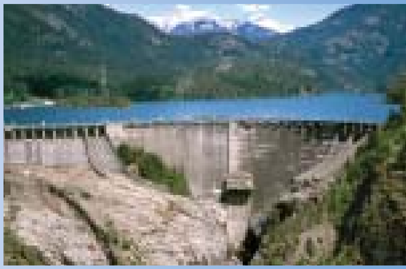
2006
Integrated Resource Plan



Seattle City Light

Seattle's municipal electric utility

2006 Integrated Resource Plan

Seattle City Light
Integrated Resource Planning
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Bald Eagle
Stateline Wind Farm
Sockeye Salmon
Diablo Dam on the Skagit River

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2006 Integrated Resource Plan Executive Summary

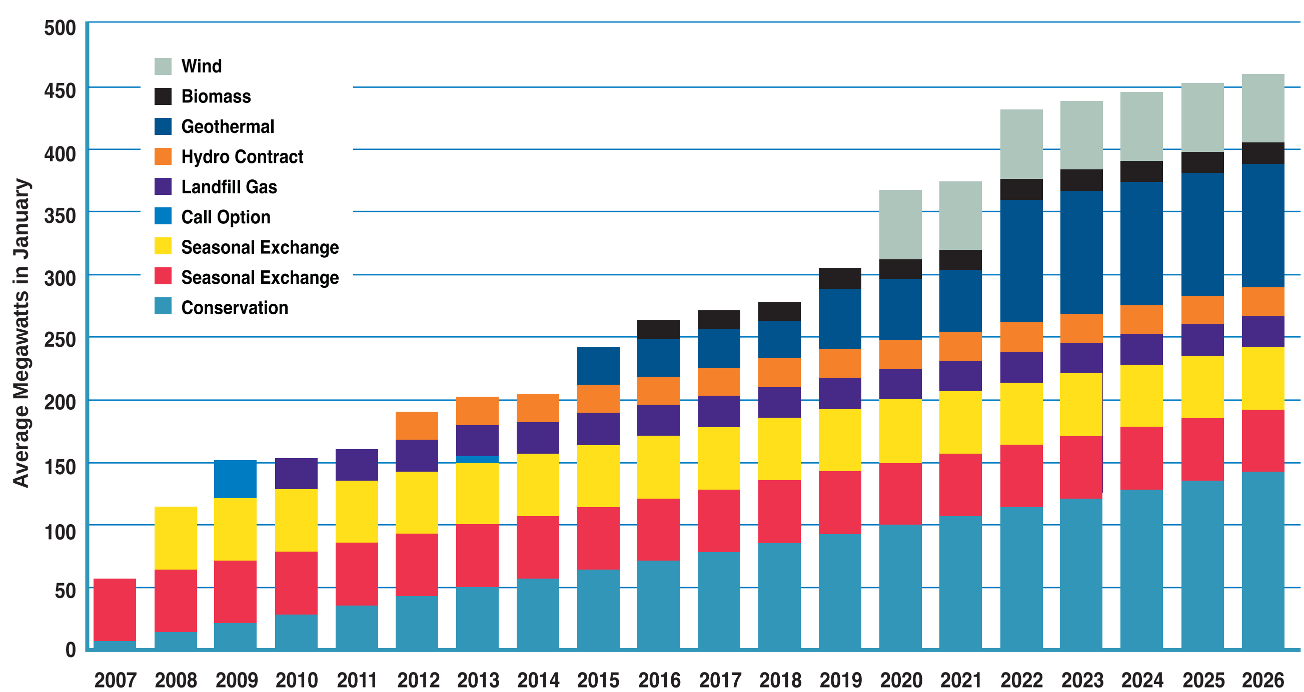
Mayor's Recommended Resource Strategy

Based upon the Integrated Resource Plan (IRP) development process, the Mayor recommends a long-range resource acquisition strategy that:

- Invests in cost-effective conservation for the next 20 years.
- Institutes cost-effective seasonal power exchanges, beginning in the near term.
- Exercises City Light's preference rights for the purchase of low-cost power from the Bonneville Power Administration in a new contract beginning in 2011.
- Plans for the near- to mid-term purchase of output from low-cost renewable resources such as a new landfill gas project and a small existing hydro project.
- Acquires output from other renewable resources such as wind and geothermal, beginning in about 2015, in compliance with State Initiative 937.

This course of action, illustrated below, is an extension of the Utility's history of obtaining low-cost power with low environmental impacts for its ratepayers/owners. Conservation is the first resource of choice, followed by seasonal exchanges that help shape resources to load. Market-based purchases have a place when there is a resource need but not enough justification for acquiring new resources. When new resources are needed, the lowest-cost renewable resources are acquired first, followed by higher-cost renewable resources. City Light expects its access to low-cost federal power will be locked in for 20 years, beginning in 2011.

Mayor's Preferred Alternative



Integrated Resource Planning Process

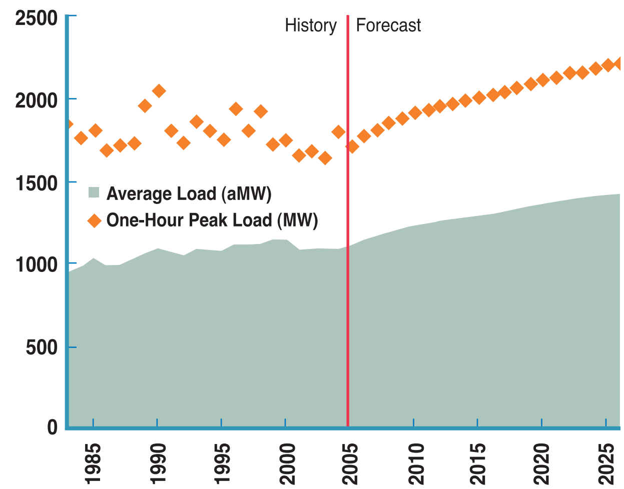
The Mayor's recommendation is the culmination of a process that included these steps:

- Involving the public, including citizens and stakeholders with diverse perspectives.
- Recruiting expertise from within and from outside the Utility.
- Licensing and installing a sophisticated computer model for power planning.
- Calibrating the model for the characteristics of City Light's complex hydroelectric operations and purchase power contracts.
- Thoroughly assessing conservation resource potential in the service area.
- Forecasting customer demand for power each month through 2026.
- Developing a resource adequacy measure, crucial for defining the timing and amount of future need.
- Developing costs and characteristics of alternative resources to be included in the candidate resource portfolios.
- Constructing and modeling Round 1 candidate resource portfolios for evaluation against four criteria: reliability, cost, risk and environmental impacts.
- Issuing a Draft Environmental Impact Statement (DEIS) for Round 1 portfolios.
- Constructing and modeling Round 2 candidate resource portfolios, based on findings and comments in response to Round 1.
- Recommending a resource strategy and near-term resource action plan.
- Issuing a final EIS.

Load Forecast and Resource Adequacy

A first step in assessing the need for additional resources is a forecast of future need, taking into account both the load forecast and the desired level of resource adequacy. The Utility's long-range forecast projects continued load growth for the service area. The graph below shows the load forecast assuming no new programmatic conservation, because the IRP treats conservation as a resource and evaluates it in the same way as other resources.

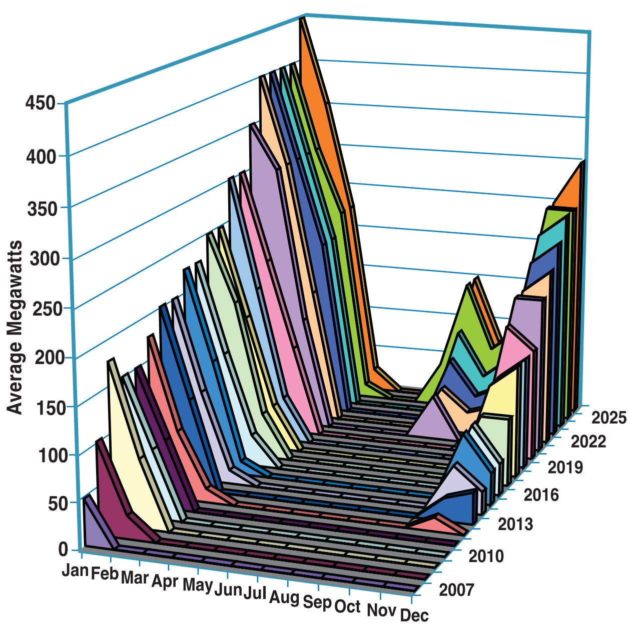
System Annual Load History and Forecast (with no new conservation program resources)



City Light is dedicated to providing a high level of resource reliability. This includes the ability to serve load even when generation capability is low. Low generation capability is usually due to drought conditions in the Pacific Northwest. The greatest threat to City Light's resource reliability is the combination of low water and high customer demand for power. High customer demand is usually due to extreme low temperatures in the winter. The IRP relies on a measure of resource adequacy that ensures that the Utility has a 95 percent confidence level of meeting loads in any given January (the highest demand month).

Using the 95 percent resource adequacy measure and assuming that 100 average megawatts of power can be purchased from the spot market, modeling the operation of City Light's existing resource portfolio shows that the Utility needs additional resources in the winter of 2007. This need increases through time as load grows and as existing contracts expire. By 2026 the need for power in the winter grows to 450 average megawatts in the winter and 200 average megawatts in the summer. The timing and amount of resource need is shown on the graph below.

95% Resource Adequacy: Projected Gap between Load and Resources



Policy Direction

The policies most germane to the Utility's Integrated Resource Plan are the recently passed Washington State Initiative 937 and Seattle City Council Resolutions 30144 and 30359.

Resolution 30144 (2000) and the Mayor's Climate Action Plan direct the Utility to meet load growth with conservation and renewable resources. Resolution 30144 also directs City Light to mitigate for greenhouse gas emissions from any fossil fuel use, and sets a long-term goal of "Net Zero" annual greenhouse gas emissions, which City Light achieved in 2005.

The Greenhouse Gas Mitigation Strategy Resolution 30359 (2001) sets standards for calculating greenhouse gas emissions and mitigation projects. The climate change policy does not prohibit City Light from acquiring electricity from resources that produce greenhouse gas, but does require the Utility to fully offset those emissions.

Initiative 937 requires utilities with more than 25,000 customers to acquire cost-effective conservation and to serve load with increasing percentages of renewable power. The intent of the initiative is consistent with existing City policy, though specifics of the legislation will likely have an impact on the timing and exact amount of conservation and renewable resource acquisition. The Mayor's preferred resource strategy complies with the City's interpretation of the initiative.

Existing Resource Portfolio

The existing portfolio includes conservation, generation resources and market resources. For nearly 30 years, City Light policy makers have been unwavering in their commitment to conservation as a resource. Generation resources include low-cost City Light-owned hydroelectric projects, power purchased at preference rates from the Bonneville Power Administration (BPA), and contract purchases from other entities. The Utility supplements these resources with power exchange agreements and purchases made in the wholesale power market.

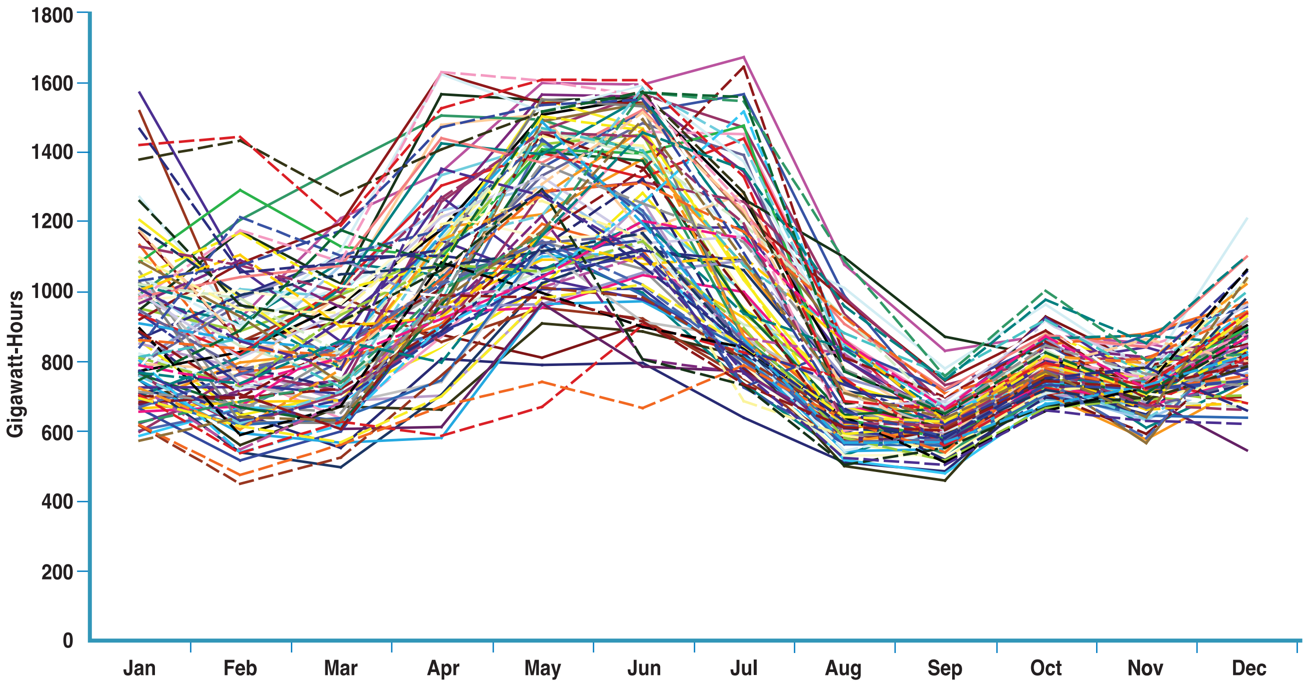
Most of City Light's power is generated by its own low-cost hydroelectric facilities, located mainly in Washington. City Light added wind power to its portfolio in 2002, with the signing of a 20-year contract for the purchase of output from the Stateline wind project in eastern Washington and Oregon. The following map shows the location of City Light's generation resources.

City Light Generation Resources

Characteristics of the existing resource portfolio influence the choice of resource additions. The two dominant characteristics are hydro variability and monthly shape. The monthly shape of generation from the existing portfolio is not in synch with service area load. Load is highest in winter, but generation is highest in late spring. This suggests the use of strategies that have the effect of reshaping generation to load. Properly constructed seasonal exchanges can accomplish this.

Hydro variability refers to the very broad range of generation capability that is determined by precipitation. Managing this variability is a challenge. The graph on the following page illustrates hydro variability, based on historical weather conditions and current river regulation. The Utility's challenge is to ensure that there are sufficient resources to provide the power needed by its customers under drought conditions, even when winter temperatures are very low. On the other hand, the Utility needs to try not to acquire too much surplus power, to avoid the risk of being unable to sell the surplus at prices that cover costs. The Utility's purpose is to serve its customers' need for electric power.

Variability in Hydro Generation



Climate Change

The IRP contains a discussion of potential impacts of climate change on hydro operations. A substantial effort to analyze climate change in the Northwest is underway using a computer model being developed by the University of Washington Climate Change Group. City Light is providing funding to bring this large scale modeling down to a level that can capture the unique nature of the major watersheds City Light relies on for hydro power. BPA and the Northwest Power and Conservation Council may pursue similar studies for the Columbia River System. City Light will continue to evaluate climate change impacts, incorporating new data as it becomes available.

Although climate change data is not yet available for all the hydropower systems from which City Light receives power, the hydro distributions for the output of the Skagit system that were used in the IRP model did include the range of extreme flow conditions that have been predicted by climate change models. The input data was based on historical data, but was not limited strictly to the recorded extremes. This approach allowed planners to see how the extremes (both lower and higher flow conditions) would effect the various resource portfolio options in terms of reliability, cost and risk.

Resource Choices

The three main categories of resources are conservation, generation and the wholesale power market. Generation resources can be further categorized as renewable and non-renewable. Many resource types were evaluated in Round 1, but the refinements of Round 2 eliminated nearly all non-renewable resources.

Conservation

City policy guidance and State Initiative 937 require the acquisition of cost-effective conservation. Certain conservation measures can improve load shape because their greatest effect in is the winter when it is cold and dark. Conservation also has the benefit of avoiding transmission costs. The conservation resource was the mainstay in both rounds of portfolio analysis, which examined both constant and accelerated paces of acquisition.

Market

The wholesale power market provides opportunities for seasonal exchanges and market purchases. Seasonal exchanges are low in cost and can help shape resources to load. Physical call options are useful for meeting a high demand that has a low probability of occurring. Both exchanges and call options are low-cost ways of meeting seasonal demand without the expense of acquiring new generation.

Renewable Generation

Renewable resources satisfy the need for power and avoid air and water pollution that endangers the environment and human health. Renewable resources could become even more advantageous with the eventual imposition of a carbon tax. Initiative 937 encourages the development of such resources, though the availability of transmission could be a problem. The cost of transmission for wind resources is especially high because transmission must be available even when the wind is not blowing. Other renewable resources likely to be available to City Light in the near term are landfill gas, geothermal and biomass.

Non-Renewable Generation

Non-renewable resources are generally fossil fuels such as coal, oil and natural gas. Their emission of greenhouse gases and air pollutants has significant impacts on the environment and human health and the necessity of mitigation makes them costly. Natural gas resources can be sited close to load and would require little in the way of transmission upgrades, while resources remote to load, such as coal, would require significant transmission, further increasing their cost.

Most fossil fuel resources have an advantageous generation profile that allows them to meet Utility customers' base energy requirements and frees up the hydroelectric resources to follow load. The only fossil fuel resource that can effectively follow load is the natural gas simple-cycle combustion turbine that can be used to meet peak load requirements or to operate during the hours preceding the peak hour, thus saving water to meet the peak requirements. Such a resource was examined.

Methodology for Analyzing Portfolios

The candidate portfolios were tested within the Reference Case developed by Global Energy Decisions (GED). The Reference Case gives forecasts of:

- Electric power prices
- Natural gas prices
- Installed capacity in the Pacific Northwest market
- Customer load for the Pacific Northwest market

The interplay of these four factors defines the power market in which the City Light is likely to be operating over the next 20 years. The IRP analysis also considered GED's four alternative scenarios that incorporate varying assumptions about the direction of the national economy and environmental legislation.

The model used for analyzing the portfolios simulated their operation based on the operating characteristics of each resource and its total cost, including fuel, operations and maintenance, and transmission. The amount of greenhouse gas emissions and air pollutants was also calculated. Costs were assigned to these emissions and considered along with other portfolio costs.

At any particular point in time, the least-cost resource is picked first, followed by the next least-cost resource, and so on, until load for that point in time is met. The portfolios were then evaluated using these four criteria:

- **Reliability.** All portfolios were designed to meet the 95 percent resource adequacy measure, but they vary in the degree of their reliance on total market purchases over 20 years.
- **Cost.** The net present value (NPV) of cash flows over 20 years for both capital and operating costs were calculated and compared.
- **Risk.** The sources of risk are uncertainty about fuel prices and the market price of power, whether buying or selling. The portfolios varied in their exposure to these sources of uncertainty. The measures for comparison of the portfolios were the coefficient of variation for net operating revenues and costs over 20 years.

- **Environmental impact.** A thorough analysis of potential environmental impacts was completed, and Draft and Final Environmental Impact Statements were prepared. CO2 emissions impacts were assigned costs that were taken into account in the 20-year net present value calculations. Total greenhouse gas and other air pollutant emissions over 20 years were calculated and compared for all portfolios. These included carbon dioxide, nitrogen oxides, sulfur dioxide and mercury.

Round 1 Analysis

Candidate portfolios were analyzed in two rounds. Round 1 portfolios were primarily exploratory and included a broad range of resources. Round 1 provided an opportunity for testing the limits of the model and for gaining insights into how it operated. Nine portfolios were modeled in Round 1. The main conclusions from Round 1 were that:

- Large capacity baseload generation technologies exacerbate the mismatch between the Utility's load shape and resource shape.
- Large un-scalable projects leave the Utility with decreasing oversupply in early years and increasing undersupply in later years.
- Heavy polluters are too costly, given the City's policies on offsetting carbon emissions (CO2) and accounting for environmental externalities (emissions of sulfur dioxide and nitrogen oxides, particulate matter and mercury).
- Large resources that are remote to load require expensive new transmission facilities.
- Seasonal energy exchanges are inexpensive and help match resources to load, though transmission availability may be a limiting factor.
- Cost-effective conservation remains the resource of choice and should be the mainstay of any portfolio.
- Reducing City Light's Slice product from the Bonneville Power Administration in favor of more Block product is not an advantageous strategy.

Round 2 Analysis

The Round 2 analysis was conducted before the passage of Initiative 937, so both compliant and non-compliant portfolios were constructed and evaluated. The Round 2 portfolios are the same in the near-term, similar in the mid-term, and differ mostly in the long-term, as summarized below:

- **Near-term.** By Round 2, it was clear that in the earliest years, seasonal exchanges and physical call options could shore up reliability in the winter at little cost. All Round 2 portfolios add conservation, seasonal exchanges and seasonal capacity contracts (call options) through 2009.
- **Mid-term.** After 2010, new generation resources are needed. The Round 2 portfolios feature the addition of varying combinations of a landfill gas resource and a small hydro contract for an existing project in the region. These are in addition to conservation, seasonal exchanges and call options.
- **Long-term.** Around 2015, different combinations of wind, geothermal, biomass and a single-cycle combustion turbine are added to meet growing load and to take the place of expiring contracts, primarily the Stateline wind contract which ends in 2021.

The Round 2 portfolios have two primary distinguishing features: compliance with Initiative 937 requirements for renewable resources, and the pace of conservation acquisition:

- Two portfolios (P4 and P5) do not comply with I-937 in the amount of renewable resources acquired. They feature the constant rate of conservation acquisition.
- Two portfolios (P7 and P8) do comply with I-937 in the amount of resources acquired. They also feature the constant rate of conservation acquisition.
- Three portfolios (P2, P3, P6) do comply with I-937 in the amount of resources acquired. They feature an accelerated rate of conservation acquisition between 2010 and 2020. Conservation acquisition would then decline steeply between 2021 and 2026, after all projected lost opportunities and retrofits are exhausted.

Portfolio Comparison

	Portfolios 2007-2026	20 Year NPV of Costs ($1000's)	Variable Cost Risk (CV)	20-Year Tons of CO2	Meets 95% Reliability Criterion
P2	Geo100 Wind55 Hydro23 LFG25 Bio15, Accel Conservation	$ 58,838	77%	1,967,686	Yes
P3	Geo125 Wind50 LFG25 Hydro23, Accel Conservation	$ 68,910	77%	1,967,686	Yes
P4	Geo50 Ex40 SCCT50 LFG25 Hydro23, 7aMW Conservation	($ 54,846)	81%	2,245,312	Yes
P5	Geo75 Ex45 LFG25 Hydro23 Wind20, 7aMW Conservation	$ 16,426	81%	1,695,872	Yes
P6	Geo120 Wind50 LFG25, Accel Conservation	$ 57,499	79%	-712,067	Yes
P7	Wind105 Geo50 Bio15 Hydro23 LFG25, 7aMW Conservation	$218,231	79%	1,732,147	Yes
P8	Geo100 Wind55 Bio15 Hydro23 LFG25, 7aMW Conservation	$170,936	80%	1,732,147	Yes

While Portfolios 4 and 5 are the least costly of the portfolios evaluated, they were eliminated from further consideration after passage of Initiative 937 because they would not meet the minimum renewable resource acquisition requirements. The remaining portfolios are compliant in renewable resources, but differ in their rate of conservation acquisition. Otherwise, they are similar until 2015, when they are distinguished by the mix and timing of varying amounts of renewable resources – wind, geothermal and biomass.

The table above illustrates how the Round 2 portfolios performed on the measures of reliability (95 percent resource adequacy), cost (20-year NPV), risk (coefficient of variation) and environmental impact (CO2 emissions).

On the cost criterion, the portfolios "without I-937" (P4 and P5 in red) outperform the portfolios "with I-937". There are two reasons for this. Initiative 937 requires purchases of resources beyond those needed to meet the 95 percent resource adequacy criterion after 2015. The I-937 requirement has no relationship to resource need. Also, I-937 limits the eligibility of some types of resources.

City Light hypothesized that accelerating discretionary conservation may reduce the costs of complying with Initiative 937. The initiative requires purchases of eligible renewable energy as a fixed percentage of retail load. If the pace of acquisition of conservation is accelerated, retail load is reduced, delaying the need for future resource additions. The results showed that the portfolios "with I-937, accelerated conservation" (P2, P3, P6 in yellow) outperformed the portfolios "with I-937, constant conservation" (P7 and P8 in green).

This suggests that a more aggressive conservation acquisition schedule may result in lower cost, partially because it reduces load, which is the basis for determining resource additions under Initiative 937. The amount of benefit by accelerating conservation programs may be substantial. In the analysis performed for this IRP, as much as half the difference in costs between the "with I-937" portfolios and the "without I-937" portfolios could be cut.

Further study is required before a conceptual "with I-937, accelerated conservation" portfolio is adopted. The accelerated conservation portfolios evaluated for this IRP are conceptual because of uncertainties about feasibility and costs. For purposes of the analysis, the same unit cost of conservation was used in the accelerated cases as in the constant case. This is an important assumption that, when altered, could reduce the attractiveness of accelerated conservation.

Nevertheless, a conceptual investigation of accelerating conservation can give useful information about strategic direction. The possible benefits of conservation acceleration under Initiative 937 strongly suggest that further study of program costs and feasibility should be conducted.

Recommendations

The Mayor's recommended resource strategy (Portfolio 8 shown in the table below) calls for:

- Continued acquisition of cost-effective conservation.
- Two low-cost seasonal exchanges to shape resources to load.
- Seasonal capacity contracts (physical call options) when advantageous.
- Output from a landfill gas facility.
- Output from an existing regional hydro facility.
- Increasing amounts of output from a regional geothermal resource.
- Output from a small local biomass facility.
- Output from a regional wind farm.

The Mayor further recommends that the Utility:

- Study the costs and benefits of accelerating the rate of conservation acquisition.
- Be given the authority to negotiate and purchase seasonal capacity contracts (physical call options).
- Pursue the low-cost strategy of long-term seasonal exchange agreements, given the current resource surplus in the West.
- Further investigate the impacts of climate change on long-term resource planning.
- Pursue acquisition of the output of a landfill gas facility.
- Continue honing its ability to evaluate the risk aspects of resource choices in the 2008 IRP.

The Mayor's recommended action plan is shown on the following page.

Preferred Alternative

Resource (aMW)	Location	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Conservation	W. WA	7	14	21	28	36	43	50	57	64	71	78	85	93	100	107	114	121	128	135	142
Seasonal Exchange	Mid-C	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Seasonal Exchange	Mid-C		50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Call Option	Mid-C			30				5													
Landfill Gas	W. WA				25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Hydro Contract	Mid-C						23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Geothermal	W. WA									30	30	30	30	50	50	50	100	100	100	100	100
Biomass	W. WA										15	15	15	15	15	15	15	15	15	15	15
Wind	E. WA														55	55	55	55	55	55	55
Total		57	114	151	153	161	191	203	205	242	264	271	278	306	368	375	432	439	446	453	460

IRP Action Plan, 2007-2008

Actions	2007	2008
Conservation Resources		
Acquire cost-effective conservation in the targeted amounts.	7 aMW by end of 4th Qtr	7 aMW by end of 4th Qtr
Investigate methods and costs of accelerating conservation resources.	Investigate delivery costs and methods by year end	Include in IRP
Generation Resources		
Investigate costs and availability of planned resources.	Go/no go decision on landfill gas by year end.	Negotiate contracts as needed.
Market Resources		
Investigate and acquire seasonal exchanges and/or seasonal market purchases to offset near-term reliability risk.	Additional 50 aMW as needed	Additional 50 aMW as needed
Other New Resources		
Collect and update information on costs of a wide range of new resources commercially available by June 2008.	Ongoing	Finalize assumptions by May for 2008 IRP
Investigate the development status, costs and commercial availability of new resource technologies.	Ongoing	Ongoing
Investigate the cost-effectiveness of hydro efficiency measures and other steps to improve Skagit output.	Further investigate Gorge Tunnel economics	Decision on inclusion in 2008 portfolios
Transmission		
Work to ensure adequate transmission to support reliable service to existing and future load needs.	Ongoing	Ongoing
Future IRPs		
Continue to refine assumptions, forecasts and modeling.	Ongoing	Ongoing
Monitor development of regional resource adequacy standards.	Ongoing	Ongoing
Assess the impacts of climate change on operations and load in greater depth.	By year end	Reflect in 2008 IRP
Evaluate distributed generation opportunity and distribution savings potential.	Conclusions by year end	Incorporate conclusions into 2008 IRP
Update the demand outlook and estimate of resource adequacy.	Results by year end	Use demand forecast for 2008 IRP
Prepare IRP Update and any EIS update.	Initiate studies and investigations listed above.	Complete 2008 IRP
File IRP with the Department of Community, Trade and Economic Development (CTED) according to administrative rules.		File IRP by September 2008

Chapter 1 – Introduction

This chapter gives a brief overview of Seattle City Light and this Integrated Resource Plan (IRP), including its purpose, the process for developing the Plan, and Plan organization.

About Seattle City Light

Founded 104 years ago, Seattle City Light is a municipal electric utility that owns and operates electricity generating, transmission and distribution facilities and serves 370,000 metered customers. City Light's service area covers about 131 square miles between Puget Sound and Lake Washington, and between Snohomish County on the north and Renton and South 160th Street on the south. The Utility serves all of the City of Seattle, plus all or part of the cities of Shoreline, Lake Forest Park, Mountlake Terrace, Tukwila, Seatac, Burien, Renton, and Normandy Park, and parts of unincorporated King County.

City Light relies on hydroelectricity for over 90 percent of its power resources, sourced from Utility-owned dams and by contract from Bonneville Power Administration (BPA) and other regional utilities. Resources also include conservation and wind power. City Light depends primarily on BPA for electric transmission to its service area and operates a local transmission network of 657 circuit miles.

About the IRP

The Pacific Northwest has not embraced retail deregulation of power markets, which swept the country from the mid-1990s through the early 2000s. At that time, it was widely believed in the electric utility industry that long-term power resource planning was no longer relevant, because "the market will provide." However, the 2000-2001 power crisis in the West underscored the dangers of relying on the wholesale power market for power resource needs. Since that time, integrated resource planning has been seen increasingly as a way of reducing risks to reliability and utility financial security.

This 2006 Integrated Resource Plan marks the beginning of a new chapter in resource planning for City Light. The last formal evaluation of long-term resources prepared by City Light, the Strategic Resource Assessment (SRA), was published in 2000 as an update of the 1997 plan. The Seattle City Council has directed City Light to re-institute long-term resource planning. An important goal of the 2006 IRP for the Utility is to rebuild long-term resource planning capabilities after a long break.

While City Light will issue updated plans every two years, integrated resource planning is truly an ongoing process. It involves continuously monitoring and re-evaluating generation and demand-side resource choices, new technologies, new market information and trends in customer demand.

City Light's mission is to provide stable, competitively priced and environmentally sound electricity to customers. The IRP process has been designed to support this mission by:

- Ensuring stable and reliable power resources through the resource adequacy requirement.
- Looking for least-cost and lower risk solutions within the context of other goals.
- Evaluating and recognizing the environmental implications of the Plan by preparing an environmental impact statement.

The overall objective of this IRP is to determine strategies for the type, amount and timing of new resource acquisitions to meet electrical load over the 20 years between 2007 and 2026. The new resources considered for this planning period are conservation, a hydroelectric efficiency improvement, wind, geothermal energy, landfill gas, biomass, cogeneration, a hydro contract, simple-cycle and combined-cycle combustion turbines, pulverized coal, and integrated gasification combined-cycle (IGCC).

For the purposes of analysis, these resources were organized into potential resource portfolios (combinations of resources) that could meet anticipated future needs. Continuation of existing conservation programs, hydro generation resources, and many existing power purchase power contracts is assumed in all portfolios.

IRP Process

City Light began preparing this IRP in 2005. The process included these often-overlapping steps:

- Involving the public, including citizens and stakeholders with diverse perspectives.
- Recruiting expertise from within and from outside the Utility.
- Licensing and installing a sophisticated computer model for power planning.
- Calibrating the model for the characteristics of City Light's complex hydroelectric operations and purchase power contracts.
- Thoroughly assessing conservation resource potential in the service area.
- Forecasting customer demand for power each month through 2026.
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- Constructing and modeling Round 2 candidate resource portfolios, based on findings and comments in response to Round 1.
- Recommending a resource strategy and near-term resource action plan.
- Recommending a resource plan to the Mayor and City Council.
- Issuing a final EIS.

Public Involvement

An integral part of the 2006 IRP process was engaging the community to receive comments and ideas about public preferences in planning for power supplies over the next 20 years. At each stage of the planning process, City Light benefited from this public involvement. Throughout, the Utility was advised by representatives of various stakeholder groups and received many comments from the public at public meetings and via the IRP website.

Doing two rounds of analysis allowed for meaningful public input. After the first round, the Utility gathered feedback about IRP assumptions, methodologies and resources evaluated. This information was then incorporated into a second round of analysis that was used to prepare the proposed Plan. This process is summarized below. For details, see Appendix A.

Public Meetings

Public meetings were held at three points in the planning process. The first meeting described the approach to the IRP, some of the assumptions that would be used, and the types of power resources to be evaluated. The second meeting described more detailed assumptions, the first round of resource portfolios and how the resource portfolios performed when evaluated on cost, risk, environmental impact and reliability. The third meeting described the second round of resource portfolios and how they performed. Each public meeting provided an opportunity for members of the public to make comments, ask questions and receive answers from City Light staff.

Stakeholder Group

A group of City Light stakeholders, reflecting a wide range of viewpoints, advised Utility staff in preparing the IRP. They represented residential, commercial and industrial customers, power suppliers, civic organizations and environmental groups. Eight stakeholder meetings have been held since October 2005, all open to the public.

IRP Website

Information and presentation materials used in public and stakeholder meetings were posted on a website to allow citizens to stay abreast of the development of the IRP. The website provided an email address and telephone numbers for the public to make comments about the IRP. Other comments were also taken throughout the process.

Many good ideas and suggestions for further research came from the public involvement process. While many ideas were incorporated into the 2006 IRP, City Light was not able to act on all of them, given limited time and resources. Ideas gathered from the 2006 IRP process will help to guide the design of the 2008 IRP, which will begin in 2007.

Organization of the IRP

This document is organized generally to parallel the development of the Plan. Following this introductory chapter, **Chapter 2** describes the policy context for planning, including local, state, regional and federal laws, policies and guidelines.

Chapter 3 describes the need for power over the next 20 years based on current trends and load forecasts; City Light's existing conservation, generation and market resources; the power supply obtained from these resources; and the resource adequacy standard used to determine how much power will be needed from additional resources to meet the expected load.

Chapter 4 identifies the new resources that are commercially available – additional conservation, renewable and non-renewable generation resources, and market resources. It also peeks ahead to highlight emerging technologies that may provide additional resources in the future.

Chapter 5 reviews the methodology City Light used to evaluate alternative resource portfolios for meeting the expected load under a range of future conditions. First, the baseline forecast or reference case is presented, including assumptions about future fuel supply, costs and electricity prices. The chapter then describes a range of possible future conditions, packaged as hypothetical scenarios. There is a discussion of the computer model used to assess the performance of alternative portfolios under these scenarios against the criteria of reliability, cost, environmental impact and risk. Finally, the objectives for selecting portfolios are presented.

Chapter 6 then presents the results of two rounds of analysis, showing the relative performance of the portfolios to meet City Light's anticipated needs, year by year through 2026. In Round 1 nine portfolios were evaluated; based on these results, eight modified portfolios were evaluated in Round 2. The recommended portfolio was selected based on the second round of analysis.

Finally, **Chapter 7** presents the Action Plan: City Light's recommended long-term strategies and action plan for implementation in the next two years.

A glossary of technical terms and acronyms used in the IRP is at the end of the document. Several appendices are published separately on a compact disk: a review of the public involvement process, the City Council resolution that directed City Light to offset greenhouse gas emissions, a description of additional resources to be monitored and evaluated for future IRPs, and the methodology used in the computer modeling.

Chapter 2 – The Policy Context: Setting the Stage for Planning

City Light's actions, including resource decisions, are determined within a policy framework. This framework includes State and federal laws as well as internal policies established by the Mayor and City Council and the Utility, and policies and guidelines of regional power planning organizations and agencies. This chapter describes the policies, laws and guidelines that have the most impact on City Light's Integrated Resource Planning (IRP) process, several of which are summarized below.

In August 2005, the first federal energy legislation in 13 years was passed. The Energy Policy Act of 2005 includes a wide range of provisions pertaining to energy efficiency, generating resources and fuel supply, energy research and development, transmission and climate change. The Western Governors Association adopted an initiative to develop renewable resources and build transmission. The Pacific Northwest region is developing resource and transmission adequacy standards and engaging the Bonneville Power Administration (BPA) in a dialogue about long-term delivery of power from the federal Columbia River power system.

Washington State recently passed a law requiring all large utilities to perform integrated resource plans, and another law that designated the Washington State Energy Facility Site Evaluation Council as the State authority for purposes of siting transmission facilities under the new federal energy legislation. Voters approved a conservation and renewable resource standard with passage of Initiative 937 in November.

Locally, the City of Seattle and Seattle City Light have maintained long-standing policies encouraging energy conservation and use of renewable resources, as well as prudent financial policies and the Utility's basic mission of providing reliable service. More recently, the City launched an initiative to reduce greenhouse gas emissions.

Meeting all the policy goals simultaneously is not possible, since they may conflict or overlap and may change rapidly. With so many organizations involved in creating laws and policies, there will always be significant uncertainty about the rules and environment under which City Light must plan to meet the electricity demand of its customers.

Table 2-1 summarizes the types of resource planning issues impacted by the various policies described in this chapter.

Table 2-1. Policies Affecting Resource Planning

Policy/ Issue	Energy Efficiency	Renewable Resources	Planning Methods	Transmission	Resource Adequacy	Power Supplies	Tax Credits	CO2 Offsets	Climate Change
Resolution 30144	❍	❍						❍	❍
Resolution 30359								❍	❍
Initiative 937	❍	❍	❍						
ESHB 1010			❍						
HB 1020				❍					
RCW 80.60		❍							
SSB 5101		❍					❍		
BPA Regional Dialogue						❍			
NPCC Policies	❍		❍		❍				
WGA Resolution 06-10	❍	❍		❍			❍		
EPACT 2005	❍	❍	❍	❍			❍		❍

City of Seattle

City Light planning and operations are guided by City and internal Utility policies relating to the environment and greenhouse gas emissions. In addition, City Light has been developing policies to manage the risks of being short or long on resources, and strategies to deal with energy surpluses and deficits.

Environment

City of Seattle and City Light environmental policies help guide the resource planning and acquisition process. These policies give general and specific direction about protecting natural resources and minimizing impacts in serving Seattle's electricity needs. City Light's Environmental Policy Statement calls for the Utility to avoid, minimize or mitigate impacts to the ecosystems that it affects and to consider environmental costs, risks and impacts when making decisions.

The Utility's Vision, Mission, Values Statement reaffirms that minimizing environmental impacts and enhancing, protecting and preserving the environment are key parts of Utility's goals. The potential for minimizing and mitigating environmental impacts in operating resources is also a consideration in evaluating specific energy resource opportunities.

Conservation and Renewable Resources

In 1992, City Council made responding to climate change an environmental priority. Out of its concern for the negative effects of greenhouse gases, the City Council passed Resolution 30144 in 2000 (see Appendix B). The resolution states that City Light should "use cost-effective energy efficiency and renewable resources to meet as much load growth as possible."

City Light has subsequently continued its long-term practice of acquiring conservation through Utility programs at an annual rate of 7 aMW, and contracted for the purchase of approximately 45 aMW of wind power (175 MW of capacity) from the Stateline Wind Project. The Council, as part of the annual reporting of Council Metrics, monitors Utility compliance with Resolution 30144.

Greenhouse Gases and Climate Change

Resolution 30144 also directed City Light to mitigate for greenhouse gas emissions from any fossil fuel use, and set a long-term goal of "Net Zero" annual greenhouse gas emissions, which City Light achieved in 2005. In 2001, the Greenhouse Gas Mitigation Strategy Resolution 30359 was passed, setting standards for calculating greenhouse gas emissions and mitigation projects. The climate change policy does not prevent City Light from acquiring electricity from resources that produce greenhouse gas, but does require that the Utility fully offset those emissions.

In February 2005, the Mayor proposed that the City achieve reductions in greenhouse gas emissions based on the Kyoto Protocol goal for the United States – a 7 percent reduction in greenhouse gas emissions compared to 1990 levels, to be achieved by the year 2012. See the news release at **http://www.seattle.gov/news/detail.asp?ID=4973&dept=40**.

To develop guidelines for meeting the goal, the Mayor appointed the Green Ribbon Commission on Climate Protection. The Commission, which includes 18 leaders from Seattle's business, labor, non-profit, government and academic communities, was specifically charged with developing local solutions to global climate disruption and developing a Climate Action Plan. The Action Plan calls on City Light to continue meeting load growth with conservation and renewable resources and offsetting emissions. It identifies other actions, including efficient use of natural gas and coordination between local gas and electric utilities in delivering efficiency services. See **http://www.seattle.gov/climate/** for more information.

To meet the requirement to offset greenhouse gas emissions, City Light estimates Utility emissions each year, and then purchases offsets; emission counts are trued up at the end of the year. Offsets are the result of actions that avoid, reduce or sequester greenhouse gas. Currently there are no federal or State laws regarding how offsets are defined, created and sold.

However, City Light has tracked guidelines being developed by non-profit and state government organizations and, with the assistance of external stakeholders, has established its own guidelines for counting emissions and selecting offsets. Some states, including California and several in the East (through the Regional Greenhouse Gas Initiative), are capping greenhouse gas emissions from power plants and other sources, and are planning for a market-based trading system for greenhouse gas offsets. City Light's sales to California utilities could be impacted by these regulations.

In the IRP analysis, the amount of greenhouse gas emissions of various resources and alternative portfolios has been calculated. The cost of offsetting those emissions are based on a range of potential mitigation costs that City Light would pay under its Council mandate, or that might be imposed through greenhouse gas regulation or taxes.

State of Washington

State laws and policies affecting resource planning are the recently passed conservation and renewable resource standard Initiative 937; requirements for integrated resource planning, facilities siting and net metering; and incentives for development of renewable resources.

Conservation and Renewable Resource Standard Initiative

Passage of Initiative 937 in November 2006 requires Washington utilities with more than 25,000 customers to acquire cost-effective conservation and renewable resources for meeting their load. It also requires these utilities to evaluate the potential for cost-effective conservation in their service territories, and establish and make public an acquisition target for conservation.

The renewable resource requirements in the Initiative increase over time: at least 3 percent of a utility's load by January 1, 2012; 9 percent by 2016; and 15 percent by 2020. This requirement can also be met by using Renewable Energy Credits, often called green tags. A financial penalty would be imposed for failing to meet the requirement. Existing hydropower is not counted toward the target.

Two City Light resources are eligible resources for meeting the target: the Stateline Wind Project, at approximately 3 percent of current load; and efficiency upgrades resulting in additional power output at City Light hydropower plants (completed after March 31, 1999), at just under 1 percent of current load.

Integrated Resource Planning

The Legislature passed ESHB 1010 (Chapter 195, Laws of 2006) in the 2006 session requiring certain Washington utilities, including City Light, to regularly prepare Integrated Resource Plans (IRPs). Under this statute, IRPs must describe the mix of energy supply resources and conservation needed to meet current and future needs at the lowest reasonable cost to the utility and its ratepayers. They are also to consider cost-effective conservation and a wide range of commercially available generation technologies including renewable technologies.

Facilities Siting

HB 1020 (Chapter 196, Laws of 2006), passed during the 2006 Legislative session designates the Energy Facility Site Evaluation Council (EFSEC) as the State's authority for siting transmission facilities under the federal Energy Policy Act of 2005. The law extends EFSEC jurisdiction to electrical transmission facilities that operate in excess of 115 kilovolts within national interest transmission corridors and also to electrical transmission lines in excess of 115 kilovolts that connect a power plant to the grid.

Net Metering

Under RCW 80.60, Washington State requires utilities to provide net-metering service to encourage development of renewable and distributed resources by measuring the difference between the electricity supplied by a utility and electricity generated by a customer. The Legislature reviewed and amended the net metering statute during the 2006 session to raise the maximum allowable generating capacity for net metering systems to 100 kilowatts.

The list of qualified generating sources for net metering (solar, wind, water, fuel cells) was expanded to include biogas from animal waste. The definition of a net metering system was expanded to include combined heat and power (CHP) or cogeneration, where heat is "useful and used". The cap on the total amount of net metering generation allowed in a utility's system was also raised from the current level of 0.1 percent of a utility's peak demand in 1996 to 0.25 percent. In 2014, the cumulative net metering generating cap is raised again from 0.25 percent to 0.5 percent of a utility's 1996 peak load.

Incentives for Renewables

In 2005, the Legislature passed SSB 5101, an investment cost recovery incentive to support certain renewable energy projects. Customers generating electricity from a renewable energy system may seek an annual incentive payment from their participating electric utility up to $2,000 annually. Utility participation is voluntary. Participating utilities, such as City Light, are allowed a credit against their public utility tax equal to the incentives paid to customers.

Regional

Regional policies and guidelines relevant to utility resource planning are summarized below, including those of the Bonneville Power Administration, Northwest Power and Conservation Council and the Western Governors Association.

Bonneville Power Administration (BPA)

BPA is the federal power-marketing agency for electricity generated from projects owned and operated by the Army Corps of Engineers and the Bureau of Reclamation. Because City Light purchases approximately 40 percent of its power supply from the BPA, decisions affecting the marketing of this power at the federal level can significantly impact City Light's resource portfolio cost, risk and reliability. City Light also relies heavily on purchases of significant amounts of transmission from BPA to transfer power from City Light's remote generating resources to its load.

BPA customers, including City Light, have joined to promote long-term, cost-based contracts to restore and protect low-cost regional power in the face of periodic attempts to divert the benefits of BPA from the Pacific Northwest.

After many years of discussions, Pacific Northwest utilities have concluded that BPA should only sell the output of the Federal Base System (federal hydropower plus the Energy Northwest nuclear power plant). All publicly owned utilities should be responsible for acquiring new resources to meet any of their loads in excess of what is allocated to them from BPA. Investor owned utilities should get a financial settlement of their residential exchange rights. Significant issues remain to be resolved.

City Light's contract with BPA expires in 2011. BPA is preparing a Policy Proposal about what new 20-year contracts will look like. In April 2006, BPA proposed that 16-year contracts be signed in November 2007 for service beginning in October 2011 and terminating in November 2027.

Northwest Power and Conservation Council

The Northwest Power and Conservation Council (NPCC) is a public agency created by the Pacific Northwest Electric Power Planning and Conservation Act of 1980. The agency is responsible for developing a regional power plan and implementing fish and wildlife programs. Its three major functions are to:

- Develop a 20-year electric power plan for the Northwest that will guarantee adequate and reliable energy at the lowest economic and environmental cost.
- Develop a program to protect and rebuild fish and wildlife populations affected by hydropower development in the Columbia River Basin.
- Educate and involve the public in the Council's decision-making processes.

Power Planning

The NPCC's 5th Power Plan (December 2004) forecasts a surplus of power for the next few years and predicts that no generation resources will be needed until at least 2010. A power surplus resulted when loads declined due to the recession after the West Coast power crisis of 2000-2001 and the decline in consumption by the aluminum industry. Regional loads fell to their early 1990s levels while many new power plants were built to respond to the power shortages experienced in 2000-2001. The Plan recommends that the region begin an aggressive conservation program, and lay the groundwork for building a large amount of wind generation and a relatively small amount of coal-fired generation that will be needed later.

Regional Resource Adequacy Standard

On May 10, 2006, the NPCC adopted a new regional standard that is intended to ensure an adequate supply of electricity for the Pacific Northwest. The regional standard is also expected to be included for the Northwest region within the broader West-wide efforts on resource adequacy by the Western Electricity Coordinating Council (WECC).

A letter dated May 1, 2006, from NPCC Chair Tom Karier described the new regional resource adequacy standard as follows:

> "The Pacific Northwest Resource Adequacy Forum (Forum) has developed a regional standard to be used for guidance in long-term resource planning. The Council adopts this standard for its own planning process and recommends that other entities in the region incorporate it into their planning efforts. The Council also recommends that this regional standard be submitted to the Western Electricity Coordinating Council (WECC) for inclusion in its development of West-wide adequacy standards.
>
> "The term 'standard' in this context does not mean mandatory compliance nor does it imply an enforcement mechanism. Rather, it is meant to be a gauge used to assess whether the Northwest power supply is adequate in a physical sense, that is, in terms of 'keeping the lights on.' It can be thought of as the minimum threshold for resource acquisition. However, the Council encourages utility planners to think beyond this minimum (as the Council did in its 5th Power Plan) and consider strategies that also protect against potentially bad economic outcomes.
>
> "The regional standard consists of a metric (something that can be measured) and a target (an acceptable value for that metric) for both energy and capacity capabilities of the system. One of these targets will be the limiting constraint for a region or sub-region in the West. For the Northwest, the energy target is most likely the limiting factor."

NPCC's regional adequacy standard is intended to address the unique characteristics of the Pacific Northwest, including the region's winter-peaking loads (compared to summer-peaking loads across most of the West) and heavy dependence on hydroelectric generation. The energy target for the Pacific Northwest is for resources to equal the expected annual load.

Western Governors Association

In June 2004, Western Governors adopted a resolution in which they agreed to examine the feasibility of developing 30,000 MW of clean and diverse energy by 2015, to increase energy efficiency 20 percent by 2020, and to provide adequate transmission to meet the region's needs through 2030.

In 2005, they created the Clean and Diversified Energy Advisory Committee (CDEAC) to oversee the work of seven task forces that examined the feasibility of reaching those goals. The task forces prepared reports with recommendations in the following areas: energy efficiency, advanced coal, geothermal, wind, biomass, solar and transmission.

At the June 2006 annual meeting, the Western Governors adopted Resolution 06-10 agreeing to draw upon the full range of recommendations contained in the CDEAC report as a basis on which to advocate for energy policy changes at the federal and regional levels and their respective states, where appropriate. Further, they agreed to support, among other things, federal energy polices that:

- Provide for a long-term (10-year) extension of the production tax credit for all renewable energy technologies, with complementary policies for consumer-owned utilities and tribes.
- Provide tax credits for energy efficiency investments.
- Raise the cap on the residential investment tax credit to $10,000 for renewable energy or distributed generation systems.
- Support improvements in national appliance efficiency standards.
- Encourage adequate funding for state programs, including energy efficiency, clean generation and storage technology research, development and demonstration programs.
- Encourage federal agencies to collaborate with Western states and regional organizations on facility siting and infrastructure planning, consistent with sound, sustainable environmental practices.
- Extend the federal Integrated Combined Cycle Combustion Turbine (IGCC) tax credit for five years and provide a tax credit program for carbon capture and sequestration for at least five years.
- Support increased federal support and tax incentives for the construction of multiple pilot facilities that demonstrate IGCC in the Western United States in high altitude areas using western coal.
- Encourage proactive, transparent, stakeholder-driven regional transmission expansion planning, defer to existing regional and sub-regional processes that meet such standards, and reform imbalance penalties to allow for greater use of the existing transmission system.

Federal

The primary federal statutes relevant to energy resource planning are the Clean Air Act, Clean Water Act and Energy Policy Act of 2005.

Environmental Regulations

At the federal level, recent EPA regulations (the Clean Air Interstate Rule and the Clean Air Mercury Rule) will set tighter limits for emissions of common air pollutants from power plants: oxides of sulfur and nitrogen, and mercury. Other regulations will further limit emissions of particulate matter. These regulations may become more restrictive during the planning period of the IRP, and states may set their own more restrictive standards as well. Meeting these limits can be a significant technical challenge, as well as a significant additional cost, for power plants that burn fossil fuel.

Federal Clean Water Act regulations are also becoming more stringent. Power plants that use water for cooling could be affected by these changing regulations, as restrictions increase on removing water from, and discharging cooling water into, surface and groundwater sources. These restrictions are often related to protecting habitat for fish and wildlife, as well as protection of human health.

The Endangered Species Act (ESA) can affect the potential to site new power plants and transmission facilities. Currently, hydropower operations are significantly regulated because of their potential impacts on ESA-listed fish species. As new species are listed, and as new information about hydropower operations' effects on those species becomes available, the operational rules may change. Consequently, this could possibly change both the amount and the timing of hydropower output. This issue is extremely important to City Light given its reliance on both its own hydropower facilities and on the Bonneville Power Administration's supply.

Energy Policy Act of 2005

In 2005, the first federal energy legislation in 13 years addressed a wide range of issues including energy efficiency, generating resources and fuel supply, the environment and transmission (**http://energycommerce.house.gov/108/energy_pdfs_2.htm**).

Energy Efficiency

Several provisions related to energy efficiency may influence the acquisition of conservation resources within City Light's service area. The Act authorizes $50 million in funding annually between 2006 and 2010 for state-administered energy efficient rebate programs for "residential Energy Star products". These include appliances, heating and cooling systems, home electronics, lighting, and windows, doors and skylights. The legislation establishes financial grants for state-run programs to achieve at least 30-percent efficiency improvements in new and renovated public buildings.

The Act provides for a number of tax deductions or credits in 2006-2007, including the following:

- A $2,000 tax credit to contractors who build new homes using 50 percent less energy for cooling and heating than a comparable home built to the 2003 International Energy Conservation Code.
- Tax credits of varying amounts to homeowners for energy efficiency improvements made to their primary residence. Qualifying improvements include efficient windows, doors, insulation, electric heat pumps, geothermal heat pumps, electric heat pump water heaters, central air conditioners, and natural gas, propane or oil water heaters.
- Varying tax credits to manufacturers of qualifying efficient appliances manufactured in the U.S. Eligible appliances include Energy Star dishwashers, clothes washers and refrigerators.
- A tax deduction of $1.80 per square foot for commercial buildings that achieve a 50-percent reduction in annual energy cost subject to certain conditions.

Generation Resources and Fuel Supply

Renewable Energy

The Production Tax Credit (PTC) for certain renewable generation was modified and extended through December 31, 2007. The credit covers facilities producing electricity from wind, closed- and open-loop biomass, geothermal, solar, small irrigation power, landfill gas, trash combustion, and certain hydropower facilities that meet placed-in-service deadlines. For most renewable resources, the PTC is currently equal to about 1.9¢/kWh for electricity produced over a 10-year period. The Act also created the Clean Renewable Energy Bond program, which can be issued to construct renewable generating resources by rural electric cooperatives, municipal governments and tribes.

Hydroelectricity

The Act authorizes $100 million for hydroelectric efficiency improvements at existing dams and modernizes the hydropower laws to allow increased production. It creates a 10-year tax credit that will apply to "qualified hydropower production" if placed in service prior to January 1, 2008. Relicensing provisions are amended to allow applicants or other parties to propose alternatives to conditions set by the agencies.

Natural Gas

The Act confirmed that the Federal Energy Regulatory Commission (FERC) has exclusive authority over siting, construction, expansion and operation of liquified natural gas (LNG) import terminals located onshore or in state waters. In addition, it confirms FERC's role as the lead agency for National Environmental Policy Act compliance and for purposes of coordinating all applicable Federal authorizations. The Act also confirms existing rights of states to review LNG terminals under the Coastal Zone Management Act, Clean Water Act and Clean Air Act.

Coal

The Act authorized $200 million per year from 2006 to 2014 for a federal government cost-share program to conduct demonstrations of commercial-scale advanced clean coal technologies. It also authorized $3 billion in the form of loans, cost sharing or cooperative agreements to encourage new sources of advanced coal-based power generation, and to upgrade existing sources of coal-based generation to improve air quality to meet current and future obligations of coal-fired generation units regulated under the Clean Air Act. The Act authorized a total of $1.095 billion over three years in funding for the Department of Energy (DOE) clean coal research and development program, and $75 million over three years for a DOE program to develop carbon capture technologies that can be applied to the existing fleet of coal units.

Innovative Technologies

The Act established a loan guarantee program to provide incentives for "innovative energy technologies" that avoid, reduce or sequester air pollutants or greenhouse gases and use technologies improved in comparison to those in commercial use. Eligible projects include renewable systems, advanced fossil energy technologies (including coal gasification), hydrogen fuel cell technology, advanced nuclear energy facilities and others. There is no cap on the amount of funds used for this program.

Nuclear Energy

The Price-Anderson Act was re-authorized for commercial nuclear power plants and DOE contractors for 20 years; it increases the indemnification for DOE contractors to $500 million. In addition, it authorizes construction of a nuclear reactor at the DOE Idaho National Laboratory that will generate both electricity and hydrogen, and creates a federal loan guarantee program to encourage the design and deployment of innovative technologies including advanced nuclear power plants.

Transmission

To promote investment in electric transmission infrastructure, FERC is directed to do an incentive rate rulemaking and provide for participant funding. In addition, it provides for expedited siting processes on both federal and private lands, and for the use of advanced transmission technologies. The Act established an Electric Reliability Organization to develop and enforce reliability standards for the bulk transmission system. The Act also requires FERC to identify the steps needed to make available real-time information on the functional status of all transmission lines within each of the transmission interconnections, and to implement such a transmission information system.

DOE is directed to study electric transmission congestion and possible designation of "national interest electric transmission corridors." The designation of such corridors could have a significant impact on the development of new electric transmission facilities. Congress has given FERC "backstop" authority to grant permits for the construction or modification of electric transmission facilities within these corridors in certain situations, including where the state siting authority has withheld approval. (In Washington, HB 1020 designates the State EFSEC to prevent a FERC backstop, as described above under State statutes.)

Climate Change

Climate change actions directed by the Act include forming a Climate Change Technology Advisory Committee charged with integrating existing federal climate change reports and activities. The Committee is to submit a national strategy to promote the deployment and commercialization of greenhouse gas intensity reductions, and to identify barriers to these technologies and ways to remove those barriers. Best Management Practices are also to be developed for calculating, monitoring and analyzing greenhouse gas intensity.

Amendments to the Public Utility Regulatory Policy Act (PURPA)

The Act amended PURPA to repeal the requirement for mandatory purchase from qualifying facilities by electric utilities if a competitive market exists, and established new criteria for qualifying cogeneration facilities.

The Act also amended PURPA to require state regulators and certain non-regulated electric utilities to consider five new standards based on the purposes of PURPA: net metering, fuel sources, fossil fuel generation efficiency, smart metering and interconnection. Washington's IRP law and City Light's IRP process meet the consideration and determination requirements required under PURPA. City Light does not anticipate the need for substantial discussion on the fuel sources and fossil fuel generation efficiency standards, since they are covered by existing State law.

Chapter 3 – The Need: Ensuring Long-term Reliable Service

For over one hundred years, City Light has delivered reliable, low-cost power to its ratepayer/owners. For most of those years, power generated by the Utility's own hydroelectric facilities, together with power purchased under contract and from the wholesale power market, was sufficient to meet the electric power needs of the service area.

Beginning in the early 1980s, the Utility initiated conservation programs to encourage its customers to use power more efficiently. This strategy was intended to defer as much as possible the acquisition of expensive new resources, especially those having a negative impact on the environment.

Policy direction from elected officials since then has reaffirmed the goal of using energy efficiently through continued funding of conservation programs. Seattle City Council Resolution 30144, April 3, 2000 (Appendix B), states that the Utility should use "cost-effective energy efficiency and renewable resources to meet load growth as much as possible." City Light subsequently contracted for the purchase of output from the Stateline Wind Project.

Among the initial steps in developing this Integrated Resource Plan (IRP) were to (1) forecast long-term load growth in the Utility's service area, and (2) evaluate the ability of the existing resource portfolio to serve future load at a predetermined level of reliability. Because it would be much too costly to acquire resources that guarantee 100 percent resource reliability, the Utility selected a level of reliability that reflects the amount of risk it is willing to accept that load will not be served. This level of reliability is embodied in a measure that is referred to as resource adequacy.

City Light's long-term forecast of service area load is discussed in this chapter, followed by descriptions of the Utility's existing portfolio of conservation, generation and market resources, power generated by these resources, and the need as measured by a target for resource adequacy.

Load Forecast

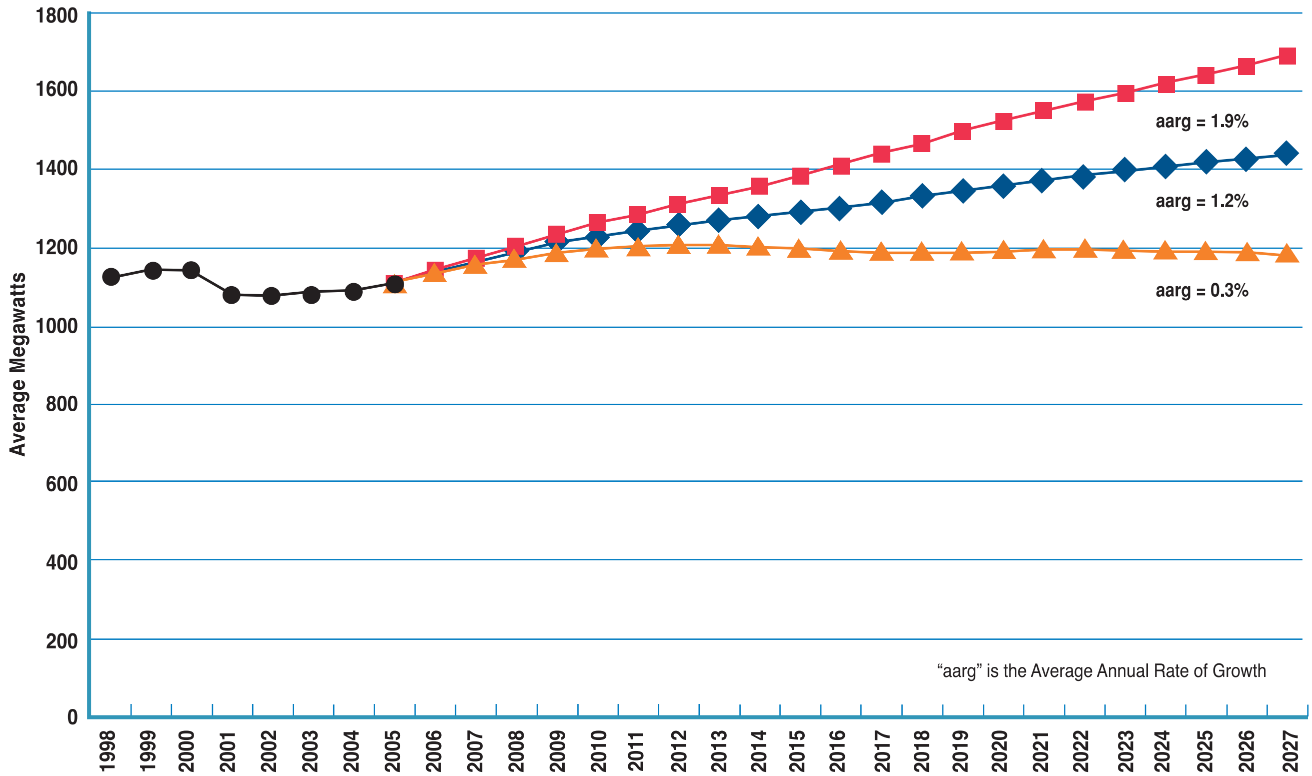
In order to plan for the acquisition of new resources, which can take many years, City Light forecasts future power consumption (or load) in its service area 20 years into the future.

The load forecast is based on forecasts of several key economic and demographic variables, primarily employment and the number of households in the service area. Recovery from the 2001-03 recession is still underway, with Seattle experiencing a construction boom in both the commercial and residential sectors. Downtown office towers are being built, despite a double-digit vacancy rate. Throughout the city, multifamily housing is displacing single-family housing and commercial buildings. Growth is expected to remain strong in the near term, with the rate of growth slowing somewhat by at least 2010.

Load Forecast Range

Figure 3-1 shows the Utility's 20-year base forecast of annual average load, with a high and low forecast to reflect uncertainty about the future. These forecasts define the range in which actual load will most likely fall. The range widens for each year into the future as uncertainty increases. Updated for each IRP, this is the Utility's best estimate of what future load will be. The forecasts do not reflect the effect of any future programmatic conservation, so that future conservation can be considered on the same basis as future generating resources in deciding how much of each to use in the IRP.

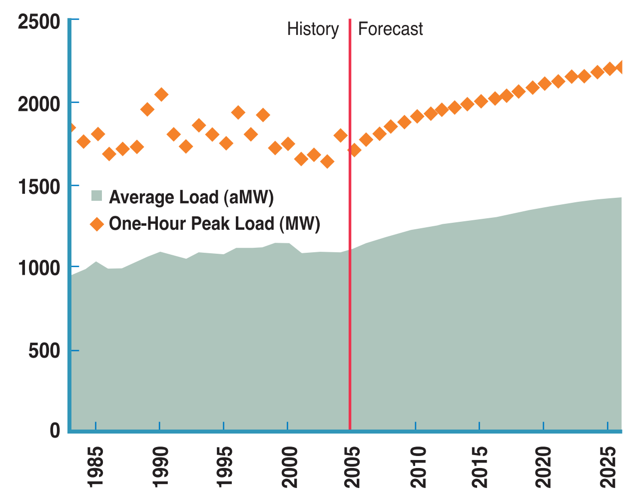
Figure 3-1. Base, High and Low Forecast (with no new conservation resources)



Peak Load Forecast

Figure 3-2 shows the average load history from 1983 through 2005 and the forecast through 2026, as well as the one-hour peak load (average load over a one-hour period). The historical data represent actual consumption and therefore reflect the impact of conservation programs in the past. As in Figure 3-1, the forecast does not reflect the effect of any future programmatic conservation. Programmatic conservation was evaluated along with other types of resources for inclusion in City Light's portfolio, as described in Chapter 4.

Figure 3-2. System Annual Load History and Forecast (with no new conservation program resources)

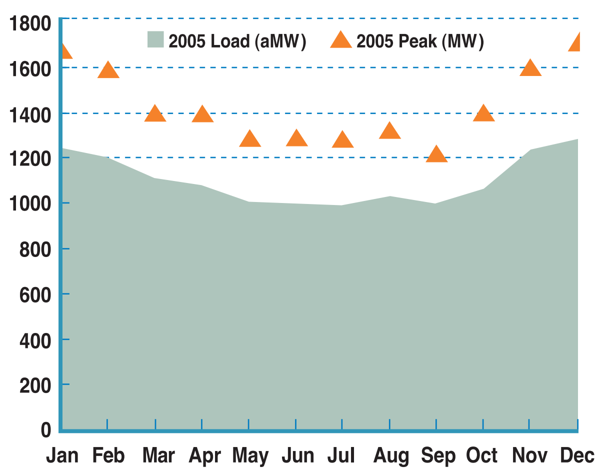


Monthly Load Shape

In planning for resource acquisition, City Light needs to know more about future load than just average annual consumption provided by the long-range load forecast. The Utility also needs to consider load shape throughout the year. Consumption in the winter is greater than in the summer because of greater customer need for heating and lighting in the winter. Average monthly variability in load is fairly predicable; typically it is about 20 percent higher in December and January than in July and August.

The Utility needs to have sufficient resources to be able to serve its customers during times of peak consumption. The one-hour peak load in any month can be many megawatts greater than the average load. Figure 3-3 shows the monthly load shape and monthly one-hour peaks for 2005. In January the one-hour peak was about 435 megawatts higher than the January average; in August the one-hour peak was nearly 300 megawatts higher than the August average. The range of variability in peak loads for November through February is much greater than in the other months. The highest historical peak of 2,055 MW occurred on December 21, 1990, when the temperature dropped to 12 degrees Fahrenheit.

Figure 3-3. 2005 Monthly Average Load and Monthly Peaks

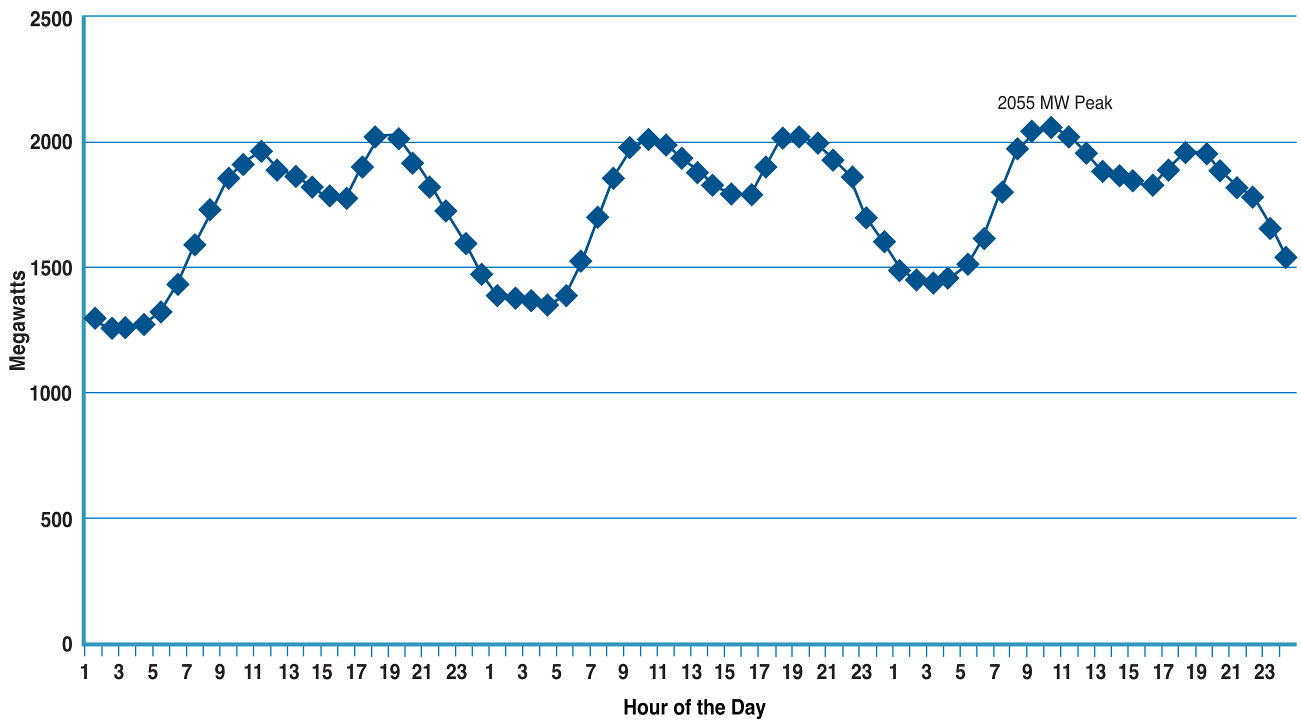


Meeting Load during Extremes of Weather

In order to assure resource reliability, the City Light must be able to serve peak loads under extreme conditions – severely cold weather that can be counted on to occur every few years, usually with little or no advance warning. Very cold weather can push hourly load as much as 50 percent higher than average monthly load. Fortunately such peaks are short-lived, and cold snaps rarely last much longer than three days. Figure 3-4 on the following page shows the hourly load shape for December 19-21, 1990, when peak load exceeded 2,000 megawatts for three consecutive weekdays.

Future peak load is only part of the equation for assessing the need for additional resources with a high level of reliability. In addition to understanding how much power might be needed under the stress of very cold weather, City Light needs to understand how existing resources operate under stress. Because almost all of the Utility's resources are hydroelectric, the system is most stressed during periods of drought. Computer modeling for the IRP used the joint probabilities for load and resource levels, together with the resource adequacy measure, to predict how much additional power the Utility will need and when it will be needed to serve fluctuating customer demand.

Figure 3-4. Peak Hourly Load – Cold Snap December 19-21, 1990



Existing Resources

City Light relies on a variety of resources to meet its power needs. The current portfolio includes conservation, generation resources and market resources. For nearly 30 years, City Light policy makers have been unwavering in their commitment to conservation as a resource. Generation resources include low-cost City Light-owned hydroelectric projects, power purchased at preference rates from the Bonneville Power Administration (BPA), and contract purchases from other entities. The Utility supplements these resources with power exchange agreements and purchases made in the wholesale power market. Existing conservation, generation and market resources are described in this section.

Conservation

In 1972, the Seattle 2000 Commission Report established conservation as the first choice resource to meet City Light's energy requirements. Since then, the Utility has been a leader in energy conservation at the local, regional and national levels, operating conservation programs on a broad scale as part of its resource portfolio. This section reviews the current conservation programs and the results of conservation efforts to date. See Chapter 4 for a summary of the 2006 assessment of future conservation resource potential.

Energy Saved by Conservation Programs

From 1977 through 2005, City Light's conservation programs saved over 10 million megawatt-hours by increasing the efficiency of electricity use in Seattle homes, businesses and industries. Conservation programs address specific energy end-uses such as efficient lighting, water heaters and laundry appliances, HVAC, motors and manufacturing equipment. They also encourage weatherization and high-efficiency construction methods. Monetary incentives to Utility customers include rebates, loans or outright purchase of savings for installed energy efficient measures.

In 2005, still-active energy efficiency measures installed under City Light conservation programs served over 10 percent of City Light's customer load, or 115 aMW. Table 3-1 shows the energy savings achieved by City Light conservation programs in 2005, and the current load served by still-active energy efficiency measures installed under a City Light conservation program in 2005 or before.

Table 3-1. Energy Savings from City Light's Energy Conservation Programs, 2005

Customer Group	Estimated New Energy Savings (aMW)	City Light Total Load Met with Conservation (aMW)
Commercial & Industrial	4.5	78
Residential & Small Commercial	1.8	37
Total Savings	6.3	115

In the early years of conservation acquisition, energy efficiency programs pursued the lower cost measures that were the most easily attained. After nearly 20 years of offering conservation programs to its customers, City Light needed a more systematic approach to selecting its conservation offerings. In late 1999, City Light and the Northwest Power Planning Council (NPPC) joined forces to develop the 2000 Conservation Potential Assessment (CPA), an analysis of the cost-effective conservation potential achievable in City Light's service territory over the next two decades. The 2000 CPA demonstrated that substantial cost-effective conservation was still available across all end uses to sustain a robust conservation program over the next several years.

Generation Resources

Most of City Light's power is generated by its own low-cost hydroelectric facilities, located mainly in Washington. As a municipal utility, it enjoys preference status in contracting for the purchase of additional low-cost power marketed by BPA. The Utility also has contracts with several other owners of hydroelectric projects in the region. City Light added wind power to its portfolio in 2002, with the signing of a 20-year contract for the purchase of output from the Stateline Wind Project. These resources, and the power generated by each, are shown in Figure 3-5 and described below. See Chapter 4 and Appendix C for generation resources that can potentially be added to City Light's portfolio in the future.

Figure 3-5. City Light Generation Resources

City Light Owned Resources

Boundary

The Boundary Project is located on the Pend Oreille River in Pend Oreille County in northeastern Washington. It is City Light's largest resource, with a peaking capability of 1,055 MW and average generation of about 490 aMW annually. As a run-of-the-river project, its power production is affected by the other projects in the river system. Because this project is located in the Columbia River Basin, it is subject to the flow regulations established by the Biological Opinion issued by the National Marine Fisheries Service for the protection of fish populations. Like most hydroelectric projects, the Boundary Project is licensed by the Federal Energy Regulatory Commission (FERC); the current license expires in October 2011.

Under the license, part of Boundary output must be sold to Pend Oreille County Public Utility District (PUD) No. 1 to meet its load growth. In addition, about 5 aMW of energy must be delivered to the PUD in compensation for encroachment of its Box Canyon Dam caused by the Boundary Project. Energy from Boundary is wheeled to consumers over BPA's transmission grid.

Skagit

The Skagit Project, including the Ross, Diablo and Gorge projects, operates as a single system on the Skagit River, about 80 miles northeast of Seattle in Whatcom County. Water released from the large Ross water reservoir flows to Diablo and Gorge. The combined one-hour peak capability is 690 MW. The license for these projects was renewed in 1995 and will be in effect for 30 years. City Light has committed to mitigation measures for fisheries, wildlife, erosion control, archaeology, historical preservation, recreation, visual quality and environmental education. Power generated from the Skagit Project is sent to Seattle over transmission lines owned by City Light.

Newhalem

This project is located on Newhalem Creek, a tributary of the Skagit River. It was built in 1921 to provide power for construction of the Skagit Project. In 1970 it was modernized and now operates under a FERC license that will expire in 2027. Power is delivered through transmission lines owned by City Light.

South Fork of the Tolt

This project, located in east King County, began commercial operation in 1995. Its one-hour peaking capability is less than 17 MW. Project costs are being offset by billing credits received from the BPA. The Northwest Power Planning and Conservation Act of 1980 authorized BPA to pay credits to its customers to encourage the development of new resources. The credits basically compensate the Utility for the difference between the cost of the new resource and the cost of buying the same power from BPA. Power from this project is delivered over a line owned by Puget Sound Energy.

Cedar Falls

Cedar Falls was built in 1905 on the Cedar River, about 30 miles southeast of Seattle in King County. It was constructed before the adoption of the Federal Power Act of 1920 and therefore does not require a license from FERC to operate. Power is transmitted by Puget Sound Energy.

Contracted Resources

Bonneville Power Administration

City Light's largest power purchase contract is with BPA. It allows the Utility to receive power from 29 hydroelectric projects and several thermal and renewable projects in the Pacific Northwest. Energy is delivered through BPA's transmission grid. A Power Sales Agreement with BPA provides for purchases of power by City Light over the ten years beginning October 1, 2001.

Under the contract, power is delivered in two forms: a shaped Block and a Slice. Through the Block product, power is delivered in monthly amounts shaped to the City Light's monthly net requirement, defined as the difference between the Utility's projected monthly load and the resources available to serve that load under critical water conditions. Under the Slice product, the City Light receives a fixed percentage of the actual output of the federal system and pays the same percentage of the actual costs of the system. Payments for the Slice product are subject to an annual true-up adjustment to reflect actual costs. Power available under the Slice product varies with water conditions, federal generating capabilities, and requirements for fish and wildlife protection and restoration.

City Light is scheduled to sign a new contract with BPA by October 2011. BPA is conducting a Regional Dialogue to address issues involved in structuring 20-year contracts that will fairly apportion its least expensive base system generation among its customers. All other power marketed by BPA will be available as variously designed products. Power will be sold primarily at two rate levels – one for the base system generation and the other a market rate for power from other resources. Any Slice product will probably be structured differently from the current product.

High Ross Agreement

In the early 1980s City Light planned to raise the height of its Ross Dam to maximize the potential output of the plant. The Canadian Province of British Columbia protested on environmental grounds. After a period of negotiations that ended with the signing of the 80-year High Ross Agreement in 1986, City Light agreed to abandon its plans and instead to purchase power from British Hydro (Powerex). Power would be delivered and priced to mimic the generation and costs that would have resulted from construction of the High Ross Dam.

The power received from this contract has a relatively high cost through 2020. At that point the cost will be drastically reduced to a few dollars per MWh because the cost portion equivalent to the service on the debt that would have been issued to build the High Ross Dam will terminate. The agreement is subject to review by the parties every ten years. The most recent review, concluded in 1998, did not result in any changes to the agreement. Power is wheeled by BPA.

Lucky Peak

The Lucky Peak Project was built in the mid-1980s by several irrigation districts. Power operations began in 1988 under a FERC license that terminates in 2030. Generation of power is secondary to the project's irrigation purpose, and most of the power output is available only in the summer months. Project costs were reduced when the outstanding long-term bonds were refinanced in early 2002. Power from this project, about 38.5 aMW, is wheeled over facilities owned by Idaho Power and BPA.

Priest Rapids

The Priest Rapids Project is owned and operated by Grant County PUD. The Project consists of the Priest Rapids Development and the Wanapum Development. City Light purchases power from this project under a 2002 agreement with Grant PUD. Since November 1, 2005, 70 percent of the Priest Rapids Project output has been allocated to Grant PUD. City Light is entitled to a share of the difference between the allocation to Grant PUD and Grant PUD's load requirements. As Grant PUD's load grows, the amount of power available to City Light will decrease.

City Light's share will come from the Priest Rapids Development from November 1, 2005 through October 31, 2009. Effective November 1, 2009, City Light's share will come from both the Priest Rapids Development and the Wanapum Development. The term of the contract runs through the end of the new FERC license period. (License renewal is currently underway.) City Light's share is expected to be about 2 to 3 aMW in 2007-2009, with a small increase in 2010, followed by gradual reduction as Grant PUD's load increases.

Grand Coulee Project Hydroelectric Authority (GCPHA)

City Light has 40-year contracts to buy half of the output from five hydroelectric projects in the Columbia River Basin built by irrigation districts. The City of Tacoma buys the other half. City Light's contracts expire over the period 2022-2027. Electric generation is mainly in the summer months and is wheeled by local entities and BPA. City Light receives about 27 aMW from this contract.

Stateline Wind Project

City Light has an agreement with PPM Energy to purchase wind energy and associated environmental attributes from the Stateline Wind Project in Walla Walla County, Washington and Umatilla County, Oregon. Through December 2021, City Light will receive wind energy with an aggregate maximum delivery rate of 175 MW per hour. Energy delivered under the contract is expected to average about 26 percent of the maximum delivery rate. City Light has also entered into an agreement through 2011 to purchase integration and exchange services from PacifiCorp and another agreement to sell integration and exchange services to PPM.

Power from Existing Generation Resources

Table 3-2 shows the recent history of power produced annually from each of the generation resources described above, as well as some that are no longer part of City Light's portfolio. The table shows how the portfolio has changed in recent years, and illustrates the variability in power production caused by weather.

Since City Light's current resource portfolio is predominantly hydro, it has the advantage of operational flexibility because of the hydro storage capability. On the other hand, it has the disadvantage of being significantly affected by weather conditions. The amount of water available for power generation is affected by the amount and the timing of precipitation, run-off from snow melt, and regulations governing the recreational use of lakes, irrigation, protection of fish habitat and other environmental concerns.

While operational flexibility allows the Utility to meet peak load easily most of the time, the ability to serve peak load can be greatly diminished at times when water levels are low. Also, the Utility's resource portfolio must be able to serve load under the prolonged drought conditions that occur periodically in the Pacific Northwest. Prior to 2006, the West experienced six consecutive years of drought conditions, with 2001 as the most severe by far.

Table 3-2. Power Generated Annually from Existing Resources (Average Megawatts)

	1999	2000	2001	2002	2003	2004	2005
OWNED GENERATION							
Boundary	508.1	431.7	267.1	452.2	408.1	398.8	395.1
Skagit - Gorge	135.4	109.3	70.4	117.0	106.3	105.2	88.7
Skagit - Diablo	116.7	92.7	54.5	102.8	84.9	8.5	74.8
Skagit - Ross	109.9	84.4	44.9	95.6	83.1	77.6	64.3
Newhalem		0.4	1.1	1.1	0.9	1.4	0.7
South Fork Tolt	8.0	5.0	4.6	8.9	5.6	6.9	5.1
Cedar Falls	8.1	5.7	7.4	9.1	7.3	7.0	4.2
Centralia (sold 2000)	78.7	31.5					
TOTAL OWNED GENERATION	965.1	760.8	449.9	786.7	696.2	685.3	633.0
PURCHASE CONTRACTS							
Bonneville Power Administration	180.6	193.7					
Bonneville Power Administration Block			200.7	152.3	147.1	137.8	109.4
Bonneville Power Administration Slice			71.5	322.4	390.9	392.8	385.1
High Ross (BC Hydro)	35.2	33.8	5.1	33.9	36.0	34.8	35.4
Boundary Encroachment (BC Hydro)	1.7	2.0	0.9	1.2	1.6	1.5	1.7
Lucky Peak	48.6	38.8	21.5	33.0	3.4	31.3	25.8
Priest Rapids (Grant County PUD)	47.1	41.4	29.9	37.3	35.5	36.0	32.9
Grand Coulee Project Hydroelectric Authority	28.6	27.2	30.9	28.3	26.9	28.9	28.5
Stateline Wind				12.2	24.7	39.7	37.4
EXPIRED CONTRACTS							
Klamath Falls (expired 2006)			37.2	81.0	74.7	81.8	66.4
Pend Oreille PUD (expired 2005)	8.1	6.6	4.9	5.0	5.4	6.7	3.0
Metro CoGeneration (expired 2004)	0.9	0.8	1.4	1.7	1.6	0.7	
Columbia Storage Power Exchange (expired 2003)	16.1	12.1	11.6	11.3	3.0		
TOTAL PURCHASE CONTRACTS	366.9	356.5	445.8	719.5	780.8	792.0	725.6

As shown in Table 3-2, the amount of power produced from owned generation in 1999 was about twice the amount produced in 2001, illustrating the risks associated with hydropower production. To make up the shortfall in 2001, City Light increased its purchases from BPA, but was nevertheless forced to make purchases from the market. By 2002, City Light had signed a new contract with BPA that nearly doubled its purchases from the federal agency. Wind power from Stateline came online in 2002, and power from that source increased over the next two years to its current level.

Outlook for Existing Generation Resources

Over the next 20 years, not all of the generation resources described above will remain as they are in the existing portfolio. Changes are likely in some contract resources, and climate change may impact hydroelectric resources in ways that are difficult to predict.

Contract Resources

City Light's license to operate Boundary Dam expires in 2011, but the Utility is confident the license for this facility will be renewed. Some contracts will expire or be modified over the planning period. For example, the Stateline wind contract for about 45 aMW expires in December 2021. City Light's share of Priest Rapids generation output will gradually decline over the 20-year period at the rate of load growth of Grant County PUD. Contracts with the Grand Coulee Project Hydroelectric Authority begin expiring in 2022.

Of potentially greater impact are the possible changes in the BPA contract. A new 20-year contract is scheduled to be in place in October 2011. Features of new contracts between BPA and its clients are currently under discussion, as described in Chapter 2. The 2006 IRP assumes City Light will continue to purchase power from BPA at present levels after 2011.

Climate Change

In the long term, climate change is expected to impact hydroelectric generation on both the federal Columbia River power system and the City Light system. As part of the integrated resource planning process, City Light is addressing the potential impacts of climate change on hydropower output and demand for electricity. The challenge is representing these potential changes in IRP modeling.

In October 2005, local experts in climate change evaluation, the University of Washington Climate Impacts Group, issued a report stating that "projected climate and hydrologic changes will likely alter the annual patterns of electricity demand and streamflow. . . . Projected warming due to climate change will likely lower electricity demand during the winter and increase demand during the summer in Washington."

While these general observations can help planners evaluate their assumptions and identify areas for additional analysis in future IRPs, the analytical model requires more specific forecasts of the monthly effects on precipitation patterns and river and stream flow. The University of Washington is developing these more detailed regional forecasts, with support from City Light and other local, state and federal agencies.

Forecasts for the Skagit and Columbia/Pend Oreille river systems are important to understanding City Light's owned hydropower and BPA power output. City Light is funding work by the University of Washington on modeling for the Skagit, and BPA and the Northwest Power and Conservation Council may pursue similar studies for the Columbia River system.

Although climate change data are not yet available for most of the hydropower systems from which City Light receives power, the hydro distribution of the Skagit system that was used in the IRP model did include a range of flow conditions predicted by climate change models. The input data were based on historic data, but were not limited strictly to the recorded extremes. This approach allowed planners to see how the extremes (both lower and higher flow conditions) would effect the various resource portfolio options in terms of reliability, cost, risk and environmental impact.

Given the complexity of the large-scale global climate models, and the challenges of scaling them down to levels that capture the unique nature of each major hydropower watershed, the process of refining the forecasts will take time. Understanding of climate change impact will improve as new data and refined modeling tools become available. City Light will continue working on the climate change issue in the context of the IRP process.

Market Resources

The wholesale electric power market in western North America plays an important role in meeting Seattle's power needs by balancing City Light's energy surpluses and shortages. Surplus power can be sold and power shortages can be made up with purchases both seasonally and over a period of years. Seasonal power can also be obtained from the wholesale market through seasonal capacity contracts (physical call options), although City Light currently has no such contracts. See Chapter 4 for potential use of market resources in the IRP.

With colder winter temperatures driving Seattle's power demand to peak in November through February and the spring snow melt driving hydropower production to peak in April to June, there is a seasonal mismatch between demand and supply of power. Keeping sufficient power generation capability to meet winter demand leads to excess generation capability the rest of the year. In addition to seasonal variation in supply and demand, precipitation may vary substantially from year to year, making it difficult to predict the supply of hydropower.

City Light actively manages its portfolio of power supply resources by purchasing and selling power in the wholesale markets and transacting seasonal exchanges of power with utilities in California. These transactions lower the rates charged to the Utility's retail customers by generating revenues from sales of surplus energy and allowing purchases of lower cost power.

Under its exchange agreement with the Northern California Power Agency (NCPA), City Light delivers 60 MW of capacity and 90,580 MWh of energy to NCPA in the summer. In return, NCPA delivers 46 MW of capacity and 108,696 MWh of energy to City Light in the winter. Deliveries to NCPA started in 1995 and will continue until the agreement is terminated.

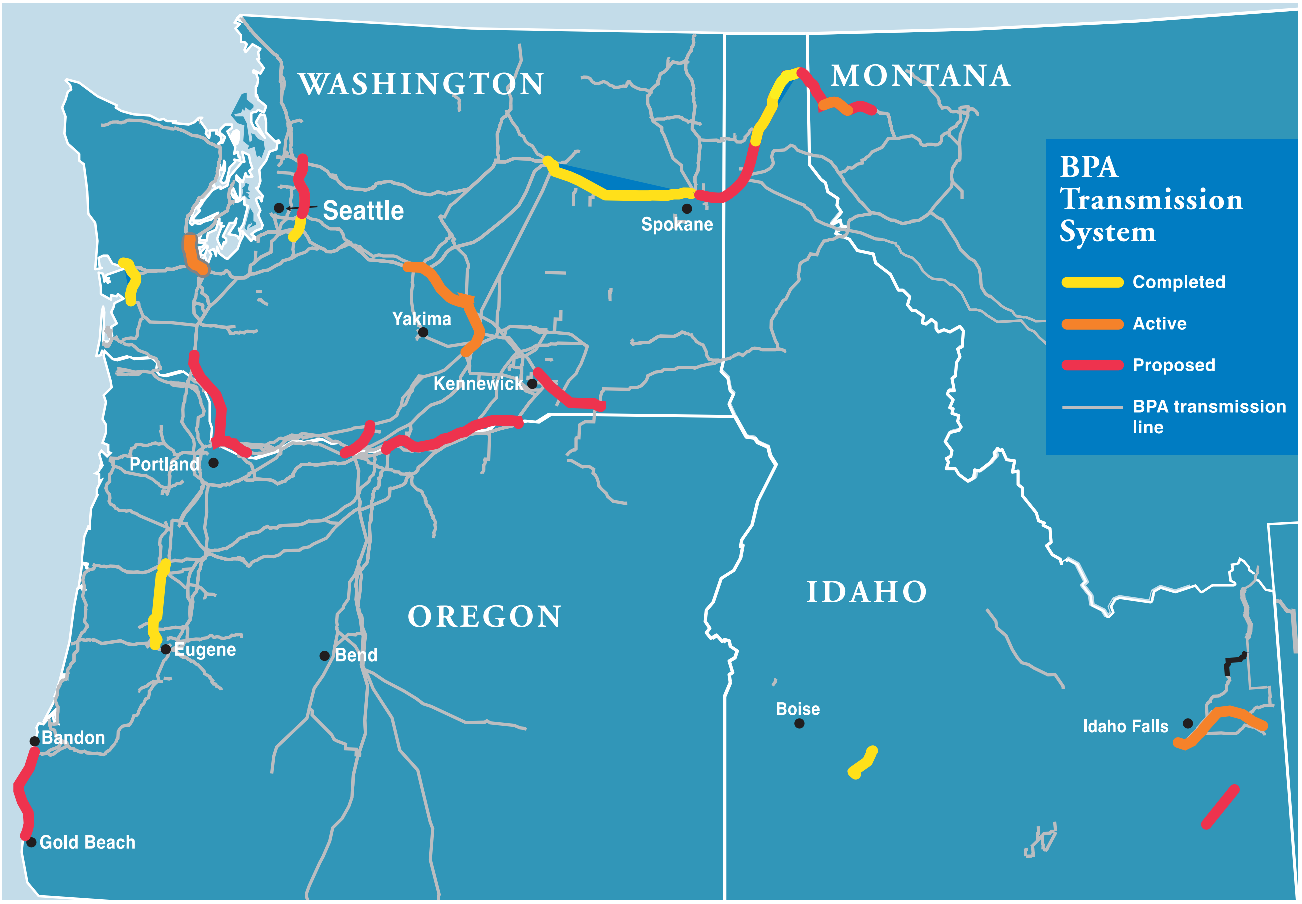
Western States Transmission System

The Western electric transmission system physically defines the wholesale market for electricity in western North America. This market is broadly made up of 11 western states, two Canadian provinces, and northern Baja California, Mexico.

Constructed primarily in the 1950s and 1960s, the high-voltage transmission system is owned by a number of both private and public utilities. In the Pacific Northwest, the Bonneville Power Administration (BPA) operates about 75 percent of the transmission system, shown in Figure 3-6. Other large transmission owner/operators, including PacifiCorp, Puget Sound Energy, Idaho Power, British Columbia Transmission Company, and Portland General Electric, operate the rest. The high voltage transmission system is near capacity in many parts of the West, including the Pacific Northwest.

Market transactions are facilitated by City Light's ownership share of the Third AC Intertie. This ownership share was acquired in 1994, when City Light signed an agreement with BPA for rights to 160 MW of transmission capability over Bonneville's share of the Third AC Intertie. The Third AC Intertie is an alternating current line that connects the Northwest region with California and the Southwest.

Figure 3-6. BPA Transmission System



Source: BPA

Resource Adequacy

Resource adequacy is a utility industry term used in long-range planning. Utility planners want to avoid acquiring resources that may not be needed; on the other hand, they seek a high level of probability that load will be served under varying conditions. The measure of resource adequacy used by resource planners reflects the level of risk that decision-makers are willing to accept that load may not be served. Past experience around the country suggests that most customers are willing to pay very high prices for power on a short-term basis rather than have power interrupted. This indicates that a high degree of resource adequacy is desired.

The degree of reliability City Light plans for is ultimately a policy decision. Planning for higher reliability can lead to a higher cost of service. However, having insufficient power can also be very costly, as witnessed during the 2001 power crisis in the West. Pacific Northwest utilities did not interrupt service to their customers; yet extremely high power costs were incurred in order to maintain reliable service. Resource adequacy targets can have both reliability and economic consequences. Recent direction from Seattle policy-makers and advice from customers has been to plan to serve load with a high degree of reliability.

Resource Adequacy in the IRP

For this IRP, City Light developed a resource adequacy target of 95 percent probability that the Utility will have sufficient power supply to meet demand without customers being unserved. In other words, 95 times out of a hundred, there will be sufficient power to meet load in a month, given the combined probabilities for high demand and insufficient resources. In developing this target, City Light planners assumed that only 100 MW of power is available for purchase from the wholesale power market under extreme conditions – where the market is under stress due to high demand, limited supply or both.

For comparison, City Light asked Global Energy Decisions (GED) to conduct a separate resource adequacy study using a measure of loss of load probability of one day in 10 years, which is a regional standard endorsed by the North American Electric Reliability Council. The result was slightly below, but very comparable to City Light's 95 percent resource adequacy measure.

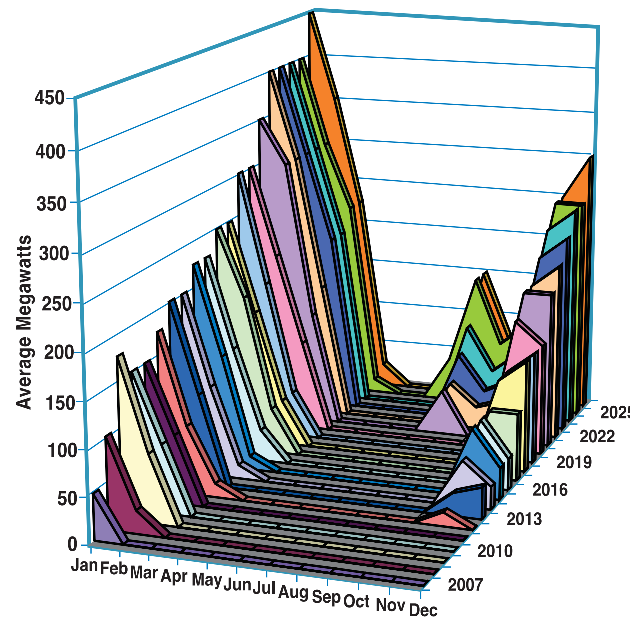
City Light's resource adequacy study showed that by 2007, the existing portfolio will not meet the 95 percent target in the winter, when system load is greatest; in other words there is more than a 5 percent risk of not being able to meet load in the winter. Unserved load could result from the combined circumstances of very low temperatures, very low water, and a limited amount of power available to City Light from the market.

New Resources Needed to Reduce Risk

Over the 20-year planning period, load is expected to continue to grow, and some of the power purchase contracts will expire. As shown in Figure 3-7, the amount of unserved load at the 95 percent level increases as the difference between load and present-day resources grows.

By 2021, when the Stateline wind contract expires, load may be unserved in late summer and early fall, as well as in winter. In order to reduce the risk of unserved energy below the 5 percent level, approximately 50 aMW of additional energy must be available in 2007. As load increases through the 20-year planning period, the amount of additional resources required grows to 450 aMW by the year 2026.

Figure 3-7. 95% Resource Adequacy – Projected Gap between Load and Resources



The resource adequacy requirement is calculated to account for the risk of variation in hydro generation and loads, and to replace the resources for which contracts have expired.

The resource adequacy study was the starting point for developing a portfolio of additional resources for the 20 years from 2007 - 2026. As described in Chapter 6, new resources, including conservation, were added to the existing portfolio, in amounts and at points in time when the resource adequacy study indicated they would be needed. This methodology produced candidate portfolios, all with the same level of resource adequacy.

Chapter 4 – The Choices: Identifying Potential New Resources

This chapter describes the various resources currently available to electric utilities and considered for this Integrated Resource Plan (IRP). They include additional conservation resources based on the 2006 Conservation Potential Assessment; generation resources (landfill gas, an efficiency upgrade to City Light's Gorge plant, biomass, wind, geothermal, natural gas, gasified coal and pulverized coal); and purchases of power from the Western wholesale energy market. Other resources, including solar and wave energy, that may become feasible in the future are also briefly discussed, with more detail provided in Appendix C.

Conservation Resources

Over three decades ago, the City of Seattle established conservation as the first choice resource to meet City Light's energy requirements. This direction has been reaffirmed over the years in a variety of resolutions, ordinances and initiatives, most recently as key element of the Mayor's Climate Action Plan.

As described in Chapter 3, City Light has implemented this direction by operating conservation programs that encourage Seattle homeowners and businesses to use energy-efficient equipment and practices. Investment in conservation resources under City Light's programs has generated significant resource and other benefits for the Utility and its customers in the form of avoided higher cost generation, deferred transmission and distribution investments, reduced air pollution and greenhouse gas emissions, and lower customer bills.

Resource Characteristics

Energy efficiency measures installed under City Light conservation programs are not dispatchable, meaning they cannot be turned off and on as needed on short notice like some generation resources. Conservation measures are more similar to baseload generation, such as coal plants, that produce power at a steady level rather than to a simple-cycle combustion turbine that may be called on only a few times in a year.

Energy savings from many conservation measures do have seasonal, daily and hourly load shapes. For example, an energy-efficient water heater saves more energy in the morning than other times of the day, because hot water use is greatest in the morning. An energy-efficient window installed in a residence with electric space heat will save more energy in the winter, when the need for space heating is greatest.

Conservation measures can be either discretionary or lost opportunity resources – relative to the timing of implementation. Discretionary conservation measures can be implemented at any time within practical limits. For example, an energy efficient window can be installed in an existing residential building now, or five years from now, with little or no effect on the cost effectiveness of the measure.

Lost-opportunity conservation must be captured at the time a new building is built or a new appliance is installed. For example if energy-efficient lamps and fixtures are not installed in a new building at the time of construction, the potential for energy savings and operational efficiency is lost until the building is replaced or, more likely, retrofitted at a much higher cost in the future.

2006 Conservation Potential Assessment

In preparation for the 2006 IRP, City Light engaged the energy analysis firm Quantec to update the assessment of conservation resource potential in City Light's service territory and develop a new CPA (2006 Conservation Potential Assessment). Quantec compiled a wide range of measure-specific, economic and market information. The data included City Light forecasts, customer characteristics surveys and conservation program achievements, along with a variety of data from secondary sources. These included the Northwest Power and Conservation Council Regional Technical Forum, the Energy Information Association and the California Energy Commission's Database for Energy Efficient Resources.

The 2006 CPA analysis considered dozens of possible conservation measures, with hundreds of permutations across segments and construction vintages, distinguishing between discretionary (e.g. shell retrofit) and lost opportunity (e.g. equipment replacement and new construction) resources.

Approach

The approach in the 2006 CPA was to identify all "technical potential" in City Light's service territory, and then determine how much of this technical potential was "achievable." Technical potential assumes that all demand-side resource opportunities may be captured regardless of their costs or market barriers. Achievable potential represents the portion of technical potential likely to be viable over the planning horizon, given prevailing market barriers that may limit the implementation of demand-side measures. For the 2006 CPA, achievable potential was assumed to be 70 percent of the technical potential.

The 2006 CPA examined energy savings available across the residential, commercial and industrial sectors in City Light's service area. The study also incorporated non-energy benefits using the method employed by the NPCC in developing the 5th Regional Power Plan. For a more detailed discussion of assumptions, approach and methodology used in developing the 2006 CPA, see the link for Conservation Potential Assessment on Seattle City Light's Conservation Webpage, **http://www.seattle.gov/light/conserve/**.

Summary of Findings

Based on the results of the 2006 CPA, the 15-year achievable conservation potential in City Light's service area is estimated at 229 aMW of electricity, representing more than 18 percent of the baseline electricity consumption forecast in that year (2020).

Table 4-1 shows this estimate of achievable conservation potential broken out in $.01 increments based on the "levelized" cost of the resource. The levelized cost is the present value of the total cost of installing and maintaining a conservation resource over its economic life, converted to equal annual payments. As the data show, nearly 75 percent of the achievable potential across all sectors is available at $.06/kWh or less. Over 95 percent of energy savings potential in the industrial sector is available at $.03/kWh or less.

Modeling Conservation for the IRP

For the purposes of developing modeling input for the 20-year IRP planning horizon, the CPA results shown in Table 4-1 were extended by five years. Conservation costs were modeled the same way as generation resources, using real levelized costs identified by the Conservation Potential Assessment. In all Round 1 portfolios, the pace of conservation acquisition was modeled at a constant rate of 7 average megawatts (aMW) per year. This constant pace of conservation acquisition was identified as producing the highest net present value through modeling sensitivities. In Round 2, an accelerated pace of conservation acquisition was also modeled (see Chapter 6).

Table 4-1. 15-Year Cumulative Achievable Potential by Cost Group

Cost Group	Residential (aMW)	Commercial (aMW)	Industrial (aMW)	Total (aMW)	Cumulative Percent
A. Up to $0.01	2.6	11.7	0.7	14.7	6%
B. $0.01 to $0.02	5.1	32.8	17.9	48.1	21%
C. $0.02 to $0.03	11.2	48.1	34.3	79.1	35%
D. $0.03 to $0.04	13.9	52.4	35.2	101.6	44%
E. $0.04 to $0.05	18.8	58.7	35.5	113.2	49%
F. $0.05 to $0.06	20.3	63.5	36.5	120.5	53%
G. $0.06 to $0.07	26.8	67.4	36.5	130.9	57%
H. $0.07 to $0.08	31.8	70.0	36.5	138.4	60%
I. $0.08 to $0.09	33.2	76.0	36.5	145.8	64%
J. $0.09 to $0.10	35.8	78.4	37.1	150.9	66%
K. $0.10 and Higher	71.3	120.4	37.1	228.8	100%

Generation Resources

Generation resources produce electrical energy from other forms of energy such as heat, potential energy (e.g. falling water, wind), solar or chemical energy. This section begins with an explanation of why types of resources rather than specific projects are evaluated, and the value of considering a broad range of operationally proven, commercially available resources that are likely to be cost-effective.

The following generation resources were analyzed for this IRP:

- Landfill gas
- Biomass (wood-fired)
- Hydro efficiency improvement at Gorge Dam
- Wind
- Geothermal
- Natural gas (simple and combined-cycle combustion turbines)
- Coal (integrated gasification combined cycle)
- Pulverized coal

Any generation resource added to City Light's existing portfolio will have characteristics that suit the Utility's future needs. The most important are costs, dispatchability, transmission requirements and environmental attributes. Cost information for new generation resources evaluated in the IRP is summarized, followed by descriptions of each resource type, including information on the other three characteristics.

Other generation resources that may become feasible in the future are summarized at the end of this section, with more detail in Appendix C.

Resource Types vs Specific Projects

Evaluating generating resource types in an IRP rather than focusing on particular generating projects has several advantages. Reliable, verifiable information about the generating technology can be used, making it possible to objectively compare the results of the quantitative analysis of candidate resources. The IRP can be focused on higher-level, long-term strategic issues rather than on the variable details of specific transactions.

In addition, the information about generating resource types that is developed in an IRP can be used as the Utility shifts from planning to implementation (resource acquisition). For example, if the resource strategy adopted in an IRP calls for City Light to acquire a specific type of generating resource, fundamental information about that resource type that was developed in the IRP can be used as a benchmark for evaluating particular generating projects.

If during resource acquisition it becomes apparent that costs or other characteristics of particular generating projects are as good or better than what was used in the last IRP, then acquisition can confidently proceed as planned. However, if costs or other characteristics are substantially worse, analysts can exercise caution and perhaps reconsider whether that type of resource still fits within the Utility's overall resource strategy.

Selecting a Range of Resources

The IRP evaluated more types of generating resources than were included in the resource recommended resource portfolio. The advantages of analyzing a reasonably broad range of generating resource types include the following:

- Each type of generating resource has a unique combination of advantages and disadvantages, including costs, benefits, opportunities and risks. Including a broad range of resource types helps to ensure that the IRP process is objective and does not prematurely narrow the field of resource alternatives.
- The net impacts of a particular type of generating resource on the Utility's overall resource portfolio are often not obvious and can remain obscured if the resource is only evaluated on a stand-alone basis.
- It is unlikely that a single type of generating resource can best meet all of the City Light's needs over the long-term. A diversified mix of resources is more likely to meet the Utility's objectives of maximizing reliability and minimizing cost, risk and environmental impacts.
- Analyzing various types of generating resources helps to identify which combinations of new resources can best complement the existing resources in the Utility's portfolio.
- Various types of generating resources have proponents and opponents. Quantitative analysis of candidate resource portfolios that combine a range of resource types provides a constructive, organized means to incorporate input from a variety of perspectives.

The IRP provides an open, rigorous and structured process for comparing and choosing from among an array of available resource types. However, evaluating a particular resource does not imply a predetermined preference for (or against) including that resource in the Utility's portfolio.

Quantitative analysis of candidate resource portfolios that mix various types of resources produces results (e.g., impacts on reliability, costs, risks, environmental impacts) that are useful for selecting which types of resources will be included in the Utility's long-term resource strategy. While the preferred strategy will likely include more than one type of resource, several types of generating resources will probably be excluded based on results from the quantitative analysis.

Costs of New Generation Resources

The 2006 IRP has been developed at a time when rapidly rising commodity prices and a devalued U.S. dollar are escalating costs for new resources. Much of this cost escalation can be traced to rising prices for steel and concrete, as global demand for these materials rises. The cost of wind turbines, many imported from Europe, has grown rapidly as a result of a devalued U.S. dollar and scarcity premiums caused by a rush to complete projects before expiration of the federal Production Tax Credit in 2007.

In the next few years, City Light expects to see higher costs for resources than represented in the 2006 IRP. However, it is likely that productive capacity for concrete, steel and wind turbines will expand, causing real prices for resources to moderate. City Light opted to not adjust resource costs in the 20-year study for what are seen as primarily near-term market trends. Table 4-2 shows the resource costs used in the 2006 IRP.

Table 4-2. Costs for New Resources (2006 Dollars)

Cost	Coal	CCCT	SCCT	Hydro	Geothermal	Wind	Biomass	Landfill Gas
Heat Rate	9,282	7,200	9,688				n/a	11,000
Capital ($/kW)	$1,575	$613	$500		$3,150	$1,500	$2,476	$1,500
Fixed O&M ($/kW-yr)	$28.35	$10.00	$12.00		$171.97	$20.00	$219.00	$134.03
Wheeling ($/kW-yr)		$14.33	$14.33	$14.33	$14.33		$14.33	$14.33
Transmission Build ($/kW-yr)	$85.14					$20.00		
Fuel	MT/WY $0.79/mmBtu	GED Gas Price Forecast	GED Gas Price Forecast	$0.00	Included in Capital	$0.00	Included in Capital	$1.00
Variable O&M ($/MWh)	$3.24	$2.85	$6.00		$2.90	$1.00	$0.00	$1.00
Integration & Shaping ($/MWh)						$7.25		

As shown in Table 4-2, transmission plays a role in estimating costs for new resources. City Light is dependent upon a regional transmission system that is highly constrained. In the IRP, it is assumed that if a new transmission line or transmission upgrade is required to interconnect a distant power resource to City Light, the Utility will have to pay a pro rata share of the transmission line according to the amount of firm capacity it needs. Transmission costs are driven by the distance between Seattle and the generating resources and the amounts of transmission capacity required. These costs are assumed to be financed over time and are incorporated as a cost of the resource. In the absence of new transmission requirements, the BPA transmission tariff is assumed.

Information about the costs of new resources came from many sources, including Global Energy Decisions, U.S. Department of Energy, Northwest Power and Conservation Council, Western Governors Association, American Wind Energy Association, and the Geothermal Resources Council. Not all cost information from these sources was consistent, despite adjustments for heat rates, capacity factors and other factors. In these cases, a cost was selected that fell within the range most frequently reported.

Resources Evaluated in the IRP

This section provides the following basic information on each generating resource type evaluated for the IRP:

- Resource technology and fuel
- Current status and outlook
- Resource characteristics (dispatchability, transmission requirements and environmental attributes)

Landfill Gas

The two forms of bioenergy generation analyzed for the IRP are landfill gas and wood waste. Existing bioenergy generating projects make up about two percent of the Pacific Northwest's total electric generating capacity, and about one percent of U.S. electricity generation. Wood wastes and landfill gas are the most prevalent fuels because there are few competing commercial uses. For existing projects, costs for these two types of fuel are negligible.

Interest in bioenergy resources has increased in recent years, with active research and development of new forms of bioenergy. The impetus for these efforts reflects growing concerns about the cost and availability of fossil fuels, as well as growing interest in finding new sources of energy that do not produce large amounts of CO_2 emissions. Certain types of bioenergy fuels could also be used as a substitute for petroleum-based fuels. In the future, this could lead to competition between alternative uses of bioenergy fuels, including transportation and electric generation.

The analysis of landfill gas in the IRP is based on costs and other characteristics of a biogas project fueled by methane collected from a solid waste landfill. Other forms of biogas not considered were methane produced at wastewater treatment plants, and methane produced from animal manure.

Resource Technology and Fuel

As organic materials in solid waste landfills decompose, high concentrations of combustible gases are released. Typically, landfill gas is composed of 50 to 60 percent methane; most of the rest is carbon dioxide. At most modern landfills, federal laws require capturing and burning the gas to minimize the risk of explosion and reduce hazardous air emissions. However, it can be put to productive use as a fuel for generating electricity using internal combustion engines or combustion turbines.

The most efficient size and form of generating technology for any particular solid waste landfill usually depend on the amount (and quality) of biogas produced by the landfill, which, in turn depends on factors such as the landfill's size, contents and age. The capacity is generally 10 megawatts or less.

Fixed and variable costs for landfill gas projects depend on the type of generating technology that is used. Smaller projects typically use internal combustion engines, while larger projects often use combustion turbines.

Current Status and Outlook

Landfill gas is used to produce electricity at 380 landfills in the United States. Recently, new landfill gas projects have been developing at a moderate pace, driven by the economics of specific landfill gas project opportunities relative to the cost of competing sources of electric generation.

Landfill gas generating projects use mature technologies. While incremental improvements may occur, significant breakthroughs are not expected. Future availability of opportunities to develop landfill gas generating projects will be influenced by the number and location of solid waste landfills.

Resource Characteristics

Transmission requirements. Most solid waste landfills are already served by the local electrical transmission and distribution network, but upgrades and new infrastructure may be required if the electricity generation exceeds the onsite needs of the landfill.

Dispatchability. Most landfill gas generating projects are operated as baseload resources, largely to help ensure that all gas produced from the solid waste landfill is burned.

Environmental attributes. Net environmental impacts are relatively small, since landfill gas generating projects consume a fuel source that would otherwise be flared. Unprocessed landfill gas may contain impurities that can create hazardous air emissions unless they are removed either before or after combustion. Depending on where the solid waste landfill is located and the types of neighboring land uses, noise from generating equipment must also be controlled.

Biomass

Resource Technology and Fuel

Biomass can be converted into fuel using thermochemical technologies such as direct combustion, gasification and pyrolysis, or biochemical technologies such as anaerobic digestion (e.g., dairy digesters) and fermentation.

City Light's analysis of biomass generation is based on costs and other characteristics of a conventional steam-electric turbine fueled by direct combustion of wood waste.

Both types of technology generate electricity by processing biomass into a combustible fuel and burning it an internal combustion engine, a combustion turbine or a conventional steam-electric turbine. In some situations, a biomass-fired conventional steam-electric turbine can be configured to both generate electricity and produce a supplemental supply of steam for use in an industrial process (i.e., industrial cogeneration).

Current applications. Conventional steam-electric turbines with or without cogeneration are the chief technology for electricity generation using wood-derived fuels.

Most existing biomass generating projects have a capacity of 50 megawatts or less, because large amounts of biomass fuels usually are not available near a single location, and long-distance transport of biomass fuels is costly. Most future biomass plants will likely have generating capacities of between 15 and 30 megawatts.

The configuration and costs of biomass generation projects vary dramatically depending on the type and availability of fuel supplies, form of generation technology and geographic location.

Fuel requirements. Biomass fuels are made from organic matter that can be burned as is or converted into a combustible material. Examples include wood waste (e.g., residues from forest thinning, logging and mill processes), agricultural residues and crops planted as fuel for energy. Because the raw forms of many biomass fuel sources have relatively low energy content, generating electricity with biomass requires large quantities of organic material.

Some types of biomass fuels such as wood waste are a byproduct of other activities and are not useful for other commercial purposes, so the cost is generally quite low. However, the amount of fuel that is available may be limited and dependent on other activities, such as timber harvesting or mill operations, that are beyond the control of the fuel user.

For biomass sources that are grown as a fuel source, suppliers must be reimbursed for the costs of production, environmental mitigation (e.g., appropriate disposal of residues), and transportation. Prices will also be affected if there are competing uses for the fuel, such as biodiesel or synthetic fuels for motor vehicles.

Current Status and Outlook

In recent years, biomass fuel production has declined in the forest products industry, been stable in the other natural resources industries and increased for solid waste. The sources and amounts of fuel for current biomass generation technology appear to be finite. Few new opportunities to acquire these types of generating resources are expected, and costs and other characteristics are likely to be highly situation-specific.

In the future, stabilization and possible expansion of the timber supply and logging and mill residues can be expected as forests recover. Also, the supply of forest thinnings could increase from more intensive commercial forest management, forest health restoration efforts and wildfire control. The woody fraction of solid waste in landfills is expected to increase with economic and population growth.

While woody residue is available in large quantities, the high cost of collection and transportation is likely to limit generation development unless cogeneration opportunities are available to help share costs. Technical difficulties and seasonality of fuel availability are likely to preclude significant use of agricultural field residues for generation. A small, undeveloped potential for energy recovery exists at municipal wastewater treatment plants.

New forms of fuels may become available with the growth of energy crops or increased harvesting of biomass residues. However, some fuels, such as ethanol, could also complement or substitute for fossil fuels used in transportation. Technologies based on biomass fuels that are not well suited to competing energy uses may be the most cost-effective for generating electricity.

Resource Characteristics

Transmission requirements. Biomass generating facilities are usually sited to interconnect at a subtransmission voltage of 69 kilovolts or less, at a substation that feeds the distribution system or at an industrial site. Due to the small size of most biomass generating facilities, major new transmission lines are often not required although line upgrades may be necessary. Integrating biomass resources into the power grid is fairly straightforward for facilities that operate in baseload and have high capacity factors (e.g., cogeneration).

Dispatchability. For biomass generating resources that are more economic to operate in baseload or must do so (as at a cogeneration facility), electrical output is held at a relatively constant level. This means these resources are not normally considered to be dispatchable – that is, their output is not increased and decreased to help balance daily system loads and generation. However, when a biomass facility is located close to electrical loads, it may be able to provide grid support in limited circumstances. Dispatchability would be improved in the future if new forms of biomass generating resources use fuels that support more flexible operation.

Environmental attributes. Biomass is a renewable resource, with relatively low environmental impacts. Perhaps most the most important environmental advantage is that biomass generation does not add large net amounts of carbon dioxide to the atmosphere. By repeating a cycle of growth and consumption of biomass materials, carbon dioxide is captured and then produced again and again, essentially forming a "closed loop" system. In addition, several types of biomass fuels contain much smaller amounts of other pollutants such as sulfur.

Biomass generation based on conventional steam-electric turbine technology consumes significant amounts of water. To produce steam, a biomass project needs a water source that can supply 23,000 to 55,000 gallons per megawatt-hour for a once-through system and 350 to 900 gallons per megawatt-hour for a re-circulating system.

Geothermal

Geothermal is the only reasonably large renewable resource that serves baseload, has a very long-term firm fuel supply, and is scalable. While other renewable energy resources like wind and solar energy generate power intermittently, and hydro availability varies from year to year, geothermal operates over 95 percent of the time, and if well managed, may operate for 100 years or more.

Although suitable sites are often difficult and expensive to find, the technologies used for geothermal generation are well proven. Geothermal generation provides a highly reliable and clean power supply with greater certainty of costs than other types of generating resources, particularly those that consume fossil fuels.

Resource Technology and Fuel

Geothermal energy is derived from heat that originates deep in the earth's crust. The heat rises to near the surface by thermal conduction and by intrusion of molten magma originating from great depth upward into the earth's crust, heating nearby groundwater and/or rock formations. As the groundwater and/or rock are heated, geothermal energy is naturally created. This energy can then be extracted and used to produce electricity.

There are three basic types of geothermal generating technologies: dry steam, flash, and binary. Dry steam technology captures steam (over 455 degrees Fahrenheit) from fractures in the ground and uses it to turn a turbine generator. Flash technology takes extremely hot water (over 360 degrees Fahrenheit) out of the ground, separates the steam from the boiling water, and uses the steam to turn a turbine generator. Binary technology takes moderately hot water (225-360 degrees Fahrenheit) and passes it through one side of a heat exchanger in order to heat an organic fluid in a separate adjacent pipe that is then used to turn a turbine generator. After its heat has been transferred to the organic fluid, the water is returned via an injection well into the reservoir to be reheated, thereby helping to maintain pressure and sustain the reservoir.

Most geothermal plants are built as 20 to 50 megawatt units, but modular systems as small as 5 megawatts have been developed. Costs vary significantly because they are highly dependent on location, project configuration and other site-specific factors.

Current Status and Outlook

The United States currently has 2,700 megawatts of geothermal generating capacity. Roughly half of the total capacity is at the Geysers projects, which are located in Northern California and use dry steam technology.

The Western Governors Association Geothermal Task Force Report identified over 5,000 megawatts of promising geothermal resource opportunities in the West and nearly 1,300 megawatts of developable geothermal generation in the Northwest. Recent proposals for geothermal development in southern Idaho, if successful, would be the first commercial development of Basin and Range resources in the Northwest.

However, the outlook for broader development of geothermal generating resources in the Pacific Northwest is unclear because extensive exploratory drilling has not been done. The most likely locations are the Basin and Range provinces of southeastern Oregon and southern Idaho and the High Cascades in southern Oregon. While the Cascades have the greatest potential for geothermal resources, feasibility of development in that area is the most uncertain.

Resource Characteristics

Transmission requirements. Transmission needs for geothermal resources vary depending on site location. Some good sites with geothermal potential are located in the vicinity of City Light owned or controlled transmission. While upgrades to the existing transmission system may be necessary to accommodate these resources, project sizes would be comparatively small. A new line would probably not be necessary, except for resources at some locations in Idaho or Oregon.

Operated as a baseload resource, a geothermal resource is relatively easy to integrate into an existing hydroelectric based electrical system. Because it has a high capacity factor (meaning that it operates virtually all of the time), the transmission can be fully utilized, thus keeping the per-megawatt-hour cost low.

Dispatchability. Geothermal energy is usually operated as a baseload resource. However, it could be dispatched when required in certain circumstances, for example to support transmission system needs. Geothermal energy can also serve as a shaping resource.

Environmental attributes. Geothermal energy is a renewable resource. No fossil fuels are required or consumed, so no carbon dioxide is produced. The main environmental impacts associated with geothermal generation are the potential for increased release of gases during extraction of steam or superheated water, and land use issues that would make it difficult or infeasible to locate geothermal generating projects in wilderness areas.

Wind Power

Over the last decade, the use of wind power has increased rapidly, making it the predominant renewable resource technology, with many large-scale installations around the world.

Resource Technology and Fuel

Wind power is the process of mechanically harnessing energy from the wind and converting it into electricity. The most common form of utility-scale wind technology uses rotors with long, slender turbine blades to turn an electric generator mounted at the top of a tall tower.

Because air has low mass, the wind itself has low energy density. The amount of wind power that can be produced at a given place is dependent on the strength and frequency of wind. Wind velocity is particularly important, because the quantity of power increases dramatically as wind speed increases.

Project scale. As of the late 1990s, capacity of individual utility-scale wind turbines was limited to roughly 0.6 megawatts. However, recent advances in materials and design have allowed manufacturers to increase the capacity. For example, in October 2006, General Electric announced that more than 5,000 of its 1.5-megawatt wind turbines had been installed. Turbines with capacities exceeding 2 megawatts are now commercially available and even larger capacities are planned.

Wind power can also be generated on a more modest scale, by using much smaller turbines as a form of distributed resource. Because the potential for such resources in City Light's retail electric service area is relatively small, the analysis for the IRP focused on larger, utility-scale forms of wind power.

In order to maximize energy output and achieve economies of scale, large numbers of wind turbine generators are often grouped together to form a wind farm project. Today's utility-scale wind farms typically encompass a total project area of several thousand acres or more, although the permanent facilities use no more than 5 to 10 percent of the total acreage.

Costs. As wind turbines have grown in size and large manufacturers have entered the market, costs for wind power projects have declined. Costs are far lower than the late 1990s.

However, declines in the capital cost of wind power projects have stopped and even reversed, in part due to increased global commodity costs (e.g., for steel and concrete), fluctuating currency exchange rates that have diminished the value of the American dollar, and high worldwide demand for wind power equipment. It is difficult to predict when and to what extent these upward pressures on the capital costs for wind power projects will moderate.

Wind power has no fuel cost, per se. However, lease payments to the owner of the land where a wind power project is located may be considered a cost of accessing the wind "fuel".

Current Status and Outlook

Wind power technology has dramatically improved during the past decade. Development of wind power has grown globally, nationally and in the Pacific Northwest. In this region alone, during the last 10 years the installed capacity of utility-scale wind power projects has increased from zero to more than 1,700 megawatts.

Recent adoption of Renewable Portfolio Standards by several states is expected to further increase interest in and development of renewable resources, especially wind power. Initiative 937, approved by Washington voters in November 2006, included requirements for conservation as well as renewable resources.

The net impacts from the increased impetus for development of renewable resources such as wind power are difficult to predict. On one hand, continued growth in development of wind power projects in the Northwest may increase economies of scale and spur innovations that lead to reductions in certain types of costs for wind power. On the other hand, the increased demand for wind power could cause upward pressure on costs, for example if utilities find it necessary to bid increasing prices for a finite amount of viable wind resources.

The Northwest Power and Conservation Council has estimated that there are approximately 6,000 megawatts of developable wind power in the Pacific Northwest over the next 20 years. The Mid-Columbia area of Washington has been identified as a prime location for new wind generation. Areas suitable for wind power development include Kittitas County, the area from the Columbia River gorge to the Southeast corner of Washington, and the Blackfoot area of north central Montana.

Major uncertainties likely to shape the future outlook for wind power include whether or not the federal Production Tax Credit is extended beyond 2007, and challenges associated with construction of new transmission facilities needed to bring large amounts of new wind power generation from good sites to regional load centers.

Resource Characteristics

Transmission requirements. Transmission is one of the most challenging issues to be addressed when considering wind power resources, for several reasons. First, many of the most favorable sites for locating wind power projects in the Pacific Northwest are in areas where the transmission system is already constrained or where transmission does not exist. To accommodate large amounts of new wind power generating capacity, new long-distance high-voltage transmission facilities will need to be built.

Second, the cost of transmission for wind power is higher per megawatt-hour than for other types of generating resources that have a higher capacity factor. Using currently available technology, the capacity factor for most wind power projects averages 30 to 35 percent, which is much lower than the capacity factor for baseload generating resources. To the extent that each type of resource must pay the full cost of reserving transmission capacity for its peak generating capacity, this means that the unit cost (in dollars per megawatt-hour) of transmission for a wind power project can be double the unit cost of transmission for a baseload generating resource.

Third, integration of wind farms into the transmission grid requires consideration of issues associated with intermittent generation

Dispatchability. The amount of wind energy that can be produced depends on both the frequency and strength of winds. Consequently, wind power is not a dispatchable resource, meaning wind power cannot be increased as needed to meet customer demand for electricity. While the reliability and availability of wind turbine generators is relatively high (over 95 percent), the actual amount of generation from a wind power project varies between zero and 100 percent of nameplate capacity.

One approach for firming up the generation from wind power projects is to coordinate their operation with dispatchable resources (e.g., combustion turbine generation) or with resources that have the ability to shape or store energy (e.g., hydroelectric generation).

Integrating wind output into a large power system is challenging because wind power generation cannot be accurately forecast. As the output of wind farms increases or decreases relative to the system load, the output of other sources of generation, such as hydro, natural gas, or coal plants, must be adjusted. Recent studies indicate that when the wind generation exceeds about 10 - 20 percent of a utility's overall resource portfolio, intermittency of the wind power resources can become a significant issue.

Environmental attributes. Wind power is a renewable resource, and is one of the most environmentally attractive utility-scale generating resources currently available. It does not consume fossil fuels or produce air emissions such as carbon dioxide.

Primary environmental concerns related to wind power are potential mortality to birds and visual impacts from the tall towers and rotating turbine blades.

Natural Gas

Natural gas technologies considered for the IRP are Combined-Cycle Combustion Turbines (CCCTs) and Simple-Cycle Combustion Turbines (SCCTs).

Resource Technology and Fuel

Combustion turbine technology has been used to generate electricity for several decades. A combustion turbine is a rotary engine composed of three basic parts. First, air is taken in through a compressor. Next, natural gas is mixed with the air and burned in a combustion chamber. The resulting mechanical energy is then used to turn a turbine at a speed of 3,600 revolutions per minute.

Combustion turbine size. Two basic forms of combustion turbines are used to generate electricity. Large "frame" machines are designed for use in stationary applications. Frame machines are currently available in capacities of up to 250 megawatts. Smaller combustion turbines, called "aeroderivatives", are modified versions of the jet engines used on modern airliners. Aeroderivative machines used to generate electricity typically have capacities between 10 and 50 megawatts, but may be much larger.

Because combustion turbine technology is comparatively flexible, a wide variety of generating project configurations is possible. Smaller applications can be built very quickly and may even be mounted on truckbeds for portability. Combustion turbine technology can also be used to build much larger generating projects at permanent sites.

Combustion turbine technology is comparatively efficient at converting fossil fuels to electricity. Higher efficiencies occur with larger machines and machines that operate at higher combustion temperatures.

Types of combustion turbine technology. There are two types of combustion turbines. The combined-cycle combustion turbine (CCCT) uses the combustion turbine to generate power and then recovers exhaust heat from the combustion turbine to make steam for a turbine generator that in turn produces additional power. The simpler and less fuel-efficient simple-cycle combustion turbine (SCCT), generates power directly.

CCCT generating projects are more complex than SCCT projects, and have higher capital costs. However, because CCCT projects are more fuel-efficient than SCCT projects, total running costs for CCCT projects are lower than for SCCT projects.

Both CCCT and SCCT generating projects are primarily fueled with natural gas. Three interstate pipelines transport natural gas to the Northwest. The Northwest Pipeline from British Columbia runs from north to south through western Washington. The two other pipelines transport gas from Alberta in Canada and from the Rocky Mountains, converging in Northeastern Oregon, proceeding through Portland and then south.

Current Status and Outlook

For the past 15 years, most new generating projects have used CCCT technology. In the Pacific Northwest, there is over 4,000 megawatts of CCCT generating capacity, most of it brought on line between 1995 and 2004. During that period, many CCCT projects were developed by non-utility generating companies for sale of power into competitive wholesale power markets. The Northwest also has slightly more than 1,500 megawatts of SCCT generating capacity, including projects developed during the 1980s and more recently.

Natural gas-fired CCCT generation became popular for several reasons. Market prices for natural gas were low during the 1990s and early 2000s, and during that period, manufacturers made major improvements in combustion turbine efficiency. Also, CCCT projects were relatively quick and easy to permit and construct. CCCT technology was also attractive because it is reliable and provides operating flexibility.

High and volatile prices for natural gas have dramatically slowed the development of new combustion turbine generating projects. Natural gas prices have recently moderated somewhat, and the natural gas industry is working to bring new sources of supply on-stream.

For example, a number of terminals have been proposed to receive imports of liquefied natural gas (LNG), both nationally and in the Pacific Northwest. Some observers believe these and other new sources of supply will help keep market prices for natural gas at moderate levels. However, the outlook for natural gas prices is a significant source of uncertainty for CCCT and SCCT generating resources.

Resource Characteristics

Transmission requirements. Siting for a new CCCT project requires access to a natural gas pipeline and electric transmission facilities that both have available capacity. Because a number of new CCCT generating projects were developed during the past decade, sites have become scarcer. However, some suitable sites may be available that would not require construction of new high-voltage transmission lines.

Dispatchability. Generating projects based on combustion turbine technology are highly dispatchable, giving them a high degree of operating flexibility. SCCT generating units can go from a cold start to full operation in less than 10 minutes. CCCT generating projects can be started up nearly as quickly, although the steam cycle takes hours to start up and shut down. However, combustion turbines operate at highest efficiency under full load. Their efficiency falls off significantly when they are operated below 75 percent of capacity.

Because SCCT generating projects have higher operating (fuel) costs than CCCT generating projects, SCCTs are usually used to meet peak load requirements and provide standby for system reliability purposes. CCCT generating projects are normally used more for baseload and mid-range purposes.

Environmental attributes. Combustion turbine generation consumes natural gas and emits pollutants such as carbon dioxide (CO2), sulfur dioxide (SO2) and nitrogen oxide (NOx). Control technologies are used to eliminate most, but not all emissions of SO2 and NOx. However, CO2 production remains a major consideration in developing generating projects based on natural gas-fired combustion turbine technology. Projects that consume large amounts of water can also be a concern.

Pulverized Coal

Coal has been used to generate electricity in the United States for more than a century. Pulverized coal generation technology was developed in the 1920s and since then has been the most common form of coal-fired generation.

Resource Technology and Fuel

Pulverized coal power plants are fueled by coal that is either extracted from an on-site mine or delivered via railroad or truck. The generation process begins by feeding pieces of coal into the power plant and crushing them into a fine powder. The coal powder is then blown, along with heated air, into a large furnace where it quickly burns. The resulting thermal energy is used to heat water in boiler pipes, creating steam. Next, the steam is used to turn a turbine generator, which produces electricity.

The combustion process produces two forms of ash. Roughly one fourth of the ash is coarser, heavier "bottom ash" that falls to the base of the combustion chamber and is removed. The other three fourths of the ash is finer, lighter "fly ash" that exits the combustion chamber with the exhaust heat and is passed through a particulate collection system. Many plants use scrubbers and other types of emission control systems to reduce the amount of pollutants that are released.

Pulverized coal power plants can be constructed in unit sizes from less than 50 megawatts to more than 700 megawatts. Some projects use multiple large units, with total plant generating capacity exceeding 1,000 megawatts at a single site. Economies of scale generally enable larger projects to produce power at a lower cost per megawatt-hour.

Fuel characteristics. Coal is a fossil fuel, available in massive amounts in several regions of the United States. Large reserves of coal are available and mines are operated in several Western states, including Montana and Wyoming. The quality of coal varies depending on the source. For example, coal from one location may have higher heat content by weight, while coal from another location may have lower sulfur content.

Compared to most other types of fuels, coal has comparatively low energy density by weight. Also, pulverized coal power plants are not able to convert the energy contained in coal to electricity as efficiently as generating resources that use other fuels.

The fuel characteristics of coal have several implications. Coal is more costly to ship across long distances than other fuels such as natural gas. As a result, in the West it has often been more cost-effective to build pulverized coal generating plants close to the mine, rather than close to where the electricity is consumed.

Costs. Fixed costs are high for pulverized coal generation, especially compared to natural gas-fired combustion turbine generation. Both the capital cost in dollars per megawatt of capacity and the fixed operating costs are higher for a pulverized coal plant. However, the cost of fuel in dollars per megawatt-hour is typically lower for a pulverized coal plant than for a natural gas-fired combustion turbine plant.

During the last several decades, air emission control costs have increased, primarily for equipment to reduce emissions of pollutants such as particulates, sulfur oxides and nitrogen oxides.

There is a significant possibility that costs will be imposed for emissions of carbon dioxide. Pulverized coal generation emits a proportionally large amount of CO2 per megawatt-hour generated, so if costs for future CO2 emissions must be paid in dollars per ton of CO_2 produced, they could become a large proportion of total costs and shift the balance of fixed and variable costs.

Current Status and Outlook

In 2005, 50 percent of the electricity generated in the United States was produced in coal-fired power plants, with about 90 percent of those using pulverized coal.

Pulverized coal power plants are less common on the West Coast. In the Pacific Northwest, coal-fired generating resources serve about 15 percent of total electrical loads. In Washington, one large coal-fired generating plant near Centralia has two 700-megawatt units that began operating in the early 1970s and until recently were supplied by an onsite surface coal mine. The plant is now fueled by coal transported from Wyoming.

Many pulverized coal generation projects in the United States have been in service for 30 years or more. While many plants have been upgraded and modernized, others have not. In the past 15 years, natural gas-fired combustion turbines have been used instead of new coal-fired generation capacity.

However, during the past several years, more than 150 new coal-fired generating units have been proposed in the U.S. One company recently announced that it intends to build 11 new pulverized coal power plants in Texas, plus as many as a dozen or more in other states.

In the West, plans to develop new coal-fired generating plants are drawing strong negative reaction and opposition from environmental organizations, consumer groups and other stakeholders. Meanwhile, some utilities have begun to scale back recent plans to build new coal plants. It is difficult to predict whether or when significant numbers of new pulverized coal generating projects will be built.

Examining the outlook for pulverized coal generation in the United States reveals sharply contrasting considerations. On one hand, pulverized coal generation is a proven, reliable technology that has relatively low direct costs and uses a domestic fuel supply that is readily available in large quantities. On the other hand, it produces larger and more damaging environmental impacts than most other generation resources.

In the future, advances in pulverized coal generating technologies may become commercially successful. For example, supercritical combustion technologies are being developed that operate at higher temperature and pressure conditions, allowing higher thermal efficiency. However, future costs for carbon dioxide emissions represent a large source of future risk and uncertainty.

Resource Characteristics

Transmission requirements. In the past, long-distance transmission lines have been constructed to bring power from coal plants near the mine to urban load centers. The cost of transporting coal long distances is relatively high, and it is less difficult to site pulverized coal generating facilities in rural areas where coal reserves are available than in highly populated areas where large amounts of power are consumed.

The Pacific Northwest electric transmission grid does not have available capacity to accommodate construction of large new pulverized coal plants in areas such as Montana to serve electrical demands in Western Washington. It is also unlikely that a new pulverized coal power plant could be permitted in Western Washington. Therefore, new long-distance transmission facilities would almost certainly be needed in order to make power from new pulverized coal resources available to this area. However, siting and permitting new transmission facilities for such a purpose may present significant challenges.

Dispatchability. Pulverized coal generating plants operate most efficiently at high capacity factors, often as high as 85 percent, so it can take from 24 to 36 hours to bring a pulverized coal plant from cold start up to full output. As a result, pulverized coal plants are usually operated as baseload resources and are not highly dispatchable.

In limited circumstances such as seasonal periods of high hydroelectric generation and low regional electric demand, pulverized coal plants may be shut down for economic reasons.

Environmental attributes. The most significant drawback of pulverized coal plants is their environmental impacts. Pulverized coal generation is a major source of carbon dioxide emissions and other greenhouse gases and pollutants, emitting more CO_2 per megawatt-hour than most other forms of fossil-fueled generation. There is currently no commercially viable technology for capturing the CO_2. At new pulverized coal generating plants, control technologies are used to remove most but not all emissions of sulfur oxides and nitrogen oxides. Other emissions from coal plants include mercury and carbon monoxide.

Pulverized coal generation also consumes large amounts of water, and coal mining has number of significant impacts on land, water and wildlife.

Coal – Integrated Gasification Combined Cycle (IGCC)

Coal processed with integrated gasification combined cycle (IGCC) technology is a new type of electric generation that is entirely different from conventional pulverized coal electric generation.

Resource Technology and Fuel

The IGCC process begins by partially combusting coal with oxygen and steam under pressure to form an energy-rich synthetic gas called "syngas". During the gasification process, ash from the coal is removed. Next, the syngas is cooled and processed to remove particulates, mercury and sulfur. The processed syngas is then used to fuel a combined-cycle combustion turbine (CCCT) generation system. The CCCT portion of an IGCC power plant is very similar to the technology used in natural gas-fired CCCT generating projects.

IGCC technology combines the efficiencies of combined-cycle combustion turbines with the relatively low cost and abundant supply of coal. It has a high degree of modularity and improved emissions control over conventional pulverized coal technology. It also has the potential to be used along with another new form of technology designed to convert carbon monoxide in the syngas into carbon dioxide and then sequester it underground.

Current Status and Outlook

Two IGCC plants are operating in the United States. One IGCC project has been proposed in the Pacific Northwest. Energy Northwest has announced that it intends to build a 600-megawatt IGCC project in Cowlitz County Washington, with commercial operation scheduled to begin in 2012.

IGCC technology is currently in the advanced stage of development. The federal government has identified IGCC as a promising new type of generating resource and has provided incentives to spur commercial development of new projects. The prospects for IGCC generation depend on further progress in making the technology reliable and commercially successful.

Using a modular design that incorporates well-proven combined-cycle combustion turbine generating technology has allowed researchers to focus on improving the gasification component of IGCC technology. The technology is expected to become commercially available in unit sizes of 250 megawatts or larger, with total generating plant sizes of 1,000 megawatts or larger.

Carbon sequestration. Compared to the other two primary components of an IGCC plant (CCCT and gasification), carbon sequestration technology is the least mature and requires the most development. As a result, some recent IGCC project proposals include a design that is "sequestration-ready". This approach may not prove acceptable, due to the risk of relying on carbon sequestration technologies whose future availability, performance and cost are uncertain.

Costs. Coal prices vary in response to fluctuations in market prices for other fossil fuels such as crude oil and natural gas. However, coal prices have historically tended to be less volatile than market prices for natural gas.

Fixed costs represent a larger proportion of total costs than for pulverized coal generation. However, variable costs are expected to be proportionally lower, largely due to the comparatively low cost of coal.

Carbon sequestration would add costs above those for a stand-alone IGCC generating project. These include the direct costs of sequestration plus a reduction in the net amount of electricity generated due to the use of power by the carbon sequestration process.

Resource Characteristics

Transmission requirements. The transmission issues associated with IGCC generation are similar to those for new pulverized coal generation. Lower emissions from IGCC generating technology may make it somewhat less difficult to site IGCC projects nearer to highly populated areas, which may mitigate the need for construction of new long distance transmission facilities. However, sites suitable for carbon sequestration may not be located in areas where transmission capacity is available.

Dispatchability. The CCCT portion of an IGCC generating project has dispatch capabilities similar to a natural gas-fired CCCT power plant. However, the gasification process and lower costs for fuel make it likely that an IGCC generating project would be operated as a baseload resource.

Environmental attributes. Compared to pulverized coal generation, IGCC generation offers several environmental advantages, mostly because particulates, mercury and sulfur are removed prior to the combustion process, rather than after it. The prospect of carbon sequestration represents another potential environmental advantage, compared to other forms of generation that consume fossil fuels. Also, IGCC technology uses about half the water consumed by pulverized coal generation.

Market Resources

The wholesale power market in the 11-state Western region is served by a transmission grid system that allows City Light to participate in many types of transactions. Seasonal exchanges and seasonal capacity contracts are two types of market transactions of interest for this IRP, in addition to long-term power purchases. (See Chapter 3 for details.)

Seasonal Exchanges

A seasonal exchange is a power transaction that takes advantage of the seasonal diversity between Northwest (winter peaking) and Southwest (summer peaking) loads. Utilities can transfer firm power from north to south during the Southwest's summer load season and from south to north during the Northwest's winter load season, allowing both utilities to maintain less generating capacity than would otherwise be necessary.

City Light's existing portfolio includes a seasonal exchange with utilities in Northern California. Exchanges are an ideal solution for meeting the Utility's seasonal needs, provided that both parties can benefit and transmission is available.

Often exchanges are done on a megawatt-hour for megawatt-hour basis. The actual delivery schedules of firm energy in the exchange may vary. For example, one utility could delivery 25 aMW for four months of the year while the other utility delivers 50 aMW for 2 months of the year.

In modeling exchanges, energy transfers were not megawatt-hour for megawatt-hour on a calendar year basis, since winter transfers to Seattle could occur from November through February, cutting across calendar years, while transfers during the summer months all occur within the same calendar year.

When assessing exchanges in the modeling process, a key consideration was having enough firm transmission capacity available at the correct times. Staff analysts first determined whether or not City Light has sufficient rights to firm transmission capacity available along the transmission path between the winter peaking utility (City Light) and the summer peaking utility (in California or the Desert Southwest). If there was not sufficient firm transmission capacity, it was assumed that new transmission capacity would need to be constructed, but a minimum of seven years was allowed before the exchange began. Any new transmission capacity required for the exchange was assumed to be a pro rata portion of an upgrade or new transmission line. This was ultimately considered as a cost of the exchange.

Another important consideration was ensuring that the total amount of City Light energy delivered during the summer months did not grow so large as to make City Light short of energy to meet growing summer loads in later years.

Seasonal Capacity Contracts

A seasonal capacity contract (also known as a physical call option) is a contract that gives the bearer the right to buy a given amount of power at an established price. The contract usually defines which generating resources the electric power will come from, and expires by a certain date. If the option is "called," the bearer of the option (the utility) takes delivery of power up to a maximum amount specified in the contract. By contrast, a financial option is settled with money and does not involve a transfer of electric power. Since the objective of this IRP is to ensure adequacy of resources, only physical call options are considered.

City Light is interested in seasonal capacity contracts because of their flexibility as a resource. They can ensure the availability of a generating resource if power is needed on a seasonal or temporary basis, without the Utility having to bear the full cost or risk of long-term resource ownership. In a sense, it is like an insurance policy that the power will be available at a certain price when needed. Like an insurance policy, the Utility must pay a "premium." The premium is a fee to the owner of the generating resource for providing this service to City Light. If City Light decides to call the option, it must also pay a pre-negotiated price for the amount of power produced by the generator who sold the option.

The availability and costs of seasonal capacity contracts vary over time. Factors often affecting the availability and costs are:

- Balance of supply and demand in the power market
- Degree of price volatility (or price risk) in the market
- Prevailing prices at the time the option is negotiated
- Expectations of both the utility and the option seller about the future of the power market

The greater the length of time before a call option is purchased, the less information is available about the above four factors. In modeling these contracts, City Light considered purchasing call options in different years throughout the 20-year planning period, mostly as a tool for balancing resource requirements. For planning purposes, the cost of the premium is estimated as the fixed costs of a simple-cycle combustion turbine for the time period covered by the contract, plus a return on investment for the turbine owner.

City Light does not view seasonal capacity contracts as a direct substitute for a generating resource, because there is more uncertainty about their long-term availability and cost. When planning for the years after 2012, these contracts only serve as "bridging" resources in the candidate portfolios. They bridge the gap in resources for a few years at a time while load grows to a size to merit purchasing or building another generating resource.

Transmission for New Resources

City Light owns only 657 miles of transmission facilities from the Skagit Project and a share of the Third AC Intertie. The Utility is dependent upon access to transmission systems owned by others to reach the Western power market for balancing its seasonal power supply and demand, and gaining access to new power supplies in the future. As congestion in the Western grid continues to grow, utilities that do not own transmission may find it increasingly more difficult to access regional power markets.

Of utmost importance to City Light's long-term resource planning is whether new transmission facilities can be permitted and built, and whether or not the energy can be transmitted to Seattle. This section identifies issues associated with acquiring long-term firm transmission.

Transmission Contracts

City Light has long-term firm transmission contracts that provide point-to-point contract demand rights of approximately 2,000 MW. These rights are predominantly purchased from the BPA under its FERC-compliant open-access transmission tariff (OATT). These rights provide City Light with some remaining flexibility to secure resources to the east and south.

City Light also has transmission agreements for lesser quantities of transmission service with PacifiCorp, Idaho Power, Avista and Puget Sound Energy. City Light uses most of this transmission capacity for current operations, leaving limited transmission transfer capability available for use in acquiring future distant resources.

In the Pacific Northwest, BPA has convened its stakeholders to assess transmission adequacy and seek solutions to the problems posed by the construction of new transmission lines. These problems include determining how much transmission is needed and when, where transmission needs to be sited, who will own and control transmission facilities, and what measures might forestall the need for construction. The Transmission Adequacy Work Group of the Northwest Power Pool's Northwest Transmission Assessment Committee is also working to address transmission adequacy for the region.

Issues

City Light does not expect to directly site and develop transmission outside of the Utility's service area. Transmission facilities required for new City Light generation resources probably will be built by someone else; however, it is in City Light interest to participate in resolving issues such as:

- Lack of available transmission capacity over the long-term.
- Lack of clear responsibility for planning and constructing transmission facilities.
- Time required from planning to construction (averages two to seven years).
- Uncertainty about who will finance, build and pay for needed transmission.
- Uncertainty about costs and rates for new transmission.
- Multi-jurisdictional siting and permitting issues.
- Lack of coordination between transmission and resource planning and development processes.

- Ultimate form of FERC regulations and the future of a regional transmission organization.

City Light may need to build more new generating resources if it cannot take advantage of seasonal diversity of power demand, importing from California or the Desert Southwest during the fall and winter to meet peak requirements. An overbuilt power market may be depressed due to the surplus of Northwest power during the summer and lack of ability to export to high demand regions.

Having a low-priced wholesale market for power during much of the year may be beneficial to industrial customers who can directly access that market. However, utilities hoping to keep costs low for their customers could suffer if adequate transmission is not available.

Anticipated Need for New Transmission

City Light may need new or upgraded transmission facilities to transmit power from any additional resources to its service area or to the existing regional transmission grid. New transmission also may be needed to improve reliability, redundancy or otherwise increase the capacity of the system to reduce or defer the need for new generation sources.

Actual transmission requirements cannot be known until the size, location and operating characteristics of proposed new resources are identified. In general, resources farther from load centers and from existing transmission lines would require more transmission construction than resources close to load centers and existing transmission lines. Table 4-3 shows assumptions about general transmission line requirement for potential new generation resources considered in the IRP.

Table 4-3. Transmission Facility Requirements

Resource Type	Miles of New Transmission Lines Needed*	Upgrade of Existing Transmission
Conservation	None	None.
City Light-Owned Hydropower	None	Uses existing transmission.
Contracts/Exchanges	None	Uses existing transmission when available.
Natural Gas - Combined Cycle	50	
Natural Gas - Simple Cycle	None	Assumes some upgrades to BPA transmission may be necessary, but because the generating capacity would be small, the upgrades would be less than BPA's rate. Therefore uses BPA's rate.
CHP (Combined Heat and Power)	None	0
IGCC Coal - after 2012 (Montana)	950	0
Pulverized Coal (Montana)	950	0
Wind (Northwest)	225	0
Geothermal (Idaho, Oregon, Western Washington)	None	Assumes some upgrades to BPA transmission may be necessary, but because the generating capacity would be small, the upgrades would be less than BPA's rate. Therefore uses BPA's rate.
Hydro Contract	None	Assumes some upgrades to BPA transmission may be necessary, but because the generating capacity would be small, the upgrades would be less than BPA's rate. Therefore uses BPA's rate.
Wind (Montana)	950	0
Biomass, Wood (Western Washington)	None	Assumes some upgrades to BPA transmission may be necessary, but because the generating capacity would be small, the upgrades would be less than BPA's rate. Therefore uses BPA's rate.
Biogas, Landfill Gas	None	Assumes some upgrades to BPA transmission may be necessary, but because the generating capacity would be small, the upgrades would be less than BPA's rate. Therefore uses BPA's rate.

*Miles from the point where the resource interconnects with the grid to Seattle.

Chapter 5 – The Methodology: Assessing Possible Futures

Preparing a long-term power plan requires many assumptions about the future. These assumptions (forecasts) are important for setting a context for evaluating different types of resources. This chapter outlines key components of the base forecast (also called the "reference" forecast) and describes four alternative scenarios to the reference forecast. Along with the reference forecast, these four scenarios were used to evaluate potential portfolios of power resources, using the criteria of reliability, cost, risk and environmental impact.

The computer model used to evaluate the portfolios is described, including sample output and constraints. The final section lists the resources used in various combinations during two rounds of portfolio analysis.

Defining the Reference Forecast

The focus of City Light's resource planning is on the Pacific Northwest. However, power price forecasts are driven by the much broader Western wholesale power market, in which City Light conducts power transactions (see Chapter 4). The Western power market is commonly influenced by such diverse factors as high summer temperatures in the Southwest and cold winter temperatures in the Northwest; transmission constraints in various locations in the West; precipitation levels in the Pacific Northwest; nuclear plant outages in California; coal plant outages in Montana, Wyoming or Utah; natural gas deliveries from Alberta, Canada; and power imports to the U.S. from Canada or Baja, Mexico.

Assembling forecasts of future market conditions is an important part of resource planning. However, there is a wide range of viewpoints about future energy market conditions, including factors such as the pace of economic growth, available generation, fuel supplies and costs for generators, regional electricity demand, power prices and greenhouse gas policies.

Objectivity and logical consistency in forecast assumptions are important to resource planning. Accordingly, City Light chose to use independently developed forecasts from Global Energy Decisions (GED), Inc. for evaluating future electricity market conditions in the Pacific Northwest and the Western United States. The following discussion describes the Reference Case – the forecast conditions related to fuel prices, resource supply and electricity prices that GED believes to be most likely.

Fuel Prices

Fuel prices are an important input into a power price outlook because they are a major determinant of generator costs to produce power. In a competitive power market, fuel prices can drive rapid changes in power prices. This section gives an overview of the fuel price forecasts used in the IRP.

Natural Gas

The market for natural gas in the Pacific Northwest is heavily influenced by national market trends because of the national network of natural gas pipelines. Unlike electricity, an extensive and interconnected pipeline system makes it possible to move natural gas from one end of the country to the other. Natural gas-fired generation plays a particularly important role in the West because it is usually the last generating unit to be dispatched (known as the "marginal unit"). Lower cost resources will be dispatched before natural gas-fired generation resources, in the absence of transmission constraints or reliability concerns.

The cost of dispatching the marginal unit frequently sets the short-term power price in the Western wholesale power market, so that the short-term (spot) power prices seen by City Light are highly correlated with price of natural gas. Given the inherent volatility of its own hydro resources and of electricity demand, City Light must buy from or sell into the power market to balance its power supply. Thus, even though City Light presently has no natural gas-fired generation, the price of natural gas will continue to be an important factor in determining City Light's wholesale power costs and revenues.

In GED's Reference Case forecast for this IRP, future natural gas prices fall considerably from first quarter 2006 levels by 2009, ranging from an annual average of $4.31 per MMBTU in 2009 to $4.94 per MMBTU in 2026 (2006 dollars). In the forecast, the following factors are important in moderating natural gas prices from early 2006 levels:

- Natural gas drilling platforms and pipelines in the Southeastern U.S. damaged by Hurricane Katrina are repaired.
- New import terminals for liquified natural gas (LNG) are constructed at ports in the United States and Mexico, allowing foreign natural gas supplies to bolster declining North American natural gas production and reserves.
- Growth in generation from resources other than natural gas helps to temper the need for more natural gas for power generation.
- In the long run, fuel prices will be influenced less by financial speculation in commodity markets and more by the market fundamentals of supply and demand.

Coal

Coal-fired generation is not as important in the Pacific Northwest as in other parts of the West, but it commonly influences Pacific Northwest power prices in light load hours. Also, because it is dispatched ahead of natural gas-fired generation, significant changes in coal-fired generation lead to the operation of more efficient or less efficient natural gas-fired generators, which influences Pacific Northwest prices in heavy load hours.

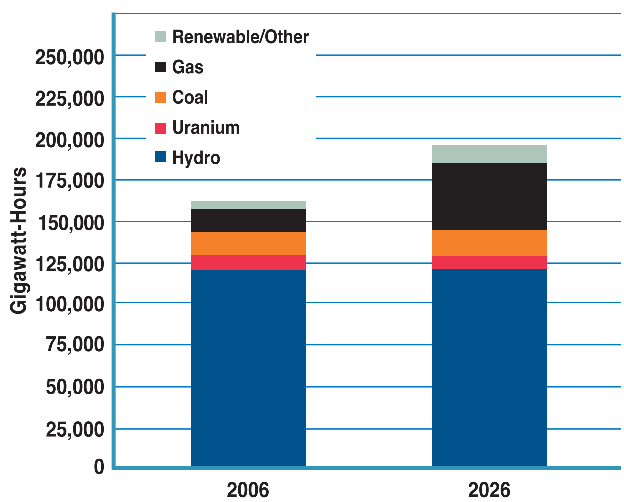
In the GED reference forecast, coal remains the single most important resource in the Western United States with respect to energy supplied for the next 20 years. Today it makes up nearly 40 percent of all electricity generation in the West. Absent costs for control of carbon dioxide, it is forecasted to continue to be a large and stable source of base-load generation.

Coal prices in the forecast grow at an average annual rate of 0.56 percent in real terms over the 20-year forecast period. At approximately $1.79 per million Btu today, it is expected to average $2.00 per ton by 2025 (in 2006 dollars). It should be noted that the GED reference forecast does not assume a carbon tax or a carbon dioxide emissions cap within the next 20 years. City Light examined the risks of a carbon tax or emission cap on coal-fired generation through scenario analysis.

Resource Supply

GED's Reference Case forecast for the Pacific Northwest used in this IRP indicates that most growth in Western power resources will come from natural gas-fired generation. Hydro, nuclear and coal-fired resources are forecast to remain relatively constant, while natural gas grows from 14,126 GWh in 2006 to 40,581 GWh in 2026, at an average annual rate of 5.4 percent. Renewables also see significant growth, from 4,821 GWh in 2006 to 10,551 GWh in 2026, an average annual rate of 4.0 percent. This forecast is illustrated in Figure 5-1.

Figure 5-1. Fuel Mix in the Reference Case



Source: Global Energy Decisions

Forecast

In 2006, most parts of the West have surplus generating capacity, including the Pacific Northwest. GED forecasts that demand in the Pacific Northwest will grow at an average of 2.3 percent annually, which is faster than the rate forecast for the City of Seattle. The Reference Case forecast estimates that the Pacific Northwest will have more than adequate reserves to meet a 12 percent recommended reserve margin for the next decade under normal conditions.

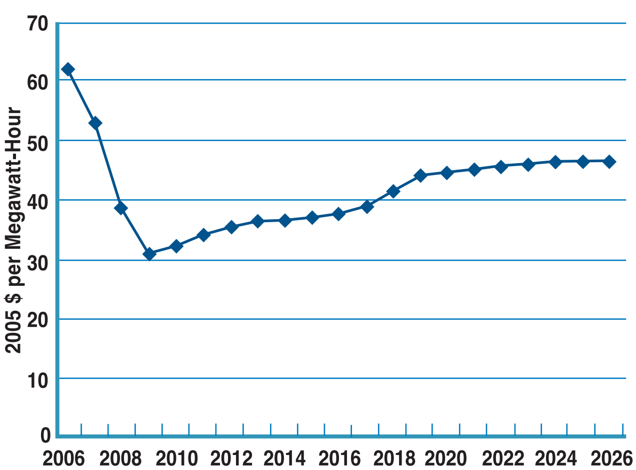
It is assumed that all City Light owned resources will continue to operate through the forecast period. Power purchase contracts are assumed to expire according to contract terms, and the BPA is assumed to continue supplying power to City Light from the Federal Columbia River System at cost-based rates.

Electricity Prices

Electricity price forecasts are used to evaluate the costs of buying power and the revenues from selling power. They determine when it is economic to make sales or to make purchases.

Spot prices for wholesale power in the Pacific Northwest are used in modeling, as shown in Figure 5-2. Following a forecasted annual average natural gas price decline from 2006 to 2009, the forecasted real price of on-peak power also falls to $31, then grows from 2009 to average $47/MWh (real 2005 dollars) by 2026. The market price decline mirrors the forecasted decline in the cost for natural gas. Since natural gas-fired generation is on the margin most of the time in the West, the spot market price and the price of natural gas tend to move in tandem.

Figure 5-2. Pacific Northwest Average Wholesale Power Prices, All Hours (Real Dollars per Megawatt-Hour)



Source: Global Energy Decisions

Envisioning Alternative Futures

While GED sees the Reference Case as the most likely future, significantly different conditions may occur. To consider alternatives to the Reference Case, variations were described as alternative future conditions, or "scenarios".

These scenarios, described below, are sets of internally consistent predictions of political trends, economic growth, regulation, technology and environmental policies. As a way of addressing uncertainty, GED developed alternative forecasts of fuel prices, power prices, electricity supply and demand that are consistent with each of the four scenarios.

Even though events are unlikely to unfold exactly as envisioned in any of the scenarios, they are designed to bracket a wide range of conditions that might reasonably be expected. GED supplied all forecasts for the scenarios over the 20-year planning period.

Scenarios: A Range of Possible Future Conditions

Each alternate scenario has a theme that is taken to its logical conclusion in terms of national environmental policy, energy policy, market forces and geopolitics. The scenarios are named Green World, Nuclear Resurgence, Return to Reliability, and Terrorism and Turmoil.

Detailed assumptions are built into each scenario about market factors such as fuel supplies, energy pricing, electricity prices, electricity demand and electricity supply in the Pacific Northwest. Table 5-1 lists the key features of each scenario.

Table 5-1. Scenarios and Key Themes

	Green World	Nuclear Resurgence	Return to Reliability	Terrorism & Turmoil
Fuels	• Need for LNG cannot be met due to inadequate gasification facilities • Coal hit hard by tightening regulations • Big push to renewable resources	• Gas and oil prices constrained	• Supply and demand for natural gas and LNG well-matched	• LNG & oil supply constrained • Higher price plateau for long term • Coal is "king" • Renewables benefit from high prices and government support
Energy Pricing	• Gas prices rise with tight supply • Power prices rise with stricter environmental controls on coal	• Gas and oil prices rise with tight supply • Prices recover after surge of nuclear builds reduces demand	• Oil and gas prices fall back to normal levels	• Gas and oil prices spike and remain high • Increase in fuel and security costs outweigh fall in demand
Economy/ Energy Demand	• No recession but low growth rates • Energy demand is down – hit by higher energy costs • Slow economic growth, and greater conservation	• Economic growth booms • Increased energy demand	• Economic growth continues at current expectations • Energy demand remains normal	• Recession and slow recovery – hit by higher energy and security costs • Lower average growth • Energy demand falls
Market Structure	• Restructuring slows – patchwork • Mix of utilities and independent power producers • Liquidity is flat • Slow recovery to overbuild	• Restructuring continues • Nuclear consortium agrees on operational pact	• Restructuring comes to halt • Reliability standards adopted • Investment in transmission infrastructure	• Restructuring comes to halt, patchwork market • Priority on security and reliability • Utilities advantaged over independent power producers • Liquidity dries up
Environment	• 5 Pollutants: SO_2, NO_x, PM2.5, and mercury phased in • Flexible market mechanisms relied upon • CO_2 reduction phased in from 2010 • Limited access to federal lands for exploration	• 5 Pollutants: SO_2, NO_x, PM2.5, and mercury phased in • Flexible market mechanisms relied upon • CO_2 reduction phased in from 2014	• Existing NO_x and SO_2 regulations enforced • Flexible market mechanisms relied upon • No federal CO_2 regulations	• Existing NO_x and SO_2 regulations enforced • Flexible market mechanisms relied upon • No federal CO_2 regulations • Federal lands open to oil & gas exploration

Source: Electric Power Horizons: Scenarios of the Global Energy Future-2005, Global Energy Decisions.

Future Generating Capacity and Fuels

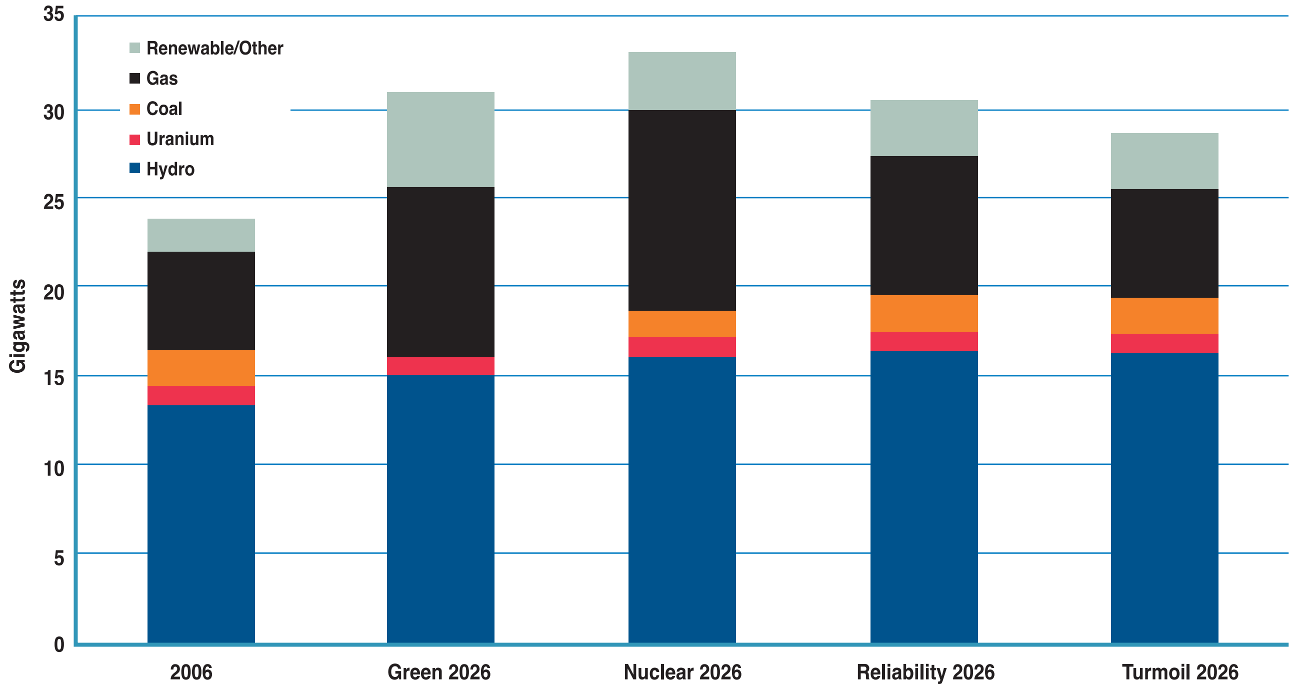
Applying their assumptions for each scenario over the next 20 years, GED arrived at four different fuel mixes available for Northwest power generation. The capacity of renewable resources increases under all scenarios, more than tripling for Green World and almost doubling for the others. This is perhaps a reflection of the successful application of Renewable Portfolio Standards (RPS) by state governments.

Renewable resources are about 17 percent of total capacity for Green World and about 10 percent in the other scenarios. Gas-fired capacity increases substantially under all scenarios as a consequence of siting liquified natural gas (LNG) facilities. Coal is completely eliminated in Green World, decreases by about a fourth in Nuclear Resurgence, and stays the same in the other two scenarios. Oil-fired generation, nuclear power (uranium), and hydro capacity see no growth in any of the scenarios.

Figure 5-3 shows the electric generation capacity and fuel mix for each future in 2026, compared to 2006.

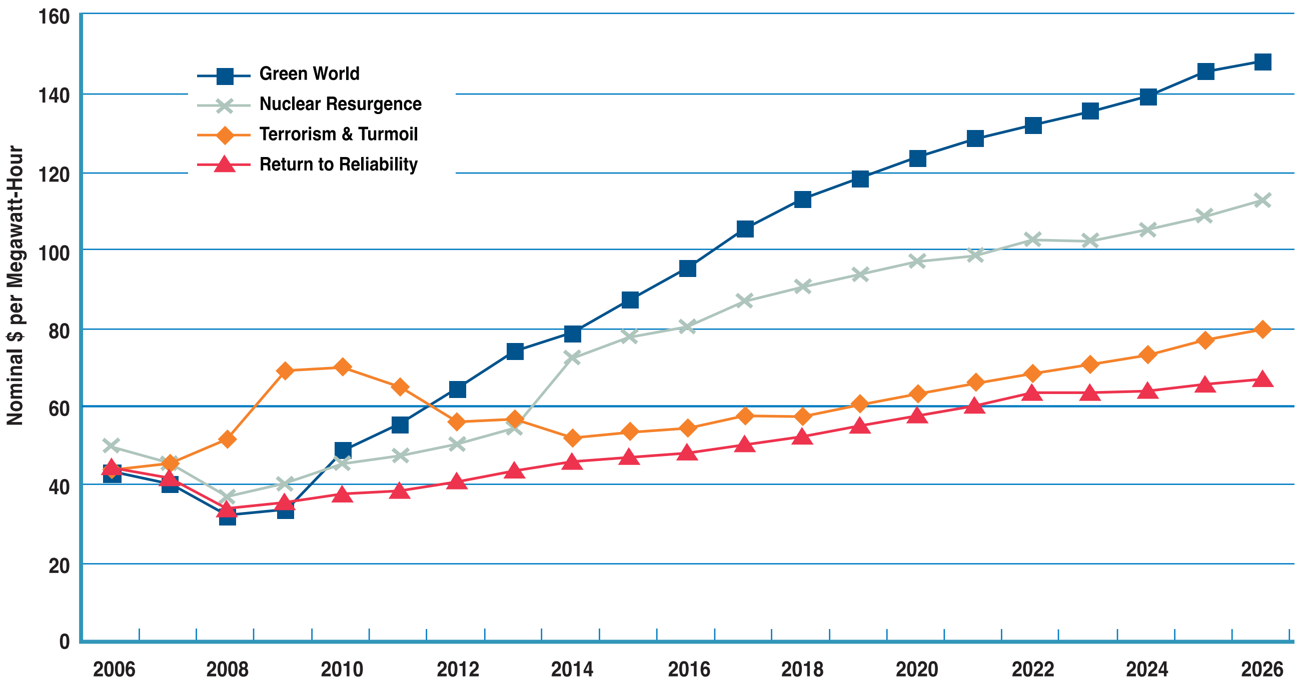
For all scenarios, natural gas is the fuel source that increases by the greatest amount in terms of output. Coal remains about the same in the Return to Reliability and Terrorism & Turmoil scenarios. Green World looks least like the other scenarios by 2026. In Green World, coal has been eliminated primarily through emissions regulation and national Renewable Portfolio Standards. The cost of meeting regulations makes power costs for Green World very much higher than for the other three scenarios.

Figure 5-3. Electric Generation Capacity by Fuel Source in WECC NW



Source: Global Energy Decisions

Figure 5-4. WECC NW (Mid-C) All-Hour Average Wholesale Electricity Price, 2006-2026



Source: Global Energy Decisions

Power Prices in the Four Scenarios

For each scenario, Figure 5-4 shows the change in power price in the WECC Northwest (Mid-Columbia) over the period from 2006 to 2026.

Defining Evaluation Criteria

City Light staff established four criteria for evaluating alternative resource portfolios:

- Provide reliable service
- Minimize cost to customers
- Manage risks
- Minimize environmental impacts

To quantify the expected performance of each candidate resource portfolio in meeting each criterion, City Light chose specific measures, listed in Table 5-2 and described on the following pages.

Table 5-2. Criteria and Measures for Evaluating Resource Portfolios

Criteria	Measures
Provide Reliable Service	Occurrence of unserved customer energy need.
Minimize Costs to Customers	20-Year net present value of portfolio costs.
Manage Risks	Volatility of portfolio costs (net revenue).
Minimize Environmental Impacts	Air emissions of $CO2$, $SO2$, NOx, mercury, and particulates. Impacts on land use, surface and groundwater, soils and geology, plants and animals, employment, aesthetics and recreation, environmental health, and cultural and history were also evaluated in the EIS.

Provide Reliable Service

A critical part of City Light's mission is to provide reliable service – meaning electricity is available when customers want to use it. Electricity is a necessary part of modern life, and is critical to health, safety and economic security. Failure to provide reliable power has serious, immediate consequences, and City Light has procedures in place to ensure that it is able to provide power or restore power quickly when needed.

The main requirements for providing reliable service are that:

- Enough power is being generated to meet the demand.
- Sufficient transmission infrastructure is available and functioning properly to bring the power to City Light's service area.
- Sufficient distribution infrastructure is available and functioning properly to bring the power from the transmission system to the customer.

IRPs usually focus on meeting a high standard of reliability for power supply and do not address availability of transmission and distribution. However, in this IRP, transmission is evaluated for all potential new resources, including transmission availability and the likelihood and cost of building new transmission.

The distribution aspects of reliability are not considered quantitatively in the IRP, with one exception. Energy savings from conservation programs are assumed to have some benefit in deferring investment in new distribution infrastructure. To quantify these benefits, the cost of all energy efficiency measures assessed in the IRP was reduced.

The reliability of power supply depends on:

- Adequacy of generating capacity to meet demand (resource adequacy).
- Adequacy of fuel (e.g. natural gas, coal, water) to generate the energy needed.
- Operational capability of the generating facility.

The question of whether there is enough generating capacity was evaluated in the IRP through the resource adequacy analysis described in Chapter 3. The resource adequacy analysis is an important step in determining the amount of resources needed, and when the resources are needed to meet the reliability standard.

In the resource adequacy analysis, City Light compared energy demand to the energy available from its owned and contracted resources, and a limited amount of market resource (see Chapter 3). Over 1,000 possible combinations of hydropower outputs (a critical issue given City Light's dependence on hydropower) and load were considered, and each combination was evaluated by month over the 20-year planning period.

In addition to ensuring an adequate amount of generating capacity, the sufficiency of the fuel, and the operational reliability of the resource must be considered. Each type of resource has its own fuel and operational uncertainties. For example:

- Hydropower depends upon precipitation, snowmelt and variations in the timing of the migration and spawning cycles of fish. Hydroelectric generation in the Northwest produces power between 45 and 65 percent of the time. Hydroelectric resources are the most flexible and least cost resources available for following load.
- Most coal plants in the West are located near the mine, so access to fuel is highly certain. Unexpected outages are relatively rare, and most western coal plants operate 85 to 90 percent of the time.
- Wind farms are able to produce electricity only when the wind blows. While generating units are highly dependable, the wind is not. Northwest wind generating plants produce power on average about 32 percent of the time, according to the Northwest Power and Conservation Council.
- Natural gas combined cycle plants sometimes face fuel supply issues, particularly in high demand periods, but this is not common when a plant is operated to meet a utility's firm load. More recently, their operations have been limited by the periodic high price of natural gas. Typically these resources can generate electricity over 90 percent of the time.

In modeling candidate resource portfolios, these uncertainties are addressed by introducing variability of hydro operations, wind patterns and forced outages. If correctly constructed, each candidate portfolio is able to meet the 95 percent resource adequacy criteria despite the above challenges. In effect, the reliability criterion is "hard-wired" by design into the resource portfolio. Each portfolio can then be examined for the number of hours of unserved energy occurring to verify it is meeting the reliability criteria.

Minimize Costs to Customers

A fundamental policy issue is balancing the cost of providing service with providing reliable service. In real terms, the cost of electricity declined in the Northwest for decades until about 1980. Even now, the Northwest enjoys the lowest cost power supply in the country due to its reliance on hydroelectric generating plants. Factors influencing cost vary for each type of resource, as described in Chapter 4.

In calculating the costs of specific resources, the IRP assumes that City Light will contract to buy the output of a resource through a power purchase agreement. Whether it is more advantageous to own a resource rather than contract for its output will be determined at the time the Utility is ready to acquire a resource and has received cost information for both approaches through competitive bidding. The exceptions are those resource alternatives that are based on contracting for energy, such as seasonal exchanges and call options.

Costs in the IRP are evaluated over the entire resource portfolio. For example, a higher cost resource may be included in small amounts in a portfolio, and that small addition can help City Light avoid investment in a much larger resource that may have lower per unit of energy costs, but higher overall costs.

The measure chosen for this criterion is 20-year net present value (NPV) of portfolio costs. The net present value accounts for the costs of the resources through time (including capital, operation and maintenance costs, fuel and financing costs) and revenues received from selling unneeded energy.

Manage Risk

Current practice in integrated resource planning emphasizes identifying and analyzing sources of risk. Many forms of risk are evaluated in the IRP; some quantitatively, and some qualitatively. Risks that can be quantified include:

- Variations in demand for electricity (City Light's load) due to factors such as weather and economic conditions.
- Generation plant output, particularly hydropower, where output can vary widely from year to year and month to month, depending on precipitation and snowmelt patterns or wind where output can vary widely from hour to hour and day to day.
- Prices for electricity on the wholesale market.
- Cost of fuel such as natural gas.
- Potential cost of complying with environmental regulations, particularly emissions.

Evaluating these risks does not guarantee that they can be determined exactly, but it does define a range of possible risk and associated costs.

Other types of risk can be more difficult, and sometimes impossible, to quantify. These include the potential for regulatory or policy changes that could affect the availability and cost of resources, policies related to transportation of fuels by pipeline or rail, and requirements related to resource and transmission adequacy.

One of the most significant types of risk that City Light deals with is the uncertainty of the cost of purchasing power or the revenues from selling power into the wholesale power market. These transactions can involve hundreds of millions of dollars annually, and the magnitude of wholesale revenues and purchases can swing by more than $100 million from year to year. As described in Chapter 4, City Light participates in the market for a variety of reasons; for example buying electricity to help meet demand during low water conditions, and using the energy storage capability at its hydroelectric projects to purchase low priced energy and store water for use later when prices are higher. Currently, City Light sells much more electricity into the market on an annual basis than it purchases, primarily because it requires more resources to meet the three-month winter peaking load requirement than are needed during the remaining nine months of the year.

Because City Light's hydro output varies so dramatically from year to year, and because so many factors determine future market prices, the Utility has developed strategies to mitigate the risk. One of the primary goals of the IRP is to illustrate the trade off between these risks and the other criteria, such as cost and reliability. The IRP does not provide "the answer", but shows how certain portfolios can result in more or less risk, and illustrates the options.

Mitigating the risk of buying and selling electricity in the market occurs in three stages:

- Designing a low-risk resource portfolio, one of the primary goals of the IRP process. This is done by evaluating the portfolios under different combinations of future conditions, such as City Light's demand for electricity, the cost of market power, the cost of natural gas and other fuels, and environmental regulations. The IRP process tests candidate portfolios against a range of conditions that might occur in the future, without knowing which set of conditions will actually happen.
- Implementing the long-term resource strategy developed in the IRP. This stage includes acquiring new resources, and may also involve entering into long-term transactions designed to improve the overall balance of loads and resources in the Utility's portfolio.
- Minimizing risk on an ongoing basis. Resource portfolios change over the years, and their output and performance can change daily or even hourly. This presents a significant challenge to Utility resource operators who must make sure City Light has enough electricity to meet demand at all times.

The criterion used to evaluate risk is the relative volatility of variable costs and net revenues across portfolios. Risk is measured for the variable costs of the resource portfolios and for net market purchases and sales. Varying fuel prices and the extent and frequency of plant operation affect variable costs. Net revenues from market purchases and sales are influenced by the extent of surplus generation and the spot market price.

For both the variable cost and net revenue risk, one measure applied is the coefficient of variation. The coefficient of variation is calculated as the standard deviation divided by the mean. It measures the degree of variance from the mean, or average. The greater the variance from average, the larger the coefficient of variation and the larger the implied risk associated with the portfolio. Another risk measure evaluated during modeling of portfolios is what percentage of Monte Carlo iterations fall within the 5 percent and 95 percent tails of the probability distribution.

Minimize Environmental Impact

Air emissions were explicitly included in the modeling and analysis of portfolios because of their importance to the environment and because they can be quantified without specific siting information. For other environmental elements including land use, surface and groundwater, soils and geology, plants and animals, employment, aesthetics and recreation, environmental health and cultural resources, each portfolio was assessed for the level of impact in each element. Each portfolio was ranked high, moderate or low (see Table 6-10 in Chapter 6 and the DEIS Summary).

For each generating resource portfolio, total emissions into the air of carbon dioxide (CO2), sulfur dioxide (SO2), nitrogen oxides (NOx), mercury (Hg), and particulates (PM) are estimated over the 20-year period. A monetary cost is applied to the emissions to approximate the cost of complying with potential environmental regulations in the future. The compliance costs of each portfolio are tabulated by year and expressed as a net present value. These costs are varied in the alternative futures to gain a sense of how well the portfolios perform under different regulatory scenarios. These costs are included in the cost evaluations described above.

Several methods can be used to determine the social costs of environmental impacts such as air emissions. In addition to the internalized cost comparisons, the model calculates net emissions for each resource portfolio (emissions generated minus emissions reductions from sales into the market that result in turning off less efficient resources). In this case, mitigation costs (or control costs) are used as a proxy for the net environmental damage from air pollutants of each portfolio. A cost measure is applied to each type of emissions to evaluate the relative environmental performance of each portfolio.

The method chosen to evaluate environmental costs in the IRP is to estimate the mitigation cost (or control cost) for total emissions of each of the five substances. This approach does not place a value on the damage done by pollutants, but does allow a direct comparison between resource portfolios with respect to estimated cost of mitigating environmental impacts. Environmental mitigation costs of each portfolio are tabulated by year and expressed as a net present value.

Certain assumptions were made in estimating greenhouse gas emissions from the generating resources. Biomass and landfill gas were assumed to have zero net impact on greenhouse gas. They were considered closed-loop systems, where the carbon dioxide emissions are equal to the carbon dioxide captured by the plants and other substances prior to being combusted.

The air emission impacts of market sales and market purchases were accounted for by using Global Energy Decisions forecasts of resources on the margin in the Western power market. City Light market sales were assumed to displace a corresponding amount of energy from the marginal generating unit in the market at the time of the sale. Conversely, market purchases were assumed to be generated by the marginal generating unit at the time of the purchase. Given that Seattle's resource portfolio is mostly comprised of hydropower, market sales could have a significant positive air emissions impact by backing down less efficient Western thermal generators on the margin, most often natural gas-fired turbines.

In evaluating and comparing candidate resource portfolios, the largest factor was frequently the amount of carbon dioxide emitted from a resource portfolio. City Light assumes that carbon dioxide emissions must be offset according to City policy. Presently, carbon dioxide offsets are averaging $5 dollars/ton for City Light, resulting in higher costs for candidate resources consuming fossil fuels.

Using the Model to Evaluate Portfolios

This section describes the analytical tool – the computer model – that City Light used to analyze the candidate resource portfolios. The Planning and Risk model is licensed by Global Energy Decisions (GED). Over several months, staff from City Light and GED worked to capture the features of City Light's existing resources – hydro variability chief among them – in the model, and to describe the operating and financial characteristics of the candidate resources that make up the portfolios.

A complete description of the resources available, the prices of fuel and power, and the load were entered into the model. It then "dispatches" or selects from among the resources available to it to meet the demand it faces each hour of the year. The dispatch is economic, meaning the model uses the cheapest resources first, and then moves up to the next least expensive resource until the demand is met. The model views the wholesale power market as a resource during this process and uses it rather than a physical resource if it is less costly to do so.

The model makes other economic decisions, in particular dispatching resources to sell into the wholesale market when it is profitable. For example, when gas prices are low enough relative to power prices that it is profitable to buy gas and produce power, the model does so. This use of a resource helps to reduce the overall cost of having it in the portfolio.

Dispatch of resources respects all constraints and restrictions on those resources. For example, combustion turbines have ramp up and ramp down rates that must be accounted for in deciding when and how to dispatch them. Similarly, there are minimum and maximum flow constraints for the Gorge project on the Skagit River to protect the fish.

As it dispatches resources, the model keeps track of the cost of operating the resources, a variety of air emissions, and the hours of load not served, among a host of other data. These are used to measure performance against the evaluation criteria.

A key feature of this model is its ability to handle uncertainty about the future – not uncertainty about which, if any, of the four futures identified will actually come to pass, but uncertainty within the futures themselves. The model can generate a sequence of random prices for fuel and power that are centered around the average price for the variable question in any of the futures.

Example Model Operation and Output

As an example of how the model works, consider the Mid-Columbia wholesale market peak price for power under the "Reference Case" future shown in Figure 5-5. In January 2010, the forecasted on-peak price is just under $38 per megawatt-hour. However, from the model's perspective, that is just the center of the distribution of market prices for power in that month for that particular future.

Figure 5-5. Mean Mid-Columbia On-Peak Power Prices, 2007-2026

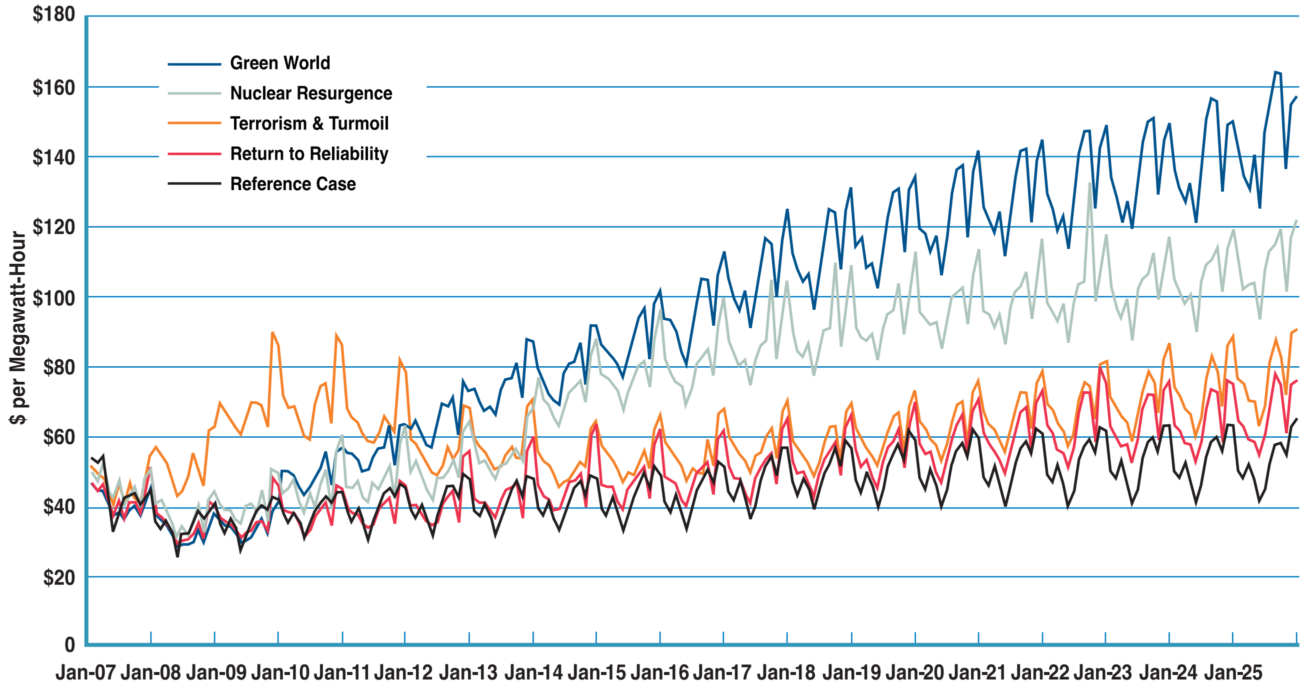


Figure 5-6 shows price distribution the model generated around that center point. The model is able to generate similar distributions for all prices in the model.

Figure 5-6. Typical Power Price Distribution

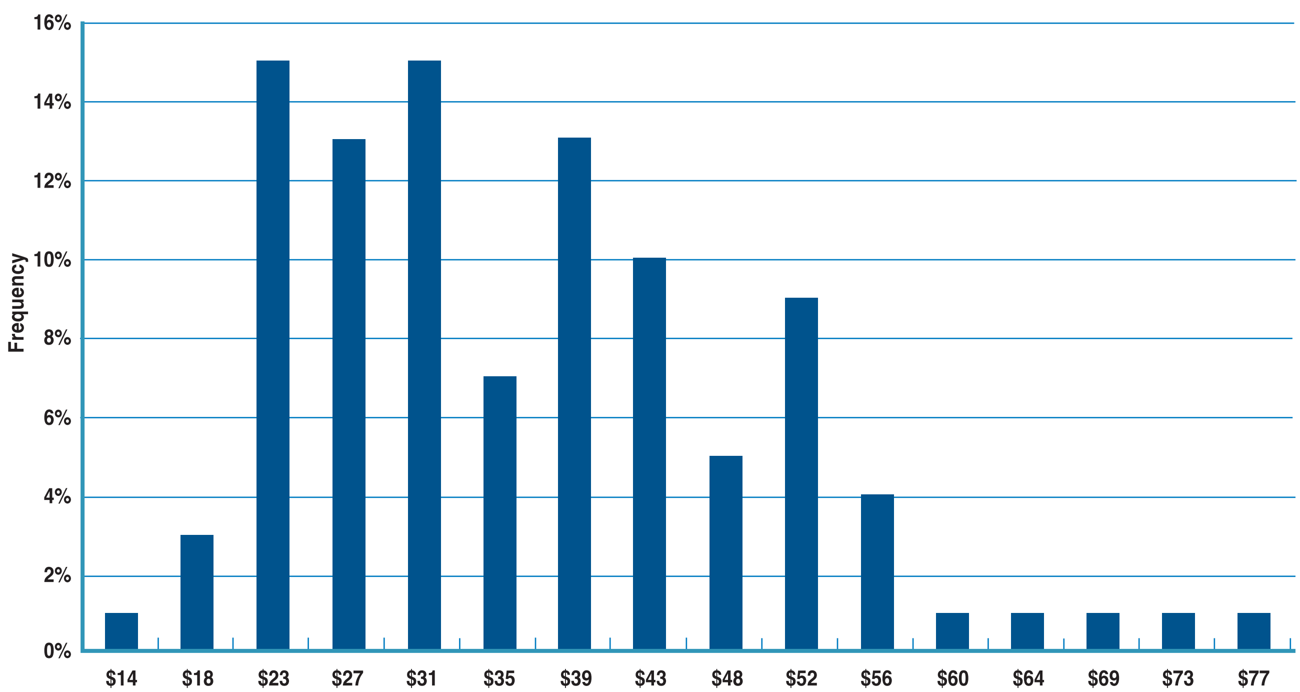
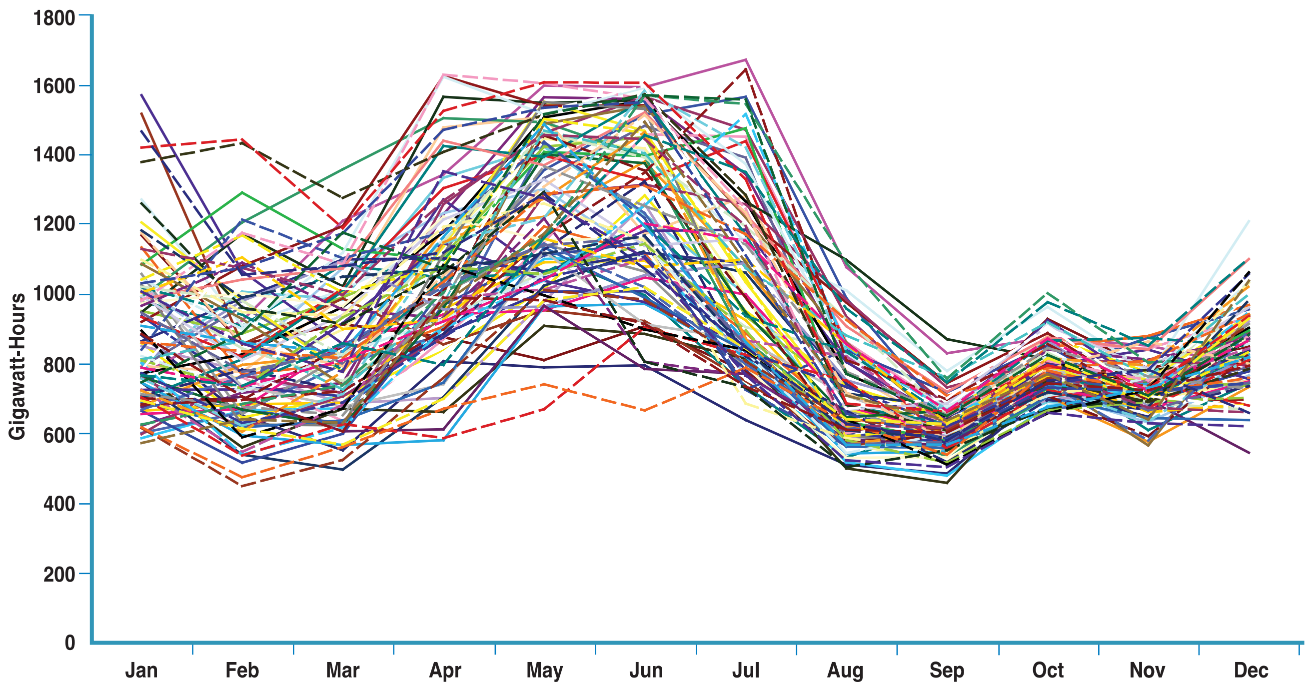


Figure 5-7. Hydro Variability



However, prices are not the only source of uncertainty. Customer demand and, critically for City Light, availability of water for generation are also uncertain. Much of the effort in modeling City Light's system went into "teaching" the model about the variability of hydro generation. Figure 5-7 shows the model-generated distribution of generation for City Light's hydro system. The pattern it produces, made up of randomly generated water years, is similar to the pattern exhibited by the historical record. However, the model is not limited to the historical record either in terms of number of years – it can produce as many water years as needed – or in terms of the range of possible water years.

Constraints in the Model

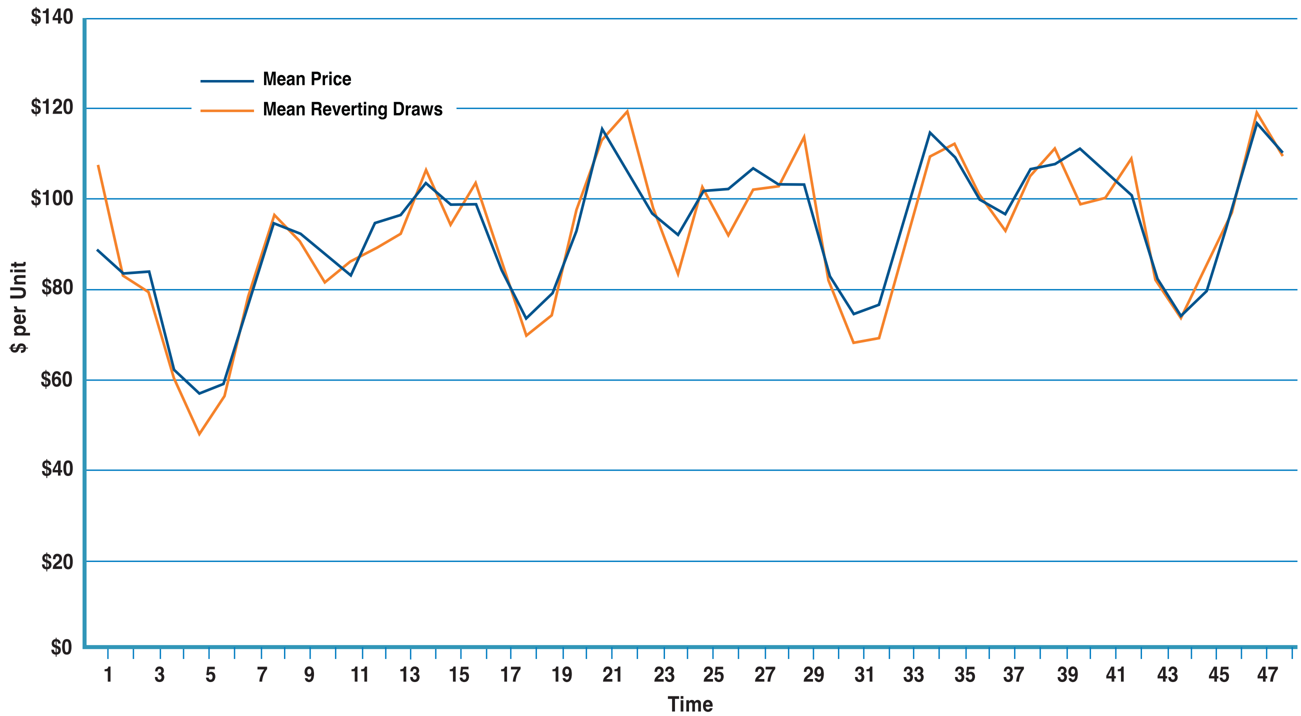
As described earlier, effects of uncertainty are captured in the model by having it make random selections, or "draws" for key outcomes. This is analogous to drawing cards from a well-shuffled deck, but adding each card drawn back to the deck and reshuffling it again before each new draw. The draws are made from many potential outcomes of fuel prices, power prices, generation and loads. The result of each new draw is equally likely to results of previous draws.

In producing the draws of fuel prices and power prices, generation and load, the model is constrained in several ways. First, relationships exist between power prices and fuel prices. This is not surprising since fuels like natural gas and coal are used to produce power. All things being equal, higher fuel prices lead to higher power prices. Of course, fuel prices themselves often move in tandem.

Second, because of the size of the hydro system in the Northwest, during the runoff period (April to June) wholesale market prices for power are often depressed as the hydro system displaces fossil fuel generation in the region. The effect is relatively short-lived, but it is important.

These correlations among the variables in the model must be accounted for when creating a sequence of, for example, prices for market power. That sequence cannot be entirely free and unconstrained, but must reflect the relationship to the draws for natural gas, hydro generation and other variables. City Light estimated several of these correlations from historical data and GED provided the others.

Figure 5-8. Mean Reverting Random Processes



The final constraint is particularly important when creating the draws of prices. The draws must not only respect the correlations noted above, but must also mirror the pattern of prices actually observed in the markets for fuels and power. These prices exhibit a pattern called mean reversion, meaning that although they vary randomly, they tend over time to return to some central value. Figure 5-8 shows an example of a sequence that exhibits mean reversion. Although the sequence in yellow bounces around, it does not stray too far from the underlying mean of the variable, in blue.

Energy prices behave very like those in Figure 5-8. The reason is that underlying the markets for fuel and power are real, physical processes driving the demand and supply for the commodity. These fundamentals determine, within reason, the limits to the size and duration of price excursions. The energy crisis of 2000-2001 is a notable exception; however, in that case, the usual market mechanisms were frustrated by gaming of the system.

Analysis

For each time step in the analysis, the model generates a set of correlated values for prices, load and generation, and dispatches the resources as described earlier. It repeats this process 100 times before moving to the next time step. In this way, instead of a single value for an output of the mode for a given time step – for example, the cost to operate the portfolio or the amount of carbon dioxide emitted – the model produces a distribution for each output. Those distributions reflect the underlying distributions and correlations for prices and other variables.

This approach to analysis, often called a Monte Carlo simulation, gives very robust results in the sense that they capture more fully the underlying uncertainties in the process. The ability of the underlying drivers of the analysis to vary randomly and in a way not directly controlled by the modeler is key. While the modeler can set the parameters of the random process – the center and spread of the distribution and its correlation to other drivers – the model selections themselves are random.

Additional details on the methodology underlying the draws are in Appendix D.

Selecting Portfolios for Analysis

Integrated resource planning involves examining a wide range of alternative resources. Washington State law (HB 1010) requires City Light to "perform a detailed and consistent analysis of a wide range of commercially available resources," including conservation. Three key objectives were considered in constructing the resource portfolios:

- Develop a wide range of resource portfolios, including those containing predominantly renewable resources, those containing predominantly non-renewable resources, and those with a mixture of renewable and non-renewable resources.
- Ensure sufficient supplies of generation each month during the 20-year period to avoid unserved energy needs with a 95-percent degree of confidence.
- Utilize a mix of resources believed to be commercially available to City Light and resources specifically recommended for inclusion in the portfolios through the public input process.

For the first round of analysis, City Light developed nine portfolios of new resources that in principle would be able to fill the resource gap determined by the resource adequacy study. Based on these results, eight new portfolios were defined for analysis in the second round. The resources listed below and described in Chapter 4 were used in various combinations to define the portfolios.

Additional Conservation

Renewable Generation

- Hydro (hydro contract, Gorge Tunnel hydro-efficiency improvement).
- Wind.
- Geothermal.
- Biomass.
- Biogas (landfill gas).

Non-renewable Generation

- Natural gas – Combined-cycle combustion turbine (CCCT), combined heat and power combustion (CHP), simple-cycle combustion turbine (SCCT).
- Coal – Pulverized coal and integrated gasification combined cycle (IGCC).

Mixed resources

- Seasonal exchanges, seasonal call option.
- Bonneville Power Administration (BPA) – 100 percent Block, 50 percent Block, 50 percent Slice.

Market resources

- Wholesale power market.

The next chapter describes in detail the Round 1 and Round 2 portfolios, and results of the analysis.

Chapter 6 – The Portfolios: Seeking the Right Mix of Resources

After gathering information on the range of resources that might be added to City Light's existing resource portfolio, candidate portfolios were constructed subject to the following criteria:

- All proposed resource portfolios were constructed to meet the prescribed level of energy resource adequacy (95 percent).
- Several of the evaluated portfolios were constructed to conform to the requirements of Initiative 937. Other portfolios were not held to this restriction, to prepare for the possibility that I-937 would not pass.
- Portfolios were built to optimize the performance of individual resources. Attempts were made to minimize costs, defer capital investments for as long as possible, or seek out economies of scale and other cost preventitive measures.

Once the portfolios were created, their performance was evaluated. The Utility conducted two rounds of portfolio analysis to allow for a comprehensive review by Utility management and the stakeholder committee, and for public review and comment. Evaluating resource portfolios in two rounds provided valuable guidance for IRP staff and opportunities to promote consensus with stakeholders and the public.

In Round 1, nearly all the available resource types were included in at least one of eight candidate portfolios. Experience gained from this exercise informed the construction of portfolios in Round 2. Several resource types, primarily coal-fired generation technologies, were eliminated from further consideration. Round 2 focused on a smaller number of resource types, varying the sizing and timing of the most promising resources.

This chapter describes in detail the portfolios selected for each round of analysis, compares their performance in terms of the criteria defined in Chapter 5, summarizes the conclusions reached, and presents the recommended portfolio.

Round 1 Analysis

The purpose of the first round of portfolio analysis was threefold:

1. To evaluate how a varied mix of resource technologies with different fixed costs, marginal costs, and capacity factors would influence overall portfolio performance.
2. To eliminate from consideration the very worst performing resource technologies in order to simplify the number of alternatives under scrutiny for Round 2.
3. To utilize the capabilities of Global Energy Decisions (GED) Planning and Risk Model to approximate candidate resources within a defined quantitative framework.

To this end, Round 1 was successful. Many complexities of the resources and portfolios were uncovered. Nine resource portfolios were evaluated through the reference case and four future "scenarios," resulting in a wealth of performance data. With this data it was possible to gain insights into the importance of resource availability, resource sizing and scalability, transmission requirements, tradeoffs between generation resources and the optimal level of conservation resources, fuel risk and capitalization issues.

Round 1 Portfolios

The nine alternative portfolio designations are listed below and the resources in each portfolio by 2026 are given in Table 6-1:

1. No Action - Rely on the Market
2. Renewables
3. Gas and 100% Block (BPA)
4. Gas, Wind and 50% Block (BPA)
5. Gas, Wind and Hydro
6. Gas, Biomass and Wind
7. Gas
8. Gas and Coal (Pulverized)
9. Wind and Coal (IGCC)

Table 6-1. Total New Resources in Round 1 Portfolios
(Average Megawatts of Output, 2026)

Resource	Resource Portfolio								
	P1 Rely on Market	P2 Renewables	P3 Gas, 100% Block	P4 Gas, Wind, 50% Block	P5 Gas, Wind, Hydro	P6 Gas, Biomass, Wind	P7 Gas	P8 Gas, Coal	P9 Wind, IGCC
Conservation		140	140	140	140	140	140	140	140
Exchange*		100	100		100	100	100	100	100
Call Option*					50				
Hydro Contract		23			23				
Hydro Efficiency		10			10				
Wind		250	50	50	50	50			150
Geothermal		25							
Landfill Gas		25			25	25			
Biomass		25				50			
CHP (co-gen.)					25				
CC Turbine			600	350	100	100	300	150	
SC Turbine					125	50	50	75	
IGCC - Coal									300
PV Coal								150	
Total 2026	0	598	890	540	648	515	590	615	690

*Call options and exchanges are temporary resources and may no longer be in the portfolio by 2026.

The quantity of resources included in each portfolio was based on energy resource adequacy, which is a measure of energy output rather than capacity. Therefore, the tables throughout this chapter show resources in average megawatts. The capacity factor is about 32 percent for wind resources, and about 50 percent for the hydro contract and hydro efficiency.

Common to all resource portfolios are 140 average megawatts of conservation and 100 average megawatts of exchange, although the exchange in Portfolio 4 (Gas, Wind and 50% Block) ends after 2011. Conservation and seasonal exchanges are cost-effective approaches to meeting seasonal resource needs.

Five of eight portfolios contain a seasonal capacity contract (a physical call option), with the amounts varying by portfolio. Physical call options provide a means for acquiring power under improbable but possible circumstances. As such, a physical call option is not likely to be exercised, but its purchase does help the Utility to make sure load will be met in such events as the combination of severe drought and an extended period of extreme weather conditions. Physical call options provide reliability for a fraction of the cost of holding a firm generating resource or purchasing power in the spot market under high demand conditions.

Two hydro resources were considered: an 18-megawatt (10 aMW) efficiency upgrade to existing City Light's hydro capacity and a 50-megawatt (23 aMW) contract for existing hydro capacity from another utility. Wind resources are included in five portfolios, with the largest amount (750 megawatts or 250 aMW) as part of the Renewables portfolio.

One portfolio features a geothermal resource. Three portfolios have landfill gas, two have biomass, and one has cogeneration. All four of these resources are comparatively small, with output of only 25 average megawatts per unit.

Simple cycle and combined-cycle natural gas turbines are included in five portfolios. In three of these, natural gas turbines make up more than half of the total resources added. Conversion of the BPA Slice product to Block in the 100-percent Block portfolio results in less BPA-supplied power being available for the existing resources portion of the portfolio, because the potentially higher amounts of electricity available under the Slice product would be forgone. Additional new resources must be added to make up for the loss to existing hydro resources. The 100-percent Block portfolio contains the most natural gas turbine output, 600 average megawatts.

Portfolio 1: Rely on the Market (No Action)

In the No Action Case, no new generation or conservation resources are acquired. Instead, all new power requirements are met with short-term purchases in the Western wholesale power market. Short-term (spot) market purchases are made at the forecasted market price, set by the marginal generating unit in the West. From an environmental perspective, this means that at any given time, air emissions will be driven by whatever generating unit is on the margin in the spot market at that time. Currently in the West, natural gas-fired generation is on the margin more than 90 percent of the time.

Portfolio 2: Renewables

The Renewables portfolio contains mainly renewable resources, plus a seasonal exchange and a physical call option. Four of the nine resources – biomass, landfill gas, the call option, and the exchange – emit pollutants. The biomass and landfill gas resources are treated as greenhouse gas neutral, but they have other emissions such as sulfur dioxide and nitrogen oxides. While the generating resources supplying the exchange would operate seasonally each year, the generating resources backing up the call option would operate only in rare situations where weather conditions, market instability or generation outages make it difficult to obtain reliable energy. The call option would not be exercised under normal weather and hydro conditions. Table 6-2 shows the schedule for new resource acquisition through 2026.

Table 6-2. Portfolio 2: Renewables – New Resources
(Average Megawatts of Output, 2007-2026)

Resource (aMW)	Location	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Conservation	W. WA	7	14	21	28	35	42	49	56	63	70	77	84	91	98	105	112	119	126	133	140
Hydro Contract	Mid-C	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Call Option	Mid-C	100	100																		
Exchange	Mid-C		100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Hydro Efficiency	W. WA		10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Wind	E. WA		50	50	50	50	50	50	50	50	50	50	50	100	100	200	200	200	200	200	250
Landfill Gas	W. WA							25	25	25	25	25	25	25	25	25	25	25	25	25	25
Geothermal	W. WA									25	25	25	25	25	25	25	25	25	25	25	25
Biomass	W. WA													25	25	25	25	25	25	25	25
Total		130	297	204	211	218	225	257	264	296	303	310	317	399	406	513	520	527	534	541	598

Portfolio 3: Gas and 100% Block

City Light purchases two products as part of its contract with the Bonneville Power Administration. One product is called "Slice," because it mimics ownership of a slice of the hydroelectric generation capacity on the BPA system. In good water years, City Light receives more megawatt-hours of generation than in bad water years. In buying the Slice product, City Light shares in the annual hydro risk that comes from the BPA hydroelectric system. A second product is called "Block," because it is taken as blocks of power. It is a firm product, where a pre-determined amount of generation is delivered by the BPA irrespective of what kind of water year occurs. The Block generation can be "shaped," or taken in different amounts at different times of the year, but does not vary from the contracted amount.

The 100 percent Block portfolio was intended to explore the effect of selecting 100 percent of City Light's BPA purchase as a Block product after 2011. It eliminates BPA's Slice product from the mix, instead taking all Block and assuming that the Utility can reshape its monthly allocation to take more firm power in the winter months. The advantage of a larger proportion of the Block product is that it allows City Light to match its BPA power purchase more closely to its needs. However, City Light would receive considerably less total power from BPA because the Block product is based upon the 1937-38 water year. In trading Slice for Block, City Light would receive on average about one-third fewer megawatt-hours than from a corresponding amount of Slice. This means that more generation must be added sooner to the portfolio to offset the loss in BPA megawatt-hours. The additional generation comes from a combined-cycle combustion turbine. In total, there is 600 aMW of output from combined-cycle turbines. Table 6-3 shows the schedule for new resource acquisition through 2026.

Portfolio 4: Gas, Wind and 50% Block

This portfolio, with 50 percent Block and 50 percent Slice, allows analysis of a different mix of products than City Light currently purchases from BPA. The advantage of trading BPA Slice product for Block product is the presumption that BPA Block can be shaped to meet the seasonal loads of the Utility. In addition to the Block and Slice products, the portfolio contains a call option, 50 aMW of output from simple-cycle turbines, and 350 aMW from combined-cycle turbines. Table 6-4 shows the schedule for new resource acquisition through 2026.

Table 6-3. Portfolio 3: Gas and 100% Block – New Resources (Average Megawatts of Output, 2007-2026)

Resource (aMW)	Location	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Conservation	W. WA	7	14	21	28	35	42	49	56	63	70	77	84	91	98	105	112	119	126	133	140
Exchange	Mid-C		100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Call Option	Mid-C	100	100	100	100	100															
Wind	E. WA		50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
CCCT	W. WA						150	150	150	150	150	300	450	450	450	600	600	600	600	600	600
Total		107	264	271	278	285	342	349	356	363	370	527	684	691	698	855	862	869	876	883	890

Table 6-4. Portfolio 4: Gas, Wind, and 50% Block – New Resources (Average Megawatts of Output, 2007-2026)

Resource (aMW)	Location	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Conservation	W. WA	7	14	21	28	35	42	49	56	63	70	77	84	91	98	105	112	119	126	133	140
Exchange	Mid-C	100	100	100	100	100															
CCCT	W. WA			150	150	150	150	150	150	150	250	250	250	250	250	350	350	350	350	350	350
Wind	E. WA						50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Total		107	114	271	278	285	242	249	256	263	370	377	384	391	398	505	512	519	526	533	540

Portfolio 5: Gas, Wind and Hydro

Like the Renewables portfolio, the Gas, Wind and Hydro portfolio contains many renewable resources. However, a significant difference is that it also contains three additions of natural gas-fired turbine capacity (in 2013, 2019 and 2021), for a total output of 225 aMW by the year 2021. Emissions come from the operation of the simple-cycle and combined-cycle turbines, the exchange contract, landfill gas, combined heat and power (CHP) and the call option. As mentioned above, landfill gas is treated as greenhouse gas neutral (no CO_2 emissions). Table 6-5 shows the schedule for new resource acquisition through 2026.

Portfolio 6: Gas, Biomass and Wind

This portfolio is similar to the Hydro, Wind and Gas portfolio, except it has no hydro. Emissions in this portfolio come from the combined-cycle and simple-cycle (CCCT and SCCT) turbines, the two biomass plants, and the exchange. With the exception of the Renewables portfolio, it has more generation capacity than other portfolios. This is because the variability of wind resources causes them to generate, on average, roughly 30 percent of their nameplate capacity. At this capacity factor, more wind plant resource must be added to get the same amount of generation as other resources with higher capacity factors. Table 6-6 shows the schedule for new resource acquisition through 2026.

Table 6-5. Portfolio 5: Gas, Wind and Hydro – New Resources (Average Megawatts of Output, 2007-2026)

Resource (aMW)	Location	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Conservation	W. WA	7	14	21	28	35	42	49	56	63	70	77	84	91	98	105	112	119	126	133	140
Hydro Contract	Mid-C	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Hydro Efficiency	W. WA	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Exchange	Mid-C	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Wind	E. WA		50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Landfill Gas	W. WA			25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
CHP	W. WA			25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
SCCT	W. WA							50	50	50	50	50	50	125	125	125	125	125	125	125	125
CCCT	W. WA															100	100	100	100	100	100
Call Option	Mid-C																			50	50
Total		140	197	254	261	268	275	332	339	346	353	360	367	449	456	563	570	577	584	641	648

Table 6-6. Portfolio 6: Gas, Biomass and Wind – New Resources (Average Megawatts of Output, 2007-2026)

Resource (aMW)	Location	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Conservation	W. WA	7	14	21	28	35	42	49	56	63	70	77	84	91	98	105	112	119	126	133	140
Call Option	Mid-C	50	50	50																	
Exchange	Mid-C		100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Wind	E. WA			50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
SCCT	W. WA					50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Landfill Gas	W. WA					25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Biomass	W. WA									25	25	50	50	50	50	50	50	50	50	50	50
CCCT	W. WA															100	100	100	100	100	100
Total		57	164	221	178	260	267	274	281	313	320	352	359	366	373	480	487	494	501	508	515

Portfolio 7: Gas

In addition to the conservation and exchange present in all portfolios, the Gas portfolio contains only natural gas-fired turbines. It is assumed that the natural gas-fired turbines would be sited in western Washington, keeping transmission costs down. Emissions in the Gas portfolio come from the exchange, the two simple-cycle turbines, and the single combined-cycle turbine. Table 6-7 shows the schedule for new resource acquisition through 2026.

Portfolio 8: Gas and Coal

In addition to conservation and a long-term exchange, the Gas and Coal portfolio produces 225 aMW from natural gas turbines and 150 aMW from a coal-fired plant by 2022. Although the coal-fired plant uses conventional pulverized coal technology, total carbon dioxide emissions are lower than in the Wind and IGCC portfolio. The Wind and IGCC portfolio has twice as much coal-fired generation. Other resources with air emissions are the exchange, the simple cycle turbine, and the combined-cycle turbine. Table 6-8 shows schedule for new resource acquisition through 2026.

Table 6-7. Portfolio 7: Gas Portfolio – New Resources (Average Megawatts of Output, 2007-2026)

Resource (aMW)	Location	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Conservation	W. WA	7	14	21	28	35	42	49	56	63	70	77	84	91	98	105	112	119	126	133	140
Exchange	Mid-C	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CCCT	W. WA			150	150	150	150	150	150	150	150	300	300	300	300	300	300	300	300	300	300
SCCT	W. WA																50	50	50	50	50
Total		107	114	271	278	285	292	299	306	313	320	477	484	491	498	505	562	569	576	583	590

Table 6-8. Portfolio 8: Gas and Coal Portfolio – New Resources (Average Megawatts of Output, 2007-2026)

Resource (aMW)	Location	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Conservation	W. WA	7	14	21	28	35	42	49	56	63	70	77	84	91	98	105	112	119	126	133	140
Exchange	Mid-C	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CCCT	W. WA			150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Coal	MT			150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
SCCT	W. WA																75	75	75	75	75
Total	W. WA	107	114	421	428	435	442	449	456	463	470	477	484	491	498	505	587	594	601	608	615

Table 6-9. Portfolio 9: Wind and IGCC Portfolio – New Resources (Average Megawatts of Output, 2007-2026)

Resource (aMW)	Location	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Conservation	W. WA	7	14	21	28	35	42	49	56	63	70	77	84	91	98	105	112	119	126	133	140
Call Option	Mid-C	70	70	70	70																
Exchange	Mid-C		100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Wind	E. WA			50	50	50	100	150	150	150	150	150	150	150	150	150	150	150	150	150	150
IGCC	MT					150	150	150	150	150	150	150	150	300	300	300	300	300	300	300	300
Total		77	184	241	248	335	392	449	456	463	470	477	484	641	648	655	662	669	676	683	690

Portfolio 9: Wind and IGCC

The Wind and IGCC portfolio contains conservation, an exchange, a 70 aMW call option that expires in 2011, three wind plant additions and two additions of IGCC capacity. The IGCC capacity is assumed to be part of a future IGCC plant constructed in Montana. Emissions from this portfolio are from the exchange, the call option and the IGCC capacity additions. The IGCC technology has lower air emissions than conventional pulverized coal technology. It is assumed that the carbon dioxide emissions would not be sequestered. Therefore, the IGCC capacity would require the purchase of carbon dioxide emission offsets. Like the Renewables portfolio, this portfolio has a comparatively large amount of total generation, with 150 aMW of wind in addition to the 300 aMW of IGCC.

As described for the Gas, Biomass and Wind portfolio, more wind capacity is required because of the low capacity factor. Table 6-9 shows schedule for new resource acquisition through 2026.

Evaluation of Portfolios

As described in Chapter 5, measures were devised for the purpose of comparing the portfolios against four evaluation criteria: cost, environmental impact, risk and reliability. All portfolios meet the reliability criterion of 95 percent resource adequacy. The other criteria and corresponding measures are shown in Table 5-2. The results of the portfolios evaluations are displayed in Table 6-10.

Table 6-10. Round 1 Portfolio Comparison

	Fixed + Variable Costs	Environmental Impacts	Cost Risk	Market Risk	Revenue Less Cost
1. Rely on Market (Do Nothing)	Best	Worst	Worst	Worst	Worst
2. Renewables	Mid	Best	Mid	Best	Best
3. Gas, 100% Block	Worst	Best	Mid	Worst	Mid
4. Gas, Wind, 50% Block	Mid	Mid	Best	Mid	Worst
5. Gas, Wind, Hydro	Best	Best	Worst	Best	Best
6. Gas, Biomass, Wind	Mid	Best	Worst	Mid	Mid
7. Gas	Best	Mid	Best	Worst	Mid
8. IGCC, Wind	Worst	Worst	Mid	Best	Worst
9. Coal, Gas	Worst	Worst	Best	Mid	Best

Best Performing

Mid Performing

Worst Performing

As shown in Table 6-10, the portfolios performing among the top third of portfolios across all five measures are:

- Renewables
- Gas, Wind and Hydro
- Gas

The top three portfolios in terms of net present value of net power costs (revenues net of costs) are:

- Renewables
- Gas, Wind, and Hydro
- Gas and Coal

The three portfolios having the least environmental impact, including residual air emissions from generation (carbon dioxide, sulfur dioxide, nitrogen oxide, particulates and mercury) are:

- Renewables
- Gas, Wind, and Hydro
- Wind, Gas, and Biomass

Environmental Impact Summary

The environmental impacts of each of the nine Round 1 portfolios are described in detail in the Draft Environmental Impact Statement.

In general, the highest levels of potential impact are associated with coal-fired resources and, to a lesser extent, geothermal and biomass. Conservation, hydro efficiency improvements at an existing City Light hydro facility (Gorge tunnel) and landfill gas resources are expected to have the fewest environmental impacts, followed by wind and gas-fired combustion turbine resources. Overall, the following resources could potentially cause significant impacts:

- Wind – due to potential high aesthetic impacts and possible impacts on birds and bats.
- Both coal-fired resources – due to several factors, including extensive ground-disturbing activities at a plant site as well as for fuel extraction and air pollutant emissions.
- Geothermal – potential physical disturbance to geologic structures, groundwater impacts and the possibility of development in pristine areas where land use and recreation impacts would be an issue.
- Biomass – potentially substantial land disturbance over an extensive area if a dedicated crop is the fuel source, as well as impacts from transporting biomass fuel.
- Gas turbines – air quality impacts.
- Market transactions – high levels of air emissions and fuel extraction, based on the assumption of resources used in market transactions.

Conclusions from Round 1 Analysis

From the analysis of the nine initial portfolios, the following conclusions were reached:

1. City Light's energy resource adequacy requirement would not be well served by large capacity "must-run" baseload generation technologies (coal and large natural gas CCCT). Such resources would exacerbate the mismatch between the Utility's seasonal load shape and resource shape.
2. Resource technologies requiring large un-scalable capital projects (coal and large natural gas CCCT) also are not well suited to City Light's interests. The small but steady annual increases in energy need would be poorly met with large projects that would leave the Utility at first with decreasing oversupply and then increasing undersupply as years go by.
3. By holding to the City's policies on offsetting carbon emissions (CO_2) and accounting for environmental externalities (emissions of SO_2, NO_x, particulate matter and mercury), resource technologies that are heavy polluters would be quickly discounted in value. This is especially true in future "scenarios" that contain a carbon tax.
4. Seasonal energy exchanges with utilities having non-congruent demand-resource balances are very cost efficient ways to acquire energy when needed, without capital investment. However, transmission availability limits the extent that this practice can be used. Also, in later years of the analysis, the supply of summer energy available for trade in an exchange may be insufficient unless there is some

modest investment in baseload generation and conservation that would increase energy availability in the summer.

5. When compared with the cost of generating resources, the level of cost-effective conservation is estimated to be just over 7 aMW per year.
6. In examining the possibility of altering the proportion of BPA products, additional restrictions on the monthly allocation of the BPA Block product were discovered, which led to the conclusion that reducing the proportion of City Light's BPA Slice product in favor of more Block product is not advantageous.

Round 2 Analysis

This section describes how City Light incorporated the findings of the Round 1 analysis in developing portfolios for Round 2, then describes the portfolios and gives the results of the portfolio evaluation based on the criteria of reliability, cost, risk and environmental impact.

Selecting Resources for Round 2

Based on the lessons learned in the Round 1 portfolio analysis, several decisions were made in developing Round 2 portfolios. Some resources were eliminated; choices were made about how market and generation resources would be used; some resources were included in all portfolios for the first nine years; several portfolios were designed to meet the requirements of Initiative 937; and two ways of phasing in conservation resources were included.

Resources Eliminated from Round 2

The two coal-fired generation technologies were eliminated from further consideration for several reasons. First, the environmental costs were high, given City policy to offset carbon dioxide emissions. Also, the Green World and Nuclear Resurgence scenarios suggest the risk of substantially higher costs of future carbon dioxide emissions. Second, the cost of new electric transmission capacity is high if the coal resources are located in Montana or Wyoming. Current transmission capacity is insufficient to bring new coal-fired generation west to Seattle. A third reason is related to scale. City Light's most pressing need is for seasonal resources, not large baseload generating plants.

Combined Heat and Power (CHP) and hydro efficiency upgrades both have desirable attributes, but were not included in Round 2 portfolios. The situational nature of these resources makes good information especially important. There is considerable uncertainty about potential amounts, costs and timing of these resources. A study of hydro efficiency upgrade potential for City Light is currently underway, but the results are not yet available. The cost and availability of both these resources will be further investigated in future updates of this Plan.

Use of Market and Generation Resources in Round 2

City Light's analysis shows that in the near-term years, the need for resources occurs only during the winter season. The acquisition of any year-round resource would add power during the rest of the year, and thus increase the market risk associated with disposing of surplus power. Therefore, Round 2 investigated seasonal power exchanges and call options, which are market resources that would help to match the resource profile to the load profile.

The best choices were seasonal exchanges and seasonal capacity contracts (physical call options). For City Light, seasonal exchanges are arrangements to receive power from a partner utility that has a winter surplus, and to deliver a like amount of power to the partner in the summer. The amount received is not necessarily exactly the same as the amount delivered.

A physical call option is an arrangement for the physical delivery of power under an agreed upon set of circumstances for an agreed upon price. The expectation is that the option would be exercised only when the Utility's other resources are hard-pressed to serve load. Such a circumstance would probably occur only during an extended cold spell combined with a prolonged drought. All Round 2 portfolios feature exchanges and call options in the near term.

Unless there is a substantial increase in conservation resources, City Light will need additional generating resources beginning in 2010. The Round 2 portfolios all have a landfill gas resource online in 2010, and six of them have 23 aMW of output from a hydro contract with another utility in 2012. As load continues to grow, the landfill gas contract increases and a variety of other resources, mainly renewable resources, are added to the portfolios. One exception is Portfolio 4, which features a simple-cycle combustion turbine (SCCT). The SCCT in this portfolio is run as a "peaker." That is, it is only run for short periods in order to meet peak load. Even though its cost per megawatt-hour is relatively high, it would only be run when market prices are even higher.

The First Nine Years

For the first nine years of the study (2007-2015), increases in energy requirements sufficient to meet the resource adequacy targets can be met with a combination of seasonal exchanges, conservation, short term call options and purchased power agreements. Certain cost-effective resources were identified as "lost opportunities." City Light believes there is a time-limited opportunity to develop these resources at relatively low cost compared to the market. These resources include landfill gas generation, a contract for existing hydro resources, call options and new seasonal exchanges.

A combination of exchanges, call options, landfill gas and a hydro contract outperformed all other resource combinations evaluated on costs for the period 2007-2015. Accordingly, the same three resources (with variations for conservation) were used in all Round 2 portfolios for the first nine years. Based upon a common set of "front-end" resources, the focus in Round 2 is on intermediate and long-term variations in resource portfolios.

Initiative 937 – Conservation and Renewable Resource Standard

Portfolios were developed before details of Washington State Initiative 937 were known. The initiative, approved by voters in November, establishes requirements for the acquisition of conservation and renewable resources by qualifying utilities. Because the outcome of the initiative was unknown at the time the Round 2 portfolios were designed, some portfolios were specifically designed to meet the requirements of Initiative 937, and others were not.

In designing the portfolios, City Light incorporated its understanding of the initiative as written, recognizing that a process to interpret the new law, would ensue if it were passed. Now that the initiative has been approved, clarification will occur in subsequent discussions and rulemaking by the State Department of Community, Trade, and Economic Development (CTED), which will oversee implementation. Failure to comply with initiative requirements results in a $50 fine for each megawatt-hour a utility is below the requirement.

Requirement to Purchase Renewable Resources

Initiative 937 has a large impact upon the design of future City Light resource portfolios. Most importantly, it requires more renewable resource purchases than current forecasts suggest will be needed after 2015. Portfolios that conform to Initiative 937 require the acquisition of new generating resources three to five years earlier than needed to meet the established resource adequacy target.

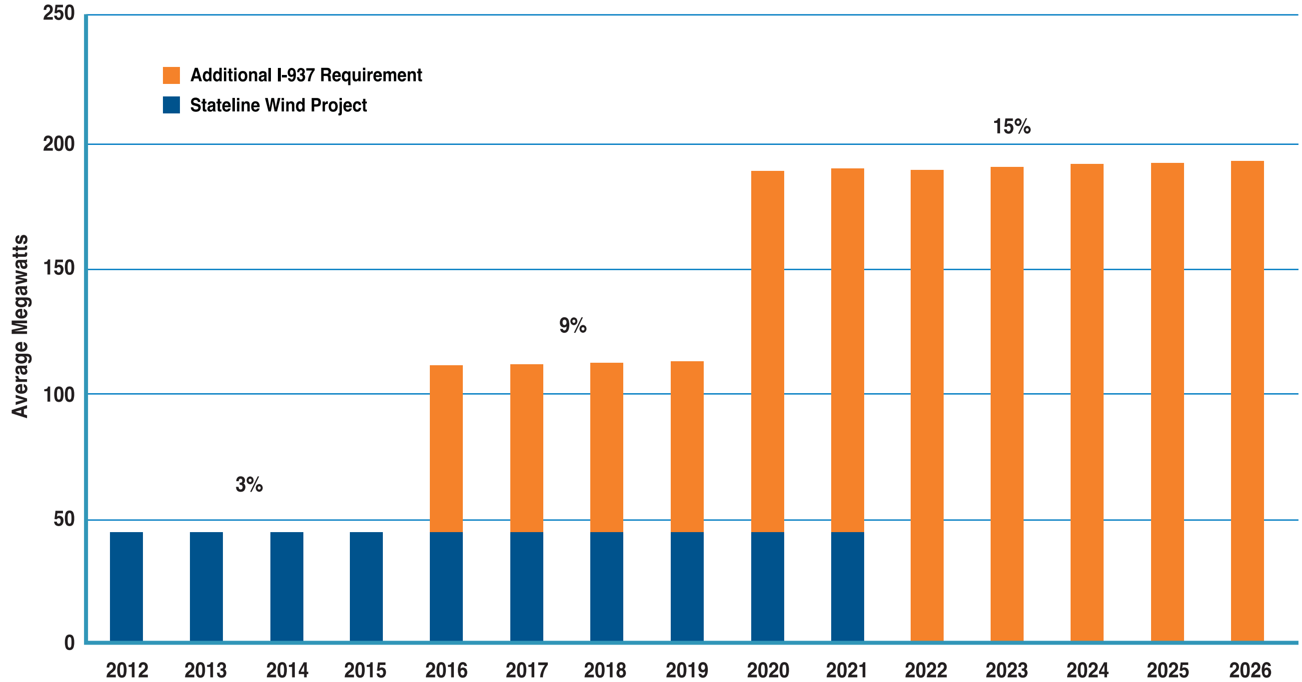
Adherence to Initiative 937 defines specific types of resources that can count toward the renewable resource requirement. For example, a cost-effective use of seasonal resource purchases or seasonal exchanges does not provide sufficient new renewable energy purchases to meet the percentage requirement of total year-round purchases. Substituting compliant resources for non-compliant resources on an accelerated schedule increases the costs of Initiative 937-compliant portfolios compared to the more seasonally tailored, non-compliant portfolios. For the most part, these incremental resource additions occur after 2015.

Following is a summary of the major components of the initiative that most affect City Light's resource planning: the requirement to purchase renewable resources, and options for compliance with the initiative.

The initiative requires that 3 percent of retail load be obtained from qualifying renewable energy by 2012, 9 percent by 2016 and 15 percent by 2020. Hydropower is not an eligible renewable resource, though certain efficiency upgrades are eligible. Based upon the current load forecast, it is estimated that City Light would need to acquire qualifying renewable resources beginning in 2016 in amounts shown in Figure 6-1: nearly 70 aMW in 2017-2019, about 145 aMW in 2020-2021, and about 190 aMW in 2022-2026.

Stateline Wind Project is expected to meet the 3 percent requirement from 2012 to 2016. The increase in the requirement from 145 to 190 average megawatts in year 2022 is caused by the expiration of the Stateline wind contract in 2021.

Figure 6-1. Renewable Resource Additions* Required Under Initiative 937



*Total annual difference compared to without Initiative 937.

Rate Increase Cap

If the difference between the cost of non-qualifying substitute resources and qualifying renewable resources has increased a utility's revenue requirement by 4 percent per year, the utility is considered in compliance. Given the renewable energy requirements, cost differentials, and typical financing mechanisms for new resources, it is not anticipated that City Light's renewable resource acquisitions would trigger this form of a 4 percent annual revenue requirement cap.

A utility may purchase Renewable Energy Credits (RECs) instead of qualifying renewable energy to be compliant with I-937. This compliance approach may be viable for City Light; however, future availability and cost for RECs are very uncertain. Many other Western states either have or will soon have renewable portfolio standards and can be in compliance using renewable resources from the Pacific Northwest. Some acquisitions of Pacific Northwest renewable resources by utilities outside the region have already begun, increasing uncertainty about future supplies and costs of RECs.

Conservation Acquisition Options

Although the specific rules for compliance with the Initiative 937 have not yet been established, discussions with the IRP Stakeholder group led to the assumption that the cost-effective constant pace of 7 aMW of conservation acquired annually is likely to meet I-937 requirements.

However, accelerating conservation acquisition was also examined in Round 2, to explore a potentially important strategy. City Light hypothesized that accelerating conservation could make a material difference in costs and offset the need for acquiring additional generating resources. Reducing retail demand with conservation also has the effect of reducing the I-937 requirements for purchasing new renewable generation, since the requirement is based upon a percentage of retail demand.

Three resource portfolios were designed with accelerated conservation. The results of modeling the accelerated conservation portfolios should be considered evidential, but non-conclusive. The modeling assumptions have several known, but unavoidable weaknesses. Foremost is that the same unit cost of conservation was applied to both the accelerated conservation portfolios and the constant rate of conservation portfolios. Although accelerating the pace of conservation activities is expected to result in higher unit costs, no study of the extent of these added costs was available.

To avoid bias, conservation modeling for the IRP is viewed from a total societal cost perspective and does not address who pays which conservation costs in what proportion. Thus, the analysis did not address whether or not City Light would need to offer expanded incentives to achieve the accelerated conservation, or what proportion of costs would be paid by the Utility and what proportion by customers.

The IRP does not address the feasibility and timing of new program designs required to achieve the accelerated conservation. Program designs and the practicalities of implementation are not typically within the scope of an IRP, where the focus is on resource strategies.

Round 2 Portfolios

The eight alternative portfolio designations are listed below, indicating those that meet the conservation and renewable resource requirements of Initiative I-937. The resources in each portfolio by 2026 are given in Table 6-11.

1. No Action - Rely on the Market
2. I-937 – Hydro, Wind (55) and Biomass (15)
3. I-937 – Hydro and Wind
4. Non-I-937 – Hydro and SCCT
5. Non-I-937 – Hydro and Wind
6. I-937 – Wind
7. I-937 – Hydro, Wind (105) and Geothermal (50)
8. I-937 – Hydro, Geothermal (100) and Wind (55)

Table 6-11. Total New Resources in Round 2 Portfolios
(Average Megawatts of Output, 2026)

Resource	Resource Portfolio							
	P1 Rely on Market	P2 I-937 Hydro, Wind, Biomass	P3 I-937 Hydro, Wind	P4 Non-I-937 Hydro, SCCT	P5 Non-I-937 Hydro, Wind	P6 I-937 Wind	P7 I-937 Hydro, Wind, Geothermal	P8 I-937 Hydro, Geothermal, Wind
Conservation		141	141	142	142	141	142	142
Exchange*		50	50	140	145	100	100	100
Call Option*		45	40	20	30	10		
Hydro Contract		23	23	23	23		23	23
Wind		55	50		20	50	105	55
Geothermal		100	125	50	75		50	100
Landfill Gas		25	25	25	25	25	25	25
Biomass		15					15	15
SC Turbine				50				
2026 Total	0	454	454	450	460	326	460	460

Portfolio 1: No Action – Rely on the Market

In the No Action portfolio, no new conservation or generation resources are acquired. Instead, all new power requirements are met with short-term purchases in the Western wholesale power market. Short-term (spot) market purchases are made at the forecasted market price, set by the marginal generating unit in the West. From an environmental perspective, this means that at any given time, air emissions will be driven by whatever generating unit is on the margin in the spot market at that point in time. Currently in the West, natural gas-fired generation is on the margin more than 90 percent of the time.

Portfolio 2: Hydro, Wind (55) and Biomass (15) – I-937

This portfolio meets the requirements of Initiative 937. Conservation is accelerated from the cost-effective constant rate. Seasonal exchanges and call options are used in order to meet the resource adequacy requirement in winter through 2009. After that, the Utility purchases the output from a landfill gas facility and enters into a contract with another regional utility to purchase a share of the output of an existing hydro facility. Farther out, a geothermal resource is added in 2016, and a wind resource replaces one of the seasonal exchanges in 2020, when a small biomass resource is also added. Table 6-12 shows the schedule for new resource acquisition through 2026.

Portfolio 3: Hydro and Wind – I-937

Through 2019, Portfolio 3 is similar to Portfolio 2. In 2020, the geothermal resource that begins in 2016 is increased five-fold, taking up some the slack from the elimination of one seasonal exchange. In 2022 50 aMW of wind generation is added. In order to meet resource adequacy in 2026, a physical call option is added. Table 6-13 shows the schedule for new resource acquisition through 2026.

Table 6-12. Hydro, Wind (55) and Biomass (15) – I-937
(Average Megawatts of Output, 2007-2026)

Resource (aMW)	Location	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Conservation	W. WA	7	15	24	34	45	55	66	76	87	98	108	119	129	131	132	134	136	138	139	141
Seasonal Exchange	Mid-C	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Seasonal Exchange	Mid-C		50	50	50	50	50	50	50	50	50	50	50	50							
Call Option	Mid-C			30	10			5													45
Landfill Gas	W. WA				10	10	10	10	10	25	25	25	25	25	25	25	25	25	25	25	25
Hydro Contract	Mid-C						23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Geothermal	W. WA										25	25	25	25	50	50	100	100	100	100	100
Wind	E. WA														55	55	55	55	55	55	55
Biomass	W. WA														15	15	15	15	15	15	15
Total		57	115	154	154	155	188	204	209	235	271	281	292	302	349	350	402	404	406	407	454

Table 6-13: Hydro and Wind – I-937
(Average Megawatts of Output, 2007-2026)

Resource (aMW)	Location	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Conservation	W. WA	7	15	24	34	45	55	66	76	87	98	108	119	129	131	132	134	136	138	139	141
Seasonal Exchange	Mid-C	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Seasonal Exchange	Mid-C		50	50	50	50	50	50	50	50	50	50	50	50							
Call Option	Mid-C			30	10			5													40
Landfill Gas	W. WA				10	10	10	10	10	25	25	25	25	25	25	25	25	25	25	25	25
Hydro Contract	Mid-C						23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Geothermal	W. WA										25	25	25	25	125	125	125	125	125	125	125
Wind	E. WA																50	50	50	50	50
Total		57	115	154	154	155	188	204	209	235	271	281	292	302	354	355	407	409	411	412	454

Portfolio 4: Hydro and SCCT – Non-I-937

Portfolio 4 is similar to Portfolios 2 and 3 through 2014. A small amount of geothermal is added in 2015, and doubled in 2021. In 2019, a simple cycle combustion turbine (SCCT) is added. This resource would be run as a "peaker;" that is it would only be run during peak demand hours when market prices are high. A third seasonal exchange is added in 2022, and both of the earlier exchanges continue through to the end of the planning period. This is the only portfolio that has a fossil fuel resource, and does not comply with I-937. Table 6-14 shows the schedule for new resource acquisition through 2026.

Portfolio 5: Hydro and Wind – Non-I-937

Portfolio 5 is similar to Portfolio 4, but instead of a SCCT, it uses a combination of expanded geothermal and a small amount of wind in the later years. Like Portfolio 4, this portfolio adds a small amount of geothermal in 2015, but instead of an SCCT in 2019, the geothermal resource is expanded, followed by the addition a third seasonal exchange in 2021 and a small amount of wind resource in 2022. In certain years, there are call options to assure that the resource adequacy target is met. Portfolio 5 also does not meet I-937 requirements, even though it does not include any fossil fuel resources. Table 6-15 shows the schedule for new resource acquisition through 2026.

Table 6-14. Hydro and SCCT – Non-I-937
(Average Megawatts of Output, 2007-2026)

Resource (aMW)	Location	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Conservation	W. WA	7	14	21	28	36	43	50	57	64	71	78	85	93	100	107	114	121	128	135	142
Seasonal Exchange	Mid-C	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Seasonal Exchange	Mid-C		50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Call Option	Mid-C			30				5													20
Landfill Gas	W. WA				25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Hydro Contract	Mid-C						23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Geothermal	W. WA									25	25	25	25	25	25	50	50	50	50	50	50
SCCT	W. WA													50	50	50	50	50	50	50	50
Seasonal Exchange	Mid-C																40	40	40	40	40
Total		57	114	151	153	161	191	203	205	237	244	251	258	316	323	355	402	409	416	423	450

Table 6-15. Hydro and Wind – Non-I-937
(Average Megawatts of Output, 2007-2026)

Resource (aMW)	Location	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Conservation	W. WA	7	14	21	28	36	43	50	57	64	71	78	85	93	100	107	114	121	128	135	142
Seasonal Exchange	Mid-C	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Seasonal Exchange	Mid-C		50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Call Option	Mid-C			30				5				5		15	10	10	5				30
Landfill Gas	W. WA				25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Hydro Contract	Mid-C						23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Geothermal	W. WA									25	25	25	25	50	50	50	75	75	75	75	75
Seasonal Exchange	Mid-C															45	45	45	45	45	45
Wind	E. WA																20	20	20	20	20
Total		57	114	151	153	161	191	203	205	237	244	256	258	306	308	360	407	409	416	423	460

Portfolio 6: Wind – I-937

Like Portfolios 2 and 3, Portfolio 6 complies with the requirements of I-937 and has accelerated conservation. It differs from them by adding a larger amount of the landfill gas resource in 2010, and it does not include a hydro contract. It starts with a small amount of geothermal in 2016, which is quadrupled in 2019, and increased yet again in 2025. Beginning in 2022, a wind resource is added. Table 6-16 shows the schedule for new resource acquisition through 2026.

Portfolio 7: Hydro, Wind (105) and Geothermal (50) – I-937

Portfolio 7 has the more wind generation than any of the other portfolios. This wind resource is not added until 2019, but it doubles in 2022. Conservation is acquired at a constant rate of 7 aMW per year. A small amount of geothermal is added in 2015, and doubles in 2020. In 2016 a small amount of biomass is added. Table 6-17 shows the schedule for new resource acquisition through 2026.

Table 6-16. Wind – I-937
(Average Megawatts of Output, 2007-2026)

Resource (aMW)	Location	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Conservation	W. WA	7	15	24	34	45	55	66	76	87	98	108	119	129	131	132	134	136	138	139	141
Seasonal Exchange	Mid-C	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Seasonal Exchange	Mid-C		50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Call Option	Mid-C			30				10		15											10
Landfill Gas	W. WA				25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Geothermal	W. WA										25	25	25	100	100	100	100	100	100	125	125
Wind	E. WA																50	50	50	50	50
Total		57	115	154	159	170	180	201	201	227	248	258	269	354	356	357	409	411	413	439	451

Table 6-17. Hydro, Wind (105) and Geothermal (50) – I-937
(Average Megawatts of Output, 2007-2026)

Resource (aMW)	Location	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Conservation	W. WA	7	14	21	28	36	43	50	57	64	71	78	85	93	100	107	114	121	128	135	142
Seasonal Exchange	Mid-C	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Seasonal Exchange	Mid-C		50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Call Option	Mid-C			30				5													
Landfill Gas	W. WA				25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Hydro Contract	Mid-C						23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Geothermal	W. WA									30	30	30	30	30	50	50	50	50	50	50	50
Biomass	W. WA										15	15	15	15	15	15	15	15	15	15	15
Wind	E. WA													55	55	55	105	105	105	105	105
Total		57	114	151	153	161	191	203	205	242	264	271	278	341	368	375	432	439	446	453	460

Table 6-18. Hydro, Geothermal (100) and Wind (55) – I-937
(Average Megawatts of Output, 2007-2026)

Resource (aMW)	Location	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Conservation	W. WA	7	14	21	28	36	43	50	57	64	71	78	85	93	100	107	114	121	128	135	142
Seasonal Exchange	Mid-C	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Seasonal Exchange	Mid-C		50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Call Option	Mid-C			30				5													
Landfill Gas	W. WA				25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Hydro Contract	Mid-C						23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Geothermal	W. WA									30	30	30	30	50	50	50	100	100	100	100	100
Biomass	W. WA										15	15	15	15	15	15	15	15	15	15	15
Wind	E. WA														55	55	55	55	55	55	55
Total		57	114	151	153	161	191	203	205	242	264	271	278	306	368	375	432	439	446	453	460

Portfolio 8: Hydro, Geothermal (100) and Wind (55) – I-937

Portfolio 8 relies on geothermal rather than wind in the final five years of the planning period. In 2019, the geothermal resource is doubled, and then doubled again in 2022. A small amount of wind is added in 2020. Conservation is acquired at a constant rate of 7 aMW per year. Table 6-18 shows the schedule for new resource acquisition through 2026.

Evaluation of Round 2 Portfolios

Round 2 portfolios were evaluated using the same criteria as the Round 1 portfolios: reliability, cost, risk and environmental impact. In addition, further qualitative screens were applied based upon prudent operational strategy and the requirements of Initiative 937, as described above.

Reliability

All resource portfolios in Round 2 meet the resource adequacy target. This criterion is "hard-wired" into each of the resource portfolios, since each resource portfolio is specifically designed to meet the reliability criteria.

Cost

Differences in generation strategies are most pronounced late in the planning period, creating most of the cost variation among portfolios. Beyond 2016, I-937 requirements are likely to drive the amount of resource additions, since they exceed the Utility's forecasted resource adequacy requirements. The major difference in the non-compliant portfolios (P4, P5) is that they are less capital-intensive and more tailored to seasonal demand, leading to lower net power costs. All non-compliant portfolios were dropped from consideration after approval of I-937 in the November 2006 election.

The accelerated conservation portfolios (P2, P3, P6) examine a potentially important strategy for complying with I-937. As explained above, these portfolios are likely to overestimate the benefits of accelerating conservation, because the full costs of accelerating conservation have not been determined. Nonetheless, it was deemed useful to explore the concept of accelerating conservation to see if it could be a wise resource strategy under I-937. While the results of modeling the accelerated conservation portfolios cannot be viewed as definitive, they strongly suggest that further investigation of this strategy is merited. Conceptually, accelerating conservation leads to reducing costs in all three of the portfolios tested by over $100 million NPV during the entire 20-year period.

The wind-dominant Portfolio 7 and the geothermal-dominant Portfolio 8 are the two main candidates for meeting I-937 requirements in the 2006 IRP. Portfolio 7 requires more capital costs for plant and transmission and has higher variable operation and maintenance costs. Table 6-19 highlights comparable costs, displaying the most important differences between the portfolios.

Table 6-19. Cost Comparison of Round 2 Portfolios

20-yr. NPV of Costs ($1000s)	P2 Accelerated Conservation	P3 Accelerated Conservation	P4 Not I-937 Compliant	P5 Not I-937 Compliant	P6 Accelerated Conservation	P7 I-937 Compliant	P8 I-937 Compliant (Preferred)
Generation PPA	$ 716,103	$ 745,895	$452,503	$522,619	$596,466	$ 830,573	$ 783,065
Conservation	$ 262,900	$ 262,900	$222,123	$222,123	$262,900	$ 222,123	$ 222,123
Transmission	$ 21,411	$ 19,381	$ 12,011	$ 16,775	$ 12,042	$ 31,444	$ 21,487
Total Cost	$1,000,414	$1,028,176	$686,637	$761,517	$871,408	$1,084,140	$1,026,676
Wholesale Revenue (minus)	$ 941,576	$ 959,266	$741,483	$745,091	$813,909	$ 865,909	$ 855,740
Net Power Cost	$ 58,838	$ 68,910	($ 54,846)	$ 16,426	$ 57,499	$ 218,231	$ 170,936

The capacity factor of geothermal energy (95 percent) affects both Purchased Power Agreement (PPA) costs and the transmission costs. The high capacity factor helps to lower average costs of production for geothermal. Transmission for geothermal resources is expected to require less construction of new transmission assets because of shorter distances to Seattle. It is also expected to have a lower cost per megawatt-hour for firm transmission than wind resources, again because of the higher capacity factor. Wholesale revenues for Portfolio 7 are $10 million (NPV) higher, but not enough to offset the cost advantages of Portfolio 8. Portfolio 8 has a net power cost NPV that is $47 million lower than Portfolio 7.

Risk

Two measures of risk were used to evaluate resource portfolios, based upon Monte Carlo analysis (see Chapter 5). The coefficient of variation measures deviation from the mean of a sampled population under different stochastic conditions. A second measure is the value at the 5 percent and 95 percent tails of the probability distribution. This measure illustrates the severity of changes under rare circumstances, on the borders of the planning envelope. The range of the values can give useful information about the "downside" and "upside" of a particular variable.

For both of these risk measures, the portfolios in Round 2 show few differences. The reason is straightforward. The Round 2 portfolios are almost entirely comprised of conservation and renewable resources. Only Portfolio 4 has a fossil-fueled resource: a natural gas-fired, simple cycle turbine.

Fossil fuels, particularly natural gas, are subject to significant price uncertainty that can lead to material differences in risk exposure between portfolios, as seen in the Round 1 analysis. An absence of fossil fuels and reliance on renewable resources in Round 2 leads to mainly insignificant differences in risk exposure between the portfolios in the base forecast. For a discussion of the performance of Round 2 portfolios in the future scenarios described in Chapter 5, see Appendix D.

For generating resources, a distinguishing risk factor is often the variable costs of operation. Variable costs in the table below are comprised of variable O&M, start-up costs, fuel costs, and CO2 offset costs. Table 6-20 displays the coefficient of variation for variable costs in Round 2 portfolios, as well as the 5 percent and 95 percent tails of the variable cost probability distribution.

Table 6-20. Variable Cost Risk Measures for Round 2 Portfolios

	Coefficient of Variation	P = .05*	P = .95*
P2	77%	$171,562	$195,845
P3	77%	$207,071	$212,490
P4	81%	$125,893	$180,744
P5	81%	$132,776	$135,072
P6	79%	$181,051	$183,956
P7	79%	$195,689	$227,531
P8	80%	$203,754	$234,559

*NPV in thousands of dollars, 3% real discount rate.

While the coefficient of variation measure indicates little relative differentiation between the portfolios, the 5 percent and 95 percent tails display some interesting differences. Portfolio 4 has by far the widest range of variable costs, indicating the highest risk. It contains 50 aMW of natural gas-fired combustion turbine generation, with all other portfolios containing only renewable resources. Fuel brings most of the risk to Portfolio 4 variable costs.

The portfolios with accelerated conservation also have a relatively low range of variable costs. They require less generating resources, helping to minimize the range of variable costs. Portfolios 7 and 8 have approximately the same degree of risk associated with variable costs.

Environmental Impacts

The Draft EIS provided an extensive review of impacts to air, land, water, aesthetics and the economy for all Round 1 portfolios. In Round 2, Portfolios 7 and 8 emerged as the most promising of the seven portfolios examined, so the Final EIS focuses on these two portfolios.

For all Round 1 and Round 2 portfolios, air emissions were measured for carbon dioxide, sulfur dioxide, nitrogen oxide, mercury and particulates. Control costs for these emissions serve as a proxy for environmental impacts to the air.

Carbon Dioxide Emissions

In evaluating air emissions, carbon dioxide dominates the control cost financial measure used in the analysis. It is also important in evaluating greenhouse gas offset costs that would be incurred under City of Seattle policy. Table 6-21 shows the total tons of carbon dioxide emissions expected from each Round 2 resource portfolio over the 20-year planning period.

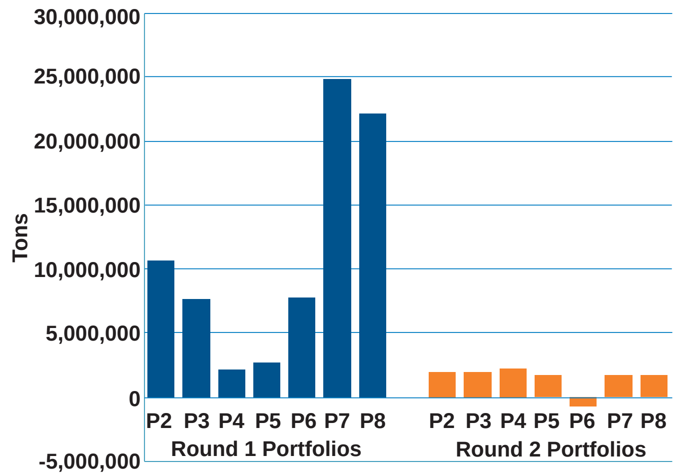
Table 6-21. Carbon Dioxide Emissions for Round 2 Portfolios, 2007-2026

Portfolio		Tons of CO2
P2	Hydro, Wind (55) and Biomass (15)	1,967,686
P3	Hydro and Wind	1,967,686
P4	Hydro and SCCT	2,245,312
P5	Hydro and Wind	1,695,872
P6	Wind	(712,067)
P7	Hydro, Wind (105) and Geothermal (50)	1,732,147
P8	Hydro, Geothermal (100) and Wind (55)	1,732,147

Carbon dioxide emissions in Round 2 portfolios are caused by market purchases and hydro contracts from existing resources. Market purchases are assessed carbon dioxide emissions at the rate of the marginal unit in the Western market, typically a natural gas-fired turbine. The hydro contract is assessed carbon dioxide emissions under the premise that utilizing an existing hydro resource from another utility will force another potential buyer to go into the market for an equivalent amount of energy. Portfolio 6 has the lowest carbon dioxide emissions, simply because it does not have a hydro contract.

In general, the emissions in Round 2 portfolios are substantially lower than Round 1 portfolios as a result of portfolio design. Figure 6-2 compares 20-year total carbon dioxide emissions for Round 1 and Round 2 portfolios.

Figure 6-2. Carbon Dioxide Emissions – Round 1 and Round 2 Portfolios (2007-2026)*



*This graph illustrates the relative difference between Round 1 and Round 2 portfolios. Specific portfolios are not directly comparable.

Other Environmental Impacts

Other environmental impacts of Portfolios 7 and 8 were also examined in the Final EIS.

Both portfolios contain landfill gas and biomass resources. Landfill gas generation is fueled by methane seeping from landfills, reducing emissions of this extremely potent greenhouse gas. Biomass generation is assumed to be carbon dioxide neutral, since it is fueled by plants or wood waste that has captured the carbon dioxide. In combination, these two resources are expected to emit approximately 992 tons of nitrogen oxides and 183 tons of particulate matter over a 20-year period in each portfolio. While these emissions are low compared to many fossil fuel generation plants, landfill gas and biomass are not free of emissions.

Geothermal resources, featured in Portfolio 8, can impact aesthetics if they are sited in or near pristine areas, and they can also affect groundwater. Wind resources, featured in Portfolio

7, can impact aesthetics and bird mortality. For a thorough discussion of the environmental impacts of Portfolios 7 and 8, see the Final EIS, online at **http://www.seattle.gov/light/news/issues/irp/**.

The Preferred Portfolio

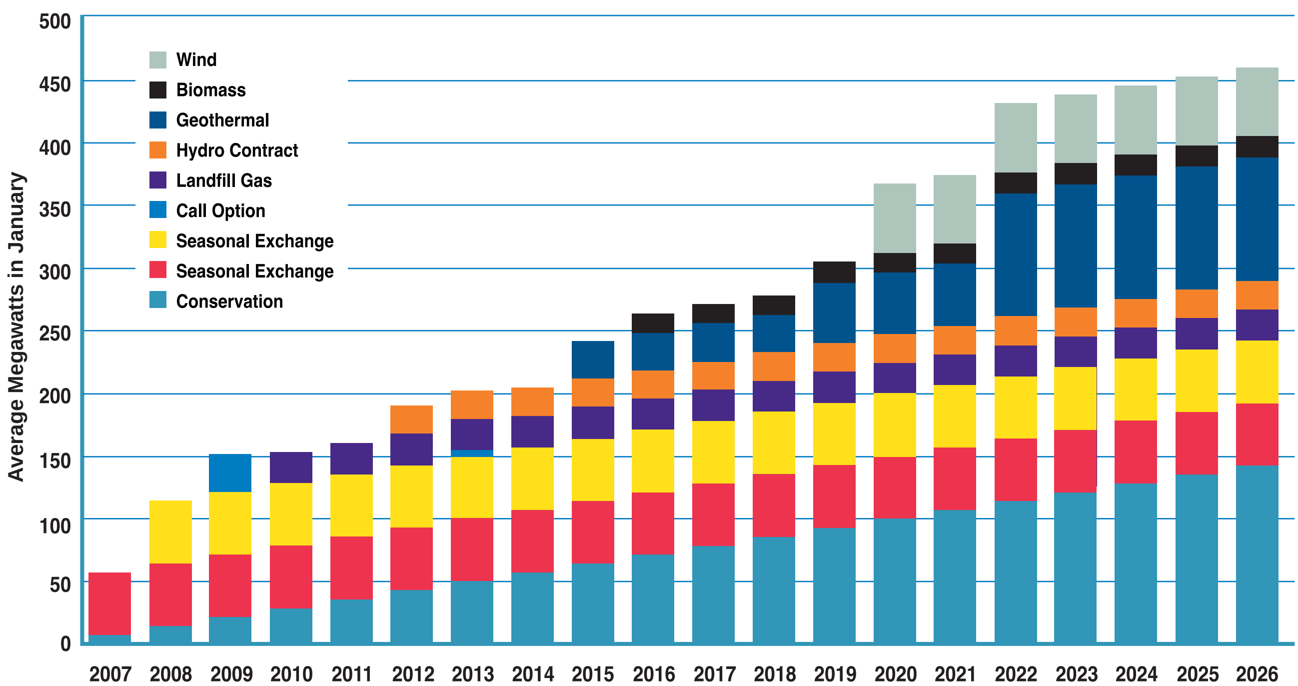
Both Portfolios 7 and 8 meet Initiative 937 requirements, satisfy the prescribed level of resource adequacy, and uphold a longstanding commitment to conservation. In the first nine years, these two portfolios call for:

- Continued acquisition of cost effective conservation at a rate of 7 aMW per year.
- Two low-cost seasonal exchanges to better match the shape of resources to load.
- Seasonal capacity contracts (physical call options) when advantageous.
- Output from a landfill gas facility.
- Output from an existing hydro facility.

After the first nine years, Portfolio 7 opts for greater use of wind resources, while Portfolio 8 opts for greater use of geothermal resources. Both wind and geothermal resources are "scalable." They can be gradually developed at the same location according to the timing of the need. This allows for cost efficiencies from improved timing and scale of resource additions, reduced development costs, and the ability to more fully utilize transmission and substations interconnections.

Comparing Portfolios 7 and 8 on the four evaluative criteria, Portfolio 8 has $47 million lower NPV of costs. It has slightly lower risk, the same degree of reliability, and there is no significant difference in environmental performance. Portfolio 8 is the preferred portfolio, shown in Figure 6-3.

Figure 6-3. Preferred Portfolio



Chapter 7 – The Action Plan: Powering Seattle for the Future

This Integrated Resource Plan (IRP) presents a course of action that utilizes the best information available. The Plan meets the overall objective of determining strategies for the type, amount and timing of new resource acquisitions to meet electrical load over the 20 years between 2007 and 2026.

The preferred portfolio satisfies the criteria established at the beginning of the planning process: reliability of service, reasonable costs, reasonable risks and limited environmental impacts. The preferred portfolio:

- Focuses on improving City Light's seasonal resource balance in the short term, thus avoiding the costs of major resource additions early in the planning period.
- More clearly identifies the reliability risk inherent in the current resource mix and provides a plan of action to mitigate that risk.
- Considers the risks attributable to new resources when evaluating them for the Plan.
- Clearly identifies the environmental impacts of resources and portfolios in the Plan, in terms of the emissions of air pollutants and impacts to land, water, wildlife and aesthetics.

Any 20-year plan faces many uncertainties and this is particularly true in an environment as dynamic and volatile as energy markets. The intent of the IRP is not to lock the City of Seattle or City Light into a 20-year course of action. Rather, the Plan provides long-term strategic direction for resource acquisition and a short-term action plan to begin moving in that direction.

City Light confronts a wide range of challenges in meeting its mission of providing stable, competitively priced and environmentally sound electricity to customers. These challenges require many decisions each year, large and small, related to power resources. Creating a long-term resource plan provides the framework for a short-term action plan that will help guide the Utility on a path that brings long-term resource benefits to customers.

Action Plan

This section describes City Light's action plan as related to resource acquisition, transmission and planning. Major elements of the Action Plan include:

Resource Acquisition

- Continue to acquire conservation resources
- Investigate new generating resources
- Evaluate and acquire cost-effective "lost opportunity" resources

Transmission

- Ensure adequate transmission capacity to meet resource needs

Planning

- Explore, monitor and evaluate potential future technologies and resources
- Enhance IRP analytical capabilities
- Keep the IRP up-to-date with new information

Resource Acquisition

Conservation

City Light began acquiring conservation resources over 25 years ago. Conservation has proven to be a good investment and City Light will continue to pursue the acquisition of cost-effective conservation.

While the cost and environmental benefits of conservation are well known, one benefit of conservation may have gone relatively unnoticed. As the Pacific Northwest's population and energy consumption grew, regional electric transmission facilities did not keep pace. Today, Seattle faces significant limitations on future use of long distance, high voltage electric transmission to access new resources. Large investments in new transmission infrastructure will be required to overcome these limitations. In a transmission-constrained future, conservation becomes more cost-effective and pragmatic as a resource. Expanding transmission infrastructure takes many years and depends upon the close cooperation of a variety of governmental agencies and electric utilities. However, the citizens of Seattle can directly control acquisition of conservation resources.

In the 2006 IRP, the Round 2 analysis identified acceleration of conservation programs as a promising resource strategy. However, additional information on costs and feasibility is needed. As part of the 2006 IRP Action Plan, a study of the costs, benefits and feasibility of accelerating conservation is recommeneded.

Generation

The IRP makes many assumptions about the availability and costs of generic resources. Implementation of the Plan requires confirming resource availability and costs for specific opportunities. If the specific resource opportunities from real world suppliers do not match the IRP assumptions, the Plan must be adjusted to more accurately reflect the costs and characteristics of the resources that are actually available.

Lost Opportunities

The 2006 IRP identifies "lost opportunity" resources including seasonal exchanges, seasonal capacity contracts, landfill gas and a contract with an existing hydro facility. These opportunities may be lost if they are not acted upon within a certain time frame and will require prompt investigation. This can mean acquiring resources ahead of schedule, if it is more cost-effective to do so than to acquire a higher cost resource at a later time.

Investigation and monitoring of new resource technologies is also important to keep abreast of future resource opportunities. Technological advancement and economies of scale can expand future choices for cost-effective and environmentally responsible resources.

During the 2006 IRP, City Light identified potential generation efficiency upgrades at its Skagit River hydroelectric facilities. Because of uncertainty about development costs, this resource was not included in the Round 2 portfolios. However, if studies prove these upgrades to be cost-effective, they can be evaluated in the context of the next IRP.

Transmission

Adequate transmission capacity can reduce the costs of new resources by allowing more seasonal exchanges and power purchases, thereby reducing the amount of generation reserves that would otherwise be necessary. Important decisions to expand regional transmission facilities in the Pacific Northwest will be made well within the 20-year time frame of this Plan. City Light will work to ensure the availability of adequate transmission facilities that are critical to Seattle's electricity supply, reliability, cost and energy policy objectives.

Future Integrated Resource Planning

Improving information and planning capabilities can enhance the quality of information available to City policy-makers and facilitate better long-term decision-making, lower costs and reduced risk.

This 2006 IRP sets the long-term strategic direction for how City Light will meet future growth in electricity demand for Seattle. However, the Plan is not etched in stone, nor should it be. Many assumptions about the future are used in the Plan. While City Light sought to use the best information and analytical methods available for the 2006 IRP, it is impossible to correctly forecast all aspects of a dynamic market, operating and technological environment. Accordingly, City Light will formally update the Plan every two years.

City Light will continue to develop and refine its modeling tools and assumptions for use in future resource planning. Demand forecasts will be prepared and updated routinely and new information on resource costs and availability will be collected. City Light will also participate in regional planning forums on topics such as resource adequacy, integration of wind resources, regional transmission planning and expansion and rule-making for Initiative 937.

During the 2006 IRP process, public input identified issues that will require further research. These included the impacts of climate change on City Light operations and distributed generation. City Light will continue to work on these topics in the upcoming IRP.

Two Year Action Plan Summary (2007-2008)

Table 7-1 summarizes the two-year action plan for the 2006 IRP.

Table 7-1. IRP Action Plan, 2007-2008

Actions	2007	2008
Conservation Resources		
Acquire cost-effective conservation in the targeted amounts.	7 aMW by end of 4th Qtr	7 aMW by end of 4th Qtr
Investigate methods and costs of accelerating conservation resources.	Investigate delivery costs and methods by year end	Include in IRP
Generation Resources		
Investigate costs and availability of planned resources.	Go/no go decision on landfill gas by year end.	Negotiate contracts as needed.
Market Resources		
Investigate and acquire seasonal exchanges and/or seasonal market purchases to offset near-term reliability risk.	Additional 50 aMW as needed	Additional 50 aMW as needed
Other New Resources		
Collect and update information on costs of a wide range of new resources commercially available by June 2008.	Ongoing	Finalize assumptions by May for 2008 IRP
Investigate the development status, costs and commercial availability of new resource technologies.	Ongoing	Ongoing
Investigate the cost-effectiveness of hydro efficiency measures and other steps to improve Skagit output.	Further investigate Gorge Tunnel economics	Decision on inclusion in 2008 portfolios
Transmission		
Work to ensure adequate transmission to support reliable service to existing and future load needs.	Ongoing	Ongoing
Future IRPs		
Continue to refine assumptions, forecasts and modeling.	Ongoing	Ongoing
Monitor development of regional resource adequacy standards.	Ongoing	Ongoing
Assess the impacts of climate change on operations and load in greater depth.	By year end	Reflect in 2008 IRP
Evaluate distributed generation opportunity and distribution savings potential.	Conclusions by year end	Incorporate conclusions into 2008 IRP
Update the demand outlook and estimate of resource adequacy.	Results by year end	Use demand forecast for 2008 IRP
Prepare IRP Update and any EIS update.	Initiate studies and investigations listed above.	Complete 2008 IRP
File IRP with the Department of Community, Trade and Economic Development (CTED) according to administrative rules.		File IRP by September 2008

Acronyms

aMW	Average megawatt
BPA	Bonneville Power Administration
CCCT	Combined-Cycle Combustion Turbines
CDEAC	Clean and Diversified Energy Advisory Committee (Western Governors)
CHP	Combined Heat and Power (Cogeneration)
CPA	Conservation Potential Assessment
CTED	Community, Trade, and Economic Development (Washington State)
DOE	Department of Energy (Federal)
EFSEC	Energy Facility Site Evaluation Council (Washington State)
FERC	Federal Energy Regulatory Commission
GED	Global Energy Decisions (consultants hired by Seattle City Light to assist with the modeling of portfolios)
GCPHA	Grand Coulee Project Hydroelectric Authority
GW, GWh	Gigawatt, gigawatt-hour
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Plan
KW, KWh	Kilowatt, kilowatt-hour
LNG	Liquified Natural Gas
Mid-C	Mid-Columbia
MW, MWh	Megawatt, Megawatt-hour
NCPA	Northern California Power Agency
NERC	North American Electric Reliability Council
NPCC	Northwest Power and Conservation Council
NPV	Net Present Value
OATT	Open Access Transmission Tariff
O&M	Operations and Maintenance
PPA	Purchased Power Agreement
PTC	Production Tax Credit
PUD	Public Utility District
PURPA	Public Utility Regulatory Policy Act (Federal)
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standard
SCCT	Simple Cycle Combustion Turbines
WECC	Western Electricity Coordinating Council

Glossary

Average Megawatt (aMW)

Average energy output over a specified time period (total energy in megawatt-hours divided by the number of hours in the time period).

Baseload Resource

A resource that runs continuously except for maintenance and scheduled or unscheduled outages.

Biomass

Plant material used as a fuel or energy source; e.g. logging or mill residues, urban wood waste and construction debris, dedicated wood or agricultural crops, and agricultural waste.

Biogas

Methane and other combustible gases released from decomposition of organic materials.

Block Product

City Light acquires power under its contract with Bonneville Power Administration in two forms: Block and Slice. The Block product is a fixed amount of power per month delivered at a constant rate through the month. (See also "Slice Product".)

Bonneville Power Administration (BPA)

A power marketing and electric transmission agency of the United States government headquartered in Portland, Oregon. BPA owns and operates the regional transmission system and markets power from the Federal Columbia River Power System. BPA is by far the largest provider of power and transmission services in the Northwest region. City Light buys over 40 percent of its firm power and most of its transmission from BPA.

Capacity Factor

The portion of full generation capacity that is actually used on average over a specified period of time. Wind facilities, for example, use about 32% of their full generation capacity over the period of a year.

Cogeneration

The multiple use of one energy source, such as the use of steam to generate electricity or power machinery as well as to provide heat. The simultaneous production and use of heat and electricity. Also referred to as Combined Heat and Power (CHP).

Combined-Cycle Combustion Turbine (CCCT)

A simple cycle combustion turbine with a heat recovery unit added. The heat recovery system recovers waste heat from the combustion turbine and uses it to create steam for additional electricity generation. A combined-cycle turbine operates most efficiently when it is run for long periods of time without being ramped up and down.

Conservation

The reduction of electric energy consumption as a result of increases in the efficiency of production, distribution and end use.

Demand

The rate at which electric energy is delivered to or by a system at a given instant; usually expressed in megawatts.

Dispatchable Resource

A resource whose electrical output can be controlled or regulated to match the instantaneous electrical energy requirements of the electric system.

Distribution System

The utility facilities that distribute electric energy from convenient points on the transmission system to customers.

Economic Dispatch

In electrical system operations modeling, the selection of the least-cost resource under a prescribed set of conditions.

Environmental Impact Statement (EIS)

A written analysis of the environmental impacts to be anticipated from a proposed construction activity (e.g. a power plant or electric transmission line, or programmatic activity). An EIS may be required by the National Environmental Policy Act (NEPA) and/or the Washington State Environmental Policy Act (SEPA) as part of the environmental review of proposed activities, including approval of plans by governmental agencies.

Federal Energy Regulatory Commission

The division of the United States Department of Energy that is responsible for regulating power generation and licensing hydroelectric dams and other generation.

Generation Capacity

The maximum amount of power that a generator can physically produce.

Geothermal Energy

Energy derived from heat deep beneath the earth's surface generated from hot rock, hot water or steam.

Gigawatt (GW) and Gigawatt-Hour (GWh)

A gigawatt is a unit of power equal to 1 billion watts, 1 million kilowatts, or 1,000 megawatts. A gigawatt-hour (GWh) is a measure of electric energy equal to one gigawatt of power supplied to or taken from an electric circuit for one hour.

Hydro Resources

Facilities used to produce electricity from the energy contained in falling water (river, locks or irrigation systems).

Integrated Resource Planning

A planning approach that projects the amount of new electricity generation and conservation needed to meet future loads by considering a range of power resource alternatives and future conditions, and using evaluative criteria including but not limited to minimizing cost.

Landfill Gas

Gas generated by the natural degrading and decomposition of municipal solid waste by anaerobic microorganisms in sanitary landfills. The gases produced, carbon dioxide and methane, can be collected by a series of low-level pressure wells and can be processed into a medium Btu gas that can be burned to generate steam or electricity.

Levelized Cost

The present value of a resource's cost (including capital, interest and operating costs) converted into a stream of equal annual payments and divided by annual kilowatt-hours saved or produced. For example, the amount borrowed from a bank is the present value of buying a house; the mortgage payment including interest on a house is the levelized cost of that house.

Load

The amount of electric power delivered or required at any specified point or points on a system. Load originates primarily at the power-consuming equipment of the customer.

Load Forecasting

The procedures used to estimate future consumption of electricity. Load forecasts are developed either to provide the most likely estimate of future load or to determine what load would be under a set of specific conditions; e.g., extremely cold weather, high rates of inflation or changes in electricity prices.

Load Profile or Shape

A curve on a chart showing power supplied plotted against time of occurrence to illustrate the variance in load in a specified time period.

Megawatt (MW) and Megawatt-Hour (MWh)

One thousand kilowatts, or 1 million watts; the standard measure of electric power plant generating capacity. A megawatt-hour (MWh) is a measure of electric energy equal to one megawatt of power supplied to or taken from an electric circuit for one hour.

Peak Capacity

The maximum output of generating plant or plants during a specified peak-load period.

Peak Demand

The maximum demand imposed on a power system or system component during a specified time period.

Peak Power

Power generated by a utility system component that operates at a very low capacity factor; generally used to meet short-lived and variable high demand periods.

Physical Call Option

A contractual agreement with a power generator to deliver power only when requested, at a pre-arranged cost per megawatt-hour.

Portfolio

A set of power supply resources currently or potentially available to a utility. Used in the IRP to mean alternative sets of resources that could be added to existing resources to meet expected future need. City Light's current portfolio consists primarily of hydroelectric resources (86 percent) with small amounts of conservation, wind, natural gas, nuclear and other resources such as coal, biomass and petroleum.

Resource Mix

The different types of resources that contribute to a utility's ability to generate power to meet its loads.

Reference Case

Forecast conditions related to fuel prices, resource supply and electricity prices that GED believes to be most likely.

Renewable Resource

A resource whose energy source is not permanently used up in generating electricity. As defined by the Pacific Northwest Electric Power Planning and Conservation Act, a resource that uses solar, wind, hydro, geothermal, biomass, or similar sources of energy to either generate electric power or reduce the customer electric power requirements.

Reserve Requirement

The requirement that a utility have capacity at its disposal that exceeds its expected peak demand by a certain percentage.

Resource Adequacy

A measure defining when a utility has sufficient resources to meet customer needs under a range of conditions that affect supply and demand for electricity. For this IRP, City Light has set a resource adequacy standard of 95 percent, meaning a 95 percent probability that all energy needs will be met.

Scenario

A possible course of future events. In the IRP, scenarios are used to compare portfolios of different energy resources under a range of possible future conditions other than the baseline forecast.

Seasonal Exchange

An agreement between two electricity suppliers to send each other electricity at different times, so they can shape their resources to fit customer demand. Such agreements work best between suppliers whose peak demands occur in different seasons. For example, City Light usually has surplus energy during the summer while its heaviest load is in the winter. Other utilities have load or resource profiles that are the reverse of City Light's, with peak demand in the summer.

Shaping

Configuring a resource portfolio so power generation capability and delivery of purchased power closely matches changes in demand over time. Shaping can help to avoid unnecessary costs and the need to sell surplus power.

Simple Cycle Combustion Turbine (SCCT)

A natural gas-fired turbine (similar to a jet engine) used to drive an electric generator. Combustion turbines, because of their generally rapid firing time, are designed for meeting short-term peak demands placed on power distribution systems. They are frequently ramped up and down as needed.

Slice Product

City Light acquires power under its contract with BPA in two forms: Block and Slice. The Slice product is an amount of power that varies year to year according to the amount of water flowing through the BPA hydroelectric system. In a good water year (above average precipitation), more power is delivered to the same customer than in a poor water year (below average precipitation). (See also "Block Product".)

Surplus Energy

Energy that is not needed to meet a utility or marketing agency's commitments to supply firm or non-firm power.

Transmission System

An interconnected network of electric transmission lines and associated equipment for the movement or transfer of high voltage electricity between points of supply and points at which it is transferred for delivery to consumers or to other utilities.

Wheeling

The use of a utility's transmission facilities to transmit power to and/or from another utility system.