*2,054,073*	*7,339,080*
Transformers	*19,690,335*	*1,667,456*	*5,172,881*	*5,419,702*	*795,296*	*1,492,176*	*5,142,824*
non-network	*10,820,523*	*734,827*	*2,997,802*	*3,140,840*	*162,487*	*804,184*	*2,980,383*
network	*8,869,812*	*932,629*	*2,175,079*	*2,278,862*	*632,809*	*687,993*	*2,162,441*
Meters	*10,634,612*	*2,994,309*	*2,074,242*	*1,327,671*	*2,016,952*	*961,595*	*1,259,844*
Streetlights/Floodlights	*9,790,944*	*4,267,374*	*1,388,333*	*681,361*	*1,869,359*	*937,964*	*646,553*
Customer Accounts & Services	60,045,006	25,411,483	12,193,422	1,370,865	13,742,860	6,025,544	1,300,831
Low-Income Assistance	8,933,500	6,972,240	447,461	50,307	504,320	911,436	47,736
Total	**$694,205,657**	**$334,113,514**	**$72,848,580**	**$57,093,376**	**$53,905,199**	**$61,766,311**	**$114,478,677**
Load (MWh)	9,677,386						
Average Cost per MWh	$71.73	$34.53	$7.53	$5.90	$5.57	$6.38	$11.83
Percent of Total Cost	100.00%	48.13%	10.49%	8.22%	7.77%	8.90%	16.49%
Net Wholesale Revenue	(149,798,266)						
Retail Revenue Requirement	**$544,407,391**						

7.6 Detailed Unbundled Revenue Requirements by Major Function

Unbundled revenue requirements used for cost allocation to retail customer classes are shown below.

Unbundled Revenue Requirements - 2007				
Functions	**Dollars**	**Subtotals**	**Totals**	**$/MWh**
ENERGY				
Power				
Direct Expenses:				
Generation O&M	$20,066,153			
Long-Term Purchased Power	240,147,177			
Basis Purchases	547,884			
Other Power Costs	7,908,114			
Article 49 Sales to Pend Oreille County	-1,568,000			
Sales from Priest Rapids	-8,765,424			
Seasonal Exchange Delivered	-2,941,119			
Basis Sales	-1,026,000			
Other Services	-7,622,600			
Subtotal		$246,746,185		
Depreciation and Amortization:				
Amortization of Hydro Project Mitigation	$1,042,921			
Amortization of High Ross Contract	347,404			
Plant Depreciation	17,313,866			
Subtotal		18,704,191		
Interest		16,285,765		
Administration and General		11,875,747		
Revenue Taxes and Payments in Lieu of Taxes:				
Revenue Taxes	$32,643,641			
Whatcom County Contract Payments	852,432			
Pend Oreille County Contract Payments	1,278,139			
Payments to Concrete School District	108,860			
Subtotal		34,883,072		
Net Income (Contribution to Equity)		12,578,309		
Net Income (Risk Management)		88,776,141		
TOTAL POWER EXPENSE			$429,849,409	$45.265
Conservation				
Direct Expenses:				
Conservation	$2,422,745			
Operating Fees (Lighting Lab)	-300,000			
Subtotal		$2,122,745		
Depreciation and Amortization:				
Amortization of Programmatic Conservation	$11,328,591			
BPA Conservation & Renewables Credit	-2,215,000			
BPA Payments for Conservation	-5,284,740			
Plant Depreciation	169,993			
Subtotal		3,998,844		
Interest		4,969,515		
Administration and General		811,342		
Revenue Taxes		1,313,292		
Net Income (Contribution to Equity)		3,838,204		
TOTAL CONSERVATION EXPENSE			$17,053,942	$1.796

Unbundled Revenue Requirements - 2007				
Functions	**Dollars**	**Subtotals**	**Totals**	**$/MWh**
Transmission-Long Distance				
Direct Expenses:				
Transmission O&M	$1,900,868			
Wheeling	39,861,676			
Transmission Services	-3,275,505			
Transmission Attachments & Cell Sites	-219,776			
Subtotal		$38,267,263		
Depreciation and Amortization:				
Amortization of Puget Intertie	$43,628			
Amortization of Puget Stillwater Substation	99,286			
Plant Depreciation	2,742,936			
Subtotal		2,885,850		
Capital Contributions and Grant Revenues		-613,889		
Interest		2,599,196		
Administration and General		1,064,999		
Revenue Taxes		4,877,317		
Net Income (Contribution to Equity)		2,007,489		
TOTAL TRANSMISSION-LONG DISTANCE EXPENSE			$51,088,225	$5.380
TOTAL ENERGY EXPENSE			**$497,991,576**	**$52.441**
RETAIL SERVICES				
Transmission-In Service Area				
Direct Expenses:				
Transmission O&M	$3,817,070			
Transmission Attachments & Cell Sites	-410,464			
Subtotal		$3,406,606		
Plant Depreciation		1,951,657		
Capital Contributions and Grant Revenues		-313,793		
Interest		1,110,112		
Administration and General		1,624,154		
Revenue Taxes		858,290		
Net Income (Contribution to Equity)		857,395		
TOTAL TRANSMISSION-IN SERVICE AREA EXPENSE			$9,494,421	$1.000
Distribution-Stations				
Direct Expenses:				
Distribution O&M-Stations	$10,908,080			
Gain on Sale of Distribution Assets	-1,026,000			
Subtotal		$9,882,080		
Plant Depreciation		5,054,748		
Capital Contributions and Grant Revenues		-60,951		
Interest		3,265,358		
Administration and General		7,072,758		
Revenue Taxes		2,782,061		
Net Income (Contribution to Equity)		2,521,999		
TOTAL DISTRIBUTION-STATIONS EXPENSE			$30,518,054	$3.214

Unbundled Revenue Requirements - 2007				
Functions	**Dollars**	**Subtotals**	**Totals**	**$/MWh**
Distribution-Wires and Related Equipment				
Direct Expenses:				
Distribution O&M-Wires and Related Equipment	$21,208,867			
Property Rental Income	-1,744,200			
Revenue from Damage	-1,436,400			
Other O&M Revenue	-3,148,800			
Construction (Installation) Charge Revenue	-410,400			
Pole Attachment Revenue	-1,000,000			
Network Rates-New Areas	0			
Power Factor Revenue	-2,430,956			
Subtotal		$11,038,111		
Plant Depreciation		34,192,925		
Capital Contributions and Grant Revenues		-24,422,089		
Interest		22,214,934		
Administration and General		11,991,004		
Revenue Taxes		6,070,232		
Net Income (Contribution to Equity)		17,157,703		
TOTAL DISTRIBUTION-WIRES & RELATED EQUIP. EXPENSE			$78,242,821	$8.239
Distribution-Transformers				
Direct Expenses:				
Distribution O&M-Transformers	$1,263,865			
Credits for Customer-Owned Transformers	313,559			
Subtotal		$1,577,424		
Plant Depreciation		8,063,549		
Capital Contributions and Grant Revenues		-4,329,390		
Interest		5,667,010		
Administration and General		783,099		
Revenue Taxes		1,297,762		
Net Income (Contribution to Equity)		4,376,914		
TOTAL DISTRIBUTION-TRANSFORMER EXPENSE			$17,436,369	$1.836
Distribution-Meters				
Distribution O&M-Meters		$2,812,759		
Plant Depreciation		1,971,300		
Interest		1,388,254		
Administration and General		1,986,020		
Revenue Taxes		900,174		
Net Income (Contribution to Equity)		1,072,218		
TOTAL DISTRIBUTION-METERS EXPENSE			$10,130,724	$1.067
Distribution-Streetlights/Floodlights				
Distribution O&M-Lights		$4,008,636		
Plant Depreciation		1,558,612		
Capital Contributions and Grant Revenues		-274,010		
Interest		712,453		
Administration and General		1,840,690		
Revenue Taxes		865,754		
Net Income (Contribution to Equity)		550,263		
TOTAL DISTRIBUTION-STREETLIGHT/FLOODLIGHT EXPENSE			$9,262,397	$0.975
TOTAL DISTRIBUTION EXPENSE			$145,590,366	$15.331
TOTAL DISTRIBUTION + IN SERVICE AREA TRANSMISSION			$155,084,787	$16.331

Unbundled Revenue Requirements - 2007				
Functions	**Dollars**	**Subtotals**	**Totals**	**$/MWh**
Customer Accounts and Services				
Direct Expenses:				
Customer Accounting and Advisory O&M	$30,344,824			
Late Payment Fees	-3,036,060			
Account Change Fee Revenue	-1,401,847			
Revenue from Miscellaneous Rentals	-170,052			
Revenue from Reconnect Charges	-225,064			
Subtotal		$25,511,801		
Plant Depreciation		11,730,654		
Interest		1,433,420		
Administration and General		13,532,096		
Revenue Taxes		5,760,523		
Net Income (Contribution to Equity)		1,107,102		
TOTAL CUSTOMER ACCOUNTS AND SERVICES EXPENSE			$59,075,595	$6.221
Low-Income Assistance				
Direct Expenses:				
Low-Income Assistance O&M	$1,058,125			
Rate Discount	5,360,752			
Bill Payment Assist. from Low-Income Acct.	248,568			
Trouble Call Charge Waiver	1,068			
DHS Administration Payments	179,988			
Account Change Fee Waiver	37,118			
Late Payment Fees	-111,990			
Subtotal		$6,773,629		
Plant Depreciation		430,479		
Interest		52,602		
Administration and General		496,586		
Revenue Taxes		855,483		
Net Income (Contribution to Equity)		40,627		
TOTAL LOW-INCOME ASSISTANCE EXPENSE			$8,649,406	$0.911
TOTAL RETAIL SERVICES EXPENSE			**$222,809,788**	**$23.463**
RETAIL CUSTOMER REVENUE REQUIREMENT BEFORE CREDIT			**$720,801,364**	**$75.904**
CREDIT FOR NET WHOLESALE POWER SALES				
Wholesale Power Purchases		$51,499,979		
Wholesale Power Sales		-241,099,142		
NET WHOLESALE POWER SALES REVENUE			-$189,599,163	
TOTAL RETAIL CUSTOMER REVENUE REQUIREMENT			**$531,202,201**	**$55.938**

Unbundled Revenue Requirements - 2008				
Functions	**Dollars**	**Subtotals**	**Totals**	**$/MWh**
ENERGY				
Power				
Direct Expenses:				
Generation O&M	$20,574,544			
Long-Term Purchased Power	223,529,463			
Basis Purchases	562,677			
Other Power Costs	8,121,633			
Article 49 Sales to Pend Oreille County	-1,610,300			
Sales from Priest Rapids	-8,765,424			
Seasonal Exchange Delivered	-3,004,039			
Basis Sales	-1,053,702			
Other Services	-7,715,300			
Subtotal		$230,639,552		
Depreciation and Amortization:				
Amortization of Hydro Project Mitigation	$1,147,076			
Amortization of High Ross Contract	347,404			
Plant Depreciation	17,996,889			
Subtotal		19,491,369		
Interest		15,578,691		
Administration and General		12,451,585		
Revenue Taxes and Payments in Lieu of Taxes:				
Revenue Taxes	$32,091,539			
Whatcom County Contract Payments	875,404			
Pend Oreille County Contract Payments	1,315,137			
Payments to Concrete School District	111,654			
Subtotal		34,393,734		
Net Income (Contribution to Equity)		14,782,852		
Net Income (Risk Management)		61,256,031		
TOTAL POWER EXPENSE			$388,593,815	$40.155
Conservation				
Direct Expenses:				
Conservation	$2,488,160			
Operating Fees (Lighting Lab)	-300,000			
Subtotal		$2,188,160		
Depreciation and Amortization:				
Amortization of Programmatic Conservation	$12,058,761			
BPA Conservation & Renewables Credit	-2,215,000			
BPA Payments for Conservation	-5,284,740			
Plant Depreciation	176,699			
Subtotal		4,735,720		
Interest		4,753,755		
Administration and General		850,683		
Revenue Taxes		1,433,531		
Net Income (Contribution to Equity)		4,510,909		
TOTAL CONSERVATION EXPENSE			$18,472,758	$1.909

Unbundled Revenue Requirements - 2008				
Functions	**Dollars**	**Subtotals**	**Totals**	**$/MWh**
Transmission-Long Distance				
Direct Expenses:				
Transmission O&M	$1,978,401.90			
Wheeling	39,588,976			
Transmission Services	-5,286,317			
Transmission Attachments & Cell Sites	-224,478			
Subtotal		$36,056,583		
Depreciation and Amortization:				
Amortization of Puget Intertie	$0			
Amortization of Puget Stillwater Substation	99,286			
Plant Depreciation	2,851,144			
Subtotal		2,950,430		
Capital Contributions and Grant Revenues		-660,151		
Interest		2,486,347		
Administration and General		1,116,640		
Revenue Taxes		4,800,039		
Net Income (Contribution to Equity)		2,359,332		
TOTAL TRANSMISSION-LONG DISTANCE EXPENSE			$49,109,220	$5.075
TOTAL ENERGY EXPENSE			**$456,175,793**	**$47.138**
RETAIL SERVICES				
Transmission-In Service Area				
Direct Expenses:				
Transmission O&M	$3,880,394			
Transmission Attachments & Cell Sites	-419,245			
Subtotal		$3,461,149		
Plant Depreciation		2,028,649		
Capital Contributions and Grant Revenues		-324,672		
Interest		1,061,915		
Administration and General		1,702,907		
Revenue Taxes		907,370		
Net Income (Contribution to Equity)		1,007,667		
TOTAL TRANSMISSION-IN SERVICE AREA EXPENSE			$9,844,984	$1.017
Distribution-Stations				
Direct Expenses:				
Distribution O&M-Stations	$11,612,144			
Gain on Sale of Distribution Assets	-1,053,702			
Subtotal		$10,558,442		
Plant Depreciation		5,318,709		
Capital Contributions and Grant Revenues		-7,376		
Interest		3,123,587		
Administration and General		7,415,706		
Revenue Taxes		3,021,812		
Net Income (Contribution to Equity)		2,964,019		
TOTAL DISTRIBUTION-STATIONS EXPENSE			$32,394,899	$3.347

Unbundled Revenue Requirements - 2008				
Functions	**Dollars**	**Subtotals**	**Totals**	**$/MWh**
Distribution-Wires and Related Equipment				
Direct Expenses:				
Distribution O&M-Wires and Related Equipment	$22,577,798			
Property Rental Income	-1,791,293			
Revenue from Damage	-1,475,183			
Other O&M Revenue	-4,004,068			
Construction (Installation) Charge Revenue	-421,481			
Pole Attachment Revenue	-1,000,000			
Network Rates-New Areas	-1,500,000			
Power Factor Revenue	-2,489,006			
Subtotal		$9,896,767		
Plant Depreciation		35,978,492		
Capital Contributions and Grant Revenues		-17,938,929		
Interest		21,250,436		
Administration and General		12,572,431		
Revenue Taxes		7,066,689		
Net Income (Contribution to Equity)		20,164,856		
TOTAL DISTRIBUTION-WIRES & RELATED EQUIP. EXPENSE			$88,990,743	$9.196
Distribution-Transformers				
Direct Expenses:				
Distribution O&M-Transformers	$1,345,442			
Credits for Customer-Owned Transformers	322,014			
Subtotal		$1,667,456		
Plant Depreciation		8,484,631		
Capital Contributions and Grant Revenues		-3,311,750		
Interest		5,420,967		
Administration and General		821,071		
Revenue Taxes		1,496,928		
Net Income (Contribution to Equity)		5,144,036		
TOTAL DISTRIBUTION-TRANSFORMER EXPENSE			$19,723,339	$2.038
Distribution-Meters				
Distribution O&M-Meters		$2,994,309		
Plant Depreciation		2,074,242		
Interest		1,327,981		
Administration and General		2,082,319		
Revenue Taxes		970,178		
Net Income (Contribution to Equity)		1,260,141		
TOTAL DISTRIBUTION-METERS EXPENSE			$10,709,169	$1.107
Distribution-Streetlights/Floodlights				
Distribution O&M-Lights		$4,267,374		
Plant Depreciation		1,640,003		
Capital Contributions and Grant Revenues		-251,671		
Interest		681,521		
Administration and General		1,929,942		
Revenue Taxes		945,957		
Net Income (Contribution to Equity)		646,705		
TOTAL DISTRIBUTION-STREETLIGHT/FLOODLIGHT EXPENSE			$9,859,831	$1.019
TOTAL DISTRIBUTION EXPENSE			$161,677,982	$16.707
TOTAL DISTRIBUTION + IN SERVICE AREA TRANSMISSION			$171,522,966	$17.724

Unbundled Revenue Requirements - 2008				
Functions	**Dollars**	**Subtotals**	**Totals**	**$/MWh**
Customer Accounts and Services				
Direct Expenses:				
Customer Accounting and Advisory O&M	$30,368,786			
Late Payment Fees	-3,113,963			
Account Change Fee Revenue	-1,413,061			
Revenue from Miscellaneous Rentals	-174,415			
Revenue from Reconnect Charges	-230,839			
Subtotal		$25,436,509		
Plant Depreciation		12,193,422		
Interest		1,371,185		
Administration and General		14,188,248		
Revenue Taxes		6,086,101		
Net Income (Contribution to Equity)		1,301,138		
TOTAL CUSTOMER ACCOUNTS AND SERVICES EXPENSE			$60,576,604	$6.260
Low-Income Assistance				
Direct Expenses:				
Low-Income Assistance O&M	$1,059,135			
Rate Discount	5,419,559			
Bill Payment Assist. from Low-Income Acct.	254,445			
Trouble Call Charge Waiver	1,097			
DHS Administration Payments	184,847			
Account Change Fee Waiver	37,429			
Late Payment Fees	-114,863			
Subtotal		$6,841,648		
Plant Depreciation		447,461		
Interest		50,318		
Administration and General		520,665		
Revenue Taxes		899,377		
Net Income (Contribution to Equity)		47,748		
TOTAL LOW-INCOME ASSISTANCE EXPENSE			$8,807,217	$0.910
TOTAL RETAIL SERVICES EXPENSE			**$240,906,787**	**$24.894**
RETAIL CUSTOMER REVENUE REQUIREMENT BEFORE CREDIT			**$697,082,580**	**$72.032**
CREDIT FOR NET WHOLESALE POWER SALES				
Wholesale Power Purchases		$46,948,649		
Wholesale Power Sales		-196,746,915		
NET WHOLESALE POWER SALES REVENUE			-$149,798,266	
TOTAL RETAIL CUSTOMER REVENUE REQUIREMENT			**$547,284,314**	**$56.553**

Appendix 1

Full Printout of Financial Planning Model Reports

Appendix 2

Documentation for Monte Carlo Based Forecast

In trying to forecast what is going to happen in the future we often look to the past. This year's biennial forecast of surplus energy sales revenue for calendar years 2007 and 2008 is more forward-looking in that it is based both on historical trends and on a variety of assumptions about the future. The rate proposal this year reflects changes made by the Power Management Division to the process that it uses to forecast surplus energy sales revenue. This memo outlines the current process.

At the end of the day, the budget will settle on a dollar figure for how much money the utility will make from the sale of surplus energy. This will be the net of how much energy the utility sells and how much it buys and the dollars associated with each category. The simplest explanation of how Power Management arrives at these numbers is that it subtracts projected retail load from projected generation to derive the projected surplus energy amount. It then multiplies this surplus energy amount by the projected energy market price to project the revenue from sales. The rest of this memo will expand the description of this process into many of the details.

Forecast Tool: Power Management utilizes an Excel based model to extract a Monte Carlo simulate. After assembling all of the forecasted monthly loads, resources and prices, Seattle City Light performs an optimization of City Light's system by backing off all resources to as low as possible at night. Following this optimization, the spreadsheet calculates the heavy load hour (HLH), light load hour (LLH), and average monthly surplus (or deficit) energy and revenues (or costs). The amount of resources, energy price and retail load are all unknown quantities. To account for uncertainty Seattle City Light performed 2001 simulations starting with distributions of the loads and resources and picking combinations of the variables before calculating the bottom line. From these data, Seattle City Light calculates averages, exceedances and other descriptive statistics used in the forecast.

Power Management provided the forecasts of monthly load, which were the basis of the loads used in this rate forecast. The load distribution file that was incorporated into the analysis was provided by Finance.

Skagit Hydroelectric Generation: The amount of energy that is obtained from the Skagit is a direct function of the amount of snow and rain that falls on the basin. City Light contracts with 3 Tier Environmental Consulting to have that company prepare a forecast distribution of Ross Lake inflows by month for a 12-month period. The model that 3 Tier uses assumed an "all climates" starting point for the inflows file that we used in the budget process. The inflows file consisted of 400 years of inflow possibilities. Each of these possible inflow scenarios was processed by an Excel spreadsheet, "Refill.xls", developed by Power Management. This spreadsheet models how the Skagit system would be operated, were that inflow series to be experienced. All physical and license constraints were observed and 400 series of monthly outflows were calculated.

Boundary Hydroelectric Generation: In a fashion similar to how City Light converts inflows into outflows, the US Army Corps of Engineers models the entire Columbia River System. For the inflows, they use the 70-year period of record 1928-1998. The flows at Boundary Dam from the Corps December 2004 study was used.

BPA Slice Purchase: City Light's Slice product purchases from the Bonneville Power Administration are modeled after a piece of the Federal Columbia River System. Each year BPA provides City Light with a study of how much Slice energy would be produced were we to have a repeat of historical water conditions. The latest study was from August 2006 and was a 60-year study using the years 1928-1988. This study was adjusted in January 2006 to account for the additional spill ordered by a federal judge overseeing the court case surrounding the Endangered Species Act.

Energy Outputs of Other Contracted Resources: The variable energy amounts associated with the Lucky Peak, Grand Coulee Project Hydroelectric Authority ("GCPHA"), Priest Rapids and State Line Wind projects were not modeled in this study. Rather, the Wholesale Contracts Unit provided fixed amounts of monthly energy output for each resource. The variable energy amounts associated with the South Fork Tolt, Cedar Falls and Newhalem Creek hydroelectric projects were also not modeled. The average monthly energy output expected from these projects, based on historical records, was assumed for this study. The values for all other resources were the contracted amounts.

Marketing Losses: After the retail load is subtracted from the resources, any surplus energy is decreased by 1.9 percent to account for the contractual transmission losses associated with selling it.

Prices: The Finance Division provided the energy prices for heavy load hour and light load hour energy. These prices were calculated from a Western Electricity Coordinating Council ("WECC") dispatch model developed by the Financial Planning Unit, which relates price and water conditions.

Appendix 3

Footnotes to Tables in Chapter 2

Footnote to Table 2.1

The data supporting Table 2.1 is documented in Appendix 1 as follows:

1. Revenue From Customers: Table 1.01, Retail Power Sales Inside System
2. Power and Power-Related Revenue: Table 1.01, Wholesale Power Sales + Other Power Sales + Transmission Services
   Minus:
   Table 1.07, BPA Payments for Conservation + Seasonal Exchange Delivered
3. Other Revenue: Table 1.01, Other Revenue
4. Power Costs: Table 1.01, Short-Term Wholesale Power Purchases + Power-Related Wholesale Purchases + Long-Term Purchased Power + Generation + Other Power Costs + Transmission + Wheeling
   Minus:
   Table 1.04, Amortization of the following items: High Ross Expenditures + Relicensing Mitigation + Puget Stillwater Sub + Puget Intertie
5. Nonpower O&M: Table 1.01, Distribution + Conservation + Customer Accounting + Administration
   Minus:
   Table 1.04, Amortization of: Conservation + Vehicles and Boats
6. Revenue Available for Debt Service: Table 1.02, Revenue Available for Debt Service
7. First Lien Debt Service: Table 1.02, Debt Service, 1st-Lien Bonds
8. Second Lien Debt Service: Table 1.02, Debt Service, 2nd Lien Bonds
9. Repayment of Sound Transit Loan: Table 1.02, Revenue Anticipation Notes
10. City Taxes: Table 1.02, Less City Taxes (shown negatively)
11. Other Uses of Funds: Table 1.03, Less Other Funds Required (shown negatively)
12. Net Revenue Available for the Capital Program: Table 1.04, Proceeds from Operations

Footnote to Table 2.2

1. Total Revenue Requirement: Table 1.01, Retail Power Sales Inside System
2. Sales (MWh): Table 1.06, Energy Sales to Customers
3. Average Retail Revenue per MWh: Table 1.02, Average Retail Revenue per MWh
4. Net Power Costs: Table 1.01, Short-Term Wholesale Power Purchases + Power-Related Wholesale Purchases + Long-Term Purchased Power + Generation + Other Power Costs + Transmission + Wheeling - Wholesale Power Sales - Other Power Sales - Transmission Services
   Minus:
   Table 1.04, Amortization of the following items: BPA Payments for Conservation + High Ross Expenditures + Relicensing Mitigation + Puget Stillwater Sub + Puget Intertie
5. Other O&M Costs: Table 1.01, Distribution + Conservation + Customer Accounting + Administration
   Minus:
   Table 1.04, Amortization of: Conservation + Vehicles and Boats
6. Other Costs Minus Other Revenues: Table 1.01, Taxes - Other Revenue
   Minus:
   Table 1.02, Investment Income + Other Income + Exchange Expense (Revenue), Net + Proceeds from Sales of Property + Operating Fees and Grants + Other Non-cash Expense (Revenue)
   Minus:
   Table 1.03, Less Other Funds Required (this is actually an addition because it's the subtraction of an amount shown negatively)
7. Additional Revenue Required to Meet Financial Policy Targets: Table 1.03, Proceeds from Operations
8. Total Revenue Requirement: Table 1.01, Retail Power Sales Inside System
9. Debt Service Coverage: Table 1.02, Debt Service Coverage Ratios, 1st & 2nd Lien Bonds
10. Probability of Revenue for Capital: Table 1.03, Probability Will Have Cash From Operations
11. Long-Term Debt as % Capitalization: Table 1.05, Debt as Pct of Total Capitalization
12. Minimum Operating Cash Balance: Table 1.05, Working Capital Account - Contingency Reserve Account Balance
13. Operating Contingency Reserve: Table 1.05, Contingency Reserve Account Balance