Rates Advisory Committee

Seattle
City Light

RATE MAKING

2003

The Seattle City Light

Guide to Rate Making

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JAMES RITCH, Acting Superintendent

(Preface Letter from superintendent)

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"Democracy is the art of thinking independently together."

Alexander Meiklejohn

The Seattle City Light (City Light) Rates Advisory Committee (RAC) is actively involved in every phase of rate setting. At each step in the rate review process (Revenue Requirements, Cost of Service, and Rate Design), members have an opportunity to express their views before and after City Light sends its reports to the Mayor. The review process actually begins about a year before the City Council (Council) adopts a rates ordinance. The last rate change took effect May 1, 2003, and the last comprehensive rate review took place in 1999. Occasionally, the Council may ask City Light to conduct additional studies; e.g., on the value of energy, the system of classifying customers, or other topics.

Determining rates for City Light requires information and analyses from the following steps:

1. Establish a financial strategy for the near future as part of a longer term financial strategy;
2. Forecast revenue requirements consistent with the financial strategy;
3. Establish a cost allocation by functional category among customer classes;
4. Develop specific rates (winter/summer, energy, demand, etc.) that, when multiplied by the expected loads for each class, collect the total class revenue requirement; and
5. Establish procedure for setting rates in suburbs that utilizes the differential between suburban and city rates, as specified in the franchise agreements.

The Committee's agenda finds a natural structure in three successive reports: Revenue Requirements Analysis (RRA), Cost of Service and Cost Allocation Report (COSACAR), and Rate Design Report (RDR), which are described in the following sections. Traditionally, the Utility has relied most heavily on the Committee's comments on cost of service and rate design. For each report the Rates Advisory Committee:

* Identifies issues for group discussion, strives for consensus, and offers suggestions to City Light staff for their consideration and response;

* May forward its recommendations to the Mayor at the same time City Light submits its recommendations;

* Responds to official review by the Mayor and Council Staff; and

* Testifies at public hearings held by the City Council before it reaches a decision.

These actions may be carried out in different ways. The Committee may make comments informally to staff at its meetings; it may request additional information or presentations on particular topics; or it may choose to write letters to City or Utility officials about areas of special concern.

Work on the next comprehensive rate review will begin in early 2004. About the time City Light staff are preparing the final revenue requirements proposal for Mayoral review, other staff are developing the COSACAR, which calculates customer class revenue requirements based on their percentage shares of marginal costs, and the Rate

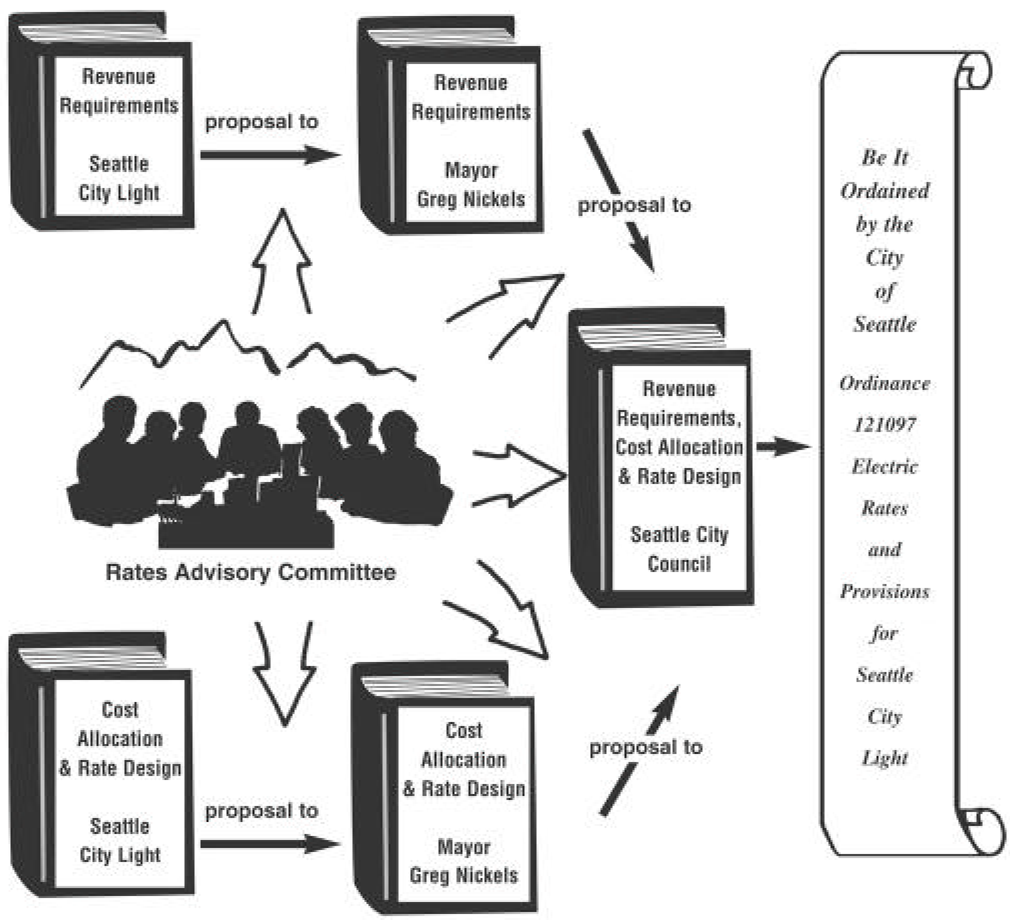
Design Report, which identifies alternative proposed rate structures. The Mayor will receive a summary of City Light's Cost of Service and Cost Allocation and the Rate Design proposals along with the Rates Advisory Committee's recommendations, if the Committee chooses to make recommendations at that point. Since the revenue requirements and cost allocation issues are significantly interrelated, RAC members should become well informed on these issues prior to final decisions on revenue requirements. The Rates Advisory Committee may ask the Mayor and later the City Council to consider revisions to the proposal. The Mayor first makes a recommendation on how to allocate costs to customer classes (from the cost analysis in COSACAR), and then selects the rate design alternatives that translate this allocation into specific rates for each class of customers.

After his review, the Mayor will forward his recommendations to the City Council at the same time that he submits his budget proposal for 2005-2006. The Council will review the Mayor's proposal either at the same time as the budget review or shortly thereafter. Final decisions on rates, and the adoption of a rates ordinance, is anticipated by November.

To summarize the sequence of decisions, the City Council will consider the revenue requirements and cost allocation issues, then rate design and, finally, will enact a rates ordinance that includes rate schedules for each customer class. Nothing is really "final" until the Council passes the rates ordinance and the new rates become law; however, public input must follow this sequence of interim decisions in order to be effective.

The Committee may elect to continue meeting for a period after the Council adopts a new rates ordinance. With the pressure off, this is a good time to explore unresolved issues or identify targets for future study. The following diagram illustrates the Committee's role in ratemaking.

THE MAKING OF A RATE ORDINANCE: DECISION POINTS FOR CITIZENS



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Step 1

Revenue Requirements and Financial Policy

Document: Revenue Requirements Analysis

"Electric utility rates should be sufficient to meet the Seattle City Light Department's revenue requirements, while charging the lowest possible cost to the ratepayer over the long run."

City Council Resolution 28004

PROJECTING UTILITY REVENUE REQUIREMENTS

The first step in setting rates is to determine the amount of money the Utility needs to meet its revenue requirements. This is usually the point in the rate review process when major budget decisions are discussed.

Electric rates are set to recover the revenue required by the Department. The more money it needs to operate and maintain its financial stability, the higher rates will be.

The City Council reviews City Light's rates periodically, and asks the Utility to conduct a new rate analysis every two to four years to support its review. Because rates are generally set in multiyear segments, the Utility must project its revenue needs several years in advance. Since customer rates and demand are interrelated (rates affect demand and vice versa), forecasting is a complex interdivisional process. Staff uses a sophisticated economic forecast to predict likely energy sales to customers, the source of almost all City Light's revenue. The financial forecast, which incorporates the demand forecast and projections of all variables affecting revenue requirements, is prepared by the Finance Division using data on all the Department's activities. A large portion of information is provided by the Power Management group. The financial forecast is updated regularly; the average life of each forecast is between three and six months.

Each revenue requirements report provides a special analysis of the reasons for rate changes. Many factors can affect the Utility's revenue needs and, hence, rates--including cost of service, changes in revenue from market energy sales, capital improvement costs, and extraordinary legal or environmental expenses. In addition to discussing costs, the revenue requirements document outlines each component of the Utility's revenue needs in detail, summarizes financial and accounting policies that affect rates, and reviews forecasts of energy sales and purchases.

Since income must be projected beforehand, and the amount of revenue the Utility will actually get is uncertain, there is inevitably an element of uncertainty built into the revenue requirements. By far the greatest source of uncertainty is the net revenue from transactions in the energy markets. Until August 1, 1996 City Light sold all its nonfirm energy in the secondary or wholesale energy markets. Until that time, the Bonneville Power Administration (BPA) provided all the energy the Department needed to fill the gap between its customer load and its firm resources. In 1996 City Light limited its purchases of BPA power to 195 MW each month (effective through October 1, 2001) and started to use part of its surplus energy to meet its customer load. Sale of the Centralia Steam Plant in May 2000 further increased City Light's firm resource deficit, making it even more reliant on the short-term wholesale power market. The Utility believed that by using the flexibility afforded by its hydroelectric generating base to take advantage of new market conditions, it could take advantage of opportunities for arbitrage in wholesale markets between different points of delivery and different hours of the day. Those activities were expected to result in additional net revenues for the Utility, but the experience of 2000-2001 proved otherwise, and it underscored the uncertainty surrounding net revenue from market transactions. In 2001, the Utility decided to reduce its exposure to wholesale market risk, and it negotiated a new 10-year contract with BPA, effective October 1, 2001, increasing its purchases of BPA power more than threefold. In July 2001, the Department also began purchasing power from the Klamath Falls Cogeneration Project, to replace the 100 aMW of energy previously supplied by Centralia. In 2002, it added another new resource, the Stateline Wind Project, which currently supplies around 29 aMW of energy, projected to increase to almost double that amount by 2005.

Electric Facts

In 1997, a year with better-than-average water conditions, City Light earned net revenue of $33.2 million on short-term wholesale market transactions. In contrast, in 2001 City Light incurred a net loss of $444.9 million on short-term wholesale market transactions as a result of extremely poor water conditions and high market prices.

FINANCIAL POLICIES

> "Revenue recovery from rates should ensure financial stability, consistent with financial policies of the Seattle City Light Department, as adopted by the Seattle City Council."
>
> City Council Resolution 28004

In 1989 (Resolution 28085), the City Council adopted the financial policies it deemed necessary to ensure that City Light maintains a sound financial posture. These financial guidelines were:

1. Rates should be set to provide for 1.8 debt service coverage on a planning basis. The coverage ratio applied to first-lien debt only. When the Department issued second-lien debt for the first time in 1990, these bonds were excluded from the coverage requirement.

2. Rates should normally be set to achieve positive net income on a planning basis.

3. Rates should be set to ensure that, with a high degree of confidence, the Department will make a positive cash contribution to its capital improvement program each year.

In 2001 (Resolution 30428), finding the guidelines set forth in the previous resolution to be insufficient to ensure City Light's financial stability under conditions of increasing wholesale power market uncertainty, the City Council adopted the following revised financial policies:

1. Rates will be set at levels which will ensure that net revenue available to fund capital requirements each calendar year will be positive with a probability of at least 95 percent, taking into account the variability of cash flows resulting from the uncertainty of water conditions, market prices, and system load.

2. A Contingency Reserve Account will be established. After payment of all current obligations, available funds in the Light Fund shall be deposited to the Contingency Reserve Account until a balance of $25 million is established. In order to provide a high probability that the Account will be fully funded within two years of the effective date, annual revenue requirements will be increased $12.5 million above the level required to achieve 95-percent probability of positive revenue available to fund capital requirements until the targeted balance of $25 million is reached. In the first year following the effective date, if net revenues are available in excess of the amount included in the forecast used to set rates, such excess funds may also be deposited to the Account, in addition to the expected deposit of $12.5 million. These additional deposits would then reduce the funding required in the second year following the effective date. The "effective date" is defined as the date when short-term debt obligations are repaid and the operating cash balance reaches the $30-million level (expected to occur mid-2004).

3. In addition to funds in the Contingency Reserve Account, the Department shall maintain sufficient operating cash balances in the Light Fund to absorb fluctuations in operating cash flows. In its rate proposals, the Department shall target a minimum month-end operating balance of $30 million.

Only the first of the three guidelines above affects rate setting directly by establishing a specific level of revenue requirements. The other two guidelines are general statements of intent but there is no mechanism to ensure they are met every year on a planning basis.

Debt Financing and Debt Service Coverage

Like most utilities, City Light uses debt financing to fund a large portion of capital improvement projects and conservation programs. There are good reasons for this strategy. It spreads the costs of service over time, thus matching them more closely to the benefits derived from the projects financed and more equally dividing expenses among the several "generations" of electric consumers that enjoy such benefits. In addition, it smoothes out the impacts of large increases or reductions in the capital investment program because it prevents steep upturns or downturns in yearly electric rates that could be economically destabilizing and potentially confusing to customers. Reliance on debt as a source of funding for capital programs, however, can lead to excessive debt accumulation and significant increases in the burden imposed by the payment and coverage of debt, which in turn leads to escalating rate increases.

The other major source of funds for capital and conservation programs available to the Utility is the revenue from current customers. Although City Light receives small amounts of funds from other sources (such as revenues from fees and charges and customer contributions for construction), its two major sources of funding for capital requirements are debt and customer revenue. One of the main purposes of the Department's financial policies is to determine the proportion of its capital requirements that will be funded by each of these two major sources of funds. A higher level of reliance on debt is linked to lower revenue contribution and thus lower customer rates in the near term, but leads to higher rates in later years, as the debt service payment and coverage requirements accumulate. On the other hand, higher revenue contribution in the near term causes higher near-term customer rates and relatively lower rates in the future.

The financial policies adopted in 1989 replaced more conservative financial policies that required a higher current revenue contribution for the capital program. The debt service coverage target until the end of 1989, for example, was 2.0. At that time it was felt that the existing policies imposed too large a burden on current ratepayers. Customer rates had increased at an annual average rate of 10.6 percent between 1980 and 1989; high inflation and interest rates and fast growing BPA power costs were major factors affecting rate increases. The major changes in financial strategies and accounting practices were the capitalization of expenditures that used to be expensed in the year they were incurred and the issuance of second-lien bonds, which are not included in the debt service coverage requirement.

This strategy, however, led to escalating accumulation of debt, which in turn has been a major force pushing customer rates higher in recent years. The ratio of debt to total capitalization increased from 54 percent in 1980 to 85 percent in 2001. Reducing the pace of debt accumulation and lowering fixed costs at the cost of ***modest*** rate increases would maintain City Light's competitiveness and provide greater flexibility to respond to changes in market conditions. A couple of years ago, the Utility looked at five scenarios to reduce reliance on debt at the cost of increased customer rates in the near- and mid-term. Two strategies, coverage of ***all*** debt 1.8 times, and the setting of a cash target for revenue financing of capital requirements, were found to be the most effective approaches to reduce debt levels and the ratio of debt to total capitalization. Although these strategies lead to rate increases in the near term, they result in lower rates over the long run and in significant reductions in the amount of debt outstanding. In the wake of the 2001 financial crisis, City Light's financial policies were modified such that the Utility now actually follows the latter of these two strategies, because it plans to set rates for 2005-2006 to achieve 95-percent probability of having greater-than-zero cash available to finance capital requirements.

Despite concerns about the increase in the pace of debt accumulation and the financial impacts of its exposure to market risk, City Light has maintained a relatively high bond rating as a result of its low-cost hydro resource base, its financial policies, and management flexibility to respond to financial and market challenges. While financial indicators such as net earnings, debt service coverage and debt-to-total capitalization ratio are still used to evaluate the credit worthiness of a utility, competitiveness and flexibility to respond to changes in the evolving electricity markets have become important factors in the determination of credit rating. A good credit rating results in lower interest rates for debt and thus keeps rates lower.

Debt Service Coverage and Net Earnings

At present, City Light must set its rates at levels that provide for at least 1.8 debt service coverage of its first-lien debt. If all planning assumptions prove to be correct, this guideline would result in the required level of net revenue available for debt service. To avoid confusion, it should be pointed out that the terms "net revenue available for debt service" and "net earnings" are not synonymous. Net revenue available for debt service reflects the difference between operating revenues and operating cash expenditures, excluding interest payments on debt. Net earnings, on the other hand, represent the true "bottom line" on the income statement. In order to arrive at this bottom line starting from net revenue available for debt service coverage, City taxes, interest expense, depreciation and amortization, proceeds of property sales, and any other noncash expenses must be subtracted. Contributions in aid of construction and any other capital grants, fees or transfers, and noncash revenues, such as gains on property sales and net revenues from energy exchanges, must be added. The following example shows these calculations using the current forecast of the 2003 revenue requirement.

Net Revenue Available for Debt Service		$227.1 million
less:		
	City Taxes	33.3 million
	Interest Expense	74.8 million
	Depreciation and Amortization	79.7 million
	Amortization of Deferred Power Costs	100.0 million
	Proceeds from Sale of Property	2.0 million
plus:		
	Gain on Sale of Property	2.0 million
	Net Revenue (Expense) from Exchanges	0.4 million
	Grants, Fees, and Transfers	16.3 million
Net Earnings (Loss)		$ 5.2 million

The 2003 forecast has first-lien debt service coverage of 1.7, slightly below the 1.8 coverage required by the Utility's financial policy. In 2001, the Department incurred $518.8 million of expenses for short-term wholesale power purchases, due to poor water conditions and high market prices, and deferred $300.0 million of those expenses to future years. One hundred million dollars of these expenses are being recognized annually in 2002, 2003, and 2004. If the $100.0 million of deferred power expenses to be recognized in 2003 is excluded from the calculation of the debt service coverage ratio for 2003, the ratio increases to 2.6.

Planned net earnings in 2003 are positive, in contrast to the prior two years. Water conditions are still below normal as of July 2003 but less so than in 2001 and 2002. In addition, the Department has acquired additional sources of power since 2001 and is currently a net seller of power, rather than a net purchaser. Consequently, City Light is now able to produce more revenue from short-term wholesale power sales than it expends for short-term purchases. At the same time, the Department will benefit when wholesale market prices are higher than anticipated, as they have been in the first half of 2003, rather than being negatively impacted by high prices.

If City Light were privately owned, its net earnings would either be reinvested in the company's operations or distributed among its stockholders as dividends. Since City Light is publicly owned, its net earnings are reinvested in the Utility. This reduces its debt-to-equity ratio and increases its, and the public's, equity in the Utility. This serves to strengthen City Light's financial position and to keep future borrowing costs down. When net earnings are negative, as was the case during 2000-2002, there is a reduction in equity and a weakening of the Utility's financial position, measured in terms of debt to total capitalization.

Financial Risk: Revenue from Market Energy Sales

One of the major sources of risk that City Light faces when planning its customer rates is the uncertainty as to the level of net revenue from its market transactions. This risk is rooted in City Light's resource base. Because the Utility is hydro-based, the energy available for use or sale varies according to water conditions. Much of the Utility's energy is used to serve customers in its service territory, and what is not is sold in electricity markets, where opportunities have expanded since the 1992 Energy Policy Act and the restructuring of the California electricity market. While City Light is usually a net seller in energy markets during the spring and early summer months and a net buyer during the rest of the year, on an annual basis it expects to have enough energy sales to receive positive net revenue from its market transactions. In good water years there is more energy than under normal or expected conditions, and net revenue from market transactions can be significantly higher than expected, as happened in 1997. In a bad water year, on the other hand, the Utility must buy additional power and incur unexpected costs. In the period 1992-1994, in 1998, and again in 2000-2001, the Department's annual expenses from energy market transactions exceeded its revenues. The impact of the uncertainty around water conditions is compounded by the fluctuations in the market prices of electricity, which vary with changes in fossil fuel prices, access to markets, sharp variations in temperature, economic conditions, and other factors affecting demand and supply.

This leads to a spate of questions: How should this inherent uncertainty be dealt with in the financial planning process? How much net revenue from market transactions should the Utility plan on as probable income? Should rates be set higher to cover the worst-case water year, or should the Utility set rates assuming average water conditions and accept a higher risk of not meeting its financial targets?

In an effort to balance the objectives of low customer rates and risk mitigation, City Light's financial plan assumes the level of net revenue from market transactions that can be expected over all water conditions. This expected level is projected using the available data on 60 years of water records and current hydroelectric resources, together with an updated forecast of energy market prices. This value of net revenue from market transactions may or may not be realized.

Prior to the passage of Resolution 28085 at the end of 1989, City Light had a formal guideline that required the financial plan to assume lower-than-expected net revenue from market sales; this approach increased the probability of receiving revenues that were equal to or higher than planned. When this guideline was binding (i.e., resulted in higher revenue requirements than the other financial policies), it led to customer rates that were higher than those that would have been set assuming expected revenue. This strategy of planning for lower-than-expected net revenue from market transactions was abandoned after the 1989 Financial Policy Review because the reduced uncertainty it brought was attained at the cost of higher rates and because it provided no guidelines for action in cases of significant differences between actual and planned values of net revenue from market sales.

Water conditions were very poor over the period 1992-1994 and there was renewed interest in analyzing mechanisms to mitigate the impacts of revenue fluctuations upon financial indicators and rate stability. Over the 1992-1994 period City Light imposed surcharges, cut expenditures, and temporarily reduced its debt service coverage target. There was an attempt to develop a consistent strategy to deal with this uncertainty.

The Finance Division proposed alternative mechanisms to mitigate the financial impact of fluctuations in water conditions. These proposals were based on the premise that the fluctuations in net revenue from market transactions could be spread over periods longer than a year, which would reduce their impact on the financial indicators of any individual year. The income statement of the Utility would reflect planned values (or close to planned values), and variances would be transferred to a balance sheet account as either deferred income or deferred loss. Several options to liquidate these balances were reviewed. The major disadvantages of these options were that they would result in more frequent rate changes, thus adversely affecting the objective of stable customer rates, and would reduce management’s flexibility. There were also questions about how benefits would be measured and about the cost of keeping a cash stabilization fund.

In 1997 a reevaluation of the issue led to the conclusion that the options discussed in the earlier report were no longer appropriate for City Light. In view of the changes in electricity markets, energy rates were expected to be increasingly market-driven instead of set by the Utility’s costs or its accounting treatment of such costs. This has proven to be partially true but not completely true, so far. While market prices do affect City Light’s revenue requirements, and therefore its rates, they continue to do so only indirectly, by affecting its total cost structure. It was also thought that the debt service coverage ratio would not be as sensitive to changes in net revenue from market transactions as it had been in the past, because net revenue from market transactions had been shrinking in proportion to debt service and coverage requirements. This was the case until 2001, when City Light incurred a huge loss from market transactions, which had a very significant negative impact on its debt service coverage ratio. There was also the belief that the debt service coverage ratio had lost importance as a means of determining the credit rating, relative to other factors such as flexibility and ability to compete. While this may in fact still be true, it is no longer a meaningful argument against instituting some type of financial stabilization mechanism. On the contrary, comments made by credit rating agencies in response to City Light's financial situation in 2001 indicate that they look very favorably on the Utility initiating measures to reduce its financial exposure to market uncertainty. Another reason why the Department chose not to pursue a stabilization fund in 1997 was the belief that the Department has relatively easy access to funds when needed. While this is generally true, it only goes so far. Neither the City Council nor the credit rating agencies look favorably upon City Light increasing its outstanding long-term debt. Borrowing to meet short-term needs, such as operating expenses, is viewed even less favorably. The need to engage in such borrowing activities during the past couple of years is one of the key reasons that City Light's credit rating has been downgraded.

In 2001, extreme financial conditions prompted the Department to revisit the idea of establishing a mechanism to mitigate the financial risk associated with fluctuations in market prices and water conditions. The policy of setting rates with the objective of achieving 1.8 debt service coverage under average water conditions had worked reasonably well prior to 2001, but it did not provide sufficient financial protection against poor water conditions combined with large spikes in market prices, such as those that occurred in 2001. As a result, the Department adopted a new policy in 2001 that requires it to set rates at levels that will ensure, with a probability of at least 95 percent, that net revenue available to fund capital requirements in each calendar year will be positive. In addition, the Council required the Department to establish a cash reserve of $25 million.

ELEMENTS OF CITY LIGHT'S REVENUE REQUIREMENTS

In 2002, City Light's operating revenue, investment income, gains on property sales, and revenue from grants, fees, and transfers amounted to $733,104,057. The portion of this amount collected through customer rates was $562,432,218, and operating expenses exclusive of City taxes amounted to $616,656,953. Actual debt service coverage was 1.61. Excluding $100.0 million of amortization of deferred 2001 power costs, debt service coverage was 2.51. In computing the debt service coverage ratio, operating expenses are expressed exclusive of City taxes because the City Charter provides that such taxes are payable only after payment of debt service and other current obligations.

For the 2005-2006 rate review, City Light will again be forecasting its expectations in the above categories. Outlined below are the major elements of the Utility's revenue requirements, as actually realized in 2002 and as forecast for 2003 by City Light's Financial Planning Model in June 2003. This forecast will be revised before the final Revenue Requirements Analysis is submitted.

EXPENSES

Purchased Power

About 40 percent of City Light's 2002 operating expenditures (exclusive of city taxes) were for energy purchases. Of these, 52 percent were BPA purchases and 16 percent were purchases from the Klamath Falls Cogeneration Project. Another 14 percent were purchases under the High Ross Agreement with Canada, from the Lucky Peak Dam in Idaho, and from the Stateline Wind Project in eastern Washington and Oregon. Other long-term power arrangements include the Columbia Basin Power Exchange and contracts with the Grand Coulee Hydroelectric Power Authority (formerly known as the South Columbia Basin Irrigation District), Grant County and Pend Oreille public utility districts, and Metro Cogeneration. In addition, City Light has seasonal energy exchange agreements with other utilities that are noncash transactions but are nevertheless recorded as expenses and revenues, based on City Light's average cost of power during the months when these transactions occur. City Light also engages in basis transactions, where energy is simultaneously bought from and sold to the same counterparty, at different locations. The effective result of these transactions is the sale of excess City Light transmission capacity. Basis sales and purchases are, however, considered to be power transactions and are recorded as such. The purchase side of these transactions is therefore included in purchased power expense.

Cost: 2002 - $246.7 million (actual); 2003 - $270.9 million (projected)

Production

In 2002, a very poor water year, City Light generated about 44 percent of the energy required for retail and wholesale sales, losses, and its own operations. In 2003, under continued poor water conditions, City Light's own generation is projected to account for 41 percent of total energy requirements. In 2004 water conditions are assumed to return to their average level and generation is expected to increase to 48 percent of energy requirements. Most of this energy is generated at the Utility's facilities on the Skagit and Pend Oreille rivers. Production expenses include operation and maintenance of City Light's hydroelectric plants.

Cost: 2002 - $18.5 million (actual); 2003 - $19.6 million (projected)

Wheeling (Line Rental)

City Light pays BPA and other agencies to wheel, or transmit, power to Seattle through transmission facilities they own. BPA is one of the major suppliers of wheeling services.

Cost: 2002- $31.1 million (actual); 2003 - $30.1 million (projected)

Transmission (City Lines)

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.

Cost: 2002 - $4.3 million (actual); 2003 - $4.6 million (projected)

Distribution

After being wheeled or transmitted to the City Light service area, electricity must be channeled to over 360,000 customers. Distribution expenses include the costs of operating and maintaining Utility substations, distribution lines, service connections, and meters.

Cost: 2002 - $37.6 million (actual); 2003 - $36.0 million (projected)

Customer Accounting and Advisory Services

This category includes the costs of reading meters, maintaining customer records, and providing technical information to customers about electric service and connections. Uncollectible accounts also appear under this item.

Cost: 2002 - $27.6 million (actual); 2003 - $26.8 million (projected)

Conservation – Direct Expense

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.

Since 1984 most conservation expenditures have been deferred and amortized like capital expenditures. However, some administrative expenses (e.g., costs of planning and managing the programs) are directly expensed and incorporated into the revenue requirements in the year they are expected to be incurred.

Cost: 2002 - $1.7 million (actual); 2003 - $2.1 million (projected)

Administration and General (A&G)

This category covers central administrative expenses for planning, financial management, and general administration. It also covers employee pensions and benefits[1], general plant maintenance, research and development projects, and recognition of liability for injuries and damages. In 1991 City Light adopted an accounting policy which allocates a share of A&G costs to capital projects. A&G costs allocated to a capital project become part of the costs of that project. They are not expensed in the year they are incurred but are instead reflected in expense over time through depreciation. This has the effect of reducing A&G actually expensed.

Cost: 2002 - $40.3 million (actual); 2003 - $41.9 million (projected)

Credits to Base Rates

This category covers rate relief for low-income customers on Schedules RLC, RLS, and RLT and credits paid to commercial and industrial customers who have purchased their own transformers.

Cost: 2002 - $7.3 million (actual); 2003 - $7.4 million (projected)

Taxes

City Light must pay a variety of taxes, including city, state, unemployment, and social security taxes. In addition, the Utility makes payments in lieu of taxes to counties in which its various facilities are located. State and city tax payments are calculated as a percentage of revenues from customer energy sales. Unemployment and social security taxes are payroll taxes that are allocated to the various capital, O&M, and deferred conservation expense accounts as loadings onto labor charges in those accounts.[2] The revenue requirement calculation to determine the amount needed to satisfy the 1.8 debt service coverage policy includes all taxes except City taxes and payroll taxes that have been allocated to capital programs and deferred expense accounts for conservation, since these are available to meet debt service payments. The numbers below include all taxes except City taxes and payroll taxes.

Cost: 2002 - $26.3 million (actual); 2003 - $27.1 million (projected)

[1] Prior to January 1991, the Department accounted for all employee pensions and benefits costs, except for those associated with capital projects and deferred conservation expenses, as an A&G expense. Since January 1991, all pensions and benefits costs have been allocated as loadings onto labor charges.

[2] Prior to 1996, the Department accounted for all payroll taxes, except for those associated with capital projects and deferred conservation expenses, as a tax expense. Since 1996, all payroll taxes have been allocated as loadings onto labor charges in O&M and capital accounts.

SOURCES OF REVENUE

Retail Power Sales

Most of City Light's revenues come from sales of electricity to customers in City Light's service area. In 2002 revenue from such sales accounted for 77 percent of total revenue. The City Light service area 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. There have been no sales to customers outside the City Light territory since 2001, when a contract with Nordstrom stores in California expired. There may be future retail sales outside of the service area, but none are anticipated at this time, and therefore none are projected for 2003 or future years.

Revenue: 2002 - $562.4 million (actual); 2003 - $552.8 million (projected)

Wholesale Power Sales and Other Power Sales

Wholesale power sales and other power sales include revenue from short-term wholesale sales, sales under long-term contracts, the value of seasonal exchange energy delivered to other utilities, the sale side of basis transactions, sales of ancillary services such as reserves and load factoring, and sales and leases of transmission capacity. In addition, it includes conservation program funding received from the Bonneville Power Administration. In 2002 about 15 percent of total revenue came from short-term wholesale power sales and about 3 percent from other power-related revenue.

Revenue: 2002 - $136.0 million (actual); 2003 - $168.1 million (projected)

Other Revenue, Investment Income, Property Sales, Grants, and Transfers

These other types of revenue account for around 5-6 percent of total revenue annually. The Department charges fees for such services as account changes, service reconnections, and installations of new and enlarged electric service. Other revenue sources also include rentals of electrical property, pole and transmission tower attachment fees, customer late payment penalty fees, billable routine operations and maintenance work performed for the benefit of an outside party, and billable work to repair damage to City Light property caused by an outside party. In addition, the Department earns interest on its investments and gains or losses on sales of surplus property, and these jointly account for about 1-2 percent of total revenue. Contributions in aid of construction (contributions which customers make toward the cost of capital projects from which they will benefit), other grants and transfers of funds from other City departments typically account for an additional 1-2 percent of total revenue.

Revenue: 2002 - $36.8 million (actual); 2003 - $39.3 million (projected)

INITIAL RATE CALCULATION

When the Utility's revenue requirement from customers has been determined, it is divided by the projected number of kilowatt-hours expected to be sold to give an average rate per kilowatt-hour (kWh):

$$\frac{\text{Rev. Req.}}{\text{kWh Sales}} = \text{Average System Rate}$$

This gives the first glimpse of what new rates will look like. The estimated rate can then be compared to the average rate in a base year to estimate the size of the overall rate change.

UNBUNDLED REVENUE REQUIREMENTS

In the 1997-1998 rate review, City Light unbundled its revenue requirements for the first time. This process was repeated and further refined during the 2000-2002 rate process. "Unbundling" refers to the separation of rates, costs, or revenue requirements into components that relate to different aspects of a utility's business. The purpose of such unbundling was to understand the costs incurred by function. The unbundled functions and the revenue requirements identified with each are shown below.

Functional Allocation of Rate-Year 2002 Revenue Requirements

Total Power	**$213,639,807**
Production	56,117,226
Purchased Power	109,496,035
Conservation	16,532,748
Transmission-Long Distance*	31,493,797
Total Retail Services	**$188,894,839**
Distribution**	140,471,220
Customer Accounts & Services	41,293,650
Low-Income Assistance	7,129,969
	$402,534,646

*Includes Wheeling
**Includes Transmission-In Service Area

The unbundling analysis identified some revenue requirements ("costs") as being directly assignable to a function and others, which needed to be allocated. All functions included directly assignable O&M costs. Credits to base rates were also directly assigned. For example, rate relief for low-income customers was assigned to the Low-Income Assistance function; and discounts paid to business customers who own their transformers were assigned to distribution costs. Costs which required allocation included general plant depreciation, administrative and general (A&G) expenses, interest expense, and taxes. Some general plant depreciation could be assigned directly to a function, but most had to be allocated based on historical labor hours; these were labor hours in certain categories or all non-A&G labor hours, depending on the item. A&G expense was allocated to all functions on the basis of non-A&G labor hours. The interest expense allocator was the book value of plant. Taxes were allocated on the basis of the effective tax rate.

Step 2

Spreading the Utility's Costs

Document: COSACAR (Cost of Service and Cost Allocation Report)

"Rates should be based on the costs of service to the customer...They should reflect a fair apportionment of the different costs of providing service among groups of customers."

City Council Resolution 28004

COSACAR: IT'S NOT A CURSE, BUT A COURSE TO EQUITABLE RATES

Once the Utility's overall revenue requirements (i.e., costs to be paid by retail customers) are projected by functional category, the next step in rate setting is to divide those costs among different customers. The Cost of Service and Cost Allocation Report (COSACAR) presents the analysis and results of this allocation.

The main focus of this chapter is to describe the major characteristics of the "Adopted Cost of Service and Cost Allocation Report 2000-2002," which was the COSACAR for the last full rate review process in 1999. A secondary task is to discuss some of the cost allocation issues anticipated in the next rate review.

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 are used to allocate the costs represented by the revenue requirements. Average annual customer rates by customer class, however, always equal average annual revenue requirements assigned to each class.

The Utility must also consider public policy desires and changes in perceptions of public policies when setting rates. For many years, at the behest of the Mayor and City Council, the Department has included special consideration for rates charged to low-income.

Then, the last rate review took into account newly negotiated franchise agreements with recently incorporated areas in suburban King County that had been served by the Utility. Terms of those new franchise agreements met the needs of both the suburban cities and City Light. Those agreements included 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.

The last rate review also took into account for the first time the increased cost to serve downtown network customers relative to the cost of serving all other customers. That rate review introduced a rate differential between network and nonnetwork customers.

Finally, the last rate review also took into account the transfer of ownership of streetlights, formerly owned by the Transportation Department of the City of Seattle, to City Light. Formerly, the cost of electricity and services to those streetlights within the City limits was billed to the Seattle General Fund. The last rate review included those streetlight costs in the bills of all customers subject to City of Seattle rates.

The balance of this section describes the following topics:

<u>Classification of Customers</u> – how customers are grouped together for ratemaking purposes.

Cost of Service Analysis – a general description of the alternative methods available for measuring costs and the marginal cost alternative the City has adopted for the Department to use in measuring the cost of providing service. Also described here is development of shares of marginal cost for use in allocating revenue requirements.

Determination of Marginal Costs of Service by functional category – an examination of marginal costs for the different functional categories and estimation of total marginal cost for each functional category.

Gradualism – a policy tool to mitigate rate increases for the most adversely affected customer classes. This tool has been used in the past. There is some chance it may not be needed in the next rate review.

Public Policy Programs – serving objectives for public bodies in the Service Territory.

Possible Cost Allocation Issues – for the next comprehensive rate review.

CLASSIFICATION OF CUSTOMERS

Utilities divide customers into categories to expedite rate setting. Theoretically, it is possible to compute the exact cost of each customer to the electric system, but such precision is technically and economically unfeasible. A more practical approach is to divide customers into homogeneous groups that reflect similar cost characteristics.

Electric Facts

The residential class represents nearly 90 percent of all customers. Yet nonresidential customers consumed over 65 percent of the nearly 9 million megawatt-hours sold in 2002.

City Light has found two features most directly affect cost of service: the amount of energy required, and the time energy is used, daily and seasonally. To translate these characteristics into appropriate pricing structures, the Utility divides customers into residential and nonresidential classes. The nonresidential classes are, in turn, divided by size of electrical service, a third important cost characteristic separating customers.

The nonresidential customers are divided into four classes based on the size of their maximum monthly kilowatt (kW) demand and location. These four categories are: (1) under 50 kW; (2) 50-999 kW; (3) 1,000 or more kW and located inside the downtown network system or 1,000-9,999 kW outside the network system; and (4) 10,000 or more kW and located outside the network system.

> "Rates should be based on the costs of service to the customer.
> Rates should reflect changes in the costs of service over time."
>
> City Council Resolution 28004

The guiding principle behind cost (i.e., revenue requirement) distribution is that rates for each customer class are based on a cost-of-service assessment with the objective of recovering revenue from each class in proportion to the system costs that each class imposes. Rates are not exactly equal to cost-of-service rates because some modifications are made. The starting point for these modifications, however, is cost of service, and the departures from it are limited in number and narrowly constrained.

City Light's history of cost-of-service assessments begins in 1971. The goal since 1974 has been for class rates to reflect cost of service. This goal has been reaffirmed in several resolutions, most recently by Resolution 28004 (July 1989), noted above.

Of all the possible standards for apportionment of the revenue requirement, cost of service is viewed as the fairest way, and it is for this reason that this standard has been used consistently by City Light in rate setting.

The utility industry has evolved two major ways to measure cost of service. One is a marginal cost methodology. The other is an average, or embedded, cost methodology. A choice must be made between these basic methodologies, bearing in mind that each methodology has numerous variants. The marginal cost method estimates the additional cost of serving an additional unit of load. The embedded cost method estimates the average cost of production with the existing equipment (and known changes).

The choice between the types of allocation methodologies is controversial because of the differential impacts each methodology has on cost shares borne by the classes. The decision to use a marginal framework for City Light was made in 1980, at a time when the City was insistent on using marginal costs in all of City Light's planning efforts in order to establish a rational basis for resource decisions. As the gap between marginal cost and average cost narrowed and as resource decision-making within the City became more refined, the City Council questioned whether the marginal framework for cost allocations was still appropriate. In a set of workshops held in 1984 and again in 1986 and 1987, individual Council members, rate experts, and ratepayers addressed this issue.

The outcome of these workshops was that there is no single “right” way to allocate costs. Both the marginal and embedded frameworks are acceptable methods and are in use throughout the country. There is **no single** "right" way because the standard for cost allocation is fairness and this standard provides no firm guidance in the realm of methodology. There are, however, good reasons to use marginal costs in rate design and resource selection, not the least of which is consistency and continuity with the past.

The decision to use a marginal cost methodology was codified once in Resolution 27726, and reaffirmed in Resolution 28004:

> "A marginal cost of service study should be the primary basis for allocating the cost of providing electric power to the rate groups."

Note that the Resolution specifies *allocating* the cost, and not setting rates equal to the marginal costs. It would be happenstance for the sum of marginal costs to equal the average of the revenue requirements. For that reason, revenues that would be secured if rates were set equal to marginal costs are calculated, and it is the shares of those hypothetical revenues that are used to allocate the required revenue requirements among customer classes.

The Department's recommendation regarding cost of service was modified in the 1997-1998 rate review. Several different cost components were developed and used in conjunction with revenue requirements divided among those same components. The 1999 rate review divided the cost components into yet finer detail.

While the modifications made in the 1997-98 and 1999 rate reviews were entirely consistent with the history of reliance on a marginal cost allocation methodology, these modifications also included aspects akin to the embedded cost methodology, especially in functionalizing the revenue requirements discussed in the previous section. Evolution of the electrical industry appears to be pushing utilization of these two methodologies ever closer together.

The basic idea of marginal cost analysis is to estimate the incremental cost to serve an additional unit of energy (kWh), and the annual costs of additional capital equipment and the additional annual operations and maintenance costs needed to serve an increment of load (kW). All the units of energy (kWh) served in a year are multiplied by the marginal energy costs and the total load (kW) is multiplied by the marginal capacity cost to determine the "total marginal cost." This total marginal cost can be estimated for each customer class by using the class energy and load as the multipliers. Each class' share of the total over all classes can then be computed directly. These class shares are then used to allocate revenue requirements.

Marginal costs are measured for different functional cost categories discussed below. Class shares for each category are computed and are used to allocate the corresponding functionalized revenue requirement. For some cost categories, the marginal cost varies by demand (kW) rather than energy (kWh), or sometimes by meter. Annual marginal costs in these instances are computed as the product of the unit marginal cost and the total demand, or total number of meters.

DETERMINING THE COSTS OF SERVICE

In calculating customer costs, City Light takes into account the fact that customers vary in the types of facilities they use and the times they use them. COSACAR distinguishes between shared and specialized facilities, and provides specific estimates of customers' times of use. The following table lays out the marginal cost categories whose shares, by customer class, were used in the last rate review for purposes of allocating the corresponding revenue requirement items.

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

Revenue Requirement Item	Marginal Cost Share
Energy SCL production Purchased Power Transmission	energy cost shares
Distribution, excluding lights[1]	distribution cost shares[2]
Distribution assigned to lights	not applicable
Customer Costs	customer cost shares[3]
Public Policy Programs	total marginal cost shares

1. Capital and maintenance expenses directly assigned to streetlights are excluded here; however, streetlights are allocated a portion of the system's distribution revenue requirements computed here.
2. Distribution costs equal the sum of capital and O&M costs for substations, in-service area transmission, general plant in the form of communications equipment, and feeders.
3. Customer costs equal the sum of capital and O&M costs for meters plus O&M for meter reading, uncollectibles, service maintenance, and customer records.

Energy Costs

In previous years, energy costs were computed for 12 time periods: winter and summer weekday day and night, and weekend day and night, plus (during winter only) peak day and night and intermediate day and night. Analyses conducted during the 1997-1998 rate review led to the adoption of 48 costing periods (four for each month: weekday day and weekday night, and weekend day and weekend night). The 1999 rate review maintained 48 periods but changed their definitions slightly to correspond more closely with standard industry definitions. The periods each month in that rate review were High Load Hours (weekday day, Saturday day, and Sunday day) and Low Load Hours (all other times).

Energy costs represent the cost to replace or acquire one additional MWh of electricity and deliver it to the edge of City Light's service area. These costs represent the single largest cost factor for the Utility among all the cost components for providing service to customers.

In previous years, City Light used Marginal Values of Energy (MVEs) as an estimate of the marginal cost of energy. These MVEs were estimated by a complicated Annual Optimization Model that determined the least cost combination of resources to serve the City Light Load. That cumbersome technique was necessary because at that time there was only a small and rudimentary wholesale electricity market. It was not possible then to study wholesale market prices to estimate the wholesale market value of electricity. A strong and apparently vibrant set of wholesale markets for electricity developed on the West Coast in the period 1996-2000. A large wholesale market close to Seattle is the Mid-Columbia transfer node for the northwestern transmission network. Forecasts of prices at this node were used as marginal wholesale costs of energy in City Light's analysis of rate setting in the 1999 rate review.

Costs of transmission, with wholesale costs of energy lost (primarily through heat) during transmission, must also be included in energy costs. Since the majority of the Department's energy is transmitted over BPA lines, BPA's costs for transmission form the basis for estimating marginal transmission costs.

Since Seattle has long had a concern for environmental issues, the wholesale electricity prices at Mid-Columbia were adjusted upwards to reflect an estimate of the cost of environmental externalities associated with production of electricity. Details about the construction and use of those "externality adders" are documented in the final COSACAR report (Chapter 4). The following information traces only the underlying wholesale price of electricity at Mid-Columbia.

Energy prices vary by time of day and by month of year. Weekday prices during the high load hours, which are from 6 a.m. until 10 p.m. each day, are higher than for either Saturday or Sunday. Average prices during low load hours that run from 10 p.m. until 6 a.m. vary through the year, but there is no significant variation in this price among the days of the week.

Demand for electrical energy is instantaneous and the quantity demanded varies over time and in response to weather conditions. The customer classes have different profiles of demand for energy which, combined with the changing values of energy over the year, produce different costs of energy for each customer class. The residential sector has the most pronounced winter peak, but there is some winter peaking evident among the small- and medium-sized nonresidential customers.

The percentages of total monthly consumption by day of week and by high- and low-load hours also varies among classes. Residential and High Demand customers have relatively more consumption on weekends than the other classes.

Time-of-use profile data to be used in the next rate review will be updated with information from 2002-2003. That profile data will be combined with forecasts of consumption by customer class to produce a forecast of the time profile of consumption for each class.

Estimates of the total marginal cost of energy are computed for each class as the product of the projected load for each customer class and the per-unit cost of energy, externalities, and transmission. The sum of these costs over all classes is computed. Each class' share of that total is determined. These shares of market costs are then used to allocate the revenue requirements assigned to energy production, purchases, and long distance transmission.

Distribution Costs

Distribution costs cover costs of distributing electricity within the service territory to the customer. There are two major categories of these costs. The first consists of costs for substations and related equipment plus the costs of feeders from substations to customers. The second major category consists of costs for customer transformers. Separate cost estimates are made for each of these components for each customer class. Total marginal costs by customer class are computed for each component. Sums of costs over all components are computed for each customer class and for the total over all classes. Each customer class' share of the total is used to allocate the corresponding revenue requirement for distribution services. The next two subsections describe the major marginal cost categories in more detail.

Substations and Related General Plant, and Wires/Poles and Related Equipment

These two categories cover transmitting and distributing electricity within the service area from the service territory boundary to the customers' transformers.

Substations take high voltage power off transmission lines, step it down to a lower voltage, and send it on to customers. All the equipment is sized for maximum demand. If a substation serves a mix of customers whose composite use reflects the use pattern of the system as a whole, then customers who are on during the system peak are responsible for the substation costs. However, if a substation predominantly serves customers who, as a group, peak during a period other than the system peak, those customers who are on during that period are responsible for the cost.

A few substations serve primarily (but not exclusively) Large and High Demand customers and the rest serve a mixed group of all customer types. The load profile for the system as a whole (less the Large and High Demand customers) tends to peak in the wintertime. Loads for the Large and High Demand customers, together, tend to peak in the summer time. These facts suggest that substation costs should be computed separately for these two groups of customers. Annual capital costs are added to annual operations and maintenance (O&M) costs for the substations.

Energy losses increase, as a percent of the load carried, as the ambient temperature increases. Thus substation costs are higher per peak MW of load for Large and High Demand customers than for other customer classes.

Feeders, represented by wires/poles and related equipment, are distribution lines that carry power from a substation to customers' transformers (or to a lateral tap from the feeder line). On the 26-kV system which is the predominant distribution system used by City Light, materials are standardized, so there is no cost differential from one customer to another, although there are construction cost differences between overhead, underground, and network feeder systems. As with other capital equipment sized for maximum demand, capital and O&M costs of feeders are assigned to customers using power during the time of peak demand on the feeders.

The following table indicates the marginal costs for these two categories of costs based on the data available for the 1999 rate review.

Marginal Costs for Substations and Wires/Poles/Vaults
Annual Cost per MW for Serving Customer Classes with Different Seasonal Peaks
(1998 $)

	Winter Peaking Class	**Summer Peaking Class**
Substations	$7,983	$8,076
Wires/Poles/Vaults	$4,347	$4,618

In the past, differences in construction and O&M costs between overhead, underground, and network feeders were ignored and costs for the overhead system was used as the standard for all customers. The 1999 rate review allocated distribution revenue requirements among major classes on the same basis as in prior years. The 1999 rate review, though, introduced information from prior studies that showed distribution costs of serving downtown network customers were significantly higher than for other customers. Those higher costs were used as a policy justification, after the initial revenue requirement allocation, to transfer more of the distribution costs to network customers. The transfer was planned to occur in two steps. The initial step transferred 25 percent of the cost differential between network and nonnetwork customers to the network customers. The second step occurred in 2002 and increased the cost share to 50 percent.

Customer Transformers

Customer transformers take power off the local feeder and step it down to a lower voltage for use by the customer. Customer transformers are sized to the maximum demand expected. Their costs, therefore, reflect both the annual costs of the types of transformers used for each customer class and the maximum demand expected for that class. The following table presents transformer costs and load factors that were used in converting annual energy usage (in kWh) to annual maximum demand (in kW)[3] from the last rate review.

[3] Annual maximum kW equals annual energy in kWh divided by 8,760 (number of hours in a year) divided by the load factor expressed as a fraction. As a hypothetical example, if annual load equals 17,520 kWh and the load factor is 50 percent, then the expected maximum demand is 4 kW (17,520/8,760 = 2, thus the annual average load equals 2 kW; 2/ 0.5 = 4 kW).

Average Marginal Cost per Peak kW for Transformers (1998 $)
and Load Factor (%)

	Res.	Small Gen. Service	Med. Gen. Serv., Total	Large Gen. Service, Total	High Demand	Street-lights
$/Peak kW for Transformer	$1.285	$1.837	$4.912	$3.883	$2.052	$1.837
Load Factor	38.050	38.050	38.190	47.990	47.880	52.374

Streetlights

Revenue requirements that are expressly for streetlights (e.g., capital costs directly assigned to streetlights) are also assigned to streetlights in the cost allocation process. For this reason, average annual rates for streetlights differ from average rates for all other customer classes. Average rates for most customer classes cover costs for electrons consumed as well as annual capital costs for generation, transmission, distribution, and normal administrative overhead functions. Average rates for streetlights cover all those costs, plus, for many (but not all) streetlights, annual capital costs for the streetlight facilities such as poles and fixtures. Consequently, the annual average rate (per kWh) for streetlights is significantly higher than for other customer classes.

Customer Costs

These are costs associated with providing electricity that are not related to the amount of energy (kWh) used by customers and include customer accounts and services, and meters and customer installation. For example, meters are required to measure the amount of energy (and demand for medium and large customers) used by customers. The types and sizes of meters installed are related to the maximum demand expected; therefore, annual capital costs as well as annual O&M costs for meters differ for each customer class.

The customer accounts and services category includes costs for customer records and bills that are prepared for every customer regardless of level of consumption. Similarly, annual costs for maintaining the service drop (line from customer transformer to the customer's meter and service panel) are required independent of the amount of energy used. Costs of uncollectible accounts also must be apportioned among customer classes.

The annual costs for meters, customer records, and service maintenance are estimated on a per meter basis. These costs are then multiplied by the projected number of meters for each class to produce estimates of total marginal costs for these cost categories. Shares of the total marginal costs are computed for each customer class and used to allocate the corresponding revenue requirement categories. The following two tables present the costs for these two categories as estimated in the 1999 rate review.

Average Marginal Cost per Meter for Customer Accounts and Services (1998 $)

Residential	Small Gen. Service	Medium Gen. Service	Large Gen. Service	High Demand
$43.63	$32.59	$94.83	$2,131.66	$34,527.20

Average Marginal Cost per Meter for Meters/Customer Installations (1998 $)

Residential	Small Gen. Service	Medium Gen. Service	Large Gen. Service	High Demand
$6.63	$21.83	$112.28	$903.98	$2,447.72

Similar to the treatment of the various distribution marginal cost components, these customer cost components are calculated for each customer class and the sum over all components is computed. Each class' share of the total is then used to allocate the revenue requirement for customer services.

GRADUALISM

Gradualism is a policy tool that states that no customer class will be required to pay a percentage increase in rates greater than some specified amount. The policy of gradualism has been in use since the early 1980s. It has been used to mitigate the effects of full implementation of the cost allocation processes whenever it seemed that some customer class would receive inordinately large rate increases compared to other classes.

Consideration of gradualism starts with a computation of annual average rates based on the preceding marginal cost share allocations. In the event that the "pure" or nongradualized results suggest that a class sustain a rate increase greater than the policy maximum, that class' rate increase is kept at the policy-directed maximum and the revenue NOT collected from this class is then shared among the other classes. Such a transfer of revenue requirements increases the rates of the recipient classes compared to what the nongradualized results would have been. The transferred revenue requirements are allocated on a proportional basis among the receiving classes.

The 1999 rate review utilized two criteria regarding gradualism. One was a cap; i.e., a maximum percentage change over rates without a change. The cap was set at six percent for the initial rate period in the 1999 rate review and at nine percent for the second period covered by the rate review. The other criterion was a floor that rates should be at least as high as rates without a change. The 1999 rate review also included three policy changes that were introduced after the gradualism calculation. The final rate effects were, therefore, further modified by these new policies and it was possible that some rates might fall outside the gradualism boundaries because of these new public policies.

PUBLIC POLICY PROGRAMS

Residential Low Income and Conservation

Elected officials in Seattle have long supported public policy programs that reduce costs for certain customers. The programs currently in place are residential low income and various conservation programs. (These are not the new public policies referenced in the previous paragraph. The new policies are described below.) Customers who qualify for low-income rates pay residential rates that are lower than for other customers. Some conservation programs are similar in that the full costs of the conservation measures installed for a customer are not borne by the customer. The various conservation programs where this applies have different qualification requirements. For both of these programs, the difference between what the customer does pay and the total cost is borne by all customers. The principle used to allocate these costs among classes is based on each class' share of the total of all marginal costs. Thus, the total marginal costs from each of the preceding cost categories are summed, over all classes, and the share of the total is computed for each class. Those shares are used to allocate these costs of public programs.

Franchise Agreements

The cities of Burien, Lake Forest Park, SeaTac, and Shoreline negotiated franchise agreements with City Light a few years ago that call for City Light to send payments to those cities based on the value of City Light energy consumed by residents of each city. In 2003 the City of Tukwila negotiated a new franchise agreement with City Light similar in broad scope to these other franchises, though different in several details. This new Tukwila franchise agreement superceded a previous franchise agreement that had Tukwila customers paying the same rates as City of Seattle customers. All five of these franchises provide for rate differentials to customers within those cities compared to rates in the city of Seattle, contingent upon consent of Seattle City Council.

Network Rates

Distribution costs to downtown network customers are substantially higher than corresponding costs for other customers because of the multiple underground feeders, protected from weather, that supply each customer. These downtown network customers receive higher quality service than other customers in the form of fewer minutes of outages each year because of failure of the distribution system. Prior to the 1999 rate review, rates to downtown network customers were not differentiated from rates to other customers. The increased cost of service and the higher quality of service to these customers, though, were arguments that they should have a higher rate than nonnetwork customers. Countering that argument, though, was the fact that the downtown network area serves a large number of people from all parts of the service territory (e.g., those from elsewhere who work, shop, or receive professional services in the area). It was argued that these people from out of the network area placed a premium on high quality electrical service in the downtown network area. On another hand, businesses in the downtown network have a power quality advantage over competitors located elsewhere. Why should those competitors subsidize the downtown locations? In 1999 the Seattle City Council, after considering the merits of all the issues, allocated 25 percent of the cost differential between network and nonnetwork service in the first time period covered by the 1999 rate review. The allocation of the network and nonnetwork cost differential was increased to a 50-percent share in the second time period covered by the 1999 rate review. This change of cost shares is akin to a gradualism approach to a rate reflecting a new policy.

Allocation of Streetlight Costs

Streetlights formerly owned by the Transportation Department of the City of Seattle were transferred to City Light in 1999. The cost of electricity and services to those streetlights previously had been billed to the Seattle General Fund. The 1999 rate review included those streetlight costs in the bills of all customers subject to City of Seattle rates.

The 1999 rate review developed a procedure to allocate revenue requirements that took into account the three new policy initiatives mentioned above, including the new franchise agreements. A number of interrelated steps were involved in integrating these new policies into the cost allocation mechanism. “COSACAR 2000-2002” describes these steps in detail.

Step 3

Rate Design --
Putting It All Together

Document: Rate Design Report

"Democracy is finding proximate solutions to insoluble problems."

Reinhold Niebuhr

THE GOAL OF RATE DESIGN

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.

Seattle's rate-setting objectives are outlined in City Council Resolution 28004. In general, electric rates should collect the Utility's revenue requirements at the lowest possible cost to the ratepayer. They should be based on the cost of service to the customer and reflect changes in the cost of service over time. Rates should be equitable--they should fairly distribute the costs of providing service to customers. Rate levels and structures should be changed in a gradual and orderly manner. Effects on low-income customers and the economic health of the community should be taken into account, and mitigation of rate increases considered. Finally, rates should encourage cost-effective conservation and efficient use of electric resources.

To accomplish these philosophical objectives, designers have three basic parameters or tools: the rate class (residential, small general service, etc.); the rate form (flat, blocked, seasonal, time-of-use, etc.); and the rate element (energy, demand, and other charges). In practice, rate forms and elements are designed simultaneously. The distinction drawn here is simply a paradigm to help you comprehend the rate-setting process.

THE TOOLS OF THE TRADE

The Rate Class

Customer classification is the preamble to rate design as well as to cost-of-service analysis. Before costs can be analyzed, the Utility needs to identify groups of customers with similar cost characteristics. Then, different rate schedules can be set for these customer classes. To develop customer groups that better reflect the true cost of service and allow more efficient rate designs, the City Council adopted a new classification system in 1986, creating three General Service classes (Small, Medium, and Large) based on demand. In 1989 the Large General Service class was split into Large and High Demand General Service. The new system grouped customers into homogeneous classes, allowing more equitable allocations and producing more efficient rate designs. In 1997 the distinction between Large Standard and Large Industrial was eliminated, and in 1999 the Standard/Industrial distinction was eliminated from the Medium General Service Class. Also in 1999 a further rate distinction was created that identified specific areas of the service territory: City, Network, and Suburban, with different costs of service and rates. Then, in May 2003, separate new rates were established for the City of Tukwila, at that suburb's request.

Electric Facts
In 2002, the average residential customer consumed a little more than 9,400 kWh annually. Average commercial customers consumed over 101,000 kWh annually. Average industrial customers consumed over 2.8 million kWh per year.

The Rate Form

Varying rate structure allows 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 forms:

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 nonresidential customers.
Block	The price of electricity changes at different levels of consumption, either increasing (inverted block) or decreasing (declining block) as more kilowatt-hours are used. American utilities have used two, three, or multiple block designs, but in recent years have moved toward simpler designs with fewer blocks. City Light has a three-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.
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 form 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 poor power factor (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. See "Other Rate Elements" below.

Other formats are also possible (e.g., U-shaped or camelback rates), but those listed above have been the most common. Each shape has different goals and advantages. For example, the declining block rate encourages energy consumption, while the inverted block rate promotes conservation and facilitates lifeline rates. The simple flat rate is easy to understand, but is a less versatile tool for meeting competing rate objectives.

When using block forms, the ratemaker may vary the size of the blocks. Seattle's first (residential) block covers daily consumption up to 10 kilowatt-hours in summer billing months and up to 16 kilowatt-hours daily the rest of the year. These amounts cover certain essential electric needs for most consumers. The second (residential) block covers daily consumption between 10 and 100 kilowatt-hours in summer, and between 16 and 167 kilowatt-hours in winter. These amounts cover electric needs for most consumers. The end block covers all daily consumption over 100 kilowatt-hours in summer and over 167 kilowatt-hours in winter.

The Rate Element

Once the Utility has fashioned specific rate forms to fit its objectives, it must fill those forms with the rate elements (charges and fees) so that the resulting revenues meet the costs of serving each customer class. Thus, the design process not only involves decisions about which rate forms to use, but which charges to use and how to allocate revenue portions among the charges. Utilities can use different rate elements or combinations of elements: energy charges (based on the <u>amount</u> of energy consumed); demand charges (based on the <u>top</u> monthly demand point); base service charges (flat service fees); minimum charges (minimum service fees charged if greater than all other charges combined); and miscellaneous fees for various services.

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. City Light sets six energy charges for both regular and low-income residential customers (three blocks for two seasons apiece). While the rates per kWh are currently the same for summer and winter, the block sizes are different.

By contrast, nonresidential (general service) rates are flat, or unblocked; the rate is the same no matter how much electricity is used. However, Large and High Demand General Service energy rates feature differentiation by time of day, with separate peak and off-peak rates.

In 1996 an additional option was introduced for certain large nonresidential customers: an energy charge based on market prices (Variable Rate General Service). This energy charge was linked to the Dow Jones California-Oregon Border Nonfirm Price (DJ-COB) minus .05¢/kWh to reflect the generally lower cost of power purchased in the Northwest. In 1997 these customers were given the choice of an energy charge linked either to the DJ-COB or to the Dow Jones Mid-Columbia price index. This market-based rate also features differentiation by time of day, with separate peak and off-peak rates.

In 2000 an additional rate was added to provide general service to New Large Loads (Schedule NLL). A New Large Load customer may elect to work with City Light to create a more tailored power delivery package either before a New Large Load is energized or after being billed under Variable Rate General Service schedules for any period of time.

Demand Charge

Medium, Large, and High Demand and Variable Rate 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.

For Large and High Demand and Variable Rate General Service customers, demand charges are even more dramatically related to the time-of-day concept than energy rates. The charge for peak period demand is much higher than the charge for off-peak demand, regardless of season.

Demand charges cover costs of transformers and some transformer losses, as well as part of the energy costs associated with high-cost periods.

Base Service Charge	City Light's rate fabric is stitched with a third yarn--a customer charge for all residential customers. In 1997 City Light replaced the earlier “minimum charge”--designed to recover recordkeeping costs--with a Customer Charge (called a Base Service Charge since 1999) for residential customers. The Base Service Charge is a fixed amount that is charged to every residential customer <u>in addition to</u> the amount charged for energy usage. This charge is set to cover half of the customer-related costs such as meter reading, billing, capital cost of the meter, etc. The nonresidential customer classes retained the minimum charge.
Minimum Charge	For nonresidential customers a minimum charge, designed to recover record-keeping costs, is charged. Of all the elements that compose the Utility's rate forms, the least weight is given to the minimum charge. The charge is low compared to base service charges that some utilities add to their bills as a monthly service fee. City Light does not assess a base service charge to nonresidential customers because its goal is to encourage energy conservation by recovering costs as far as possible through rate components controllable by the customer. The Medium General Service classes have neither a base service charge nor a minimum charge due to the limitations of the current computer billing system. All costs are recovered through the energy and demand charges.
Other Rate Elements	Miscellaneous service fees: In addition to the main elements or charges, City Light sets fees to cover miscellaneous services. Although these fees are not part of City Light's rate schedules, they do have an effect, albeit minor, on the Utility's revenues. Examples of special fees include those for trouble calls, new or changed accounts, service disconnections, hookups for new or enlarged electric service, installations of floodlights and alley lights, and rental equipment. Transformer and primary metering discounts: Discounts are extended to general service customers as compensation for providing their own transformers (based on current marginal replacement costs) and as compensation for power losses occurring in the transformer (if the meter is located on the utility side of the transformer). Interruptibility: High Demand and Variable Rate General Service rate schedules include an interruptible feature, whereby the Utility can request voluntary interruption during peak load periods. If such interruption occurs, the demand charge is waived for the billing period in which the interruption takes place.

Residential rate discount: Schedule REC, RLC, RES, RLS, RET, and RLT rates are available to low-income and low-income elderly or disabled residential customers. Usually, these rate assistance rates are set approximately 50 percent lower than regular residential rates. However, due to surcharges and BPA adjustments occurring over the last couple years, rate assistance rates are now approximately 40 percent of regular residential rates. Approximately 14,000 customers receive this form of rate assistance. The total cost of the rate assistance program in 2003 is expected to be about $7.5 million. This cost is spread to all other customer classes.

RATE DESIGN: LINKING RATES TO POLICY

The selection of rate forms and elements is really the process of translating rate objectives into concrete design criteria. Needless to say, this process 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 rates in view of the City's long-range philosophical goals.

The 2002 calendar-year revenue requirement of $413 million ($403 million from energy sales to customers)[4] resulted in an average system rate increase of 6.3 percent (excluding surcharges and BPA adjustments) spread over 2001 and 2002[5]. The rate review was guided by the following policies, most recently affirmed in City Council Resolution 28004. These concepts give flesh to the principles outlined at the beginning of the section:

1. Residential rates shall be designed in ascending blocks to encourage conservation and provide lifeline rates (via the lower-priced first block).

2. Summer and winter rates should reflect seasonal and, where cost effective, hourly differences in cost of service.

3. City Light shall provide rate assistance and certain other free, or reduced cost, services to low-income customers.

4. Rates with energy and demand charge components shall not be designed in declining blocks.

5. The Utility shall offer interruptible rates, discounts for customer-owned transformers, and credits for power losses where appropriate.

6. The Utility shall assess half the cost for trouble calls and special charges for new or changing accounts.

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[4] *Adopted Revenue Requirements Analysis 2000-2002*, Appendix 4, Table 1.01, Seattle City Light, February 2000.
[5] *Adopted Rate Design Report*, page p.4, Seattle City Light, February, 2000.

Resolution 28004 also stated that rates should not include a customer charge, and that billing costs could be recovered through a minimum charge. This policy is still followed in nonresidential rate design. However, Ordinance 118475 (the 1997-98 rates ordinance) established a customer charge (now called a Base Service Charge) for the residential class. This charge replaced the minimum charge for this class only and was set to recover half the cost of billing and other costs unrelated to the quantity of electricity consumed.

As a general rule, the Department prefers not to change rate forms or elements radically because it engenders instability and confusion. However, the emphasis of the forms can gradually be modified to keep the Utility's prices close to the actual cost of service. The process of fine-tuning rate forms involves varying the elements or charges within them.

For example, although the inverted block has been in effect since 1944, the level of inversion has changed significantly in recent years to reflect fluctuations in the cost of energy. In 1980 City Light sharply increased the degree of inversion so that the winter end-block rate was two and a half times the first-block rate. This change reflected the dramatic leap in the cost of new resources that occurred when Seattle's hydropower base was exhausted. Unable to meet its peak demand, the Utility had to rely on increasingly expensive BPA power. In subsequent rate reviews, the degree of inversion declined in response to lower estimated marginal costs of electricity.

Seasonal Rates

Seasonal rates were developed for nonresidential customers in 1974, and for residential customers in 1977, to reflect the costs of supplying electricity at different times of the year. In the Northwest, it is more expensive to supply electricity in winter when demand for heating energy is highest, and in periods of low water availability. To deal with shortages, City Light must purchase power from BPA and other outside sources. On the other hand, power is often so plentiful in spring and summer that we can sell the surplus to southwestern utilities that have a heavy air-conditioning demand.

In 1980 the Utility increased the difference between summer and winter rates for the same reason it increased the degree of inversion between rate blocks--to translate the real cost picture into an equitable rate structure so consumers could respond appropriately. Higher winter rates were in effect four months of the year (December-March until August 31, 1992, and November-February until the 1997-1998 rate change).

As a result of the MVEs developed in 1996, City Light recommended a change in the seasonal rate structure to one in which there would be six months in the higher rate period and six months in the lower rate period.[6] In 1997 the seasonal rate periods were changed to six months in the higher rate period (winter season: September through February) and six months in the lower rate period (summer season: March through August). Shifting

[6] Soder, Jane. *Seasonal Rate Period Definitions*. Seattle City Light, Rates Unit Issue Paper, April 17, 1996.

September and October into the winter (higher rate) period more closely followed the new monthly MVEs, and had minimal impact on customer bills.

During the 2000-2001 energy crisis, the winter-summer rate distinction was discontinued in order to help mitigate a significant jump in winter rates as a result of necessary surcharges and BPA increases. It was also less complex and confusing to apply these surcharges without apportioning them between seasonal changes in rates. (There were no changes in the Residential block structure threshold definitions for winter and summer.) Winter and summer rates per kWh and demand charges remain the same at this time for all customer classes.

However, in July, 2001, still feeling the effects of the energy crisis, City Light attempted to rein in those residential customers who were consistently very high energy consumers by adding a third block to residential rates. This "end block" charge nearly doubled the second-block rate for customers who used more than 60 kWh per day in the summer and more than 125 kWh per day in the winter. Subsequently, with residential rates effective July 14, 2002, the third-block rates were reduced and the level of consumption at which third-block rates begin was increased.

Time-of-Day Rates

Another time-based rate form was added in 1984 to reflect hourly peaks in demand, since they too can affect the cost of power. City Light adapted time-of-day rates to the schedules of its large nonresidential customers to encourage them to shift consumption from the peak use period (7 a.m. to 10 p.m. Monday through Friday) to the off-peak period (nighttime and weekends) when energy costs less. Under time-of-day rates, customers whose normal demand billings are 1,000 or more kilowatts per month pay smaller energy and demand charges for off-peak use. Approximately 156 customers are currently served under time-of-day rates. In 1996 the peak period definition was changed to 6 a.m. to 10 p.m. to be consistent with the current wholesale market definition of heavy load hours. In 1999 Saturday (6 a.m. to 10 p.m.) was added to the peak period to reflect the fact that wholesale market prices in daylight hours on Saturday were comparable to weekday prices.

WHY THE RATE ELEMENTS WERE ALTERED IN 2000-2003

In 2000-2003, the rate forms for nonresidential customers remained basically the same as those introduced in 1986 except that the distinction between commercial and industrial was eliminated. However, in 2000-2002 some of the rate elements were adjusted to reflect current costs of service, policies and market conditions. The following were the most significant modifications made to existing rate schedules:

1. The seasonal billing distinction of six months at higher rates and six months at lower rates was altered to apply the same rates to both summer and winter periods. As discussed above, this change was implemented in order to help mitigate significantly

higher winter bills due to surcharges and BPA increases during, and as a result of, the energy crisis.

2. A third block was added to the previous two-block structure of residential rates. This "end block" is aimed at curbing those customers who consistently use significantly more energy then the average customer.

3. Separate rate schedules were established for Standard City, Suburban, and Network customers because renegotiated franchise agreements allowed suburban rates to be higher than City of Seattle rates, and because higher rates were needed to cover higher costs for Medium and Large General Service customers in the downtown network area.

4. Commercial and Industrial subclasses in the Medium General Service classes were merged. This change was the result of analysis that showed that rate impacts on the Industrial subclasses would be minimal. Such impacts had been mitigated by the policy of gradualism since the 1986 change in the customer classification system.

5. For the Large and High Demand General Service rate schedules, the definition of the "peak period" was changed from 6 a.m.-10 p.m. Monday through Friday to 6 a.m.-10 p.m., Monday through Saturday. As indicated above, this change was made to be consistent with the current wholesale market definition of heavy load hours.

6. In May 2003, separate rates were established for the City of Tukwila as a result of a renegotiated franchise agreement. Prior to this, Tukwila customers were charged the same rates as City of Seattle customers.

Electric Facts

Large and High Demand General Service customers consumed about 2,495,505 megawatt-hours in 2002, almost 28 percent of City Light's service area sales.

THE COMPUTATION

The last step in rate setting is to lay out the equations on the computer. After selecting design criteria, City Light considers several rate alternatives before recommending one to the Mayor. These alternatives may vary in emphasis of principles and criteria. Each one has an accompanying set of equations that transforms the design concepts into concrete numbers (rates) for each customer class.

For you repressed mathematicians, the basic equation for the recommended 2000-2002 Residential rate schedule was:

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

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 end block charge - summer
P_3	=	Price of end block – summer
X	=	Base Service Charge

(K_3,K_4, P_3 and P_4 are the same as above, but for the winter blocks)

The equation, if used today, would add K_5, P_5, K_6, and P_6 to represent the current end block.

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.

Comparison of 2002 Average Utility Rates in U.S. Cities by Rate Sector (cents/kWh)

	Residential	Commercial	Industrial
Seattle	6.0	5.3	5.0
Memphis	6.3	5.9	3.9
San Antonio	7.1	5.6	5.6
Jacksonville	6.8	6.3	3.8
Chicago	8.7	7.8	5.3
Baltimore	7.5	5.4	3.8
Phoenix	8.7	7.5	5.6
Los Angeles	10.0	9.6	8.1
San Diego	10.4	10.4	8.5
Boston	13.1	9.5	8.2
New York	17.0	14.5	11.0
Philadelphia	10.2	8.8	5.8
U.S. Average	8.4	7.9	4.8

Sources:
1. Investor-Owned Utilities: FERC Form I, Electric Utility Annual Report, May 1, 2003
2. Publicly Owned Utilities: Information from each utility, May 2003
3. U.S. Average: U.S. Department of Energy

Comparisons of Monthly Residential Electric Bills in U.S. Cities (1,000 kWh)

	January 1998	January 2003	Five-Year % Change
Seattle	$48.62	$75.73	55.8%
Memphis	64.57	63.92	-1.0%
San Antonio	57.29	71.58	24.9%
Jacksonville	68.15	68.15	0.0%
Chicago	103.11	84.10	-18.4%
Baltimore	81.24	74.37	-8.5%
Los Angeles	104.69	104.69	0.0%
San Diego	104.96	153.17	45.9%
Boston	127.73[1]	120.24[2]	-5.9%
New York	161.82[1]	177.99[2]	-4.3%
Philadelphia	135.60	133.80	-1.3%

Sources:
"Comparison of Residential Electric Rates," Jacksonville Electric Authority, Jacksonville, Florida (January 1998 and January 2003).
[1] *"Residential Service Bill Comparison, 25 Largest Cities,"* Texas Utilities (December 1997 and December 2002).
[2] *"Typical Bills and Average Rates Report, Edison Electric Institute," July 2002.*

Comparisons of Average Monthly Northwest Electric Bills
Rate Schedules in Effect May 1, 2003

	Seattle City Light (City of Seattle)	Tacoma (City of Tacoma)	Puget Sound Energy (City of Bellevue)	Snohomish County PUD (City of Everett)	Avista Utilities (City of Spokane)	Portland General Electric (City of Portland)
Residential (1,000 kWh)	$ 73	$ 63	$ 62	$ 82	$ 60	$ 80
Small General Service (7,500 kWh, 25 kW)	460	461	547	568	674	573
Medium General Service (45,000 kWh, 150 kW)	2,828	2,293	3,433	3,311	3,068	3,096
Large General Service (1 million kWh, 5,000 kW)	59,179	58,909	72,082	65,887	53,435	71,239
High Demand General Service (18 million kWh, 60,000 kW)	1,006,925	898,780	902,316	1,099,131	876,454	974,770

Source: Direct contact with individual utilities.

What the Law Says About Rate Setting

"Someone has tabulated that we have put 35 million laws on the books trying to enforce the 10 Commandments."

Bert Masterson
Wall Street Journal

DIFFERENT LAWS FOR DIFFERENT UTILITIES

How does a citizen assess the rate-setting process? One blunt test is whether the utility appears to be meeting legal regulations and policy guidelines established by local, regional, and federal authority.

The way in which a utility is regulated--and rate decisions are reached--depends on who owns the utility. Private or investor-owned utilities (IOUs) are corporations managed by boards of directors elected by stockholders. In Washington, IOUs are regulated by the Washington Utilities and Transportation Commission, which schedules public hearings on proposed rate or tariff changes, known as rate cases.

By contrast, public electric systems are nonprofit organizations owned by representative governments. Public systems come in three varieties: regional authorities like the Bonneville Power Administration, operated and regulated by the federal government; public utility districts (PUDs) like Snohomish County PUD, which are separate units of government run by elected commissioners; and municipal utilities such as Seattle City Light and Tacoma Power, which are controlled by city councils or council-appointed boards.

A third species of utility is the electric cooperative that brought electricity to millions of rural customers in the South and Midwest. Co-ops are governed by boards of directors elected by customers and subject to their own bylaws. The Washington Uniform Commercial Code and State Constitution contain sections that apply to co-ops.

As public agencies, municipal utilities conduct their business at meetings open to the public. The policies that govern City Light, including its rates, are formally adopted by the City Council.

Electric Facts

Nearly two-thirds of the nation's 2,800 electric utilities are publicly owned--about 1,850 of those are municipally owned. Another 894 are electric co-ops, and about 75 are state PUDs. Although only 240 electric utilities are private, they serve nearly three-fourths of the U.S. households, generating 72 percent of all kilowatt-hours sold.[7]

[7] 2002 Annual Directory and Statistical Issue, Public Power, American Public Power Association.

FEDERAL REGULATION

The federal government controls interstate wholesale (inter-utility) rates charged by IOUs and the rates charged by regional authorities like BPA to their customers. In 1978 Congress passed the Public Utility Regulatory Policies Act (PURPA) that requires large electric systems to consider a range of standards. PURPA Sections 111, 113, and 114 set forth the following standards:

Cost of Service	Rates for each class should track the cost of serving each class.
Declining Block Rates	Electric rates should not decline as usage increases, unless costs justify it.
Time of Use Rates	Rates should vary by both season and time of day if utility costs vary accordingly.
Lifeline Rates	Utilities should provide electricity below cost for essential levels of service.
Interruptible Rates	Customers should be offered interruptible rates if they are cost-effective to the utility.
Load Management	Utilities should offer cost-effective load management techniques to customers.
Consumer Information	Utilities should provide information to customers about existing and proposed rate schedules. Ratepayers have the right to intervene and participate in rate-setting processes.

In addition to these standards, PURPA supports other policies relating to advertising, master metering, rate adjustment, and termination of service. The City of Seattle adopted all PURPA proposals except the cost-of-service and advertising standards. The City Council rejected the former because it is too ambiguous, and the latter because it does not apply to public utilities.

More recent federal legislation relates to opening of utility-owned transmission systems to competitive use by other energy providers. The National Energy Policy Act of 1992 required that the transmission facilities of public and private electric utilities be made available on an equitable basis to all parties wishing to use those facilities. In 1996 the Federal Energy Regulatory Commission (FERC) issued its Order 888, which requires transmission owners to offer transmission services to other companies under the same terms and conditions that they offer them to themselves. It also encourages the formation of independent system operators (ISOs) to provide open access to the transmission system under a grid-wide tariff that applies to all eligible users. This Order significantly expanded the potential for wholesale competition in the provision of electricity. In 1997 City Light developed a transmission (wholesale) tariff to meet the FERC requirements.

STATE REGULATION

The Washington Utilities and Transportation Commission regulates the rates of IOUs. Although municipal utilities are exempted from the Commission's legal standards, they meet the standards in practice. State guidelines include:

* All rates shall be published for public review.
* Rates shall be just, fair, reasonable, and sufficient.
* Rates shall not be unduly preferential or discriminatory.

These legal standards present the absolute minimums. In reality, City Light's customers expect far more from their utility.

LOCAL REGULATION

The City Council has adopted several resolutions and ordinances in the last few years prescribing rate studies, policies, and structures. New legislation often incorporates older laws, in order to simplify and consolidate city law. Resolution 28004 (1989) is the most recent Council resolution that summarizes current policy on the three phases of ratemaking--revenue requirements, cost analysis, and rate design. It prescribes social, economic, financial, and procedural standards for rate setting and reaffirms the City's commitment to public information and involvement.

In December 2001 the City Council adopted new financial policies which provide that rates will remain at their current levels (unless increased by the Council or adjusted to pass through changes in Bonneville rates) until all short-term debt obligations have been repaid and cash balances in the Department operating account have reached the level of $30 million. The Department now projects that this point will be reached in the third quarter of 2004. Retail rates can then be set on the basis of new guidelines that give greater recognition to the increased level of risks that the Department faces, given current conditions in power markets. It is anticipated that when the new financial policies take effect in 2005, over 50 percent of the Department’s future capital requirements will be financed from operating revenue.

REGIONAL REGULATION

To complete the picture, another level of authority should be mentioned. Although no regional agency currently regulates Northwest utility rates, BPA and the Northwest Power Planning Council do have some influence on retail electric rates. BPA has an interest in seeing its low-cost wholesale power passed along to the final customer in lowered retail rates. The regional Council has a broader mission in encouraging the utilities of the region to work together to preserve its resources. The Regional Power

Act, which created the Council, also sets limits on rates BPA can charge various classes of customers.

SEEKING A HIGHER STANDARD

Of course, the law provides only a general measure of a utility's rates. However, the utility seeks not only to comply with basic legal standards, but also to forge even more exacting standards based on feedback from its customers and ratepayer/reviewers.

Toward an Agenda

"Animals are such agreeable friends – they ask no questions, they pass no criticisms."

George Eliot

WHO MAKES THE ISSUES?

You may well wonder how citizen committees structure their review and identify focal points for discussion. How can someone unfamiliar with the rate-making labyrinth recognize technical issues that are worthy of pursuit?

The 2003 Rates Advisory Committee will begin its work discussing issues related to City Light's Suburban rates: streetlights, rate differentials, etc. (See below for more on these issues.)

However, as a rule, a natural format is provided in the three rate-making steps described in the manual. Committees have found it expedient to organize their work, at least chronologically, around these milestones. Thus, the following order suggests itself: revenue requirements and financial policies; cost of service and cost allocation; and rate design. You will hear presentations and receive preliminary materials as the draft reports for each phase are prepared. In these reports, staff presents rate topics and alternatives under consideration. Committees have often added a fourth topic to the list: how well the rate review process is working. Issues are also identified by City Council staff who serve the Council's Energy and Environmental Policy Committee. Following each rate review, the Council develops a work plan for the Utility that targets issues for further review. The work plan is then adopted in the form of a resolution. In addition, Council staff periodically issue reports exploring topics that interest Council members.

The City Budget Office reviews the Utility's rate reports for the Mayor. From this review, the Budget Office staff develop an independent sense of which issues are important. If the Committee desires, staff will discuss their views with the Committee.

Another source for issue selection is the work of past rate committees. You may wish to review the last committee's recommendations in particular to see if they were acted upon or, if not, why.

Of course, the most important agenda setter is you. Taking the law, City policies, and your own ideas as starting points, you may decide to prioritize issues you feel should be addressed. The Committee is under no obligation to accept anyone's agenda but its own.

ISSUES IDENTIFIED FOR THIS RATE REVIEW

For your information, the following rates-related issues are potentially facing the committee:

1. Should suburban rates be increased to the maximum allowable by law prior to implementation of the results of the 2005-2006 Rate Review?

2. Should suburban streetlight rates be incorporated into the suburban rates?

3. Should there be different rates for each suburban jurisdiction?

4. What changes should be made in the general provisions of the rate ordinance?

5. Should the demand charge be increased (and the energy charge decreased) to recover more of our costs through the demand charge?

6. Should we continue to have three blocks in the Residential rate structure? What should the threshold be for any blocks?

7. Should low-income programs return to 50% of regular rates? Are there any changes in eligibility that should be made?

8. Should the Utility establish an up-front charge for new large developments to fund future distribution system requirements and/or to encourage developers to provide more reliable load estimates?

9. Should the power factor charge be increased in order to more strongly encourage low-power-factor customers to correct their power factor?

10. Should time-of-use rates be adopted for medium general service customers?

11. What changes should be made in the sections of the municipal Code regarding New Large Loads?

12. Should we take the next step in recognizing the differential in the cost of service to network customers vs. non-network customers?

13. How should we use the marginal value of energy?

14. How should we incorporate environmental externalities into our cost analysis?

15. Is there a place for interruptible rates in our rate structure?

16. Will we continue to pass through changes in BPA rates?

17. Should we continue to offer customers a rate that is indexed to market prices?

18. Are there services for which City Light does not now charge that could provide additional revenue if we established fees?

19. Should we continue to have a customer charge and, if so, should it be increased to cover a greater share of customer-related costs?

THE VIEWS OF PAST RATES ADVISORY COMMITTEES

Over the years, citizen rate committees have developed recommendations on a variety of issues. Occasionally, committees have recorded split opinions, with majority and minority views.

1992-1993 RAC

The 1992-1993 RAC was in an unusual position. First, it was asked to discuss and approve a 10-percent surcharge on rates. Then, beginning in September, the Committee reviewed and discussed a rate increase proposal from City Light and the Mayor calling for a two-step rate increase. The first step would have raised rates an average of 9.2 percent on May 1, 1993 with an additional average increase of 3.7 percent on January 1, 1994. However, by March of 1993 the water situation in the region had deteriorated to the point that the Mayor revised his proposal to raise rates an average of 16.3 percent with an additional 5.7-percent surcharge to be effective until January 1, 1994.

The Committee's recommendation to the City Council was to raise rates by the original 9.2 percent with a reasonable surcharge to cover only weather-related expenses. The City Council adopted a permanent rate increase of 12.6 percent with a temporary 4.1-percent surcharge that was removed November 1, 1993.

Other issues addressed by the 1992-1993 Committee included whether the cost of rebuilding deteriorating underground distribution systems should be included in the rates of customers served by such systems, whether the policy of "gradualism" regarding industrial customer rates should be continued, and whether rates should include a customer charge. On the first issue of rebuilding deteriorating underground distribution systems, the Committee recommended that the costs continue to be included in the general rate base. This recommendation was consistent with the Council's eventual decision. With respect to "gradualism," the Committee voted in favor of doing away with it. However, the Council continued to apply it in the approved rates. No recommendation was made by the Committee on the issue of a customer charge because no agreement could be reached.

1995-1996 RAC

The 1995-1996 Committee questioned the use of a marginal (versus an embedded) cost methodology in cost allocation. As a result, a reexamination of the two methods[8] concluded that, while “adjustments to this methodology may be appropriate based on current information and the approaching competitive wholesale energy environment,” a marginal cost allocation methodology reflects a rate structure designed to promote conservation and efficient use of energy. In other words, rates are designed to give appropriate price signals to allow customers to “make economically optimal choices” with regard to energy consumption.

[8] Laschober, Paula. *Cost Allocation Methodology,* Seattle City Light, Rates Unit Issue Paper, April 15, 1996.

This Rates Advisory Committee endorsed the policy of maintaining a debt service coverage ratio of 1.8 for the Department's senior debt, which was adopted by the City Council in February 1995. The Committee's further recommendation of a 1.0 coverage ratio for junior debt was not adopted by the Council.

The Committee also recommended that projected cost savings of $10 million be reflected in the 1996 rates rather than over five years, supported the recommendation of an R. W. Beck consultant study regarding a strategic systems plan, and urged continued support of City Light's conservation goals in spite of potential future reductions in outside financing.

1997-1998 RAC

The 1997-1998 Rates Advisory Committee agreed with the City Light recommendation to implement a customer charge to achieve full recovery for metering and billing costs for the Residential class. In July 1997 a customer charge was established for residential customers, replacing the minimum charge, to recover **one-half** of metering, billing, and other customer-related costs. The RAC also advised City Light to reevaluate the residential dual block structure.

This RAC recommended that a pilot green-pricing program be developed for implementation in 1998. Green pricing, and the acquisition of a green-power generation source, was studied as part of the Department's Customer Choice program in 1998. A voluntary green power program was implemented in 2002. It allows residential and business customers to pay a small amount above their regular energy bill that is earmarked for the development of new, renewable resources. The Committee also supported City Council's resolution regarding the selection of environmentally sensitive resources and the control/reduction of industrial-sector pollution.

The 1997-1998 RAC also addressed City Light's revenue requirements, recommending, among other things, that the Utility maintain its 1997 and 1998 A&G costs at the 1996 level in nominal terms and that it develop meaningful measures to compare the level of those costs with those of other utilities. It also recommended that City Light be given the option of contracting a wide range of services out to private vendors, and that it seek opportunities to reduce or eliminate exposure to high-cost power resources.

In the area of cost allocation, the RAC recommended that City Light compare its industrial rates to those of other utilities and reevaluate its treatment of distribution costs. It was also suggested that City Light develop exit fees for customers seeking retail access to the energy market. With respect to City Light's experimental market rate schedule for its largest customers, the RAC recommended that some transmission and conservation costs be removed from the retail services charge.

Regarding low-income assistance, the RAC recommended graduated rate relief based on need, and consideration of a voucher system by which qualified low-income customers could procure appliance repair service from private vendors. In 1999 City Light did implement a low-income appliance repair program with service provided by a private vendor at no cost to the customer. This program was discontinued in May 2002.

1999 RAC

In 1999, while agreeing with City Light's proposal of charging higher rates to customers receiving network service, the Committee suggested a more gradual phasing in of network rates. The RAC proposed a phase-in schedule over the three-year period that would set network rates in 2002 to reflect only half of the cost-of-service differential between network and nonnetwork service. (The Mayor's proposal would have set rates in 2002 to reflect the full cost of the differential.) The City Council ultimately decided to accept this recommendation and to phase in network rates up to 50 percent of the cost differential in 2002.

The Committee also felt that residential and small general service customers receiving network service should pay higher rates than nonnetwork customers in those classes. Further, the Committee recommended that network costs not recovered from network customers in a given class should be recovered from nonnetwork customers in that class, rather than being spread across all customer classes. Neither of these recommendations was accepted by City Council.

The 1999 RAC recommended that City Light amortize the remaining costs associated with City Light's High Ross contract over the period from 2000 through 2035, rather than expensing these costs through 2020, as recommended by the Mayor. The Council accepted the recommendation on this point and lowered the rate increase as a result. The Committee recommended that the Council not accept the Mayor's proposal to shift the costs of streetlighting in the city of Seattle from the City's General Fund to all other City ratepayers. However, the Council did not accept this recommendation.

Conclusion

As you can see, numerous recommendations by rates committees have been adopted in part or in full. In many cases, committees have lent their support to Utility recommendations, strengthening their chances of eventual approval. But disagreements and split opinions are just as important, because they tell the Utility, the Mayor, and the Council that there may not be a community consensus on these matters.

Oliver Holmes, Jr.

Rates in Context:
A Historical Perspective

"When I want to understand what is happening today. . .I look back."

Oliver Holmes, Jr.

CITY LIGHT'S BEGINNINGS

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 century, the firm bought up a number of small local electric companies, consolidated them in the Seattle Electric Company, and established a 20-cents-per-kilowatt-hour basic rate. By comparison, the average rate paid by customers in 2002 was about than one-third that amount (6.29¢/kWh).

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. For the next half-century, though, public and private power systems competed to serve Seattle.

By 1905 Cedar Falls, one of the nations first municipally owned hydroelectric projects, was generating electricity for Seattle's streetlights, under control of the Water Department. The project performed unexpectedly well, producing so much electricity that the City Council voted to offer the surplus for general sale at 8.5¢/kWh. 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.

ROSS' VISION

It was called the Seattle Lighting Department then and for many years to come, and it found its future in the vision of the legendary J. D. Ross, the self-taught engineer who succeeded Arms in March 1911. The Lake Union hydro plant was outfitted with an oil-fired steam plant and the first of three turbogenerators was installed in 1914. At Cedar Falls a new masonry dam was completed. But within a few years, following federal approval of hydroprojects on the upper Skagit River, construction had begun on Gorge

Dam and powerhouse, and the emphasis of City Light's generation program had shifted northward. The average rate for electricity was 4.5¢/kWh.

Two generators at Gorge began operating in 1924, and construction efforts concentrated on a second dam and powerhouse at Diablo. North Substation, the Utility's first major substation, was also completed that year. As a botanical enthusiast and a great believer in good public relations, Ross insisted on attractive landscaping around the new developments and on making them accessible to the public. In 1928 the first official Skagit Tour was conducted, beginning a tradition that still flourishes today.

Meanwhile, the high cost of Diablo and other concerns had sparked friction between Ross and Seattle Mayor Frank Edwards, who summarily fired Ross in March 1931. When Mayor Edwards himself was recalled by the voters four months later, Ross was reinstated as superintendent.

In 1935 City Light's staff moved into a new two-story office building at Third Avenue and Madison Street in downtown Seattle, where the Utility's headquarters remained through 1995. Development of the Skagit continued, with Diablo beginning operations in 1936. A second major substation in south Seattle began operations that year. So did the Bonneville Project, forerunner of today's Bonneville Power Administration. Appointed as its first administrator in November 1937 was none other than J. D. Ross--on loan from City Light. Ross continued to wear two hats until his death in 1939. He was later interred near his beloved Skagit River, and Ruby Dam was renamed Ross Dam in his honor.

RATES DECLINE

Seattle's initial high rates were not surprising, since it always costs more to develop a new product. As sales increase, the economy of scale begins to lower unit costs, and prices decline. Once Seattle developed the Skagit system, it became much cheaper to enhance its electric investment, while encouraging greater use of the abundant supply. The average rate paid by City Light customers dropped to 2.1¢/kWh in 1940.

About this time the Bonneville Project was given charge of marketing the power generated by Grand Coulee Dam and, under the new name of Bonneville Power Administration, became the Federal Government’s Northwest's power marketing agency. In 1941 transmission lines from the Skagit to Seattle were upgraded from 165 to 240 kilovolts, securing greater efficiency at lower cost. The following year the Northwest Power Pool was formed to coordinate sales and power exchanges among utilities within the region. Throughout the 1940s the War Department established aluminum plants in the Northwest, which increased the importance and complexity of power management in the region. A new precedent was set for environmental planning in 1947, when City Light funded the Skagit Hatchery, built to preserve the salmon and steelhead runs whose habitat was being altered by the Skagit project.

Mandated by a vote by Seattle residents in 1951, City Light purchased all the Seattle-area properties of Puget Sound Power & Light for $26.6 million. With the acquisitions, which included the Canal Substation and the Georgetown steam plant, now a historical site, Seattle at last had a unified power system. Bothell and Broad Street Substations were added that year, and a fourth generator was installed at Gorge Powerhouse as City Light's system continued to grow. The 47-year-old Yesler Substation was retired, and the City began dismantling the duplicate distribution system once used by Puget Power.

In the early 1950s, Seattle increased the generation power of its plants and began simplifying and consolidating its far-flung facilities. With the City's electric rates dropping to less than a penny per kilowatt-hour in 1957, a time of new construction began. The North Service Center was opened, and work began on turning the two-story downtown City Light Building into a nine-story "skyscraper." Gorge High Dam was built, and new turbines were added to Diablo in 1958. The downtown building was finished in 1959, and the Canal Substation was completed in 1960.

In 1963 when John Nelson became superintendent, residential customers were paying 0.95¢/kWh for electricity. The Utility kicked off a long-range plan to make Seattle's neighborhood distribution lines more efficient by enlarging their capacity from 4 to 26 kV. (By 2002, this conversion eliminated more than 150 small substations, leaving Seattle with only 14 major substations.) The 1960s were also an era of expansion for City Light: Boundary Dam and powerhouse were built on northeastern Washington's Pend Oreille River and started operation in 1967. Three more substations were added: East Pine in 1967, University in 1968, and Massachusetts in 1969. Kiket Island was purchased in 1969 in partnership with Snohomish County Public Utility District as a proposed site for a nuclear facility--a project that was later abandoned.

THE BEGINNINGS OF CONSERVATION AND PUBLIC INVOLVEMENT

As demand for power climbed to an unprecedented high, Seattle took action to meet the need. In 1970, when residential customers were paying an average of 0.84¢/kWh, the City applied for a permit to raise Ross Dam, and soon afterward acquired an eight-percent share in the coal-fired generating plant at Centralia. The Newhalem powerhouse, damaged by fire four years earlier, was reopened with modernized facilities and the first fully automated City Light generators. Over the next 12 years, all the City's generating facilities were automated for direct control from Seattle's Power Control Center.

In 1971 City Light joined the Washington Public Power Supply System (WPPSS), a consortium formed to finance large public power generating facilities. Seattle subscribed to an eight-percent share in WPPSS nuclear plants 1, 2, and 3. Major interties with the Southwest had expanded the Northwest's power grid, and in 1974 BPA became a self-financing agency, no longer funded by government appropriation.

In 1971 Seattle increased its rates for the first time in 50 years. Gordon Vickery was appointed superintendent in June 1972. The Office of Environmental Affairs was established 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. City Light established a research and development program to study conservation and alternative energy sources. The need for such research hit home in 1973 when the first of two major droughts of the decade hit Washington just as Union Substation, City Light's twelfth major substation, was added to the system. The "Kill-a-Watt" campaign, a forerunner of City Light's subsequent conservation program, combated the drought by promoting conservation.

In the early 1970s, City Light began using a variety of techniques to enable its ratepayer-owners to participate in key energy decisions. These included newsletters, workshops, open houses, public meetings and hearings, and citizen advisory forums. Since 1972 more than 46 advisory groups have examined proposals ranging from rate increases to new generating facilities to conservation and environmental programs. The first Citizens Rates Advisory Committee joined in reviewing the 1974 rate increase, which brought the average electric rate to about a penny per kilowatt-hour. The Committee has been convened approximately every two years since then, with the exception of 1990, 2000, and 2002 when there were no formal rate reviews, to advise the Utility on electric rates.

In 1976, "Energy 1990", a study authorized by the City Council, recommended an aggressive conservation effort to reduce Seattle's projected energy growth by 20 percent by the year 1990. The Council accepted this recommendation and then decided against Seattle's participation in WPPSS nuclear plants 4 and 5. A citizens committee played a key role in influencing that critical decision.

The worst drought of the century up to that time hit the area in 1977, forcing City Light to supplement its depressed hydroelectric output with the purchase of extraordinary amounts of power from other sources. A drought surcharge was levied to meet the cost of the purchases. The year also saw another rate increase and the institution of a winter charge for most residential customers. As the first "seasonal rate," this 10-percent higher charge reflected the higher cost of providing winter service, giving customers a signal, or economic incentive, to reduce power usage during times of greater demand.

City Light received authorization from the FERC to construct High Ross Dam to increase its power-generating capability. The Office of Conservation was established and City Light conducted its first experiment in residential solar energy, called Project Weathervane. Viewland-Hoffman, City Light's thirteenth major substation, came on line.

NEW RESOURCES AND PRICE SIGNALS

By 1978 conservation had become the prevailing energy policy. City Light began several conservation services, including its free home energy check program, home insulation financing for low-income seniors, water heater thermostat reductions, and lighting consultations for business and industry. The U.S. Department of Energy supported the effort with a conservation grant. Robert Murray became superintendent in 1979 and, under his leadership, City Light began to overhaul its rates policies. In 1980 City Light initiated several changes supported by members of the Citizens Rates Advisory Committee: seasonal rates, a two-step residential rate schedule featuring lifeline rates, and a marginal cost-of-service approach to rate setting. A major rate increase that year raised the average cost per kilowatt-hour from 1.3 cents to about 1.6 cents.

Following a City Council resolution, City Light established an energy resources planning process to coordinate the City's electric power supply with short- and long-range demands. City Light also reaffirmed its commitment to conservation by creating a separate conservation division. In December 1980, Congress adopted the Northwest Power Planning and Conservation Act that 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.

The conservation program was further expanded in 1981 to include more commercial and industrial customers. In March, Joseph P. Recchi became City Light's eighth superintendent. That year the Copper Creek project was shelved due to environmental concerns, and the City reserved the right to buy 10 percent of the output of Creston coal plant in eastern Washington. Creston-Nelson Substation was completed, becoming the City's fourteenth major substation.

The 1982 rate increase brought the average kilowatt-hour cost of electricity in Seattle to 2.15 cents--still less than half the price in 1920. In 1984 rates were increased again to cover inflation, higher taxes, increased BPA power rates, and rising production costs. The rate increases of the 1970s and early 1980s were partly the result of the double-digit inflation that struck key sectors of the nation's economy. By 1978 Seattle had reached the end of the era of inexpensive hydropower. The cost of developing new resources--whether conservation, contract purchases, or generating resources--was much greater than in earlier years. The price of BPA power, for example, increased fivefold between 1979 and 1985. Nevertheless, City Light's rate increases did not greatly outstrip cost of living increases. Between 1970 and 1986, during which City Light's rates increased 3.6 times, average retail prices in the Seattle area increased 2.7 times.

The Grand Coulee Project Irrigation Authority (formerly known as the South Columbia Basin Irrigation District) became the first generating resource added to City Light's system after Boundary Dam and powerhouse. In 1983 the Creston option was rejected by the City Council because of reduced energy demand, economic uncertainty, and environmental concerns. Power from the Centralia steam plant, which City Light had previously sold to other utilities, was brought on line for Utility use. The City also acquired nearly four megawatts of cogeneration from a power plant fed by methane gas at Seattle's Metro Sewage treatment facility. 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. This agreement provided City Light an assured supply of low-cost energy while preserving an environmentally sensitive valley in British Columbia.

NEAR-TERM REGIONAL ENERGY SURPLUS

The Utility's first Strategic Resource Plan was developed in 1984. This plan marked the initiation of long-range financial planning over a 20-year horizon that has continued to the present.

In spite of a near-term regional energy surplus, City Light continued to build conservation program capability. Planning of new financial incentive programs for multifamily and commercial building retrofits was initiated. City Light also played a major role in the revision of the Seattle Energy Code, which was expected to yield energy savings equivalent to 35 average megawatts by the year 2005.

1984 also marked the completion of a customer classification study that proposed the restructuring of commercial and industrial customer rate classifications. 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 costs of service.

In October 1984 Randall Hardy became City Light's ninth superintendent. As a former BPA regional manager and director of the Pacific Northwest Utilities Conference Committee, Hardy brought organizational expertise and a knowledge of regional energy issues to the Utility.

In 1985 City Light continued to lay the groundwork for future rate stability by diversifying resources to reduce dependence on BPA, replacing the former two-step cost allocation process with a one-step process, and calculating a new cost baseline to reflect the regional energy surplus and a lowered marginal value of energy. A new Multifamily Conservation Program was also initiated. This was the first financial incentive program in Seattle for weatherizing multiple-unit dwellings.

The Citizens Rate Advisory Committee made recommendations, which were adopted by the Mayor and City Council, that $7 million in unanticipated revenues be returned to ratepayers through reduced November and December rates, and that a $4.5 million low-income assistance fund be established.

RESOURCE DIVERSIFICATION

City Light's distribution system began receiving power in 1986 from a more diverse mix of sources than ever before. New resources included the first energy from the High Ross Dam Agreement, Columbia Storage Power Exchange energy, the Rocky Brook small hydro plant, and the final Columbia Basin Irrigation Districts project. In addition, Units 55 and 56 at the Boundary Project were brought on line, bringing its total peak generating capacity to 1,055 MW. 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.

A major accomplishment contributing to City Light's financial stability in 1986 was the successful sale of a major refunding bond issue of nearly $250 million to advance refund 1981, 1982, and 1985 bonds. This was the largest bond issue in City Light history. As a result, the Utility's ratepayers would save approximately $1.4 million per year in debt service costs over the next 24 years.

In the rates area, the nonresidential customer classification system recommended in 1984 was implemented, as were time-of-day rates for large commercial and industrial customers. The average 9.5-percent rate increase implemented for 1986-87 was the lowest percentage increase since 1974.

Drought conditions prevailed through most of 1987. For City Light, heavily reliant upon its own hydroelectric resources, this could have meant a rate increase. However, prudent power purchases were made to keep City Light's reservoirs at acceptable levels, summer surplus power sales were curtailed, short-term energy exchanges were initiated with Puget Power, and market conditions kept purchased power prices low. The Utility, the Citizens Rate Advisory Committee, the Mayor, and the City Council jointly recommended that no rate increase be implemented for 1988.

The Energy Management Services Division formalized its four-point energy conservation policy in 1987. A policy designed to respond to the regional energy surplus that was expected to continue another 7-10 years, it included research into cost-efficient conservation technologies, education of customers on the value of energy efficiency, pilot programs to test conservation measures, and the use of codes incentives and advice to assure energy efficient design.

City Light and the City of Seattle Department of Construction and Land Use were presented a $910,000 BPA "Early Adopter" award for implementing an energy code equivalent to the Model Conservation Standards established by the Northwest Power Planning Council. It included the most aggressive commercial energy code in the region. The standards were expected to save 35 average megawatts of energy by the year 2005, an amount comparable to that provided by the Lucky Peak Project.

Winter bill prorating was introduced in December 1987. This new practice allocated winter rate charges more equitably to cover winter consumption.

City Light entered 1988 still in a drought condition, and sales of surplus power were $25 million below projections. The expected revenue shortfall was partially recovered through a $6.7 million internal cost cutting effort and a one-time refund from the State of public utility taxes paid on revenues that had been used for debt-service payments. However, after three years of stable rates, it became obvious that increased operating costs would make an adjustment in customer rates unavoidable. With guidance from the Citizens Rates Advisory Committee, new rates requiring a 4.4-percent overall increase were proposed by the Mayor, to go into effect June 1, 1989. This increase was well below the rate of inflation for the previous three years and represented roughly half the projected rate of inflation for the next two-year period.

The Lucky Peak Hydroelectric Project came on line in 1988, about $35 million under budget. This project is owned by four irrigation districts in Idaho; City Light buys the power output and directs the operation of the plant under a 50-year contract. In addition, City Light negotiated a contract with Pacific Gas and Electric which made it possible to send 200 MW south in the summer, when Southwest demand is greatest, in return for a like amount to meet City Light's winter heating loads.

The biggest news of 1988 was an August 31 outage that blacked out a 50-square-block area in downtown Seattle. This outage was caused by a vault fire that destroyed six feeder cables. Power was restored after an 80-hour round-the-clock effort by City Light crews.

FINANCIAL POLICY AND PRODUCTIVITY CHANGES

In 1989, following a directive from the Seattle City Council, a comprehensive review of City Light financial policies was conducted. It was carried out by a team of managers from City Light, the Office of Management and Budget and other key City departments, and the City Council. It included discussions with representatives of two major bond-rating agencies and other financial specialists.

The study concluded that City Light's financial position was sound and that current conditions allowed for some relaxation of financial planning standards. Consequently, the Utility's required debt service coverage ratio was reduced from 2.0 to 1.8. This meant a reduction in revenue requirements, which was immediately translated into a rate decrease of 2.4 percent that took effect January 1, 1990.

In 1989 City Light also concluded the first phase of a comprehensive productivity study. This included analysis of workloads, work force levels, retirement trends, and use of overtime. In addition, an in-depth Value of Customer Service survey and analysis was completed. In the conservation area, a major accomplishment was the opening of the Lighting Design Lab, a pioneering regional facility demonstrating state-of-the-art lighting products and promoting energy-efficient design.

A week before Christmas 1990, a blizzard hit the city, knocking out service for some 25,000 customers. Though the city was nearly paralyzed by snow, City Light crews had most customers back in service just one day later. The experience did emphasize the movement in the region toward energy deficit, however, as December 21 marked a new daily load record of 42,548 megawatt hours. This record was more than 1,500 megawatt hours above the old record set in February 1989. A new one-hour record demand of 2,056 megawatts was also set. Not all the weather news was bad, however. A good water year filled reservoirs and boosted sales of surplus power to a record $39 million.

NEW DIRECTIONS

City Light achieved a major success in the resource area with a 1991 agreement on the relicensing of the Skagit Hydroelectric Project. The unprecedented agreement with state, federal, tribal, and environmental groups called for a $100 million program to mitigate the environmental impact of the Utility's Skagit River dams. The agreement followed 14 years of studies and negotiations and paved the way for relicensing approval by the FERC.

In a 1991 reorganization, 10 management positions were eliminated and various new and restructured work units were created. Plans to invest approximately $5 million for remodeling service centers to accommodate a centralized customer service staff were initiated. A new voice messaging system significantly improved customer telephone access to City Light. And the average transmission and distribution crew size was reduced from seven to four; this move created 13 new crews, the equivalent of 97,000 labor hours.

1991 also saw the kickoff of an expanded Energy Smart Design Program, dramatically improving conservation among commercial customers. A joint effort with BPA, the program offered $5.6 million in rebates and other financial incentives to customers installing energy conservation measures in new or remodeled buildings.

The sale of bonds was an important financial event for City Light in 1991, as the Utility completed some innovative financing to fund its Capital Improvement Program. Adjustable rate revenue bonds in the amount of $45 million were issued, taking advantage of very low short-term interest rates.

In October of 1991, Superintendent Randall Hardy left City Light to head the Bonneville Power Administration. While the City conducted a national search for his replacement, Malcolm Macdonald, Deputy Superintendent for Electric Services and Construction, was appointed Acting Superintendent.

In the rates area, the City Council approved a one-month shift in the winter billing period, to become effective November 1, 1992. This change aligned City Light's higher rate period with its higher cost period (November through February) and was expected to generate a one-time revenue increase in 1992 of approximately $10 million. This change was equivalent to an average rate increase of about 3.3 percent.

Significant power projects completed in 1992 included the rebuilding of the Innis Arden residential underground distribution system, installation of 1,200 new streetlights in three neighborhoods to combat crime and improve safety, and the design phase for a new $21.6 million system control center.

In 1992 City Light also developed the most aggressive conservation program in its history, committing it to meeting a large part of expected future load growth with 100 average MW of conservation. In addition to the existing programs for commercial and industrial customers and for weatherization of multifamily units, two new programs began generating energy savings. These were the Home Water Savers Program, which distributed energy efficient shower heads to 193,000 customers, and the Long-Term Super Good Cents Program, which was designed to encourage contractors to build multifamily buildings that are more energy efficient than the state code.

In August of 1992 Roberta Palm Bradley was appointed Superintendent of City Light. Some of the changes she brought to the Utility included employee forums, an open line for the expression of employee concerns, and the involvement of work teams in interviewing and selecting their supervisors.

In the financial arena, 1992 was a challenging year. The winter of 1991-1992 brought a return of drought conditions. Sales of surplus power were again $25 million below projections. The revenue shortfall was partially recovered by a 10-percent across-the-board surcharge (5 percent for low-income customers) which was in effect from September 1992 through April 1993. However, the Utility recorded the first operating loss in its history, $14.1 million.

RESTRUCTURING AND CONTINUED DROUGHT

In 1993 City Light restructured itself into two operating branches and five support divisions. The Wholesale Branch was responsible for the acquisition and transmission of power and the Retail Branch grouped all functions directly serving customers. Four corporate goals were also adopted: customer satisfaction, employee satisfaction, safety, and financial health. These changes were implemented with the intent of making the Utility function more effectively.

The year began with an Inaugural Day windstorm, with winds clocked at 64 miles per hour at Seattle-Tacoma Airport. More than 100,000 City Light customers experienced power outages. Working around the clock, crews restored power to 75 percent in 24 hours and the rest within five days. The cost of the damage was $2.3 million. In October another major outage occurred, precipitated by a vault fire at Third Avenue and Cedar Street, just north of downtown. Power was lost in a 37-block area and it was estimated that 1,800 customers were affected. Repairs were completed within 80 hours, but the cost of the damage was $1 million.

1993 was no better than 1992 for precipitation, as drought conditions (the second worst in 115 years) continued in the Northwest. In contrast to the forecast that the Utility would receive $19.7 million in net nonfirm energy sales revenues, City Light actually had to buy a substantial amount of nonfirm energy to serve its load, resulting in a net expense of $11.5 million. The continuation of the 1992 rate surcharge into 1993 helped cover some of the unexpected costs, while an aggressive cost control effort trimmed $2.8 million from City Light's budget and reduced staffing by 29 positions. Nevertheless, the rate increase that took effect on May 1, 1993, included another drought-related surcharge of 4.05 percent in addition to the base rate increase of 12.6 percent. The average increase was actually 6.5 percent over the previous rates with the 10-percent surcharge. This general rate increase was the first since 1989.

While City Light was recognized in 1993 by the U.S. Department of Energy for having one of the nation's five best energy conservation programs, the Utility also began construction of a new $54 million small hydroelectric generating project on the South Fork of the Tolt River, east of Seattle.

Construction was also initiated on the new system control center, and a down payment was made on City Light's $34.4 million share of the Third Pacific Northwest-Southwest AC Intertie. This intertie allows power exchanges and sales to the Southwest.

For the second year in a row, City Light experienced a net operating loss--$10.1 million. Nevertheless, the City Council removed the drought surcharge of 4.05 percent on rates as of November 1, because it appeared that weather conditions had improved the reservoir picture. The Utility also sold the largest bond issue in its history, $453 million, the majority of which was used to defease all pre-1992 parity bonds. The sale represented a significant savings of future interest costs on City Light's debt.

As it turned out, weather conditions did not continue to improve into 1994, and the City Council approved another rate surcharge of 8.9 percent to alleviate yet another shortfall in nonfirm energy sales revenue. That surcharge took effect on June 1, 1994, and remained in effect through February 1995. The surcharge allowed the Utility to end 1994 with a small positive net income amount of $271,000.

As a result of a 1994 R. W. Beck study of City Light’s infrastructure, a strategic approach for improvements was initiated. Phase 1, to be completed by the end of 1995, was to provide a draft framework, identifying by plant element a six-year infrastructure requirement plan and a corresponding six-year financial requirement plan. Phase 2, to be completed in mid-1996, would incorporate the Utility’s business drivers (such as the Comprehensive Business Plan, the Energy Resources Strategy, and the Financial Forecast).

City Light's energy conservation program earned recognition in 1994 as one of five efforts nationwide with exemplary demand side management programs. New contracts signed in 1994 exceeded long-range goals by 37 percent and cumulative savings through that year totaled 49 megawatts.

Roberta Palm Bradley resigned as superintendent in the summer of 1994, and in late 1994 Gary Zarker was appointed Superintendent of City Light. Among the changes he brought to the Utility was a reorganization into five branches: Executive, Wholesale, Electrical Services, Customer Services, and Finance and Administration. A new Account Executive office in the Customer Services Branch signaled the intention of being more customer responsive.

TOWARD A NEW COMPETITIVE ENVIRONMENT

Since 1992 legislation enacted by the U.S. Congress and regulatory responses to this legislation at the federal and local levels have significantly accelerated the pace of change in the electric power industry. The National Energy Policy Act of 1992 required that the transmission facilities of public and private electric utilities be made available on an equitable basis to all parties wishing to use those facilities. The intention of this Act was to create a fully competitive wholesale market for generation. In 1995 the FERC issued a Notice of Proposed Rule-Making in which a number of changes in regulatory requirements were proposed to implement the mandates of the 1992 Act. In various states, the regulatory bodies with jurisdiction over electric utilities initiated discussions regarding retail wheeling (the requirement that retail utilities provide access to competing suppliers of electric power over their own transmission and distribution systems for the purpose of serving their retail customers). The Washington State Utilities and Transportation Commission issued a Notice of Inquiry requesting comments from interested parties on these issues. At the same time, the entry of new suppliers into the energy market, particularly nonutility generators, and low prices of fossil fuels, especially natural gas, resulted in the availability of electric power in the Western region at unusually low prices. City Light filed comments in response to both the Notice of Proposed Rule-Making and the Notice of Inquiry.

New rates for 1995 and 1996 were adopted in early 1995. The 1995 increase of 5.7 percent replaced the 8.9-percent surcharge noted above. Though counted as an increase over base rates without the surcharge, the system average rate actually decreased by 2.9 percent in comparison to the rates with a surcharge. The principal reasons for the increase were low expected nonfirm power sales and BPA power and wheeling rate increases to become effective October 1. In fact, after three years of drought and low streamflows, the region had bountiful rainfall in 1995, with output at City Light's hydroelectric plants far above normal. Surplus power in 1995 brought in revenues of more than $26 million, and financial results for the year were the best since 1990. The Utility's debt service coverage ratio was higher than the target used in setting the 1995-1996 rates. The 1996 rate increase of 5.3 percent, approved by the City Council in 1995, was nevertheless implemented. This increase was required to cover a significant increase in the Department's debt service, which was related to normal replacements and upgrades, as well as new projects coming on line.

Immediately after a $60 million bond sale in September 1995, City Light offered Washington State residents the opportunity to invest in revenue bonds in denominations of $500. These mini-bonds were well received and yielded proceeds of $2.3 million. Both issues were used to finance a portion of the capital improvement and conservation programs. Culminating a process which began in 1977, when the license for the Skagit hydroelectric projects expired, the FERC issued a May 1995 order renewing the license and accepting most of the terms of the Skagit Settlement Agreement of 1991. This settlement, one of the largest and most complex of its kind in the U.S., provides approximately $100 million over the next 30 years for fish and wildlife, environmental, cultural, and recreational improvements.

A new System Control Center opened in 1995 to control City Light's generating facilities more efficiently, improve wholesale power market trading, and more quickly and safely restore service in emergencies and disasters. In addition, using an existing 30-year-old Seattle Water Department reservoir, a new hydro project was brought on line in 1995. This is on the South Fork of the Tolt River and has a peak generating capacity of 16.8 megawatts.

The move into new headquarters at Key Tower in 1995 allowed City Light to consolidate 900 employees into one building closer to other City government offices, and to avoid substantial repairs to the old building, as well as the expense of leasing additional office space.

Amid continuing changes within the industry, City Light continued to move aggressively to preserve the benefits of public power and take advantage of a new and competitive future. In 1995 City Light was one of only 12 utilities nationwide joining U.S. Energy Secretary Hazel O'Leary in signing the Global Climate challenge, a voluntary effort to reduce global warming through conservation, efficiency improvements, and environmental protection measures.

In 1996 City Light experienced its best water year in four decades. High net income allowed financing of more capital requirements (nearly half) from current revenue and less from debt, as nearly $80 million in new plant assets were added during the year. Borrowings for the year were less than half those that had been planned, with lower debt representing lower rates than previously expected for the future. In addition to the favorable water conditions, the local economy improved, resulting in a 4.5-percent increase in sales of electricity over 1995. In contrast to years past when commercial growth led sales increases, 1996 sales growth was led by residential accounts at 5.1 percent.

In 1996 the FERC issued its Order 888, which requires transmission owners to offer transmission services to other companies under the same terms and conditions that they offer it to themselves. It also encourages the formation of ISOs to provide open access to the transmission system under a grid-wide tariff that would apply to all eligible users. This Order significantly expanded the potential for wholesale competition in the provision of electricity. In this growing competitive arena, City Light played an active role in the Comprehensive Review of the Northwest Energy System, which recommended that the four Northwest states restructure their retail electric markets by July of 1998, in organizations charged with improving the security of the West Coast transmission grid, and in the attempted formation of an independent grid operator (IndeGO) for the Northwest transmission grid.

In order to further improve its competitive position, City Light took advantage of the opportunity to amend its contract with BPA. Prior terms of the contract guaranteed City Light an entitlement to whatever firm power it needed to fill in the gap between its customer load and its firm resources. As of August 1, 1996, however, City Light agreed to buy 195 average MW per year for five years from BPA, well below its prior entitlement of about 260 MW; it supplied additional power required either from its own nonfirm resources or via purchases on the wholesale market, under the assumption that these costs would be lower than BPA rates. The amended contract allowed the Department to displace portions of the contracted amount of BPA purchases in increasing amounts from 1997 through September 2001, subject to payment of an availability charge. As part of the amendment process, BPA unbundled its rates, separating transmission from power charges and making transmission charges more flexible. City Light planned to take advantage of the change to avoid paying wheeling costs for BPA firm power, resulting in annual savings of $2.3 million.

Other improvements during 1996 included work on a new Consolidated Customer Service System and a new financial management system, and development of a Work Management System to promote greater efficiency and responsiveness to customer needs. City Light and Seattle Public Utilities (which combined the City’s water, solid waste, and drainage and wastewater utilities) began collaboration to implement a new consolidated Call Center, and formed the Conservation Cluster Group in order to provide joint program delivery and reduce duplicative contacts with customers.

In the preparation of 1997-1998 rates 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. They also allowed the Department to offer an experimental market-based rate schedule (Schedule 44) to its largest customers. Under the new rate schedule, the energy portion of standard rates was replaced with market prices for electricity. The schedule, which was optional for customers served under Schedule 42 (High Demand General Service), went into effect October 1, 1996. Two customers (one with two meters) chose the optional schedule in October, and one more came on line in November. Unfortunately, market prices, which had been very low prior to implementation of the new schedule, increased significantly by the end of 1996, so customers on the optional rate paid nearly

10 percent more for the energy portion of their bill (during the last quarter of 1996) than they would have had they remained on City Light's standard rates.

The experimental Rate Schedule 44 became a continuing optional schedule for High Demand General Service customers when new 1997 rates went into effect. Over the entire experimental period, which extended from October 1, 1996, through, March 5, 1997, the four meters on this schedule realized a 5-percent savings on the energy portion of their bills, in comparison to the Utility's standard High Demand General Service rates (Schedule 42). They paid more than they would have under standard rates at the end of 1996, but market energy prices decreased sufficiently in the early part of 1997 for an overall savings to these customers during the six-month experimental period.[9] Nevertheless, two customers decided to return to the standard rate schedule at the end of the experimental period. The other customer, with two meters, returned one of its meters to the standard rate in October 1997, and the other in September 1998. This customer paid more for market-indexed energy that it would have under City Light's standard rate schedule. The optional rate schedule (now called Variable Rate General Service-Schedule VRC for City customers, or Schedule VRT for Tukwila customers) continues to be available.

INDUSTRY RESTRUCTURING CONTINUES

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. In Washington, several utilities had experimented with pilot retail access programs and many (including Seattle City Light) offered some form of market-based rates to large customers. 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.

City Light began positioning itself in 1997 to take advantage of and learn from experience in California's open market, by bidding for and winning two contracts to supply power to California consumers. As of April 1, 1998, the Department began supplying electricity to 28 Nordstrom stores throughout California. In May 1998 the Department also began supplying power to the Association of Bay Area Governments, an aggregator of power for 104 local governments and 30 service districts clustered around San Francisco Bay. These contracts allowed City Light to gain experience in establishing state-of-the-art systems for remote metering and load management, as well as experience with both fixed rates and rates tied to the Dow Jones California-Oregon Border index for remote customers. They also demonstrated that City Light had the technical and business know-how to compete in new markets.

[9] Geist, Arlene. *History and Financial Impacts of Seattle City Light's Market Based Rate (Schedule 44), Seattle City Light, Rates Unit Paper, January 1999.*

Other 1997-1998 efforts to keep the Utility in a good competitive position included the initiation of a comprehensive 12-year rehabilitation of Boundary Dam, completion of a similar rehabilitation of the Skagit River plants, and completion of a 10-year plan for improving downtown Seattle's distribution network. City Light's focus on projects of the highest strategic and operational value resulted in savings of nearly $70 million and was expected to help the Utility trim another $150 million from capital spending by the year 2002. In 1997 a continuation of the excellent water conditions that began in 1996 allowed the Utility to fund a substantial portion of capital expenditures from operating revenues and reduce its debt issuance once again to levels below those which had been forecasted. Water conditions in 1998, however, were far worse than normal and income from nonfirm energy sales was negative; nevertheless debt issuance was still somewhat lower than forecasted, reflecting the Department's continued effort to carry out its capital program more efficiently and keep future rates low.

New rates went into effect March 6, 1997. Though the system average rate decreased by 0.4 percent, average changes for rate classes varied from –4.8 percent for High Demand-Standard General Service to +1.5 percent for Residential and Medium General Service-Industrial. Standard and Industrial subclasses in the Large General Service and High Demand General Service classes were merged into one class, completing a reclassification process for these two classes that began in 1984. New seasonal rate definitions were implemented to more accurately reflect the pattern of market energy prices; the "summer" billing period was defined as March through August, while the "winter" billing period was defined as September through February. On July 1, 1997, a flat customer charge replaced the minimum monthly charge for Residential customers, and their first-block energy price was reduced.

The system average rate decreased again, by 0.6 percent, with new rates that went into effect March 1, 1998. As in 1997, however, average changes for classes varied, from –4.3 percent for Small General Service to +1.5 percent for Residential and Medium General Service-Industrial. In both years, the variation in average rate changes among classes was the result of two principal influences: updating of the marginal costs of energy to reflect market conditions and the environmental impact of energy use; and unbundling of City Light's costs into functional areas, each with their own functional allocator.

Reasons for the decrease in overall rates for the 1997-1998 period included: expected continued growth in energy sales which would provide additional revenue; limitation of the increase in power costs via the 1996 agreement with BPA and more reliance on the spot market; reductions in the 1997-1998 O&M budget; and lower capital spending and more financing of the CIP from current revenues (as discussed above), which limited the increase in the debt service coverage requirement. The Utility's continuing effort to control its costs led to the 1998 decision to maintain rates at the 1998 level with no change through February 2000.

City Light continued its commitment in the area of conservation by exceeding targeted savings in both 1997 and 1998. Some of the conservation programs available to customers included: Energy Smart Design (conservation incentives for businesses), LaundryWise and WashWise (promotion of efficient clothes washers in businesses and homes), Utility Cost Watch (energy management for customers with large combined utility costs), Climate Wise Partners (companies and the City in partnership to reduce greenhouse gas emissions), the Built Smart Program (incentives for new resource-efficient apartments), LightWise (promotion of low priced, high quality compact fluorescent lights), and the Water Heater Rebate Program (to reward purchasers of energy efficient electric water heaters). Continuing its long tradition in environmental protection, the Department also completed purchases of 6,300 acres of Skagit and Nooksack River salmon and wildlife habitat, earning the 1998 "Public Service Award" from The Nature Conservancy of Washington.

Anticipating that industry restructuring would give customers new options, City Light initiated a series of customer focus groups and neighborhood workshops in 1997 and conducted a statewide poll in November to explore issues and public attitudes. While the majority of the Utility's citizen-owners expressed satisfaction with City Light rates and reliability, many desired a greater array of services and more direct assistance. One of the results of the effort to listen to customers was the Customer Choice 2000 project. This project involved work teams from all sectors of the Utility who analyzed potential ways to give customers meaningful choices, both for rates and for innovative service options. Choices that were considered feasible, equitable to nonparticipating customers, and likely to provide actual value to customers were to be implemented over the next few years. Such choices were anticipated to include, for example, contract rates, extension of the market-indexed rate option to more customers, a new renewables rate, and a power quality monitoring and diagnostics service. Large, unexpected changes in wholesale markets in 2000-2001, however, interfered with the full realization of these plans.

With Y2K (Year 2000) and its attendant technology problems on the near horizon, City Light joined with all other City departments in the Summit Project, a major information technology and business process change project that was designed to replace the City's financial management system (SFMS). The decision to go ahead with this project was made in June 1997. The system was implemented in 1999.

In both 1997 and 1998, members of the Washington State Legislature proposed several bills related to restructuring of the electric industry. Two of these, ESSHB 2831 (the "unbundled costs" bill) and ESSB 6560 (the "customer service" bill), passed in early 1998. These bills required the state's larger utilities to provide a variety of information about costs, service quality, reliability, rates, service territory agreements, etc., to the legislature. City Light participated actively in both provision of the information and development of its presentation in forums attended by representatives of utilities, energy marketers, government agencies, and other interested parties. Studies carried out in response to the bills showed that Washington's average 1996 (the last year for which complete data were available) rate of 4.5¢/kWh was 65 percent of the national average rate of 6.9¢/kWh; and that City Light's rate-year 1998 average forecasted cost of 3.92¢/kWh was 90 percent of the average of all 13 reporting utilities in Washington, which was 4.34¢/kWh. (Note: The actual calendar year 1998 average rate was 3.87¢/kWh.)

In addition to the reorganization of the Utility's five branches and the creation of External Affairs and Strategic Planning groups, a Power Marketing group, was created which separated the buying and selling of market power from the scheduling of power (which continues to be carried out by the System Control Center). In 1999 this group exceeded its goals for nonfirm power sales.

In 1999 City Council approved the first City Light rate increases since 1996, initially raising average system rates 3.2 percent, still well below local consumer price index growth. A second increase of 3 percent was also approved effective March 1, 2002. This new multiyear rate structure was intended to support City Light's financial requirements through 2002 with an attempt to establish predictability in a volatile power market.

With the rates effective December 1999, separate, higher rates were created for suburban areas (outside the Seattle City limits), and City Light signed 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.

City Light benefited from improved water conditions and effective cost controls in 1999 to record a net income of $7.7 million. The debt service coverage target of 1.80, representing the average ratio of the past decade, was exceeded.

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.

FACING AN ENERGY CRISIS

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 a prior decision 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. The FERC refused to police the western energy market where the prices were neither just nor reasonable. In addition, in keeping with City Light's policy of "Fish First," power managers maintained minimum stream flows to protect salmon habitats along the Skagit River, saving one of the strongest runs of endangered King Salmon in many years. The Nisqually Earthquake of February 2001 had no effect on powerhouses, generation stations, and dams, but the distribution system suffered outages affecting 19,000 customers.

In October 2000 Ordinance 120111 was passed to protect existing customers from the very high costs of providing service to new large loads. In addition to paying for installation, New Large Load (NLL) customers are offered two options for purchasing power: Schedule VRC (discussed earlier), or a "tailored power delivery package." Under the latter option, the Utility's obligation to serve does not require it to use its historically low-cost energy to serve NLLs. New large loads have not materialized as expected, but some facilities that can eventually house high-density energy loads have been built and others are on hold.

Implementation of the Strategic Resources Plan went forward. 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 City Light began a new contract with BPA for a 4.6676-percent "slice" of the power generated by BPA, as well as the purchase of a fixed "block" of power from BPA. 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 can meet its load in almost all months under poor water conditions with resources it controls. This protects against the effects of future drought and also produces surpluses in good water conditions that can be sold in the marketplace. Combined with more conservative financial policies, the result is that the Utility will pay back its energy crisis debt more quickly and move to lower and more stable rates in the future.

City Council approved raising rates in January, March, and July 2001 to pass through a portion of high purchased power costs, as well as passing through to ratepayers an additional increase in BPA costs in October 2001. City Light's customers rallied to the Utility's call for curtailment and conservation of an additional 10 percent 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 also deferred from recognition in 2001 to 2002-2004 ($100 million each year). Even with the deferral, the net loss for the year was a new high, $73.3 million, and the Department incurred $182 million of short-term debt that was repaid in early 2003.

In November 2001 the rains returned and steady precipitation continued through the winter, promising an above-normal water year for 2002. While water conditions and snow accumulations in all watersheds were more than 100 percent of normal in 2002, 2003 (to mid-June) have fallen below normal: about 78 percent of normal water at Skagit and Cedar/Tolt, and 91 percent of normal water at Boundary.

Three rate changes took place in 2002 and two occurred in early 2003. In 2002, the second step of downtown network rate increases originally adopted in 1999 to bring network rates closer to cost of service was implemented. In addition, a BPA pass-through in April decreased rates by about one percent, and the price of residential third-block energy consumption was reduced at the same time that the level of consumption at which the third-block rates begin to apply was raised. In the first half of 2003, another BPA pass-through raised rates about one percent, and higher rates were adopted for Tukwila customers as the result of a new franchise agreement.

In 2002 the Department incurred $125 million more short-term debt, to be repaid in November 2003, to cover cash shortfalls, in spite of cost cutting totaling $30 million. After this debt is paid off, Seattle City Light expects rapid financial recovery, such that the new financial policies can take effect and rates can be decreased in 2005.

Even though City Light faced, and still faces, significant financial challenges in 2002-2003, non-financial events of note in 2002 included the formation of Northwest Power Works by City Light and other utilities in the Pacific Northwest to counter FERC’s push to divide the nation’s electrical industry into a few large market regions, all governed by the same market rules. By year-end, the organization had grown into an extensive coalition of local and national consumer groups, as well as utility and state regulators primarily located in the west and southeast.

City Light’s conservation programs celebrated their 25th anniversary in 2002. In order to satisfy its mandate that all load growth be supplied by conservation and renewable resources, the Utility increased its energy conservation commitment from 6 aMW/year to 9 aMW/year. In addition, a new agreement was signed with BPA whereby that agency would pay City Light for energy savings. BPA funding amounted to $16.7 million in 2002 and is expected to reach approximately $10 million in 2003. Seven of the 9 aMW saved in 2002 came from the commercial sector; City Light staff provided technical assistance and retrofits, and 85 percent of the larger customers were managing their energy use with the help of the Meter Watch program by year-end.

The Department also initiated its Green Power program in 2002. Under this program, customers can voluntarily contribute funds that are used for renewable energy projects, principally solar. Four solar projects in schools and public buildings were in place by the end of 2002. City Light also participates in sustainable building design through its Leadership in Energy and Environmental Design (LEED) Incentive Program and participation in the LEED Renewable Energy Credit and Built Green Incentive programs.

In 2002 City government officials studied the results of the energy crisis and initiated an effort to protect customers from similar events in the future. The Mayor appointed a blue-ribbon panel to look at governance of the Utility, and this group made recommendations that included the establishment of a City Light Advisory Board. A six-member Board of technical experts with electric utility and business experience was appointed by the Mayor and City Council in early 2003, with a mandate to provide city officials and City Light with independent outside advice in the areas of risk management, finance, and power markets.

OVERVIEW: LOAD GROWTH AND RATE CHANGES

City Light's service territory's population has been relatively stable, with growth of 1.4 percent in the five-year period 1998-2002. In the same five years, the demand for electricity decreased 5.1 percent. Change in demand has been uneven in recent years. In 1991 and 1992, warmer than normal weather and sluggish employment growth in the service area resulted in decreased consumption. In 1993 consumption increased by about 1.7 percent over that of 1992, but then it decreased again in 1994 and 1995. The largest increase in the last five years occurred between 1995 and 1996 (4.5 percent). This was primarily the result of weather conditions, but also reflected an underlying growth trend due to improving economic conditions in the Seattle area. Load was expected to grow slowly over the 1999-2002 period, for a total increase over the four-year period of 3.5-4.0 percent.

However, because of the impact of drought and extraordinarily high market prices in 2000 and 2001, the Utility sought to lower system load in order to control its power costs. In addition, the energy crisis coincided with, and contributed to, a downturn in the economy (e.g., the dot.com stock crash, airline industry failures, travel and tourism decline, etc.). Price response to higher electricity rates also contributed to the 2001 decline in load.

The 2000 load forecast reflected the expectation of continued strong economic growth. This view was bolstered by a building boom in the service area, including large luxury hotels, new office buildings, and energy-intensive facilities for telecommunications, research, and biotechnology firms. Instead of growing by the approximately 20 aMW that were forecast, however, system load for 2000 remained about the same level as in 1999. By the end of 2001, load had fallen back to the level it was at in 1994.

The Utility will continue to face load uncertainty. No one knows when local recovery from the recession will begin and how long it will be before the economy reaches its previous level. The rate at which currently vacant office space and space wired for dense electronics becomes occupied depends on the strength of the recovery

The table below lists each general rate change over the last 32 years for City Light. (Note: A change in the definition of the winter rate season, which took effect in November 1992, increased the average customer rate in that year only by 3.3 percent.)

Average Rate Change by Year (percentages)	
Year	Average Rate Increase (Decrease)
1971	7.0
1974	8.7
1977	15.0
1980	40.7
1982	37.3
1984	30.0
1986	9.5
1989	4.4
1990	(2.4)
1993	12.6
1995	5.7
1996	5.3
1997	(0.4)
1998	(0.6)
2000	3.2
2001	56.2
2002	(0.6)
2003	1.4

A Rate Maker's Who's Who

KEY PLAYERS IN THE RATE REVIEW PROCESS

Mayor's Office

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

Tim Ceis, Deputy Mayor

Andrew Lofton, Chief of Departmental Operations

City Council

Peter Steinbrueck, President. He conducts City Council hearings and makes committee assignments.

Heidi Wills, Chair, Energy and Environmental Policy Committee. She chairs the Council's four-member Committee, which reviews Utility recommendations for the Council.

Jim Compton (Vice Chair), **Margaret Pageler**, **Nick Licata**, **Richard Conlin,** and **Jan Drago**, Councilmembers. These are members of the Energy and Environmental Policy Committee.

Benjamin Noble, William Alves, and **Carol Butler**, City Council Staff. Legislative Analysts assigned to Utility issues.

Finance Division

Dwight Dively, Director. He is responsible for the city's accounting and treasury functions, as well as debt management.

City Budget Office

Susan Cole, Team Lead. She supervises review of City Light's budget and rate proposals and serves as liaison with the Mayor's Office and City Council.

Thomas Dunlap, Strategic Advisor. He reviews City Light's budget and rate proposals.

Seattle City Light

Jim Ritch, Acting Superintendent. As acting superintendent of the Utility, he approves final recommendations before they are sent to the Mayor.

Dana Backiel, Deputy Superintendent, Generation Branch. She oversees all the engineering, operations, and maintenance functions associated with generating electricity from City Light's owned plants.

Jesse Krail, Deputy Superintendent, Distribution Branch. He oversees the divisions charged with design, construction, operation, and maintenance of the Utility's transmission and distribution facilities.

Joan Walters, Deputy Superintendent, Customer Services Branch. She oversees all aspects of customer relationship, billing, and account maintenance, as well as City Light's energy conservation activities.

Mike Sinowitz, Deputy Superintendent, Power Management Branch. He oversees the System Control Center, as well as management of the Utility's power budget, resource portfolio, power marketing, risk management, and wholesale contracts.

Carol Everson, Acting Deputy Superintendent, Finance and Administration. She oversees the Utility's financial, information technology, and facilities management divisions.

Joe McGovern, Acting Director, Finance Division. He is ultimately responsible for the budget, financial plans, accounting, and rate reports produced by the Finance Division.

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

Paula Laschober, Acting Financial Planning Unit Manager. She directs preparation of cost of service and rate design reports.

Garry Crane, Senior Economist. He analyses cost of service and cost allocation issues, and prepares the COSACAR (Cost of Service and Cost Allocation Report).

Robert Bartley and **Arlene Geist**, Economists. They analyze rate issues and help prepare reports on cost of service and rate design, including the Rate Design Report.

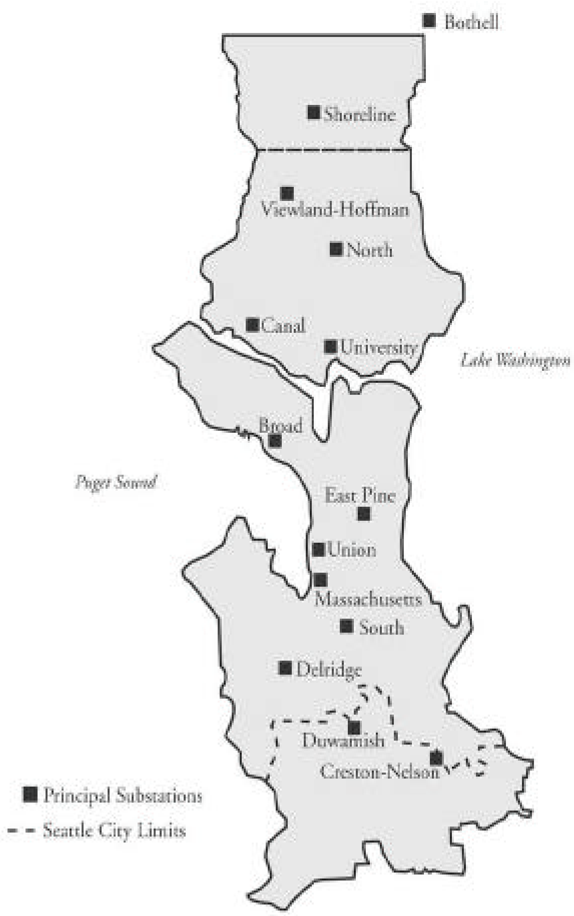
Brud Easton, Principal Economist. He coordinates the revenue requirements analysis and preparation of the long-range financial plan.

Judy Blinder, Senior Economist. She analyzes issues related to revenue requirements and financial planning, and prepares reports in these areas.

Nick Dreyer, Energy Research and Evaluation Analyst. He prepares load data and other data important for cost of service and rates analyses.

Seattle City Light

Service Area



Power Resources

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