Review Panel

Seattle
City Light

Guide to
RATE MAKING

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Introduction

The purpose of this document is to explain how Seattle City Light sets its electric retail rates. The Guide to Rate Making consists of seven sections.

Section 1 provides an overview of pertinent parts of the Ordinance that created the Review Panel for whom this Guide has been written, how that panel is to be constructed and what its functions are expected to be.

Section 2 explains what the revenue requirement is, how it is set and how it is related to City Light's financial policies. Elements of City Light's revenue requirements and other cash flow activities are explained in detail. This is the first phase of the rate setting process.

The Revenue Requirements Analysis determines the size of the pie to be paid by retail customers and the Cost of Service and Cost Allocation analysis results in a division of the pie among the various customer classes based on cost of service. Section 3 provides an overview of the cost of service and cost allocation process. This is the second phase in rate setting.

Once we know how much money we need to continue serving our customers and understand the relative cost of serving different customer classes, we proceed to the third, and final, phase of rate setting--rate design--described in Section 4. Rate design is the process of shaping rates, charges, and credits for customer classes so that each of the classes contributes its portion of the Utility's revenue requirement in a way that is consistent with City goals and policies.

Section 5 provides an overview of key events that have affected Seattle City Light over the years. The intent of this section is to briefly summarize the long history of the development of electrical service in Seattle and the Northwest, and also give a glimpse of the multiple concerns of citizens and decision makers.

Section 6 lists the key personnel who are responsible for the rate making decisions at Seattle City Light. The last section provides a glossary and abbreviations used in this document.

1. The Review Trail -- Where the Review Panel Fits Into the Rate-Making Process

1.1 The Review Panel

Seattle City Ordinance 123256, passed in March 2010, established a Review Panel (Panel) and defined its role and composition. Some of its pertinent parts are described below.

<u>1.1.1 Composition of the Panel</u>

The Panel is comprised of nine members drawn from among City Light's customers, occupying numbered positions #1 through #9:

Position #1: An economist or similar profession, preferably with a background in energy economics or commodity risk management;
Position #2: A financial analyst or similar profession, preferably with a background in financing large capital projects;
Position #3: A representative of a non-profit or non-governmental organization whose mission is to advocate for the efficient use of energy, preferably with knowledge of the electricity industry;
Position #4: A representative from among City Light's residential customers, preferably with knowledge of the electricity industry;
Position #5: A representative from among City Light's commercial customers, preferably with knowledge of financial planning and budgeting;
Position #6: A representative from among City Light's industrial customers, preferably with a background in financial planning and budgeting;
Position #7: A representative from among the advocates for City Light's low income customers, preferably with experience navigating City government and knowledge of the electricity industry;
Position #8: At large
Position #9: A representative from among City Light's suburban franchise areas.

The Mayor appoints the odd-numbered positions, beginning with Position #1 and the Council appoints the even-numbered positions beginning with Position #2. All Panel members are confirmed by the City Council.

1.1.2 Terms of Appointment to the Panel

The term of the appointment of members to the Panel is three years, except that at the inception of the Panel in 2010 Positions #1, #2, and #3 were appointed for a term of one year and Positions #4, #5, and #6 were appointed for a term of two years. This allows for staggered appointments of three Panel members each year thereafter, thus ensuring a degree of continuity of Panel membership. A member whose term has expired continues to serve until a successor has been confirmed by the Council.

1.1.3 The Role of the Panel.

The Panel's role is to:

(a) review and assess City Light's strategic plan and provide an opinion on the merits of the plan and future revisions to it to the Mayor and the Council;

(b) assist the Mayor and the Council in engaging rate payers in discussions of the merits and implications of the strategic plan;

(c) provide an assessment to the Mayor and the Council of the adequacy of financial policies to protect the financial integrity of the utility and the sufficiency of the policies to support implementation of the adopted strategic plan;

(d) review changes to City Light's rates not already authorized by the Seattle Municipal Code and provide an opinion to the Mayor and the Council on the adequacy and prudence of such rate changes in light of adopted planning assumptions and financial policies;

(e) in its second year or earlier, and at least once every three years thereafter, assess City Light's rate design to ensure that rates send the appropriate signals to customers to use electricity efficiently; and

(f) in its second year or earlier, and at least every three years thereafter, assess City Light's implementation of marginal cost allocation among customer classes to ensure that it provides a fair allocation of costs among customer classes and takes account of changes in costs and consumption.

As noted in the Introduction, there are three phases to Seattle City Light's rate making process: revenue requirements, cost allocation and rate design. During the current rate making process, the views of the Review Panel are being solicited for the second and third phases. Members have an opportunity to express their views on these matters prior to the adoption of a rate ordinance by the City Council. The Panel will be providing recommendations related to a rate proposal prepared by City Light and submitted by the Mayor for Council consideration as part of the 2013 budget process. The Council will vote on the rate proposal in late November 2012.

During this process, the Panel may:

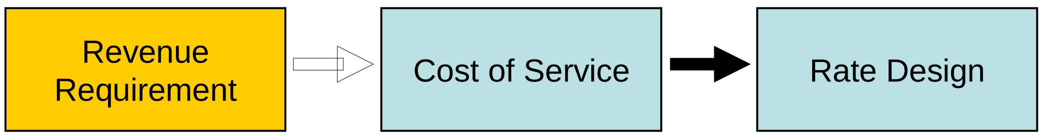
- Review the rate proposal and supporting materials;
- Identify issues for group discussion, requesting materials and information from City Light staff;
- Strive for consensus positions on the significant issues related to City Light rates;
- Respond to requests by City Council staff;
- Write letters to City or Utility officials about areas of special concern;
- Provide a formal report of its findings;
- Testify at public hearings held by the City Council before it reaches a decision.

City Council and Panel review of the Mayor's 2013 rates proposal will occur concurrently from October to early November 2012. After Council review of the Mayor's proposal, and consideration of the Panel's views, a final decision on rates and the adoption of a rates ordinance follows. Nothing is "final" until the Council passes the rates ordinance and the new rates become law.

2. Revenue Requirements Analysis

2.1 Revenue Requirement: First of Three Steps in Setting Rates

City Light's rate setting process has three major elements: (1) determination of revenue requirements, that is, determining the amount of revenue needed to be collected from customers in order to cover the costs of doing business; (2) cost allocation, which distributes these costs across customer classes and determines the average annual rate by class; and (3) the design of customer rates and charges.



The revenue requirement is the amount of money that City Light needs to collect from customers to cover the cost of its operations, and to generally ensure stable ongoing financial strength.

As part of the biennial budget process, City Light determines the revenue requirement needed to support its adopted budget. When possible, rates are set in two-year segments, aligning with the budget. Therefore, the Utility must project its costs and revenue needs several years in advance. Forecasting is a complex process that involves staff from throughout City Light. The financial forecast incorporates projections for retail demand, wholesale sales, and for all other variables affecting revenue requirements.

For the 2013-14 rate review process that will take place in 2012, the revenue requirement will essentially be determined by the outcome of the Strategic Planning process that began in 2010 and ending in early 2012.

2.2 Elements of City Light's Revenue Requirements

The Revenue Requirement is defined as the amount of revenue that must be collected from retail customers to cover all costs including power purchases, operations, debt service, taxes and other expenditures above what is covered by revenues from wholesale power sales and other sources. It is also called Cash from Retail Power Sales before Discounts.

The Department's cash transactions can be grouped into the following six major categories:

	Category
1	Operating cash to be received from major revenue sources
2	Operating cash to be spent on major operational expenses
3=1-2	Cash available for debt service
4	Cash to be spent for debt service and other subordinate purposes
5=3-4	Cash from operations
6	Cash to be spent on capital investments and operating expenses treated like capital investments ("deferred O&M")

The Cash Flow Table from the Revenue Requirements Analysis used to set rates in 2011-2012, which is displayed in Table 1, provides an outline of the major categories of cash that City Light takes into account when determining the revenue requirement. Those categories are explained below.

Table 1
Cash Flow Table from Revenue Requirements Analysis 2011-2012
$ Millions

	2010 Rate Study	Forecast 2011	Forecast 2012
Cash from Retail Power Sales before Discounts	$614.8	$651.5	$692.3
Cash from Wholesale Power Sales, Net	120.0	96.8	102.1
Cash from All Other Sources	70.4	71.5	70.9
Cash to Rate Stabilization Account	0.0	(22.0)	(2.9)
Cash to Power Contracts	(289.3)	(272.9)	(286.0)
Cash to Operations	(202.2)	(222.8)	(216.2)
Cash to Rate Discounts	(6.5)	(6.8)	(7.2)
Cash to Uncollectable Revenue	(5.5)	(5.8)	(6.2)
Cash to State Taxes and Franchise Payments	(31.2)	(32.9)	(34.4)
Cash Available for Debt Service	**$270.5**	**$256.5**	**$312.4**
Cash to City Taxes	(38.6)	(40.7)	(42.8)
Cash to All Other Purposes	(3.5)	(2.3)	(5.2)
Cash to Debt Service	(150.7)	(142.7)	(173.2)
Cash from Operations	**$77.8**	**$70.8**	**$91.3**
Cash from Contributions	29.7	31.6	19.5
Cash from Bond Proceeds	148.9	188.3	210.3
Cash to Capital, Conservation and Deferred O&M	$256.4	$290.7	$321.0

2.2.1 Operating Cash Sources

2.2.1.a Cash from Retail Power Sales before Discounts

Most of City Light's revenues come from sales of electricity to customers in City Light's service area, which includes the cities of Seattle, Shoreline, Burien, and Lake Forest Park, portions of the cities of Normandy Park, Tukwila, Renton, and SeaTac, and portions of unincorporated King County. When calculating the customer revenue requirement, City Light first takes account of all revenue to be received from other sources and all expenses except city taxes, debt service payments and minor cash balancing amounts. The customer revenue requirement is the amount that must be added to the revenues from all other sources to make sure both expenses (with the exceptions noted) and the City Council's mandated financial policies are met. More detail on those financial policies is provided below.

Retail Power Sales before Discounts is the cash that the Department will receive from:

1. Energy Charges ($ per kWh) applied to the energy used by Retail Customers

2. Capacity Charges ($ per kW) applied to the capacity used by Retail Customers
3. Base Service Charges ($ per day) applied to the number of Residential Retail Customers.

Rate discounts are provided to low income customers, and a few non-residential customers receive bill discounts because they purchase some electrical equipment that City Light normally purchases or because they are metered in a non-standard way. These are accounted for as expenses, and are explained in more detail below.

Table 1 shows that retail revenues are expected to account for about 80% of City Light's total revenues in 2011-2012.

2.2.1.b Cash from Wholesale Power Sales, Net

City Light participates in the West Coast wholesale energy market, carrying out transactions with other utilities and entities that produce or purchase power. Net wholesale power sales are defined as revenues from short-term wholesale sales minus short-term wholesale purchases. In general, City Light is now 'long' on energy resources on an annual basis, but some short-term purchases are necessary to balance load.

Over the past decade, through 2010, net wholesale energy revenue was the greatest source of uncertainty in estimating City Light's revenue requirements. However, in March 2010 the City Council adopted Ordinance 123260 establishing parameters for the Rate Stabilization Account (RSA) within the Light Fund. The main purpose of the RSA is to absorb deviations in City Light's annual net wholesale energy revenues from the planned amount. Therefore, this source of revenue uncertainty has been significantly reduced.

Net Wholesale Revenue is forecasted using the methodology described in Ordinance 123260; that is, the average of actual net wholesale revenue received by City Light from 2002 through the most recent complete year, with allowance for modifications by the Council. Forecasted amounts for 2011 and 2012 are $96.8M and $102.1M, respectively.

2.2.1c Cash from All Other Sources

In addition to revenue from retail and wholesale power sales, City Light receives operating cash from other sources such as long-term power contracts, transmission and power-related services, interest on investments, sales of surplus property, operating grants, and other fees and charges.

2.2.1.d Cash to Rate Stabilization Account (RSA)

The RSA became operational on January 1, 2011. The Department reached the initial funding target of $100 million on January 1, 2011, through a combination of the existing $25 million Contingency Reserve, 2010 revenues from an RSA surcharge, 2010 cash from operations and 2010 bond refunding savings realized in 2010 and 2011. The RSA surcharge was lifted as of January 1, 2011.

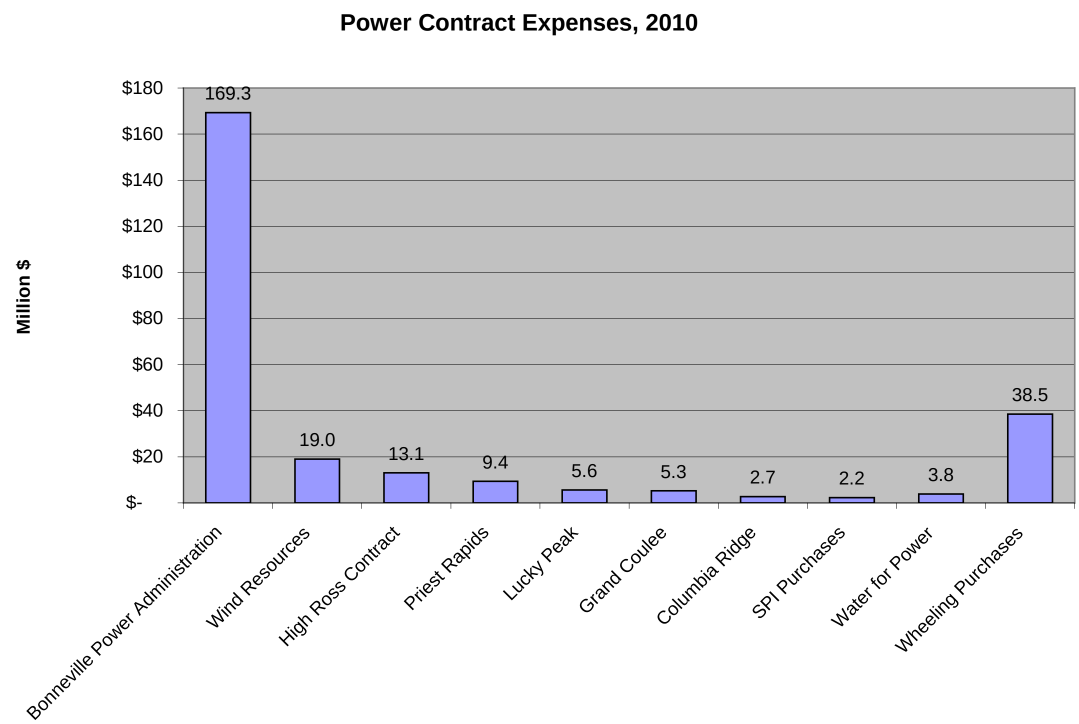
On a quarterly basis, if City Light receives less net wholesale revenue than planned, funds are transferred from the RSA to City Light's operating account; likewise, if City Light receives more net wholesale revenue than planned, funds are transferred to the RSA from City Light's operating account. If the amount in the RSA falls to $90 million or less, it is replenished with a stepped automatic retail rate surcharge. The Cash Flow Table above shows that City Light forecasted transfers to the RSA of $22 million in 2011 and $2.9 million in 2012.

2.2.2 Operating Cash Uses

2.2.2.a Cash to Power Contracts

Cash to Power Contracts is the sum of cash spent on long-term power purchases, wheeling (transmission on lines owned by others) purchases, and various administrative payments made by City Light to other agencies for the rights to operate its hydro projects. City Light has several long-term contracts to buy power from other utilities. The largest contract is with the Bonneville Power Administration (BPA). Figure 1 shows City Light's power contract expenses in 2010. Most of City Light's wheeling expenditures are for purchases of transmission provided by the Bonneville Power Administration.

Figure 1



2.2.2.b Cash to Operations

Cash to Operations is the sum of cash spent on production, transmission, distribution, non-programmatic conservation, customer accounting and administration. Each of these components is briefly described below.

Production expenses include operation and maintenance costs of City Light's hydroelectric plants.

City Light transmits power from its Skagit Hydroelectric Project through transmission lines owned by the Department. This item covers the cost of operating and maintaining these and other transmission lines owned by the Department.

Distribution expenses include the direct expenses of operating and maintaining substations, power lines, line transformers, poles, service connections, meters, and streetlights.

City Light's conservation program offers grants and loans to help residential customers weatherize their homes. The Utility also has programs for weatherizing and installing energy-efficient lighting in multifamily residences, and extends incentives to commercial and industrial customers for weatherization and installation of energy-efficient equipment and processes. Most of City Light's conservation work is treated like a capital expense ("deferred O&M") and is funded mostly with bonds. The conservation expense that is recognized as part of annual operations is for planning, management and customer information and assistance.

Customer Accounting includes the costs of reading meters, maintaining customer records, and providing technical information to customers about electric service and connections.

The administration category covers central administrative expenses for planning, financial management, and general administration. It also covers employee pensions and benefits, general plant maintenance, research and development projects, claims for injuries and damages, and environmental clean-up payments.

2.2.2.c Cash to Rate Discounts

This category includes the cash required to fund rate discounts and other services provided to about 14,000 low-income customers. Residential customers that qualify for City Light's low-income rate discount program receive a 60% rate discount over standard residential rates.

2.2.2.d Cash to Uncollectable Revenue

This category includes retail revenue not collected from customers who do not pay their bills.

2.2.2.e Cash to State Taxes and Franchise Payments

City Light pays state utility taxes on retail revenue. Approximately 2.0% of total revenue is exempt from this tax; the tax on the remainder is 3.873%. City Light also makes payments to counties where the Department's dams are located. These payments are treated the same as taxes. City Light also has franchise agreements with the suburban cities of Tukwila, Burien, SeaTac, Shoreline and Lake Forest Park that provide for payments by the Department to these cities. These franchise payments are included in this expense category.

2.2.3 Cash Available for Debt Service

The difference between Operating Cash Sources and Operating Cash Uses equals the cash available for debt service. The Department's financial policies require that, in an expected planning sense, the amount of cash available for debt service should equal 1.8 times the cash required to cover annual debt service. The rationale for this policy is to provide assurance that debt service can be paid and, thereby, give lenders the confidence to continue to provide loans when the Department needs to borrow again. This target can be reached in a number of ways; the two most obvious are adjusting retail rates or cash expenditures.

2.2.4 Cash to City Taxes, All Other Purposes and Debt Service

City Light is in the electricity business, one of the most capital intensive businesses in the world. The expensive capital equipment is paid for over an extended period, approximating the useful life of the equipment. This means that at any point in time, City Light has a large amount of debt outstanding which must be serviced each year. The City Charter stipulate that city taxes take a junior lien to debt service. Thus, the cash available for debt service is used, first, to pay debt service costs; the residual is then available to pay city taxes, which are 6% of retail revenue. Finally, this residual covers or absorbs changes in cash balances needed to make the Department's Balance Sheet accounts balance. These changes in cash balances are caused by changes in accounts payable and receivable, materials and supplies, and unbilled revenues.

Note that the size of debt service in a year is determined by prior actions. Policy makers can do little if anything about that for the current year. City taxes and other cash uses also are mostly out of control of City Light decision makers, but even if they could be changed by City Light decisions, they would not affect revenue requirements in the base year of the rate case as they do not play a role in ensuring that cash available for debt service coverage is at the policy-stipulated level.

2.2.5 Cash from Operations, Contributions and Bond Proceeds

The residual left after all items discussed above have been taken into account is Cash from Operations.

Cash from Contributions comes from customer payments for construction of new service connections, non-standard electrical service equipment, or relocations of City Light's equipment; capital grants and reimbursements from federal, state and local governments; and, through September 2011, BPA grants for conservation measures. While contributions are a source of cash, they are unreliable as a source of debt service payment funding. Therefore, they do not help reduce the customer revenue requirement in the year received. They do, however, reduce the requirement for debt financing of the utility's capital program, thus reducing future debt service expense and the rates that would have to cover it.

Bond Proceeds is the cash received from issuance of bonds.

2.3.6 Cash to Capital, Conservation and Deferred O&M

Capital additions use the majority of funds described in the paragraph above. Additional uses of the cash include payment for long-lived conservation measure expenses and hydro plant licensing charges ("deferred O&M"). These uses of cash do not affect current period revenue requirements. Changes in capital expenditures can have an impact on future rates, however, by affecting future debt service requirements.

2.3 Financial Policies and the Revenue Requirement

Resolution 31187, adopted by City Council in March 2010, established Seattle City Light's financial policies. They are:

1. To set electric rates at levels sufficient to achieve a debt service coverage ratio of 1.8;
2. To manage the capital improvement program so that, on average, over any given six-year capital improvement program, it will fund 40% of the expenditures with cash from operations.

To meet the above stated financial policies, in addition to covering all other net costs, retail customer rates must be high enough to yield enough revenue to cover City Light's debt service obligation by 1.8 times. Note that in Table 1, the Cash Available for Debt Service equals 1.8 times the Cash to Debt Service. The extra cash (0.8) is used to pay for capital expenditures, reducing the amount City Light needs to borrow, thereby reducing debt service in future years and the size of future rate increases.

2.4 Simplified Examples of Determination of Revenue Requirements

This section shows how financial policy choices can affect revenue requirements. The examples are hypothetical and are used for purposes of illustration. Table 2 provides initial assumptions used for these simplified examples. Net revenue from sale of wholesale power is the only source of revenue other than retail sales and is assumed to be $100 million. Retail sales, of course, equal the revenue requirements. There are five expense categories, totaling $500 million. Debt Service for the year equals $175 million and capital projects total $237 million. Table 2 also provides estimates of city and non-city tax rates as well as the retail load and interest rate expected when the debt service coverage (DSC) ratio equals 1.8. There is an expectation in the model that if the DSC ratio is set at a higher level the bond market will react favorably and loan the Department money (i.e., buy the Department's bonds) at a lower interest rate; and vice versa.[1]

Table 3 presents results for three different DSC ratios where DSC = 1.8 is considered the Base Case. The table shows total revenue requirements, average system rate, cash available from operations, amounts borrowed (bond proceeds) as well as the percent of the capital projects funded by cash from operations. Effects on future costs are also presented: the rate on bonds sold, the cost for one year's amortization of the new bonds and the total payment of interest and all payments over the life of the new bonds.

When the DSC ratio drops, retail revenue requirements and the average system rate drop. But, so, too, does cash available for capital projects. Hence, when the DSC ratio drops, the amount that must be borrowed increases – which decreases the percent of capital projects funded by cash

[1] The equation in this example for the revised interest rate when the DSC is changed is:
Base Rate * (1 – (DSC – 1.8) * .25). Thus, if the base interest rate when the DSC is set at 1.8 is 4.5%, then the interest rate when the DSC is set at 2 equals: 4.5% * (1-(2-1.8)*.25) = 4.275%. This illustrates that when a more stringent DSC is set, there is an expectation the markets would see less risk and, thereby, be willing to lend money at a lower rate. The equation is meant to illustrate a principle rather than project exactly how the markets would react.

from operations - and the interest rate on the new bonds is expected to rise. The payment for one year on the new borrowing increases as does the total interest paid and total of all payments over the life of the bonds because more has been borrowed at a higher interest rate. The opposite occurs when the DSC ratio is increased.

Table 2

Initial Assumptions		
	Dollars are MILLIONS	
Revenue Sources		
	Net Wholesale	100.0
Expenses		
	Energy	330.0
	Distribution	70.0
	Customer Accounting	30.0
	Administration	63.0
	Rate Discounts	7.0
Debt Service		
	Debt Service (DS)	175.0
Capital Projects		
	Total Capital Expense	237.0
Total Load (MWH)		9,200,000
Future Interest rate when DSC=1.8=		4.50%
Maturity of new borrowing (years)		25
Non-City tax rate		5%
City Tax rate		6%

Table 3

	Results Associated with DSC ratios		
	1.5	**1.8**	**2**
		(Base Case)	
Retail Revenue Requirements (Million $)	697.4	752.6	789.5
Average Rate ($/MWH)	75.80	81.81	85.81
Cash Available for Capital Projects			
Cash from Operations (Million $)	45.7	94.8	127.6
Bond Proceeds (Million $)	191.3	142.2	109.4
% of Capital Projects funded by Cash	19.3%	40.0%	53.9%
Effects on Future Costs			
Interest rate on Borrowing	4.84%	4.50%	4.28%
1 Year's amortization of borrowing (Million $)	13.36	9.59	7.21
Total interest pymnts over 25 years (Million $)	142.6	97.5	70.8
Total pymnts over 25 years (Million $)	333.9	239.7	180.1

Table 4 summarizes differences with the Base Case of DSC ratio = 1.8. Tables 3 and 4 show how financial policies, in this case setting the DSC ratio, affect both the near term revenue requirement and average system rate, but also have lingering effects, and in this case, in the opposite direction, on debt service costs for future years.

Table 4

	Impacts Relative to DSC = 1.8	
	DSC = 1.5	**DSC = 2**
Retail Revenue Requirements (Million $)	-55.3	36.8
Average Rate ($/MWH)	-6.01	4.00
Cash Available for Capital Projects		
Cash from Operations (Million $)	-49.2	32.8
Bond Proceeds (Million $)	49.2	-32.8
% of Capital Projects funded by Cash	-20.8%	13.8%
Effects on Future Costs		
Interest rate on Borrowing	0.34%	-0.23%
1 Year's amortization of borrowing (Million $)	3.77	-2.38
Total interest pymnts over 25 years (Million $)	45.0	-26.7
Total pymnts over 25 years (Million $)	94.2	-59.5

3. Cost Allocation--

Document: COSACAR
Cost of Service and Cost Allocation Report

3.1 Cost of Service and Cost Allocation: Second of Three Steps in Setting Rates

Once the revenue requirements are set, the cost of service analysis allocates revenues across functional cost components (this is called ‘functionalization’ or ‘unbundling’), and then divides these unbundled costs among customer classes. This allocation is calculated via a Cost of Service Model (COSM), and the supporting written report is known as the Cost of Service and Cost Allocation Report (COSACAR). In summary, the revenue requirements determine the size of the pie to be paid by retail customers and the cost allocation analysis divides the pie among the various customer classes. The section on rate design explains how specific rates are determined that are expected to collect the desired amount of revenue from each customer class.

There are two sets of costs referenced in the title of COSACAR. The first “cost” represents marginal costs to provide electric service to each customer class. The second “cost” represents total costs borne by retail customers in a year (i.e., annual revenue requirements). These two costs are not the same. <u>Shares</u> of the marginal costs by customer class are used to allocate the costs represented by the revenue requirements.

There are three steps involved here. First, the total revenue requirements are divided among various functional categories such as energy, substations, etc. This step is called Functionalizing the Revenue Requirements. The next step is to develop marginal cost shares by customer class for each functional category. The third step is to use the customer class shares of marginal costs for each functional category to assign those revenue requirements to classes for that function. For example, if customer class X has a 20 percent share of energy marginal costs, it is assigned 20 percent of the energy-related revenue requirements.

In addition to recognizing the different costs in the title of COSACAR, other constraints on the utility must be taken into account in the Cost of Service Model that determines the allocation of revenue requirements among customer classes. The Utility must also consider public policy desires and changes in perceptions of public policies when setting rates.

There are three special considerations here. (1) For many years, at the behest of the Mayor and City Council, the Department has included discounts in rates charged to low-income residential customers. (2) The Department has franchise agreements with incorporated areas in suburban King County that are served by the Utility. Those agreements include payments by City Light to the franchise cities, and different rates for suburban customers compared to city customers, with limits on rate differentials between suburban and Seattle city customers. (3) The cost to serve downtown network customers is higher than costs to serve similar customers elsewhere. The full costs of network service from Medium and Large General Service customers in the downtown network area are now recovered via rates but residential and small general service customers in the downtown network are exempted, by policy, from network rates.

The balance of this section briefly describes the following topics:

Functionalizing Revenue Requirements – Allocating the total revenue requirement among functional cost categories.

Classification of Customers – How customers are grouped together for ratemaking purposes.

Cost of Service Analysis –Development of shares of marginal costs by customer class for use in allocating the functionalized revenue requirements.

Policy Adjustments – Serving objectives established by public bodies in the service territory.

3.2 Unbundling or Functionalizing Revenue Requirements

"Unbundling" refers to the separation of costs, or revenue requirements into functional components, such as power, distribution, etc., that relate to different aspects of a utility's business.

The total for revenue requirements equals the sum of a large number of very detailed cost items. Many of those detailed revenue requirement or cost items are directly assignable to a particular cost function, while others must be spread across several functions. For example, the detailed cost item for rate relief for low-income customers is directly assigned to the Low-Income Assistance function; and discounts paid to business customers who own their transformers are assigned to distribution costs. In contrast, the detailed cost item for administrative and general (A&G) expenses is spread across all functions on the basis of non-A&G labor hours. Similarly, interest expense is allocated based on the book value of plant, and taxes are allocated on the basis of the tax rate.

The unbundled functions and associated revenue requirements from the 2007-2008 rate review (the last time this analysis was performed) are shown in Table 5. Net wholesale revenue is shown towards the bottom of the table because it is allocated among customer classes based on the allocation of all other functionalized items combined.

In general, these revenue requirement costs have corresponding costs of service where the cost of service is calculated as if, for example, all energy is purchased at market rates plus marginal environmental costs, all distribution services are provided by new facilities, etc. Thus, though there is a link, there is a distinction between revenue requirement costs and costs of service from new facilities or from purchases of wholesale power. Shares by customer class developed from the marginal costs of service are used in dividing the functionalized, total revenue requirement pie among the various customer classes.

In summary, there are two sets of division of the total revenue requirement pie. First, the total is divided among functional cost components. Then each of those components is divided among customer classes. After all functional cost components have been allocated among customer classes, total revenue requirements for each class are computed as the sum over all functional revenue requirements assigned to each class.

Table 5
Functional Allocation of 2007-2008 Revenue Requirements (2 year totals)
Million Dollars

Total Energy	**$954.2**
Production	162.4
Purchased Power	656.0
Conservation	100.2
Transmission-Long Distance	35.5
Total Retail Services	**$463.7**
Distribution	326.6
Transmission-In Service Area	19.3
Stations	62.9
Wires and Related Equipment	167.2
Transformers	37.2
Meters (except meter reading)	20.8
Streetlights/Floodlights	19.1
Customer Accounts & Services	119.7
Low-Income Assistance	17.5
Total	**$1,417.9**
Net Wholesale Revenue Credit	**(339.4)**
Final Revenue Requirement	**$1,078.5**

3.3 Classification of Customers

Customers are separated into rate categories based on three cost characteristics: amount of energy required, time of use (daily and seasonally), and service size. To translate these characteristics into appropriate pricing structures, the Utility divides customers into residential and nonresidential classes. The nonresidential or general service classes are further divided by size and type (network or non-network) of electrical service. Table 6 displays the major rate classes.

Table 6
Rate Classes

	Non-network	**Network**
Residential	No kW considerations	
Small	< 50 kW	
Medium	50 – 999 kW	50 – 999 kW
Large	1,000 – 9,999 kW	1,000+ kW
High Demand	10,000+ kW	

Customers are also divided by geographic region because suburban franchise agreements have particular terms that require separating costs for these customers from City of Seattle customers. In the 2007-2008 rate review, geographic regions included City, Tukwila, and Other Suburban.

Since then, franchise agreement terms have changed, so for future rate cases most suburbs will require their own cost allocation. City Light now has separate rate schedules for Burien and Shoreline

3.4 Cost of Service Analysis

3.4.1 Guidelines

The goal of cost allocation is a fair and equitable apportionment of the costs of providing service (energy, demand, customer costs) among customer classes. Past Council Resolutions pertaining to rate-setting have provided guiding principles and a general policy framework for this analysis. These key guiding principles include the following:

Marginal Cost of Service Study: City Light rates shall be based on a marginal cost-of-service study, which shall be the primary basis for allocating the costs of providing electric services among the customer classes.

Gradualism Adjustments: If a change in the cost-of-service allocation results in extreme bill fluctuations for a particular customer class compared to other customer classes, a method of mitigating these bill impacts may be considered and implemented. Such mitigation may include gradually moving to rates based on full costs of service over two or more rate change periods.

Conservation Expense: Since the City Council considers that conservation is a power resource, conservation expenditures shall be allocated to all customer rate classes.

Low Income Rates and Bill Payment Assistance Expense: The costs of providing low income rates and bill payment assistance to low-income residential customers shall be allocated to all customer rate classes.

3.4.2 Marginal Cost of Service

There are alternative ways to allocate revenue requirements among customer classes, the two most common being an embedded cost approach and a marginal cost approach. City Light has used a marginal cost approach since the early 1980s; this policy choice to use marginal cost methodology has been studied extensively and reaffirmed a number of times over the past two decades.

A marginal cost analysis estimates the incremental cost to serve what can be considered the ‘last’ unit of energy or peak load. This is the kind of analysis all serious businesses must use in order to determine the change in cost associated with expanding or contracting or understanding the cost of providing that ‘last’ unit. Without that information, businesses could expand or contract without full understanding of the economic implications of their action or could price their output without understanding how much that ‘last’ unit actually cost. In contrast, an embedded cost analysis would reflect a computed historical cost for City Light to provide a kWh of energy, or serve incremental peak load. For example, the marginal cost of, say, peak demand services would be based on the current replacement cost for all the components required to provide distribution services, whereas the embedded cost of peak demand services would be based on the historical cost of the existing distribution system.

All the units of energy (kWh) served in a year are multiplied by the marginal energy costs and the peak load (kW) is multiplied by the marginal capacity cost to determine the total marginal cost of service. Note that the resulting theoretical total marginal cost of service is not the actual cost of service for City Light. Marginal costs by function for each customer class are used to develop cost shares by function by customer class, and these shares are used to allocate the functionalized total revenue requirement (or actual cost of service) among customer classes.

Table 7 lays out in general terms the marginal cost category methodology that was used in the last rate review.

Table 7
Relation of Revenue Requirement Components to Marginal Cost Shares Used to Allocate the Requirements Among Customer Classes

Revenue Requirement Item	Marginal Cost Share
Energy SCL production Purchased power Conservation Transmission – long distance	Marginal energy costs
Distribution Transmission in Service Area Stations Wires & Related Equipment Transformers Meters (excludes meter reading) Streetlights/Floodlights	Marginal distribution costs in each category, which include both capital and O&M costs. Marginal costs for wires and transformers are further separated by network and non-network.
Distribution assigned to Lights	100% assigned to Lights
Customer Accounts and Services, including meter reading	Marginal costs include O&M for meter reading, uncollectibles, service maintenance, and customer records.
Low Income Assistance	Total marginal cost shares
Net Wholesale Revenue (credit)	Share of all assigned marginal costs

3.4.3 Marginal Cost Shares for Energy, An Example

This section presents background and a summary of the steps used in creating marginal cost shares of energy as one example of determining marginal cost shares by class.

(1) The Department conducts an on-going Time-of-Use (TOU) study of all large customers and takes frequent statistical samples of smaller customers who represent all classes to estimate consumption by hour by day (weekday, Saturday, Sunday or holiday) by month by customer class.

(2) The Department prepares an annual load forecast by customer class in two steps. First, it uses historical data to estimate coefficients in a model that relates consumption to economic and demographic factors. Next, it uses in that model forecasts of these factors that have been accepted for use in the City of Seattle to produce a forecast load.
(3) The annual load forecast is then turned into monthly, 4 time-periods-per-month (WD HLH, SA HLH, SU HLH, LLH), and 2 time-periods-per-month (HLH, LLH) forecasts by using information provided by the TOU study. These loads by time period can be turned into estimates of average MW per period (by dividing by number of hours in each period), from which an estimate of the peak costing period for a month and year can be determined.

As examples, Figures 2 and 3, below, illustrate the previously projected averages of MW/hour for the months of 2007 for the four costing periods plus the average for each month for Residential and Large General Service Nonnetwork customers. The Residential class has a clear winter peak and, typically, Sunday peak, whereas the Large class, which has large commercial and industrial customers, has a less distinct seasonal pattern but clear weekday high load hour peak periods each month.

(4) Engineering information is used to estimate energy losses (MWH per time period) at the various stages of the transmission and distribution systems for each of the four costing periods each month. These estimated losses are added to consumption to determine the total amount of energy, by time period, needed to serve the consumption load of each customer class.

Figure 2

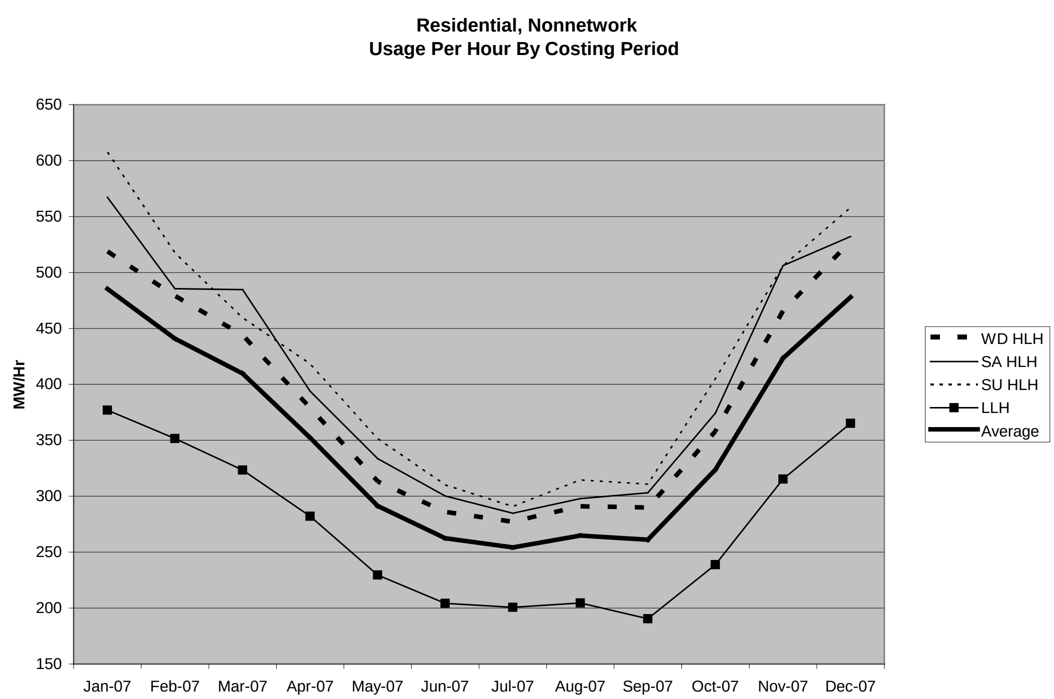
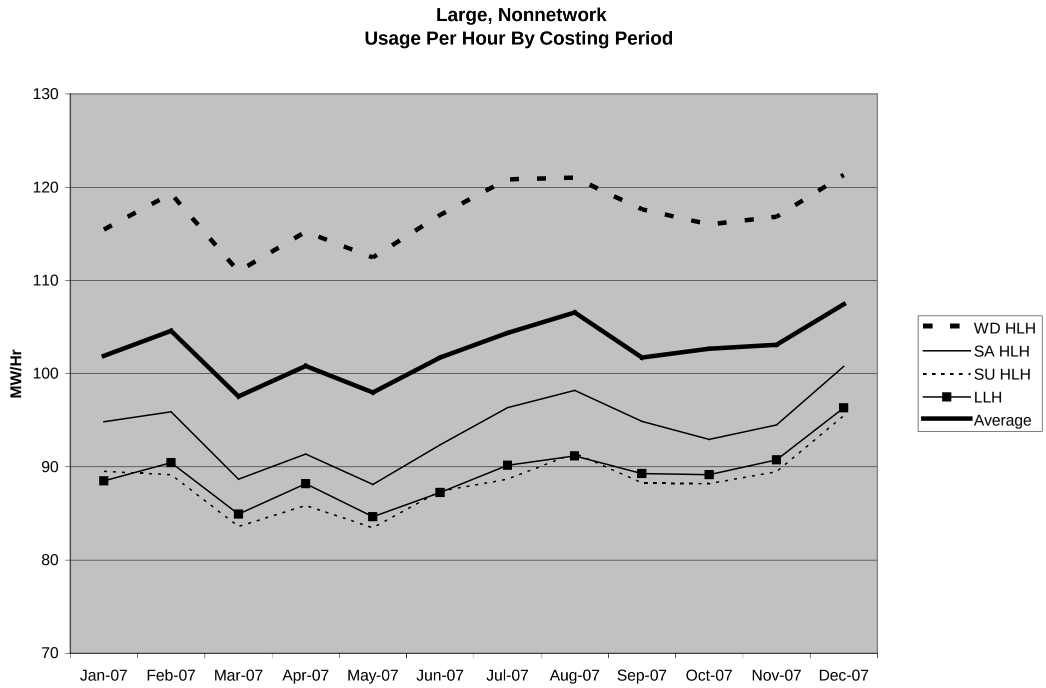


Figure 3



(5) Marginal values of energy ($/MWh) for HLH and LLH periods each month are projected that equal base-case forecasts of wholesale prices plus estimates of marginal environmental costs of providing energy.
(6) Marginal costs of energy by customer class equal the product of the total amount of energy, by time period, needed (i.e., the consumption load plus the distribution losses) of each customer class and the corresponding marginal values of energy.
(7) Marginal cost SHARES of energy by customer class are derived by summing over all customer classes the marginal costs of energy from step (6) and computing the share for each customer class as a proportion of the total for all classes. These shares are used to allocate the energy-related revenue requirements among customer classes.

The last rate case set rates for the two-year period 2007 and 2008. Hence it used estimates of marginal costs for the sum of the two-year period to create marginal cost shares. As illustrations, Figures 4 and 5 present the total of marginal costs of energy by nonnetwork class for the sum of the two years, and the corresponding shares. The two figures look identical, except that Figure 4 shows total dollars and Figure 5 shows shares of total marginal costs of energy. The sum of the percents is less than 100 percent because network loads are not included.

Figure 4

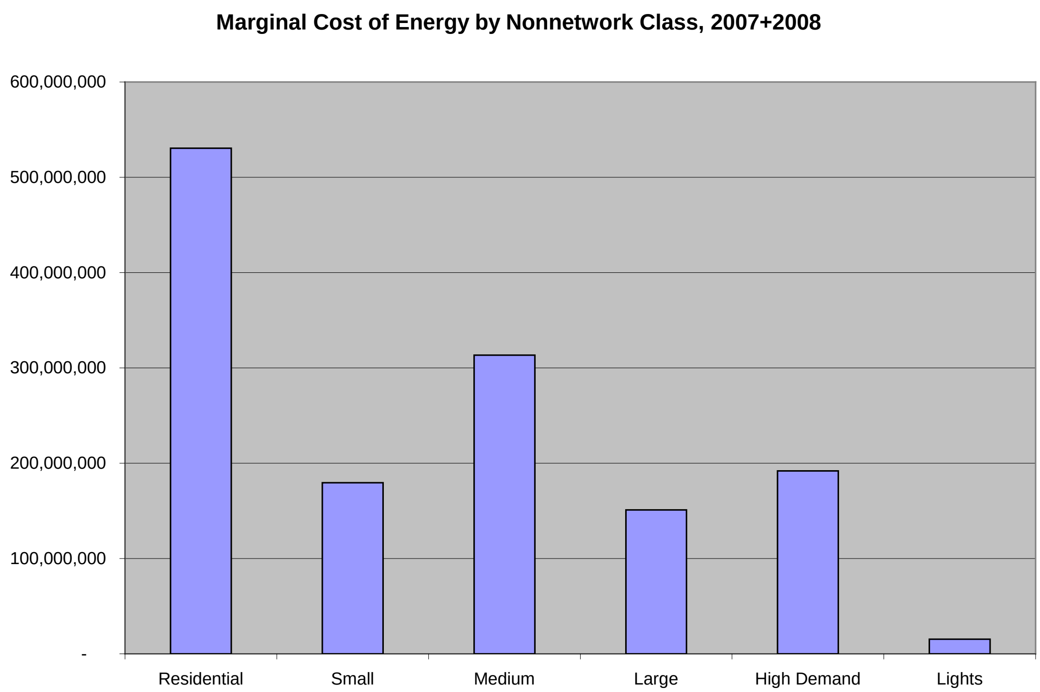
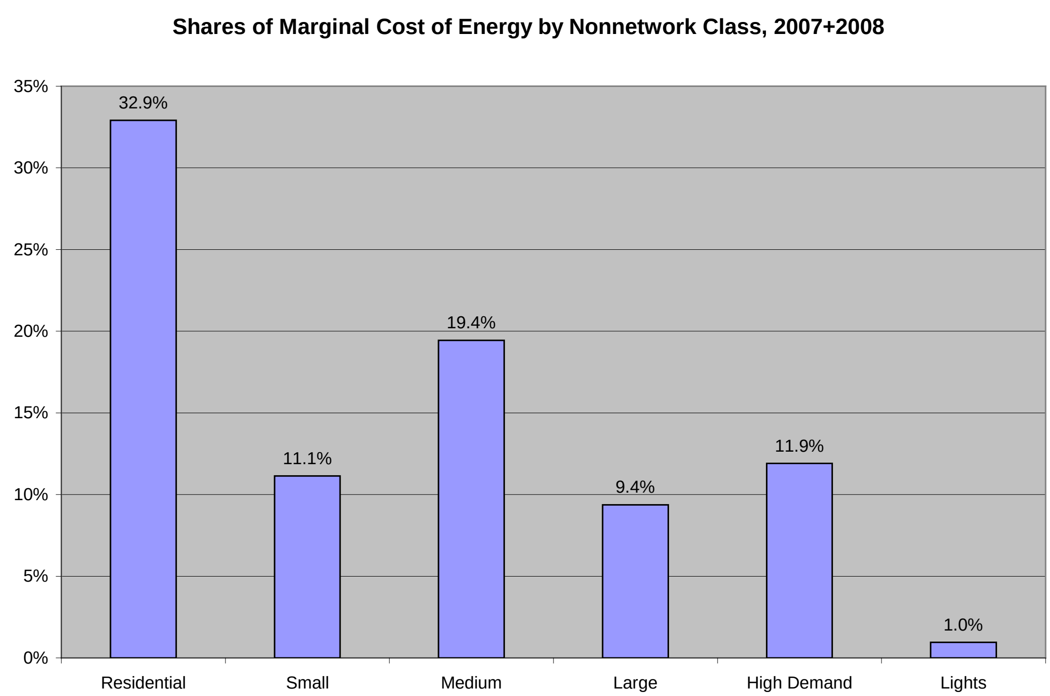


Figure 5



3.5 Initial Allocation of Revenue Requirements by Marginal Cost Shares

Examples of marginal cost shares by class by function for the 2007-2008 rate case are presented in Table 8. Note that the marginal cost shares for energy in Table 8 are identical to the shares presented in Figure 5. Revenue requirements for nonnetwork customers are displayed in Table 9. These results equal the product of the marginal cost shares by class by functional category and the corresponding total revenue requirement for the entire service territory for that functional category.

Table 8
Example of Marginal Cost Shares Used to Allocate of Revenue Requirements Among Customer Classes, 2007-2008

	Total Nonnetwork (EXcludes Network Residential & Small)						
	Total	Residential	Small	Medium	Large	High Demand	Lights
Energy							
Production	85.716%	32.907%	11.139%	19.440%	9.370%	11.904%	0.956%
Purchased Power	85.716%	32.907%	11.139%	19.440%	9.370%	11.904%	0.956%
Transmission - Long Distance	85.716%	32.907%	11.139%	19.440%	9.370%	11.904%	0.956%
Conservation	85.716%	32.907%	11.139%	19.440%	9.370%	11.904%	0.956%
Retail Service							
Total Distribution							
- Transmission - In Service Area	85.917%	37.866%	11.008%	19.000%	8.642%	8.665%	0.736%
- Stations	83.852%	36.956%	10.744%	18.543%	8.434%	8.457%	0.719%
- Wires & Related Equipment	100.000%	45.631%	12.755%	21.320%	9.745%	9.727%	0.431%
- Transformers	100.000%	37.581%	12.855%	31.030%	9.961%	7.735%	0.838%
- Meters, (except Meter Reading)	90.978%	63.407%	20.312%	6.583%	0.437%	0.239%	0.000%
- Streetlights/Floodlights							100.000%
Customer Costs	94.641%	81.860%	7.713%	1.389%	2.667%	1.010%	0.000%
Low-Income Assistance	83.229%	34.376%	10.628%	17.967%	8.668%	10.729%	0.851%
Total							

Table 9
Example of Allocation of Revenue Requirements Among Customer Classes, 2007-2008

		Total Nonnetwork (Excluding Network Residential and Small)						
Total $	**Svc.Terr. Total**	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	954,167,369	817,877,676	313,986,453	106,284,026	185,493,502	89,408,631	113,587,716	9,117,347
Production	162,436,608	139,234,772	53,452,776	18,093,699	31,578,250	15,220,846	19,337,072	1,552,129
Purchased Power	656,006,616	562,305,088	215,871,132	73,072,112	127,530,000	61,469,985	78,093,525	6,268,334
Transmission - Long Distance	35,526,700	30,452,199	11,690,719	3,957,294	6,906,516	3,328,969	4,229,234	339,468
Conservation	100,197,445	85,885,618	32,971,826	11,160,922	19,478,737	9,388,831	11,927,885	957,416
Retail Service	463,716,575	382,337,317	213,023,637	42,993,319	55,098,741	26,158,845	23,982,295	21,080,480
Total Distribution	326,607,753	254,568,521	109,075,292	31,908,817	50,299,961	21,454,043	20,900,339	20,930,068
- Transmission - In Service Area	19,339,405	16,615,766	7,322,974	2,128,962	3,674,494	1,671,223	1,675,711	142,400
- Stations	62,912,954	52,753,849	23,249,910	6,759,301	11,666,253	5,306,013	5,320,262	452,111
- Wires & Related Equipment	167,233,564	124,227,640	56,686,338	15,845,115	26,484,748	12,105,758	12,084,055	1,021,626
- Transformers	37,159,708	22,889,337	8,602,117	2,942,528	7,102,583	2,279,909	1,770,497	191,703
- Meters, (except Meter Reading)	20,839,893	18,959,701	13,213,953	4,232,912	1,371,882	91,140	49,814	0
- Streetlights/Floodlights	19,122,229	19,122,229	0	0	0	0	0	19,122,229
Customer Costs	119,652,199	113,239,813	97,947,378	9,229,269	1,662,427	3,191,660	1,209,079	0
Low-Income Assistance	17,456,624	14,528,983	6,000,967	1,855,233	3,136,353	1,513,142	1,872,876	150,411
Total	1,417,883,944	1,200,214,993	527,010,090	149,277,346	240,592,243	115,567,476	137,570,011	30,197,827
Share of Total Service Territory	100.000%	84.648%	37.169%	10.528%	16.968%	8.151%	9.702%	2.130%

3.6 Final Adjustments to Revenue Requirement Allocations

The final stages of the Cost of Service Model include the development of revenue requirements for the franchise cities based on the assumption that all non-network customers of a class have the same unit cost. Next comes allocating the total net wholesale revenue credit among all customer classes based on each class' share of the total costs so far allocated.

3.6.1 Franchise Agreements

Franchise agreements with the cities of Tukwila, SeaTac, Burien, Lake Forest Park, and Shoreline provided for payments from City Light to the governments of those cities (those costs are embedded in the total revenue requirements) and allowed higher rates to customers in the franchise cities than for corresponding non-network customers in the City of Seattle. The agreements allowed an 8 percent higher rate on the energy portion of the bill and, for Tukwila in 2007 and 2008, allowed a 6 percent higher rate on the remaining portion of the bill. The rate differentials, multiplied by projected load, are added to the suburban rates.

Table 10 shows for the last rate case the $/MWh for the energy and non-energy portions of the revenue requirements for Seattle nonnetwork customers and the adjusted rates to Tukwila and the other suburbs. The difference between the adjusted rates and the corresponding Seattle rates were then multiplied by the projected loads to produce the adjustments to total revenue requirements assigned to the suburban areas, shown in the bottom portion of Table 10.

Table 10
Some Calculated Results Associated with Adjustments to Suburban Revenue Requirements

	adj %	Total	Residential	Small	Medium	Large	High Demand
Base Energy, $/MWH, Seattle		49.784	50.166	50.211	49.718	49.377	48.932
Base Non-Energy, $/MWH, Seattle		23.273	34.035	20.311	14.768	14.447	10.331
Adjusted Energy, $/MWH, Tukwila	8%	53.353	54.180	54.228	53.695	53.327	52.846
Adjusted Non-Energy, $/MWH, Tukwila	6%	16.392	36.077	21.530	15.654	15.313	10.951
Adjusted Energy, $/MWH, Oth. Subs	8%	54.072	54.180	54.228	53.695	53.327	
Tukwila, MWH		1,001,216.000	116,543.000	63,963.000	183,627.000	224,480.000	412,603.000
Other Suburbs, MWH		2,049,243.000	1,317,004.000	285,830.000	399,788.000	46,621.000	-
Adjustment 1, D Energy Rev. from Tukwila	8%	3,956,897	467,722	256,932	730,364	886,730	1,615,149
Adjustment 1, D Non-Energy Rev. from Tukwila	6%	928,990	237,994	77,949	162,710	194,577	255,760
Adjustment 1, D Energy Rev. from Oth.Subs	8%	8,207,966	5,285,531	1,148,145	1,590,131	184,160	-
Total Franchise Adjustment		13,093,854	5,991,246	1,483,026	2,483,205	1,265,467	1,870,909

Note that the revenues on which payments to the franchise Cities are paid exclude revenue associated with surcharges for undergrounding or other special services not covered by standard rates. The payments to the franchise Cities and adjustment to rates, therefore, are all associated with base rates only.

The total of this incremental revenue from those differential rates is assigned as a credit to residential customers within the City of Seattle.

3.6.2 Adjustment for Network Residential and Small General Service Loads

Revenue requirements and loads associated with residential and small general service customers in the Network area are transferred to the corresponding Seattle nonnetwork customer groups.

3.6.3 Condensed Summary of Final Allocation of Revenue Requirements for 2007-08

Tables 11-13 present a condensed summary of the results of the cost allocation process for the 2007-08 rates. Table 11 presents the final allocated revenue requirement for the total Seattle City Light service area. The top row presents the allocation based on the various marginal cost shares. The next row presents the share of the revenue requirements allocated by those marginal cost shares. The third row uses the shares from the second row to allocate the expected credit from wholesale net revenue. The fourth row presents the franchise adjustments from Table 10. Note that the amount for the Residential class equals the total franchise adjustments over all classes ($13,093,853) that is a credit to Seattle Residential customers less the costs for Residential franchise customers ($5,991,246).

Table 11
Final Revenue Requirement Allocation to Total City Light Service Territory

	Total Service Territory						
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Cost Share Rev.Reqmnts	1,417,883,944	545,377,653	175,493,584	319,550,312	209,694,557	137,570,011	30,197,827
Share of Cost Shr Rev Req	100.000%	38.464%	12.377%	22.537%	14.789%	9.702%	2.130%
Wholesale Net Revenue	-339,397,429	-130,546,491	-42,007,720	-76,490,431	-50,194,372	-32,929,993	-7,228,423
Other Adjustments	0	-7,102,607	1,483,026	2,483,205	1,265,467	1,870,909	0
Tot Revenue Requirement	**1,078,486,515**	**407,728,555**	**134,968,890**	**245,543,086**	**160,765,653**	**106,510,928**	**22,969,404**
Load, MWH	**19,173,605**	**6,411,733**	**2,431,239**	**4,750,645**	**3,068,805**	**2,321,353**	**189,830**
Average Rate	**56.248**	**63.591**	**55.514**	**51.686**	**52.387**	**45.883**	**121.000**
Rate without Change	61.389	67.235	58.808	60.675	57.472	53.533	75.264
Pct Chg in Rate	**-8.37%**	**-5.42%**	**-5.60%**	**-14.82%**	**-8.85%**	**-14.29%**	**60.77%**

Table 12 is composed of two sub-tables which present the final allocated revenue requirement broken out by network vs. nonnetwork customers. Note that the totals in the top row of Table 12 for the nonnetwork customers for Medium, Large, High Demand, and Lights equal the totals in Table 9. The totals for Residential and Small customers in Table 12 equal the totals for those customers in Table 9 plus the amounts initially allocated to those customers when they were evaluated as customers within the network territory. (The network results for Residential and Small are not presented in this document.)

Table 12
Final Revenue Requirement Allocation to Nonnetwork and Network Customers

	Total Nonnetwork (Includes Network Residential & Small)						
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Cost Share Rev.Reqmnts	1,244,798,795	545,377,653	175,493,584	240,592,243	115,567,476	137,570,011	30,197,827
Share of Cost Shr Rev Req	87.793%	38.464%	12.377%	16.968%	8.151%	9.702%	2.130%
Wholesale Net Revenue	-297,966,214	-130,546,491	-42,007,720	-57,590,319	-27,663,269	-32,929,993	-7,228,423
Other Adjustments	0	-7,102,607	1,483,026	2,483,205	1,265,467	1,870,909	0
Tot Revenue Requirement	**946,832,581**	**407,728,555**	**134,968,890**	**185,485,129**	**89,169,675**	**106,510,928**	**22,969,404**
Load, MWH	**16,895,810**	**6,411,733**	**2,431,239**	**3,730,917**	**1,810,738**	**2,321,353**	**189,830**
Average Rate	**56.039**	**63.591**	**55.514**	**49.716**	**49.245**	**45.883**	**121.000**
Rate without Change	61.252	67.235	58.808	59.386	55.698	53.533	75.264
Pct Chg in Rate	**-8.51%**	**-5.42%**	**-5.60%**	**-16.28%**	**-11.59%**	**-14.29%**	**60.77%**

	Network (Excludes Residential and Small)				
	Total	**Residential**	**Small**	**Medium**	**Large**
Cost Share Rev.Reqmnts	173,085,149			78,958,069	94,127,081
Share of Cost Shr Rev Req	12.207%			5.569%	6.639%
Wholesale Net Revenue	-41,431,215			-18,900,112	-22,531,103
Other Adjustments	0			0	0
Tot Revenue Requirement	**131,653,934**			**60,057,957**	**71,595,978**
Load, MWH	**2,277,795**			**1,019,728**	**1,258,067**
Average Rate	**57.799**			**58.896**	**56.910**
Rate without Change	62.210			65.392	60.026
Pct Chg in Rate	**-7.09%**			**-9.93%**	**-5.19%**

Table 13 is composed of three sub-tables and provides additional detail on the final revenue requirement allocation to nonnetwork customers by breaking it out geographically.

Table 13
Final Revenue Requirement Allocation to Nonnetwork Customers by Geographic Area

	Seattle Nonnetwork (Includes Network Res & Small)						
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Cost Share Rev.Reqmnts	1,020,047,186	424,670,928	150,825,475	202,970,092	98,264,886	113,117,979	30,197,827
Share of Cost Shr Rev Req	71.942%	29.951%	10.637%	14.315%	6.930%	7.978%	2.130%
Wholesale Net Revenue	-244,167,651	-101,653,046	-36,102,940	-48,584,743	-23,521,565	-27,076,935	-7,228,423
Other Adjustments	-13,093,854	-13,093,854	0	0	0	0	0
Tot Revenue Requirement	**762,785,681**	**309,924,029**	**114,722,535**	**154,385,349**	**74,743,321**	**86,041,044**	**22,969,404**
Load, MWH	**13,845,351**	**4,978,186**	**2,081,446**	**3,147,502**	**1,539,637**	**1,908,750**	**189,830**
Average Rate	**55.093**	**62.256**	**55.117**	**49.050**	**48.546**	**45.077**	**121.000**
Rate without Change	60.578	66.380	58.600	59.094	55.381	52.784	75.264
Pct Chg in Rate	**-9.05%**	**-6.21%**	**-5.94%**	**-17.00%**	**-12.34%**	**-14.60%**	**60.77%**

	Tukwila					
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Cost Share Rev.Reqmnts	64,944,388	9,813,089	4,510,800	11,841,387	14,327,079	24,452,033
Share of Cost Shr Rev Req	4.580%	0.692%	0.318%	0.835%	1.010%	1.725%
Wholesale Net Revenue	-15,545,672	-2,348,949	-1,079,746	-2,834,461	-3,429,458	-5,853,058
Other Adjustments	4,885,888	705,716	334,881	893,074	1,081,307	1,870,909
Tot Revenue Requirement	**54,284,604**	**8,169,855**	**3,765,935**	**9,900,001**	**11,978,928**	**20,469,884**
Load, MWH	**1,001,216**	**116,543**	**63,963**	**183,627**	**224,480**	**412,603**
Average Rate	**54.219**	**70.102**	**58.877**	**53.914**	**53.363**	**49.612**
Rate without Change	60.021	70.818	61.600	62.175	57.757	56.999
Pct Chg in Rate	**-9.67%**	**-1.01%**	**-4.42%**	**-13.29%**	**-7.61%**	**-12.96%**

	Other Suburbs				
	Total	**Residential**	**Small**	**Medium**	**Large**
Cost Share Rev.Reqmnts	159,807,221	110,893,636	20,157,309	25,780,764	2,975,511
Share of Cost Shr Rev Req	11.271%	7.821%	1.422%	1.818%	0.210%
Wholesale Net Revenue	-38,252,891	-26,544,496	-4,825,034	-6,171,115	-712,245
Other Adjustments	8,207,966	5,285,531	1,148,145	1,590,131	184,160
Tot Revenue Requirement	**129,762,296**	**89,634,670**	**16,480,419**	**21,199,780**	**2,447,426**
Load, MWH	**2,049,243**	**1,317,004**	**285,830**	**399,788**	**46,621**
Average Rate	**63.322**	**68.060**	**57.658**	**53.028**	**52.496**
Rate without Change	66.476	70.150	59.700	60.410	56.247
Pct Chg in Rate	**-4.74%**	**-2.98%**	**-3.42%**	**-12.22%**	**-6.67%**

4. Rate Design --
Putting It All Together

4.1 Rate Design Introduction

Once we know how much money we need to continue serving our customers, and understand more about the relative cost of serving different customers in the future, we are ready to take the final step in rate setting.

Rate design is the process of shaping rates, charges, and credits for customer classes so that the classes meet their portion of the Utility's revenue requirement in a way that is consistent with City goals and policies.

4.1 The Three Parameters of Rate Design

City Light rate designers have three basic parameters or tools at their disposal: the rate class (residential, small general service, etc.); the rate structure (flat, blocked, seasonal, time-of-use, etc.); and the rate element (energy, demand, and other charges). In practice, rate structures and elements are designed simultaneously. The distinction drawn here is simply a paradigm to help comprehension of the rate-setting process.

4.1. 1 Rate Classes

City Light groups customers with similar costs and metering characteristics into large categories called rate classes. The most basic differentiation is between residential and non-residential classes. The non-residential classes are also called commercial/industrial classes; they are distinguished by peak demand size. Each rate class is served and charged under a particular rate schedule.

Other factors besides the characteristics noted above led to the establishment of separate rate schedules for customer groups.

One such factor was the establishment of franchise agreements with the cities of Burien, Lake Forest Park and Shoreline effective in 1999, an agreement with SeaTac effective in 2000, and a revision to the franchise agreement with Tukwila in 2003. Rates to customers in the franchise cities are higher than for corresponding customers elsewhere in the service territory because of terms in those agreements. However, the majority of the additional revenue received by City Light from these higher rates is passed directly back to the governments of each franchise City, via a monthly payment.

Another factor affecting some suburbs leading to separate rate schedules has been the inclusion of the costs of various undergrounding projects in Shoreline and Burien in the rates collected from ratepayers in those cities. These costs are also collected based on the terms of the franchise agreements.

Finally, separate rates were also established for Medium and Large General Service customers in the downtown network area because of higher costs to serve those customers.

City Light's principal rate schedules are shown in Table 14. In addition to these rate schedules, there are also others such as those for street and flood lighting, pole attachments and low power factors.

Table 14
Rate Schedules

Rate Schedule Name	Rate Schedule
Residential: City	RSC
Residential: Suburban	RSS
Residential: Tukwila	RST
Residential: Shoreline	RSH
Residential: Burien	RSB
Residential Elderly/Disabled: City	REC
Residential Elderly/Disabled: Suburban	RES
Residential Elderly/Disabled: Tukwila	RET
Residential Elderly/Disabled: Shoreline	REH
Residential Elderly/Disabled: Burien	REB
Residential Low-Income: City	RLC
Residential Low-Income: Suburban	RLS
Residential Low-Income: Tukwila	RLT
Residential Low-Income: Shoreline	RLH
Residential Low-Income: Burien	RLB
Small General Service: City	SMC
Small General Service: Suburban	SMS
Small General Service: Tukwila	SMT
Small General Service: Shoreline	SMH
Small General Service: Burien	SMB
Medium Standard General Service: City	MDC
Medium Standard General Service: Suburban	MDS
Medium Standard General Service: Tukwila	MDT
Medium Standard General Service: Shoreline	MDH
Medium Standard General Service: Burien	MDB
Medium Network General Service	MDD
Large Standard General Service: City	LGC
Large Standard General Service: Suburban	LGS
Large Standard General Service: Tukwila	LGT
Large Standard General Service: Shoreline	LGH
Large Standard General Service: Burien	LGB
Large Network General Service	LGD
High Demand General Service: City	HDC
High Demand General Service:Tukwila	HDT

4.1.2 Rate Structure

Varying rate structures allow the rate-setter to more accurately bill usage according to cost, and to allocate revenues within as well as between customer classes. Over the years, utilities have developed a variety of rate structures, the most common of which are described below.

Flat	The simplest rate form bills electricity use at the same uniform price per kilowatt-hour no matter how much energy is consumed. City Light has a flat rate for small and medium nonresidential customers.
Block	The price of electricity changes at different levels of consumption. City Light has a two-block rate for residential customers.
Inverted Block	The price charged per kilowatt-hour increases as consumption increases. Each succeeding "block" (or increment) of energy consumption during the billing period costs more than the preceding energy block. Residential customers in Seattle have inverted block rates to encourage conservation. In addition, this rate structure is consistent with the economic theory of increasing marginal costs of electricity production.
Declining Block	The price charged per kilowatt-hour decreases as consumption increases. Each succeeding "block" (or increment) of energy consumption during the billing period costs less than the preceding energy block, encouraging electricity consumption.
Time of Use	Prices can also be varied by season or time of day. This rate structure assesses higher prices for usage during peak demand periods such as winter or early evening. Seattle has time-of-day rates for large and high demand nonresidential customers.
Lifeline	Another name for the inverted rate, expressing a different purpose. The first block of electricity is priced below cost to cover essential uses such as lighting, cooking, and refrigeration. The revenue lost in the first block is made up in higher-priced succeeding blocks.
Power Factor	This is a special rate that charges nonresidential customers for having a low power factor (e.g., using a large amount of magnetizing energy required for operating motors). Because this energy is not measured by regular billing meters, special reactive meters are installed to measure it. This rate is not designed to generate revenue, but to induce customers to install capacitors to provide their own magnetizing energy.
Interruptible	A discounted rate sometimes offered to large nonresidential customers who permit portions of their service to be turned off during system shortages or periods of high cost.

4.1.3 Rate Elements

Once the Utility has identified specific rate structures to fit its objectives, it must fill them with the rate elements (charges and fees) so that the resulting revenues meet the costs of serving each customer class. Utilities can use different rate elements or combinations of elements: energy charges, demand charges, base service charges, minimum charges, and miscellaneous fees for various services. We describe the main rate elements used by City Light below.

Energy Charge	The Utility's various energy charges generate most of its revenues. Meters measure electric consumption in units of 1,000 watts (kilowatts) used and the number of hours they are used. For example, ten 100-watt light bulbs burning for one hour would appear on a bill as an energy charge for one kilowatt-hour (kWh) of electricity
Demand Charge	Medium, Large, and High Demand General Service customers are also billed for maximum demand, as measured by demand meters. City Light's demand meters measure consumption at 15-minute intervals throughout the day. The customer's highest rate of use over a 15-minute period is recorded each month and multiplied by the demand charge to determine the demand billing.
Base Service Charge	The Base Service Charge is a fixed amount that is charged to every residential customer in addition to the amount charged for energy usage. This charge is set to cover half of the customer-related costs such as meter reading, billing, and capital cost of the meter.
Minimum Charge	For nonresidential customers a minimum charge, designed to recover the same costs as the residential base service charge, is charged if the customer's bill is not above the minimum charge. City Light does not assess a base service charge to nonresidential customers because its goal is to encourage energy conservation by recovering costs as much as possible through rate components controllable by the customer.

4.2 Linking Rate Design to Policy

The selection of rate structures and elements is the process of translating rate-setting policy objectives into concrete design criteria. This involves making value judgments and trade-offs as the Department seeks to balance sometimes contradictory goals. Each rate review presents a new opportunity to reevaluate this process in view of the City's long-term goals.

Past Council resolutions have set out the policies that City Light should follow in setting rates. These include:

1. Rates shall be designed in ascending blocks to encourage conservation where blocks are feasible.

2. Rates with demand charge components shall not be designed in declining blocks.

3. City Light shall have a residential first block for the essential needs of residential customers that should be priced below the average cost of service to those customers.

4. Discounts shall be provided to customers with customer-owned transformers and to customers who are metered before transformation.

5. City Light shall investigate where cost-effective time-of-use and seasonal differentiation options can be implemented.

6. The impacts of the costs of electricity shall continue to be mitigated for low income customers.

As a general rule, the Department prefers not to change rate structures or elements radically because it engenders instability and confusion. However, the emphasis of the structures can gradually be modified. The process of fine-tuning rate structures involves varying the elements or charges within them.

4.3 Rate Computations

Each rate design has an accompanying set of equations that transform design concepts into concrete numbers (rates) for each customer class.

For example, the basic equation for the Residential rate schedules is:

$$R = K_1P_1 + K_2P_2 + K_3P_3 + K_4P_4 + XM$$

The symbols in the equation stand for:

R = The class revenue requirement
K_1 = Number of kWh subject to the first block charge - summer
P_1 = Price of first block - summer
K_2 = Number of kWh subject to the second block charge - summer
P_2 = Price of second block – summer
K_3 = Number of kWh subject to the first block charge - winter
P_3 = Price of first block – winter
K_4 = Number of kWh subject to the second block charge - winter
P_4 = Price of second block – winter
X = Base Service Charge per day
M = Number of days

As an example, the charges as of January 1, 2011 for Schedule RSC (Residential, Seattle) are:

	Summer	Winter
First Block per KWh (P_1 & P_3)	$0.0461	$0.0461
Second Block per kWh (P_2 & P_4)	$0.0956	$0.0956
Base Service Charge per Day (X)	$0.1155	$0.1155

The equation for the Small General Service rate schedule is similar to the Residential equation, except that there are no blocks. The equations for Medium, Large, and High Demand General Service users are more complex because the revenue requirement for these classes is spread between demand charges and energy charges. For large users, the equations also include variables for time-of-day consumption.

5. Rates in Context: A Historical Perspective

5.1 City Light’s Predecessors

The light bulb was only three years old when, in 1882, Thomas A. Edison perfected the first means of lighting a large area from a central source. Seattle lit up for the first time in 1886 when the Seattle Electric Light Company, a private corporation located on Jackson Street, used a direct-current system to provide streetlighting and residential service at a flat per-bulb rate. While carbon-arc lights had been used in Southern California since 1882, Seattle's was the first incandescent light west of the Rockies.

For the next 13 years the City was served by a variety of "neighborhood electric companies," since direct current could be transmitted only over short distances. In 1892 several of these companies were united under the Consolidated Union Electric Company. Development of the alternating current transformer seven years before had opened possibilities for distributing power over greater distances. One of the first firms to take advantage of the new technology was the Boston-based holding company of Stone & Webster. About the turn of the twentieth century, the firm bought up a number of small local electric companies, and consolidated them in the Seattle Electric Company.

In 1902 the citizens of Seattle approved a $590,000 bond issue to develop the Cedar River as a source of hydroelectric power. This, and the plan to use surplus water from the Volunteer Park reservoir for generating power to light Seattle streets, marked the beginning of public power in the City. By 1905 Cedar Falls, one of the nation’s first municipally owned hydroelectric projects, was generating electricity for Seattle's streetlights, under control of the Water Department. For the next half-century, though, public and private power systems competed to serve Seattle.

In 1907 the City's first electrical substation was established at Seventh Avenue and Yesler Street. Beginning in 1909, the City's buildings and homes were wired for electricity by teams of technicians who were the precursors of today's City Light staff. By 1910 demand for Seattle's municipal power had risen sharply and the City Council decided to separate the lighting functions from the Water Department. A new department was formed on April 1, 1910, under Superintendent Richard Arms, and Seattle City Light was born.

5.2 Early City Light and the Legacy of J.D. Ross

The new city department was called the Seattle Lighting Department and it found its future in the vision of the legendary J. D. Ross, the self-taught engineer who succeeded Arms after eleven months in March 1911. Ross was associated with City Light until 1939. Under Ross:

- The Lake Union hydro plant was outfitted with an oil-fired steam plant
- A new masonry dam was completed at Cedar Falls
- Federal approval of hydro projects on the upper Skagit River was obtained
- Gorge, Diablo and Ruby dams (renamed Ross dam after the death of J.D. Ross) with associated powerhouses were built
- Tours of the Skagit hydro projects were begun.

5.3 Northwest and City Light Developments Prior to the 2000-2001 Energy Crisis

This section summarizes the key developments that occurred in the energy industry in the Pacific Northwest and at City Light starting in the 1930's and ending prior to the Energy Crisis in 2000-2001. The major events that have helped to shape what Seattle City Light is today are:

- Grand Coulee Dam, first of the Columbia's major dams, constructed in the 1930's by federal government.
- Bonneville Power Administration (BPA), established in the late 1930's, became the federal government's power marketing agency in the Pacific Northwest.
- Northwest Power Pool formed in 1942 to coordinate sales and power exchanges among utilities within the region.
- City Light purchased all Seattle-area properties of Puget Sound Power & Light in 1951.
- Boundary Dam and powerhouse were built by City Light on northeastern Washington's Pend Oreille River in the 1960's and started operation in 1967.
- City Light joined the Washington Public Power Supply System (WPPSS) in 1971, a consortium formed to finance large public power generating facilities.
- The Office of Environmental Affairs was established in Seattle in 1972 and studies began on a proposed dam at Copper Creek on the lower Skagit River, sparking legal and environmental controversy that lasted for a decade.
- In 1980, City Light initiated several changes supported by members of the Citizen's Rates Advisory Committee: seasonal rates, a two-step residential rate schedule featuring lifeline rates, and a marginal cost-of-service approach to rate-setting.
- In December 1980, Congress adopted the Northwest Power Planning and Conservation Act, which supported the Utility's aggressive conservation efforts and emphasis on renewable resources. The Act also formalized the Bonneville Power Administration's role as regional power coordinator.
- In 1984 the Department reached an 80-year agreement with the government of British Columbia (Canada) which provides the energy and capacity that would have been generated by the raising of Ross Dam.
- 1984 marked the completion of a customer classification study. Formerly classified by broad end-use categories, customers would be classified according to load size in the future. This step was taken to more accurately classify customers according to cost of service.
- In 1985 a new Multifamily Conservation Program was initiated, the first financial incentive program in Seattle for weatherizing multiple-unit dwellings.
- In 1986 BC Hydro delivered the first energy from the High Ross Dam Agreement to City Light. Also, Units 55 and 56 at the Boundary Project were brought on line. Producing 30 to 50 percent of the electricity sold in City Light's service area, Boundary is the Utility's largest single source of power.
- The Lucky Peak Hydroelectric Project came on line in 1988. This project is owned by three irrigation districts in Idaho and one in Oregon; City Light buys the power output and directs the operation of the plant under a 50-year contract.
- In 1995 FERC issued a new 30-year license for the operation of the Skagit Hydroelectric Project. The South Fork of the Tolt River generating facility, with a capacity of 16.8 megawatts, also came on line.

- In 1996 the FERC issued its Order 888, which required transmission owners to offer transmission services to other companies under the same terms and conditions that they offer it to themselves. It also encouraged open access to the transmission system.
- During 1996, City Light unbundled its revenue requirements (into generation, purchased power, transmission, distribution, customer services, and public purposes programs) for the first time. These unbundled revenue requirements were used, together with unbundled marginal cost allocators, to more accurately allocate the components of the revenue requirements to customer classes.
- By the end of 1998, all 50 states and the District of Columbia had initiated some form of legislative or regulatory process to examine retail competition and deregulation of the electric industry, and mandatory retail competition was under way in at least 13 states. Active short-term power markets had developed, and energy futures contracts were available on the New York Mercantile Exchange. The competitive market of most interest to City Light, California, was officially opened to competition as of March 31, 1998 for all consumers in the service territories of investor-owned utilities.
- With the rates effective December 1999, separate, higher rates were created for suburban areas (outside the Seattle City limits) as a result of new 15-year franchise agreements to serve the cities of Shoreline, Burien, and Lake Forest Park. City Light signed a similar franchise agreement with the City of SeaTac starting in 2000 and Tukwila arranged to revise its agreement with City Light in 2003 along the same general lines.
- Also in 1999, in a major step toward Seattle's goal of "carbon-neutral" generation, City Light arranged for the sale of its 8-percent ownership share of the coal-fired Centralia Steam Plant, and pursued new sources of sustainable energy by forming a "Green Power" alliance with the Los Angeles Department of Water and Power.

5.4 Facing an Energy Crisis in Early 2000's

Starting in the Spring of 2000, City Light was confronted by a mounting crisis triggered by California's reform of its power marketplace. This, combined with the worst drought in recorded history in the Pacific Northwest, the sale of the Centralia Steam Plant, and prior decisions to reduce the amount of power purchased from BPA, forced City Light to purchase more power on the open market than had been planned. The cost of this power was far higher than had ever been experienced in the past. At year's end, City Light reported a $52 million net income loss, the largest loss in the Utility's history.

A new Strategic Resources Plan adopted by the City Council was expected to free Seattle from the wildest swings of the wholesale power market. The plan called for more energy from BPA, the purchase of 100 average megawatts (aMW) of power from the State Line (wind) Project, and another 100 aMW to be supplied by the Klamath Falls combustion turbine. However, before all the preparations to implement the Strategic Resources Plan were completed, further difficulties plagued the industry. Water conditions worsened and there was a contrived shortage of electricity in California, forcing spot market prices to astronomical levels.

In July 2001, City Light began receiving the energy output of 100 MW of capacity from the Klamath Falls (southern Oregon) gas-fired combustion turbine power plant under a five-year contract, renewable for five additional years. In October of the same year City Light began a new contract with BPA that provided more power than the previous contract. By the end of 2001, City Light had completed contracts for the purchase of the output of the State Line Wind Project in southern Washington-northern Oregon. The net effect of City Light's resource changes in 2001 was that the Utility could meet its load in almost all months under poor water conditions with resources it controlled. These new power purchase agreements protected City Light against the effects of future droughts and also produced surpluses in good water conditions that could be sold in the marketplace.

The financial crisis associated with the multiple bad events required raising rates in January, March, and July of 2001, as well as passing through to ratepayers an additional increase in BPA costs in October 2001. City Light called for curtailment and conservation from its customers, which resulted in a 10 percent reduction of electricity use. This reduced consumption saved as much as $80 million for energy purchased in 2001. However, $300 million of excess power costs were deferred from recognition in 2001 to 2002-2004 ($100 million each year). Even with the deferral, the net loss for 2001 was a new high, $73.3 million, and the Department incurred $182 million of short-term debt that was repaid in early 2003.

Precipitation improved so that water conditions and snow accumulations in all watersheds were more than 100 percent of normal in 2002. This change illustrated once more the volatility of weather and the effects on output (in this case, improvements) from hydro generation plants.

City Light's conservation programs celebrated their 25th anniversary in 2002. During the same year, the Department initiated its Green Power program, under which customers could voluntarily contribute funds to be used for renewable energy projects, primarily solar.

In 2003 City Light redeemed $182.2 million in revenue anticipation notes (RANs) and repaid another $125 million of RANs later that year. At year end, Seattle City Light had paid off all external debt remaining from the 2000-2001 energy crisis but still owed $70 million to the City of Seattle cash pool.

5.5 City Light since 2004

Jorge Carrasco was nominated to be Superintendent in December 2003 by Mayor Nickels and was confirmed by the City Council in early 2004. Superintendent Carrasco began working immediately on one of his and the City Light Advisory Board's priorities: an initiative designed to transform City Light into a high-performance organization. The transformation began with an internal survey, designed to identify workplace issues and improvements. Many issues identified in the survey were addressed quickly. Cross-divisional issues became part of longer term action plans.

As 2005 began, City Light had paid off $300 million in short-term debt incurred during the energy crisis a few years earlier and had started paying down long-term debt. At the same time, operating cash reserves had grown and bond-rating agencies upgraded City Light's financial outlook.

2005 also was a year for more focus on transforming City Light into a high-performance organization. Because of skilled-labor shortages and future retirements (50 percent of the utility's workforce would become eligible for retirement over the next five years), greater emphasis was placed on workforce planning, enhanced recruitment, apprenticeship training, and succession planning. Following the wise decisions of Northwest policymakers not to move toward retail electricity deregulation, City Light continued its commitment to the vertically-integrated utility model that had served its customers so well. The utility recognized that more attention needed to be focused on the reliability of its regional transmission system. The utility also began work on a new energy strategy in the face of enormous pressure on our environment, global warming, and the predicted end of the era of fossil fuels.

The Hanukah Eve Storm hit the Seattle area on the evening of December 14, 2006. No natural disaster so devastating had hit our area in more than 40 years. Half of City Light's customers were without power – most for only a few hours, but some for as long as nine days. The damage to the distribution system was unprecedented.

During 2007, two independent, outside studies of City Light's storm response were conducted. A series of 65 recommendations were made to improve the utility's restoration and response time related to outages. By October 31, 2007, all 46 of the most urgent – Tier 1 – recommendations were accomplished. Most of the remaining Tier 2 and Tier 3 recommendations were completed by the end of the year.

In 2008, a new 17-year power-sales agreement was signed with the BPA securing the utility's ability to buy economical, reliable, clean energy from BPA effective October 2011 after the old contract would expire. City Light also determined that saving energy would become the utility's new power plant.

The aftermath of the global financial crisis that unfolded after September 2008, into 2009 and 2010, proved to be financially challenging years for Seattle City Light. Wholesale energy prices fell dramatically during 2009, causing a significant drop in revenue from surplus power sales. Spending was reduced to meet the shortfall. On January 1, 2010, a 13.8 percent rate increase went into effect. Rates had not been increased since 2002 and had actually dropped by 12.1 percent during those seven years. In addition, other budget cuts were made in order to reduce spending.

A slow economic recovery and lower electricity prices during 2009-2010 contributed to net wholesale revenues being lower than projected two years in a row. To mitigate volatility in the wholesale energy markets, the City Council, in March 2010, adopted Ordinance 123260 establishing parameters for the Rate Stabilization Account (RSA). The main purpose of the RSA is to absorb fluctuations in City Light's annual net wholesale energy revenues as compared to the amount of those revenues assumed in the budget. In November 2010, the City Council approved rate increases of 4.3% for 2011 and 3.2% for 2012.

5.6 Load Growth and Rate Changes

Table 15, below, shows Seattle City Light's retail load and its growth rate since 2000. During 2001 the retail load decreased by more than 5% as a result of the significant increase in rates that City Light implemented that year in response to the energy crisis. The energy crisis had many contributing factors. Some were individual players in the energy commodity markets who 'gamed' the California wholesale price system by withholding some power from the market, creating artificially high wholesale market prices. Meanwhile, City Light suffered through one of the driest water conditions in many years, so it was obligated to buy much more than normal amounts of power on the open market at extraordinarily high prices.

Table 15
Annual Retail Load

	Ann. % Chg	MWH
2001	-5.12%	8,975,792
2002	-0.59%	8,923,130
2003	-0.19%	8,905,944
2004	1.29%	9,020,525
2005	1.56%	9,161,465
2006	3.20%	9,454,505
2007	1.54%	9,599,911
2008	1.13%	9,708,507
2009	-0.16%	9,693,424
2010	-3.33%	9,370,996

Retail load declined following the national economic recession that started in December 2007. Even though the economic recession officially ended in June 2009, the recovery has been extremely sluggish, which explains the drop in retail load in 2009 and 2010.

Table 16 shows City Light's electric rate changes since 1971. The average rate increase of 56.2% in 2001 represents the cumulative effect of several increases that were implemented that year as a result of the energy crisis. Small changes in rates during 2003-2005 and 2009 are due to an automatic pass-through of the decreases/increases in rates that the BPA charges City Light. Due to economic recession and its negative impacts on City Light's financials in 2009, the City Council passed a 13.8% rate increase effective 2010. The rest of the rate increase in 2010 is due to the BPA pass-though.

Table 16

Average Rate Change by Year (percentages)

Year	Average Rate Increase (Decrease)	Year	Average Rate Increase (Decrease)
1971	7.0	1997	(0.4)
1974	9.0	1998	(0.6)
1977	5.0	2000	3.2
1980	40.7	2001	56.2
1982	37.3	2002	(0.6)
1984	30.0	2003	1.4
1986	9.5	2004	(2.1)
1989	4.4	2005	(2.2)
1990	(2.4)	2007	(8.4)
1993	12.6	2008	(0.2)
1995	5.7	2009	(0.4)
1996	5.3	2010	15.1

Despite the overall upward trend in its rates over the past thirty years, City Light continues to have some of the lowest rates in the country, as the following table shows.

Table 17

Comparison of 2010 Average Utility Rates in U.S. Cities by Customer Class

(cents/kWh)

City	Residential	Commercial	Industrial	System
Seattle	7.23	6.22	5.56	6.65
Indianapolis	7.82	8.76	6.45	6.83
San Antonio*	8.68	7.50	7.50	7.46
Charlotte	8.98	6.89	5.40	7.51
Nashville*	9.25	10.80	8.12	8.95
Denver	11.09	8.94	6.21	9.11
El Paso	11.27	10.91	6.48	9.75
Jacksonville*	11.50	9.79	8.01	10.08
Phoenix	11.54	10.11	7.83	10.63
Chicago	12.25	10.10	6.79	11.44
Baltimore	14.26	7.47	7.40	11.55
Los Angeles	12.60	12.50	11.00	12.40
Boston	16.58	15.11	13.68	15.37
U.S. Average: Preliminary	**11.58**	**10.26**	**6.79**	**9.88**

* Publicly owned

Sources:

1. Investor-Owned Utilities: Edison Electric Institute Typical Bills & Average Rates Report – May 2011
2. Publicly Owned Utilities: Information from each utility, May 2011

6. A Rate Maker's Who's Who

Key Players in the Rate Review Process

Mayor's Office

Mike McGinn, Mayor. He reviews City Light's reports and recommendations before forwarding his recommendations to the City Council.

Ethan Raup, Director of Policy and Operations. He may review City Light's reports and recommendations before they go to the Mayor.

City Council

Richard Conlin, President. He conducts City Council hearings and makes committee assignments.

Bruce Harrell, Chair, Energy, Technology & Civil Rights Committee. He chairs the Council's three-member Committee, which reviews Utility recommendations for the Council.

Nick Licata and **Richard Conlin** are also members of the Energy, Technology & Civil Rights Committee. **Mike O'Brien** is an alternate member.

Michael Jerrett, staff for Councilmember Bruce Harrell.

Jennifer Samuels and **Vinh Tang**. Energy, Technology & Civil Rights Committee staff.

Ben Noble, Director of City Council Central Staff.

Tony Kilduff and **Dan Eder**, City Council Central Staff. Legislative Analysts assigned to Utility issues.

City Budget Office

Beth Goldberg, Director. Develops and monitors budgets for City Departments.

Cameron Keyes, Assistant Director, Infrastructure Budget Lead.

Calvin Chow, Budget Analyst, oversees issues related to Seattle City Light.

Greg Hill, Utility Rates Analyst.

Seattle City Light

Jorge Carrasco, Superintendent. As superintendent of the Utility, he approves final recommendations before they are sent to the Mayor.

Steve Kern, Power Supply and Environmental Affairs Officer. He oversees all the engineering, operations, and maintenance functions associated with generating electricity from City Light's owned plants and directing power planning and wholesale sales from all contract and owned resources. He also oversees the environmental affairs, conservation resources, utility support services and integrated resource planning divisions.

Philip West, Customer Service and Energy Delivery Officer. He oversees the divisions charged with design, construction, operation, and maintenance of the Utility's transmission and distribution facilities as well as the security, customer care and billing operations.

DaVonna Johnson, Human Resources Officer. She oversees talent acquisition, employee relations and services as well as safety and apprenticeship programs.

James Baggs, Internal Compliance Officer. He makes sure that the utility is in compliance with NERC and FERC standards.

Phil Leiber, Chief Financial Officer. He oversees the Utility's finance, accounting, information technology, corporate performance, risk management and strategic planning divisions.

Paula Laschober, Director, Finance Division. She is ultimately responsible for the budget, financial plans, and rate reports produced by the Finance Division.

Eyvind Westby, Budget Manager. He directs preparation of City Light's annual budget.

Kirsty Grainger, Financial Planning Unit Manager. She directs preparation of financial forecasts as well as revenue requirement and rate design reports.

7. Glossary and Abbreviations

Billing Determinants

The measures of consumption (kWh, kW, number of meters) used to calculate a customer's bill or to determine the aggregate revenue from rates from all customers. Billing determinants must follow the structure of rates so that if rates are blocked, seasonally differentiated, time-differentiated, or separated by demand and energy measures, then the billing determinants must be organized in the same fashion.

CIP

Capital Improvement Program - A plan or document, either for the City of Seattle or a specific department like City Light, indicating the capital facilities planned, the estimated cost, and the schedule for completion of the projects.

Debt Service

Payments of interest and principal required to pay off a debt. City Light pays debt service to its bondholders.

Debt Service Coverage Ratio

The debt service coverage ratio in any given year is equal to the amount of net revenue available to pay debt service divided by payments of principal and interest on the Department's fixed-rate debt. City Council Resolution 31187 of March 2010 established a Rate Setting Guideline that electric rates be set at levels sufficient to achieve a debt service coverage ratio of 1.8.

Demand Charge

That portion of a customer's bill for electric service based upon the electric capacity (kilowatt) demanded or required by power-consuming equipment and billed under an applicable rate schedule.

Demand/Billing Demand

In a public utility context, the rate at which electric energy is delivered to or by a system, expressed in kilowatts, kilovoltamperes, or other suitable unit, at a given instant or averaged over any designated period of time. Seattle City Light records demand averaged over a 15-minute interval for rate billing purposes for customers having demand meters.

Energy

That which does or is capable of doing work. Electric energy is a measure of the amount of usage and is measured in kilowatt hours or megawatt hours.

Energy Charge

That portion of a customer's bill for electric service based upon the electric energy (kilowatt-hours) consumed.

FERC

Federal Energy Regulatory Commission -The division of the United States Department of Energy that is responsible for regulating power generation; formerly called the Federal Power Commission.

Kilovoltamperes (KVA)

1000 voltamperes. The voltamperes of an electric circuit are the mathematical product of the volt and the amperes of the circuit. This is the basic unit of measure of “apparent power” which includes “real power” (the rate of supply of energy, measured in kilowatts) and “reactive power” (a component of power necessary for motors and other magnetic equipment, measured in kilovars).

KW, MW

KW (kilowatt) is a standard unit of electrical power equal to 1000 watts. MW (megawatt) is a standard unit of electrical power equal to 1000 kW.

KWh, MWh

KWh (kilowatt-hour) is the standard unit to measure electricity; it is the energy equivalent to that expended in one hour by one kilowatt of power. A kilowatt is 1,000 watts of power. For example, ten 100-watt light bulbs lit for one hour use one kilowatt-hour (1000 watt-hours) of electricity. Electricity use determines the total number of kilowatt-hours on a bill. One MWh (megawatt-hour) equals 1000 KWh.

NERC

North American Electric Reliability Corporation - Mission is to ensure the reliability of the North American bulk power system. NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission to establish and enforce reliability standards for the bulk-power system. NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast, and summer and winter forecasts; monitors the bulk power system; and educates, trains and certifies industry personnel.

Power Factor

The ratio of real or actual power (kilowatts) to apparent power (kilovolt-amperes) for any given load and time. Power factor is measured in percent and varies from 0 to 100%. City Light’s standard is 97 percent. Customers with power factors less than 97 percent are subject to a power factor charge that increases as the power factor decreases.