Appendices

A – IRP Public Involvement Process

B – City Council Earth Day Resolution 30144 (2000)

C – Resources for Future Monitoring and Evaluation

D – Technical Issues

Appendix A. IRP Public Involvement Process

Seattle City Light is a municipally owned utility that provides an essential public service and plays a significant role in the community. Therefore, the Utility wants to incorporate the interests of its customers and other stakeholders in its integrated resource planning. This is particularly important because the long-term resource strategy developed in an IRP process seeks to satisfy customer needs and community objectives. Actively involving stakeholders in the IRP process can make it more responsive, produce more meaningful results and promote understanding and support for specific long-term resource decisions that will need to be made in the future.

Therefore, the public involvement program for City Light's IRP effort during 2005 and 2006 has been designed to provide opportunities for participation by customers and other local stakeholders, as well as representatives of groups that have expertise on various aspects of the regional electric power system.

Key objectives for public involvement in City Light's 2006 IRP process are:

- Involve customers, regional experts and other stakeholders during the entire IRP process.
- Integrate the public involvement program with analytical activities for the IRP, by including opportunities for stakeholders to review and comment on various inputs and analyses.
- Actively promote two-way communication, group learning and consensus building.
- Gather, balance and incorporate a broad spectrum of perspectives, ideas and suggestions.
- Use multiple communication channels to provide several ways for members of the public to learn about City Light's 2006 IRP process and to provide input.

OVERVIEW

This appendix summarizes how public input was used in the developing City Light's IRP. Many methods were used to encourage City Light customers to understand and have an impact on the resource mix for the Utility's future energy needs. During 2005 and 2006, input was gathered from the public as well as City Light employees, using a variety of methods. Activities included:

- Consultations with the Seattle City Council Energy and Technology Committee, Mayor and Mayor's staff
- One meeting with City Light employees
  - Intranet notification and department individual notification
- Seven stakeholders' meetings (guests included)
  - E-mail notification
  - Telephone notification
  - City Light web site announcements
- Three public meetings
  - E-mail notification
  - Community council notification
  - Stakeholder members notification
  - Newspaper ads
  - Newspaper press releases
  - Internal employee communication
  - Invitations to community groups
- Public meetings broadcast on the Seattle Channel
- Three *Light Reading* issues inviting people to comment
  - Mailings to all City Light customers
- An IRP link from City Light's home page to keep people up to date and a specific email address so they could ask questions and/or make comments and suggestions
  - 19 email responses
- Presentations to eight Community Councils during the summer of 2006
- U.S. mail
  - Three letters, one comment card

- Telephone

The purposes of public involvement were to:

- Gather input along the way in the long-term resource choices.
- Inform stakeholders of the IRP process and ask for input and guidance.
- Inform the general public about resource options and gather their comments and questions.
- Raise awareness of the importance of long-term planning and City Light's need for additional resources beyond their current resource mix.
- To assure the City Council and Mayor that the planning was not done in isolation.

Ultimately, the goal of City Light's public involvement program for the IRP was to help staff and elected officials make the best decisions with the public's best interest assured.

Seattle City Light's web page, and public meeting schedules were advertised and the public could choose to view any of the agendas or handouts from any of the meetings**.** Agendas, handouts and PowerPoint presentations are online at http://www.seattle.gov/light/news/issues/irp/#participate.

Each of the major types of public involvement – the stakeholder group and public meetings – are described below.

STAKEHOLDER GROUP

One of the primary vehicles to promote broad public involvement in City Light's 2005-2006 IRP was created by forming and working with an IRP Stakeholder Group. The IRP Stakeholder Group has a diverse membership, and provided a forum for in-depth participation throughout the IRP process.

The Stakeholder Group includes representatives of City Light's retail electric customers and other local stakeholders, along with experts drawn from several groups that are actively involved in regional energy issues.

Energy policy staff from the Mayor's office and the City Council were invited to attend and participate in the group meetings. All group meetings were announced in advance and were open to the public.

The meetings were designed to enable City Light staff to work directly with the IRP Stakeholder Group. Each meeting typically began with presentations on one or more topics by City Light staff, followed by interactive group discussion. While the IRP Stakeholder Group is a valuable source of ideas and suggestions, it does not have formal policy-making responsibilities.

Stakeholders

Members of the Stakeholder Group and their affiliations are listed below:

- David Staley, Amgen
- Steven LaFond, Boeing
- Stuart Clarke, Bonneville Power Administration
- Amy Solomon, Bullitt Foundation
- Mike Albert, citizen
- Rhys Roth, Climate Solutions
- Vita Boeing, citizen
- Robert Kahn, Northwest Independent Power Producers
- Tom Eckman, Northwest Power and Conservation Council
- Danielle Dixon, Northwest Energy Coalition
- Kelly Ogilvie, Greater Seattle Chamber of Commerce
- Virginia Felton, citizen
- John Chapman, University of Washington
- Mike Morris, Business Owners and Managers Association
- Steve Grose, Virginia Mason Medical Center

Staff participants are:

- Carol Butler, City Council Staff
- Alec Fisken, Mayor's Office of Policy and Management

Questions Posed by Stakeholders

Listed below is a sampling of some of the questions posed by the Stakeholders:

- How do the reserve standards fit in?
- Concern about transmission
- Are you relying on historical trends?
- What happens in 2025?
- Will there be increased funding for conservation?
- Are there plans to buy or build more wind power?
- Is bird killing a big issue with wind power?

- What are PSE and PG&E's assumptions?
- Recommend doing sensitivities on key variables
- Recommend looking at the option values of smaller plants
- Inquiry about the landfill assumptions
- What about the rate impact on the portfolio options
- Are the emissions from SCL's contracts being considered?
- Have you considered climate change impacts?

Stakeholder Meetings

Seven Stakeholder meetings were held. Dates and main topics are listed below. More detailed information, including presentation materials, is online at http://www.seattle.gov/light/news/issues/irp/#participate.

October 27, 2005. The Stakeholder members represent government agencies; and residential, commercial, and industrial customers of Seattle City Light. At this first meeting, the Integrated Resource Planning process was discussed and an overview of the scope of work was presented.

February 2, 2006. David Clement, the newly hired IRP Director was introduced. The following discussions covered forecasts, new resources, conservation, resource adequacy and environmental assumptions.

March 7, 2006. The IRP assumptions were presented along with the first draft of the IRP with scenario options, conservation and generation resources.

May 2, 2006. Resource needs and the first go-round for the Round One (nine portfolios) were introduced.

June 29, 2006. The nine Round 1 portfolios were discussed and comments taken.

October 5, 2006. The Draft EIS was introduced and members were encouraged to attend the EIS public hearing on October 10, 2006. Resource assumptions were presented and the four Round 2 portfolios were presented along with the assumptions leading to the Round 2 decisions.

November 2, 2006. Round 2 portfolios were discussed along with the I-937 requirements. The results of the Draft Environmental Impact Statement were presented.

PUBLIC MEETINGS

All three public meetings were held in the Bertha Knight Landes Room in City Hall. Handouts included the PowerPoint presentations, Comment Cards, Fact Sheets, Frequently Asked Questions (FAQs), and a Glossary. Below is a synopsis of the IRP public meetings. More detailed information, including presentation materials, is online at http://www.seattle.gov/light/news/issues/irp/#participate.

November 14, 2005. Press releases were issued inviting people to the first IRP public meeting. The meeting was held at the Bertha Knight Landes Room in City Hall from 4:00pm – 7:00pm. Marilynn Semro, Wholesale Contracts, and Corinne Grande, Science Policy, presented information on the status of the IRP process and the process for the Environmental Impact Statement. Small group discussions followed and an IRP email comment address was shared. Seven people attended.

July 18, 2006. Email announcements, newspaper ads, *Light Reading* (SCL's billing insert) in the March/April 2006 and July/August 2006 bills, special email invitations to the Stakeholders, all-employee invitations, and press releases inviting City Light customers to the Bertha Knight Landes Room in City Hall from 5:30pm – 7:00pm.

A PowerPoint presentation was given by David Clement, IRP Director, on the process of an IRP and assumptions leading up to the resource portfolio options. Nine resource portfolios were displayed around the room and handouts were given to attendees. After the presentation, attendees were encouraged to ask questions and make general comments about the portfolio options. Refreshments were served; 20 people attended. This was broadcast on the City's public television station.

November 14, 2006. A mailing list of all email and letter inquiries was activated, inviting all who expressed an interest or made a comment about the IRP; *Light Reading* (City Light's billing insert) announcement in the November/December 2006 issue to all City Light customers; press releases and ads; lead story of City Light's web page; special invitation to all IRP stakeholders; internal communications inviting all City Light employees; notification to Community Councils.

The meeting, attended by 25 people, was held on November 14, 2006 from 5:30pm – 7:30pm in the Bertha Knight Landes Room at City Hall. A PowerPoint presentation given by David Clement, IRP Director, on what was learned from the Round 1 assumptions and portfolios leading up to the two Round 2 portfolios, both meeting the requirements for Initiative 937. Participants were encouraged to ask questions and make comments during the presentation. This meeting was broadcast on the City's public television station.

Questions and Comments

Below is a sampling of some of the questions and comments made at the public meetings:

Questions included:

- Seasonal peak pricing?
- Which resources can be turned on and off?

- Can you create hydrogen with excess generation?
- Does the cost of conservation include the reduction costs and transmission losses?
- What are the energy cost assumptions over the 20-year period?
- Achievable conservation as a fraction of total cost effective resources.
- Which portfolios meet the requirements for I-937?
- Are we selling energy products outside the area?
- Can the green energy program be restricted to sources of electricity that have negative green house gas?
- Any possibility of improving building codes?
- Is there a potential for tidal resources in Puget Sound?
- Where is the solar?
- What is City Light's position and level of interest in distributed generation?
- Is it realistic to not include nuclear power in the resource portfolios?

Comments included:

- Carbon neutral in portfolios – in environmental matrix
- Show the costs with carbon
- Like to have commercial bear the conservation costs if they are not taking conservation steps
- Analyze accelerated pace of conservation
- Provide more data on your total current consumption by customer sector
- There is more conservation potential on the table
- Support conservation in the commercial sector

Correspondence from the Public

Seattle City Light encouraged its customers to contact the utility in writing with comments and questions about the IRP. City Light created a link to the IRP from its main web page. At the time of this writing, 15 emails were received, one comment card and two letters.

The number of page views on the City Light's IRP web page were also tracked. Over 3,000 views were recorded as of July 2006.

Below is a synopsis of the written comments:

Recommendations included:

- Hydro output (2)
- Geothermal
- Generator operated by pedaling a bike
- For Nuclear (2)
- More conservation measures (3)
- Waste to energy
- Wind and solar should be supplemental, not core
- New renewable resources
- No new non-renewable thermal resources
- Distributed generation
- Cogeneration
- Sell shares in the power production of wind generating system

General comments and questions received from correspondence included:

- Questioning assumptions such as natural gas prices, the cost of carbon emission, coal-fired generation, and high prices for pulverized coal and simple cycle gas (2)
- BPA assumptions are not clear
- Why was the conservation potential analyzed over 15 years?
- Requesting information on the meetings (2)
- Status of an IGCC plant in Washington
- How many MWs are needed?
- Increase use of salmon hatcheries

CONCLUSION

Seattle City Light provided several opportunities for the public to become involved including: three public meetings; a designated email to receive public comment; eight community Council meetings; seven stakeholder meetings; letters from interested individuals and groups; and phone calls. City Light's IRP team was open to all comments and suggestions.

A recommended portfolio was not decided until the conclusion of the project at the end of 2006. Options remained open through most of the integrated resource planning process, allowing public input to continue to have value in shaping analysis and recommendations.

This is only the beginning of the biennial review process for resource planning. Customers will be invited to participate at every step during the updates. In addition, all interested parties are encouraged to participate during the City Council review of the IRP. More information about the Council's review can be obtained at http://www.seattle.gov/council/. See Energy and Technology Committee.

Appendix B. City Council Resolution 30144 (2000)

A RESOLUTION proclaiming the City of Seattle's actions supporting and honoring Earth Day 2000 (adopted April 10, 2000).

WHEREAS, the thirtieth anniversary of Earth Day will be celebrated worldwide during April 2000; and

WHEREAS, since its inception in 1970, Earth Day has inspired major environmental initiatives in the United States including the Clean Air Act, Clean Water Act and Endangered Species Act, as well as a national grassroots environmental movement; and

WHEREAS, Earth Day 2000 is mobilizing citizens, businesses and governments throughout the world to address climate change and to transition the world's economy toward energy efficiency solutions built on clean, safe and renewable resources; and

WHEREAS, cities play a significant role in environmental protection and enhancement through their departmental operations, their regulatory authority, their service delivery to citizens and businesses, and their ability to influence and participate in the policy choices of local, state and federal agencies; and

WHEREAS, the City of Seattle has long been recognized as a national leader in promoting, supporting and financing a variety of environmental programs that have produced substantial and meaningful improvements in the region's environmental quality including reductions in greenhouse gases; and

WHEREAS, Mayor Paul Schell proclaimed in his 2000 State of the City address that programs respecting and protecting the environment are one of his top four priorities for the next two years; and

WHEREAS, Earth Day 2000 presents the ideal opportunity for the City and its citizens to celebrate the City's many environmental accomplishments and to renew and expand Seattle's commitment to the environment by establishing new initiatives to address the region's most pressing environmental challenges including climate change;

Now therefore,

BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY OF SEATTLE, THE MAYOR CONCURRING, THAT:

Section 1: The Seattle City Council recognizes and commends the many environmental accomplishments achieved by the City, with the support and participation of its citizens and businesses, including, but not limited to:

1. Over 20 years of conservation leadership exhibited by City Light in delivering energy conservation programs and services designed to acquire cost effective energy savings to meet the utility's energy requirements and to improve energy efficiency measures and practices in customer homes, businesses, and industries. From 1991 (the Kyoto protocol baseline year) through 1998, City Light's energy conservation programs have saved 1.8 million megawatt-hours. Savings in 1998 alone were 400,000 megawatt-hours, enough to power one out of eight Seattle homes. Over the 1991-1998 period, energy savings from conservation programs resulted in 1.5 billion pounds of avoided carbon-dioxide emissions to date. Many of these energy savings and avoided emissions will continue to accrue from conservation measures with lifetimes extending well into the future. These energy savings and their environmental benefits were acquired at a cost of $167 million to City Light and an additional $53 million on the part of participating customers. To acquire these greenhouse gas impacts in the transportation sector, it would have been necessary to garage 19,000 vehicles in every year from 1991 through 1999.

2. City Light's transformation from a "power first" electric utility two decades ago to today's "fish first" philosophy, i.e. protect and restore the salmon runs on the Skagit River. Recognizing that hydroproject operations contributed to declining salmon runs, City Light altered flows on the Skagit River to support the survival needs of salmon. The Skagit now supports the largest and healthiest runs of pink and chum salmon in the Northwest. The chum runs in turn support the largest overwintering population of bald eagles in the contiguous United States. The chinook run in the upper Skagit remains stable even while runs have declined elsewhere in Puget Sound.

3. Over ten years of national and international leadership in environmentally sound solid waste management. Since 1987, Seattle has led the world in reducing, reusing and recycling. Over $12 million has been saved by recycling instead of sending material to landfills since Seattle's recycling program began. In 1999 alone, an estimated 350,000 tons of waste were either recycled or composted instead of landfilled, thereby conserving energy and avoiding tons of greenhouse gas emissions from decomposing solid waste.

4. The seventy percent of City employees who work in the central business district and help reduce traffic congestion by participating in the City's commute trip reduction program and commute by bus, bike, vanpool, walking or other alternative to a single occupancy vehicle.

5. The Seattle Millennium Project, culminating on Earth Day 2000, which restored salmon habitat on four miles of the city's largest urban creeks. The work on Longfellow, Taylor, Pipers and Thornton Creeks also improved drainage runoff and reduces potential flooding damage.

6. The nearly 100,000 acres of forests and wetlands that have been permanently preserved by the City in the Skagit and Cedar River watersheds, protecting critical habitat for numerous species of fish and wildlife.

7. The regional water conservation program which, since 1989, has saved over 50 billion gallons of water, which translates to 30 million gallons a day less than demand would have been without conservation. Not only has this savings been cost effective for Seattle's customers, but it has kept additional water in Cedar and Tolt Rivers to meet the needs of salmon and other instream needs.

8. The City's increased use of the 145 compressed natural gas vehicles (CNG) in its fleet. CNG vehicle emissions are substantially less than gasoline vehicles, including about 25 percent less carbon dioxide, the primary source of greenhouse gases.

9. The Seattle Parks and Recreation restoration of wetlands at Pritchard Beach, Carkeek, Golden Gardens, and Matthews Beach parks and acquisition of 600 acres of precious green spaces through land purchases, transfers and donations.

10. The overwhelming support by Seattle voters in 1996 for the Sound Transit high capacity regional transit system including light rail in the City of Seattle, the partnership between the City and Sound Transit to implement the light rail system and neighborhood based planning and zoning changes around each station to promote transit-oriented development coupled with the City's pledged financial support of $43 million to complete the light rail system.

11. The City's commitment to implementing the core strategies of the Growth Management Act, by encouraging the development of compact, walkable urban communities linked by transit that will accommodate 50,000 to 60,000 new households by 2014. Our success in this endeavor will prevent sprawl, conserve habitat, protect watersheds, and preserve our farmlands, forests, and wilderness areas.

Section 2. The City of Seattle supports the Earth Day 2000 initiative to focus attention on one of the world's most urgent environmental challenges: reducing greenhouse gases to help mitigate global warming through increased energy efficiency and non-carbon based energy sources. The City of Seattle will reduce greenhouse gas emissions in its own operations and through community actions by:

1. Establishing a long-range goal of meeting the electric energy needs of Seattle with no net greenhouse gas emissions. City Light's power resource portfolio is composed primarily of resources that produce little or no greenhouse gas emissions. Immediately,

City Light will meet growing demand with no net increase in greenhouse gas emissions by:

a) Using cost-effective energy efficiency and renewable resources to meet as much load growth as possible.

b) Mitigating or offsetting greenhouse gas emissions associated with any fossil fuels used to meet load growth.

2. Planting 20,000 trees by Earth Day 2000 and an additional 20,000 by 2003, sequestering tons of carbon dioxide over the life of the trees.

3. Supporting state and federal policy initiatives like Climate Wise that enhance energy efficiency, encourage renewable resource development and reduce greenhouse gas emissions.

4. Constructing all new and renovated City facilities greater than 5000 square feet of occupied space to be certified "green" by meeting the US Green Building Council's "silver" standard for sustainable buildings. Meeting this policy will maximize energy and water use efficiency and reduce the use of non-sustainable resources in City facilities.

5. Reducing vehicle emissions by transitioning the City fleet to a greater use of alternative fuel vehicles; by 2002 approximately 10 percent of the City's cars and light duty trucks will be alternative fueled vehicles and by 2005, approximately 20 percent.

6. Hosting the region's Earth Day 2000 event at Seattle Center, celebrating the theme of "Clean Energy Now" with a series of informational booths, activities, music and vendors.

Section 3. The City of Seattle also supports the opportunity Earth Day creates for inspiring individuals and groups to take action on other critical environmental challenges. In recognition of Earth Day 2000, the City of Seattle commits to:

1. Eliminating the use of the most hazardous insecticides and herbicides in City owned landscapes by June 2000 and reducing the remaining use of pesticides by an additional 30 percent by 2002.

2. Improving salmon habitat through continued restoration of Seattle's major creek systems and continuing the trend of reducing per capita water use by one percent a year for the next ten years.

ADOPTED by the City Council of the City of Seattle this ______ day of _______________, 2000, and signed by me in open session in authentication of its adoption this _____ day of ________________, 2000.

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President of the City Council

THE MAYOR CONCURRING:

Paul Schell, Mayor

Filed by me this ___________ day of __________________, 2000.

City Clerk

April 3, 2000

(Version 5)

Appendix C. Resources for Future Monitoring and Evaluation

Detailed quantitative modeling for Seattle City Light's 2006 Integrated Resource Plan (IRP) has been performed for candidate resource portfolios composed of varying types and amounts of new electric resources. Resources selected for modeling have proven technologies, are commercially available and cost-effective in utility-scale applications. It was not practical to evaluate the full spectrum of additional resources that may become feasible during the next 20 years.

Not being selected for modeling for the 2006 IRP does not mean that City Light has no prospective interest in that resource. The Utility is interested in any resource that meets Seattle's needs, public policy objectives, and whose application can bring value to all customers.

This appendix provides information about additional types of resources that were not modeled for the 2006 IRP, but show potential to become more significant in the future.

- Solar Power
- Sea Power
- Fuel Cells
- Combined Heat and Power
- Distributed Generation
- Nuclear Power

City Light will issue updated IRPs every two years, but integrated resource planning is an ongoing process. The Utility will be continuously monitoring and re-evaluating generation and demand-side resource choices, new technologies, new market information and trends in customer demand. As additional types of new resources become commercially viable, they can be included in the quantitative modeling for future IRPs.

EVALUATING EMERGING TECHNOLOGIES

Because the 2006 IRP is City Light's first long-term integrated resource planning effort since 2000, extensive start-up activities have been required to rebuild the Utility's long-term resource planning capabilities. These included hiring and training resource planning staff, developing new analytical capabilities, installing a sophisticated portfolio analysis model and calibrating it for City Light's extensive hydroelectric operations. Given the nature of IRP models, deadlines, and the need to adopt an IRP in 2006, it would not have been practical to quantitatively model large numbers of new resource types, especially those exhibiting limited applications or uncertain cost and performance characteristics

However, staying abreast of emerging technologies and efforts to bring new forms of resources into the mainstream can help the Utility and its stakeholders identify additional resources that may merit more extensive consideration in the future.

The last several years have seen rapid growth in funding for research and development (R&D) on various new forms of electric resource technologies. Two major factors increase the prospects for technological breakthroughs that may enable new forms of electric resources to become commercially viable in the future:

- Increases in the costs of conventional generating resources, including those that burn fossil fuels such as natural gas.
- Growing concerns about global climate change, spurring interest in electric resources that do not produce CO2.

Higher costs and environmental risks associated with conventional fossil-fueled resources are helping to make other forms of resources more attractive, and encouraging efforts to increase the performance and availability of renewable resources and other competing types of resources.

POTENTIAL FUTURE RESOURCES

For each type of resource, this section provides the following information:

- Description of resource technology
- Current status
- Fixed and variable costs
- Fuel requirements (if any)
- Transmission requirements
- Dispatchability
- Environmental considerations (e.g., air emissions)
- Outlook

Solar Power

Description of Resource Technology

Two general types of technologies are available to convert energy from the sun into electricity: photovoltaic and solar thermal.

Photovoltaic technology uses solid-state semiconductor devices to convert sunlight directly into direct-current electricity. Photovoltaic technology was first discovered in the nineteenth century and became more broadly known when the silicon solar cell was invented in the 1950s. The amount of electricity produced by a photovoltaic source varies with the amount of surface area used to collect sunlight. As a result, smaller photovoltaics can be used in distributed applications such as residences and commercial buildings. Photovoltaic installations with bigger surface areas can be used to produce electricity on a larger scale.

Solar thermal is a large-scale technology. It uses mirrors to gather and concentrate heat from the sun to heat a fluid and make steam, which is then used to power a generator and produce electricity. The first application of solar thermal technology occurred in the 1970s.

Whether photovoltaic or solar thermal technology is used, the amount and timing of solar power production depends on the location of the generation source. The largest amount of solar power can be produced in locations that receive more frequent sunshine, and at latitudes (and times of the year) where the sun shines more directly at the earth. Of course, solar power is also produced during the daytime, not at night.

Current Status

To date, solar power has been most successful in niche applications, rather than as a large-scale source of electricity. For example, solar installations can be cost-effective in remote locations such as small communities that are isolated from the electrical grid. Remote applications of solar power are often combined with battery systems that provide power for nighttime consumption and are recharged during daylight hours.

Solar power has not yet made significant inroads as a large-scale source of power for utility systems. While solar power environmental advantages and other benefits, a primary drawback so far has its higher cost relative to competing types of resources.

Fixed and Variable Costs

Costs for currently available forms of solar technologies are high compared with other types of resources.

For example, the U.S. Department of Energy (DOE)[1] estimates that the capital cost to develop a 5-megawatt photovoltaic system in 2007 would be $4,598 per kilowatt. Fixed operating and maintenance (O&M) costs are estimated at $51.70 per kilowatt-year. Variable O&M costs would be zero.

DOE estimates that costs of a 100-megawatt solar thermal system would be $3,047 per kilowatt. Fixed O&M costs are estimated at $10.64 per kilowatt-year. Variable O&M costs would be zero.

Fuel Requirements

Sunlight is used to produce solar power. No other form of fuel is required or consumed.

Transmission Requirements

In distributed and small-scale applications, solar power generally does not use high-voltage transmission facilities. In fact, solar power can be used in situations where transmission facilities are not available or would be cost-prohibitive.

In large-scale applications, new transmission facilities may be required. For example, if solar power is developed in a sunnier location such as eastern Washington, new transmission facilities may be needed to move the power to the Seattle area.

Dispatchability

Solar power is produced when the sun is shining. In other words, solar power is an intermittent resource that is not dispatchable.

In addition, a larger proportion of solar power can be produced in the Northwest during the summer months. This makes solar more attractive for utilities that, unlike City Light, need more resources during summer months than during winter months.

Environmental Considerations

Solar power is very attractive in terms of its environmental impacts. Because it uses only sunlight to generate electricity, no fuel or water is consumed and no air or water emissions are produced. The primary environmental impacts of solar power facilities involve land use, such as the surface area required for photovoltaics.

Outlook

While solar power is currently more expensive than other available types of electric resources, the outlook for future cost reductions has recently become more promising. Extensive R&D is ongoing and has recently produced significant breakthroughs.

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[1] Energy Information Administration/Assumptions to the Annual Energy Outlook 2006 (Report # DOE/EIA-0554 (March 2006).

For example, as noted above, current photovoltaic technology uses silicon wafers, which involve comparatively high materials costs. However, an alternative form of technology has been developed that uses non-silicon semiconductor materials that promise to allow the production of thin-film solar cells at dramatically reduced costs. Several companies are currently building facilities to produce this new form of photovoltaic technology.

Because of the inherent benefits offered by solar power and the potential for costs to become more economical in the future, City Light will continue to monitor the development of new forms of solar power technology.

Ocean Power

Description of Resource Technology

A variety of forms of ocean power have been identified, including power produced using energy from tidal, wave, salinity gradient and thermal gradient sources.

One form of tidal power is similar to hydroelectric power and uses the "head" created by the difference between water levels at high and low tides. There are a few existing examples of tidal barrage dams, including a 240-megawatt project in France and a 20-megawatt project on an inlet of the Bay of Fundy in Canada. The greatest potential for this type of sea power exists in areas that have large tidal amplitudes, such as Alaska.

Another form of tidal power converts energy from tidal currents into electricity. Unlike a barrage dam, this form of tidal power does not require impounding water in a tidal lagoon. Instead, kinetic energy is extracted from the current created by ebbing and flooding tides. Several demonstration projects have been developed in Europe. Projects have also been proposed or are being considered in the U.S. These include several projects that are being evaluated by Tacoma Power and by Snohomish County PUD. A major determining factor for the generating potential from tidal currents is the speed of the current.

Ocean power can also be generated using waves. Several forms of technologies are under development, including oscillating water columns, tapered channel systems and pendular devices. The amount of generating potential from wave power is determined by the height and the speed of waves at the project site.

Salinity gradients are another energy source that could potentially be used to produce electricity. This technology would capture the energy that is released when fresh water is mixed with salt water, for instance at locations where rivers discharge into the ocean or another body of salt water.

Finally, thermal gradients in the ocean could potentially be used to produce electricity. This approach would capture energy from differences in the temperature of water near the surface of the ocean and colder water at lower depths. A major determining factor for the generating potential from this type of ocean power is the ocean temperature differential available at a project site.

Current Status

Until recently, comparatively little attention was given to the development of ocean power in the U.S., but interest has been growing during the last several years.

While a utility-scale ocean power project has not been developed in the Pacific Northwest, two types of ocean power have been receiving attention. These are tidal current power and wave power. As noted above, two publicly owned utilities in Washington are investigating opportunities to develop tidal current power projects at a number of sites in Puget Sound. In addition, several companies are working on demonstration projects for wave power.

Other forms of ocean power have received less attention. Acceptable sites for tidal barrage dams have not been identified. Technologies for salinity gradients are in their infancy and further R&D is required. Available temperature differentials in the Northwest do not appear to be large enough to make ocean power from thermal gradients an attractive alternative.

Fixed and Variable Costs

Estimates of costs for the different types of ocean power technologies are not well established. For instance, costs for ocean power are not reported as part of the U.S. DOE Energy Information Administration 2006 Annual Energy Outlook.

However, the current costs to develop ocean power are generally recognized as being significantly higher than the costs for other types of electric resources. For example, according to the Energy Efficiency and Renewable Energy branch of the U.S. Department of Energy[2], "Economically, wave power systems have a hard time competing with traditional power sources. However, the costs to produce wave energy are coming down. Some European experts predict that wave power devices will find lucrative niche markets."

Fuel Requirements

No fuel is directly used or consumed to produce ocean power.

Transmission Requirements

At many sites where ocean power could be developed in the Pacific Northwest, new transmission facilities would be needed to integrate the power with the main transmission grid. Depending on the location, expansions to the main transmission grid may also be required.

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[2] A Consumer's Guide to Energy Efficiency and Renewable Energy, U.S. DOE EERE (http://www.eere.energy.gov/consumer/renewable_energy/ocean/index.cfm/mytopic=50009).

Dispatchability

Tidal current power is intermittent, but predictable. Larger amounts of power can be produced on days when the tidal amplitude is greater and during the peak portion of each ebb and flood tide. No power is produced during slack water periods between ebb and flood tides.

Wave power is intermittent and less predictable. More power can be produced when waves are larger, typically as the result of higher and more sustained winds.

Environmental Considerations

Different forms of tidal power can create differing forms of environmental impacts. For example, a tidal barrage dam can create significant impacts on the tidal lagoon that is impounded. Tidal current projects may affect sea life, either directly or by altering sedimentary activity on the sea floor. Wave power projects can interfere with fishing activities and affect scenic qualities in areas where they are located.

A significant environmental advantage of ocean power is that it does not consume fossil fuels and produces no air emissions.

Outlook

In the Pacific Northwest, the two most promising forms of ocean power appear to be tidal current power and wave power. An increasing amount of attention is being devoted to research, development and demonstration of these technologies. While neither form of technology appears to be immediately viable, breakthroughs may occur in the next decade. City Light intends to monitor ongoing activities related to ocean power, with an emphasis on tidal current power and wave power.

Fuel Cells

Description of Resource Technology

Fuel cells are electrochemical devices that convert hydrogen and oxygen into direct current electricity and water. No combustion occurs and the process is efficient, clean, quiet and reliable.

Unless an external source of hydrogen is available, fuel cell systems typically require two basic components:

- First, a fuel reformer is used to convert a fuel source such as natural gas or methanol into hydrogen.
- Second, hydrogen from the fuel reformer is fed into the anode of the fuel cell and oxygen enters the fuel cell through the cathode. A catalyst within the fuel cell is then used to facilitate a reaction between the hydrogen and the oxygen, splitting hydrogen atoms into protons and electrons. The protons and electrons take separate

paths to the cathode, with the protons being conducted through the anode and out to an external circuit with an electrical load.

A single fuel cell produces roughly 0.7 volts of electricity; many fuel cells are combined together in “stacks”, to create electricity at the desired voltage level. Heat is also produced by fuel cells.

Various types of fuel cell technologies have been created; several types are undergoing further R&D. Examples of specific technologies include phosphoric acid, proton exchange membrane, molten carbonate, solid oxide, alkaline and protonic ceramic.

Current Status

R&D work has been underway for a number of years and is proceeding on several forms of fuel cell technologies. While some attention is focused on fuel cells that could be used to produce electricity on a large scale, more effort is being devoted to fuel cells that can be used in smaller, more mobile applications such as transportation and to power electronic devices such as laptop computers. Some forms of fuel cells could be used in distributed applications to serve as an alternative or supplement to power from the utility grid.

Fixed and Variable Costs

Costs for commercially available forms of fuel cells have been declining, but are still high compared to the costs for other types of electric resources. For example, the U.S. Department of Energy (DOE)[3] estimates that the capital cost to develop a 10-megawatt fuel cell system in 2007 would be $4,374 per kilowatt. Fixed operating and maintenance (O&M) costs are estimated to be $5.15 per kilowatt-year. Variable costs would include costs for hydrogen or, more typically, another type of fuel that would be used to produce the hydrogen.

Fuel Requirements

Fuel cells themselves consume hydrogen as their fuel source. However, as described above, another fuel source is typically required such as natural gas or methanol.

Transmission Requirements

Fuel cells can be installed in more types of locations than many other electric resources. As a result, it may be possible to install fuel cells at sites where no new transmission facilities would be required, or even at locations that could benefit the existing transmission system.

[3] Energy Information Administration/Assumptions to the Annual Energy Outlook 2006 (Report # DOE/EIA-0554 (March 2006)

Dispatchability

Certain forms of fuel cells can be turned on and off relatively easily, making them attractive in terms of their dispatchability.

Environmental Considerations

Unless hydrogen can be produced from a non-polluting source, hydrocarbon-based fuels such as natural gas or methanol must be used. Consumption of natural gas produces a net increase in CO2 and other emissions.

Outlook

Further research, development and demonstration work is proceeding on various types of fuel cell technologies, which may lead to further reductions in costs. Much of this work is focusing on mobile applications to provide power for transportation and electronic devices. However, breakthroughs in these types of fuel cells may also be transferable to fuel cells that could be used for large-scale electricity generation. In addition, fuel cells could become useful in distributed applications on utility systems.

Over the longer term, if technological breakthroughs lead to large-scale production of hydrogen, fuel cells could become a highly attractive source of power. City Light intends to monitor development of this potential resource.

Combined Heat and Power

Description of Technology

Combined heat and power (CHP) is characterized as the simultaneous production of thermal energy and electricity. CHP projects may be implemented in commercial, industrial or multi-family residential settings. CHP projects often displace the use of boilers that would otherwise be used to produce thermal energy for on-site use, with the added benefit of producing electricity. The electricity produced may be consumed on-site, or it may be sold to the local utility or a third party.

In the CHP sector, the largest amount of power is produced using combustion turbines, either in single cycle or combined cycle mode. To a lesser extent, internal combustion engine and boiler/steam turbine CHP projects have been developed. Fuel cells and microturbines can also be used, but CHP projects using these technologies have not made significant inroads to date.

The majority of CHP projects are fueled with natural gas, although CHP can also be implemented on a more limited basis at industrial facilities that burn other fuels (e.g., wood waste at paper mill or refinery gas at a petroleum refinery).

Unlike generating facilities that exclusively produce electricity, most CHP projects are intimately connected to the host facility's critical activities. From an operating perspective, the host site's requirements for thermal energy generally take priority over the production of electricity. This can also increase the number and complexity of issues involved in developing a CHP project, compared with development of a standalone electric generating project.

Current Status

Among existing CHP installations in the U.S., the largest share of electricity production occurs at projects with a generating capacity of 20 megawatts or greater, including a significant amount at projects with generating capacities of 100 megawatts or more.

Until recently, some industry observers believed there was significant potential to develop new CHP projects, and that such development would occur as the need for new resources grew. However, recent development of CHP projects has not occurred as vigorously as expected, partly because of substantial increases in market prices for natural gas, the leading fuel of choice for CHP projects. Other contributing factors include disruptions and uncertainties in the wake of failures of various efforts to restructure the electric utility industry, including the western energy crisis of 2001. CHP project economics largely depend upon the cost of power from alternative suppliers. In locations where the cost of power from local utilities or from the regional wholesale power market tends to be below the average cost of power from a CHP project, CHP projects will be slow to develop.

Fixed and Variable Costs

Costs and other characteristics of individual CHP project opportunities can vary widely, based on specific circumstances. CHP projects with larger generating capacities can have lower costs, due to economies of scale. However, the most cost-effective size for a CHP project depends on the amount of thermal energy that is required, as well as the seasonal and diurnal profile of thermal energy consumption.

As an illustration of the variability of costs for CHP projects, the Northwest Power and Conservation Council's Fifth Northwest Power Plan identified example projects with the following characteristics and benchmark costs:

- Reciprocating engine generator that burns natural gas to produce 0.5 megawatts of electricity and heat water to supply hot water to a hospital, at a benchmark cost of power of $73 per megawatt-hour.
- Combustion turbine generator that burns natural gas to produce 9 megawatts of electricity and a heat recovery steam generator to supply an institutional space-heating load, at a benchmark cost of power of $94 per megawatt-hour.
- Combustion turbine generator that burns natural gas to produce 48 megawatts of electricity and a heat recovery steam generator to supply steam for an industrial process, at a benchmark cost of power of $47 per megawatt-hour.

Fuel Requirements

As noted above, most CHP projects consume natural gas. However, other types of fuel sources may be available in specific circumstances.

Transmission Requirements

Transmission requirements for CHP projects depend on the location of the CHP facility, which in turn is usually determined by the location of the host thermal load. In cases where the thermal load is at a site that also consumes significant amounts of electricity, development of a CHP project may help to reduce or defer the need to construct new electric transmission facilities.

Dispatchability

The majority of CHP projects operate on a more or less continuous basis, driven by the needs of the thermal loads at the host facility. As a result, most CHP projects are not dispatchable and instead operate in baseload mode.

Environmental Considerations

CHP projects that consume natural gas produce air emissions that are typical for the type of generating technology employed (e.g., combustion turbines, internal combustion engines). However, CHP projects may provide a net reduction in air emissions compared to conventional natural gas-fired generation by using natural gas to produce both thermal energy and electricity.

CHP projects that produce steam as the source of thermal energy also consume water and may emit water vapor into the air.

Outlook

The outlook for significant development of large amounts of CHP projects appears somewhat less promising than it was several years ago. This is mostly due to higher and more volatile costs for natural gas, the primary fuel source for most CHP projects. Identifying a specific quantity of CHP to include in a utility's long-term resource plan is also difficult due to large variations among real-world CHP project opportunities.

However, specific CHP opportunities may become available in Seattle City Light's service area. City Light will remain receptive to such opportunities and evaluate each opportunity on its own merits.

Distributed Generation

Description of Resource Technology

Distributed generation can be defined as the production of electricity at or near locations where electricity is consumed. This is in contrast with the traditional hierarchical model of the utility system, which is based on building large generating facilities, located in distant places, often requiring high-voltage transmission facilities to move power across long distances from the generating facilities to the utility's service area, and finally delivering power through a local distribution system.

Distributed generation uses many smaller generating resources located at strategic points within the utility's network, closer to retail customer electrical loads.

Rather than being a replacement for central-station power plants or existing utility systems, distributed generation can provide incremental additions to the utility's overall portfolio of electric resources.

Distributed generation may employ one or more specific types of electric generating technologies, for example:

- Solar power
- Fuel cells
- Microturbines
- Combustion turbines
- Internal combustion engines
- Combined heat and power

In addition to helping to meet a utility's need for electric resources, the capability to implement distributed generation can help to achieve one or more of the following objectives:

- Increase service reliability to meet critical needs of certain customers (e.g., hospitals, uninterruptible industrial processes).
- Provide premium quality power (e.g., voltage regulation, frequency control) that exceeds normal standards of utility service.
- Improve overall stability and resiliency of the utility grid system (e.g., strengthen weak areas of the system or promote faster recovery from outage events).
- Reduce or defer the utility's need to add new transmission and distribution facilities, in some cases.
- Maximize overall fuel efficiency and reduce net air emissions (e.g., through use of combined heat and power).
- Facilitate development of distributed renewable resources (e.g., solar and small wind).

Opportunities to realize the potential benefits from distributed generation described above are highly situation-specific and cannot be implemented through one-size-fits-all approaches. To capture potential benefits from distributed generation opportunities, an integrated approach is needed to evaluate each opportunity in terms of impacts on the utility's electric resource portfolio and its transmission and distribution system.

Current Status

As noted above, distributed generation projects typically have smaller capacities than large, central-station generating facilities. Because a variety of types of generating technologies can be used and because the specific circumstances of each project can vary significantly, the types of distributed generation projects that have been developed also tend to be quite diverse.

The major barriers that have impeded development of distributed generation projects are:

- Widely varying and sometimes highly restrictive conditions that utilities imposed on establishment of electrical interconnections between distributed generation projects and the utility's electrical grid. Utilities have explained that strong protections are needed to ensure that distributed generation facilities do not create unstable or unsafe conditions on the utility's electrical system.
- Structural and regulatory mechanisms that caused economic disincentives for utilities that may have otherwise been willing to cooperate with the development of distributed generation projects.

In recent years many states, including Washington, have passed "net metering" legislation designed to remove barriers to the development of distributed energy resources. In addition, on May 12, 2005, the Federal Energy Regulatory Commission issued Order No. 2006, establishing standard interconnection procedures for generators with capacities of less than 20 megawatts.

Fixed and Variable Costs

As noted above, the structure and level of costs for distributed generation projects are highly situational and can vary substantially.

Costs for several underlying generating technologies that are used for distributed generating projects are described in the IRP and other sections of this appendix.

Fuel Requirements

The type of fuel used in a specific distributed generation project depends on the underlying generating technology. These may include natural gas, industrial by-products, diesel or other petroleum products, wood waste, methane, solar energy and agricultural waste.

Transmission Requirements

As described above, many distributed generation opportunities are viewed as having the ability to reduce or defer the need to construct new transmission facilities.

Dispatchability

Dispatchability for a specific type of distributed generation project depends on the underlying generating technology used, and may also be determined by the needs of electric loads at the generation site. For example, a combined heat and power project that provides steam to a hospital may need to be operated in baseload mode, even though a dispatchable generating technology (e.g., combustion turbine) is used.

Environmental Considerations

Environmental impacts created by a distributed generation project depend on the underlying generation technology. Renewable generating technologies generally have fewer and less damaging environmental impacts. Net impacts from generating technologies that consume natural gas may be lower in combined heat and power applications.

Outlook

One recent development that may lead to increased opportunities for distributed generation is the emergence of the concept of the "Smart Grid". The GridWise Alliance (www.gridwise.org) describes this concept: "An electric system that will employ new distributed 'plug and play' technologies using advanced telecommunications, information and control approaches to create a society of devices that functions as an integrated transactive system."

Under the Smart Grid approach, distributed generation would play a more active and prominent role in the overall power system. This could cause a larger number of distributed generation opportunities to become economically viable, and may lead to future growth of the distributed generation sector.

Nuclear Power

Description of Resource Technology

Nuclear power produces electricity through the controlled release of energy from nuclear reactions. The basic form of technology in use at existing nuclear generating stations employs the process of nuclear fission from a material such as uranium to produce heat, which is then used to produce steam and propel a steam turbine.

Technological aspects that are unique to nuclear power generation include nuclear fuel processing, operational control of the nuclear reaction process, and handling and storage of radioactive waste. Certain other technological aspects of nuclear power generation are similar to other forms of large central station generation, particularly the use of steam turbines.

Current Status

Commercial generation of nuclear power has a troubled history around the world, across the U.S. and in the Pacific Northwest. Development of nuclear power facilities dropped off following major accidents at Three Mile Island in 1979 and at Chernobyl in 1986.

The only operating nuclear power plant in the Pacific Northwest is Energy Northwest's Columbia Generating Station located near Richland, Washington. This facility uses a boiling water reactor and has a net generating capacity of 1,157 megawatts. It has been in commercial operation since December 1984.

During the last several decades, there has been little public interest in the U.S. in the construction of new nuclear power plants. In addition to plant operating safety, concerns about nuclear power include major cost overruns like those that occurred in the 1970s and early 1980s, and problems related to the handling and storage of radioactive waste.

Nevertheless, the nuclear power industry and its contractors have continued to conduct research and development on newer forms of nuclear power generation. The Federal Energy Policy Act of 2005 included $4.3 billion in incentives to promote the development of nuclear power facilities.

Fixed and Variable Costs

No new nuclear reactor unit has been ordered in the U.S. since the late 1970s. Most projections for costs of new nuclear facilities are based upon inclusion of new technologies and designs that have not been constructed. As a result, any estimate of the long-term cost of new nuclear generating projects is speculative.

However, it is relatively safe to say that new nuclear generating facilities would be highly capital-intensive. Fixed O&M costs are also highly uncertain, as are variable operating costs.

It should be noted that some types of costs for nuclear power plants may be relatively predictable, such as certain costs related to normal steam plant operations and maintenance. However, the unique characteristics of nuclear power generation, including costs related to nuclear fuel and radioactive waste contribute to cost uncertainty.

Fuel Requirements

Nuclear generating facilities consume fissionable material such as plutonium.

Transmission Requirements

Assuming that a new nuclear power plant could be sited in the Pacific Northwest, it would very likely be located in a place that would require construction of new high-voltage transmission facilities.

Dispatchability

Because of their proportionally high fixed costs and the operating characteristics of the technology, nuclear power plants typically operate in baseload mode and are not dispatchable.

Environmental Considerations

Advocates of nuclear power frequently emphasize that this form of electric resource does not consume fossil fuels and therefore produces no CO2 or other forms of air emissions. Opponents of nuclear power point out that it has many other forms of environmental impacts, including issues related to fuel mining and processing, plant operating safety, handling and storage of radioactive wastes, and plant decommissioning.

Outlook

The outlook for development of new nuclear power facilities is not clear or highly promising, especially in the Pacific Northwest. While it produces no CO2 and newer forms of nuclear generating technologies may offer improved operating safety, these advantages are offset by cost and environmental concerns. There appears to be little public acceptance for nuclear power. Therefore, siting a new nuclear facility in a state along the West Coast would likely be highly controversial and difficult. Other constraints are the high up-front capital costs, long lead time for project development, and costs and liability risks associated with radioactive wastes and decommissioning.

Appendix D. Technical Issues

The topics covered in this appendix are:

- Planning and Risk Model Description
- Treatment of Stochastic Variables in Planning and Risk
- Treatment of Air Emission Costs
- Long-Range Load Forecast
- Calculation of Resource Adequacy
- Explanation of Round Two Portfolio Results (Base Case)
- Explanation of Scenario Results (Alternate Futures)
- Risk Measures
- Purchased Power Agreement Assumptions

Planning and Risk Model Description

Much of the analysis for this IRP was performed using modeling software purchased from a leading industry consulting firm, Global Energy Decisions. The software used is a portfolio management package specific to the electric operations called “Planning and Risk” (P&R). P&R is a module for the MARKETSYM suite of products and has been used by many utilities for long term planning projects, including long term resource plans. P&R is an hourly dispatch model with Monte Carlo capabilities.

P&R was used by the IRP team to evaluate various resource portfolios by subjecting them to a range of market and operational conditions and then quantifying their performance. The primary factors that influence the performance of a resource portfolio were modeled stochastically to simulate the conditions under which utilities function. Variable factors include load, electric and gas prices, hydroelectric generation and outages.

P&R provides output data for the evaluation of physical generation assets, financial instruments, and transmission projects. For more information on P&R, see http://globalenergy.com/products-ma-planning-risk.asp

The Correlation Matrix

There are seven stochastic series that are correlated to mimic typical market and operational events for analyzing Seattle City Light's portfolio. In the following diagram, the "+, -, and 0" symbols denote the general sign of monthly correlation between the series where "+" indicates a positive relationship, "-" indicates a negative relationship and "0" indicates an orthogonal relationship. Each relationship between two series is represented by a set of independent monthly correlation coefficients. No coefficients of serial correlation are represented in this diagram.

Indices	Boundary Generation	Columbia River Generation	Skagit Generation	COB Price	MID-C Price	Natural Gas Price	SCL Loads
Boundary Generation							
Columbia River Generation	+						
Skagit Generation	+	+					
COB Price	-	-	-				
MID-C Price	-	-	-	+			
Natural Gas Price	0/-	0/-	0/-	+	+		
SCL Loads	0	0	0	+	+	0/+	

Variability of the Series

Each series identified above has expected values indicating the median probability path as determined through historical observation. Each series also has a set of seasonal short-term volatility parameters and mean reversion factors which are used to vary the result stochastically by month while reducing the difference between the actual and expected value over time. The combination of these effects allows the analyst to evaluate possible combinations of resources in conditions that simulate real life market and operational events. See next section for more information on the treatment of stochastic variables in the Planning and Risk Model.

Treatment of Stochastic Variables in Planning and Risk

The stochastic process employed by Global Energy Decision's *EnerPrise Planning and Risk* model is a two-factor, lognormal, mean-reversion model. One factor represents short-run variations that are mean reverting. In the case of market price, for example, these variations might come from weather events or plant outages. The other factor represents longer-term variations that follow a random walk. Using price again as an example, these variations reflect the effects of factors such as uncertain fuel supply, load growth, or variations in hydro generation.

Mean reversion implies that after the variable is initially displaced from its expected value, it will tend to revert back towards it over time. The model uses separate volatility and correlation parameters to capture short-run and long-term variations. The rate at which the random variable reverts to the expected value, the correlations and volatilities are inputs that are typically estimated from historical data for the variable in question.

The specific equations are:

$$S_{n,t} = S_{n,t-1} + L_{n,t} - L_{n,t-1} + \alpha_{n,t}(L_{n,t-1} - S_{n,t-1}) + \sigma^S_{n,t}\varepsilon^S_{n,t} - \mathrm{Var}[S_{n,t}]/2$$

$$L_{n,t} = L_{n,t-1} + \delta_{n,t} - (\sigma^L_{n,t})^2/2 + \sigma^L_{n,t}\varepsilon^L_{n,t}$$

$$\mathrm{E}\,[\varepsilon^S_{n,t} \cdot \varepsilon^L_{n,t}] = \mathrm{Cov}^{S,L}_{n,t} = 0 \Rightarrow \rho^{S,L}_{n,t} = 0$$

$$\mathrm{E}\,[\varepsilon^S_{m,t} \cdot \varepsilon^S_{n,t}] = \mathrm{Cov}^S_{m,n,t} \neq 0 \Rightarrow \rho^S_{m,n,t} \neq 0$$

$$\mathrm{E}\,[\varepsilon^L_{m,t} \cdot \varepsilon^L_{n,t}] = \mathrm{Cov}^L_{m,n,t} \neq 0 \Rightarrow \rho^L_{m,n,t} \neq 0$$

Where

E = the expectation operator

m = commodity (fuel price, power price, load, or hydro generation)

n = commodity (fuel price, power price, load, or hydro generation)

t = time step (day for prices and loads, or week for hydro generation)

S_n = logarithm of short-run or spot price for commodity *n*

L_n = logarithm of long-run or equilibrium price for commodity *n*

$\alpha_{n,t}$ = rate of mean-reversion in spot price for commodity n in period *t*

$\delta_{n,t}$ = expected rate of growth (drift) of equilibrium price for commodity n in period *t*

$\sigma^2_{n,t}$ = volatility of spot price returns for commodity n in period *t*

σ^L_n = volatility of equilibrium price growth rate for commodity *n*

ε^S = normally distributed random vector (mean = 0, s.d.= 1)

ε^L = normally distributed random vector (mean = 0, s.d.= 1)

$\rho^{S,L}$ = correlation of spot and long run price stochastic changes

$\rho^S_{m,n}$ = correlation of spot price stochastic changes for commodities *m* and *n*

$\rho^L_{m,n}$ = correlation of drift rate stochastic changes for commodities *m* and *n*

Var() = variance

$\mathrm{Cov}_{m,n}$ = variance-covariance matrix for stochastic changes in commodities *m* and *n*

The model is quite general, and suitably parameterized can capture the features of many real stochastic processes quite well. It uses a linear congruential pseudo-random number generator to produce the pseudo random terms, and antithetical sampling to reduce sampling variance and increase speed.

Stochastic Parameters: Short-Term

Global Energy Decisions provided estimates of short-term volatility and mean-reversion parameters for the processes for prices, load, and hydro generation from least squares regressions on historical data. They excluded the period of the energy crisis for power prices and capped gas prices at $20/MMBtu.

The model draws daily values for power prices, shaping them to produce hourly spot prices for that day.

To estimate the parameters for the hydro generation, Global Energy Decisions first divided the year in four "hydro generation" seasons: Summer (hold) July-October, Fall (draft) November-January, Winter (refill) February-March, and Spring (runoff) April-June. The regressions pooled the data for the same season across the years in the sample period. For the short-term correlations they used the correlation between the contemporaneous residuals of the regressions for each season.

The short-term mean reversion parameter for a variable can be estimated as follows. Let p = ln(P), where P is the spot (short-term) value of the variable. The discrete time mean-reversion process is:

$$p_t - p_{t-1} = (1 - e^{-\alpha})(\overline{p} - p_{t-1}) + \varepsilon_t$$

or

$$p_t = (1 - e^{-\alpha})\overline{p} + e^{-\alpha} \cdot p_{t-1} + \varepsilon_t$$

This equation can be re-parameterized as:

$$p_t = a + b \cdot p_{t-1} + \varepsilon_t$$

and although it contains lagged values of the dependent variable, it can be consistently estimated by ordinary least squares provided that the error term is not serially correlated to give an estimate of α, the mean reversion parameter.

Stochastic Parameters: Long-Term

Estimating long-term volatility and the correlation of variables for such electricity and natural gas prices is somewhat more subjective than estimating the short-term parameters for several reasons. First, wholesale market prices for electricity are not available for the twenty or more years that would be necessary to statistically estimate its long-run volatility. Regulation of natural gas wellhead and transmission rates in past years also make the available long-term prices for natural gas a more challenging subject for simulation.

For natural gas, an annual long-term volatility of 14.51% was adopted from econometric analysis by Pindyck (Energy Journal, 1998), based on data for the 1970-1996 period. This rate was scaled down to a daily rate by dividing by the square root of 365. Lacking long-term data for wholesale electricity prices, the assumption was made that the same annual long-term volatility is appropriate for electricity. This assumption may be justified by noting that electricity is a manufactured commodity whose long-run price is largely determined by the cost of fuel. Through experimental calibration and judgment, a long-term drift correlation rate of 0.95 was assumed between each pair of gas and electric prices, gas and gas prices, and electric and electric prices. This near-unity value results in electricity and natural gas prices tending to move together over any particular Monte Carlo trajectory.

Treatment of Air Emission Costs

Air emissions were explicitly included in the modeling and analysis of portfolios because of their importance 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 and history, each portfolio was assessed for the level of impact in each element and ranked high, moderate or low. (See the Final Environmental Impact Statement, Chapter 1 Summary, Table 1-5.)

For each generating resource portfolio, total emissions into the air of carbon dioxide, sulfur dioxide, nitrogen oxides, mercury, and particulates are estimated over the 20-year period. A monetary cost is applied to the emissions to facilitate evaluating 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 the how well the portfolios perform under different regulatory scenarios. These costs are included in the cost evaluations described above.

There are several methods to determine the societal costs of environmental impacts such as air emissions. In addition to the internalized cost comparisons described above, the net emissions for each resource portfolio (emissions generated minus emissions reductions from sales into the market that result in turning off of less efficient resources) are calculated. Global Energy Decisions (GED) has evaluated the cost of complying with recent federal emission limits that establish a cap on emissions of SO2, NOx, and mercury and a hypothetical goal of meeting the Kyoto limits on CO2. GED determined the per ton cost required to bring all emissions from power plants in the US to these limits. These per ton costs were used as a proxy for the environmental cost for each ton of emissions from a new power plant. It is assumed that any new source of generation will have to comply with the overall cap on emissions of SO2, NOx, mercury, and CO2 (if implemented). The per ton cost estimate for particulates was based on studies done for the Environmental Protection agency on the control cost of limiting this pollutant.

The measure for this criterion is both quantitative and qualitative. The qualitative impacts on elements of the environment are evaluated in the Draft and Final Environmental Impact Statements. The quantitative measure is the total emissions into the air of carbon dioxide (CO2), sulfur dioxide (SO2), nitrogen oxides (NOx), mercury (Hg), and particulate (PM). For each generating resource portfolio, emissions are estimated over the 20-year period. A cost measure is applied to the emissions to facilitate evaluating 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. Seattle 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 Seattle's resource portfolio that is comprised mostly 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. Seattle City Light assumes that carbon dioxide emissions must be offset according to City policy. Presently, carbon dioxide offsets are averaging $5 dollars/ton for Seattle City Light, resulting in higher costs for candidate resources consuming fossil fuels. A range of potential CO2 costs were used in the analysis, including the $5 offset price, going up to $25, or higher, depending on the scenario. See Appendix D – Technical Issues for details.

Calculating Quantity and Cost of Air Emissions

The amount of air emission of the greenhouse gas carbon dioxide (CO2) and four pollutants (nitrogen oxides (NOx), oxides of sulfur (SO2), mercury (Hg), and particulates (PM)) were calculated for each portfolio over the 20 year planning period.

Emission rates (the amount of pollutant emitted per unit electricity produced) for each resource type are listed below. Air emissions impacts resulting from electricity production will vary widely among the resource types, and between plants of the same type of technology, depending on its age and pollution control equipment. The numbers following assume new plants complying with existing air pollution control requirements.

Air Emissions per Unit of Electricity by Generation Type

	SO2 lbs/MWh	**NOx** lbs/MWh	**Mercury** lbs/MWh	**Particulates** lbs/MWh	**CO2** lbs/MWh
CCCT	0.00432	0.216	0	0.00504	857
SCCT	0.00581	0.2906	0	0.00678	1153
CHP	0.0028	0.0144	0	0.00336	571
Coal (Pulverized)	1.47	1.43	4.38x10^-5	0.133	1979
Coal (IGCC)	0.68	0.62	2.03x10^-6	0.0882	1979
Wind	0	0	0	0	0
Biomass (wood)	0	0.80	0	0.259	0(closed loop)
Landfill Gas	0	0.66	0	0.1067	0(closed loop)
Geothermal-Binary	0	0	0	0	0
Conservation	0	0	0	0	0
Hydro Efficiency	0	0	0	0	0

Market Emission Rates (Vary by Month)– Average, Minimum, Maximum

		Heat Rate Btu/kWh	NOX lb/MWh	SO2 lb/MWh	CO2 lb/MWh	Mercury lb/MWh	Particulates lb/MWh
Reference Case							
	ave	8,403	0.40	0.05	1,038	7.90E-06	0.20
	min	7,516	0.13	0.00	902	2.32E-06	0.01
	max	9,992	1.06	0.24	1,193	2.94E-05	1.40
Terrorism & Turmoil							
	ave	8,145	0.33	0.05	1,006	5.92E-06	0.26
	min	6,310	0.26	0.04	951	4.36E-06	0.18
	max	10,463	0.44	0.08	1,103	1.26E-05	0.58
Green World							
	ave	8,723	0.37	0.06	1,042	6.91E-06	0.31
	min	6,226	0.26	0.04	951	4.36E-06	0.18
	max	10,591	0.44	0.08	1,103	1.26E-05	0.58
Return to Reliability							
	ave	8,664	0.37	0.06	1,038	6.80E-06	0.30
	min	6,435	0.26	0.04	951	4.36E-06	0.18
	max	11,559	0.44	0.08	1,103	1.26E-05	0.58
Nuclear Resurgence							
	ave	9,283	0.41	0.07	1,069	7.48E-06	0.34
	min	6,265	0.26	0.04	951	4.36E-06	0.18
	max	10,676	0.44	0.08	1,103	1.26E-05	0.58

Once the emission rate for each resource is established, it is multiplied by the amount of energy produced by that resource in each portfolio to determine the total emissions. This is done for each of the five emission categories (CO2, NO_X, SO2, Hg and PM) in each portfolio. The general calculation is:

Emissions (pounds) = Emission Rate (pounds/MWh) x Electricity Produced (MWh)

Note, the cost of the pollution control required to meet existing regulations is included in the capital and operating costs of each resource that was used in the model. Even with these controls, there will be remaining "residual emissions." The emission rate indicates SCL how much of each pollutant is still being emitted, because the pollution control equipment does not eliminate 100% of the emissions.

To determine a "cost" associated with residual emissions, a "price tag" for each pound of greenhouse gas or pollutant must be chosen. This is a complex process and there is no single correct answer, given the range of views and lack of precise knowledge, about the relative value of environmental impacts. In the absence of any regulatory requirement, these costs are labeled externality costs. If, through regulations or some other means, these costs are actually determined and paid for by the source of the residual emissions, they are then considered to have been internalized.

The distinction between external cost and those that are internalized has been an important one in the evaluation of environmental impacts and costs in IRPs, but may be blurred under new regulatory requirements. The structure of recent EPA regulations, and most of the proposed state and federal legislation for greenhouse gas emission limits, relies on an approach called cap and trade. Under cap and trade, there are firm limits on total emissions from the entire power industry, so a new plant would have to buy allowances, or permits, to emit pollutants. Most probably, new plants would purchase emission allowances. So, under likely future regulation regimes, external costs are at least partially internalized.

In this IRP, the potential cost of new regulations has been used as a proxy for external costs. This approach does not calculate the "damage cost" of the emissions - the cost of the health and environmental impacts of emissions above the required controls. There are no recent estimates of damage costs, and they are difficult to calculate.

For the Reference Case, Global's cost estimates ($/ton) for meeting EPA's new (Spring 2005) regulations for NOx, SO2, and mercury, and for particulates (Global based particulate data on EPA estimates), were used. In each of the other Global scenarios, Global made different assumptions about the level and timing of future air emission limits. These assumptions resulted in different timing and levels of emission costs. For CO2, SCL's mitigation cost estimates will be used, except for the Green World and Nuclear Resurgence futures, where Global's CO2 cost estimates will be used.

The NPV of the cost of emissions from new generation resources and contracts for the Round 2 portfolios 7 and 8 (P7 – More Wind, and P8 – More Geothermal) are shown below. Note that the negative numbers in the Contracts column are the result of exchanges in which City Light delivers energy during periods when market emissions rates are higher because less efficient power plants are selling into the wholesale market (thus displacing those emissions) and receives a smaller amount of energy in return, at times when the market emissions rates are lower. There is very little difference between the portfolios.

NPV (3%) – 20 Year	Portfolio 7 – More Geothermal		Portfolio 8 – More Wind	
	Generation	Contracts	Generation	Contracts
CO2	0	$5,871,889	0	$5,871,889
NOx	$1,250,725	$14,285	$1,249,497	$14,285
SO2	0	($64,787)	0	($64,787)
Mercury	0	($59)	0	($59)
Particulates	$406,026	($675,672)	$405,369	($675,672)
Total	$1,656,751	$5,145,656	$ 1,654,866	$5,145,656
Total 20 Year NPV (Generation+Contracts)	**$6,802,407**		**$6,800,522**	

More detailed information about the environmental impact of the portfolios is contained in the Draft and Final Environmental Impact Statements. They cover impacts to elements of the environment, including soils and geology, air quality, surface and groundwater, plants and animals, energy and natural resources, environmental health, land use, aesthetics and recreation, cultural resources, and employment.

Emission Costs Used in the Reference Case

Year	CO2 2006$/ton	SO2 2005$/ton	NOx 2005$/ton	Hg 2005$/lb	Particulates
2007	$5.00	$1,102	$1,261	$3,000	$ 3,300
2008	$5.00	$1,102	$1,261	$3,000	$ 3,300
2009	$5.00	$1,102	$1,261	$3,000	$ 3,300
2010	$5.00	$1,102	$1,261	$35,000	$ 3,300
2011	$5.00	$1,102	$1,261	$35,000	$ 3,300
2012	$5.00	$1,102	$1,261	$35,000	$ 3,300
2013	$5.00	$1,102	$1,261	$35,000	$ 3,300
2014	$5.00	$1,102	$1,261	$35,000	$ 3,300
2015	$5.00	$1,746	$1,970	$35,000	$ 3,300
2016	$5.00	$1,746	$1,970	$35,000	$ 3,300
2017	$5.00	$1,746	$1,970	$35,000	$ 3,300
2018	$5.00	$1,746	$1,970	$35,000	$ 3,300
2019	$5.00	$1,746	$1,970	$35,000	$ 3,300
2020	$5.00	$1,746	$1,970	$35,000	$ 3,300
2021	$5.00	$1,746	$1,970	$35,000	$ 3,300
2022	$5.00	$1,746	$1,970	$35,000	$ 3,300
2023	$5.00	$1,746	$1,970	$35,000	$ 3,300
2024	$5.00	$1,746	$1,970	$35,000	$ 3,300
2025	$5.00	$1,746	$1,970	$35,000	$ 3,300
2026	$5.00	$1,746	$1,970	$35,000	$ 3,300

Emission Costs Used in the Green World Scenario

Year	CO2 2006$/ton	SO2 2005$/ton	NOx 2005$/ton	Hg 2005$/lb	Particulates
2007	$5.00	$1,127	$1,747	$3,000	$ 3,300
2008	$5.00	$1,127	$1,747	$3,000	$ 3,300
2009	$5.00	$1,127	$1,747	$3,000	$ 3,300
2010	$5.00	$1,127	$1,747	$35,000	$ 3,300
2011	$5.00	$1,127	$1,747	$35,000	$ 3,300
2012	$5.00	$1,127	$1,747	$35,000	$ 3,300
2013	$5.00	$1,127	$1,747	$35,000	$ 3,300
2014	$20.87	$1,127	$1,747	$35,000	$ 3,300
2015	$24.96	$1,811	$2,183	$35,000	$ 3,300
2016	$29.24	$1,811	$2,183	$35,000	$ 3,300
2017	$33.72	$1,811	$2,183	$35,000	$ 3,300
2018	$38.40	$1,811	$2,183	$35,000	$ 3,300
2019	$45.92	$1,811	$2,183	$35,000	$ 3,300
2020	$53.80	$1,811	$2,183	$35,000	$ 3,300
2021	$62.03	$1,811	$2,183	$35,000	$ 3,300
2022	$70.65	$1,811	$2,183	$35,000	$ 3,300
2023	$73.86	$1,811	$2,183	$35,000	$ 3,300
2024	$77.19	$1,811	$2,183	$35,000	$ 3,300
2025	$80.64	$1,811	$2,183	$35,000	$ 3,300
2026	$84.22	$1,811	$2,183	$35,000	$ 3,300

Emission Costs Used in the Return to Reliability Scenario

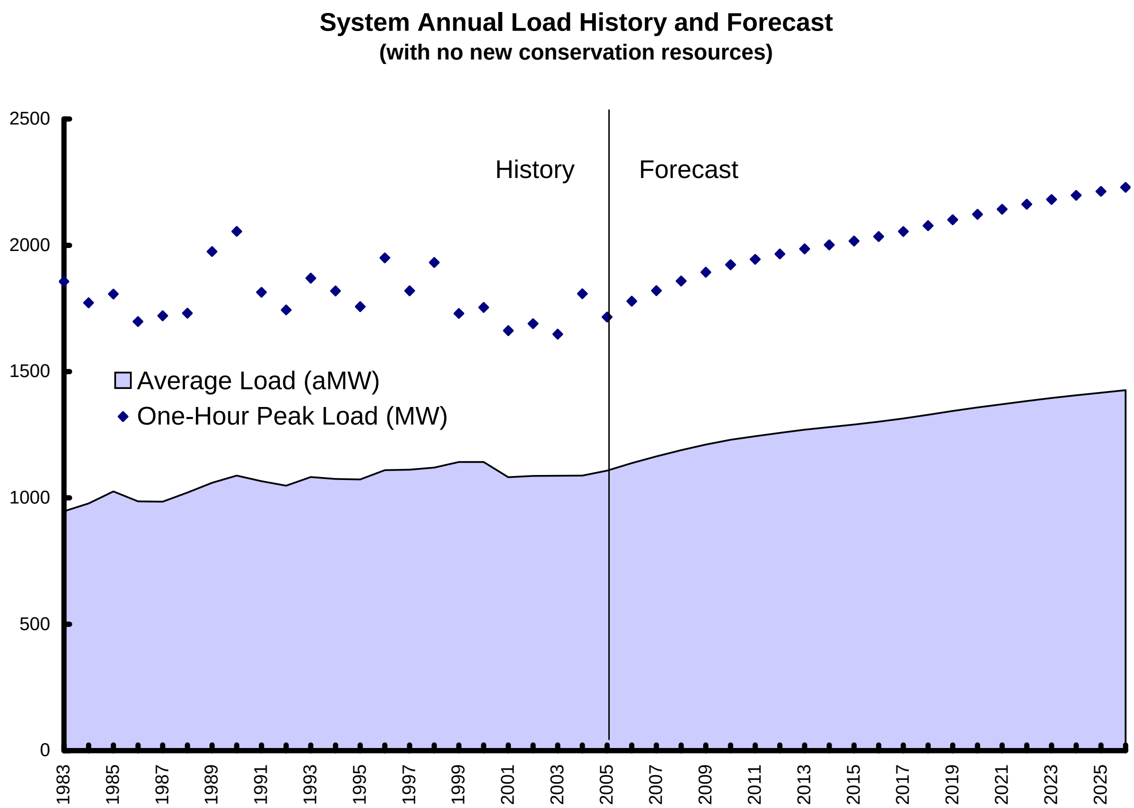
Year	CO2 2006$/ton	SO2 2005$/ton	NOx 2005$/ton	Hg 2005$/lb	Particulates
2007	$5.00	$1,127	$1,747	$3,000	$ 3,300
2008	$5.00	$1,127	$1,747	$3,000	$ 3,300
2009	$5.00	$1,127	$1,747	$3,000	$ 3,300
2010	$5.00	$1,127	$1,747	$35,000	$ 3,300
2011	$5.00	$1,127	$1,747	$35,000	$ 3,300
2012	$5.00	$1,127	$1,747	$35,000	$ 3,300
2013	$5.00	$1,127	$1,747	$35,000	$ 3,300
2014	$5.00	$1,127	$1,747	$35,000	$ 3,300
2015	$5.00	$1,811	$2,183	$35,000	$ 3,300
2016	$5.00	$1,811	$2,183	$35,000	$ 3,300
2017	$5.00	$1,811	$2,183	$35,000	$ 3,300
2018	$5.00	$1,811	$2,183	$35,000	$ 3,300
2019	$5.00	$1,811	$2,183	$35,000	$ 3,300
2020	$5.00	$1,811	$2,183	$35,000	$ 3,300
2021	$5.00	$1,811	$2,183	$35,000	$ 3,300
2022	$5.00	$1,811	$2,183	$35,000	$ 3,300
2023	$5.00	$1,811	$2,183	$35,000	$ 3,300
2024	$5.00	$1,811	$2,183	$35,000	$ 3,300
2025	$5.00	$1,811	$2,183	$35,000	$ 3,300
2026	$5.00	$1,811	$2,183	$35,000	$ 3,300

Emission Costs Used in the Nuclear Resurgence Scenario

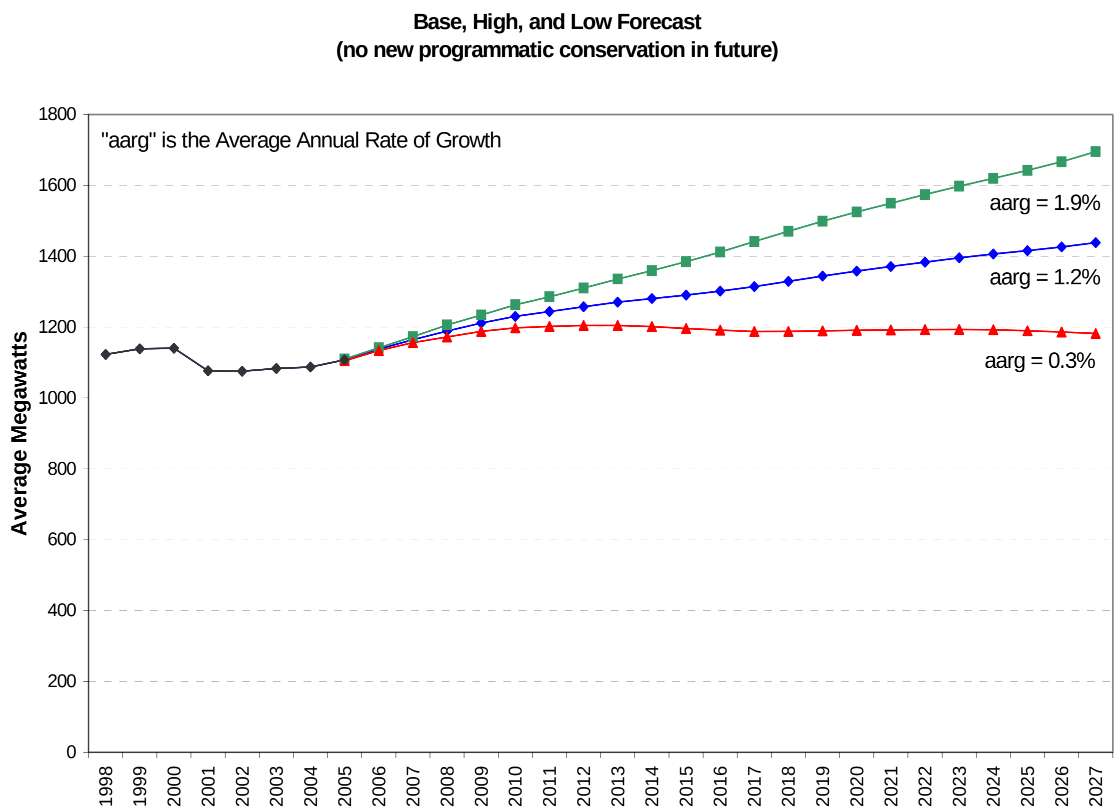
Year	CO2 2006$/ton	SO2 2005$/ton	NOx 2005$/ton	Hg 2005$/lb	Particulates
2007	$5.00	$1,127	$1,747	$3,000	$ 3,300
2008	$5.00	$1,127	$1,747	$3,000	$ 3,300
2009	$5.00	$1,127	$1,747	$3,000	$ 3,300
2010	$5.00	$1,127	$1,747	$35,000	$ 3,300
2011	$5.00	$1,127	$1,747	$35,000	$ 3,300
2012	$5.00	$1,127	$1,747	$35,000	$ 3,300
2013	$5.00	$1,127	$1,747	$35,000	$ 3,300
2014	$20.87	$1,127	$1,747	$35,000	$ 3,300
2015	$24.96	$1,811	$2,183	$35,000	$ 3,300
2016	$29.24	$1,811	$2,183	$35,000	$ 3,300
2017	$33.72	$1,811	$2,183	$35,000	$ 3,300
2018	$38.40	$1,811	$2,183	$35,000	$ 3,300
2019	$45.92	$1,811	$2,183	$35,000	$ 3,300
2020	$53.80	$1,811	$2,183	$35,000	$ 3,300
2021	$62.03	$1,811	$2,183	$35,000	$ 3,300
2022	$70.65	$1,811	$2,183	$35,000	$ 3,300
2023	$73.86	$1,811	$2,183	$35,000	$ 3,300
2024	$77.19	$1,811	$2,183	$35,000	$ 3,300
2025	$80.64	$1,811	$2,183	$35,000	$ 3,300
2026	$84.22	$1,811	$2,183	$35,000	$ 3,300

Long-Range Load Forecast

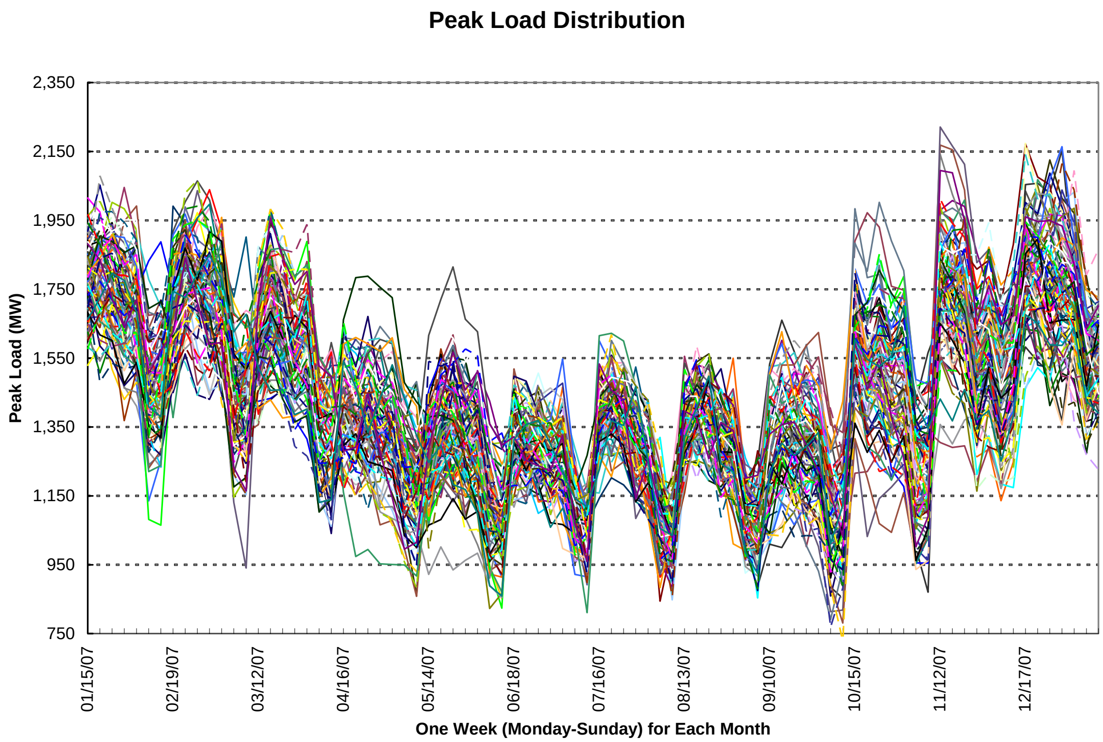
The long-range forecast of system load and peak was adjusted in preparation for the IRP analysis. The published system load forecast assumes that the utility continues to pursue the acquisition of cost-effective conservation twenty years into the future. For the IRP, conservation is treated as a resource, along with other resource types, to meet load. The conservation assumption in the published forecast, therefore, had to be backed out of the Utility's long-range forecast in order to create a base forecast for IRP modeling that does not include conservation. The forecast of peak load was also adjusted. The graph below shows system load and peak load history from 1983 and the forecast through 2026.



In order to take uncertainty into account, the Utility also produces a high and a low forecast. These forecasts were adjusted in order to add back the conservation assumed in the published forecast, consistent with the adjustment made to the base forecast. The graph below shows the base, high, and low load forecasts, under the assumption of no new programmatic conservation. The high forecast has an average annual growth rate of 1.9%; the base forecast, a rate of 1.3%; and the low, 0.3%. It is estimated that there is a 90% probability that actual load (adjusted for conservation) would fall between the high and low forecasts.



SCL provided GED with actual hourly load history for the period 1990-2004, as well as an hourly forecast of load (adjusted for conservation) through 2026, for use in their Risk and Planning model. These data were used to develop a range of probable peak load for a representative week (Monday through Sunday) for each month of the year. For each day, there are 100 data points, based on historic frequency distributions and the forecast of load. Load varies more in the winter than in summer, and more on weekdays than weekends. Data for 2007 are shown in the table below.

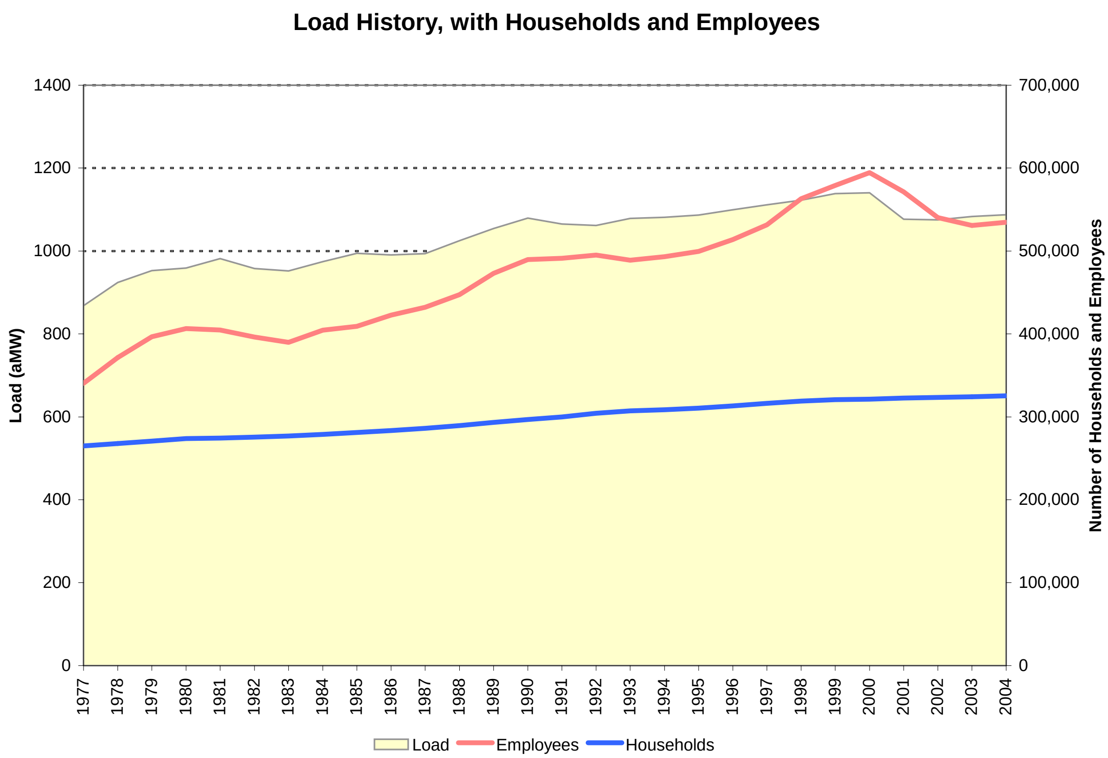


Below is a summary of the published long-range load forecast of system load and how it was developed.

Economic and Demographic Forecast

The forecast of load growth is based on forecasts of many demographic and economic variables for the service area. Dick Conway and Associates produces the economic and demographic series for SCL's service area that are inputs to the Utility's load forecasting model. For each of nine customer sectors, the load forecasting model uses the correlations between load history and the histories of selected economic and demographic variables to project future load. The main drivers for the load forecast are the number of households and the number of employees for several commercial and industrial categories in the service area.

The graph below shows service area load, households and employees for the period 1977 through 2003. The relationship between system load and the number of employees is strong, though the amount of consumption per employee has been declining since the mid-1980s. The Utility began promoting conservation to its non-residential customers at about that time. The decline in consumption per employee is also likely due to the change in mix of manufacturing and non-manufacturing jobs in the service area. The number of households continues to grow, though consumption per household is also declining.

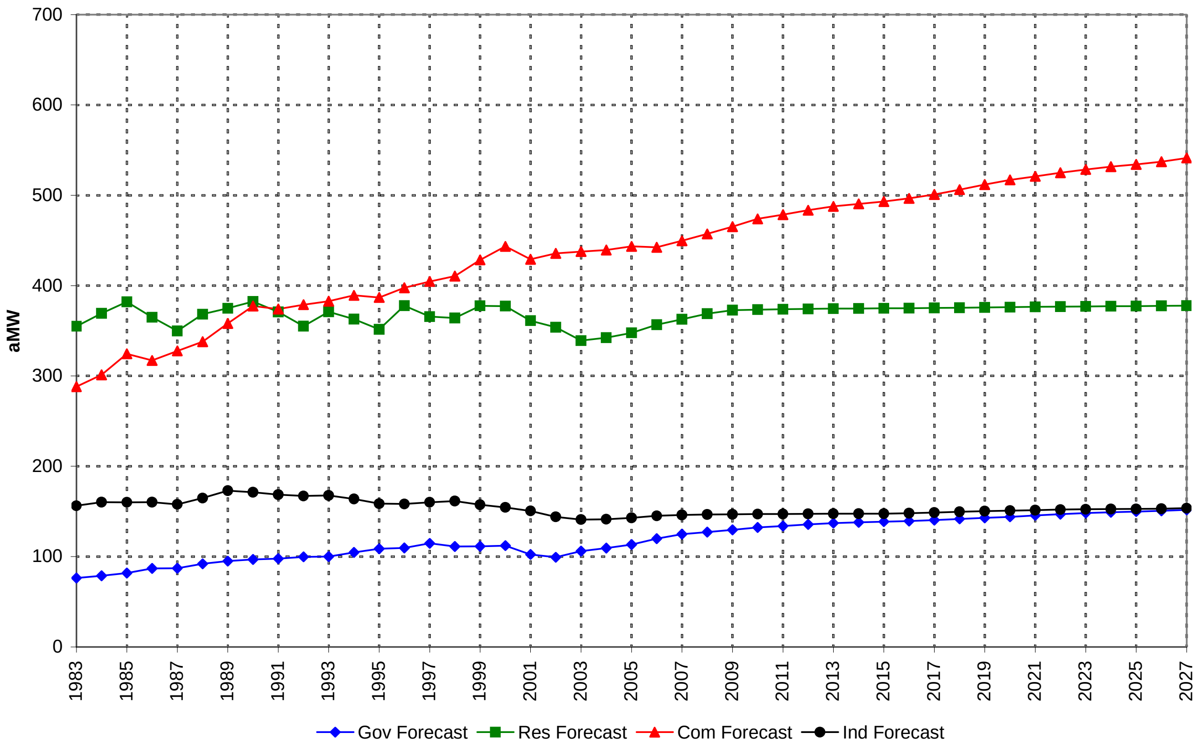


Load Forecast by Sector

The long-range system load forecast is built up from separate forecasts of nine sectors: residential, commercial, government, food, metal, stone, aerospace, ship building, and other manufacturing. Using historical power consumption, economic, and demographic data, equations are estimated for each sector. For industrial sectors that have only a small number of number of large firms, adjustments may be made based on relevant information about particular firms.

Power consumption by the major customer classes—residential, commercial, government, and industrial—has grown at different rates. Commercial consumption has grown the fastest and has outstripped residential consumption since the early 1990s. This trend is expected to continue through the forecast period. The load forecast assumes that commercial load recovery will lead, followed by load recovery in the government sector, then the residential sector. The graph below shows load history for residential, commercial, government, and industrial classes.

History (through 2003) and Forecast of Class Load



In addition to power consumed by retail customers, the system load forecast includes an estimate of power the utility must generate in order to cover losses (e.g., line losses) and power consumed in operations.

Residential Load Growth

The residential class is expected to exhibit a slower rate of growth in the future. Although the number of residential units will continue to increase as a result of increasing density, average power consumption per household is not expected to increase. The historic decline in consumption per household can be attributed to several factors. Many single-family houses switched from electric space and water heating to natural gas in the 80s and 90s. Conservation measures have been installed by single family and multi-family building owners, with and without utility incentives. Most new residential construction is apartment and condominiums, changing the mix of housing types in favor of smaller units. New construction is also energy efficient, as are new appliances. Residential customers have also decreased consumption in response to the 58% increase in electric rates in the early 2000s.

Non-Residential Load Growth

The commercial sector is expected to continue to be the fastest-growing. Office towers and buildings continue to be built as downtown expands north to the Lower Queen Anne and South Lake Union areas, and south to the SODO (south of downtown) area. Load growth for the industrial sector is flat or even declining slightly as light manufacturing moves to suburbs south and north of the service area. The government sector will grow with transportation infrastructure construction and various Port of Seattle ventures.

The average annual rate of growth for the system load forecast through 2027 is 0.8%. We expect that the pre-recession high of 1,141 aMW will be reached in 2007, when the number of jobs in the service area is projected to regain its previous high.

Calculation of Resource Adequacy

The calculation of resource adequacy is very important to the 2006 Integrated Resource Plan because it is the basis of the design of all prospective portfolios under consideration in the plan. Resource adequacy is typically a measure of both energy (MWh) and capacity (MW). Seattle City Light has the benefit of significant hydro resources at its disposal and so is not likely to be capacity constrained. For this reason the discussion of resource adequacy for our purposes will center on energy sufficiency.

The importance of resource adequacy to the study contributed to the methodology used. The Planning and Risk model (P&R) produced the stochastic elements of the study, but the majority of the calculations were completed in a spreadsheet where the separate steps, detailed in the following, could be observed.

- Used P&R to generate 3250 iterations of generation and load (GWh). This was done by changing the "seed" values and chaining multiple runs together to get a data set with increased size sufficient for the study. The data was generated monthly and included all existing resources, no new conservation efforts and the assumption that our BPA contracts would continue under current conditions.

  Energy not served (ENS) is defined by

  $ENS_{m,i} = MAX(LOAD_{m,i} – GENERATION_{m,i}\ ,0)$ where m=month, i=iteration

- Calculated the amount expected to be available from the market. It was assumed Seattle City Light would have access to 100 MW of purchased power in each hour even under the most constrained conditions. This was converted to an energy number (GWh) by month and by iteration.

- Calculated the amount that could be provided by new generation. The capacities of new possible generation used are the following: (0 MW, 15 MW, 25 MW, 35 MW, 50 MW, 75 MW, 100 MW, 125 MW, 150 MW, 175 MW, 200 MW, 225 MW, 250 MW, 300 MW, 350 MW, 400 MW, 450 MW, 500 MW, 600 MW). For each of these amounts, the energy amount (GWh) was calculated and added to the amount available from step 3 (market energy available).

  $ENS'_{m,i} = MAX(ENS_{m,i} - (MARKET_{m,i} + NEW\ GENERATION_{m,i}),0)$

The number of ENS' that was greater than zero was counted by month. This number of "months with insufficient energy" was divided by the total number of iterations to give a percentage. This percentage indicated the percent of iterations that failed to provide sufficient energy with the indicated amount of new generation. This percentage when looked at from a success rate gives the level of resource adequacy that would be attained with this level of new generation. This was calculated for the following levels of resource adequacy: 80%, 85%, 90%, 92.5%, 95%, 97.5%, and 99%.

Example: In January 2008, with 175 MW of additional generation there were 115 iterations out of 3250 that had positive ENS after adding 100 MW from the market. This is 3% of the iterations and therefore would be a suitable outcome for a 97% resource adequacy level.

The 95% level of resource adequacy was chosen as an appropriate benchmark for Seattle City Light system reliability and so the generation that would be required under each month was calculated from this study and provided.

Explanation of Round Two Portfolios Results (Base Case)

This section discusses the quantitative findings of Round 2 analysis and is segmented into the following sections:

- Capital Costs (Plant, Transmission, Conservation Program Spending)
- Variable Costs (Fuel, Start Up, O&M, CO2 Offset)
- Net Revenues from Purchases and Sales
- Externality Costs of Air Emissions
- Risk (Stochastic treatment of variation in costs and revenues)

It should be noted that all costs are discounted by 3% per annum and in all costs are relative to the "base case" or "no action" case (P1).

Capital Costs

The financing of capital costs is modeled on the assumption that proposed resources are developed by a third party (an independent power producer, or IPP) and the generation would be secured by purchased power agreement. The terms of the financing assumed for the IPP is 60% debt financing at 7% APR and a 15% return on equity. Costs are in thousands of real dollars using a real discount rate of 3% per annum.

	Fixed Costs ($000s NPV)	Plant	Trans-mission	Conserva-tion	Total
P1	Do Nothing	$ -	$ -	$ -	$ -
P2	Geo100 Wind55 Hydro23 LFG25 Bio15, Accel Cons	$ 518,432	$ 18,722	$ 240,217	$ 777,371
P3	Geo125 Wind50 LFG25 Hydro23, Accel Cons	$ 512,999	$ 16,835	$ 240,217	$ 770,051
P4	Geo50 Ex40 SCCT50 LFG25 Hydro23, 7aMW Cons	$ 312,567	$ 10,530	$ 200,961	$ 524,057
P5	Geo75 Ex45 LFG25 Hydro23 Wind20, 7aMW Cons	$ 350,153	$ 14,633	$ 200,961	$ 565,747
P6	Geo120 Wind50 LFG25, Accel Cons.	$ 411,633	$ 10,317	$ 240,217	$ 662,167
P7	Wind 105, Geo 50, Bio 15, Hydro 23, LFG25, 7aMW Cons	$ 621,908	$ 27,395	$ 200,961	$ 850,264
P8	Geo 100, Wind 55, Bio 15, Hydro 23, LFG 25, 7aMW Cons	$ 565,148	$ 18,799	$ 200,961	$ 784,908

Variable Costs

Variable Costs are expenditures related to resource dispatch, the generation of power, and its transmission. The variable costs below are estimates of the incremental cost of each portfolio but do not include the costs of operating Seattle City Light's current resource portfolio. These variable costs are annual summations of the monthly average values taken from a probabilistic modeling approach.

Some information regarding portfolio cost will reflect data provided in Appendix C - Resources for Future Monitoring and Evaluation. Below are additional assumptions regarding resource operation that may not be included elsewhere.

Fuel Cost Assumptions:

- Biomass – partial collection cost and opportunity cost: $2.00 per MMBtu
- Landfill Gas – opportunity cost: $1.00 per MMBtu
- Natural Gas – based on Global Energy Decisions WECC Fall 2005 Forecast

Plant Operation Restrictions:

- Dispatchable resources including biomass, gas fired, geothermal, and landfill gas generation were constrained by chronological and economic constraints to prevent unrealistic hourly dispatching driven by economic and operational optimization. Most of the restrictions included a minimum run time, minimum down time, warm-up time, and stop costs.
- Variable O&M costs include any applicable federal production tax credits (PTC). Renewed production tax credits were only assumed to apply to wind resources constructed before 2010 and non-wind renewable resources constructed before 2011. In the eight resource portfolios of round 2, only the landfill gas plants constructed in 2010 were rewarded PTC for ten years at a rate of $15.20/MWh.

- CO2 Offset Costs were applied at a rate of $5.00 (2006$) per ton of CO2 emissions.

	Variable Costs and Benefits ($000s NPV)	Fuel Cost	Start Up Cost	Relative Variable O&M	CO2 Offset Costs	Fixed O&M	Relative Subtotal Variable Costs
P1	Do Nothing	$ -	$ -	$ -	$ -	$ -	$ -
P2	Geo100 Wind55 Hydro23 LFG25 Bio15, Accel Cons	$24,347	$2,650	$ 9,848	$ -	$116,666	$153,510
P3	Geo125 Wind50 LFG25 Hydro23, Accel Cons	$17,608	$2,475	$ 8,001	$ -	$152,143	$180,227
P4	Geo50 Ex40 SCCT50 LFG25 Hydro23, 7aMW Cons	$40,377	$2,238	$(10,934)	$1,427	$ 82,029	$115,137
P5	Geo75 Ex45 LFG25 Hydro23 Wind20, 7aMW Cons	$23,075	$2,113	$(10,458)	$ -	$ 99,869	$114,600
P6	Geo120 Wind50 LFG25, Accel Cons.	$17,638	$1,958	$ 7,435	$ -	$129,753	$156,783
P7	Wind 105, Geo 50, Bio 15, Hydro 23, LFG25, 7aMW Cons	$27,619	$1,889	$ 18,766	$ -	$127,554	$175,828
P8	Geo 100, Wind 55, Bio 15, Hydro 23, LFG 25, 7aMW Cons	$27,550	$2,111	$ 10,877	$ -	$141,178	$181,717

Net Revenues from Purchases and Sales

From the probabilistic analysis of loads and generation, it was estimated that Seattle City Light currently has sufficient resources to meet at least an 83% resource adequacy level, on average allowing for only modest purchases of 100 aMW or less per month in the highest load months. Achieving a reliability standard to 95% now and through the future means adding resources. Washington Initiative I-937 which recently passed also requires Seattle City Light to purchase additional power generation over the next twenty years.

This amounts to a situation where Seattle City Light will have surplus generation and will be looking to selling it power production into the regional market to recapture some of the capital expenditures made to build this generation. Most of Seattle City Light's power production comes from hydroelectric dams. Hydro production is typically low in the summer and winter, and high in the spring. This means that surplus power is often sold into a low price market and purchases are made from a high priced market.

The following data indicates the Costs (Revenues) of Market Purchases and Sales. It reflects only new resources and new power purchase agreements.

	Reliability Measures	Market Purchases Less Sales (GWh)	Cost of Market Purchases Less Sales ($000's NPV)
P1	Do Nothing	-	$ -
P2	Geo100 Wind55 Hydro23 LFG25 Bio15, Accel Cons	(32,079.83)	$ (948,690)
P3	Geo125 Wind50 LFG25 Hydro23, Accel Cons	(32,913.70)	$ (966,498)
P4	Geo50 Ex40 SCCT50 LFG25 Hydro23, 7aMW Cons	(24,323.13)	$ (747,216)
P5	Geo75 Ex45 LFG25 Hydro23 Wind20, 7aMW Cons	(25,141.54)	$ (750,893)
P6	Geo120 Wind50 LFG25, Accel Cons.	(27,596.37)	$ (819,820)
P7	Wind 105, Geo 50, Bio 15, Hydro 23, LFG25, 7aMW Cons	(29,451.43)	$ (872,402)
P8	Geo 100, Wind 55, Bio 15, Hydro 23, LFG 25, 7aMW Cons	(29,039.55)	$ (862,152)

Externality Costs of Air Emissions

One of the important criteria of portfolio evaluation is that of environmental impacts. The following data estimates of air pollutants are calculated from two sources. The first source is from generated emissions based on the dispatch of proposed portfolios. The second source is the estimated indirect pollutants of regional generation that would either supplement or be replaced by Seattle City Light's market activities. These market based emissions per MWh of sales and purchases vary by month and time of day.

For information on air emissions and their costs by portfolio please refer to the Environmental Impact Statement.

Explanation of Scenario Results (Alternate Futures)

The highlights of performing Planning and Risk runs of the eight portfolios under alternate future energy prices and carbon emission taxes is described below. Refer to Table 5-1 in Chapter 5 of the main document for descriptions of the alternate futures used in scenario analysis.

Green World

The critical characteristics of this scenario are the substantial increases in CO_2 taxes post 2010 and higher energy prices. The effects on the variable costs are most notable in the increased cost of running the SCCT in portfolio 4. Portfolios 2, 7, and 8 all have biomass plants which would use more fuel as they are dispatched at a greater frequency to capture economic benefits of high power prices. CO_2 taxes are included in the model and still the SCCT runs enough to accrue an increase of over $4 million in CO_2 taxes. With power prices escalating above the marginal cost of generation, portfolios with excess capacity appear strongly profitable. Caution must be exercised when interpreting these numbers; slight changes in a multitude of uncontrollable factors could eliminate these expected "profits". The Green World scenario clearly points out that a combination of high natural gas prices and CO_2 taxes reduce the attractiveness of fossil fuel generation (SCCT).

Green World - (Costs in NPV $000)

	Changes to Fuel Costs	Changes to Purchases Less Sales	Changes to Carbon Offset Costs
P1	$ -	$ -	$ -
P2	$18,346	$(1,916,366)	$ -
P3	$ 3,733	$(1,919,788)	$ -
P4	$56,200	$(1,042,150)	$4,111
P5	$ 3,590	$ (992,773)	$ -
P6	$ 2,299	$(1,122,289)	$ -
P7	$27,348	$(1,833,401)	$ -
P8	$27,144	$(2,166,205)	$ -

Nuclear Resurgence

Tight energy supply leads to higher prices which then subside with the advent of new era in nuclear generation. Fuel costs for the seven portfolios increase, but not to the heights of "Green World". In terms of market transactions the kinked power price forecasts makes timing of generation additions very important. Portfolios 2, 3, and 6 lose out to portfolios 7 and 8 by having higher amounts of conservation and lower amounts of generation capacity which can be more easily marketed. CO2 taxes are imposed post 2014, and this adds over $2.5 million in taxes to P4.

Nuclear Resurgence - (Costs in NPV $000)

	Changes to Fuel Costs	Changes to Purchases Less Sales	Changes to Carbon Offset Costs
P1	$ -	$ -	$ -
P2	$13,989	$ (548,526)	$ -
P3	$ 2,924	$ (550,501)	$ -
P4	$35,971	$ (364,547)	$2,714
P5	$ 2,566	$ (326,740)	$ -
P6	$ 1,806	$ (410,697)	$ -
P7	$21,327	$(1,268,687)	$ -
P8	$21,217	$(1,256,098)	$ -

Return to Reliability

Overall reduction in energy prices leads to fewer resources being "in the money". An increased reliance regionally on gas-fired generation undercuts some of the portfolios with higher marginal costs. This leads to a reduction in fuel costs overall and a reduction in economic dispatch of plants (sales). Carbon output is down in a more competitive power market.

Return To Reliability - (Costs in NPV $000)

	Changes to Fuel Costs	Changes to Purchases Less Sales	Changes to Carbon Offset Costs
P1	$ -	$ -	$ -
P2	$ 5,287	$(239,073)	$ -
P3	$ 5,155	$(231,871)	$ -
P4	$ 8,880	$(179,898)	$(1,482)
P5	$ 1,129	$(179,355)	$ -
P6	$ 952	$(201,915)	$ -
P7	$ 6,845	$(225,236)	$ -
P8	$ 6,780	$(222,446)	$ -

Risk Measures

Risk is a measure of uncertainty. The amount of hydroelectric generation held by Seattle City Light in comparison to other utilities is prone to a high degree of uncertainty. The quantity of water flow, the natural timing of its arrival at SCL dams, and the decisions of other utilities governing water flow are all uncertain. Energy markets, while related to hydro flows, are also very uncertain and can lead to additional revenue uncertainty. In order to express this uncertainty, it is beneficial to examine quantitatively the expected level of risk that is characteristic of each of the evaluated portfolios.

Risk metrics are for the final year of the study and are nominal. The reason that risk metrics are only generated for the final year in the study is to avoid capturing the variation of a changing portfolio over time and interpreting it as variation between portfolios. Risk measures are also calculated without discounting. The risk metric is only a measure of relative variability and has no value as a discounted measure in NPV terms.

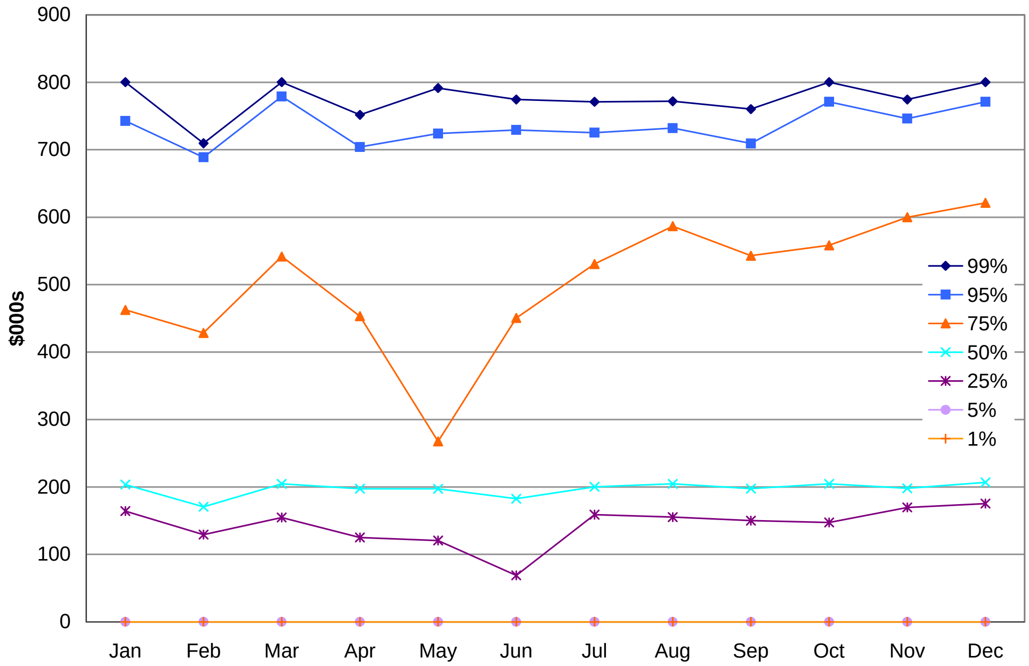
Please note that Fuel Cost and Variable O&M graphs are accurate for their depiction of costs from the addition of resources and do not carry costs from the existing portfolio. However, Net Purchases (Sales) graphs do include the output of the existing portfolio. Total Cost data also include the proceeds from market sales as well.

For each future and portfolio the Coefficient of Variation (CV) was also calculated. The CV is simply the standard deviation of the 100 scenarios divided by the mean of the 100 scenarios. This gives the relative measure of the dispersion of outcomes in a percentage format that can be used to compare different portfolios.

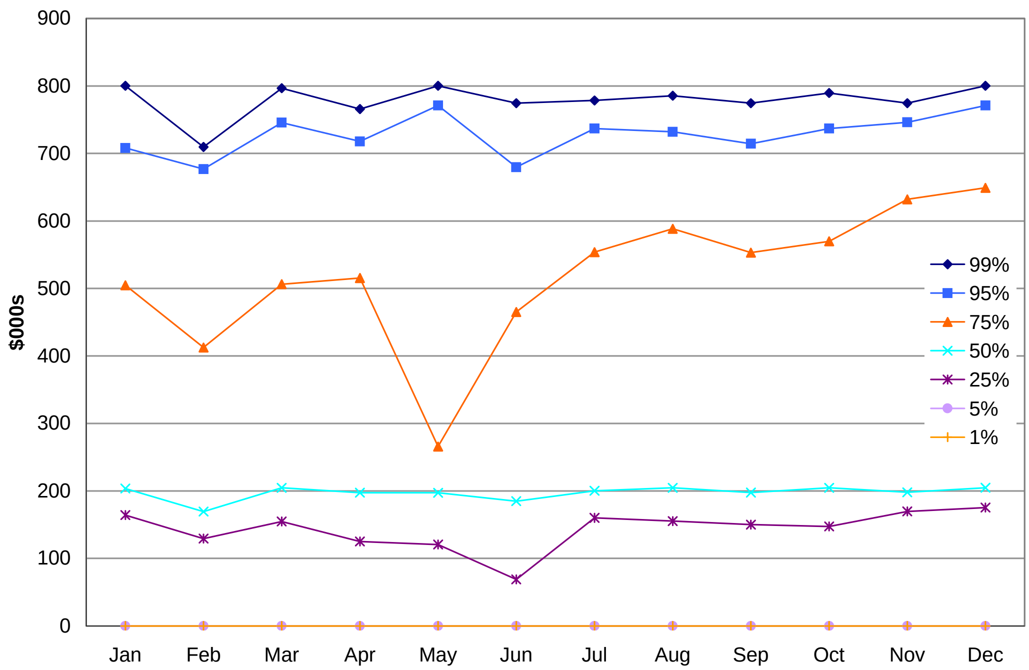
Fuel Cost

Portfolio 7 and 8 of the Round Two analysis shows that there is little difference in the probability of adverse occurrences or the severity of high fuel cost events. It is interesting to note that the median fuel cost changes monthly to reflect the displacement from low cost spring hydro-electric power.

Portfolio 8 Fuel Cost Percentiles 2026

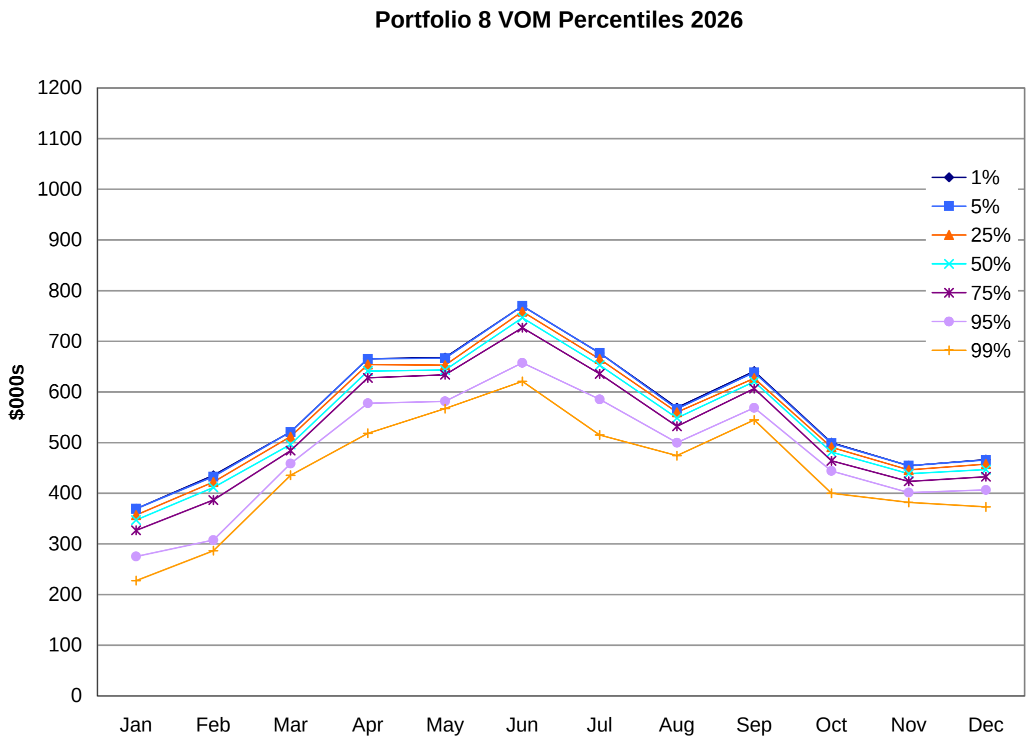


Portfolio 7 Fuel Cost Percentiles 2026

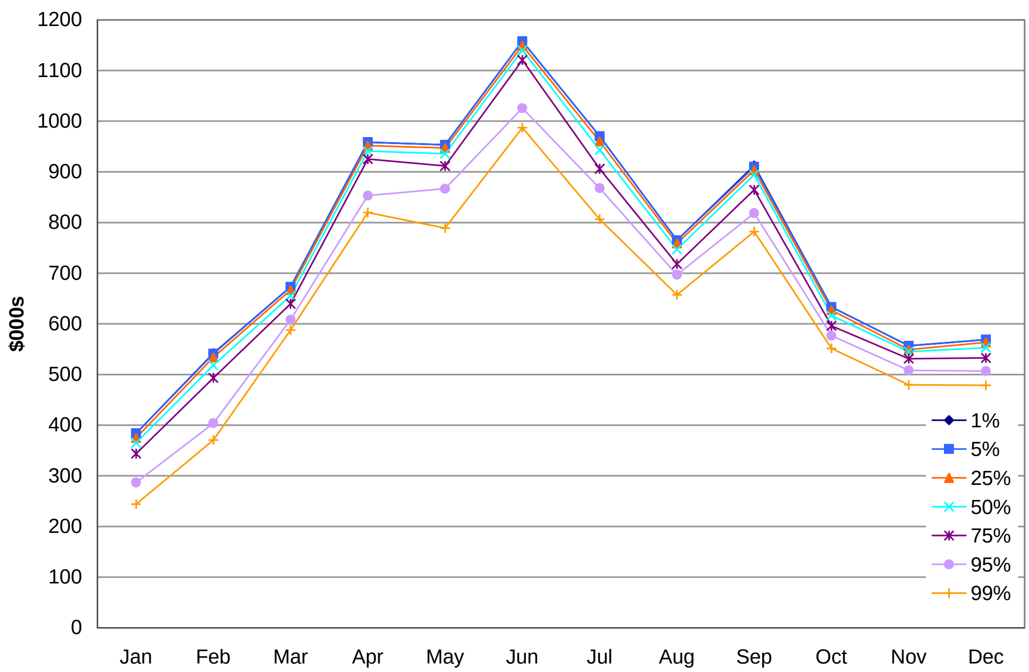


Variable O&M

While the overall shape of variable O&M costs is similar between portfolios 7 and 8, there is a significant difference between the level of cost. Clearly evident from the following graphs, portfolio 7 has higher variable O&M costs from its reliance on wind power where portfolio 8 uses geothermal. The difference in the portfolios variable O&M is due to the difference in generation types only. Note that the dispersion of costs is no greater for portfolio 7 versus portfolio 8.



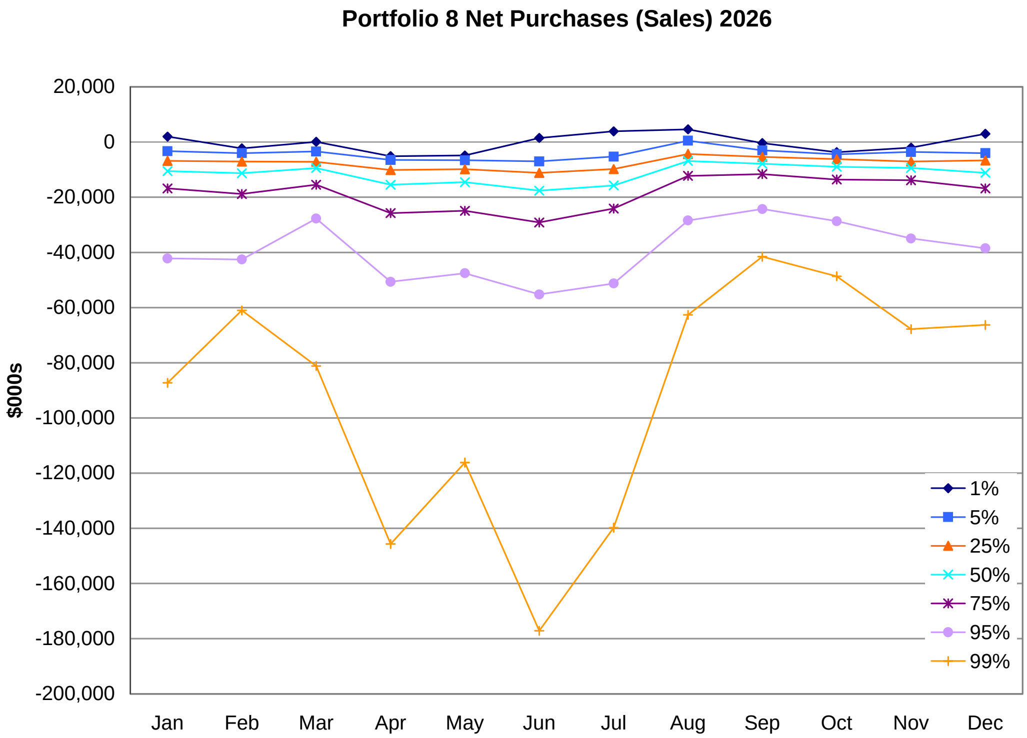
Portfolio 7 VOM Percentiles 2026



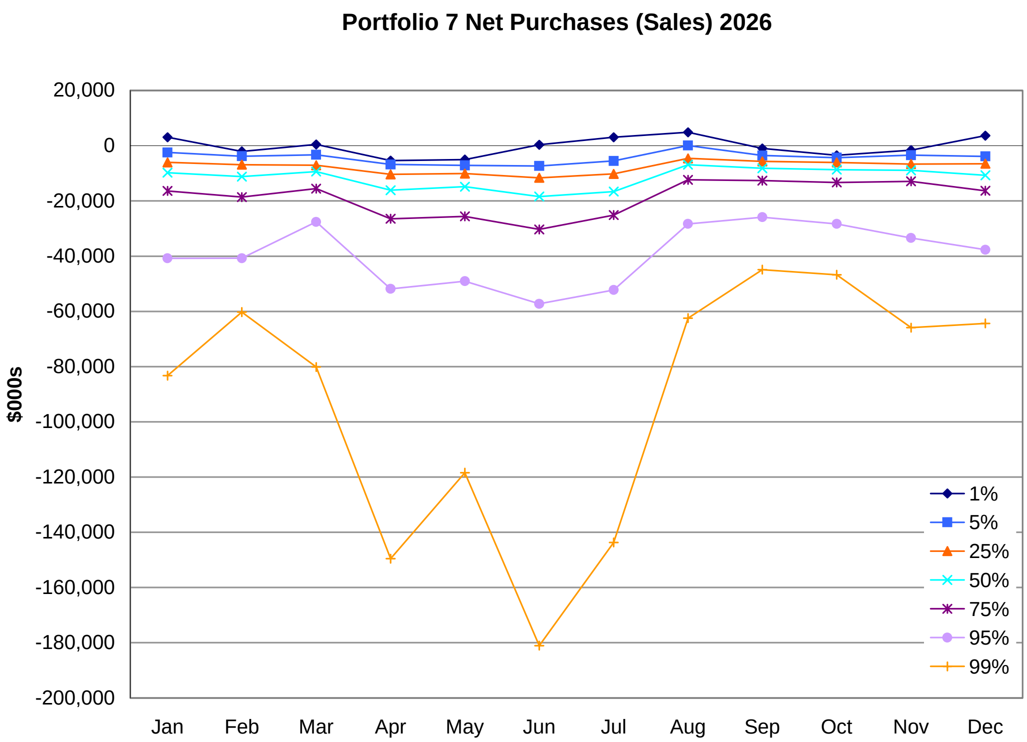
Market Purchases Less Sales

A primary focus of this IRP was to make resource decisions based on the 95% resource adequacy standard. Selecting resource additions based on this standard essentially frees City Light from reliance on the market in almost all but the very catastrophic situations. This is reflected in the following diagrams where only the 1% level of occurrences has a positive level of net purchases. The extreme negative purchases (positive net sales) displayed between the 95th and 99th percentiles indicates the unlikely sales revenues that can occur in times of energy market supply shortfalls resulting in price spikes.

The risk to portfolios 7 and 8 is in the lack of revenues received from optimizing the resource portfolio. Because both the portfolios have mostly similar resources there is little difference in the risk of lost revenue opportunities.



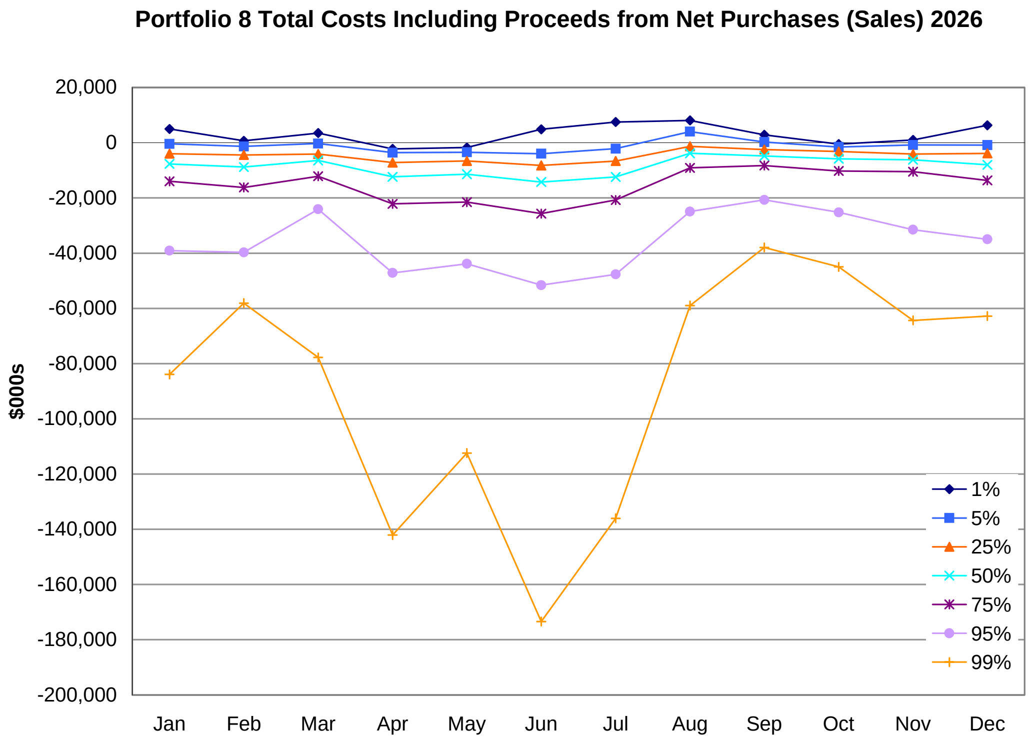
Portfolio 8 Net Purchases (Sales) 2026
$000s
20,000
0
-20,000
-40,000
-60,000
-80,000
-100,000
-120,000
-140,000
-160,000
-180,000
-200,000
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
1%
5%
25%
50%
75%
95%
99%



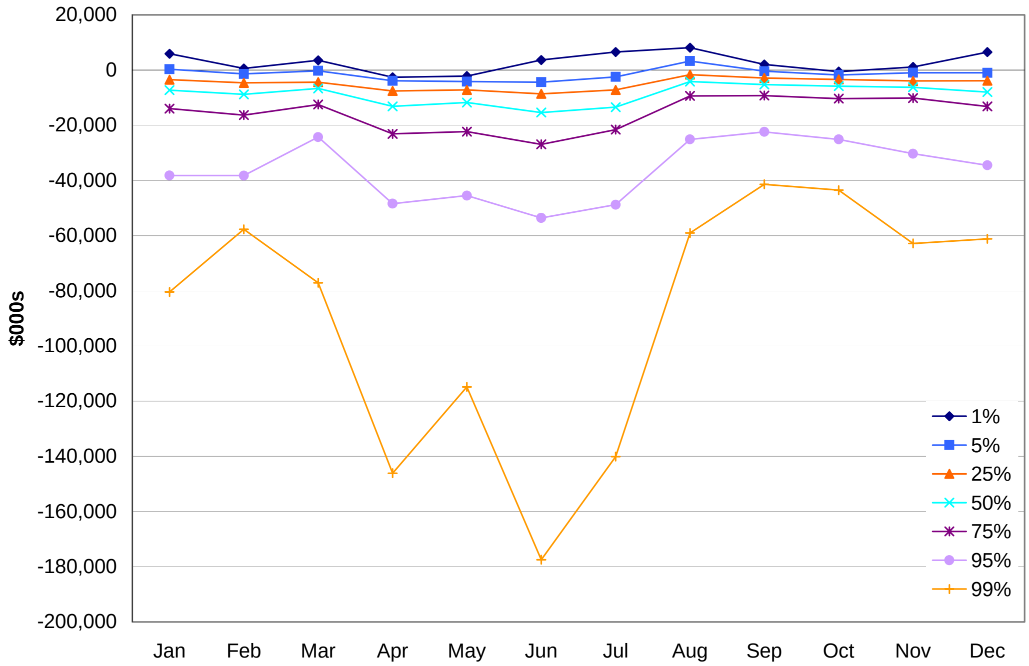
Portfolio 7 Net Purchases (Sales) 2026
$000s
20,000
0
-20,000
-40,000
-60,000
-80,000
-100,000
-120,000
-140,000
-160,000
-180,000
-200,000
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
1%
5%
25%
50%
75%
95%
99%

Relative Variable Costs (Total)

It is evident from the following graphs that the level of cost risk is greatly outweighed by the performance of the resources in the market. Here once again the revenue from marketing excess generation is similar in both portfolio 7 and 8, reducing the differences seen in Variable O&M.



Portfolio 7 Total Costs Including Proceeds from Net Purchases (Sales) 2026



The graphs above portray the monthly percentile occurrences that resulted from a stochastic analysis for portfolios 7 and 8 for the year 2026. Their purpose is to reflect the severity of possible events so that we can compare the two portfolios and determine if one offers a significant advantage in terms of risk avoidance.

The displayed graphs do not reveal a sizeable difference in risk profiles. The relative frequency of events and their severity is nearly identical. This is not surprising when we examine the contents of portfolios 7 and 8. They are nearly identical in construction and in the types of generation that are involved. In the evaluation of other portfolios, particularly in round one, risk was a more important factor in the determination of worthwhile generation technologies.

Purchased Power Agreement (PPA) Assumptions

For purposes of cost comparisons between resource portfolios, City Light made a simplifying assumption. All generating resources costs are evaluated as if an independent power producer (IPP) will supply the power though entering into a purchased power agreement (PPA) with City Light. Through the PPA, the independent power producer would recover all its costs for development, construction, and operation of the generating resource, plus a return on investment. Making the assumption of an IPP supplying all power to City Light will not alter the relative rankings of the resource portfolios.

In reality, City Light will evaluate both a PPA and ownership of a generating resource when issuing a future request for proposals. In general, it is expected that the eligibility of an IPP to capture a production tax credits for renewable resources would outweigh the financing advantages of public ownership. Nevertheless, both options will be evaluated.

For purposes of consistency in comparing costs in the IRP, all generating resources are assumed to be supplied by an independent power producer having the following characteristics:

- A target capital structure of 60% debt, 40% equity
- Return on equity of 15%
- State income tax rate averaging 5.9% across the Pacific Northwest
- Federal income tax rate averaging 35%
- 100% dividend payout
- Stock buyback to maintain target capital structure
- Debt term of 15 years
- An interest rate on debt of 7%
- Property tax rate of 1%
- Production tax credits for renewable resources equal to $15.20 per MWh

For each resource portfolio, a 20-year pro forma income statement is produced with the above assumptions. The results determine the annual revenue (costs to City Light) required by the independent power producer to supply the power to City Light under a PPA. This PPA cost is added to the capital costs for conservation programs and for new transmission required by each portfolio to calculate the total cost of power. Revenues from wholesale sales are added to each portfolio to calculate net power costs.