WEATHERING THE STORM

Seattle City Light
2000 Annual Report

Mission Statement:

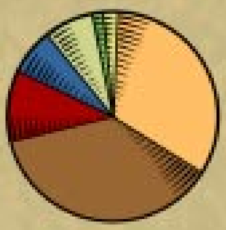
Seattle City Light is in business to sustain and enhance the community's quality of life by providing excellent energy services to our customers and to be the most customer-focused, competitive, efficient, innovative, environmentally responsible utility in the United States.

2000 HIGHLIGHTS

Financial *(in millions)*	*2000*	*1999*	*% Change*
Total operating revenues	$ 396.1	$ 372.7	6.3
Total operating expenses	434.1	317.3	36.8
Net operating income (loss)	(38.0)	55.4	(100+)
Investment income	9.8	4.1	100+
Interest expense, net	(53.2)	(47.9)	11.1
Gain on sale of Centralia Steam Plant	29.6	—	100+
Other expense, net	(0.2)	(3.9)	(100+)
Net income (loss)	$ (52.0)	$ 7.7	—
Debt service coverage, prior lien bonds	**1.26**	**1.90**	—

Energy	*2000*	*1999*	*% Change*
Total generation	6,683,032,000 kWh	8,454,114,000 kWh	(20.9)
Firm energy load	10,131,094,087 kWh	10,097,176,585 kWh	0.3
Peak load (highest single hourly use)	1,769,440 kW (December 11, 2000)	1,729,933 kW (February 8, 1999)	2.3
Average number of residential customers	316,758	312,849	1.2
Annual average residential energy consumption	10,293 kWh	10,593 kWh	(2.8)

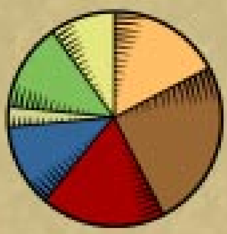
2000 Operating Dollar



Sources

(cents per dollar)

- 34¢ Residential
- 36¢ Commercial
- 11¢ Industrial
- 8¢ Governmental
- 7¢ Gain on sale of Centralia steam plant
- 2¢ Interest earnings
- 2¢ Unbilled revenue (net change) & other



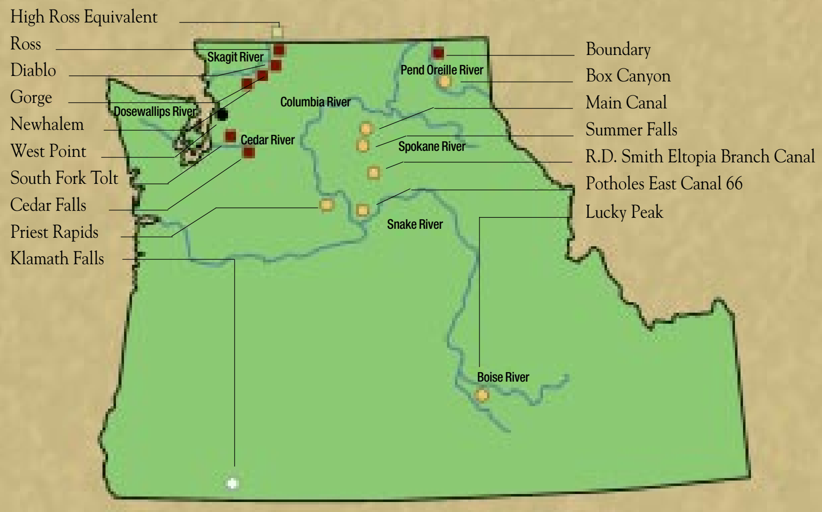
Uses

(cents per dollar)

- 17¢ Long-term purchased power
- 25¢ Wholsale power transactions, net
- 19¢ Operating materials & supplies
- 13¢ Operating salaries & wages
- 3¢ Operating employee benefits
- 13¢ Interest on bonds
- 10¢ Taxes & Other

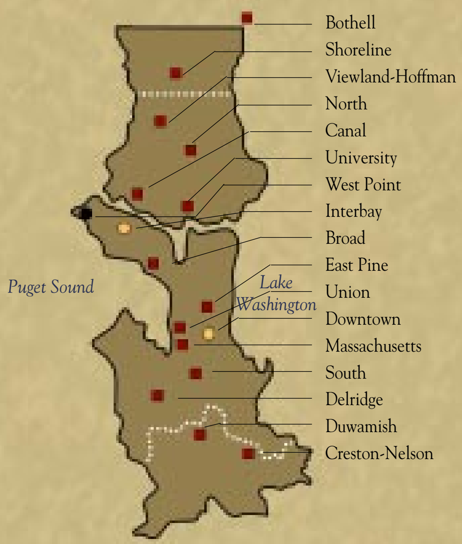
Energy Resources

- Owned Hydro Plants
- Long-term Hydro Contracts
- Long-term Co-generation Contract
- Treaty Rights from British Columbia
- Future Long-term Contract



Service Area

- Principal Substations
- Future Substations
- Long-term Co-generation Contract
- Seattle City Limits



SOUNDINGS

December 24, 1999
Previously approved 3 percent City Light rate increase takes effect.

April 2000
With their Earth Day Resolution, the Mayor and the City Council reaffirm Seattle's commitment to meeting energy needs through reliance on renewable resources and CO_2-mitigated resources.

May
Sale of Centralia Steam Plant closes. California wholesale energy prices suddenly surge to $100 per megawatt hour (MWh).

June, July, August
Wholesale power costs fall slightly, but soon climb again.

September
Seattle City Council approves amended Strategic Resources Plan and authorizes necessary borrowing to meet capital needs.

October
City Light concludes new 10-year contract negotiation with the Bonneville Power Administration for a "slice" of the BPA system and a "block" of assured supply. Seattle City Council approves new rate ordinance for Large Load Customers such as Internet data centers. Council also approves purchase of 100 MW of power from the Klamath Falls, Oregon, gas turbine plant.

November
Rainfall and snow pack decline to 31 percent of normal levels.

December
Precipitation level drops to 41 percent of normal. Seattle City Council approves 10 percent rate surcharge beginning in 2001. Power market rates exceed 1,000 percent of previous highs. City Light borrows $99 million to finance capital program.

January 2001
Ten percent rate surcharge takes effect. An 18 percent base rate increase is scheduled for March 2001. "10% at Home and At Work" conservation program begins.

A PERFECT STORM

The year 2000 and the first half of 2001 represent a journey we would really not like to repeat, yet the past 18 months revealed strengths about Seattle City Light and its community that confirm the unique power of public ownership.

The year began with a quiet success as we passed the Y2K threshold without a glitch. Then, starting in spring, City Light was confronted by a mounting crisis triggered by California's flawed reform of its power marketplace. No one could — or did — predict the ensuing mayhem as wholesale energy prices spiked to 1000 percent of their previous historic highs.

Seattle City Light might have been spared the worst effects of this deregulation fiasco had it not coincided with something else no one could or did predict: the second worst drought in the recorded history of the Pacific Northwest. This drained our region's hydroelectric "batteries" and forced us to purchase more power than previously planned on an inflated market.

And so City Light spent much of the year navigating a course to deal with both the worst hydro conditions in its history and soaring wholesale energy prices. Any miscalculation could have been disastrous, but Seattle City Light, elected officials, and its owner-customers demonstrated that they were up to the challenge. Solid planning, skilled staff, rapid responses, and engaged consumers combined to help us identify alternative sources, find the best deals on the market, reduce demand, and shoulder the higher rates and borrowing needed to weather 2000 and beyond.

And we did it without sacrificing our commitments to environmental quality, salmon restoration, low income rate relief, effective energy independence, and other fundamental public values. As Seattle City Council Member Heidi Wills, chair of the Energy and Environmental Policy Committee, recently commented, "This crisis has a 'green lining' by redoubling Seattle's commitments to conservation, environmental stewardship, and renewable energy sources."

Of the many crises and challenges faced by Seattle City Light during its first century, this has been among the most severe, and 2001 promises even more strenuous tests. At the same time, City Light's managers, employees, and customers, and Seattle's elected leadership have come through the experience stronger and more capable.

Gary Zarker
Superintendent, Seattle City Light
June 2001

SETTING OUT

Seattle's interdependence with the rest of the region and with the nation was never more clear than in 2000. A number of factors, some distant, some local, combined to entangle City Light and its rate payers in the electrical energy crisis triggered by California's disastrous experiment with deregulation. As a result, City Light purchased more power on the open market than it had planned at costs far, far higher than anyone had ever experienced before or imagined possible.

At the end of 2000, City Light was left with a net income of negative $52 million, the largest loss in the utility's history. The new Strategic Resources Plan adopted by the City Council will soon free Seattle from the wildest swings of the wholesale power market. With more energy from the Bonneville Power Administration (BPA), purchase of 100 average megawatts (aMW) of wind power from the planned State Line Project in southwest Washington state, and another 100 aMW to be supplied by the Klamath Falls turbine, City Light will be back on course toward its goal of relative energy independence.

The winds are still blowing hard, but City Light's ship is sound, its crew skilled, and its compass steady. A sheltered harbor lies ahead.

GALE WARNINGS

The question of how to manage the delivery of electricity has confounded people since the 19th century. In order to ensure reliable, low-cost electricity, the citizens of Seattle voted in 1902 to borrow money to construct their own power system. They believed that by owning this important commodity themselves, they would be free of the supply manipulation and price gouging then common around the region and nation. Since then, Seattle City Light has built its own generation system as an integral part of municipal government and a regional power network.

California's energy history followed a different course. Except for a few publicly-owned utilities, electricity is provided by three large corporations. In the early 1990s, when the price of electricity was low and the economy was becalmed in one of its deepest recessions, state political leaders sought to guarantee that power would be delivered at the lowest possible cost. At the same time, the apparent inevitability of deregulation made investment in new generation too risky for either public or private providers.

Then economic recovery lifted California out of its doldrums, and demand quickly overshot supply. Energy loads among the state's neighbors were also rising fast, leading them to pull back generation that they once exported and setting the stage for a regional supply crunch.

California's deregulation advocates promised stability and low prices. Their strategy relied on "the genius of the marketplace" to balance supply and demand and, theoretically, give everyone what they wanted by capping retail rates, liberating wholesale prices, and mandating conservation charges. "Everybody wins," was a common refrain in deregulators' speeches.

The situation was exacerbated by a sudden jump in the price of natural gas, which had idled at historic lows for a decade. The connection of western gas fields in British Columbia and Alberta to new transcontinental pipelines diverted gas from western markets. This contributed to doubling and then tripling previous rates for the gas needed to fuel California's electrical generators.

In May 2000, wholesale energy rates doubled. In June they doubled again. After a two month respite,

BURNING CLEAN

City Light signed a five-year contract with Klamath Falls in November 2000 for 100 average megawatts (aMW) of power, with a five-year renewal option. The 500-megawatt turbine is being developed jointly by the City of Klamath Falls and PacifiCorp Power Marketing of Portland. Klamath Falls is in southern Oregon, with good access to natural gas pipelines and the main electrical transmission line between California and the Northwest. It also incorporated the latest clean air mitigation strategies.

City Light will begin receiving power from the turbine as soon as it begins commercial operation in July 2001. The total value of the contract depends on natural gas prices over the next five years, but City Light estimates a projected savings of about $22 million over the market price of electricity during those five years.

The Klamath Cogeneration Project is one of the cleanest fossil fuel plants in the U.S. Mayor Schell and the City Council have stipulated that carbon emissions attributable to Seattle's share of the turbine be fully mitigated. City Light will work to augment the environmental strategies already in place at Klamath Falls.

when each megawatt hour still cost three to four times what it had in prior years, the price shot up to 10 times historic levels. The volatility of the market was dramatized in December when cable television's Weather Channel broadcast an erroneous daily forecast for subzero temperatures in the Pacific Northwest. Energy prices suddenly spiked from an already high $200 per megawatt hour to an astronomical $2,000/MWh by day's end.

This is no joke for utilities that must have power and will pay anything for it. The California market design required the state's utilities to reinvent their power supply each and every day — and on some days, the power was just not available. Blackouts disrupted economic life and threatened public safety. The restructured system prevented the utilities from recovering their costs in rates. California's largest utility, Pacific Gas & Electric, teetered and then fell into bankruptcy.

These power markets went mad just as City Light needed to replace 100 megawatts of capacity from the sold Centralia Steam Plant. Its planned replacement, the Klamath Falls combined cycle combustion turbine plant, was still a year away from operation. Fortunately, City Light marketers purchased half of the needed power ahead, at a substantial savings. While City Light still needed to deal with the western power market, buying ahead reduced the exposure to rising prices. Then the cost doubled and redoubled. The astronomical prices of summer compelled City Light to approach the City Council in September for a 10 percent surcharge.

WATER, WATER NOWHERE

Water is literally the fuel, and reservoirs the batteries, that run City Light's hydroelectric generators on the Skagit and Pend Oreille rivers. Accordingly, City Light power planners pay very close attention to the weather. At the end of November 2000, a mere 4.5 inches of rain had fallen at the Skagit River during the month — compared to 14.5 inches for a normal year. Both rainfall and snow pack on the Skagit and Pend Oreille rivers continued to post the lowest levels on record through the winter.

The Northwest had seen low-water years before such as the drought of 1977, the state's worst to date. Typically, normal or above-normal precipitation returns by the following year after a drought. These earlier power deficits have been met with short-term conservation and curtailments, and long-term energy efficiencies. For example, the city turned off every other streetlight to save power in 1977.

Nothing so drastic was required in 2000, but as the market demanded higher and higher prices, the utility embarked on an aggressive public campaign to reduce power purchases through a commitment at home and at work to save 10 percent of the utility's energy use commencing January 8, 2001. Clearly the program will help, but with low water behind its dams, City Light has been forced to go to the wholesale market more frequently and for more power than in the past — just as prices soared to historic highs.

HEAVY CHOP

The extreme fluctuations of the power market that bankrupted California's venerable Pacific Gas & Electric and the lack of rain in the Northwest both came as a surprise, but these events did not find City Light or Seattle's elected officials unprepared or unwilling to act. Seattle and City Light have a history of looking ahead.

In 1970, the City Light planners saw that the power supply was not unlimited and the utility began to prepare for a new future. The era of large dam construction had ended, but load growth was projected to double every 10 years as it had in previous decades. In 1973, before there was a Mideast oil crisis, City Light inaugurated its Kill-a-Watt program to encourage conservation. In 1976, conservation was made a major component of Seattle's energy policy on the simple principle that a kilowatt saved equaled, in some cases exceeded, a kilowatt generated.

City Light put into place a thoughtful and rigorous policy for acquisition of new resources: buy only what you need and buy the cheapest first. This led to a series of conservation and generation investments that kept the utility in control of its destiny.

In 1996, Seattle streamlined its various planning processes to shape its Strategic Resources Plan. At that time, market power was cheaper than that provided by the Bonneville Power Administration (BPA), so Seattle hedged its future resources by adding market purchases to its portfolio along with BPA and its other long-term contracts and owned capacities.

Four years later, this position became untenable as the California experiment fizzled and market power costs soared. Even before prices started to climb, City Light began plotting a new course. Seattle needed to be free of the wholesale market and was committed to renewable and environmentally responsible energy sources.

COURSE CORRECTIONS

In April 2000, the City Council adopted City Light's 2000 Strategic Resources Plan, which committed the utility to double the current conservation over the next 10 years and to acquire 100 MW of renewable resources over the next 10 years. Most significantly, the plan called for a new relationship with BPA.

City Light and other power generators had long negotiated for a "slice" of the Bonneville Power Administration's federal hydroelectric system. For Seattle, this would equal about 5 percent of the power generated by BPA. The actual amount of power will fluctuate, depending on rainfall. City Light will accept some risk of reduced power output caused by meeting fish-protection regulations on the Columbia River system. City Light will pay about 5 percent of BPA's system costs, including any budget overruns and debt payments to the U.S. Treasury. This sharing of risk with BPA also entitles City Light to enjoy any system benefits. For example, if a portion of Seattle's slice is sold to other parties, Seattle will receive the proceeds, and City Light will be able to market any surplus energy associated with its percentage of the system.

The contract also gives City Light a "block" of BPA power. A block is a firm amount of power shaped (or scheduled) to a monthly net requirement. All together, City Light will buy 493.8 average megawatts for the first five years of the contract and 608.2 average megawatts for the second five years. The contract runs from Oct. 1, 2001 to Sept. 30, 2011. City Light's cost over the 10 years is estimated at about $1.2 billion. Based on price forecasts, the contract could save City Light as much as $878 million compared to purchasing power from the wholesale market.

The Strategic Resources Plan also authorizes contracting for 100 MW of output from a combustion turbine as insurance against adverse weather and water conditions and extraordinary load growth. The Earth Day Resolution adopted in April 2000 commits the utility to fully mitigate greenhouse gas emissions from such a source. The sale of the Centralia coal-fired power plant — the largest point source of air pollution in the Pacific Northwest — and City Light's participation in the new Klamath Falls, Oregon, gas turbine plant were part of this long-term strategy. But 13 months would elapse before Klamath would come on line to replace Centralia power.

But City Light had an ace in the hole. It had reorganized its energy management staff to create an agile Power Marketing Group (PMG) in July 1999. This talented organization swung into action with around-the clock, hourly analyses of the price of electricity, power flows, and system loads. The PMG examines the forward market for electricity and the day-ahead market to determine the best price for both the power that City Light buys and the power that it sells. In 2000, City Light bought and sold power from 58 different marketers under 255 contracts for power, transmission services, and related facilities, and realized a net savings of $4.2 million, 19 percent better than its first year.

GROWING APPETITES

The Internet has moved us toward more decentralized systems. We can use the Internet to buy products from stores around the country. While this web is distributed around the globe, Internet transactions themselves have led to a concentration of electricity demands at key nodes along the nation's fiber optic backbones.

Seattle's role as the nation's second most wired city is the result of ready access to high-speed Internet services for homes and businesses. This in turn has spurred the proliferation of data centers, sometimes called "server farms" or "telco hotels." Each of these high-tech facilities houses computer equipment to support information and communication systems in a constant environment of 72 degrees Fahrenheit. They consume power 24 hours a day and as the economy becomes more automated, they have become critical elements in the economic infrastructure.

Data centers have a voracious appetite for electricity. A traditional office building consumes about eight watts per square foot. A modern office building with air conditioning and connections for computers and office machines uses about 25 watts per square foot. Data center equipment can use up to 200 watts per square foot. Depending on the size of the building and related equipment, one data center can consume as much electricity as thousands of homes.

The data centers proposed for City Light's service area over the next two years could increase the total load by more than 250 MW or 25 percent, an unprecedented increase in the utility's history. This is as much power as is now produced by all three dams on the Skagit River. Data centers present numerous challenges to producing power and delivering it to the customer. Therefore, City Light engineers have carefully evaluated the impact of this on our wires and substations and are developing plans based on different growth and funding scenarios.

TRIMMING SAILS

Prior to 2000, wholesale electricity rarely cost more than $30 per megawatt hour. Seattle produces most of its own power for less than $10. The Bonneville Power Administration sold its power for $22. Beginning in May 2000 however, utilities saw the cost of electricity go to $60 per MWh. From there the cost shot up beyond $500.

In a normal year, City Light buys 10 percent of its power from other utilities and on the open market, and still sells excess power when it has a surplus. In low water years, more energy must come from the West Coast marketplace.

Seattle's elected officials, the City Council and the Mayor, have demonstrated strong leadership by

Not Our First Storm:
A Brief History of City Light

Next year will mark the centennial of the vote that led to the creation of City Light. One hundred years ago, Seattle citizens wearied of private monopoly ownership of the city's primary electric utility and transit services. Public ownership advocates led by City Engineer Reginald H. Thomson proposed development of a municipal electric power plant at Cedar Falls in the city's newly acquired Cedar River Watershed.

On March 4, 1902, voters approved $500,000 in bonds for the new power plant. Current for streetlights arrived in Seattle in January 1905 and customers lined up for residential service when it became available nine months later. They also approved several additional bond issues to expand the plant and Seattle's city-owned electrical system.

Even in the early 1900s, most of Seattle's nearby dam sites were claimed by private utilities. The river with the best potential, the Skagit, lay some 100 miles north in Whatcom County. When a prior claim to develop the site expired in 1918, pioneering City Light Superintendent James D. Ross did not hesitate to win federal permits to build dams there.

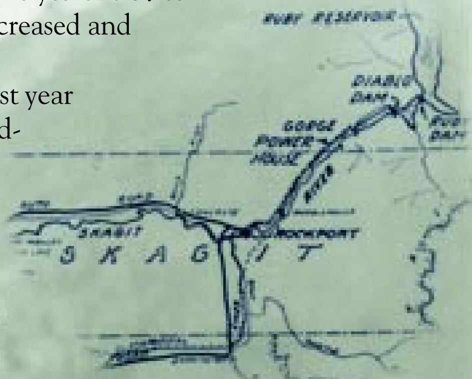
The first Skagit plant, Gorge Dam and power house, started supplying power to Seattle in 1924. Five years later, the City of Seattle completed Diablo Dam four miles upstream, but there was no power house and, consequently, no power. The Great Depression delayed the completion of the power house until 1936 during which time City Light paid down the debt on the dams with income from rates. The power deficit was made up with the Lake Union Steam Plant, while City Light workers shared jobs to cut costs and prevent layoffs. Finally in 1951, Ross, the third Skagit plant, came on line.

Also in 1951, Seattle approved a bond issue to purchase the properties of the investor-owned Puget Sound Power and Light Co. (now part of Puget Sound Energy). City Light merged two dissimilar power systems without interrupting service to customers, and went on to become a national leader among electrical utilities, public and private alike.

In October 1973, before the Yom Kippur War oil embargo, City Light began encouraging conservation. In 1975, Seattle wisely rejected an expanded role in two nuclear power plants then under construction. City Light's Energy 1990 study identified a solution close to home: it was cheaper to save kilowatts than to generate them.

In 1977, a drought struck Washington, one of the top 10 natural calamities ever to hit the state. Washington was declared a disaster area. City Light had to ask for a surcharge on light bills to buy power from other utilities. Streetlights were turned out and a large thermometer on the City Light Building tracked conservation by customers. The years 1987 to 1989 were dry as well. In 1992, three years of low water began. Rates were increased and surcharges added, but then scaled back as rainfall levels returned to normal.

Thus, the economic, technical, and environmental challenges of the past year are nothing new to City Light — nor is its record of overcoming and transcending them through hard work, innovation, and strong community support.



recognizing the complexity of the energy situation and by supporting the rates and borrowing needed to sustain the utility.

City Light and elected officials also recognized and addressed a new ingredient in the energy equation: large loads created by computer data centers and other telecommunication businesses.

Computers are not the only new customers needing large amounts of power. Bio-technology companies use large amounts of electricity for their research and manufacturing. The New Large Load Ordinance, passed October 9, 2000, allows City Light to negotiate rates with customers who need more than 10 MW of power. In keeping with Seattle's long-standing practice of basing charges on cost of service, these new customers will pay for any additional infrastructure and power purchase costs incurred by City Light. The fee will vary depending on the type of infrastructure required, but all the costs — whether for a few transformers or an entire substation — will be paid by the customer. The cost of the additional power will reflect current market costs.

Steady as She Goes

Seattle City Light rate payers enjoyed the lowest electricity prices of any urban area in the nation in 2000. Since 1973, customers have helped reduce overall load growth by investing in conservation. In 1976, the Seattle City Council placed conservation on top of the resource acquisition hierarchy. Between 1977 and 2000, conservation measures have saved 5.7 million megawatt hours, enough electricity to power the city for 18 months. Seattle City Light has had the region's most aggressive utility conservation program for more than 20 years, spending $360 million to date. This has paid off for customers, whose bills have been lowered by an aggregate of a quarter of a billion dollars.

City Light and the Northwest Power Planning Council joined forces in early 2000 to develop the Conservation Potential Assessment (CPA), an evaluation of how much more energy City Light could save in the next 20 years. The key findings from the CPA, incorporated into City Light's 2000 Strategic Resources Plan, were as follows:

- Up to 260 aMW of additional cost-effective conservation can be acquired by customers in City Light's service territory over the next 20 years.
- Opportunities to save energy are available to all customer groups.
- City Light's existing conservation programs will capture roughly half of the achievable conservation potential. More effort is needed to get the rest.

With the emergence of the West Coast energy crisis and City Light's imminent need for cost-effective, environmentally benign resources to meet future power requirements, City Light has initiated a conservation acceleration strategy designed to tap the remaining conservation potential in its service territory. This strategy calls for doubling conservation savings from six to 12 average MW per year over the next decade. This expansion will be achieved through City Light's proven conservation incentive programs, more stringent energy codes, and market transformation programs.

As a municipal utility, City Light has many different goals, ranging from assuring that its infrastructure meets the visual and functional expectations of the neighborhoods it serves to ensuring economic development and customer service. Five areas of the city have been identified by the Office of Economic Development as attractive to high tech development. South Lake Union and Interbay may need 100 MW of additional distribution system capacity in the next several years. Other areas included in this planning are Rainier Valley, Downtown, and the Stadium Transition Zone.

Planning and preliminary testing continued in 2000 for two other new programs that promise to save energy. A load-shedding pilot will allow City Light to notify commercial customers of impending price hikes on the power market so that they can curtail use for short periods. City Light and the customer will share in the resulting cost savings. The Seattle Meter Watch will allow downtown commercial customers to use the World Wide Web to view their energy use real-time, so that they can gauge the effectiveness of their own conservation measures. These products are planned for initial implementation in July 2001.

Meanwhile in residential neighborhoods, City Light staff members work closely with citizen representatives and urban planners to ensure that new and upgraded installations fit the needs and characters of the communities they serve. In the University District, the City Transportation Department (SeaTran) and City Light cooperated in combining service on utility poles for a savings of $300,000. In West Seattle's Alaska Junction area, City Light worked with the neighborhood to install special-look street lighting. City Light has drafted a public benefits policy framework addressing various neighborhood plan initiatives such as lighting, undergrounding, and property disposition.

To encourage conservation, City Light will now buy back energy from customers who install their own renewable energy sources. This Net Metering arrangement saves the customer money and City Light benefits from a reduced load as well as additional supplies of power. This arrangement is available to customers who operate solar, wind, hydro, and fuel cell generating systems of 25 KW or less.

Finally, at the North Service Center, City Light workers began testing a Capstone micro-turbine, a self-contained power unit that generates 3000 KW of electricity. The electricity powers the building and uses exhaust gasses for heating. This new technology may be an option for City Light customers in the future, and the Distribution Branch is gaining valuable experience in this technology's potential long term public benefit.

WATCHING OUR WAKE

On April 22, 2000 — Earth Day — the Seattle City Council reaffirmed our city's long-standing policy of responsible environmental stewardship. City Light was directed to meet the electrical needs of Seattle with no net greenhouse gas emissions or harm to the natural habitats and to meet load growth by using cost-effective energy efficiency and renewable resources.

Since the Chinook salmon was listed as a threatened species in 1999, City Light has kept to its policy of "fish first." In 2000, the utility continued its work to preserve this unique icon that is so reflective of the history and the culture of the Pacific Northwest. City Light efforts have long exceeded license requirements and other environmental standards. City Light's news for the salmon is good.

In 2000, the adult Chinook return to the Skagit River was 16, 930, compared to a 10-year average of 6,497. Approximately 77 percent of these fish spawn inside a 25-mile reach of the river just below the Skagit project. Smolt (juvenile salmon migrating from freshwater to saltwater) production was estimated at 6 million in 1999-2000 season. If only one half of one percent of these Chinook smolt return as adults, the 2003 run could be as large as 30,000.

One of the major causes of the decline of the salmon is the loss of habitat to development, logging, and agriculture. In recognition of this, City Light purchased 150 acres of key habitat on the Suiattle River, a tributary of the Skagit system. This now-protected parcel includes a broad corridor along the river, off-channel wetlands, and spawning and rearing habitat for Chinook.

Further downstream, City Light began a major project to help restore the Browns and Hall Slough on the Skagit River delta. The scarcity of high quality estuary habitat — where salt water and fresh water mix — is a major factor limiting the survival of smolt in the entire Skagit River system. City Light also launched an extensive research program into the bull trout population behind its Skagit dams, one of only four healthy stocks in the state. These and other efforts helped to earn City Light the 2000 Skagit Watershed Council's Partnership Award.

On the Tolt River in north King County, City Light began a project in partnership with King County and others to reconnect the river with a key portion of its flood plain by moving back levees. This reach is the most important section of the Tolt system for Chinook spawning, but it has been altered dramatically over the years by flood control levees along both banks. The wider flood plain will absorb the fluctuations in water levels and permit the river to flow more slowly.

And on the Cedar River, where Seattle built its first hydroelectric plant in 1905, City Light has joined in a Habitat Conservation Plan with Seattle Public Utilities. The plan provides a failure monitoring system for the penstock intake gate. This will allow the remote closing of the water intake should the penstock fail during a major seismic event.

City Light's environmental efforts were not limited to salmon recovery. Pollution prevention is an important part of the utility's operations. City Light reduced its use of pesticides by 80 percent in 2000, as compared to average usage between 1995 and 1999. This was accomplished through a combination of reducing weed control efforts in some non-essential locations, increasing use of manual weed removal, and experimenting with non-chemical methods of weed control such as radiant heat and flame weeders.

City Light led a citywide effort to adopt health and environmental criteria for environmentally responsible janitorial products. These criteria were incorporated into new contracts for janitorial supplies and services. City Light has also reduced more than 77,000 lbs. of hazardous waste by recycling spent lamps in 2000 – City Light's first year of recycling this waste. A new treatment system at Boundary Dam now cleans 40,000 gallons of water contaminated every year in the washing of large oily parts from generator systems.

Finally, Seattle City Light was the first utility in the country to test plastic sleeves on utility poles. The sleeves are shrink-wrapped onto the end of the pole to reduce the risk of soil contamination from wood preservatives such as copper chromium arsenate. The sleeves will also extend the life of the poles.

CLEARING THE AIR

City Light is committed to meeting all growth in electricity demand with no increase in greenhouse gas emissions. City Light reports greenhouse gas emission reductions from conservation and other measures annually as part of the U.S. Department of Energy's voluntary reporting program. Currently, 36 local businesses and organizations cooperate with City Light on Climate Wise Action Plans to reduce greenhouse emissions.

City Light's Climate Wise Partners have documented more than 30,000 metric tons per year of CO_2 reductions — the equivalent of removing 6,000 vehicles from the road. City Light has entered into a partnership with The Climate Trust to solicit Requests for Proposals to further mitigate greenhouse gases.

BELOW DECKS

While California blackouts made national headlines, City Light workers in every division quietly plied their trades, modernizing systems, upgrading infrastructure, learning new skills, and meeting the day-to-day challenges of serving the public.

Joint development of the Consolidated Customer Services System with Seattle Public Utilities was completed in 2000 and "go live" scheduled for April 2001. This three-year project moved City Light's customer billing system off a Legacy mainframe computer onto a client-server based system, combining it with Seattle Public Utilities. This major change required the creation of new business processes, the development of new rules and procedures, exhaustive testing, and extensive staff training.

The remodeled South Service Center opened in 2000 and work on the North Service Center was well underway. A new Apprenticeship Training Facility at the South Service Center was dedicated to house City Light's 43-year-old apprenticeship training program where employees learn the highly technical and demanding skills of line workers. This program has paid dividends in increased efficiency and greater safety while producing a steady flow of skilled employees into City Light's work force.

The Center for Office Technology awarded City Light's ergonomic program the "Outstanding Office Ergonomics Award" for the public sector in 2000. The Safety & Health Team worked with more then 800 employees to promote injury prevention through timely ergonomic intervention. The program helped to minimize work related musculoskeletal disorders and to reduce lost work hours and workers' compensation costs associated with these injuries.

This skilled workforce also maintained City Light's high standard for reliability in 2000. The Power Management Branch was able to report that the average customer went without power for no more than 43 minutes during the year, well below the system tolerance of 50 minutes, and the Downtown Network chalked up another year without any power outages. Fair weather helped to achieve this, but the credit really belongs to highly dedicated employees and a well-maintained system.

City Light's past investments in its infrastructure are paying off with fewer service interruptions. When outages occur, power managers, public safety officials, and media relations staff can now track the progress of restoring service in real-time on the utility's internal computer system.

The Generation and Plant Operations Division completed 98 percent of the work projected under the Capital Improvement Program, at 96 percent of the budgeted cost. These were all cost savings and were not the result of any deferred maintenance. City Light staff has been assuming more responsibility for design and engineering and relying less on consultants. Examples of in-house projects were the Cedar Falls design work for compliance with the Cedar River Habitat Conservation Plan, and sub-projects related to the Boundary Dam in the far northeast corner of Washington State.

As an example, City Light crews at Boundary Dam completed rehabilitation of Generator 54, the fourth of six turbines to be reworked. City Light workers have demonstrated that they could accomplish the 12-year project at 25 percent below the original estimated cost of $131 million. Boundary Dam crews designed and built massive lathes to smooth turbine rotors and other components to exacting tolerances. The entire rehabilitation project is scheduled for completion in 2007.

Employees at City Light's power plant on north King County's Tolt River made on-site repairs to a cracked generator waterwheel and maintained production of approximately eight megawatts of desperately needed electricity. The outstanding effort by the City Light team came at a time when market power had become prohibitively expensive.

Overall, City Light's 20 generators in six power houses achieved 85.9 percent availability, exceeding the goal of 85.4 percent. This was accomplished through the hard work and dedication of City Light staff and despite the temporary loss of half of the Tolt generator's production.

THE COURSE AHEAD

October 2001 will mark a major milestone with culmination of multi-year planning and negotiations leading to a new Bonneville Power Administration contract, new renewable resources, and an enhanced conservation program. Seattle will still need to occasionally buy electricity on the open market, but these purchases will be balanced by sales and will constitute a small part of the system load.

The experience of 2000 and the spring of 2001 tested every member of City Light's crew and every part of its ship: the capacities of its organization and resources, the skills of its employees, the leadership of Seattle's elected officials, the solidarity of its customer-owners, the durability of its values. In each of these instances, the utility met the challenge, and emerged stronger for the experience.

The waters in 2001 are still uncertain. But even if they prove rougher than in 2000 and the sea runs hard against the utility, the endurance and skill gained during this year of the Perfect Storm will see City Light and its customers safely to home port.

SUMMARY OF FINANCIAL RESULTS IN 2000

City Light's financial results in 2000 were severely affected by volatility in wholesale power markets in the Western region. The Department's reliance on market purchases to serve load was increased by subnormal water conditions in the watersheds in which its hydroelectric plants are located. Market prices in the second half of the year reached levels that were several times higher than prices in previous years. The resulting increase in purchased power costs caused the Department to incur a net loss of $52.0 million.

The City Council has responded to the sudden increase in power costs by adopting two power cost adjustments of 9.8% and 18.0%, effective January 1 and March 1, 2001 respectively. Other rate increases are likely to be adopted in 2001.

Revenue

Operating revenue in 2000 totaled $396.1 million, an increase of $23.3 million from the 1999 level. Revenue from sales to retail customers in the Department's service area rose from $366.0 million in 1999 to $383.7 million in 2000, an increase of 4.8%. The increase in revenue reflects the general rate increase authorized by the City Council with an effective date of December 24, 1999. Energy billed to retail customers was virtually unchanged from 1999 to 2000. Growth of 1.3% in energy billed to commercial customers (including governmental accounts) was offset by decreases of 0.1% in energy billed to industrial customers and 1.6% in billings to customers in the residential classes. Accrued but unbilled revenue increased by $2.6 million for all classes combined.

Sales to Nordstrom facilities in California generated an additional $7.9 million, an increase of $5.9 million from the 1999 level. This increase reflected a change in the terms of the Department's contract with Nordstrom, which tied the price of power delivered under the contract to prices in the wholesale market.

Power Costs

The cost of power supply in 2000, including the cost of long-term purchased power contracts, short-term wholesale power transactions, operation and maintenance costs in City Light's generating plants, transmission and other power costs, totaled $235.0 million in 2000, an increase of $117.4 million from the amount recorded in 1999.

Wholesale Power Transactions, Net. The large increase in power supply costs was due to a change in the Department's balance of loads and resources from 1999 to 2000 and to a sharp increase in the price of power in wholesale energy markets. In 1999, the Department had significant amounts of surplus power available for sale in the wholesale market due to favorable water conditions. In 2000, however, the Department was required to buy power in the wholesale market to offset a firm resource deficit. The Department's planning for 2000 had assumed that firm load would exceed firm resources available to the Department, due primarily to a 1996 amendment to the Department's contract with the Bonneville Power Administration that limited purchases from Bonneville to 195 average MW. The impending sale of the Department's 8% share of the Centralia Steam plant was expected to increase the firm resource deficit further by 81 average MW. Water conditions that were below normal in 2000 caused an additional reduction in the energy available to meet load. The Department intended to rely on purchases of power in the wholesale market to fill the gap between firm loads and resources. Wholesale market prices were expected to be at the levels experienced in 1999, when prices generally ranged from $10 per MWh to $40 per MWh. However, prices in wholesale power markets in the Western region began to increase in May 2000 and by August had reached levels that were several times higher than prices in the prior year. Prices remained high the second half of the year and peaked in December. For the year 2000 as a whole, the Department purchased 1,981,189 MWh of energy in the wholesale market at an average price of $93.32 per MWh for a total cost of $184.9 million. Offsetting this cost was revenue of $88.7 million from the sale of 1,657,261 MWh of energy at an average price of $53.50 per MWh. Sales took place primarily before the sharp increase in prices, while most purchases occurred in the second half of the year. The net expense related to wholesale market sales and purchases in 2000 was therefore $96.2 million, an increase of $113.4 million over the 1999 level, when favorable water conditions resulted in net revenue of $17.2 million from wholesale market sales and purchases. In addition, reported expenses include $16.6 million of booked out energy that was scheduled into and out of the same point of delivery. Sales of reserve capacity provided an offset of $3.9 million to power costs.

Long-term Purchased Power. The cost of power available to the Department under long-term contracts with other utilities in 2000 was $75.0 million, a decrease of $5.0 million from the 1999 level. A change in amortization period from 35 years to 50 years relating to costs associated with the British Columbia contract for deliveries of power in lieu of construction of the High Ross Dam (the High Ross contract) accounts for the decrease in purchased power costs. This contract provides for delivery of 35.4 average MW of power to the Department each year from 1986 through 2065 in return for an annual capital payment of $21.8 million from 1986 through 2020, plus imputed operations and maintenance costs and other costs. From 1986 through 1999, the payments were being amortized over 35 years. In setting rates for the period beginning in 2000, the City Council authorized the Department to amortize the remaining capital payments over a period of 50 years in equal annual amounts of $12.7 million, resulting in expenses related to the High Ross contract to be $9.1 million lower than in 1999. The cost of other purchased power contracts changed little from 1999 to 2000. Payments to the Bonneville Power Administration were $1.4 million higher in 2000 because less surplus power was used to displace power from Bonneville in 2000 than in 1999. Lower generation due to poor water conditions resulted in a reduction of $1.0 million in payments for power from Lucky

Peak and others except for power exchanges. Valuation of the energy receivable and deliverable at year-end under various exchange contracts with other utilities resulted in an additional expense of $2.8 million.

Generation. The cost of operating and maintaining the Department's generating resources in 2000 was $25.7 million, a decrease of $5.4 million from the prior year. Sale of the Centralia Steam plant in May 2000 resulted in a reduction of $6.7 million in operating costs relative to the cost of operating the plant for a full year in 1999. Hydroelectric generation costs increased by $1.3 million from 1999 to 2000.

Transmission. Transmission costs, including both the cost of wheeling power over the lines of other utilities and the cost of operating and maintaining the Department's transmission infrastructure, declined by $0.7 million from 1999 to 2000. All of this decrease is attributable to lower costs of operations and maintenance for the Department's transmission system, which were $0.8 million below the 1999 level. Wheeling costs at $17.0 million were $0.1 million higher than in 1999.

Power Marketing and System Control. Costs associated with the Department's power marketing unit and energy management systems increased from $4.5 million in 1999 to $5.5 million in 2000.

Other Operating and Maintenance Expenses

Operating and maintenance expenses, excluding those related to power supply and transmission, declined by $6.3 million from 1999 to 2000. Distribution expenses were $2.6 million lower than in 1999 as a higher proportion of staff resources were allocated to capital improvement projects. Customer accounting and customer service costs increased by $2.1 million. Almost half of the increase ($1.0 million) was attributable to an increase in charges for uncollectible accounts. Administrative and general expenses decreased by $5.7 million. Administrative and general costs allocated to capital projects increased by $4.3 million from 1999 to 2000, reflecting the shift in emphasis from operating to capital projects in the main operating divisions.

Taxes

Expenses for taxes and payments to other jurisdictions totaled $42.9 million in 2000, an increase of $4.2 million over the 1999 level. Higher revenues resulted in an increase of $2.5 million in revenue-based tax payments to the City of Seattle and the State of Washington. The remainder of the increase reflects higher contractual payments to counties in which City Light facilities are located, higher franchise payments to cities outside Seattle which are served by City Light, an increase in taxable contributions in aid of construction and an increase in the calculated arbitrage rebate liability.

Depreciation and Amortization

Depreciation and amortization expense was $55.5 million in 2000, an increase of $1.5 million from the 1999 level. The increase reflects an increase of $51.1 million in the value of plant and equipment in 2000 resulting from the Department's continuing investment in its capital improvement program.

Gain on the Sale of the Centralia Steam Plant

In May 2000, the sale of the Centralia Steam plant was completed. The Department received $41.4 million in proceeds from the sale and recorded a gain of $29.6 million.

Investment Income

The Department realized $9.7 million in income from investment of available cash balances in 2000, an increase of $5.6 million from 1999. Valuation of the Department's investments at market prices at year-end accounted for $3.4 million of this increase. The remainder of the increase reflects higher cash balances available for investment.

Other Deductions

In 1999, the Department recorded $3.9 million in charges related to non-recurring expenses and adjustment in that year. In 2000, such charges and adjustment resulted in a net expense of $0.2 million, an improvement of $3.7 million.

Debt Expense

Interest expense and other charges related to the Department's outstanding debt totaled $53.1 million in 2000, an increase of $5.2 million over the 1999 level. Interest accrued on $158 million in first-lien bonds issued in October 1999 was $9.4 million in 2000, or $7.7 million above the prior year's level. Interest on the Department's second-lien variable-rate bonds was $0.8 million higher in 2000 than in 1999. Offsetting these increases were interest savings from the redemption of outstanding bonds at maturity, an increase of $1.3 million in interest during construction, and a reduction in miscellaneous interest expense.

Net Income and Debt Service Coverage

As a result of all of the factors discussed above, the Department recorded a net loss of $52.0 million in 2000. Net revenues available for debt service, including the proceeds of the sale of the Centralia Steam plant[1] were sufficient to cover first-lien debt service payments 1.26 times.

[1] ***City Light's bond ordinances define Gross Revenue to include the proceeds of property sales. The $41.4 million proceeds received by the Department from the sale of the Centralia Steam plant was therefore included in net revenue available for debt service in computing coverage. The gain on the sale of the Centralia Steam plant, reported on the operating statement, totaled $29.6 million.***

SUPERINTENDENT, SEATTLE CITY LIGHT DEPARTMENT:

We have audited the accompanying balance sheets of the City of Seattle – City Light Department (the Department) as of December 31, 2000 and 1999, and the related statements of operations and changes in retained earnings and of cash flows for the years then ended. These financial statements are the responsibility of the Department's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with auditing standards accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Department as of December 31, 2000 and 1999, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles accepted in the United States of America.

Deloitte & Touche LLP

Deloitte & Touche LLP

Seattle, Washington

March 30, 2001

Balance Sheets

As of December 31,	*2000*	*1999*
Assets		
Utility Plant, at Original Cost:		
Plant in service, excluding land	$ 1,811,151,094	$ 1,735,104,405
Less accumulated depreciation	(756,498,165)	(731,545,437)
	1,054,652,929	1,003,558,968
Construction work-in-progress	152,981,465	118,281,967
Nonoperating property, net of accumulated depreciation	6,613,263	6,366,276
Land and land rights	27,919,760	28,029,695
	1,242,167,417	1,156,236,906
Capitalized Purchased Power Commitment	**65,855,587**	**73,854,788**
Restricted Assets:		
Municipal Light & Power Bond Reserve Account:		
Cash and equity in pooled investments	53,087,023	39,954,532
U.S. government securities	13,348,344	21,893,730
Bond proceeds and other:		
Cash and equity in pooled investments	3,969,797	679,865
	70,405,164	62,528,127
Current Assets:		
Cash and equity in pooled investments	21,100,253	62,080,012
Accounts receivable (net of allowance of $3,590,000 and $3,290,000)	68,780,916	55,442,628
Unbilled revenues	35,437,430	32,160,350
Materials and supplies and coal inventory, at average cost	21,548,144	21,824,632
Prepayments and other	2,061,280	7,009,588
	148,928,023	178,517,210
Other Assets:		
Deferred conservation costs, net	79,936,854	71,186,295
Other deferred charges, net	33,818,445	23,541,651
	113,755,299	94,727,946
	$ 1,641,111,490	**$ 1,565,864,977**

See notes to the financial statements.

As of December 31,	*2000*	*1999*
Equity And Liabilities		
Equity:		
Retained earnings	$ 247,990,953	$ 300,019,689
Contributions in aid of construction	125,474,828	113,259,359
	373,465,781	413,279,048
Long-term Debt:		
Revenue bonds, due serially	1,103,992,500	1,041,342,000
Less bond discount and premium, net	(3,875,722)	(6,116,829)
Less deferred charges on advanced refunding	(37,164,273)	(41,188,656)
Less revenue bonds due within one year	(39,760,000)	(36,179,500)
	1,023,192,505	957,857,015
Noncurrent Liabilities:		
Accumulated provision for injuries and damages	6,452,407	5,976,313
Long-term purchased power obligation	65,855,587	73,854,788
Less obligation due within one year	(8,355,000)	(7,875,000)
	63,952,994	71,956,101
Current Liabilities:		
Accounts payable and other	103,101,707	49,918,806
Accrued payroll and payroll taxes payable	3,423,297	3,118,751
Compensated absences payable	9,449,249	9,072,861
Accrued interest	14,654,120	14,733,181
Revenue bonds due within one year	39,760,000	36,179,500
Purchased power obligation due within one year	8,355,000	7,875,000
	178,743,373	120,898,099
Deferred Credits	**1,756,837**	**1,874,714**
Commitments and Contingencies (Notes 3, 6, and 9)		
	$ 1,641,111,490	**$ 1,565,864,977**

See notes to the financial statements.

Statements of Operations and Changes in Retained Earnings

Years Ended December 31,	*2000*	*1999*
Operating Revenues	**$ 396,065,874**	**$ 372,750,765**
Operating Expenses:		
Long-term purchased power	74,999,373	79,984,055
Wholesale power transactions, net	108,575,194	(18,865,574)
Power marketing and system control	5,504,322	4,508,274
Generation	25,665,927	31,071,778
Transmission	20,295,706	20,960,408
Distribution	34,523,307	37,138,587
Customer service	28,578,761	26,504,669
Administrative and general	37,593,250	43,310,839
City of Seattle occupation tax	24,002,685	21,791,151
Other taxes	18,857,370	16,869,928
Depreciation	55,498,917	54,022,390
	434,094,812	317,296,505
Net operating income (loss)	(38,028,938)	55,454,260
Other Income and Deductions:		
Investment income	9,753,106	4,140,404
Interest expense	(48,097,827)	(42,740,018)
Amortization of debt expense	(5,054,837)	(5,208,932)
Gain on sale of Centralia Steam Plant	29,639,799	
Other expense, net	(240,039)	(3,907,245)
	(13,999,798)	(47,715,791)
Net income (loss)	**(52,028,736)**	**7,738,469**
Retained Earnings:		
Beginning of the year	300,019,689	292,281,220
End of the year	**$ 247,990,953**	**$ 300,019,689**

See notes to the financial statements.

Statements of Cash Flows

Years Ended December 31,	*2000*	*1999*
Operating Activities:		
Cash received from customers	$ 492,199,632	$ 449,089,525
Cash paid to suppliers and employees	(374,875,524)	(301,825,330)
Taxes paid	(40,833,895)	(40,592,305)
Net cash provided by operating activities	76,490,213	106,671,890
Capital and Related Financing Activities:		
Proceeds from long-term debt, net of premium	100,491,983	159,132,847
Bond issue costs paid	(256,391)	(438,200)
Principal paid on long-term debt	(36,179,500)	(35,285,000)
Interest paid on long-term debt	(53,988,291)	(45,537,530)
Acquisition and construction of capital assets	(177,974,051)	(155,498,414)
Proceeds from sale of Centralia Steam Plant	41,399,047	
Proceeds from sale of other property, plant, and equipment	406,836	32,930
Contributions in aid of construction	8,405,446	6,335,359
Net cash used for capital and related financing activities	(117,694,921)	(71,258,008)
Investing Activities:		
Proceeds from long-term loans receivable	385,090	905,132
Long-term loans issued	(115,363)	(629,136)
Proceeds from sale of investments	8,216,000	1,000,000
Interest received on investments	8,161,645	5,242,824
Net cash provided by investing activities	16,647,372	6,518,820
Net increase (decrease) in cash and equity in pooled investments	(24,557,336)	41,932,702
Cash and equity in pooled investments at beginning of year	102,714,409	60,781,707
Cash and equity in pooled investments at end of year	**$ 78,157,073**	**$ 102,714,409**

Reconciliation of Net Operating Income to Net Cash Provided By Operating Activities:

Years Ended December 31,	*2000*	*1999*
Net operating income (loss)	$ (38,028,938)	$ 55,454,260
Adjustments to reconcile net operating income (loss) to net cash provided by operating activities:		
Depreciation and amortization	63,510,859	61,227,747
Cash provided by (used for) changes in operating assets and liabilities:		
Accounts receivable	(8,420,793)	(3,902,688)
Unbilled revenues	(3,277,080)	(629,526)
Other deferred charges	3,484,498	1,058,526
Materials and supplies and coal inventory	(1,524,255)	(2,805,070)
Prepayments and other	4,322,595	(4,401,932)
Provision for injuries and damages	476,094	2,545,751
Accounts payable and other	55,384,180	(1,382,034)
Accrued payroll and payroll taxes payable	304,546	(761,848)
Compensated absences payable	376,388	463,179
Other	(117,881)	(194,475)
Net cash provided by operating activities	$ 76,490,213	$ 106,671,890

Cash and Equity in Pooled Investments at December 31 Consist of:

Cash and cash equivalents	$ 23,103,365	$ 6,339,840
Equity in pooled investments	55,053,708	96,374,569
	$ 78,157,073	**$ 102,714,409**

See notes to the financial statements.

Notes to Financial Statements

Years Ended December 31, 2000 and 1999

Note 1: Operations and Summary of Significant Accounting Policies

The City Light Department (the Department) is the public electric utility of the City of Seattle (the City). The Department owns and operates certain generating, transmission, and distribution facilities and supplies electricity to approximately 349,600 customers. The Department supplies electrical energy to other City agencies at rates prescribed by City ordinances. The establishment of the Department's rates is within the exclusive jurisdiction of the City Council. A requirement of Washington State law provides that rates must be fair, nondiscriminatory, and fixed to produce revenue adequate to pay for operation and maintenance expenses and to meet all debt service requirements payable from such revenue. The Department pays occupation taxes to the City based on total revenues.

The Department also provides nonenergy services to other City agencies and received $1.4 million in 2000 and 1999 for such services. Included in accounts receivable at December 31, 2000 and 1999, are $7.5 million and $4.8 million, respectively, representing amounts due from other City departments for services provided, reimbursements, and interest receivable on cash and equity in pooled investments.

The Department receives certain services from other City agencies and paid approximately $27.5 million and $26.6 million, respectively, in 2000 and 1999 for such services. Included in accounts payable for the same time periods are $6.2 million and $6.3 million, respectively, representing amounts due other City departments for goods and services received.

Accounting Standards

The accounting and reporting policies of the Department are regulated by the Washington State Auditor's Office, Division of Municipal Corporations, and are based on the Uniform System of Accounts prescribed for public utilities and licensees by the Federal Energy Regulatory Commission (FERC).

Pursuant to Statement No. 20 of the Governmental Accounting Standards Board (GASB), *Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities That Use Proprietary Fund Accounting*, the Department elected to apply all Financial Accounting Standards Board (FASB) statements and interpretations except for those that conflict with or contradict GASB pronouncements.

In June 1999, GASB issued Statement No. 34, *Basic Financial Statements—and Management's Discussion and Analysis—for State and Local Governments*, which requires reporting on the value of infrastructure assets effective for fiscal years beginning after June 15, 2001, for Phase I Governments, with total annual revenues of $100 million or more in fiscal year 1999. The Department does not anticipate a material impact to its financial position or operations as a result of implementation of GASB Statement No. 34.

In June 1998, FASB issued Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*. This standard was amended in June 2000 by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities*. Both standards are effective for fiscal years beginning after June 15, 2000, and were adopted by the Department as of January 1, 2001. SFAS Nos. 133 and 138 require that the fair value of derivative financial instruments be recognized as either assets or liabilities on the Department's balance sheet. Changes in the fair value of a derivative instrument would be included in earnings. The Department concluded regarding long-term contracts for electric energy and related commodities such as transmission and reserve capacity, and for all purchase orders of other commodities used in the business, that transactions outstanding at December 31, 2000, constituted normal purchases and sales under SFAS Nos. 133 and 138, and as such are not subject to the requirements of SFAS No. 133. The Department also had outstanding purchases of electric energy at December 31, 2000, under short-term forward contracts that are considered to be derivatives under FASB interpretations guiding the implementation of SFAS No. 133, as some of the energy is subject to net settlement through the bookout process and may not be physically delivered. For the contracts that the Department believes are required to be accounted for under the standard, the Department recorded an asset of $5.4 million, a liability of $6.7 million, and a deferred loss of $1.3 million on January 1, 2001. The deferred loss is anticipated to be reversed in 2001 when the contracts are carried to term. In accordance with City Council Resolution No. 30290, the deferred loss is a regulatory asset pursuant to SFAS No. 71. Thus, the adoption of SFAS Nos. 133 and 138 will have no impact on recorded earnings. The Department's conclusions regarding the accounting treatment and financial statement impact of SFAS No. 133 could change based on interpretations of issues pending before the FASB.

Utility Plant

Utility plant is recorded at original cost which includes both direct costs of construction or acquisition and indirect costs, including an allowance for funds used during construction. The allowance represents the estimated costs of financing construction projects and is computed using the Department's most recent long-term borrowing rate. The allowance totaled $5.6 million and $4.2 million in 2000 and 1999, respectively, and is reflected as a reduction of interest expense in the statements of operations and changes in retained earnings. Property constructed with contributions in aid of construction received from customers is included in utility plant. Contributions totaled $15.7 million in 2000 and $10.4 million in 1999. Amortization totaled $3.5 million and $3.1 million, resulting in net contributions of $12.2 million and $7.3 million in 2000 and 1999, respectively. Provision for depreciation is made using the straight-line method based upon estimated economic lives, which range from three to 50 years, of related operating assets. The Department uses a half-year convention method on the assumption that additions and replacements are placed in service at mid-year. The composite depreciation rate was approximately 3.3% in 2000 and 1999. When operating plant assets are retired, their original cost together with removal costs, less salvage, is charged to accumulated depreciation. The cost of maintenance and repairs is charged to expense as incurred, while the cost of replacements and betterments is capitalized.

Other Assets

Other assets consist of deferred programmatic conservation and weatherization costs incurred for purposes of load reduction and energy efficiency. These costs are being recovered through rates over 20 years. Also included are deferred mitigation expenditures spent under settlement agreements associated with the FERC operating license for the Skagit Hydroproject, unamortized debt expense, real estate and conservation loans, and a portion of the annual payment to British Columbia for the treaty regarding the addition to Ross Dam, which are being recovered over four to 36 years. Billable work in progress is also included.

Restricted Assets

In accordance with the Department's bond resolutions, state law, or other agreements, separate restricted assets have been established. These assets are restricted for specific purposes including the establishment of the Municipal Light & Power (ML&P) Bond Reserve Account, financing of the Department's ongoing Capital Improvement Program, and other purposes.

Cash and Equity in Pooled Investments and Investments

The City pools and invests all temporary cash surpluses for City departments. These residual investments may consist of deposits with qualified public depositories; obligations of the United States or its agencies or wholly owned corporations; obligations of eligible government-sponsored enterprises; and certain bankers' acceptances, commercial paper, general obligation bonds or warrants, repurchase agreements, reverse repurchase agreements, mortgage-backed securities, and derivative-based securities; and are in accordance with the Revised Code of Washington (RCW) 35.39.032 and 39.58. According to City policy, securities purchased will have a maximum maturity of no longer than 15 years, and the average maturity of all securities owned should be no longer than five years. Also by City policy, the City may operate a securities lending program and there were transactions during 2000 but not during 1999. There were no securities lending program transactions outstanding at year-end 2000 or 1999. The Department's equity in residual investments is reflected as cash and equity in pooled investments. The City's residual investment pool did not include reverse repurchase agreements at the end of 2000 or 1999; the City did invest in such instruments during both years. Derivative-based securities were owned by the City pool during 2000 and 1999 and at both year ends. These securities were callable U.S. government agency instruments. Earnings and adjustments to fair value from the investment pool are prorated monthly to City departments based on the average daily cash balances of participating funds.

Banks or trust companies acting as the City's agents hold most of the City's investments in the City's name, with respect to credit risk as defined in GASB Statement No. 3, *Deposits with Financial Institutions, Investments (including Repurchase Agreements), and Reverse Repurchase Agreements.* All transactions are executed with authorized security dealers, financial institutions, or securities lending agents on a delivery versus payment basis.

The first $100,000 of bank deposits are federally insured. The Washington State Public Deposit Protection Commission (PDPC) collateralizes deposits in excess of $100,000. The PDPC is a multiple financial institution collateral pool. There is no provision for the PDPC to make additional pro rata assessments if needed to cover a loss. Therefore, the PDPC protection is of the nature of collateral, not of insurance.

Securities with maturities exceeding three months at time of purchase are reported at fair value on the balance sheets; the net increase (decrease) in the fair value of those investments is reported as part of investment income. At December 31, changes in the fair value of investments resulted in an unrealized gain of $862,604 for 2000 and loss of $2,497,774 for 1999.

The cash pool operates like a demand deposit account in that all City departments, including the Department, may deposit cash at any time and can also withdraw cash out of the pool without prior notice or penalty. Accordingly, the statements of cash flows reconcile to cash and equity in pooled investments.

Cash and cash equivalents included in cash and equity in pooled investments at December 31 consist of:

	2000	*1999*
Restricted assets:		
Municipal Light & Power		
Bond Reserve Account	$ 15,682,128	$ 2,481,063
Bond proceeds and other	1,171,565	42,199
	16,853,693	2,523,262
Current assets	6,249,672	3,816,578
	$ 23,103,365	$ 6,339,840

Equity in pooled investments and U.S. government securities are reported at fair values based on quoted market prices for those or similar securities and are as follows at December 31:

	2000	*1999*
Restricted assets:		
Municipal Light & Power		
Bond Reserve Fund:		
Equity in pooled investments	$ 37,404,895	$ 37,473,469
U.S. government securities	13,348,344	21,893,730
Bond proceeds and other:		
Equity in pooled investments	2,798,232	637,666
	$ 53,551,471	$ 60,004,865
Current assets:		
Equity in pooled investments	$ 14,850,581	$ 58,263,434

Compensated Absences

Permanent employees of the Department earn vacation time in accordance with length of service. A maximum of 480 hours may be accumulated and, upon termination, employees are entitled to compensation for unused vacation. At retirement, employees receive compensation equivalent to 25% of their accumulated sick leave. The Department accrues all costs associated with compensated absences, including payroll taxes.

Accounts Payable and Other

The composition of accounts payable and other is as follows:

	2000	1999
Vouchers payable	$ 14,907,362	$ 15,043,107
Power accounts payable	71,140,213	17,666,148
Interfund payable	6,224,826	6,325,951
Taxes payable	6,168,185	5,256,886
Claims payable, current	1,571,387	652,449
Guarantee deposit and contract retainer	2,798,571	1,394,478
Other accounts payable	291,163	3,579,787
	$ 103,101,707	$ 49,918,806

Revenue Recognition

Service rates are authorized by City of Seattle ordinances. Billings are made to customers on a monthly or bimonthly basis. Revenues for energy delivered to customers between the last billing date and the end of the year are estimated and reflected in the accompanying financial statements under the caption unbilled revenues.

The Department's customer base is comprised of four identifiable groups, which accounted for electric energy sales as follows:

	2000	1999
Residential	38.2%	38.8%
Commercial	41.0	38.4
Industrial	12.1	12.5
Governmental	8.7	10.3
	100.0%	100.0%

Use of Estimates

The preparation of the financial statements in conformity with accounting principles accepted in the United States of America requires management to make estimates and assumptions that affect amounts reported in the financial statements. The Department used significant estimates in determining reported unbilled revenues, accumulated provision for injuries and damages, allowance for doubtful accounts, accrued sick leave, and other contingencies. Actual results may differ from those estimates.

Significant Risk and Uncertainty

The Department is subject to certain business risks that could have a material impact on future operations and financial performance. These risks include water conditions, weather, and natural disaster related disruptions; collective bargaining labor disputes; fish and other Endangered Species Act (ESA) issues; Environmental Protection Agency regulations; federal government regulations or orders concerning the operations, maintenance, and/or licensing of hydroelectric facilities; and the deregulation of the electrical utility industry.

Reclassifications

Certain 1999 account balances have been reclassified to conform to the 2000 presentation.

Note 2: Jointly Owned Plant

The Department was one of eight public and private utilities that constructed and owned as tenants-in-common a 1,343 megawatt (MW) coal-fired, steam-electric generating plant located near Centralia, Washington. The Department's ownership interest was 8% until May 7, 2000, when the plant was sold to TransAlta Corporation, a Canadian corporation. Proceeds received from the sale were $41.4 million and the gain on the sale was $29.6 million. The Department's share of operating expenses and plant investment associated with the Centralia Steam Plant is included in the accompanying financial statements until the date of sale. The Department's share of the investment in the Centralia Steam Plant at December 31, 1999, was:

Utility plant in service	$	28,620,025
Less accumulated depreciation		(20,889,960)
	$	7,730,065

Note 3: Long-term Debt

Prior Lien Bonds

In December 2000, the Department issued $98.8 million in ML&P Revenue Bonds that bear interest at rates ranging from 4.5% to 5.625% and mature serially from December 1, 2006, through 2025.

In October 1999, the Department issued $158.0 million in ML&P Revenue Bonds that bear interest at rates ranging from 5% to 6% and mature serially from October 1, 2006, through 2024.

Proceeds from the 2000 and 1999 bond issues were used to finance a portion of the Department's ongoing capital improvement and conservation program.

Prior lien bonds outstanding at December 31, 2000, totaled $998.2 million. Principal redemptions extend through 2025 with interest to be paid at rates ranging from 4.50% to 6.00%. Future debt service requirements on these bonds are as follows:

Year ending December 31,	Principal redemptions	Interest requirements	Total
2001	$ 37,360,000	$ 53,105,842	$ 90,465,842
2002	39,291,500	51,259,217	90,550,717
2003	40,250,000	49,274,905	89,524,905
2004	44,915,000	47,143,019	92,058,019
2005	45,531,000	44,804,890	90,335,890
Thereafter	790,845,000	393,230,193	1,184,075,193
	$ 998,192,500	$ 638,818,066	$ 1,637,010,566

The Department is required by ordinance to fund reserves for prior lien bond issues in an amount equal to the lesser of (a) the maximum annual debt service on all bonds secured by the reserve account or (b) the maximum amount permitted by the Internal Revenue Code (IRC) of 1986 as a reasonably required reserve or replacement fund. Upon issuance of the 2000 bonds, the maximum annual debt service on prior lien bonds increased from $86.7 million to $92.1 million. The IRC's requirement increased from $72.4

million to $77.3 million. At December 31, 2000, the balance in the reserve account was $66.4 million at fair value. The reserve must be fully funded by December 1, 2005.

The Department has issued several refunding revenue bonds for the purpose of defeasing certain outstanding prior lien bonds. Refunding revenue bonds were recently issued in 1993 and 1998. Proceeds from the refunding bonds were placed in separate irrevocable trusts to provide for all future debt service payments on the bonds defeased. Accordingly, neither the assets of the respective trust accounts nor the liabilities for the defeased bonds are reflected in the Department's financial statements. The bonds defeased in 1998 and 1993 had outstanding balances at cost of $94.7 million and $10.0 million as of December 31, 2000, respectively. Funds held in the respective trust accounts on December 31, 2000, will be sufficient to service and redeem the defeased bonds.

In March 2001, the Department issued $503.7 million in ML&P Improvements and Refunding Revenue Bonds with interest rates ranging from 5.125% to 5.50%. The arbitrage yield for the 2001 bonds is 4.99%. Arbitrage yield, when used in computing the present worth of all payments of principal and interest on the bonds, produces an amount equal to the issue price of the bonds. The 2001 bonds mature serially from March 1, 2004, through 2026. Proceeds will be used to finance certain capital improvements and conservation programs and to defease certain outstanding prior lien bonds.

Subordinate lien bonds

The Department is authorized to issue a limited amount of adjustable rate revenue bonds, which are subordinate to prior lien bonds with respect to claim on revenues. Subordinate lien bonds may be issued to the extent that the new bonds will not cause the aggregate principal amount of such bonds then outstanding to exceed the greater of $70 million or 15% of the aggregate principal amount of prior lien bonds then outstanding. Subordinate bonds may be remarketed daily, weekly, short-term, or long-term and may be converted to prior lien bonds when certain conditions are met.

In December 1996, the Department issued ML&P Adjustable Rate Revenue Bonds in the amount of $19.8 million, subject to a mandatory redemption schedule spanning the period from June 1, 2002, to June 1, 2021. These bonds were marketed weekly at an interest rate ranging from 2.85% to 5.75% during 2000. Proceeds were used to finance a portion of the capital improvement and conservation program.

The 1990 bonds and 1991 Series B bonds were $21.6 million and $19.0 million, respectively, at December 31, 2000, and were marketed on a short-term basis during 2000 with interest rates ranging from 3.35% to 6.00%.

The 1991 Series A bonds and the 1993 bonds were $25.0 million and $20.4 million, respectively, at December 31, 2000, and were priced weekly at interest rates from 2.75% to 6.00% in 2000.

As of December 31, 2000, the Department had outstanding subordinate lien bonds totaling $105.8 million. Future principal redemptions and interest requirements on these bonds, based on estimated interest rates ranging from 4.00% to 6.20% through year 2021, are as follows:

Year ending December 31,	*Principal redemptions*	*Interest requirements*	*Total*
2001	$ 2,400,000	$ 4,677,362	$ 7,077,362
2002	3,360,000	4,257,021	7,617,021
2003	3,585,000	3,971,370	7,556,370
2004	4,115,000	3,860,794	7,975,794
2005	4,445,000	3,850,608	8,295,608
Thereafter	87,895,000	29,241,648	117,136,648
	$ 105,800,000	$ 49,858,803	$ 155,658,803

Revenue Anticipation Notes

In March 2001, the Department issued $182.2 million in ML&P Revenue Anticipation Notes (Notes). $136.7 million of the Notes bear interest at a rate of 4.50%, and $45.5 million bear interest at a rate of 5.25%. The arbitrage yield of the Notes is 3.75%. The Notes mature in March 2003, and the proceeds will be used to finance 2001 operating expenses. The Notes are special limited obligations of the Department payable from and secured by gross revenues. The Notes are on a lien subordinate to prior lien bonds and subordinate lien bonds; there is no reserve account securing repayment of the Notes, and there is no coverage requirement for the Notes.

Fair Value of Bonds

The fair value of the Department's long-term debt is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to the Department for debt of the same remaining maturities. Carrying amounts and fair values are as follows at December 31:

	2000		*1999*	
	Carrying amount	*Fair value*	*Carrying amount*	*Fair value*
Long-term debt:				
Prior lien bonds	$ 994,611,605	$ 925,154,114	$ 927,637,863	$ 919,026,000
Subordinate lien bonds	105,505,173	105,800,000	107,587,307	107,900,000
	$1,100,116,778	$1,030,954,114	$ 1,035,225,170	$1,026,926,000

Amortization

Bond issue costs, discounts, and premiums are amortized using the effective interest method over the term of the bonds.

The excess of costs incurred over the carrying value of bonds refunded on early extinguishment of debt is amortized as a component of interest expense using the straight-line method. Deferred refunding costs amortized to interest expense totaled $4.0 million in 2000 and $4.2 million in 1999. Deferred refunding costs in the amount of $37.2 million and $41.2 million are reported as a component of long-term debt in the 2000 and 1999 balance sheets, respectively.

Note 4: Seattle City Employees' Retirement System

The Seattle City Employees' Retirement System (SCERS) is a single-employer public employee retirement system, covering employees of the City of Seattle and administered in accordance with Chapter 41.28 of the Revised Code of

Washington and Chapter 4.36 of the Seattle Municipal Code. SCERS is a department of the City of Seattle.

All employees of the City of Seattle are eligible for membership in SCERS with the exception of uniformed police and fire personnel who are covered under a retirement system administered by the state of Washington. As of the actuarial valuation date, there were 4,681 annuitants receiving benefits and 8,669 active members of SCERS. In addition, 703 vested terminated employees were entitled to future benefits, and 161 terminated employees had restored their contributions due to the provisions of the portability statutes and may be eligible for future benefits.

SCERS provides retirement, death, and disability benefits. Retirement benefits vest after five years of credited service; while death and disability benefits vest after 10 years of service. Retirement benefits are calculated, generally, as 2% multiplied by years of creditable service, multiplied by average salary, based on highest 24 consecutive months excluding overtime. The benefit is actuarially reduced for early retirement.

Actuarially determined contribution rates both for members and for the employer were 8.03% of covered payroll during 2000 and 1999.

SCERS issues stand-alone financial statements that may be obtained by writing to the Seattle City Employees' Retirement System, 801 Third Avenue, Suite 300, Seattle, WA 98104; telephone (206) 386-1292.

Employer contributions for the City of Seattle were as follows:

Year ended December 31,	*Annual pension cost (millions)*	*Annual required contribution (millions)*	*Percentage contributed*
1997	$ 28.3	$ 28.3	100 %
1998	30.6	30.6	100
1999	16.7	29.7	178

Actuarial data

Valuation date	January 1, 2000
Actuarial cost method	Entry age
Amortization method	Level percent
Amortization period of the funding excess from January 1, 1997	30 years
Asset valuation method	Market

*Actuarial assumptions**	*Percentage*
Investment rate of return	8.00 %
Projected general wage increases	4.50
Cost-of-living year-end bonus dividend	0.67

***** Underlying price inflation at 4.0%.***

Note 5: Deferred Compensation

The Department's employees may contribute to the City of Seattle's Voluntary Deferred Compensation Plan (the Plan). The Plan, available to City employees and officers, permits participants to defer a portion of their salary until future years. The deferred compensation is paid to participants and their beneficiaries upon termination, retirement, death, or unforeseeable emergency.

Effective January 1, 1999, the Plan became an eligible deferred compensation plan under Section 457 of the IRC of 1986, as amended, and a trust exempt from tax under IRC Sections 457(g) and 501(a). The Plan is operated for the exclusive benefit of participants and their beneficiaries. No part of the corpus or income of the Trust shall revert to the City or be used for, or diverted to, purposes other than the exclusive benefit of participants and their beneficiaries.

The Plan is not reported in the financial statements of the City or the Department.

It is the opinion of the City's legal counsel that the City has no liability for investment losses under the Plan. Under the Plan, participants select investments from alternatives offered by the Plan Administrator, who is under contract with the City to manage the Plan. Investment selection by a participant may be changed from time to time. The City does not manage any of the investment selections. By making the selection, participants accept and assume all risks inherent in the Plan and its administration.

Note 6: Long-term Purchased Power and Wholesale Power Transactions, Net

Bonneville Power Administration

The Department purchases electric energy from the U.S. Department of Energy, Bonneville Power Administration (BPA) under a long-term contract expiring on September 30, 2001. The BPA rate structure is based on the total amount of energy delivered and the monthly peak power demand.

Until August 1, 1996, the Department was an actual computed requirements customer of BPA and was entitled to buy from BPA the energy required to fill the variance between its customer load and its firm power resources. The Department had a right to displace this entitlement, by payment of an availability charge. Effective August 1, 1996, the contract with BPA was amended, through the remaining

Schedule of funding progress for the City of Seattle (dollar amounts in millions):

Actuarial Valuation Date	*Actuarial Value of Assets (a)*	*Actuarial Accrued Liabilities (AAL) Entry Age (1)(b)*	*Unfunded AAL (UAAL) (2)(b-a)*	*Funded Ratio (a/b)*	*Covered Payroll (3)(c)*	*UAAL as a Percentage of Covered Payroll ((b-a)/c)*
1/1/1998 (4)	$ 1,224.6	$ 1,266.7	$ 42.1	96.7%	$ 341.5	12.3%
1/1/1999	1,375.0	1,326.6	(48.4)	103.6	370.4	(13.1)
1/1/2000	1,582.7	1,403.1	(179.6)	112.8	370.4	(48.5)

1. Actuarial present value of benefits less actuarial present value of future normal costs based on Entry Age Actuarial Cost Method.

2. Actuarial accrued liabilities less actuarial value of assets, Funding Excess if negative.

3. Covered payroll includes compensation paid to all active employees on which contributions are calculated.

4. Reflects increased COLA (cost of living adjustment) benefits adopted by the City Council after the valuation was completed.

life of the contract, to limit purchases to 195 megawatts (MW). The Department can still displace part of this amount by paying an availability charge; BPA energy displaced was 1.3 average MW (aMW) in 2000 and 14.4 aMW in 1999. Power purchased under this contract was 193.7 aMW in 2000 and 180.6 aMW in 1999. The 1996 contract amendment required payment of a diversity fee of $2 million that is being amortized over the remaining contract period, which concludes September 30, 2001.

In 1983, the Department entered into separate net billing agreements with BPA and Energy Northwest (formerly the Washington Public Power Supply System), a municipal corporation and joint operating agency of the state of Washington, with respect to sharing costs for the construction and operation of three nuclear generating plants. Under these agreements, the Department is unconditionally obligated to pay Energy Northwest a pro rata share of the total annual costs including debt service to finance the cost of construction, whether or not construction is completed, delayed, or terminated, or operation is suspended or curtailed. The net billing agreements provide that these costs be recovered through BPA rates. One plant is in commercial operation. Construction of the other two plants has been terminated.

In October 2000, the Department signed a new Block and Slice Power Sales Agreement with BPA covering purchases of power for the 10-year period beginning October 1, 2001. Under the terms of this contract, the Department will be entitled to purchase 493.8 aMW of firm power from October 1, 2001, through September 30, 2006. Firm power available under the contract will increase to 608.2 aMW in the second five years of the contract period to provide for load growth and to offset a decline in power available through the Department's contracts with the Columbia Storage Power Exchange, Pend Oreille County PUD, and Public Utility District No. 1 of Grant County. As a result of an allocation agreement among BPA customers, the Department will receive 330 aMW of this firm energy in the form of a Slice product, through which the Department will receive a fixed percentage (4.6676 percent) of the actual output of the Federal Columbia River Power System and will be required to pay that same percentage of the actual costs of the system. Payments for the Slice product will be subject to adjustments to reflect actual costs. In addition to the 330 aMW firm power available to the Department from the Slice product, the Department expects to receive some nonfirm power from its share of the Slice product under average water conditions. The actual amounts of firm and nonfirm energy will vary with water conditions, federal generating capabilities, and fish and wildlife restoration requirements. The remaining 163.8 aMW of firm energy in the first five-year period and 278.2 aMW in the second five-year period will be received as a block of power shaped to the Department's monthly net requirement, defined as the difference between the Department's projected monthly load and firm resources available to serve that load.

Lucky Peak

In 1984, the Department entered into a purchase power agreement with four irrigation districts to acquire 100% of the net output of a hydroelectric facility constructed in 1988 at the existing Army Corps of Engineers Lucky Peak Dam on the Boise River near Boise, Idaho. The irrigation districts are owners and license holders of the project. The agreement, which expires in 2038, obligates the Department to pay all ownership and operating costs, including debt service, over the term of the contract, whether or not the plant is operating or operable.

The power purchased under this agreement was 38.8 aMW and 48.6 aMW in 2000 and 1999, respectively. To properly reflect its rights and obligations under this agreement, the Department includes as an asset and liability the outstanding principal of the project's debt, net of the balance in the project's reserve account.

British Columbia – Ross Dam

In 1984, an agreement was reached between the Province of British Columbia and the City of Seattle under which British Columbia will provide the Department with power equivalent to that which would result from an addition to the height of Ross Dam. The agreement was ratified by a treaty between Canada and the United States in the same year. The power is to be received for 80 years and began in 1986. The Department makes annual payments to British Columbia of $21.8 million, which represent the estimated cost the Department would have incurred for financing had the addition been constructed. The payments are charged to expense over a period of 50 years, through 2035.

The Department is also paying equivalent operation and maintenance costs. Payments made for this purpose totaled $153,499 and $148,987 in 2000 and 1999, respectively. The power available for purchase under this agreement was 33.9 MW and 35.2 MW, and up to 175 MW and 223 MW of actual peak capacity in 2000 and 1999, respectively.

In addition to the direct costs of power under the agreement, the Department incurred costs of approximately $8 million in prior years related to the proposed addition and was obligated to help fund the Skagit Environmental Endowment Commission through four annual $1 million payments. These costs have been deferred and are being amortized to purchased power expense over 35 years.

Other Long-term Purchase Power Agreements

The Department also purchases energy from Public Utility Districts (the PUDs) No. 1 of Pend Oreille County and No. 2 of Grant County, under agreements expiring August 1, 2005, and December 31, 2005, respectively; the Grand Coulee Project Hydroelectric Authority (the Authority) which includes the South, East, and Quincy Columbia Basin Irrigation Districts under 40-year agreements that expire from 2022 to 2027; and the Columbia Storage Power Exchange until expiration of the agreement on March 31, 2003. Power purchased under these contracts was 87.3 aMW in 2000 and 99.9 aMW in 1999. Rates under the PUD, excluding Pend Oreille County, and Authority contracts represent the share of the operating and debt service costs in proportion to the share of total energy to which the Department is entitled whether or not these plants are operating or operable.

Minimum Payments Under Purchase Power Contracts

The Department's share of minimum payments under its contracts with the PUDs, irrigation districts, power exchange corporation, Lucky Peak Project and British Columbia – Ross Dam, excluding operating costs, for the period from 2000 through 2020 are:

Year ending December 31,	*Minimum payments*
2001	$ 46,128,311
2002	42,136,970
2003	39,777,624
2004	39,785,775
2005	40,807,668
Thereafter	368,454,700
	$ 577,091,048

Payments under these long-term contracts totaled $50.3 million in 2000 and $48.9 million in 1999. Energy received represented 45.4% of the Department's total purchases under firm power contracts during 2000 and 50.5% during 1999.

Wholesale Power Transactions, Net

Power transactions in response to seasonal resource and demand variations include purchases and sales at market under short-term agreements and exchanges of power under long and short-term contracts. Revenues from sales of surplus energy and capacity totaled $103.8 million in 2000 and $53.2 million in 1999. Expenses for purchases of deficit energy totaled $212.4 million in 2000 and $34.3 million in 1999. Wholesale power contract commitments outstanding at December 31, 2000 and 1999, were $42.5 million and $1.1 million, respectively, for purchases. For power sales contracts, there were no outstanding commitments as of December 31, 2000, and $1.0 million outstanding as of December 31, 1999. Fluctuations in annual precipitation levels and other weather conditions materially affect the energy output from the Department's hydroelectric facilities. Accordingly, power transactions in and out may vary significantly from year to year. Wholesale power transactions, net are reflected in the statements of operations and changes in retained earnings.

In March 1998, the Department was certified as a scheduling coordinator with the California Independent System Operator to submit schedules and sell power and ancillary services in California.

In November 2000, the Department and the City of Klamath Falls, Oregon, entered into an agreement for the purchase of energy and capacity from the Klamath Falls Cogeneration Project, a 500 MW unit consisting of two combustion turbines fueled by natural gas and a steam generator. Under the terms of the contract, the Department will receive 100 MW of capacity from the project beginning on the project's on-line date, estimated to be July 1, 2001, and for five years thereafter, with an option to renew the contract for an additional five years. Minimum required contract payments over the five-year agreement for fixed capacity charges total $63.9 million and in addition the Department assumes gas price and exchange rate risks for gas from Alberta, Canada.

Note 7: Deferred Costs

Deferred costs comprise programmatic conservation costs and a portion of the payment to British Columbia for Ross Dam. City Council-passed resolutions authorize the debt financing and deferral of all programmatic conservation costs incurred by the Department. Approximately $14.2 million and $15.9 million in programmatic conservation costs were deferred in 2000 and 1999, respectively. These costs are to be recovered through rates over 20 years. In 2000 and 1999, $5.4 million and $4.7 million, respectively, were amortized to expense. The total remaining balances of unamortized conservation costs at December 31, 2000 and 1999, were $79.9 million and $71.2 million, respectively. Amounts related to the deferral of debt payments for Ross Dam are $9.1 million and $-0- for 2000 and 1999, respectively. This deferral will be amortized between 2021 and 2035.

Note 8: Provision For Injuries and Damages

The Department is self-insured for casualty losses to its property, for environmental cleanup, and for certain losses arising from third-party damage claims. The Department establishes liabilities for claims based on estimates of the ultimate cost of claims. The length of time for which such costs must be estimated varies depending on the nature of the claim. Actual claims costs depend on such factors as inflation, changes in doctrines of legal liability, damage awards, and specific incremental claim adjustment expenses. Claims liabilities are recomputed periodically using actuarial and statistical techniques to produce current estimates that reflect recent settlements, claim frequency, industry averages, city-wide cost allocations, and other economic and social factors. The estimate for incurred but not reported (IBNR) claims was increased $492,989 in 2000 and $2.2 million in 1999, on a discounted basis. Liabilities for lawsuits, claims, and workers' compensation were discounted over a period of 12 to 16 years in 2000 and 1999 at the City's average annual rate of return on investments, which was 6.167% in 2000 and 5.692% in 1999. Liabilities for environmental cleanup and for casualty losses to the Department's property do not include IBNR and are not discounted due to uncertainty with respect to regulatory requirements and settlement dates, respectively.

The schedule below presents the changes in the provision for injuries and damages during 2000 and 1999:

	2000	*1999*
Unpaid claims at January 1	$ 6,628,762	$ 5,937,189
Payments	(1,501,512)	(5,056,196)
Incurred claims	2,896,544	5,747,769
Unpaid claims at December 31	$ 8,023,794	$ 6,628,762

The provision for injuries and damages is included in current and noncurrent liabilities as follows:

	2000	*1999*
Noncurrent liabilities	$ 6,452,407	$ 5,976,313
Accounts payable and other	1,571,387	652,449
	$ 8,023,794	$ 6,628,762

Note 9: Commitments and Contingencies

Operating Leases

In December 1994, the City entered into an agreement on behalf of the Department for a 10-year lease of office facilities in downtown Seattle commencing February 1, 1996. In early 1996, the City purchased the building in which these facilities are located, thus becoming the Department's lessor.

The Department also has four other long-term operating leases for smaller facilities used for office and storage purposes.

Expense under the leases totaled $3.5 million and $3.6 million in 2000 and 1999, respectively. Deferred credits related to the 10-year lease of office facilities in downtown Seattle totaled $1.6 million and $1.8 million in 2000 and 1999, respectively.

Minimum payments under the leases are:

Year ending December 31,	*Minimum payments*
2001	$ 3,526,121
2002	3,629,610
2003	3,629,976
2004	3,526,208
2005	3,536,877
Thereafter	294,740
	$ 18,143,532

Other

Associated with the FERC operating license for the Skagit Hydroproject, which is in effect until the year 2025, are settlement agreements which commit the Department to undertake certain mitigation activities. The mitigation cost is estimated at $40.5 million, of which $29.5 million have been expended.

The estimated financial requirement for the Department's 2001 capital improvement and conservation program is $132.5 million, and the Department has substantial contractual commitments relating thereto.

Some fish species that inhabit waters where hydroelectric projects are owned by the Department or where the Department purchases power have been listed under the ESA as either threatened or endangered. In 1995, the National Marine Fisheries Service (NMFS) developed a broad species recovery plan for the Columbia River Basin and supplemental plans in 1998 and 2000, based on biological opinions relating to the Columbia and Snake River fisheries. As a result, the Department's power generation at its Boundary Project has been reduced in the fall and winter when the region experiences its highest sustained energy demand, and the Boundary Project's firm capability has also been reduced. In the opinion of the Department, it is unlikely that new biological opinions will result in significant changes in flows that would affect Boundary Project, Priest Rapids, and the Bonneville system. While it is unclear how other fish listings, including bull trout and chinook salmon, may affect the Department's hydroelectric projects and operations, the Department has entered into agreements that include extensive measures to protect fish and were intended to mitigate all potential impacts of its projects on the Cedar, Skagit, and South Fork Tolt rivers.

Section 401 of the federal Clean Water Act requires states to provide a water quality certification as a precondition for federal actions including licensing of hydroelectric projects. An agreement was reached for the Newhalem Creek plant on minimum stream flows necessary to protect fish and incorporated into the FERC license issued in 1997. The effect on power generation capability is not known, but the Department anticipates that, in most cases, measures taken pursuant to the ESA should also serve to satisfy Clean Water Act requirements.

Effective November 22, 1999, the Department committed to pay a total of $11.6 million over 10 years ending 2008 to Pend Oreille County, on behalf of the county and certain school districts and towns located therein, to compensate for loss of revenues and additional financial burdens associated with the Department's operation of the Boundary Hydroelectric Project on the Pend Oreille River. The combined impact compensation and retroactive payment totaled $1.0 million annually for 2000 and 1999.

Financial Summary

For the years ended December 31,	*2000*	*1999*	*1998*	*1997*	*1996*
Balance Sheet					
Assets					
Utility plant, net	$ 1,242,167,417	$ 1,156,236,906	$ 1,072,654,414	$ 1,013,700,966	$ 977,989,653
Capitalized purchased power commitment	65,855,587	73,854,788	81,330,278	88,756,582	94,465,223
Restricted assets [A]	70,405,164	62,528,127	60,129,933	56,166,032	52,443,919
Current assets [A]	148,928,023	178,517,210	130,463,176	145,498,789	151,715,855
Other assets	113,755,299	94,727,946	84,168,892	74,545,834	68,036,045
Total assets	$ 1,641,111,490	$ 1,565,864,977	$ 1,428,746,693	$ 1,378,668,203	$ 1,344,650,695
Equity & Liabilities					
Equity [A]	$ 373,465,781	$ 413,279,048	$ 398,284,823	$ 408,450,084	$ 374,439,654
Long-term debt, net	1,023,192,505	957,857,015	830,973,490	771,670,124	769,109,579
Noncurrent liabilities	63,952,994	71,956,101	75,958,677	83,623,913	90,789,505
Current liabilities	178,743,373	120,898,099	121,460,514	113,179,296	109,133,937
Deferred credits	1,756,837	1,874,714	2,069,189	1,744,786	1,178,020
Total equity & liabilities	$ 1,641,111,490	$ 1,565,864,977	$ 1,428,746,693	$ 1,378,668,203	$ 1,344,650,695
Statement Of Operations					
Operating Revenues					
Residential	$ 148,343,023	$ 142,542,347	$ 134,622,904	$ 136,934,204	$ 132,505,751
Commercial	159,202,753	141,105,588	135,685,224	137,216,230	132,806,239
Industrial	47,085,945	45,891,368	50,234,594	52,418,715	49,771,070
Governmental	33,669,484	37,766,052	37,360,320	38,241,277	38,990,344
Sales for resale	-	-	1,556,314	-	-
Unbilled revenue-net change	3,277,080	629,526	1,166,004	(2,099,434)	2,597,289
Total sales of electric energy	391,578,285	367,934,881	360,625,360	362,710,992	356,670,693
Other revenues	4,487,589	4,815,884	3,287,770	3,427,171	3,061,751
Total operating revenues	396,065,874	372,750,765	363,913,130	366,138,163	359,732,444
Operating Expenses					
Long-term purchased power	74,999,373	79,984,055	79,999,162	73,952,830	67,357,080
Wholesale power transactions, net	108,575,194	(18,865,574)	17,105,639	(21,325,153)	(6,871,852)
Power marketing and system control	5,504,322	4,508,274	3,716,008	3,228,159	3,142,173
Generation	25,665,927	31,071,778	31,019,177	30,687,731	29,411,054
Transmission	20,295,706	20,960,408	19,866,792	20,575,865	18,983,536
Distribution	34,523,307	37,138,587	35,974,507	34,240,097	34,074,948
Customer service	28,578,761	26,504,669	29,365,498	27,509,669	24,685,271
Administrative and general	37,593,250	43,310,839	37,831,932	37,210,668	42,387,664
Taxes	42,860,055	38,661,079	38,162,001	37,105,624	36,089,689
Depreciation	55,498,917	54,022,390	54,213,420	51,892,420	45,916,579
Total operating expenses	434,094,812	317,296,505	347,254,136	295,077,910	295,176,142
Net operating income (loss)	(38,028,938)	55,454,260	16,658,994	71,060,253	64,556,302
Gain on sale of Centralia Steam Plant	29,639,799	-	-	-	-
Other income (expense), net	(240,039)	(3,907,245)	(1,214,197)	(6,931,565)	(1,558,908)
Investment income [A]	9,753,106	4,140,404	7,222,664	8,467,693	5,648,899
Total operating and other income	1,123,928	55,687,419	22,667,461	72,596,381	68,646,293
Interest Expense					
Interest expense	53,651,607	46,952,066	42,809,590	43,284,665	42,347,221
Amortization of debt expense	5,054,837	5,208,932	5,356,167	5,198,827	5,247,412
Interest charged to construction	(5,553,780)	(4,212,048)	(2,921,783)	(2,317,158)	(1,961,320)
Net interest expense	53,152,664	47,948,950	45,243,974	46,166,334	45,633,313
Net income (loss)	$ (52,028,736)	$ 7,738,469	$ (22,576,513)	$ 26,430,047	$ 23,012,980

[A] *GASB Statement No. 31, "Accounting and Financial Reporting for Certain Investments and for External Investment Pools", was implemented in 1997 to report investments at fair value and the fair value adjustments as part of investment income. Accordingly, values and amounts for 1996 were restated and equity includes the cumulative effect of implementing GASB Statement No. 31.*

Interest Requirements and Principal Redemption on Bonded Debt

As of December 31, 2000

	Prior Lien Bonds			Subordinate Lien Bonds	
Years	*Principal*	*Interest*	*Total*	*Principal*	*Interest* [B]
2001	$ 37,360,000	$ 53,105,842	$ 90,465,842	$ 2,400,000	$ 4,677,362
2002	39,291,500	51,259,217	90,550,717	3,360,000	4,257,021
2003	40,250,000	49,274,905	89,524,905	3,585,000	3,971,370
2004	44,915,000	47,143,019	92,058,019[A]	4,115,000	3,860,794
2005	45,531,000	44,804,890	90,335,890	4,445,000	3,850,608
2006	46,980,000	42,500,405	89,480,405	4,775,000	3,703,927
2007	49,530,000	40,032,928	89,562,928	5,305,000	3,572,170
2008	48,855,000	37,793,833	86,648,833	5,840,000	3,342,551
2009	48,550,000	35,139,687	83,689,687	6,270,000	3,075,680
2010	47,900,000	32,474,867	80,374,867	6,705,000	2,771,929
2011	46,900,000	30,111,039	77,011,039	7,345,000	2,722,544
2012	46,350,000	27,488,177	73,838,177	7,785,000	2,604,703
2013	45,635,000	24,900,450	70,535,450	8,425,000	2,262,284
2014	45,035,000	22,341,550	67,376,550	8,865,000	1,799,802
2015	44,505,000	19,831,588	64,336,588	9,410,000	1,331,760
2016	43,920,000	17,386,751	61,306,751	7,755,000	786,304
2017	42,655,000	14,992,238	57,647,238	2,600,000	518,751
2018	40,575,000	12,686,575	53,261,575	2,750,000	369,051
2019	38,380,000	10,488,263	48,868,263	1,300,000	207,744
2020	34,925,000	8,408,805	43,333,805	1,355,000	128,858
2021	31,230,000	6,541,925	37,771,925	1,410,000	43,590
2022	28,555,000	4,797,619	33,352,619	-	-
2023	26,670,000	3,197,315	29,867,315	-	-
2024	25,890,000	1,694,712	27,584,712	-	-
2025	7,805,000	421,466	8,226,466	-	-
Totals	$ 998,192,500	$ 638,818,066	$ 1,637,010,566	$ 105,800,000	$ 49,858,803

[A] ***Maximum debt service—see Note 3 on page 20.***

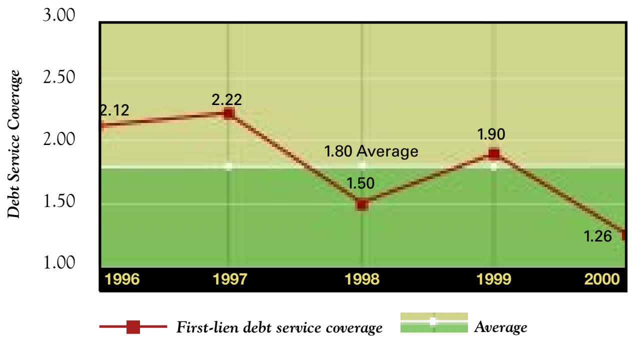
[B] ***Based on actual and estimated interest rates ranging from 4.00% to 6.20%.***

Debt Service Coverage: Prior Lien Bonds

For the years ended December 31,

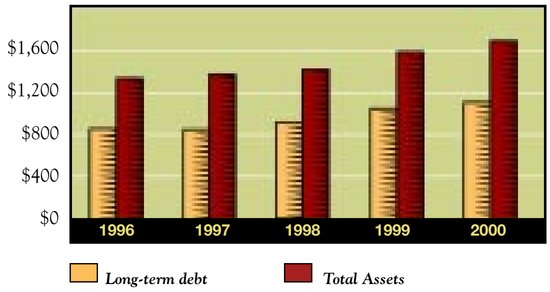
	Revenue Available for Debt Service	*Debt Service Requirements*	*Debt Service Coverage*
2000	$104,629,835	$83,205,503	1.26
1999	143,335,963	75,394,637	1.90
1998	105,024,128	69,898,371	1.50
1997	157,402,022	71,035,264	2.22
1996	144,099,243	68,001,376	2.12

Debt Service Coverage: 1996-2000



Long-term Debt to Total Assets

(In Millions)



Statement of Bonded Debt

As of December 31, 2000

Name of Bond	When Due	Interest Rate (%)	Amount Issued	Amount Redeemed	Amount Outstanding 12/31/00	Amount Due Within One Year	Accrued Interest
Bonds redeemed at 12-31-00							
General Lien Bonds							
1903-14	1923-1924		$ 4,044,000	$ 4,044,000			
Revenue Bonds [A]							
1917-95	1923-2020		1,330,288,500	1,330,288,500			
TOTAL			$ 1,334,332,500	$ 1,334,332,500			
Prior Lien Bonds							
Series 1992	2001	5.200	$ 4,740,000		$ 4,740,000	$ 4,740,000	$ 102,700
Series 1992	2002	5.300	4,710,000		4,710,000		104,012
Series 1992	2003	5.400	5,680,000		5,680,000		127,800
Series 1992	2004	5.500	5,630,000		5,630,000		129,021
Series 1992	2005	5.625	5,575,000		5,575,000		130,664
Series 1992	2006-2012	5.750	72,250,000		72,250,000		1,730,990
Series 1992	2013-2014	6.000	19,310,000		19,310,000		482,750
Series 1992	2015-2017	5.750	33,450,000		33,450,000		801,407
Series 1993	2001	4.700	27,620,000		27,620,000	27,620,000	216,357
Series 1993	2002	4.800	28,840,000		28,840,000		230,720
Series 1993	2003	4.900	27,250,000		27,250,000		222,542
Series 1993	2004	5.000	28,525,000		28,525,000		237,708
Series 1993	2005	5.100	29,795,000		29,795,000		253,257
Series 1993	2006	5.200	23,020,000		23,020,000		199,507
Series 1993	2007	5.300	24,200,000		24,200,000		213,767
Series 1993	2008	5.400	12,020,000		12,020,000		108,180
Series 1993	2009-2010	5.450	25,415,000		25,415,000		230,853
Series 1993	2011-2013	5.500	12,425,000		12,425,000		113,896
Series 1993	2014-2018	5.375	25,645,000		25,645,000		229,736
Series 1994	2001-2004	6.000	11,960,000		11,960,000	2,575,000	358,800
Series 1995	2001	5.000	1,770,000		1,770,000	1,770,000	29,500
Series 1995	2002	4.500	241,500		241,500		3,622
Series 1995	2002-2004	5.000	4,825,000		4,825,000		80,417
Series 1995	2005	4.800	456,000		456,000		7,296
Series 1995	2006-2007	5.000	4,650,000		4,650,000		77,500
Series 1995	2008	5.125	2,515,000		2,515,000		42,965
Series 1995	2009	5.300	2,655,000		2,655,000		46,905
Series 1995	2010	5.400	2,805,000		2,805,000		50,490
Series 1995	2011	5.500	2,970,000		2,970,000		54,450
Series 1995	2012	5.600	3,145,000		3,145,000		58,707
Series 1995	2013-2018	5.625	23,285,000		23,285,000		436,594
Series 1995	2019-2020	5.700	9,815,000		9,815,000		186,484

Continued on next page.

Name of Bond	When Due	Interest Rate (%)	Amount Issued	Amount Redeemed	Amount Outstanding 12/31/00	Amount Due Within One Year	Accrued Interest
Series 1996	2002-2008	5.250	$ 7,055,000		$ 7,055,000		$ 92,597
Series 1996	2009	5.300	1,235,000		1,235,000		16,364
Series 1996	2010	5.400	1,300,000		1,300,000		17,550
Series 1996	2011-2013	5.500	4,365,000		4,365,000		60,019
Series 1996	2014-2021	5.625	16,045,000		16,045,000		225,633
Series 1997	2003-2018	5.000	21,425,000		21,425,000		535,625
Series 1997	2019-2022	5.125	8,575,000		8,575,000		219,734
Series 1998	2001-2004	4.500	2,790,000		2,790,000	655,000	62,775
Series 1998	2005-2008	4.750	18,990,000		18,990,000		451,012
Series 1998	2009-2020	5.000	82,390,000		82,390,000		2,059,750
Series 1998	2004-2019	4.750	59,545,000		59,545,000		235,699
Series 1998	2021	4.875	11,250,000		11,250,000		45,703
Series 1998	2024	5.000	19,205,000		19,205,000		80,021
Series 1999	2006-2007	5.000	6,250,000		6,250,000		78,125
Series 1999	2008-2009	5.750	13,500,000		13,500,000		194,062
Series 1999	2010	5.875	2,500,000		2,500,000		36,719
Series 1999	2011-2024	6.000	135,750,000		135,750,000		2,036,250
Series 2000	2006	5.000	2,875,000		2,875,000		11,979
Series 2000	2007	4.500	3,015,000		3,015,000		11,306
Series 2000	2008	5.250	3,150,000		3,150,000		13,781
Series 2000	2009-2011	5.500	10,505,000		10,505,000		48,148
Series 2000	2012-2018	5.625	32,325,000		32,325,000		151,523
Series 2000	2019	5.250	5,715,000		5,715,000		25,003
Series 2000	2020	5.300	6,015,000		6,015,000		26,566
Series 2000	2021	5.250	6,330,000		6,330,000		27,694
Series 2000	2025	5.400	28,900,000		28,900,000		130,050
Total Prior Lien Bonds			$ 998,192,500		$ 998,192,500	$ 37,360,000	$ 14,193,285
Subordinate Lien Bonds							
Series 1990	2001-2015	3.350-5.250 [B]	$ 21,600,000		$ 21,600,000	$ 900,000	$ 199,504
Series 1991	2001-2016	2.750-6.000 [B]	44,000,000		44,000,000	700,000	250,017
Series 1993	2001-2018	2.750-6.000 [B]	20,400,000		20,400,000	800,000	61,368
Series 1996	2002-2021	2.850-5.750 [B]	19,800,000		19,800,000	-	58,315
Total Subordinate Bonds			$ 105,800,000		$ 105,800,000	$ 2,400,000	$ 569,204
Total Bonded Debt			$ 1,103,992,500		$ 1,103,992,500	$ 39,760,000	$ 14,762,489

[A] ***Including bonds defeased through refundings and Subordinate Lien Bonds.***

[B] ***Adjustable rates in effect during 2000.***

Customer Statistics

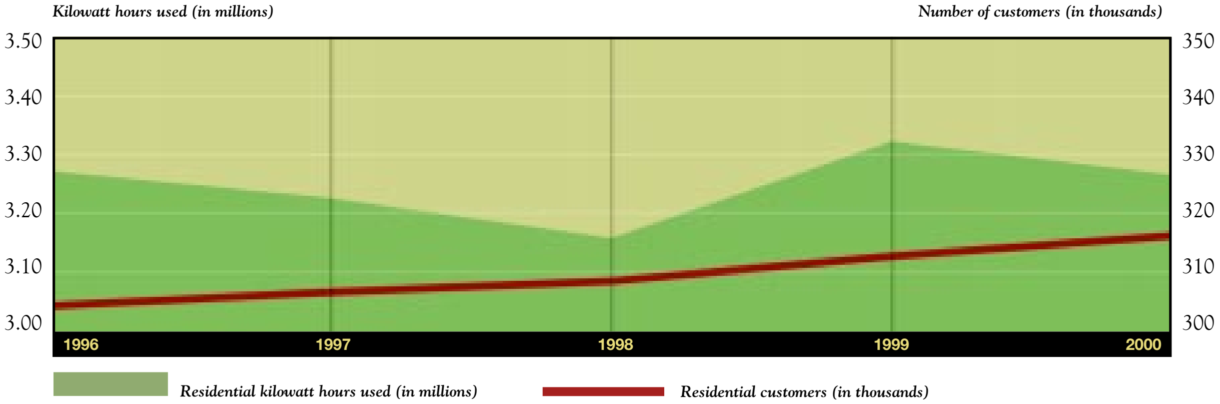
For the years ended December 31,	*2000*	*1999*	*1998*	*1997*	*1996*
Average Number Of Customers					
Residential	316,758	312,849	308,564	306,629	304,287
Commercial	30,839	30,568	30,376	30,243	30,005
Industrial	276	279	286	291	295
Governmental	1,686	1,817	1,836	1,869	1,945
Sales for Resale	-	-	1	-	-
Total	**349,559**	**345,513**	**341,063**	**339,032**	**336,532**

Kilowatt Hours (In 000's) *		2000		1999		1998		1997		1996
Residential	34%	3,260,325	35%	3,314,126	34%	3,153,926	35%	3,221,824	36%	3,267,794
Commercial	41%	3,885,959	39%	3,742,142	39%	3,607,461	38%	3,560,037	38%	3,506,608
Out of service area (commercial)	1%	96,399	1%	89,906	1%	63,876	0%	-	0%	-
Industrial	14%	1,340,396	14%	1,341,721	15%	1,454,783	16%	1,474,754	15%	1,412,509
Governmental	10%	902,865	11%	986,754	11%	996,077	11%	983,445	11%	987,010
Sales for Resale		-	-	-	-	58,508	-	-	-	-
Unbilled kWh—net change	-	70,948	-	13,150	-	23,052	-	(7,829)	-	14,079
Total	100%	9,556,892	100%	9,487,799	100%	9,357,683	100%	9,232,231	100%	9,188,000

** Percentages exclude sales for resale and unbilled kWh-net change.*

Average Annual Revenue Per Customer (In Service Area)	2000	1999	1998	1997	1996
Residential	$ 468	$ 456	$ 436	$ 447	$ 435
Commercial	$ 4,906	$ 4,552	$ 4,423	$ 4,537	$ 4,426
Industrial	$ 170,601	$ 164,485	$ 175,645	$ 180,133	$ 168,715
Governmental	$ 19,975	$ 20,785	$ 20,349	$ 20,461	$ 20,046

Residential Consumption



Customer Statistics

For the years ended December 31,		2000	1999	1998	1997	1996
Average Annual Consumption Per Customer (Kwhs) [A]						
Residential	- Seattle	10,293	10,593	10,221	10,507	10,739
	- National	10,623	10,237	10,284	10,072	10,275
Commercial	- Seattle	126,010	122,420	118,700	117,714	116,867
	- National	71,640	68,858	69,489	68,679	67,250
Industrial	- Seattle	4,856,507	4,809,036	5,086,654	5,067,883	4,788,116
	- National	1,909,814	1,930,929	1,933,285	1,825,789	1,757,938
Governmental	- Seattle	535,507	543,068	542,526	526,188	507,460
	- National [B]	n/a	106,614	110,403	106,354	108,668
Average Rate Per Kilowatt Hour (Cents) [A]						
Residential	- Seattle	4.55	4.30	4.27	4.25	4.05
	- National	8.21	8.16	8.26	8.43	8.36
Commercial	- Seattle	3.89	3.72	3.72	3.85	3.79
	- National	7.20	7.26	7.41	7.58	7.64
Industrial	- Seattle	3.51	3.42	3.45	3.55	3.52
	- National	4.45	4.43	4.48	4.54	4.60
Governmental	- Seattle	3.73	3.83	3.75	3.89	3.95
	- National	6.82	6.83	6.63	6.89	6.94
Total	- Seattle [C]	4.06	3.89	3.87	3.93	3.88
	- National	6.66	6.64	6.74	6.85	6.86

[A] *Source of national data: Edison Electric Institute, source and disposition data (2000 preliminary, 1999 revised to actuals).*

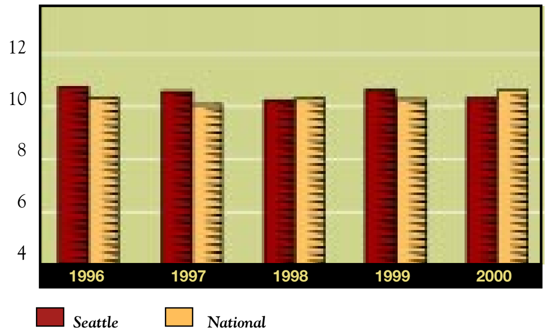
[B] *2000 data not available as of this printing.*

[C] *Seattle total includes the unbilled revenue adjustment. Other Seattle rates on this schedule do not include this adjustment.*

NOTE: The latest rate adjustment is effective July 1, 2001. Rates are set by the Seattle City Council. Notice of public hearings may be obtained on request to The Office of the City Clerk, Municipal Building, 600-4th Avenue, Room 104, Seattle WA 98104.

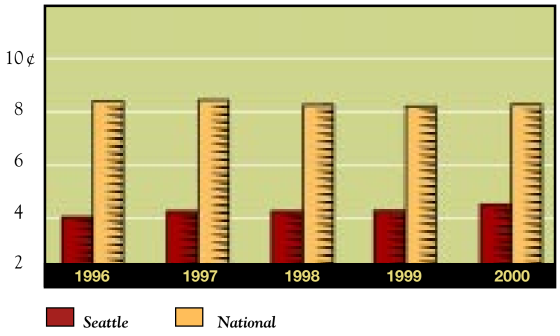
Average Annual Residential Consumption

(In thousands of kilowatt hours)



Average Residential Rates

(In cents per kilowatt hour)



Power

For the years ended December 31,	2000	1999	1998	1997	1996
Power Costs					
Hydraulic generation [A]	$ 28,288,083	$ 26,746,081	$ 26,360,001	$ 27,678,950	$ 26,619,873
Steam generation [A, B]	7,521,097	14,664,491	14,963,065	13,067,074	12,739,214
Long-term purchased power	74,999,373	79,984,055	79,999,162	73,952,830	67,357,080
Wholesale power purchases [C, D]	212,402,254	34,295,550	52,032,908	14,106,211	11,974,145
Wholesale power sales [C, D]	(103,827,060)	(53,161,124)	(34,927,269)	(35,431,364)	(18,845,997)
Owned transmission [A]	5,775,106	6,504,089	5,818,679	5,826,148	5,855,282
Wheeling expenses	17,001,385	16,864,661	16,683,699	17,355,147	15,700,345
Power marketing and system control	5,504,322	4,508,274	3,716,008	3,228,159	3,142,173
Total power costs	$ 247,664,560	$ 130,406,077	$ 164,646,253	$ 119,783,155	$ 124,542,115
Power Statistics (1000's Kwh)					
Hydraulic generation	6,405,929	7,764,312	6,160,442	8,346,762	7,921,980
Steam generation [B]	277,103	689,802	712,095	538,374	602,360
Long-term purchased power	3,149,215	3,213,813	3,016,515	2,814,135	2,349,801
Wholesale power purchases [C, D]	2,459,825	1,159,875	2,198,887	922,229	803,311
Wholesale power sales [C, D]	(2,230,670)	(2,672,264)	(2,019,502)	(2,834,626)	(1,892,277)
Other [E]	(504,510)	(667,739)	(710,754)	(554,644)	(597,175)
Total power delivered	**9,556,892**	**9,487,799**	**9,357,683**	**9,232,230**	**9,188,000**
Average cost per kWh delivered (in mills)	**25.915**	**13.745**	**17.595**	**12.974**	**13.555**

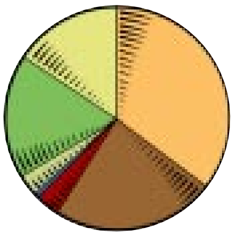
[A] *Including depreciation.*

[B] *The Centralia Steam Plant was sold in May 2000.*

[C] *Wholesale purchased power can fluctuate widely from year to year depending upon water conditions in Seattle City Light's drainage area. During 1998 and 2000, the drainage area experienced lower water conditions. Conditions were favorable in 1996, 1997 and 1999.*

[D] *Wholesale power purchases and sales also include "bookouts" and reserve capacity transactions.*

[E] *"Other" includes Article 49 delivery, self-consumed energy, system losses, net power exchanges (for years 1996 through 1999), and miscellaneous power transactions. Net power exchanges in 2000 are included in "Long-term purchased power".*

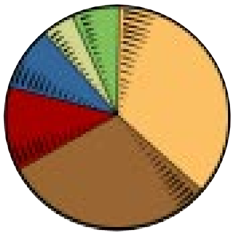


2000 Sources of Power
(in percent of gWh)

Generated
- 35% Boundary
- 24% Skagit
- 3% Centralia Steam
- 1% Cedar Falls & So. Fork Tolt

Treaty
- 3% BC Hydro

Purchased
- 18% Miscellaneous
- 16% BPA



2000 Uses of Power
(in percent of gWh)

Service Area
- 36% Commercial
- 31% Residential
- 13% Industrial
- 9% Governmental

Other
- 4% Other
- 7% City Light Operations/Services

Changes In Owned Total Generating Installed Capability

Year	Plant	KW Added	Peaking Capability Total KW
1904-09	Cedar Falls Hydro Units 1, 2, 3 & 4	10,400	10,400
1912	Lake Union Hydro Unit 10	1,500	11,900
1914-21	Lake Union Steam Units 11, 12 & 13	40,000	51,900
1921	Newhalem Hydro Unit 20	2,300	54,200
1921	Cedar Falls Hydro Unit 5	15,000	69,200
1924-29	Gorge Hydro Units 21, 22 & 23	60,000	129,200
1929	Cedar Falls Hydro Unit 6	15,000	144,200
1932	Cedar Falls Hydro Units 1, 2, 3 & 4	(10,400) [A]	133,800
1932	Lake Union Hydro Unit 10	(1,500) [A]	132,300
1936-37	Diablo Hydro Units 31, 32, 35 & 36	132,000	264,300
1951	Georgetown Steam Units 1, 2 & 3	21,000	285,300
1951	Gorge Hydro Unit 24	48,000	333,300
1952-56	Ross Hydro Units 41, 42, 43 & 44	450,000	783,300
1958	Diablo Plant Modernization	27,000	810,300
1961	Gorge Hydro, High Dam	67,000	877,300
1967	Georgetown Plant, performance test gain	2,000	879,300
1967	Boundary Hydro Units 51, 52, 53 & 54	652,000	1,531,300
1972	Centralia Units 1 & 2	102,400	1,633,700
1980	Georgetown Steam Units 1, 2, & 3	(23,000) [A]	1,610,700
1986	Boundary Hydro Units 55 & 56	399,000	2,009,700
1987	Lake Union Steam Units 11, 12 & 13	(40,000) [A]	1,969,700
1989-92	Gorge Units 21, 22, & 23, new runners	4,600	1,974,300
1993	Centralia Transmission Upgrade	5,000	1,979,300
1995	South Fork Tolt	16,800	1,996,100
2000	Centralia Units 1 & 2	(107,400) [B]	1,888,700

[A] *Retirement of units (decrease in total capability).*

[B] *The Centralia steam plant was sold in May 2000.*

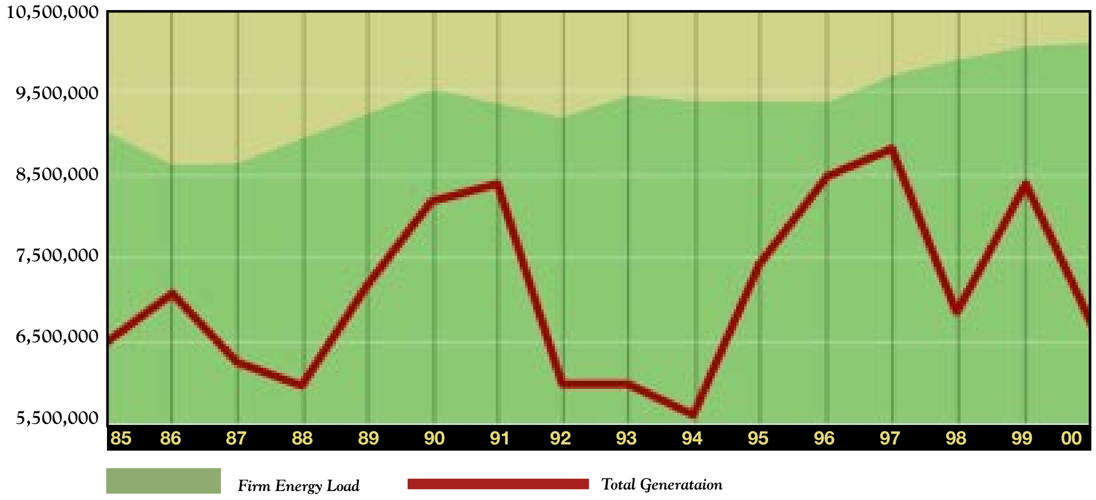
System Requirements

Year	Kilowatts Average Load	Kilowatts Peak Load[C]
1950	154,030	312,000
1955	381,517	733,000
1960	512,787	889,000
1965	635,275	1,138,000
1970	806,813	1,383,000
1975	848,805	1,429,387
1980	963,686	1,771,550
1985	1,025,898	1,806,341
1986	996,648	1,699,434
1987	987,070	1,724,726
1988	1,022,442	1,731,518
1989	1,059,272	1,979,528
1990	1,088,077	2,059,566
1991	1,065,987	1,815,164
1992	1,048,055	1,743,975
1993	1,082,616	1,875,287
1994	1,074,852	1,819,323
1995	1,072,692	1,748,657
1996	1,110,133	1,950,667
1997	1,111,035	1,816,152
1998	1,120,178	1,928,854
1999	1,142,382	1,729,933
2000	1,142,383	1,769,440

[C] *One-hour peak.*

Total Generation and Firm Energy Load

(In megawatt hours)

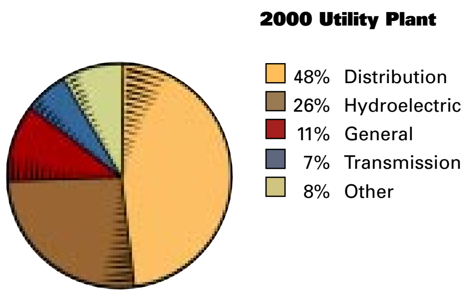


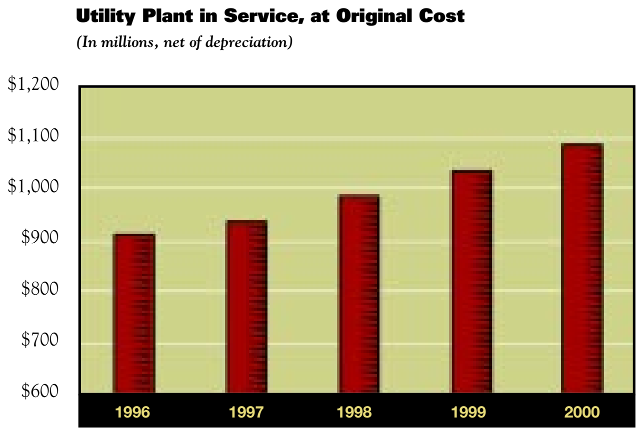
Utility Plant, at Original Cost

For the years ended December 31,	*2000*	*1999*	*1998*	*1997*	*1996*
Steam plant* [A]	$ -	$ 28,620,025	$ 28,701,981	$ 28,513,553	$ 28,081,635
Hydroelectric plant*	531,705,122	507,902,539	496,924,588	482,814,231	471,002,970
Transmission plant*	135,787,595	130,371,827	129,608,725	128,870,027	125,810,457
Distribution plant*	953,429,070	892,578,913	838,265,006	773,078,710	727,614,852
General plant*	218,149,068	203,660,796	175,365,459	165,564,632	157,075,200
Total electric plant in service	**1,839,070,855**	**1,763,134,100**	**1,668,865,759**	**1,578,841,153**	**1,509,585,114**
Accumulated depreciation	(756,498,166)	(731,545,437)	(685,315,961)	(642,639,293)	(598,452,675)
Total plant in service, net of depreciation	1,082,572,689	1,031,588,663	983,549,798	936,201,860	911,132,439
Nonoperating properties, net of depreciation	6,613,263	6,366,276	6,225,934	5,854,060	6,327,458
Utility plant, net of depreciation	1,089,185,952	1,037,954,939	989,775,732	942,055,920	917,459,897
Construction work-in-progress	152,981,465	118,281,967	82,878,682	71,645,046	60,529,756
Net utility plant	$ 1,242,167,417	$ 1,156,236,906	$1,072,654,414	$ 1,013,700,966	$ 977,989,653

[A] *The Centralia steam plant was sold in May 2000.*

* *Including land.*





Payroll and Employee Benefits

For the years ended December 31,	*2000*	*1999*	*1998*	*1997*	*1996*
Full-time equivalent positions	1,647	1,627	1,623	1,678	1,778
Straight time	$ 74,381,880	$ 71,440,967	$ 67,273,819	$ 66,823,852	$ 68,559,759
Overtime	16,288,007	13,978,470	9,330,099	7,404,511	6,280,851
Vacation and other	15,680,918	15,474,009	13,899,876	13,555,234	13,929,593
Total payroll	106,350,805	100,893,446	90,503,794	87,783,597	88,770,203
Employee benefits	27,328,937	24,418,514	23,084,040	22,389,857	21,248,714
Total payroll and employee benefits	$ 133,679,742	$ 125,311,960	$ 113,587,834	$ 110,173,454	$ 110,018,917
Percentage of employee benefits (including vacation) to straight time	57.8%	55.8%	55.0%	53.8%	51.3%

***Note:** 1999 straight time and overtime were revised in 2000 to use the general ledger as the reporting source going forward. Beginning in 1998, the general ledger was used as the reporting source for vacation and other and employee benefits. In previous years, the payroll system was the reporting source.*

Taxes and Contributions to the Cost of Government

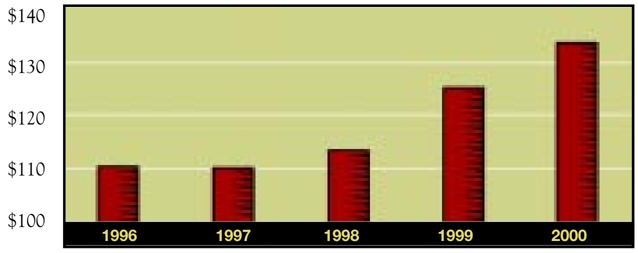
For the years ended December 31,	*2000*	*1999*	*1998*	*1997*	*1996*
Taxes					
City occupation and business taxes	$ 25,107,376	$ 22,692,502	$ 21,590,832	$ 21,745,774	$ 21,047,317
State public utility and business taxes	15,631,467	14,205,768	14,405,965	13,734,158	13,371,007
Other special taxes	184,271	(108,057)	684,723	261,614	357,815
Contract payments for government services	1,936,941	1,870,866	1,480,481	1,364,078	1,313,550
Total taxes as shown in statement of operations	42,860,055	38,661,079	38,162,001	37,105,624	36,089,689
Taxes/licenses charged to accounts other than taxes	9,012,216	8,874,311	7,380,933	8,832,738	8,400,757
Other contributions to the cost of government	3,513,674	4,686,514	3,479,904	3,237,229	3,442,587
Total miscellaneous taxes	12,525,890	13,560,825	10,860,837	12,069,967	11,843,344
Total taxes and contributions	$ 55,385,945	$ 52,221,904	$ 49,022,838	$ 49,175,591	$ 47,933,033

***Note:** Electric rates include all taxes and contributions. The State Public Utility Tax for retail electric power sales was 3.873%.*

The City of Seattle Occupation Utility Tax was 6% for retail electric power sales and 5% for out-of-state retail electric power sales.

Payroll and Employee Benefits

(In millions)



Retail Electrical Customer Investment

For the years ended December 31,	*2000*	*1999*	*1998*	*1997*	*1996*
Conservation [A]					
Non-programmatic					
conservation expenses [B]	$ 1,959,891	$ 2,540,280	$ 2,330,961	$ 2,819,454	$ 3,302,633
Conservation programs [C]					
Non-low income	13,787,361	16,136,265	16,121,498	12,121,898	16,455,878
Low income	1,882,941	1,820,369	1,646,120	1,624,811	1,624,056
External conservation funding					
Bonneville Power Administration					
Non-low income	-	(1,680,060)	(3,064,427)	(5,310,336)	(9,904,627)
Low income	-	-	2,594	(167,540)	(427,887)
Customer obligation repayments [D]	(1,468,189)	(2,306,792)	(2,803,620)	(2,279,366)	(1,064,557)
Low-income Energy					
Assistance [E]	3,856,448	4,026,366	4,180,513	4,506,452	4,866,331
Non-hydro Renewable					
Resources [F]	238,015	241,715	221,748	265,458	282,514
Net public purpose spending	$ 20,256,467	$ 20,778,143	$ 18,635,387	$ 13,580,831	$ 15,134,341
Revenue from electric sales	$ 391,578,285	$ 367,934,881	$ 360,625,360	$ 362,710,992	$ 356,670,693
Percent public purpose spending	5.2%	5.6%	5.2%	3.7%	4.2%
Energy savings in year (MW hours) [G]	698,947	668,669	615,814	565,618	530,769

Note: Certain prior year amounts have been restated to conform to the current presentation.

[A] *Non-programmatic conservation is funded from current revenues. Conservation programs are financed by either debt or current revenues.*

[B] *Non-programmatic expenditures include the regional Lighting Design Lab, support of energy codes and early adopter activities, program planning, evaluation, data processing, and general administration.*

[C] *Non-low income programmatic conservation includes expenditures for program measures, incentives, field staff salaries, and direct program administration. Low-income programmatic conservation includes these expenditures for the Department's Low-Income Electric and Low-Income Multifamily Programs.*

[D] *Customer obligations repaid in each year include payments on outstanding five-year or ten-year loans, plus repayments in the first year after project completion for utility-financed measures.*

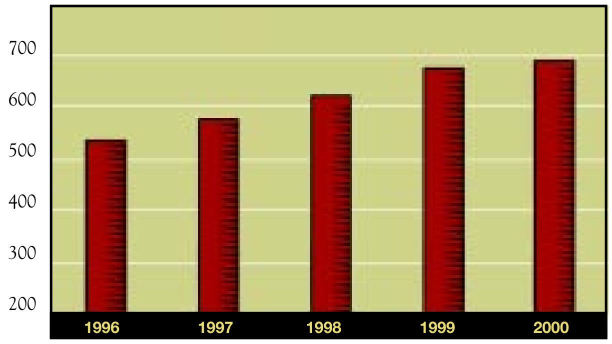
[E] *Low-income assistance includes rate discounts; payments from the low-income account (from interest earnings to help low-income customers with bill payments); and waivers of charges for appliance repair, trouble calls, account changes, and administration.*

[F] *Co-generation from the West Point Sewage Treatment plant is funded from current revenues. The Department purchased from King County approximately 7,554 MWh of energy generated by three reciprocating engines using methane gas from the treatment plant. Total electrical output will be purchased under the power purchase contracts executed with Metro in 1983, until termination of the agreement in September 2003.*

[G] *Electricity savings in each year are from cumulative conservation program participants for completed projects with unexpired measure lifetimes.*

Energy Saved Through Conservation

(In thousands of MWh)



Elected Officials
(As of January 2001)

Mayor
Paul Schell

Seattle City Council
Margaret Pageler, Council President
Chair: Legislative Department and Intergovernmental Affairs
Chair: Water Resources, Solid Waste, and Public Health Committee

Jim Compton
Chair: Public Safety and Technology Committee

Richard Conlin
Chair: Neighborhoods, Sustainability and Community Development Committee

Jan Drago
Chair: Finance, Budget and Economic Development Committee
Chair: Labor Relations Policy Committee

Nick Licata
Chair: Culture, Arts and Parks Committee

Richard McIver
Chair: Transportation Committee

Judy Nicastro
Chair: Landlord/Tenant and Land Use Committee

Peter Steinbrueck
Chair: House, Human Services, Education and Civil Rights Committee

Heidi Wills
Chair: Energy and Environmental Policy Committee

City Attorney
Mark Sidran

Executive Team

Gary Zarker
(206) 684-3200
Superintendent

Dana Backiel
(206) 386-4500
Deputy Superintendent- Generation Branch
Generation Engineering
Generation Plant Operations
Generation Program Management
Boundary Capital Improvement Project
Skagit Capital Improvement Project

Paula Green
(206) 386-4530
Deputy Superintendent- Power Management Branch
System Control Center
Power Marketing Monthly
Power Marketing Real Time
Resource Administration
Automated Systems

Jesse Krail
(206) 615-1505
Deputy Superintendent-Distribution Branch
Systems Engineering
North Electric Service
South Electric Service
Central Electric Service
Power Stations
Distribution Program Management
Apprenticeship Office

Andrew Lofton
(206) 684-3361
Deputy Superintendent-Customer Services Branch
Account Executives
Account Services
Energy Management Services
Hearing Officer

Jim Ritch
(206) 386-4500
Deputy Superintendent-Finance and Administration Branch
Finance
Facilities Management
Information Technology

Nancy Glaser
(206) 684-3117
Director of Strategic Planning
Acting Director of Environment and Safety

Bill Kolden
(206) 684-3125
Director of Human Resources

Bob Royer
(206) 615-0050
Director of Communications and Public Affairs