

Rates Advisory Committee

**Seattle
City Light**



**Guide to
RATE MAKING**

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***The Review Trail --
Where You Fit Into the
Rate-Making Process***

"Democracy is the art of thinking independently together."

Alexander Meiklejohn

Seattle City Ordinance 123032, passed in July 2009, established a Rates Advisory Committee (RAC) and defined its role and composition. Some of its pertinent parts are:

Section 2. Establishment. An ad hoc City Light Department (Department) Rates Advisory Committee (RAC) is established that will be convened each time the Mayor proposes changes to the Department's base rates,

The RAC shall consist of nine members drawn from among the Department's customers, five of whom shall be nominated by the Mayor and four by the chair of the City Council Committee responsible for oversight of the Department (Chair), all of whom shall be confirmed by the City Council.

The Chair shall nominate at least one member from each of the residential and small commercial customer groups. The Mayor shall nominate at least one member each from the large commercial or industrial, network, and suburban customer groups.

Section 3. Organization. The RAC may adopt rules for its own procedures, including quorum requirements and the frequency of meetings. The RAC shall select a member to act as the principle liaison with the Mayor and the City Council.

Section 4. Mission. The RAC shall provide advice to the Mayor and the City Council solely on issues relating to the adequacy and appropriateness of the Department's revenue requirements and rate design proposals, and other rate-related issues identified by the Mayor or the City Council during the RAC's tenure.

Section 5. Reporting. The RAC shall keep a written record of its proceedings which shall be a public record. The RAC shall report its findings and recommendations in writing to the Mayor and the Council at least two weeks prior to action on the rate legislation by the responsible Council Committee. The RAC shall endeavor to find consensus, but significant disagreements on findings or recommendations should be noted in its written report.

There are three phases to the rate making process: revenue requirement, cost allocation and rate design. During the current rates process, the views of the Seattle City Light (City Light) Rates Advisory Committee (RAC) are being solicited for the first phase in the rate setting process. In this phase, City Light establishes a financial strategy for the near future as part of a longer term financial strategy and forecast revenue requirements consistent with that financial strategy. . Members have an opportunity to express their views on this matter prior to the adoption of a rates ordinance by the City Council. City Light is not proposing any changes to the the existing rate structure or to cost allocation. The last comprehensive rate review took place in 2006 and established rates for 2007 and 2008¹, and the cost allocation and rate design established in that process and currently in effect will be retained for 2010.

¹ Some suburban rates have changed since then to reflect special undergrounding projects there which those customers will pay for as well as reflecting

The RAC will be providing recommendations related to a rate proposal prepared by City Light and submitted by the Mayor for Council consideration as part of the 2010 budget process. The proposal will be considered for approval by the Council during late November, as part of the 2010 budget approval process.

During this process, the Rates Advisory Committee may:

- * Review the 2010 rates proposal and supporting materials;
- * Identify issues for group discussion, request materials and information from City Light staff for response, strive for consensus positions on the significant issues related to City Light rates;
- * Respond to requests by City Council staff;
- * Write letters to City or Utility officials about areas of special concern;
- * Provide a formal report of its findings;
- * Testify at public hearings held by the City Council before it reaches a decision.

City Council and RAC review of the Mayor's 2010 rates proposal will occur concurrently from September to November. The Rates Advisory Committee may ask the City Council to consider revisions to the proposal.

After Council review of the Mayor's proposal, and consideration of the RAC's views, a final decision on rates and the adoption of a rates ordinance follows. Nothing is "final" until the Council passes the rates ordinance and the new rates become law.

The Committee may elect to continue meeting for a period after the Council adopts a new rates ordinance. This time could be used to identify topics to be addressed during a future rates process.

some changes in payments requested by suburban cities which have franchise agreements with City Light. Changes in suburban rates for this latter reason were approved by City Council.





***Financial Policies and
Revenue Requirements***

***Document: Revenue
Requirements Analysis***

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

City Council Resolution 30933
November, 2006

RELATIONSHIP BETWEEN FINANCIAL POLICIES AND THE REVENUE REQUIREMENT

The Revenue Requirement is the amount of funding that the utility needs to cover the cost of its operations, pay for debt service and capital expenditures, and to otherwise ensure a stable ongoing financial profile for the utility. Financial policies affect the Revenue Requirement by specifying the coverage for debt service included in the Revenue Requirement, which affects the portion of capital expenditure funding that will be covered by operating cash flow versus bonds. This, in turn, determines over time the portion of the utility's total capitalization that is debt funded. The financial policies also specify minimum cash balances to be maintained by the utility.

FINANCIAL POLICIES

In 2005 (Resolution 30761), the City Council adopted revised financial policies it deemed necessary "to restore the financial strength of City Light and recover the rate advantages of public power". Some of the findings and the financial guidelines in this Resolution are:

Section 1. Finding. The Council finds that changes in City Light's financial policies are required at this time in order to (1) maintain the cash reserves available for unanticipated financial circumstances and (2) reduce the level of debt outstanding.

Section 2. Rate Setting Guideline. It is the policy of the City of Seattle to set electric rates at levels that will ensure that first and second lien debt shall achieve a debt coverage ratio of 2.0.

It is also the policy of the City of Seattle that there shall be positive net revenue available to fund capital requirements in each calendar year at a probability of at least 95%, taking into account the variability of cash flows resulting from the uncertainty of water conditions, market prices and system load.

For purposes of calculating the information to be reported, net revenue available to fund capital requirements is defined as the amount of revenue remaining after payment of operating and maintenance costs, principal and interest on outstanding debt, taxes, deposits to the Bond Reserve Fund or the Contingency Fund and all other current obligations.

Any rate proposal shall include rates sufficient to attain both of these rate setting guidelines.

In the event that City Light's financial performance exceeds the 2.0 target, every effort will be made to dedicate some share of the additional revenues to increasing the cash funding of the capital program or defeasing outstanding debt.

Section 3. Contingency Reserve Account. A Contingency Reserve Account will be established in the Light Fund. Once available, funds from the former Bond Reserve Account in the amount of \$25 million shall be immediately deposited in the Contingency Reserve Account.

Council directs that the remaining balance of the former Bond Reserve Account be used for additional debt reduction, by either defeasing outstanding debt or reducing the amount of debt to be issued in the next ten years.

Funds in the Contingency Reserve Account shall be used to pay for extraordinary costs associated with the operation of the electrical system. City Light shall make all prudent reductions in operating and capital expenditures and shall make all prudent increases in borrowing for the capital program before requesting access to the Contingency Reserve Account. No transfer or expenditure from the Contingency Reserve Account shall be made except as authorized by ordinance.

Within two years of the withdrawal of funds from the Account, available net revenues shall be deposited in the Account until the targeted balance of \$25 million is restored.

Section 4. Operating Cash Balances. In addition to funds in the Contingency Reserve Account, City Light shall maintain sufficient operating cash balance in the Light Fund to absorb fluctuations in its operating cash flow. In its rate proposals, City Light shall target a minimum month-end operating cash balance of \$30 million.

Section 5. Debt-to-Capitalization Ratio. City Light shall set electric rates to achieve a debt-to-capitalization ratio of 60% by year-end 2010. The debt-to-capitalization ratio is the total amount of debt outstanding divided by the sum of accumulated equity and debt outstanding. For rate periods beginning on or before January 1, 2006, each rate proposal shall include a multiyear financial forecast indicating the expected debt-to-capitalization ratio on December 31 of each year 2006 through 2011. In the projection of the annual operating and capital expenditures, City Light shall base these financial forecasts upon plans and assumptions incorporating prudent and cost-effective management. The forecasts shall also reflect the effects of an Asset Management Program for the capital program.

Section 6. Asset Management Program. City Light shall implement a comprehensive Asset Management Program or its equivalent no later than January 1, 2007. The changes in the capital program that result from instituting this program shall be quantified and presented with each City Light rate proposal and budget after that date.

Section 7. Performance Report. City Light shall annually report to ratepayers on its performance. The performance measures shall be developed with input from ratepayers, the Council, and the Mayor.

Section 8. Resource Requirement. City Light shall continue to use a 95% coverage policy in planning to serve customer load. City Light shall secure sufficient long-term power resources so there shall be a 95% probability that City Light will have sufficient power to meet its customer load in any given year and that City Light's financial risk of

having to buy power on the spot market during a period when prices are escalating will be reduced.

Ordinance 121812, passed by City Council on May 5, 2005 and signed by the Mayor on May 26, 2005 modifies the Contingency Fund provision to get the \$25 million contingency reserve fund from another source.

This ordinance authorizes City Light to withdraw the funds in the bond reserve and meet the reserve requirement with a surety bond. On the effective date of the surety bond, all cash from the reserve fund was deposited in the Light Fund, \$25 million of which established a Contingency Reserve Fund; the remainder of the funds were to be used for debt reduction, either by use for capital expenditures to avoid issuance of future debt or by defeasance of current outstanding debt.

Proposed retail rates are adjusted so that the revenue requirements derived from retail sales satisfy the above financial policies.

Effect of Continuing the Existing Financial Policies on the 2010 Revenue Requirement

The existing financial policies will require a higher revenue requirement in 2010 than might be required under an alternative set of financial policies. It is particularly the current requirement of collecting 2.0 times debt service coverage that results in this. The current 2.0 times debt service coverage has the following benefits:

1. Provides cash funding for capital expenditures that avoid the need for additional borrowing. As a result, the utility's debt to capitalization decreases over time.
2. The operation of the two constraints of:
 - a. setting rates to provide for debt coverage ratio of 2.0, along with
 - b. the requirement that there shall be positive net revenue available to fund capital requirements in each calendar year at a probability of at least 95% (taking into account the variability of cash flows resulting from the uncertainty of water conditions, market prices and system load)

together serve to reduce the likelihood of having to make significant reductions in utility services in the event that planned revenues from surplus power sales do not materialize as budgeted.

For 2010, the Mayor and utility will propose changes to the financial policies that have dual benefits: (1) reducing the 2010 revenue requirement by lowering the debt service coverage requirement, while (2) continuing to reduce the likelihood of having to make significant reductions in utility services in the event of uncertainty of water conditions, market prices and system load.

The change to the financial policies proposed involves reducing the debt service coverage target from 2.0 to 1.6 in 2010, 1.7 in 2011, and 1.8 in 2012, while adding an automatic wholesale revenue adjustment mechanism to adjust rates prospectively to reflect volatility in wholesale revenues. This proposal is discussed in significant detail in a separate document.

REVENUE REQUIREMENTS

The Department must 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 process that involves staff from throughout several of City Light's internal divisions (including Finance and Power Supply). Staff uses a sophisticated economic forecast to predict likely energy sales to customers, the source of the largest share of 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.

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 wholesale energy markets. As noted above, the Utility is proposing a new mechanism to address this source of uncertainty—an automatic wholesale revenue adjustment mechanism.

ELEMENTS OF CITY LIGHT'S REVENUE REQUIREMENTS AND OTHER CASH FLOW ACTIVITIES

The Department's cash transactions can be grouped into the following major categories: (1) Cash from major revenue sources which, among others, include the Department's retail revenues. In a planning sense, these retail revenues equal the Department's retail revenue requirement. (2) Cash to or for major operational categories. (3) Cash available for debt service which equals the difference between the first two categories. (4) Cash paid for city taxes, debt service and some other accounts. (5) The difference between items 3 and 4 equals Cash from Operations. This plus cash from contributions and bond proceeds equal the total for item 6. (6) Cash for capital and conservation projects and some deferred charges.

(1) Operating Cash From

Retail Power Sales

Most of City Light's revenues come from sales of electricity to customers in City Light's service area. In 2008, revenue from such sales accounted for 60 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.

Wholesale Power Sales, Net

Wholesale power sales are revenues from short-term wholesale sales net of short-term wholesale purchases. In general, City Light is now 'long' on energy resources on an annual basis, but there are times within a year when some short-term purchases are necessary. This is the most volatile of the major sources of revenue because of fluctuations in amount of power to sell from City Light's hydro system and variability in wholesale energy prices. The amount of wholesale revenue City Light has received in recent years has ranged from a high of \$140 million in year 2006 to a low of a projected \$69 million in 2009.

Power Contracts

City Light's contracts with the Bonneville Power Administration (BPA) generate several sources of cash (or equivalent) for City Light. BPA reimburses City Light for developing a new power generation facility on the South Fork of the Tolt River. BPA also reimburses City Light for having over-estimated BPA's costs of residential exchange benefits that BPA pays to certain of its customers. The costs of BPA's residential exchange benefits get rolled into rates BPA charges customers such as City Light. Given the realization that BPA overcharged for those costs, BPA is now reimbursing City Light for the past over-charges. This reimbursement is expected to last for a total of seven years.

City Light contracts with Grant County (WA) to pay for some of the costs of its hydro facilities in exchange for some of the power and, for purposes of revenue here, some of the revenue derived from sales of power from those facilities by Grant County.

City Light has a contract to sell some power to the Pend Oreille (WA) PUD. That revenue is included here.

Power Marketing, Net

City Light sells transmission services over its own lines. City Light also receives revenue from basis sales, capacity sales, seasonal exchanges, and other power-related services.

Other Sources

These other types of revenue account for around 4-5 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), transfers of funds from other City departments, and grants from other government entities typically account for an additional 1-2 percent of total revenue.

Interest on Cash Accounts

City Light earns interest on its working capital account and other funds that it owns.

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(2) Operating Cash To

Power Contracts

City Light has several long-term contracts to buy power from other utilities. In 2008, City Light purchased approximately 47 percent of its total available system energy from long-term contracts. Several contracts specify the amounts of energy that City Light will buy from these utilities over the year. Others provide City Light a share of the output from resources in exchange for sharing costs. The largest purchase is from the Bonneville Power Administration (BPA). This contract contains provisions for buying both a fixed amount and also a share of output. The following sections describe existing firm power contracts.

Also included in this category are costs for wheeling over BPA lines and lines owned by other utilities since these costs are required in order to get purchased power to Seattle.

Some of City Light's Power Contracts are:

***** Bonneville Power Administration**

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

Through the Block product, power is delivered to the Department in stipulated monthly amounts. Under the Slice product, the Department receives a fixed 4.6676 percent of the actual output of the Federal System and pays the same percentage of the actual costs of the system. Payments for the Slice product are subject to an annual true-up adjustment to reflect actual costs. Power available under the Slice product varies with water conditions, federal generating capabilities and fish and wildlife restoration requirements.

***** Lucky Peak Hydroelectric Power Plant**

The Lucky Peak Hydroelectric Power Plant (Lucky Peak) was developed by three Idaho irrigation districts and one Oregon irrigation district (The “Districts”) and began operation in 1988. Its FERC license expires in 2030. The plant is located on the Boise River, approximately ten miles southeast of Boise, Idaho, at the Lucky Peak Dam and Reservoir. The rated capability of the three generating units at the plant is 101 MW. Since generation is concentrated in the summer months, the plant has no peak capability during City Light’s winter peak period.

City Light entered into a 50-year power purchase and sales contract (effective from date of operation) in 1984 with the Districts under which City Light will purchase all energy generated by Lucky Peak, in exchange for payment of costs associated with the plant and royalty payments to the Districts. City Light also signed a transmission services agreement with Idaho Power Company (Idaho Power) to provide for transmission of power from Lucky Peak to a point of interconnection with the Bonneville system

***** Grand Coulee Project Hydroelectric Authority**

City Light, in conjunction with the City of Tacoma, Department of Public Utilities, Light Division (Tacoma), has power purchase agreements with three Columbia Basin irrigation districts for acquisition of power from five hydroelectric plants under 40-year contracts expiring between 2022 and 2027. These plants, which utilize water released during the irrigation season, are located along irrigation canals in eastern Washington and have a total installed capacity of approximately 129 MW. The plants generate power only in the summer and thus have no winter peak capability. Plant output and costs are shared equally between the Department and Tacoma.

***** Wind Generation**

An October 2001 agreement with PacifiCorp Power Marketing provides for City Light's purchase of wind-generated energy and associated environmental attributes (such as offsets or emission reduction credits) primarily from the State Line Wind Project in eastern Washington and Oregon. Under the agreement, City Light receives wind energy from July 1, 2004, through the end of the contract on December 31, 2021, the maximum delivery rate will be 175 MW per hour.

***** High Ross**

In 1984, an agreement was reached between the Province of British Columbia and the City under which British Columbia provides City Light with power equivalent to that which would have resulted from an addition to the height of Ross Dam. The agreement was ratified through a treaty between Canada and the United States in the same year. The power is to be received for 80 years, and delivery of power began in 1986.

***** Wheeling**

The Department pays other entities, such as BPA, Idaho Power, and Avista, for transmitting City Light power over facilities they own.

***** Water for Power**

These costs include payments for administrative costs to the Federal Energy Regulatory Administration (FERC), and payments to other entities for use of water and land used by the Department's hydro facilities.

Production

Production is operation and maintenance of City Light's hydroelectric plants. Most of this energy is generated at the Utility's facilities on the Skagit (Ross, Diablo and Gorge plants) and Pend Oreille (Boundary plant) Rivers.

Transmission

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

Distribution

After being wheeled or transmitted to the City Light service area, electricity must be channeled to over 380,000 customers. Distribution expenses include the direct expenses of operating and maintaining substations, power lines, line transformers, poles, service connections, meters, and streetlights. Distribution expenses have been gradually increasing by more than the rate of inflation over the past few years and that trend is expected to continue. This is due in part to efforts being undertaken to improve system reliability, such as increasing the level of expenditure for tree trimming. It also reflects O&M expenditures related to planning and maintaining large interagency projects

requiring City Light distribution infrastructure, such as Sound Transit and relocation of equipment on the Alaskan Way Viaduct.

Conservation

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.

Customer Accounting

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

Administration

This category covers central administrative expenses for planning, financial management, and general administration. It also covers employee pensions and benefits, general plant maintenance, research and development projects, and recognition of liability for injuries and damages such as legal claims and toxic clean-up payments. 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 in a year.

Rate Discounts

This category covers rate relief for low-income customers and credits paid to commercial and industrial customers who have purchased their own transformers.

Uncollectable Revenue

Retail revenue not collected from customers who do not pay their bills.

Non-City Taxes and Franchise Payments

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

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(3) Cash Available for Debt Service

The difference between (1) Cash From and (2) Cash To equals the cash available for debt service. The Department's financial policies direct the Department to plan to have a debt service coverage equal to 2.0 (Resolution 30933, adopted November, 2006, Section 4.B.1.) . That is, the policy requires that, in an expected planning sense, the amount of cash available for debt service should equal twice the cash required to cover annual debt service. The rationale for this policy, given the volatility of actual expenses and, especially, net wholesale revenue, is to provide insurance that debt service can be paid and, thereby, give lenders confidence to continue to provide loans when the Department needs to borrow again. This target can be reached in a number of ways; the two most obvious are adjusting retail rates or cash expenditures. The financial policy says specifically that "rates shall be set to ensure a debt coverage of 2.0." (Emphasis supplied.)

The rate proposal for 2010 proposes a reduction in the debt service coverage target of 2.0, and the addition of a wholesale revenue adjustment mechanism. City Light has written a white paper examining the operation of the existing financial policies. City Light has also written a white paper proposing the changes noted above. These materials will be available for review and consideration by the RAC.

(4) Debt Service, City Taxes and Other Cash Uses

City Light is in the electricity business, one of the most capital intensive businesses in the world. The expensive capital equipment is paid for over an extended period, approximating the useful life of the equipment. This means that at any point in time, City Light has a large amount of debt outstanding which must be serviced each year. The contracts that record the terms under which money the Department borrows must be repaid stipulate that city taxes take a junior lien to debt service. Thus the cash available for debt service is used, first, to pay debt service costs, then the residual is available to pay city taxes. This same residual, if still positive, may also be used to add amounts to a bond reserve account or a contingency reserve account, if necessary. Finally, this residual covers or absorbs cash balances needed to make the Department's Balance Sheet accounts balance.

(5) Cash from Operations, Contributions and Bond Proceeds

The residual left after all items in category 4 have been satisfied from the cash available for debt service (category 3) is Cash from Operations. That cash from operations plus contributions in aid of construction from customers and cash from bond proceeds finances the next category of uses of funds.

(6) Cash to Capital Projects, Conservation and Deferred Charges

The Department's financial policies direct the Department to plan to have a 95% probability that the funds available to support capital projects will be positive, that is, providing at least \$1 to fund capital projects. (This is also in Resolution 30933, Section 4.B.1.) Capital additions comprise the majority of funds from category 5. Additional charges against the cash available from category 5 include deferred conservation expenses, project license charges and High Ross charges.





Cost Allocation--

Document: COSACAR

Cost of Service and Cost Allocation Report

COST ALLOCATION OVERVIEW

Cost allocation is not a subject of the current rate review process. The results of the previous cost allocation study from 2006 will be continued into 2010. Nonetheless, a brief overview of the cost allocation process follows.

Once the Utility's overall revenue requirements (i.e., costs to be paid by retail customers) are projected, the next step in rate setting is to allocate those revenue requirements among functional cost components. Subsequently, it is necessary to divide those costs among different customers. A Cost of Service and Cost Allocation Report (COSACAR) presents the analysis and results of this allocation. The allocation is calculated via a Cost of Service Model (COSM).

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. Shares of the marginal costs are used to allocate the costs represented by the revenue requirements. In order to allocate the revenue requirements by shares of marginal costs, the revenue requirements must be allocated among functional components similar to the marginal costs of service. This allocation of the revenue requirements is called ‘functionalizing’ the revenue requirements. A result of the analysis is that average annual customer rates by customer class always equal average annual revenue requirements assigned to each class.

In addition to recognizing the different costs in the title of COSACAR, other constraints on the utility must be taken into account in the Cost of Service Model that determines the allocation of revenue requirements among customer classes.

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

The last rate review took into account franchise agreements with incorporated areas in suburban King County that are served by the Utility. Terms of those 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 the increased cost to serve downtown network customers relative to the cost of serving all other customers. That rate review allowed recovery of full costs of network service from Medium and Large General Service customers in the downtown network area.

The balance of this section briefly describes the following topics:

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

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

Cost of Service Analysis –Described here is development of shares of marginal cost for use in allocating revenue requirements.

Public Policy Programs – serving objectives for public bodies in the service territory.

FUNCTIONALIZING REVENUE REQUIREMENTS

“Unbundling” is another name for functionalizing revenue requirements and 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 is to understand the costs incurred by function. The unbundled functions and the revenue requirements identified with each in the last rate case are shown below. Also shown are the net revenues which were then expected from wholesale sales that offset these costs. The functionalized items are allocated among customer classes by marginal cost shares, described below, then the net wholesale revenue is allocated based on the shares of all the functionalized items.

Functional Allocation of 2007-2008 Revenue Requirements (2 year totals)

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

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 administrative and general (A&G) expenses, interest expense, and taxes. 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.

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.

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.

Non Residential General Service Classes

Small	< 50 kW
Medium	
Nonnetwork	50 – 999 kW
Network	50 – 999 kW
Large	
Nonnetwork	1,000 – 9,999 kW
Network	1,000 or more kW
High Demand	10,000 or more kW

COST OF SERVICE ANALYSIS

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.

There are alternative ways to allocate revenue requirements. The two main contenders are a marginal cost approach and an embedded cost approach. City Light has used a marginal cost approach since the early 1980s. The decision to use a marginal cost methodology has been studied extensively and reaffirmed a number of times. The general procedure was codified 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 has been modified in several rate cases extending back to the 1997-1998 rate review. Several different cost components have now been developed and used in conjunction with revenue requirements divided among those same components. While the modifications made have been 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 a 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 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. 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.

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 and COSM distinguish between shared and specialized facilities, and provide specific estimates of customers' times of use. The following table lays out in general terms 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 Conservation Transmission	Energy cost shares
Distribution, by subcategory, excluding lights ¹	Various 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. These costs are further subdivided per the table presented earlier and costs for wires and related equipment and transformers are further divided between network and nonnetwork customers.
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.

PUBLIC POLICY PROGRAMS

Residential Low Income

Elected officials in Seattle have long supported public policy programs that reduce costs for certain customers. Customers who qualify for low-income rates pay residential rates that are lower than for other 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.



***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 30933, adopted November 2006. 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 Classes

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

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

One such factor has been the establishment of franchise agreements with the cities of Burien, Lake Forest Park, SeaTac, Shoreline and Tukwila. All of these cities negotiated 15-year franchise agreements with City Light, beginning in 1998, 1999 or 2003. The agreements call for City Light to send payments to these cities based on the value of City Light energy consumed by their residents. New rate classes were established for these

suburban cities because their franchise agreements allowed suburban rates to be higher than corresponding City of Seattle rates.

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

A final factor leading to separate rate schedules has been the inclusion of the costs of various undergrounding projects in Shoreline and Burien in the rates collected from ratepayers in those cities.

City Light’s principal rate schedules are shown in the table below. In addition to these rate schedules, there are also others such as those that cover street and flood lighting, pole attachments and low power factors.

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

Large Standard General Service: Shoreline	LGH
Large Network General Service	LGD
High Demand General Service	HDC
High Demand General Service:Tukwila	HDT

The Rate Form

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

Flat	The simplest rate form bills electricity use at the same uniform price per kilowatt-hour no matter how much energy is consumed. City Light has a flat rate for small and medium nonresidential customers.
Block	The price of electricity changes at different levels of consumption, 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 two-block rate for residential customers.
Inverted Block	The price charged per kilowatt-hour increases as consumption increases. Each succeeding "block" (or increment) of energy consumption during the billing period costs more than the preceding energy block. Residential customers in Seattle have inverted block rates to encourage conservation.
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.

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, demand charges, base service charges, minimum charges, 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 four energy charges for both regular and low-income residential customers (two blocks for two seasons apiece). While the rates per kWh are currently the same for summer and winter, the block sizes are different.
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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.

Demand Charge	<p>Medium, Large, and High Demand General Service customers are also billed for maximum demand, as measured by demand meters. City Light's demand meters measure consumption at 15-minute intervals throughout the day. The customer's highest rate of use over a 15-minute period is recorded each month and multiplied by the demand charge to determine the demand billing.</p> <p>For Large and High Demand 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.</p>
Base Service Charge	<p>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.</p>
Minimum Charge	<p>For nonresidential customers a minimum charge, designed to recover record-keeping costs, is charged if the customer's bill is not above the minimum charge. City Light does not assess a base service charge to nonresidential customers because its goal is to encourage energy conservation by recovering costs as far as possible through rate components controllable by the customer.</p>

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 goals.

The rate review is guided by the following policies as stated in City Council Resolution 30933 (adopted November, 2006). These concepts give flesh to the principles outlined at the beginning of the section:

1. Rates shall be designed in ascending blocks to encourage conservation where blocks are feasible.
2. Rates with demand charge components shall not be designed in declining blocks.
3. City Light shall have a residential first block for the essential needs of residential customers that should be priced below the average cost of service to those customers.
4. Discounts shall be provided to customers with customer-owned transformers and to customers who are metered before transformation.

5. City Light shall investigate where cost-effective, time-of-use, and seasonal differentiation options can be implemented.
6. City Light shall consider setting a fixed charge for all rate classes to stabilize revenues and bills, taking into account other rate elements, but at a level that sends the appropriate price signal to customers.
7. The impacts of the costs of electricity shall continue to be mitigated for low income customers.
8. In order to balance demand and energy price signals, City Light shall propose a contract demand charge for large and high demand general service customers to send price signals to customers with new or expanded service requests that will encourage those customers to manage their loads.

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.

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.

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.

Time-of-Day Rates

City Light adapted time-of-day rates to the schedules of its large and high demand nonresidential customers to encourage them to shift consumption from the peak use period (6 a.m. to 10 p.m. Monday through Saturday, excluding major holidays) to the off-peak period (all other times) 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.

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.

The basic equation for the Residential rate schedules is:

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

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 first block charge - winter
P ₃	=	Price of first block – winter
K ₄	=	Number of kWh subject to the second block charge - winter
P ₄	=	Price of second block – winter
X	=	Base Service Charge

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 2008 Average Utility Rates in U.S. Cities by Customer Class
(cents/kWh)

<u>City</u>	<u>Residential</u>	<u>Commercial</u>	<u>Industrial</u>	<u>System</u>
Seattle	6.32	5.43	4.82	5.64
Indianapolis	7.22	8.07	5.71	6.48
Memphis*	8.00	7.00	5.00	7.00
San Antonio*	9.11	8.35	NA	8.06
Austin*	9.88	9.02	6.22	8.70
Jacksonville*	10.21	8.36	6.66	8.66
Denver	1.024	8.45	6.30	8.59
Los Angeles*	10.70	10.00	9.20	10.20
Phoenix	10.88	9.58	7.91	10.07
Chicago	11.57	10.32	8.69	11.06
El Paso	12.22	11.91	7.14	10.63
Baltimore	14.13	9.83	8.52	12.30
U.S. Average Est.	11.52	10.06	6.66	9.77

* Publicly owned

Sources:


1. Investor-Owned Utilities: Edison Electric Institute Typical Bills & Average Rates Report – Winter 2009
2. Publicly Owned Utilities: Information from each utility, May 2009
3. U.S. Average: U.S. Department of Energy

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 30933 (2006) 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.

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.



***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 2008 was about 28 percent that amount (5.64¢/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 nation's 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 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 Federal Energy Regulatory Commission (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 three irrigation districts in Idaho and one in Oregon; City Light buys the power output and directs the operation of the plant under a 50-year contract. In 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.² 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 (later called Variable Rate General Service-Schedule VRC for City customers, or Schedule VRT for Tukwila customers) continued to be available through 2006.

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

² Geist, Arlene. *History and Financial Impacts of Seattle City Light's Market Based Rate (Schedule 44)*, Seattle City Light, Rates Unit Paper, January 1999.

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.

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 AND FAILURE OF FIRST RESTRUCTURING ATTEMPTS

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 were 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 did not require it to use its historically low-cost energy to serve NLLs. New large loads did not materialize as expected, but some facilities that could eventually house high-density energy loads were built.

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.

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. Water conditions and snow accumulations in all watersheds were more than 100 percent of normal in 2002.

2000 and 2001 also provided realization that restructuring the electricity market along the lines proposed by Federal Energy Regulatory Commission (FERC) and activated in California would not provide secure energy resources at reasonable cost. Superintendent Zarker played a national leadership role opposing the FERC's efforts to impose its national deregulation proposal, including the controversial Standard Market Design.

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.

Even though City Light faced 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 multi-year funding for conservation amounted to \$16.7 million over the next seven years. 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.

March, 2003 also saw City Light redeeming \$182.2 million in revenue anticipation notes (RANs) issued in March 2001. In November of that year, it repaid another \$125 million of RANs, borrowed in November 2002. At year end, Seattle City Light had paid off all external debt remaining from the 2000-2001 energy crisis and owed \$70 million to the City of Seattle cash pool. In August, City Light issued \$251.85 million in long-term debt, with a true interest cost of 4.44 percent. \$115.68 million was used to refinance 1993 bonds, achieving a \$6.6 million net present value savings for customers. The remaining balance was used to finance capital improvement and conservation programs.

CURRENT MANAGEMENT PUSHES TO TRANSFORM CITY LIGHT

Jorge Carrasco was nominated to be Superintendent in December 2003 by Mayor Nickels and was confirmed by the City Council in early 2004. Superintendent Carrasco began working immediately on one of his and the Advisory Board's priorities: an initiative designed to transform City Light into a high-performance organization. The transformation began with an internal survey, completed by 74 percent of the utility's employees and designed to identify workplace issues and improvements. In June, City Light discussed the survey results at employee-led meetings with all 42 of the utility's work groups. Many issues identified in the survey were addressed quickly within individual workgroups. Cross-divisional issues became part of longer term action plans.

At the end of 2004, the Superintendent reduced his direct reports from nine to four: Power Supply and Environmental Affairs, Customer Service and Energy Delivery, Chief Financial Officer, and Human Resources Officer. He also created an Office of the Superintendent which included Public Affairs and Communications, External Affairs, and a Chief of Staff to handle City Council and Advisory Board coordination and the daily logistics of the office.

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

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

2006 had several accomplishments. For a second year, City Light achieved net-zero greenhouse-gas emissions, demonstrating City Light's environmental stewardship. Another was reducing by more than 40 percent the length of time it takes for customers to get new or changed service connections.

Climate change, much in the news in preceding years, came to Seattle's doorstep on the evening of December 14, 2006, when the Hanukah Eve Storm hit the Seattle area. No natural disaster so devastating had hit our area in more than 40 years. Half of our customers were without power – most for only a few hours, but some for as long as nine days. The damage to our distribution system was unprecedented. And there were predictions that we will continue to experience damaging storm seasons that are more intense than in years past. On the bright side, the utility's net income for 2006 was \$161.8 million, the best ever.

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

City Light achieved net-zero greenhouse-gas emissions for a third year in a row in 2007.

The Department was able to offer a substantial rate decrease effective January 1, 2007 (-8.4%) yet still realized net income of \$113.5 million.

The utility's risk management effort was expanded in 2007. A risk oversight director was hired to lead the newly formed risk management group. This group develops and refines the analytical tools, policies, and procedures needed for the utility's risk-

management program. In accordance with best practices, risk oversight was reorganized into front, middle, and back offices. A risk metric was selected and developed to aid in managing the volumetric risk (a measurement of resource sufficiency) that City Light faces. Additionally, market manipulation training was given to the utility's power marketers and risk oversight committee members. Also in 2007, a hedging strategy incorporating the use of the newly developed metric was approved for 2008.

2008 saw many accomplishments along with the reconfirmation of Superintendent Carrasco by the City Council in June. City Light moved forward with technological upgrades to bolster customer service, building up both the asset management program and the outage management system, both of which advance emergency preparedness. The utility introduced "e-billing" which provided e-mail billing statements, options for one time or recurring payments, and other account management improvements.

Standard and Poor's and Moody's Investors Service raised ratings on the utility's bonds in 2008, signaling confidence in the utility's finances.

An historic, new 17-year power-sales agreement was signed in 2008 with the Bonneville Power Administration (BPA) securing the utility's ability to buy economical, reliable, clean energy from BPA – about 530 average megawatts annually – after the current contract expires in 2011. City Light also negotiated two power exchange contracts with other utilities. With the utility's existing wind resources, City Light will have a total of 55.5 average megawatts of renewables, helping to meet the state mandated goals by 2020.

Other accomplishments in 2008 included unveiling the utility's Strategic Plan, a blueprint that guides improvements to infrastructure, develops a diverse and efficient power portfolio, and ensures continued financial strength. City Light added 102 new positions – 63 in the skilled trades.

Finally, in 2008, City Light realized a visionary conservation effort that is expected to change the way the utility does business. The time is gone when another dam can be built to meet increasing demands for power, hence City Light plans to turn to its workhorse – conservation. Saving energy will become the utility's new power plant.

OVERVIEW: LOAD GROWTH AND RATE CHANGES

City Light's service territory's population was 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 was uneven for several 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. A large increase 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 next table shows the uneven development of retail load since the year 2000. The effects of the significant increase in rates in 2001 (shown in the table after this) as a reaction to the energy crisis that started in California are significant. The energy crisis had many contributing factors. Some were individual players in the energy commodity markets who ‘gamed’ the California wholesale price system by withholding some power from the market, creating artificially high wholesale market prices. Criminal penalties have been levied against some players in that market as a result of their illegal behavior. Wholesale prices in that period increased, some of which increased by a factor of nearly 100 for a short time; rolling monthly average prices increased by a factor of nearly 20 for a short time. Meanwhile, City Light was suffering through one of the driest water conditions in many years so it was obligated to buy much more than normal amounts of power on the open market at these extraordinarily high prices.

Annual Retail Load

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

Because of the national economic depression that started in 2007/2008 that has affected the local area, annual load is expected to decline in 2009 and 2010 before growing at a rate of less than 1 percent in 2011. The Utility will continue to face load uncertainty.

The next table lists rate changes since 1971 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.) Some of the annual changes in after the year 2000 represent the cumulative effect of several changes within the year brought about by the energy crisis. Some of the recent small changes represent effects of automatically passing through decreases in rates that the Bonneville Power Administration charges its customers, such as City Light. The decline in rates in 2007 was made possible by a combination of factors. Two of the factors were: (1) an expectation of a decrease in net power costs associated with an expectation of strong net revenues from short term wholesale power transactions, and (2) higher transmission revenues and a decrease in debt service expense associated with lower capital improvement program expenditures in years 2002 to 2004 and liquidation of the Bond Reserve Fund which was replaced with a surety bond in 2005.

Average Rate Change by Year (percentages)	
Year	Average Rate Increase (Decrease)
1971	7.0
1974	9.0
1977	5.0
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
2004	-2.1
2005	-2.2
2007	-8.4

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. He may review City Light's reports and recommendations before they go to the Mayor.

City Council

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

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

Jean Godden and **Richard Conlin** are also members of the Energy and Technology Committee.

Michael Jerrett, staff for Councilmember Bruce Harrell.

Jennifer Samuels and **Vinh Tang**. Energy and Technology Committee staff.

Ben Noble, Director of City Council Central Staff.

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

Department of Finance

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

Cameron Keyes, Assistant Director, Infrastructure Budget Lead

Karl Stickel, oversees issues related to Seattle City Light.

Greg Hill, Utility Rates Analyst.

Seattle City Light

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

Sung Yang, Chief of Staff. He is responsible for communications and liaison with other City departments and officials.

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

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

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

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

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

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

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

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