The 2026 INTEGRATED RESOURCE PLAN

Seattle City Light:
Partnering in a Clean Energy Future

APPENDICES

TABLES

FIGURES

ACRONYMS

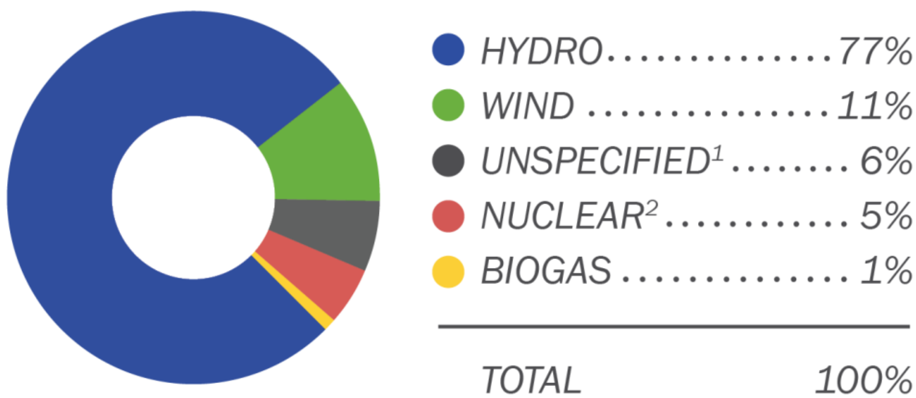
ATB	Annual Technology Baseline
BA	Balancing Authority
BESS	Battery energy storage system
BIPOC	Black, Indigenous, or People of Color
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CCA	Climate Commitment Act
CEAP	Clean Energy Action Plan
CEIP	Clean Energy Improvement Plan
CETA	Clean Energy Transformation Act
CO_2	Carbon dioxide
CO_{2e}	Carbon dioxide equivalent
COB	California-Oregon Border
CONE	Cost of New Entry
CVaR	Conditional Value at Risk
DON	Department of Neighborhoods
DSMPA	Demand-Side Management Potential Assessment
EIA	Energy Independence Act
ELCC	Effective load carrying capacity
EUE	Expected unserved energy
FCRPS	Federal Columbia River Power System
FERC	Federal Energy Regulatory Commission
FY	Fiscal year
ICE	Intercontinental Exchange
IRP	Integrated Resource Plan
ISO	Independent system operator
LOLE	Loss of Load Expectation
LOLEv	Loss of Load Event
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
LSE	Load-serving entity
Mid-C	Mid-Columbia

MoLOLEv	Monthly Loss of Load event
MW	Megawatt
MWh	Megawatt-hour
REC	Renewable energy credit
NERC	North American Reliability Corporation
NITS	Network Integration Transmission Service
NPV	Net present value
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
NWPCC	Northwest Power and Conservation Council
NWPP	Northwest Power Pool
POD	Point of delivery
POR	Point of receipt
PPA	Power purchase agreement
PRM	Planning reserve margin
PTDF	Power Transfer Distribution Factor
PTP	Point-to-point
PUD	Public Utility District
PV	Photovoltaic
QCC	Qualifying capacity contribution
RARE	Resource Adequacy Renewable Energy
RFP	Request for proposal
RTO	Regional transmission organization
SAM	System Advisor Model
SCGHG	Social cost of greenhouse gas
SMR	Small modular reactors
SWEDE	Southwest/East Diversity Exchange
UTC	Utilities and Transportation Commission
VOLL	Value of lost load
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program

APPENDIX 1: CURRENT RESOURCE PORTFOLIO

City Light's existing resource portfolio has been curated to be among the cleanest and lowest cost in the nation. This portfolio includes many past investments in energy conservation (also known as energy efficiency), City Light owned hydropower resources, existing hydropower and renewable energy contracts from regional partners, and wholesale market purchases. Energy conservation programs have contributed to reducing City Light's customer energy use by the equivalent of several large traditional thermal power plant additions. Figure 1.1 shows City Light's 2024 power supply mix.

Figure 1.1. Seattle City Light's 2024 Power Mix



[1] Unspecified energy consists of market purchases that are assigned to the utility including purchases made by City Light to balance or match its loads and resources, along with market purchases made by BPA. Unspecified energy may incidentally include coal or natural gas resources. Any emissions associated with unspecified market purchases are offset through City Light's GHG neutrality policy.
[2] This fuel represents a portion of the power purchased from BPA.

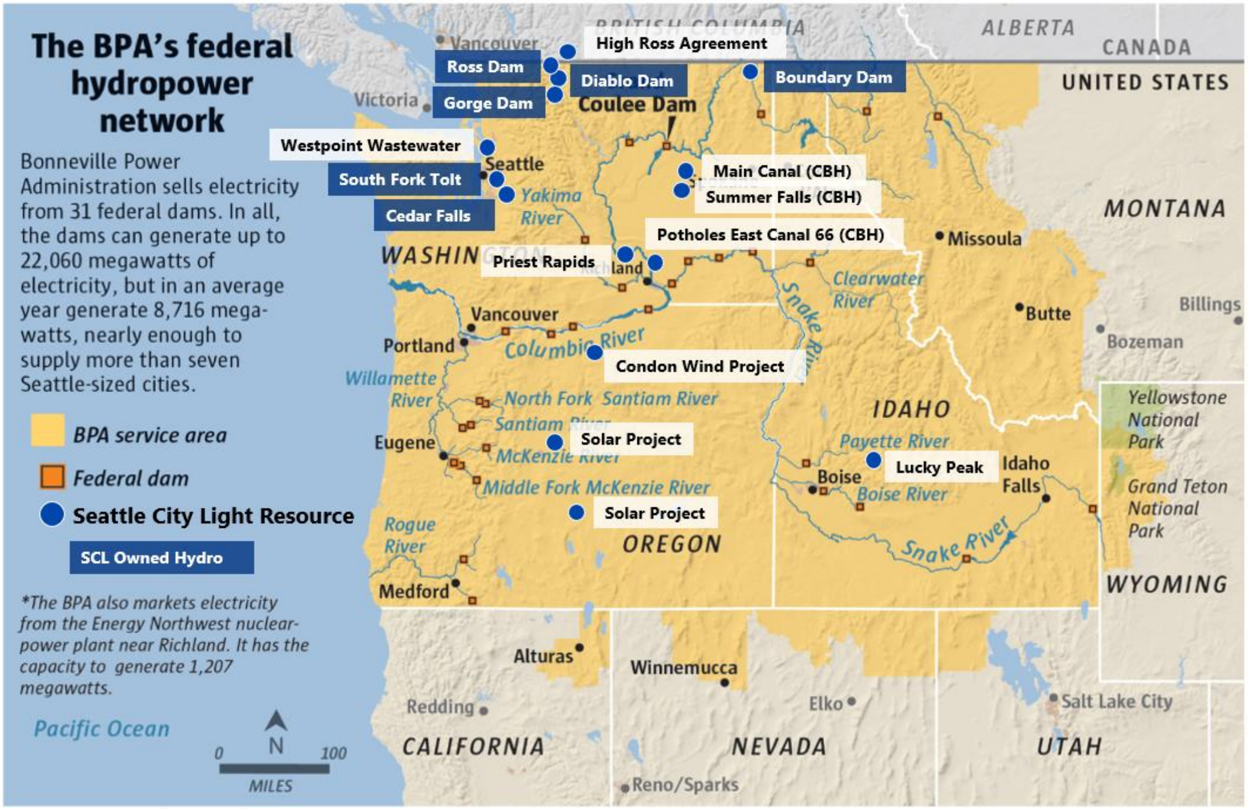
City Light's power supply mix generally consists of about 77% hydropower, approximately half of which is supplied by four hydroelectric projects owned and operated by the city.[1] Beyond generating hydropower, City Light has the responsibility to operate its hydroelectric projects for flood risk mitigation, fish habitat protection, and summer recreation. Additionally, in coordination with Seattle Public Utilities, the Cedar Falls and South Fork Tolt hydro projects provide municipal water supply.

[1] City Light's power supply mix is presented in the utility's Fuel Mix Disclosure, which can be found at: www.commerce.wa.gov/energy-policy/electricity-policy/fuel-mix-disclosure/. Percentages listed above are from the 2024 Fuel Mix Disclosure Summary Report, the latest report approved at the time of writing.

Most of the remaining hydropower is purchased from the Bonneville Power Administration (BPA), a nonprofit federal power marketing agency. City Light's power purchase from BPA also incorporates BPA's nuclear, unspecified market purchases, and wind resources. BPA's nuclear and unspecified market purchases represent 6% and 5% of City Light's power supply mix, respectively. Between BPA's wind resources, City Light's renewable energy credit (REC) purchases, and City Light's power purchase agreement with a 50 MW wind project in Oregon, wind power has become a larger component of City Light's resource supply representing roughly 11%. The remaining 1% of City Light's power mix comes from biogas facilities. Figure 1.2 shows the locations and types of resources owned and operated by City Light. Figure 1.3 shows BPA's federal hydropower network, with Seattle City Light's resources layered on top.

Figure 1.2. Seattle City Light's Generation and Non–BPA Contracted Resources

Figure 1.3. BPA's Federal Hydropower Network with Seattle City Light's Generation and Non-BPA Contracted Resources



Sources Esri, Mark Nowlin (The Seattle Times)

City Light Owned Generation

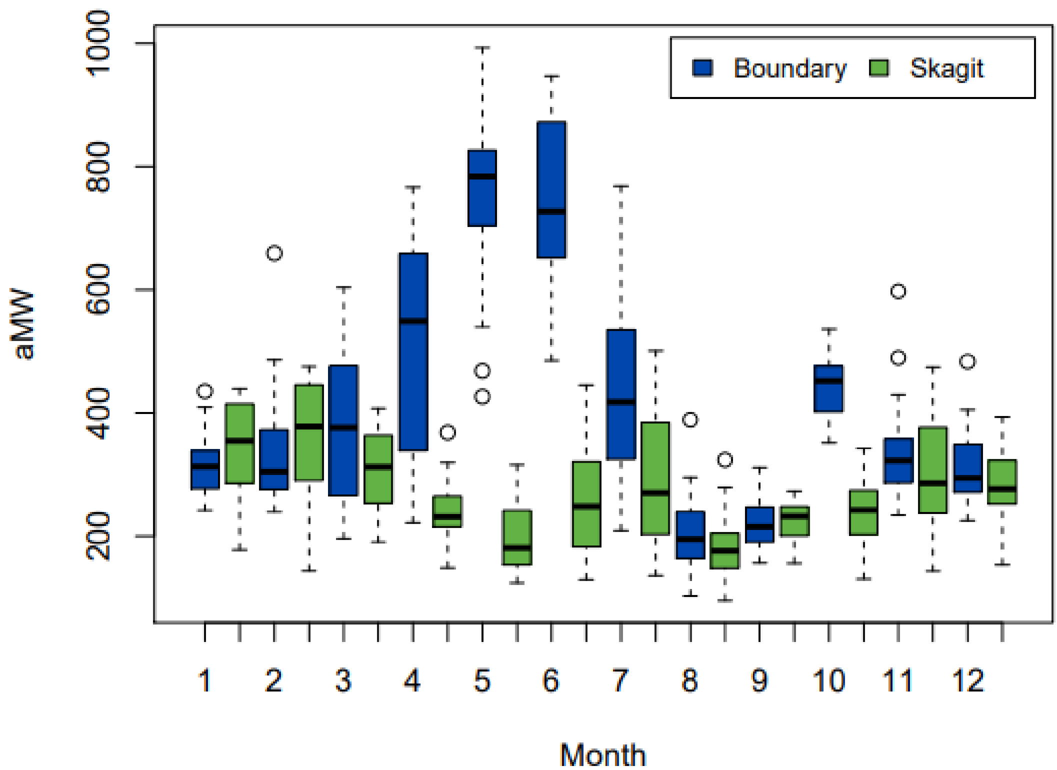
Approximately half of City Light's hydroelectric power is provided by four projects owned by City Light.

Boundary Dam is City Light's largest resource, with a peaking capability of around 1,100 MW and an annual generation of about 415 average megawatts (aMW). It is located on the Pend Oreille River in northeastern Washington. Under the Federal Energy Regulatory Commission (FERC) license, part of Boundary output must be sold to Pend Oreille County Public Utility District No. 1 (Pend Oreille Public PUD) to meet the Pend Oreille Public PUD's load growth. In addition, about five aMW of energy must be delivered to the Pend Oreille Public PUD in compensation for Boundary Dam's encroachment on Box Canyon Dam. While the Boundary Project produces the most power of any of City Light's owned resources and has substantial operational flexibility, it has only modest storage capacity, limiting its ability to shape generation to match City

Light's load. Energy from Boundary Dam is delivered to City Light's customers over BPA's transmission grid.

The Skagit Project includes the Ross, Diablo, and Gorge Dams in the North Cascades, which have a combined one-hour peaking capability of about 750 MW at full pool and an average generation of about 270 MW annually. The Skagit Project has generous storage capacity at Ross Lake, but also significant operational constraints throughout the year for fish habitat protection. City Light's transmission lines carry the power generation from the Skagit Project to Seattle. Figure 1.4 shows average monthly generation over 20 years from the Boundary and Skagit Dam projects.

Figure 1.4. Boundary and Skagit Average Monthly Generation (2005–2024)



Additional power is provided by City Light's small hydro projects: South Fork Tolt and Cedar Falls. South Fork Tolt has a one-hour peaking capability of less than 17 MW. Cedar Falls Dam has a one-hour peaking capability of 30 MW. Both projects deliver power via Puget Sound Energy's transmission lines per a long-term bilateral agreement. Figure 1.5 shows the average monthly generation over 20 years for these two hydro projects.

Figure 1.5. Cedar Falls and South Fork Tolt Average Monthly Generation (2005–2024)

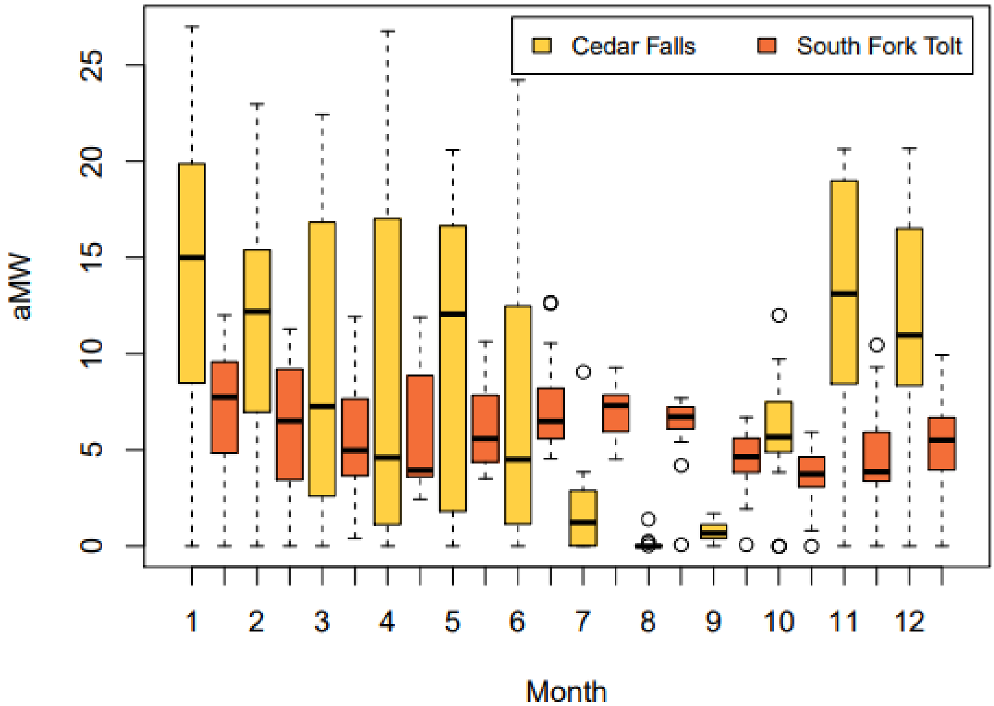
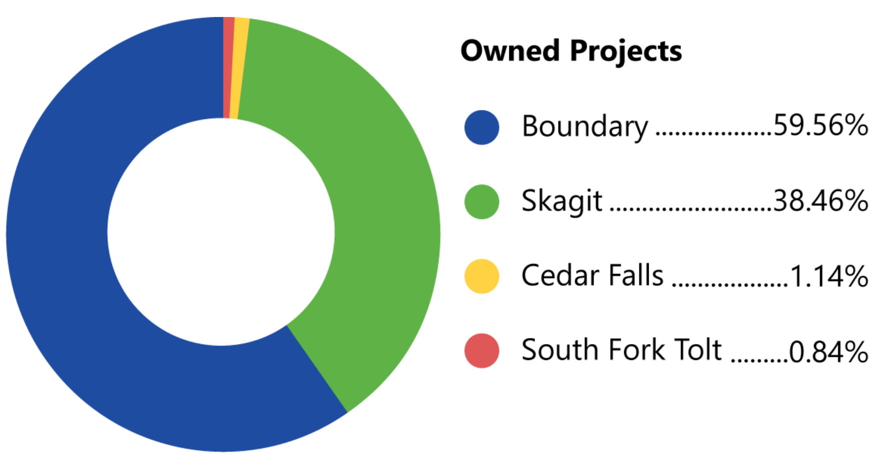


Figure 1.6 shows the proportions of total owned generation provided by each of City Light's owned hydroelectric resources.

Figure 1.6. Proportions of City Light's Owned Generation (2005–2024)



City Light Power Purchase Contracts

City Light's largest power purchase contract is with BPA. The contract allows the utility to receive power from 31 federally owned hydroelectric projects and several thermal and renewable projects in the Pacific Northwest. The energy is delivered to BPA's customers, including City Light, over BPA's transmission grid. In December 2008, City Light signed a contract with BPA to continue City Light's access to the power resources that BPA markets through September 2028. Under this BPA contract, power is delivered in a "block" product in which allocated power is delivered in flat amounts for heavy-load and light-load hours by calendar month. Monthly total energy delivered to City Light is shaped according to City Light's Net Annual Requirement, defined by BPA as the difference between City Light's projected annual load and City Light's resources dedicated to load service under critical hydro-year conditions.

In December 2025, City Light signed a contract to renew its BPA power contract for October 2028 through September 2044. Under the new contract, City Light will purchase a hybrid "Slice/Block" product from BPA that will generally provide 550 aMW to 800 aMW depending on hydro conditions. The Slice portion of the product gives City Light the power delivery capabilities and constraints of a simulated "slice" of the BPA hydroelectric system. The Slice product allows City Light to shape power deliveries for each day on an hourly basis, which provides City Light with greater flexibility to meet load peaks and manage the intermittency of other variable energy renewable resources in its power supply portfolio.

The High Ross Agreement is an 82-year treaty with the hydropower operations division of the Canadian Province of British Columbia (BC Hydro). In 1984, City Light abandoned plans to raise the height of Ross Dam in exchange for power purchases from BC Hydro (acting through its subsidiary Powerex). The additional power delivery and price of that additional power were determined based on expected generation and costs City Light would have incurred had construction taken place (from 13 aMW to 67 aMW depending on the month). The treaty runs until 2066.

The Seven Mile Encroachment contract associated with the High Ross Treaty allowed BC Hydro to raise the Seven Mile Reservoir, which reduced the output at Boundary Dam due to encroachment on the tailrace. As a result, BC Hydro returns or pays for the energy that would otherwise have been generated at Boundary Dam if Seven Mile Reservoir had not been raised (about 2 aMW).

The Lucky Peak Contract is a long-term (50-year) contract for power generated by the Lucky Peak hydro irrigation project, located near Boise, Idaho. Because of its location near Boise, Lucky Peak can sell power to all major western trading hubs (Mid-Columbia [Mid-C], California-Oregon Border, Palo Verde, Mead, and Four Corners) without encountering normal transmission constraints, meaning City Light has the option to sell to the highest price market. City Light has power purchase contract rights to Lucky Peak output (approximately 34 aMW) until 2038.

The Priest Rapids Project consists of two dams: the Priest Rapids Dam and the Wanapum Dam. City Light purchases a fraction of the total power generated by this project under two agreements with Grant Public Utility District (Grant PUD), which owns and operates the project. The term of the agreements extends to the end of the current federal license for the project, April 2052. Seventy percent of Priest Rapids Project's output has been allocated to Grant PUD. Under one agreement, City Light purchases about two to three average megawatts of output at the production cost of the facility. Under the second agreement, City Light has the option to receive a share of proceeds, if any, from an auction of 30 percent of the output, or to purchase the share of the output (about 18 aMW) at the price set in the auction. For this analysis, it is assumed City Light has taken the second option to purchase its allocation of the power generated by the Priest Rapids Project. City Light uses BPA's transmission lines to deliver the power it receives from this project to its customers.

The Columbia Basin Hydro contracts deliver power from five Columbia River Basin hydroelectric projects. The projects are part of three irrigation districts, so electric generation is greatest in the summer months. City Light has contracts to buy half of the output, or about 27 aMW, from all five Columbia River Basin hydroelectric projects. City Light's contracts expire at different times between 2022 and 2027. Only one of the projects will be under contract at the start of the Integrated Resource Plan (IRP) study period, January 2026. This project provides only an expected 13 aMW to City Light's annual power supply portfolio.

The Columbia Ridge Landfill Gas Project is a 20-year power purchase agreement with Waste Management Renewable Energy, LLC to purchase approximately 12 aMW each year from its landfill. As organic materials decay in a landfill they release methane, which can be collected and burned to produce electricity. The plant began commercial operations in January 2010. The Columbia Basin Co-Op and BPA provide transmission to deliver power from the project to City Light's load. This project qualifies under the Energy Independence Act (or I-937) as renewable energy. The contract was prematurely terminated in 2025; however, because the 2026 IRP model finalized inputs in 2024 it was included in City Light's current resource portfolio in the IRP model runs.

The King County West Point Treatment Plant Project is a 20-year power purchase agreement that began in February 2010 with King County to purchase the output from a methane gas–producing digestor at the wastewater treatment plant in Discovery Park in north Seattle. The expected output of this project is 2.5 aMW. Methane is a by-product of the wastewater treatment process that is collected and burned to produce electricity. The plant is inside City Light's service area, so no third-party transmission is required to deliver the power to load. This project also qualifies under the Energy Independence Act (or I-937) as renewable energy.

Condon Wind is a wind farm in northern Oregon with a nameplate capacity of 50 MW. City Light has entered into a five-year power purchase agreement (PPA) for energy produced at Condon Wind, with deliveries beginning June 1, 2023.

Table 1.1 shows City Light's 2024 owned and contracted energy resources.

Table 1.1. City Light's 2024 Energy Resources

Resource	2024 Energy Produced (MWh)	Percentage of Grand Total	Year Contract Expires
Owned Generation			
Boundary	3,025,434	30.7%	
Gorge	689,925	7.0%	
Diablo	363,142	3.7%	
Ross	411,631	4.2%	
Cedar Falls	6,841	0.1%	
South Fork Tolt	44,885	0.5%	
Total Owned	**4,541,858**	**46.1%**	
Contracts			
BPA Block	4,278,100	43.4%	2028
Priest Rapids	19,184	0.2%	2052
Columbia Basin Hydro	251,860	2.6%	2022–2027
High Ross	315,307	3.2%	2066
Seven Mile	3,263	0.0%	2066
Lucky Peak	290,821	3.0%	2038
Columbia Ridge	69,446	0.7%	2028/2033
King County WW	9,647	0.1%	2033
Condon Wind	73,861	0.7%	2028
Total Contracts	**5,311,489**	**53.9%**	
Grand Total	**9,853,347**	**100.0%**	

City Light Energy Conservation, Demand Response, and Customer Solar

Energy conservation programs encourage customers to use power more efficiently and allow the utility to defer the acquisition of expensive new supply-side resources, including those that negatively affect the environment. Energy conservation is low cost and has low environmental impacts, as it does not produce greenhouse gas (GHG) emissions. It is also a local resource and can be strategically deployed within City Light's service territory. Integral to developing the IRP, energy conservation programs help City Light maintain its status as a GHG-neutral utility, support the city's environmental and climate change policy goals, and meet the requirements of I-937.

Energy conservation programs are designed for all customer classes and apply to a range of energy end-uses such as lighting, water heaters, laundry appliances, HVAC, motors, and manufacturing equipment. These programs provide energy conservation information and financial incentives that encourage customers to, for example, insulate their homes, install energy efficient appliances, or install efficient lighting in commercial and industrial establishments. In 2024, City Light's energy conservation programs accounted for approximately 71,187 MWh.[2]

Starting with the 2024 IRP, City Light began evaluating demand response programs using the same modeling framework as it uses to evaluate candidate supply-side resources. Demand response refers to changes in electricity usage through programs that incentivize customers to alter their normal consumption patterns. This can include direct calls to reduce consumption during specific periods of time, time-of-use rates, and customer-side energy storage. City Light's peak loads are expected to grow faster than its average loads, and demand response programs can be a local, low cost, and low environmental impact source of energy to help meet those peak loads.

City Light's 2026 Demand-Side Management Potential Assessment (DSMPA) targets 75% of future energy conservation efforts in the commercial sector, with the remaining 25% split between residential and industrial sectors. City Light's 2026 DSMPA outlines economically efficient and achievable customer-side energy contributions by sector (Table 1.2). For more information, see Appendix 2: Demand-Side Management Potential Assessment.

[2] 2024–2025 EIA Conservation Targets and Achievement Dashboard. Updated September 10, 2025. deptofcommerce.app.box.com/s/y27oz4btzu41qjzorjijhy44xquuoa1u/file/1981892505215

Table 1.2. 2026 DSMPA Achievable Economic Potential

2026 DSMPA Results	2-Year (2026–2027)	4-Year (2026–2029)	10-Year (2026–2035)	20% of 10-Year
Commercial Conservation (aMW)	17	31	62	12
Industrial Conservation (aMW)	1	3	6	1
Residential Conservation (aMW)	3	5	9	2
Total Conservation (aMW)	**21**	**39**	**78**	**16**
Demand Response (MW)	6	12	15	N/A

City Light Market Participation

Wholesale Energy Market

City Light sells and purchases power in the wholesale energy market to supplement its owned generation and contracted resources. Market participation is particularly important to City Light, because 90% of City Light's current resource portfolio is hydroelectric, which is highly variable in nature as it is dependent on seasonal water availability and the operating constraints defined in each individual hydro project's FERC license. City Light has surplus energy throughout most of the year during typical conditions, which can be sold in the energy market to offset operating costs. When power is insufficient to meet demand, City Light makes market purchases to compensate for the deficit. Most of this trading occurs through bilateral transactions.

Western Energy Imbalance Market

City Light joined the Western Energy Imbalance Market (WEIM) in April of 2020. Balancing Authorities (BAs) such as City Light start each hour with generation resources committed to meet their own forecasted load. Imbalances occur within the hour because load and generation typically vary slightly from what is forecasted. BAs have traditionally managed imbalances by relying on manual dispatches and extra power reserves.

The WEIM solves these imbalance problems through an automated five-minute energy dispatch service. Participants in the WEIM can voluntarily provide bids to increase or decrease dispatch of their generation resources to help meet other participants' load imbalances. The WEIM market operator automatically selects the bids that result in the least-cost resource mix with respect to both generation and transmission operational parameters, commonly referred to as security constrained economic dispatch or SCED.

The WEIM allows participating BAs to leverage the benefits of near-real-time energy balancing without sacrificing their existing autonomy; BAs remain responsible for procurement or self-provision of reserves and other ancillary services. The WEIM does not change City Light's responsibilities for resource adequacy, reserves, and other reliability-based functions required by the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC). The WEIM does, however, change how participating BAs deal with imbalances in real time.

The WEIM's automation and economic dispatch lower costs for participants to balance energy. This market becomes even more valuable as additional renewable resources connect to the grid, because these resources often have variable output that increases the total amount of energy on the grid that must be balanced.

Western Organized Day-Ahead Markets

Finally, City Light is evaluating whether to join a regional day-ahead energy market. Day-ahead markets expand the regional energy dispatch optimization potential of imbalance markets such as the WEIM to the day-ahead time frame. This greatly expands the volume of available energy in the market, and therefore the potential benefits to regional participants of market optimization in meeting loads with least-cost resources.

City Light Participation in Regional Planning

Independent system operators (ISOs) and regional transmission organizations (RTOs) were formed across North America during the late 1990s and 2000s as regulatory bodies intended to achieve several electricity industry objectives, including electricity market fairness, efficiency, and reliability. However, at the time of writing, an ISO/RTO has not been established in the West, with the exception of the CAISO, which includes most areas of California. Some reliability, market fairness, and efficiency policies for the West have been established by FERC, WECC, and other regional entities such as the Western Power Pool (WPP), formerly known as the Northwest Power Pool (NWPP). The WPP coordinates other regional reliability programs, including a Reserve Sharing Program, the Pacific Northwest Coordination Agreement, and the Western Frequency Response Sharing Group. In recent years, concerns about system reliability have increased throughout the West as a result of the impending retirement of GHG-emitting energy generation resources, electrification efforts, and clean energy legislation and policies requiring increased integration of intermittent renewable resources for load service.

City Light has been working with the WPP and regional stakeholders since 2019 to design and implement the Western Resource Adequacy Program (WRAP). The program aims to enhance and increase electricity reliability for entities across the Western Interconnection. WRAP began its first non-binding phase in the summer of 2021 and is still under development. City Light plans to maintain its status as a participant with nonbinding status with a commitment timeframe to become fully binding in the Winter 2027–2028 season.

The program design centers on a regional reliability requirement intended to ensure that, in the event of extreme system demand, a participating load-serving entity (LSE) will be able to purchase available energy from other participating LSEs who are able to generate power in excess of their own load obligations. Based on self-reported generation capability from participating LSEs, the program operator will model regional requirements to maintain a 0.1 Loss of Load Expectation (LOLE) reliability standard across the program footprint (for definition and discussion of LOLE, please see Appendix 9: Resource Adequacy). The program is capacity-based for all thermal and other dispatchable generation resources, but generation capability will be based on historical energy generation for intermittent renewables like wind, solar, and run-of-river hydro, and for energy-constrained resources like storage hydro. The total regional capacity needed to meet that requirement will be allocated equitably to program participants based on amount of load served, via an assigned planning reserve margin (PRM), which will be updated prior to the start of each summer and winter season. Participating LSEs are required to demonstrate sufficient capacity to meet their assigned PRM seven months in advance of the next summer or winter season. Once the program moves into its binding phase, LSEs who do not demonstrate sufficient capacity are subject to penalty charges with proceeds distributed to surplus LSEs.

Carbon-Free Energy Attributes

When City Light sells energy from a specific resource, it is unable to claim environmental (carbon-free) attributes of that portion of energy in its own portfolio. Selling "specified" energy from renewable or non-carbon-emitting resources impacts the total non-emitting resource attributes considered to be serving City Light's retail load.

Table 1.3 shows 2020–2024 specified sales for Ross, Boundary, and Lucky Peak dams. Specified sales include bilateral and WEIM sales.

Table 1.3. City Light Specified Sales (MWh)

Year	Boundary		Ross	Lucky Peak	Annual Totals
	Bilateral	WEIM	WEIM	Bilateral	
2020	794,746	41,304	10,400		**846,450**
2021	351,077	197,136	42,333		**590,546**
2022	295,464	116,752	40,774		**452,990**
2023	176,733	90,030	160,501		**427,264**
2024	548,088	71,453	157,977	73,099	**815,657**
Average	**433,222**	**103,335**	**82,397**	**73,099**	**626,581**

APPENDIX 2: DEMAND-SIDE MANAGEMENT POTENTIAL ASSESSMENT

Seattle City Light completes a Demand-Side Management Potential Assessment (DSMPA) biannually to produce estimates of the magnitude, timing, and costs of conservation (henceforth referred to as "conservation" or "energy efficiency") and demand response resources in its service territory over the next 20 years. The most recent DSMPA (2026 DSMPA) was completed in 2025 with forecasts for demand-side resources beginning in 2026. The results of the 2026 DSMPA are incorporated as an input into the 2026 IRP.

The DSMPA analysis includes the conservation potential assessment (CPA) and demand response potential assessment (DRPA). The DSMPA identifies energy efficiency and demand response potential in City Light's major customer sectors—residential, commercial, and industrial—while accounting for the impacts of climate change and building electrification.[3] This study accomplishes several objectives:

- Fulfills statutory requirements of Chapter 194-37 of the Washington Administrative Code (WAC), Energy Independence Act (I-937). The WAC requires that City Light identify all achievable, cost-effective conservation potential for the upcoming 10 years.[4] The WAC also specifies that City Light's public biennial conservation target should be no less than the pro rata share of conservation potential over the first 10 years. The study fulfills regulatory requirements by establishing City Light's energy conservation targets for the 2026-2027 biennium.
- Supports City Light's compliance with Washington State's Clean Energy Transformation Act (CETA), passed as Senate Bill 5116 in April 2019, to inform City Light's energy efficiency and demand response short- and long-term targets.[5] In addition, this study informs City Light's near-term interim targets for its Clean Energy Implementation Plan (CEIP) as required by CETA. This study, more broadly, supports City Light's Clean Energy Action Plan, a 10-year action plan described in Appendix 4: Regulatory Requirements to meet CETA requirements.

[3] The 2026 DSDMPA included demand response potential for managed electric vehicle (EV) charging and conservation potential for efficient, residential EV chargers. We did not estimate conservation potential for efficient EV chargers in the commercial sector.
[4] Washington State Legislature. *Energy Independence Act*. Washington Administrative Code Chapter 194-37.
[5] CETA requires proposing interim targets for meeting the standard under RCW 19.405.040(1) during the years prior to 2030 and between 2030 and 2045. This study estimates potential over 20 years, from 2026 through 2045.

- Develops up-to-date estimates of energy conservation measure (ECM) datasets for the residential, commercial, and industrial market sectors using measures consistent with the Northwest Power and Conservation Council's (Power Council) 2021 Power Plan, the Regional Technical Forum (RTF), and other data sources.
- Provides inputs into City Light's IRP and progress update reports. The DSMPA study period aligns with the timeline for City Light's 2026 IRP and provides direct inputs into that analysis. The IRP requires a thorough analysis of conservation potential to properly assess the reliability, cost, risk, and environmental impact of different resource portfolios for power generation, as well as to assess other demand-side resources that are not part of the CPA.
- Informs City Light's planning and budget setting for customer programs and City Light's load forecast.

Inputs to the analysis include City Light–specific data compiled from the 2022 Northwest Energy Efficiency Alliance (NEEA) Residential Building Stock Assessment (RBSA),[6] NEEA's 2019 Commercial Building Stock Assessment (CBSA),[7] and other regional data sources. The analysis uses methodology consistent with the supply curve workbooks of the Power Council's 2021 Power Plan, published in March 2022.[8] It also incorporates savings and costs for all ECMs in the Power Council's 2021 Power Plan[9] workbooks and selected unit energy savings (UES) workbooks from the RTF.[10]

The analysis also calculated estimates of the demand response potential (summarized in the following subsections) that align with the Power Council's demand response methodology and provided the data needed to meet Washington State's CETA requirements.

---

[6] Northwest Energy Efficiency Alliance. *2022 Residential Building Stock Assessment*.
[7] Northwest Energy Efficiency Alliance. *2019 Commercial Building Stock Assessment*.
[8] The 2021 Power Plan is a regional plan that provides guidance on resources to ensure a reliable and economical regional power system from 2022 to 2041. The Power Council develops supply curves covering a variety of supply- and demand-side resources, considers how to best meet the region's power needs across a range of future scenarios (balancing cost and risk), develops a draft plan, and gathers public input before releasing the final version.
Results from the Power Council's Ninth Power Plan were not included, as the planned completion will be in fall 2026. However, data from the draft Ninth Power Plan, such as updated regional transmission and distribution (T&D) avoided costs and program administration cost factors were included where applicable.
[10] RCW 19.285.040 requires CPAs to use methodologies consistent with those used by the Power Council's most recent regional power plan.

Findings Overview

City Light analyzed three types of potential through the DSMPA process and IRP optimization modeling:

- **Technical potential:** This is the total amount of energy efficiency that could be achieved within City Light's service territory assuming that all feasible resource opportunities can be captured regardless of cost and market barriers, such as customer willingness to adopt. The potential is only limited by physical and operational constraints.
- **Achievable technical potential:** This is the portion of technical potential that could realistically be realized during the study's period, considering market barriers such as customer awareness, willingness to adopt measures, and historical program participation rates. It includes savings, regardless of the acquisition mechanism, that may be acquired through utility programs, improved codes and standards, and market transformation without considering cost-effectiveness.
- **Achievable economic potential:** This is the portion of achievable technical potential determined to be cost-effective by the IRP's optimization modeling, in which either bundles or individual energy efficiency measures are selected based on cost and savings. The cumulative potential for these selected bundles constitutes achievable economic potential.

Table 2.1 shows the results from this study, representing the 20-year technical, achievable technical, and achievable economic potential for each resource considered.

Table 2.1. Summary of Energy Savings and Demand Reduction Potential, Cumulative 2045

Resource	Energy (aMW)			Winter Coincident Peak Capacity (MW)		
	Technical Potential	Achievable Technical Potential	Achievable Economic Potential	Technical Potential	Achievable Technical Potential	Achievable Economic Potential
Energy Efficiency	245	202	103	279	228	108
Demand Response	N/A	N/A	N/A	N/A	193	14

This study characterizes conservation potential in terms of an average megawatt (aMW), which is commonly used in the Northwest to represent the amount of conservation potential. An average megawatt is equivalent to the energy produced by the continuous operation of one megawatt of capacity for a period of one year.[11]

Conservation Potential Assessment (CPA) Findings

The CPA found 124 average megawatts (aMW) of achievable technical conservation potential in the first 10 years (cumulative in 2035) in City Light's service territory.[12] To inform I-937 and CEIP energy efficiency targets, City Light calculated two-year and four-year cumulative achievable technical potential. Cumulative achievable technical potential equals 29 aMW in the first two years and 54 aMW in the first four years.

City Light used its GridPath model to select energy efficiency measures based on the levelized total resource cost (TRC) over a 20-year period. Overall, the cumulative 20-year achievable economic potential is 103 aMW, with 78 aMW acquired in the first 10 years. The *pro rata* share (20% of 10-year achievable economic potential), which represents City Light's minimum biennial target, equals 16 aMW. All estimates of potential in this report are presented at the generator, which means they include line losses.[13]

Technical Potential

Table 2.2 shows the cumulative technical potential for each sector in 2045.[14] Overall, the technically feasible conservation potential by 2045 was 245 aMW, which is the equivalent of 16% of forecasted baseline sales. The CPA results are presented as a percentage of forecasted baseline sales, which provides a useful benchmark for comparison against City Light's previous studies. The baseline sales reported in the subsequent tables include City Light's EV forecasts for the commercial and residential sectors. They do not include industrial forecasts for spot loads or district steam since these categories require custom engineering work that does not conform to the standard efficiency measures in the industrial sector. Similarly, streetlighting is not included in the baseline sales data because City Light has installed all efficient measures in this segment, and there is no remaining potential. The residential, commercial, and

---

[11] Northwest Power and Conservation Council definition of an aMW.

[12] An aMW refers to a unit of measure that represent one million watts (MW) delivered continuously 24 hours a day for each day of the year (for a total of 8,760 hours in non-leap years). A detailed description of MW and aMW can be found on the Power Council's website: www.nwcouncil.org/reports/columbia-river-history/megawatt

[13] City Light estimates T&D line losses to be 8.31%, so the minimum biennial target at a customer site is 14.3 aMW.

[14] City Light selected the year 2045 as the final year for the DSMPA analysis to align with its long-term planning (GridPath model) timeline and to comply with CETA's requirement for 100% clean electricity by 2045.

industrial sectors account for 19%, 15%, and 8% of the 20-year technical potential, respectively. Please note that due to rounding, some values presented in the tables and figures may not sum precisely.

Table 2.2. Cumulative Technical Potential by Sector (2026–2045)

Sector	Baseline Sales–20-Year (aMW)	Technical Potential–20-Year (aMW)	Technical Potential as % of Baseline Sales
Residential	512	97	19%
Commercial	908	138	15%
Industrial	109	9	8%
Total	**1,530**	**245**	**16%**

Achievable Technical Potential

Table 2.3 shows the cumulative achievable technical potential for each sector in 2045. Overall, the analysis identified 202 aMW of technically feasible achievable potential by 2045—the equivalent of 13% of forecasted baseline sales. The residential, commercial, and industrial sectors account for 16%, 12%, and 7% of the cumulative achievable technical potential, respectively.

Table 2.3. Cumulative Achievable Technical Potential by Sector (2026–2045)

Sector	Baseline Sales–20-Year (aMW)	Achievable Technical Potential–20-Year (aMW)	Achievable Technical Potential as % of Baseline Sales
Residential	512	81	16%
Commercial	908	113	12%
Industrial	109	8	7%
Total	**1,530**	**202**	**13%**

Table 2.4 provides two-year, four-year, 10-year, 20-year, and pro rata share (20% of the 10-year potential) of the cumulative achievable technical potential by sector.[15] These time increments align with regulatory reporting cycles, support short- and long-term planning needs, and correspond to key milestone years for energy conservation goals and utility resource planning. The commercial sector provides the majority of the

[15] Under Chapter 194-37 of the WAC Energy Independence Act, City Light's public biennial conservation target must be no less than 20% of the 10-year potential—representing its *pro rata* share. The CEIP requires a four-year planning roadmap.

cumulative achievable technical potential. This is due to the commercial sector's higher baseline sales compared with those of the residential and industrial sectors.

Table 2.4. Cumulative Achievable Technical Potential by Sector and Time Period

Sector	Achievable Technical Potential (aMW)				
	2-Year (2026-2027)	4-Year (2026–2029)	10-Year (2026–2035)	20-Year (2026–2045)	20% of 10-Year Potential
Residential	7	13	35	81	7
Commercial	20	38	82	113	16
Industrial	1	3	6	8	1
Total	**29**	**54**	**124**	**202**	**25**

Achievable Economic Potential

After incorporating the achievable technical levelized cost of conserved energy bins, City Light's GridPath model identified an optimal amount of annual conservation. Bundling resources into distinct cost groups allowed the portfolio optimization model to select the combination of conservation cost bundles by sector that provided City Light with the least-cost portfolio alongside renewable resources while also achieving resource adequacy targets, I-937 requirements, and CETA requirements. By integrating conservation choices alongside renewable supply options into the portfolio optimization model, City Light captured the different value streams from all resources within the same analytical framework.

The resulting IRP analysis selected 103 aMW of achievable economic potential by 2045, with sector-specific selections shown in Table 2.5. Cumulative 20-year achievable economic potential accounted for 7% of the total baseline sales in 2045. The commercial sector had the greatest achievable economic potential relative to baseline sales, accounting for 9% of the 2045 commercial baseline sales. This was followed by the industrial sector's cumulative achievable economic potential, which accounted for 7% of the 2045 commercial baseline sales. Finally, the residential sector's cumulative achievable economic potential made up 2% of the 2045 residential baseline sales.

The IRP portfolio optimization model differentiated the levelized TRC by sector, allowing it to select the specific energy efficiency cost bins that best fit City Light's portfolio and minimize overall costs. The model also recognized that the conservation supply curves for each sector have different shapes, limits, and elasticities. As shown in Table 2.5, the achievable economic potential represented a levelized TRC of $30 or less per megawatt-hour for residential, $160 or less per megawatt-hour for commercial, and $70 or less per megawatt-hour for industrial.

Table 2.5. Cumulative Achievable Economic Potential by Sector (2026–2045)

Sector	Levelized TRC ($/MWh)	Baseline Sales 20-Year (aMW)	20-Year Achievable Economic Potential (aMW)	Achievable Economic Potential as % of Baseline Sales
Residential	30	512	13	2%
Commercial	160	908	82	9%
Industrial	70	109	8	7%
Total	**N/A**	**1,530**	**103**	**7%**

Table 2.6 provides the two-, four-, 10-, and 20-year cumulative achievable economic potential estimates by sector. The final column shows the pro rata share of the achievable economic potential, which represents the lower limit for the biennial conservation target (as defined by I-937). Overall, 20% of the total 20-year achievable economic potential is achieved in the first two years, and 76% is achieved in the first 10 years.

Table 2.6. Cumulative Achievable Economic Potential by Sector and Time Period

Sector	Achievable Economic Potential – aMW				
	2-Year (2026–2027)	4-Year (2026–2029)	10-Year (2026–2035)	20-Year (2026–2045)	20% of 10-Year Potential
Residential	3	5	9	13	2
Commercial	17	31	62	82	12
Industrial	1	3	6	8	1
Total	**21**	**39**	**78**	**103**	**16**

For discussion of the conservation potential, further details can be found in the 2026 DSMPA report.[16]

Demand Response Potential Assessment (DRPA) Methodology

This section summarizes the demand response potential that provided the inputs to City Light's GridPath model.

[16] Seattle City Light. 2026 Demand-Side Management Potential Assessment. www.seattle.gov/documents/departments/citylight/demandsidemanagementpotentialassessment.pdf

The DRPA assessed the following products:

- Residential Batteries Direct Load Control (DLC)
    - Batteries DLC
    - Batteries DLC – Highly Impacted Communities
- Residential Space Heat and Cool Direct Load Control (DLC)
    - Connected Heat Pump DLC
    - HVAC AC and Heat DLC Switch
    - Residential Bring Your Own Thermostat (BYOT)
- Residential Direct Load Control (DLC) Water Heat
    - Heat Pump Water Heater (HPWH) DLC Grid-Enabled
    - Electric Resistance Water Heater (ERWH) DLC Grid-Enabled
    - ERWH DLC Switch
- Residential Managed Electric Vehicle (EV) Direct Load Control (DLC)
- Residential Behavior
- Residential Critical Peak Pricing (CPP)
- Residential Peak Time Rebate Pricing
- Residential Time of Use (TOU) Pricing Opt-In
- Residential Time of Use (TOU) Pricing Opt-Out
- Commercial and Industrial Demand Curtailment
- Commercial and Industrial Critical Peak Pricing (CPP)
- Commercial Space Heat and Cool Direct Load Control (DLC)
    - Small Commercial HVAC DLC Switch
    - Medium Commercial HVAC DLC Switch
    - Small Commercial BYOT DLC
- Commercial Batteries
    - Small Batteries DLC
    - Large Batteries DLC
- Commercial Electric Vehicle Support Equipment (EVSE) Charger Control
    - Heavy Duty (HD)
    - Light Duty (LD)
    - Medium Duty (MD)
- Commercial Grid Interactive Efficient Buildings Curtailment
- Commercial Time of Use (TOU) Pricing
- Commercial Electric Vehicle (EV) Time of Use (TOU) Pricing
- Industrial Curtailment
- Industrial Critical Peak Pricing (CPP)

This 20-year study time horizon starts in 2026; however, it takes time to design, promote, and implement new programs. This study assumes that Commercial EV TOU, Residential TOU Opt-out, and Commercial TOU all start in 2027 and that all other products start in 2026. Future planning activities may investigate other demand response products in addition to the ones presented in this study.

This analysis modeled all products cumulatively, assuming they are competing within the market. This analysis used a T&D value of $41.08 in 2026 dollars to reflect the latest regional data available.[17] The modeling incorporated City Light Tempwise pilot evaluation data to inform the thermostat demand response direct load control modeling. Additionally, the design for the Commercial and Industrial (C&I) curtailment program is aligned with the necessary specifications to ensure its effectiveness within the model. The model assumes participation from up to 10 entities, each capable of achieving at least a 1 MW load reduction, with curtailment durations of up to 72 hours. Time-of-Use (TOU) periods are accounted for in the modeling, using the following definitions:

- **Winter (Nov-Mar)**: Morning peak period of 6 a.m. to 9:59 a.m. and evening peak period of 5 p.m. to 8:59 p.m. (4 hours each), with mid-peak between the two.
- **Summer (Jun-Aug)**: Evening peak period of 5 p.m. to 8:59 p.m., with mid-peak starting at 6 p.m.
- **Shoulder (Apr/May/Sept/Oct)**: No peak period; only off-peak and mid-peak.

The analysis updated data sources and incorporated feedback from the 2024 DRPA, as well as ongoing input throughout this study period, to ensure that the analysis remains accurate and reflective of current conditions.

DRPA Findings Overview

This assessment considered 29 total demand response product options (listed above) to estimate total winter and summer achievable demand response potential in City Light's service area. The model did not incorporate recurring back-to-back events as consecutive events are not permitted for the products analyzed and could have had an impact on demand reduction and customer attrition rates. The DRPA modeled residential TOU for both customer opt-in and customer opt-out adoption scenarios. The DRPA reported the residential TOU opt-out as the primary results presented (unless noted otherwise).

Table 2.7 lists the estimated resource potentials (by 2045) for all demand response products for the residential, commercial, and industrial sectors during winter and

[17] T&D value based on Northwest Power and Conservation Council Ninth Power Plan draft assumptions and adjusted to 2026 dollars.

summer in the second, fourth, tenth, and final year of the program. The greatest achievable potential by 2045 is seen in the winter months of the residential program, reaching 138.2 MW.

Table 2.7. Summary of Conservation Results by Sector

Sector	Achievable Technical Potential (MW)			
	2027	2030	2036	2045
Residential Winter	16.1	47.1	89.9	138.2
C&I Winter	9.9	27.1	41.1	55.1
Total Winter	**26.0**	**74.1**	**131.0**	**193.4**
Residential Summer	15.3	41.3	72.1	113.6
C&I Summer	13.1	35.9	55.1	75.5
Total Summer	**28.4**	**77.2**	**127.2**	**188.1**

Note: Totals may not sum due to rounding.

Table 2.8 identifies the winter demand response economic potential selected by the GridPath model, which is the achievable economic potential of the commercial critical pricing product, the only demand response product selected by the GridPath model. This selection offers significant achievable potential in both winter and summer seasons, with an estimated potential of 14.3 MW in 2045 at a levelized cost of negative $31 per kilowatt-year.[18]

Table 2.8. Demand Response Achievable Economic Potential (MW)

Sector	Winter Achievable Economic Potential (MW)			
	2027	2030	2036	2045
Commercial	6	15	15	14
Total	**6**	**15**	**15**	**14**

Note: Totals may not sum due to rounding.

[18] The negative levelized cost for commercial critical peak pricing is result of applying a T&D deferral levelized cost of 41.08 $/kW-year. This deferral cost is applied to all demand response products and in the case of the product commercial critical peak pricing causes the overall levelized cost to be negative.

APPENDIX 3: LOAD FORECAST

One of the most critical steps in future power planning is establishing an expectation of future power supply needs. For the purposes of the Integrated Resource Plan (IRP), this involves an assessment of how much total energy City Light customers are expected to consume over a period of time (load), the maximum amount of energy they are expected to consume instantaneously (peak demand), and how rapidly they are expected to change their instantaneous needs (flexibility or ramp).

City Light's system load forecast used in this IRP Report was finalized in late 2024 and is referred to as the "2026 IRP" load forecast.[19] The 2026 IRP 20-year load forecast anticipates overall continued load growth trends in electricity demand for City Light's service area. This growth is primarily driven by transportation and building electrification and is tempered by increasing equipment efficiency trends.

Load Forecast Modeling Methodology

City Light has employed an end-use load forecasting approach since 2018. This approach accounts for load impacts from customer-driven adoption of technologies, such as equipment efficiency trends, transportation electrification, customer solar, and building electrification (e.g., space and water heating, cooling). The forecast uses hourly load shapes and a probabilistic modeling framework to forecast future peak loads based on historical weather patterns, adjusted for gradually warming temperatures.

Load impacts due to energy efficiency, demand response, and customer-sited solar are not initially included in the forecast but are determined by the Demand-Side Management Potential Assessment (DSMPA). These values are then incorporated as inputs into the IRP process. For this reason, the load forecasts in Figure 3.1 and Figure 3.2 below show the IRP baseline load forecasts with historical energy efficiency incorporated, but without the impacts of new energy efficiency, demand response, or customer-sited solar.

Comparison to Previous Forecasts

The 2026 IRP load forecast shows that growth trends in electricity demand for City Light's service area are expected to continue through the duration of the study period (2026–2045). Figure 3.1 shows a comparison of the 2026 IRP Report annual average system load forecast—finalized in late 2024 and also used in the 2026 DSMPA—to the

[19] The 2026 IRP load forecast reflects the policies in place at the time it was finalized. It does not account for the more recent rescission of some Federal EV policies, short-term tariff impacts, or recent increases in service requests for data centers.

previous two forecasts: the 2024 IRP Progress Report average system load forecast (finalized in late 2023) and the 2024 DSMPA load forecast (finalized in late 2022). Figure 3.1 shows that the 2026 IRP annual average system loads are expected to grow at a rate similar to that of the 2024 IRP annual average system load forecast, and at a notably faster rate than that of the 2024 DSMPA forecast. Figure 3.2 compares the annual average and peak hourly load forecasts in the 2026 IRP Report against those used in the 2024 IRP Progress Report. This figure illustrates the nominal changes in annual average forecast loads from the 2024 IRP Progress Report to the 2026 IRP Report; while the 2026 IRP Report forecast hourly peak loads show little change, forecast peak loads decreased slightly from the previous load forecast.

Figure 3.1. System Load Forecast Used in the 2026 IRP and Comparison with Previous Forecasts

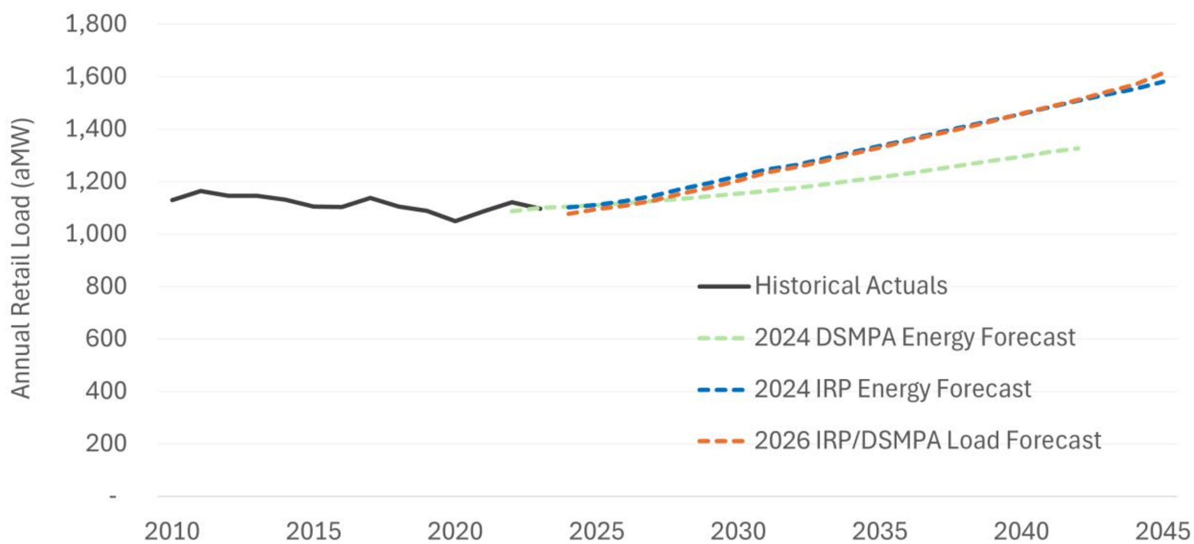
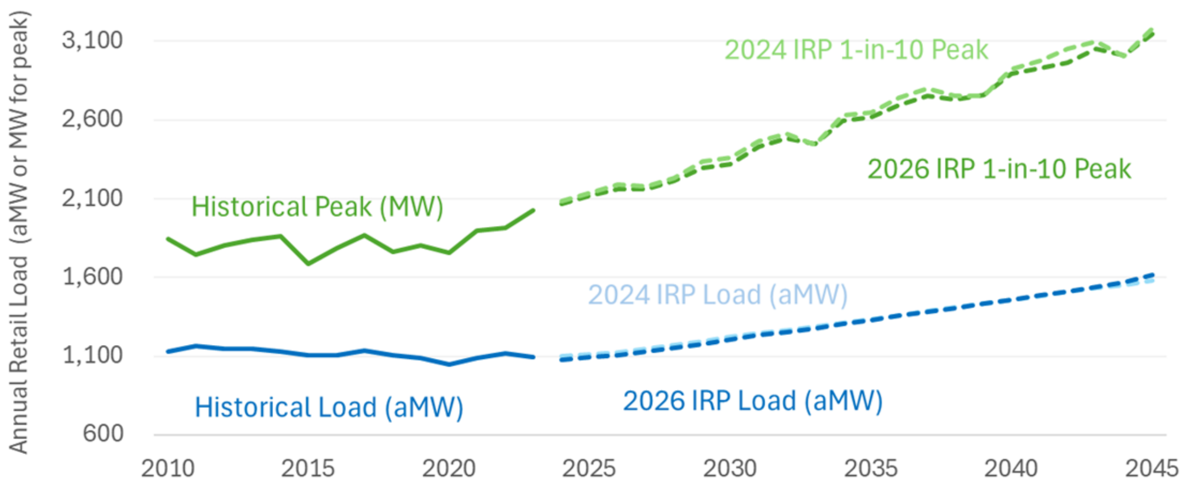


Figure 3.2. Annual Average Energy and Peak Hourly System Load Forecasts Used in the 2026 IRP Compared to the 2024 IRP



Factors Driving the Load Forecast

Relative to the 2022 and earlier IRP load forecasts, the 2026 IRP load forecast shows a faster rate of load growth due to electric vehicle and heat pump penetration, regulatory changes, building codes, and customer behaviors. Incorporating these factors in the 2024 IRP and 2026 IRP load forecasts results in load peaks growing faster than the annual average energy, which is consistent with historical observations over the past 10 years.

Figure 3.3 shows the drivers of load growth and reduction that have the largest impacts to annual average load projections overall. Transportation electrification and building electrification were the two largest drivers of forecast load increases over the 20-year IRP study period. Programmatic energy efficiency and behind-the-meter (BTM) solar (also known as “customer solar”) were primarily responsible for reductions in the forecast load.

Figure 3.3. Annual Average MW System Load Forecast Used in the 2026 IRP by Driver

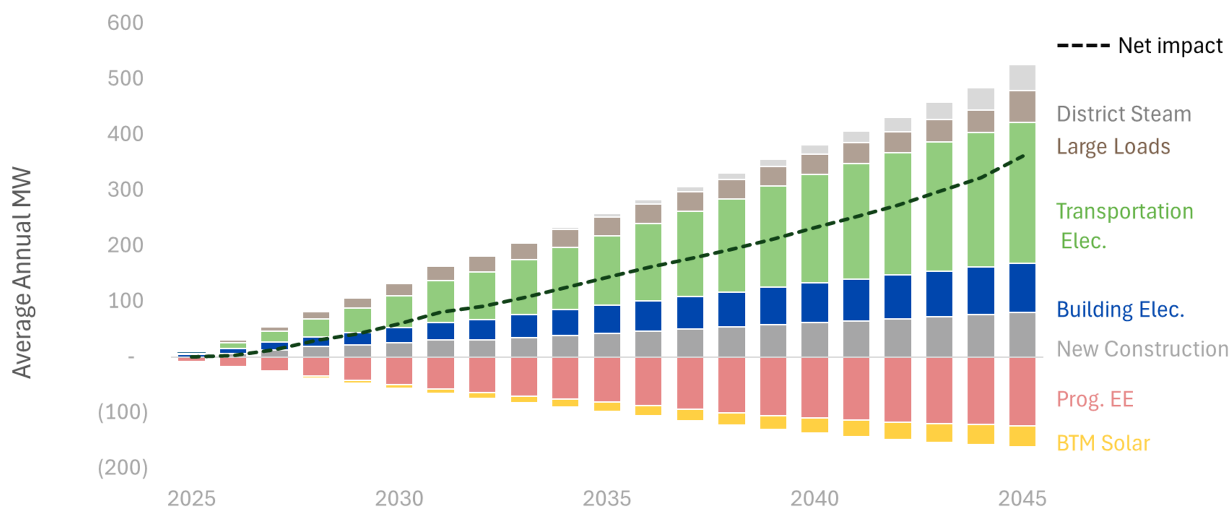


Figure 3.4 and Figure 3.5 show the impact of transportation electrification, new air conditioning, and building electrification for sample summer and winter days in 2045 to illustrate changing dynamics by the end of the present IRP study period.[20] New residential cooling contributes to the summer peak on the July sample day shown in Figure 3.4, whereas electrification of space and water heating drives the winter peak for the December sample day shown in Figure 3.5. The overall shape of these diurnal loads is generally what one would expect to see in the future: summer peaks in the afternoons (when cooling loads are highest), and winter peaks once in the morning and once in the evening (when heating loads are highest).

[20] Figure 3.4 and Figure 3.5 each show a sample illustrative day from the model. The graphs do not show averages of the model output over a set period of time and are intended to only provide examples of how the load might look in the future.

Figure 3.4. Sample Summer Day Load Forecast in Year 2045 (MW)

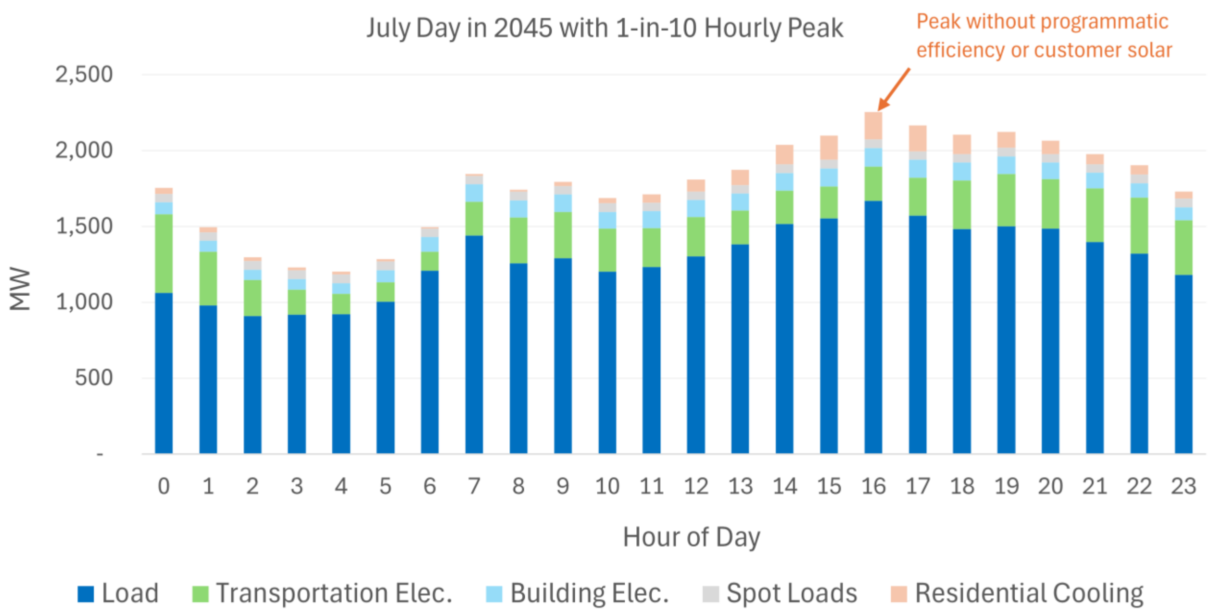
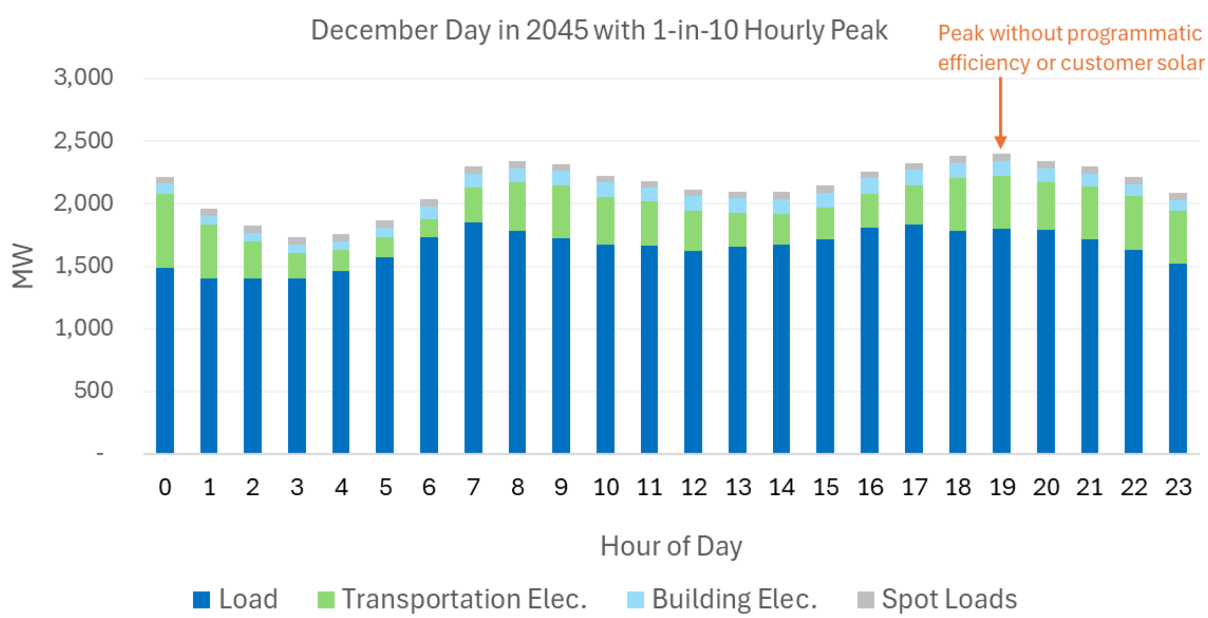


Figure 3.5. Sample Winter Day Load Forecast in Year 2045 (MW)



APPENDIX 4: REGULATORY REQUIREMENTS

City Light is required to comply with several regulations aimed at addressing the greenhouse gas (GHG) emissions associated with the energy it generates, transacts, and delivers. Following are some of these policies:

- Seattle's Sustainable Buildings and Sites Policy, establishing a commitment to GHG neutrality (set by City Council in 2000)
- Washington's Energy Independence Act, I-937 (signed into law in 2006)
- Washington's Clean Energy Transformation Act (signed into law in 2019)
- Washington's Climate Commitment Act (signed into law in 2021)
- Washington's Clean Fuel Standard (signed into law in 2021)
- California's Global Warming Solutions Act (signed into California law in 2006; however, City Light did not meet reporting and compliance applicability until 2020 when it joined the Western Energy Imbalance Market)

The goals and requirements of these regional policies will help utilities, including City Light, accelerate the rate of carbon-free resource adoption necessary to reduce state and regional energy sector emissions. In addition to reducing emissions, a number of these regulations seek to ensure renewable energy transitions are done in a socially conscientious manner by putting environmental justice and equity at the center of these climate policies.

Though much of City Light's portfolio already comprises renewable and non-emitting resources, it must strive to eliminate the remaining sources of fossil fuel-derived energy in its portfolio to comply with legislative requirements. Reducing and eliminating emitting resources will require leveraging a broad portfolio of solutions.

City Light must comply with reporting programs that are governed by different jurisdictions and authorities. These programs apply distinct emissions calculations and reporting frameworks that are designed to achieve their intended policies and objectives. For example, City Light's neutrality efforts aim to identify all emissions associated with City Light's business activities, including those associated with its energy portfolio, and use offset credits to meet its neutrality goals. Meanwhile, City Light's compliance with varying Cap-and-Invest programs require the utility to report and provide eligible compliance instruments for electricity transactions generated in, imported into, or exported out of the given jurisdiction.

City Light GHG Neutrality

In 2000, the City Council set a long-term goal for City Light to achieve GHG neutrality while meeting all of the city's electricity needs. In 2005, City Light became the first electric utility in the country to achieve zero net GHG emissions. To maintain this status, City Light completes an inventory of its GHG emissions every year. The largest source is from market purchases of power, both directly by City Light and through the Bonneville Power Administration (BPA). Other sources include fossil fuels used in vehicles and equipment, leakage of sulfur hexafluoride (SF_6), a potent greenhouse gas used in electrical equipment; employee air travel; and natural gas used for building and water heat and fuel in emergency generators. City Light purchases carbon offset credits for these emissions, which are registered through organizations like the Climate Action Reserve and the Verified Carbon Standard.

I-937 Renewable Portfolio Standard

The Washington State Energy Independence Act, also known as I-937, requires electric utilities serving at least 25,000 retail customers to meet specific targets for renewable energy use (15% by 2020 and beyond)[21] and set two- and ten-year energy conservation to serve their loads.[22] Compliance for renewable energy use can be met on an annual basis in one of three ways:

- A utility may always comply with I-937 by using eligible renewable resources[23] and/or renewable energy credits (RECs) to meet 15% of its customer retail load.
- If a utility has no load growth, it may use eligible renewable resources and/or RECs to meet 1% of its retail revenue requirement and offset any incremental nonrenewable energy purchases.
- A utility may spend at least 4% of its annual retail revenue requirement on the incremental cost of eligible renewable energy and/or RECs.[24]

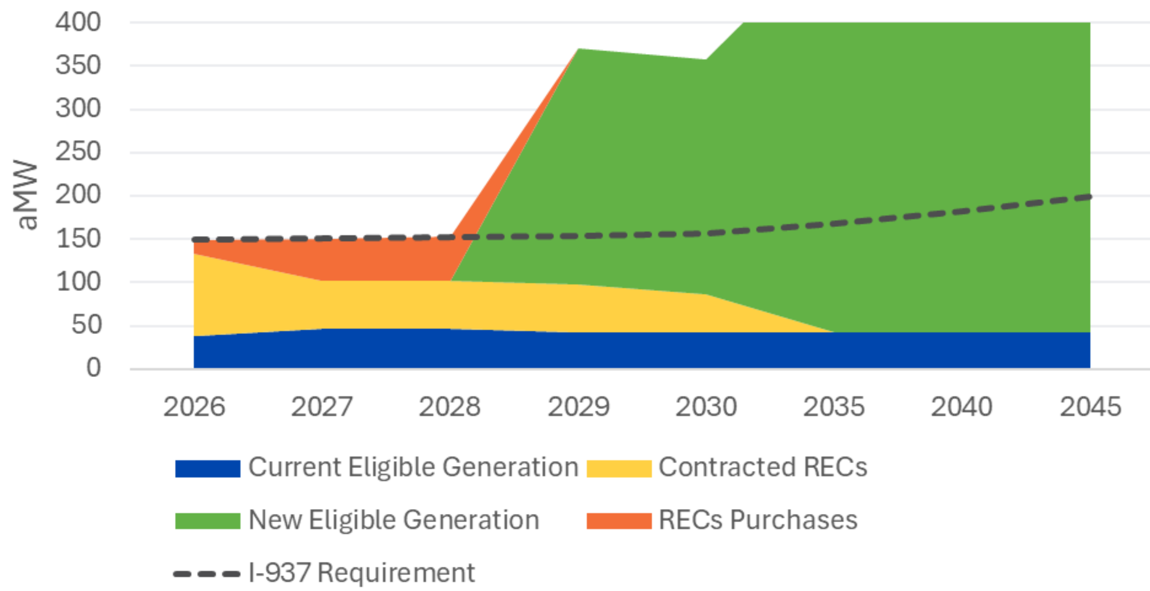
To comply with I-937 requirements, City Light used the "no load growth" compliance option from 2019 to 2022. In 2023, City Light chose to comply with the 15% pathway. City Light's load has steadily increased since 2021 and the utility will likely need to

[21] Revised Code of Washington (RCW) 19.285.040(2).
[22] RCW 19.285.040(2) and WAC 194-37-070(2).
[23] "Eligible resources include incremental hydro, wind, solar energy, geothermal energy, landfill gas, wave, ocean or tidal power, gas for sewage treatment plants, and biodiesel fuel and biomass energy." Energy Independence Act (EIA). November 2006. www.commerce.wa.gov/energy-policy/electricity-policy/eia/
[24] The retail revenue requirement refers to the portion of a utility's annual budget approved by its governing body or regulator that is intended to be recovered through rates.

continue meeting I-937 requirements by meeting 15% of retail load with eligible resources and RECs.

Current eligible resources and contracted RECs are not enough to meet I-937 requirements, but with planned renewable energy resource additions and REC purchases—as per the 2026 Integrated Resource Plan (IRP) preferred portfolio—City Light is well-positioned for meeting I-937 requirements for renewable energy into the future as shown in Figure 4.1. New eligible generation to meet City Light's energy and capacity needs causes City Light to have surplus RECs starting in 2029, eliminating the need for spot REC purchases. Due to the surplus, City Light does not anticipate needing to renew its long-term contracted REC purchases that expire in the 2030s.

Figure 4.1. I-937 Needs



Compliance for energy conservation is further described in Appendix 2: Demand-Side Management Potential Assessment.

Clean Energy Transformation Act

CETA requires electric utilities in Washington state to meet the following milestones:

- Utilities must remove coal-fired generation from Washington's allocation of electricity by 2026.

- Washington retail sales must be GHG-neutral, with at least 80% renewable or non-emitting, by 2030.
- Washington electricity retail sales must be 100% renewable or non-emitting by 2045.

CETA requires utilities to submit a Clean Energy Implementation Plan (CEIP), which outlines progress toward meeting these milestones while ensuring an equitable distribution of energy benefits and reducing burdens to vulnerable populations and highly impacted communities. The CEIP includes renewable energy, energy efficiency, and demand response targets. The most recent CEIP was approved by Seattle City Council in September 2025.[25]

The milestones are modeled in GridPath's capacity expansion model.[26] The model must choose a mix of resources so that by 2030 generation from GHG-free resources exceeds 80% of retail sales and this generation plus purchased RECs exceeds 100% of retail sales. The RECs required by I-937 exceed those required by CETA. Additionally, generation from GHG-free resources (without REC purchases) must exceed 100% of retail sales by 2045. These model constraints influence each portfolio's mix of resources.

The Clean Energy Action Plan (CEAP) is a 10-year plan required by CETA to show how the utility plans to meet the CETA milestones at the lowest reasonable cost and at an acceptable resource adequacy standard. This plan consists of the demand-side resources, supply-side resources, and transmission selected by the IRP model for the years 2026–2035. Additionally, CETA requires that the IRP and CEAP be informed by the results of the Demand-Side Management Potential Assessment (DSMPA), sets a resource adequacy requirement, and identifies necessary transmission acquisitions. Each of these requirements are addressed in the 2026 IRP report and appendices.

CETA also requires electric utilities to consider the social cost of greenhouse gas (SCGHG)[27, 28] as part of the total portfolio cost when developing their IRPs and CEAPs. The assumed SCGHG, as published by the Washington Department of Commerce, in 2026 dollars per metric ton of CO_2e is shown in Figure 4.2.

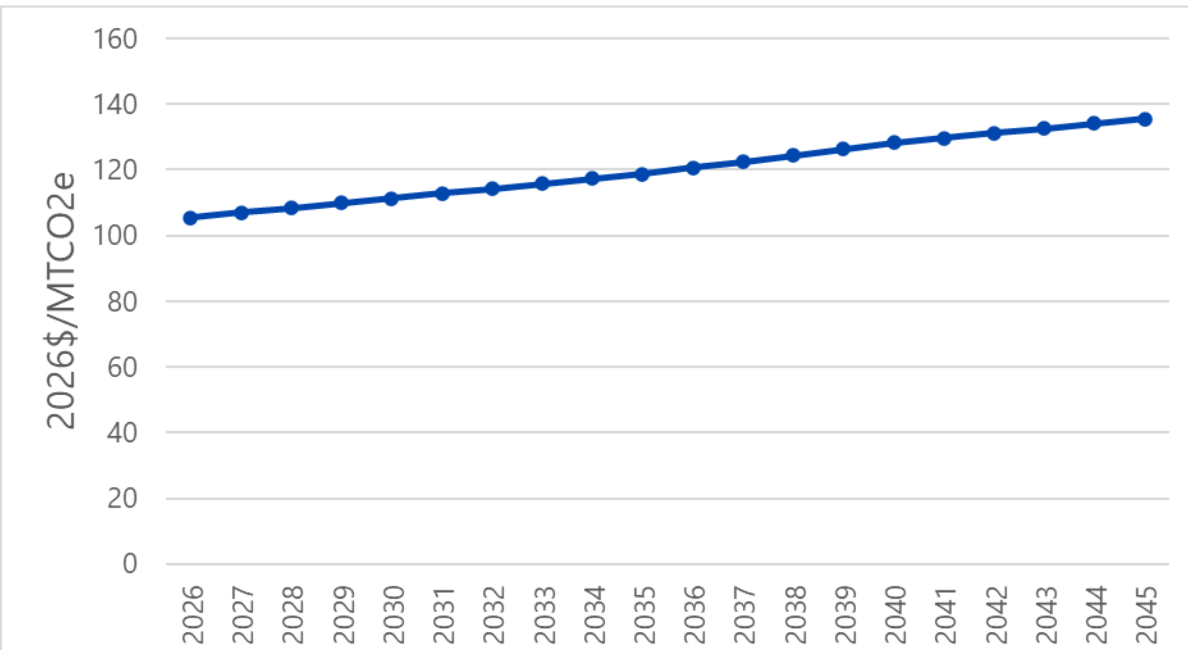
[25] www.seattle.gov/city-light/energy/power-supply-and-delivery/clean-energy-implementation-plan
[26] GridPath is City Light's open-source grid analytics framework. More details can be found in Appendix 8: Model Framework.
[27] www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act/social-cost-carbon
[28] Revised code of Washington related to IRPs that governs SCGHG methodology is 3a under 19.280.030.

In the 2026 IRP, this SCGHG cost-adder is applied to all unspecified energy (i.e., purchased electricity without a known or declared fuel type) serving retail load. There are three sources from which City Light would incur this adder:

- A small percentage of unspecified power in the BPA power contract
- Several of City Light's long-term contracts (e.g., High Ross contract)
- City Light spot market purchases from unspecified generating sources

The SCGHG cost calculations incorporate the CETA-assigned emissions rate of 0.437 metric tons of carbon dioxide equivalent (CO_2e) per megawatt-hour of unspecified energy, using the SCGHG value in 2026 dollars per metric ton of CO_2e.

Figure 4.2. 2026 IRP Assumed Social Cost of Greenhouse Gas (2026–2045)



Climate Commitment Act

The Climate Commitment Act (CCA) was signed into law in May 2021. It was designed to ensure that the state meets the GHG limits outlined under the Climate Pollution Limits bill (RCW 70A.45.020). The CCA creates a Cap-and-Invest program. This program sets an emissions allowance budget for the state and puts a cap on the allowable emissions associated with large emitters (those producing more than 25 thousand metric tons of emissions). Over time, the amount of allowable emissions will decrease to ensure that the state meet statutory limits.

Entities covered under the Cap-and-Invest program, including City Light, must report on their emissions and obtain eligible instruments to cover their compliance obligations. Some entities, including City Light, receive free allowances to offset the cost burden associated with program compliance. City Light’s hydroelectric projects are not considered to generate emissions under this program. However, City Light must report and provide compliance instruments for any emissions associated with energy that is imported into the state of Washington, such as wholesale power from emitting sources or power generated by a source that cannot be documented.

This policy has a relatively low impact on the portfolio expansion decisions City Light would make and, so it is not explicitly modeled in the IRP. However, effects of this policy are reflected in the market price forecasts and load forecast. The policy is considered outside of the IRP for internal policy and short-term decisions.

Clean Fuel Standard

The Clean Fuel Standard (CFS), signed into law in 2021, is a Washington state regulation designed to reduce transportation pollution. The Department of Ecology tracks pollution created by the use of various types of transportation fuels, from gasoline and diesel to electricity and hydrogen.

The CFS requires suppliers of high-pollution transportation fuels to either reduce their pollution over time or purchase credits, so that the money can be used to address the harms from that pollution. Suppliers of low-pollution transportation fuels can opt in to the CFS, generating credits that can be sold to high-pollution suppliers.

Under CFS legislation, City Light's supply of carbon-neutral electricity makes the utility eligible to generate CFS credits when customers use City Light electricity to power electric vehicles. The state allows City Light to use revenue from the sale of these credits to invest in initiatives that reduce air pollution, improve the power grid and the local economy, and continue to expand access to EV charging.

The CFS has no impact on the portfolio expansion decisions City Light would make and so it is not explicitly modeled in the IRP. It is considered outside of the IRP for internal policy and short-term decisions.

California’s Global Warming Solutions Act

In 2006, California’s Global Warming Solutions Act gave the California Air Resources Board (CARB or ARB) the authority to implement a Cap-and-Invest program to meet the state's established GHG emissions targets. Although California requires electric power entities to report emissions and comply with its programs, City Light's electricity transactions did not initially meet reporting and compliance requirements. When City Light entered into the WEIM and acquired a scheduling coordinator identification in the California Independent System Operator (CAISO) market, it became obligated to report applicable electricity transactions (imports, exports, wheeled) associated with California. City Light must provide compliance instruments for the emissions associated with applicable electricity transactions.

This policy has a relatively low impact on the portfolio expansion decisions City Light would make, so it is not explicitly modeled in the IRP. However, effects of this policy are reflected in the market price forecasts, and it is considered outside of the IRP for internal policy and short-term decisions.

Secondary Legislative Impacts

Several other pieces of legislation have a significant impact on City Light's system load forecast, which was used as an input to the 2026 IRP.

- Seattle's Building Emissions Performance Standard, enacted in December 2023, requires non-residential and multifamily buildings larger than 20,000 square feet to meet progressively stronger GHG emissions targets over the next two decades. Covered buildings must eventually reach net-zero emissions by 2041–2050. This has significantly increased expected loads as a result of increased building electrification.
- Washington's Transportation Electrification Strategy legislation, enacted in early 2023, intended to ensure electric vehicle incentives and infrastructure are accessible and available to all people in Washington and advance Washington's market and infrastructure readiness to support new electric vehicle sales. This legislation and strategy significantly increased expected transportation electrification loads in City Light's service territory.

The expected impact of these policies were incorporated into City Light's load forecast used in the IRP. These assumptions were set in late 2024. Since the time the assumptions were set, the industry has seen large changes in the operating environment including decreased federal incentives for electric vehicles, which may impact how quickly our customers transition to electrification. City Light follows these developments closely and will update future load forecasts and IRPs as more information becomes available.

APPENDIX 5: RESOURCE OPTIONS

As part of the 2026 IRP, both established and advanced technologies were assessed in GridPath (see Appendix 8: Model Framework for a more detailed description of the GridPath model) as candidate resources to help meet City Light's portfolio requirements over the 20-year IRP study period. Established resource technologies that were considered for portfolio expansion in the model included utility-scale solar photovoltaic (PV), short-duration (four-hour) lithium-ion battery energy storage systems (BESSs), and onshore wind. Advanced technologies were handled separately via break-even analyses. Advanced technologies considered in this study included long-duration energy storage, enhanced geothermal systems, small modular reactors (SMRs), and green hydrogen peaker plants. Demand side resources chosen in the 2026 Demand-Side Management Potential Assessment (DSMPA) were included in City Light's modeled existing portfolio, and as such, did not vary across different candidate portfolios.

Established Technologies

City Light allowed as candidates in the portfolio expansion portion of the study only carbon-free resource technologies that were commercially available at a utility scale at the time inputs to the model were finalized:

- onshore wind
- solar PV
- short-duration BESSs

Table 5.1 provides more details on the model's supply-side candidate resources.

Table 5.1. Modeled Supply-Side Candidate Resources

Technology	Location(s)	Data Sources and Notes
Onshore Wind	Gorge (Washington-Oregon border) Idaho Montana	National Renewable Energy Laboratory (NREL)-based wind shapes Vibrant Clean Energy's Resource Adequacy Renewable Energy (RARE) dataset Request for Proposal (RFP) responses NREL Annual Technology Baseline (ATB)
Solar PV	Central Washington Northeast Washington Oregon Idaho	NREL-based solar shapes RFP responses NREL ATB
BESSs	On-system On Bonneville Power Administration's (BPA's) system Co-located with renewables	RFP responses NREL ATB 85% round-trip efficiency Duration selected by model (4-hour minimum)

The 2026 IRP used candidate utility-scale wind resources located in the Columbia River Gorge on both the Oregon and Washington side as well as wind resources in Idaho, and Montana. However, due to City Light's lack of current transmission rights from Montana, the 2026 IRP did not include Montana wind resources as candidates until 2035, as this is the first year the model assumed additional transmission capacity would be available. The generation profiles for these locations were taken from a blend of Vibrant Clean Energy's RARE Power Dataset and NREL wind resource profiles available through the System Advisor Model (SAM) tool.

The 2026 IRP included candidate solar PV resources located in central and northeast Washington, Oregon, and Idaho; power generation profiles were created using NREL's SAM tool. The SAM's solar profiles are derived from the National Solar Radiation Database (NSRDB), which is a serially complete collection of hourly and half-hourly historical measurements of global horizontal, direct normal, and diffuse horizontal irradiance by location. The SAM tool uses these data in combination with solar panel specifications to estimate hardware- and location-specific solar generation output.

Finally, the 2026 IRP model included candidate four-hour BESSs with an 85% round-trip efficiency. These candidate resources were assumed to be located within City Light's balancing area, on BPA's transmission system, or co-located with candidate solar PV projects. Short-duration BESS operations were modeled endogenously in GridPath, charging at times of relatively low resource need and low market prices and discharging at times of high resource need, high market prices, or both.

New resource availability was assumed to be unconstrained for the purposes of this IRP study. Unconstrained availability helps the utility understand the volume of resources that will be needed to meet City Light's needs. However, in reality, new resource availability is quite constrained, and City Light will be competing with other utilities and large electricity users for available projects to meet the demonstrated need.

Capital, operations and maintenance, and curtailment cost data for candidate wind resources, solar PV resources, and short-duration BESSs were derived from a combination of NREL's ATB and responses to City Light's 2023 resource acquisition RFPs. Assumptions around resource pricing were finalized in late 2024, prior to the implementation of many of the financially impactful policies enacted by the current federal administration. Of the policies that were enacted by the time resource pricing for the IRP were required to be finalized, much uncertainty remained around the longevity and specific financial impacts to generation resource pricing. The short time between the change in federal administration and deadline for finalizing IRP inputs did not allow third parties to complete analyses of policy impacts to resource pricing. These analyses were therefore not available for City Light's reference and use to inform the 2026 IRP.

Figure 5.1 and Figure 5.2 show City Light's low, mid, and high cost scenarios for solar and wind, respectively. For both sets of cost scenarios, the initial representative cost of the resource in 2025 was determined from a blend of NREL's ATB and City Light's 2023 RFP responses. The high cost scenarios both propagate this value forward in time, unchanged. The low cost scenario for solar PV uses linear interpolation from the initial blended 2025 cost to the NREL ATB Class 7 Moderate (including the Production Tax Credit (PTC)) cost by 2030 and then follows the ATB Class 7 Moderate costs through 2045. Similarly, the low cost scenario for wind uses linear interpolation from the initial blended 2025 cost to the NREL ATB Class 10 Moderate cost by 2030, and tracks the ATB Class 10 Moderate costs through 2045. The mid cost scenarios for both wind and solar PV were derived by averaging their respective low- and high cost forecasts.

Figure 5.1. Solar Cost Scenarios ($2026)

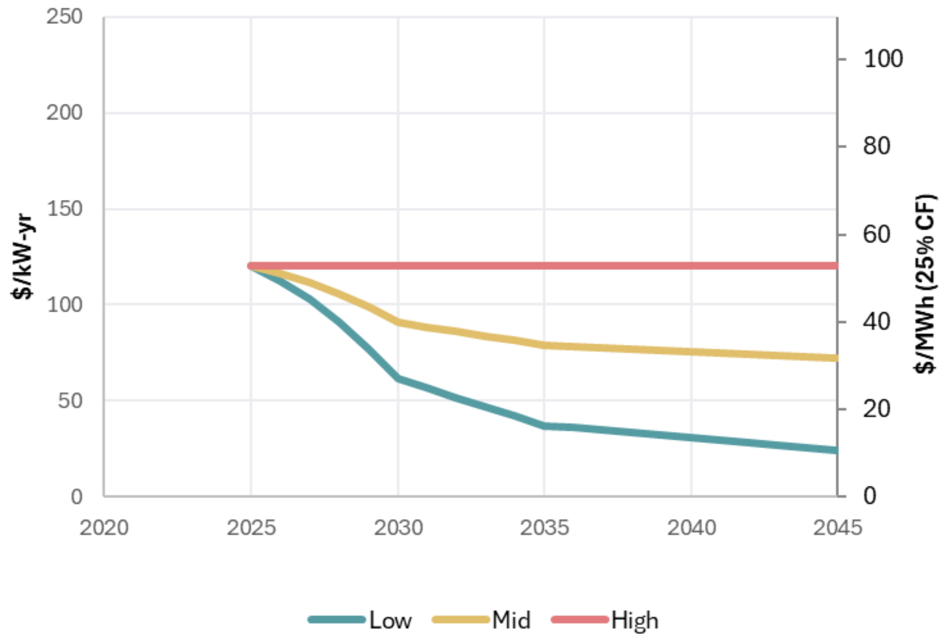


Figure 5.2. Wind Cost Scenarios ($2026)

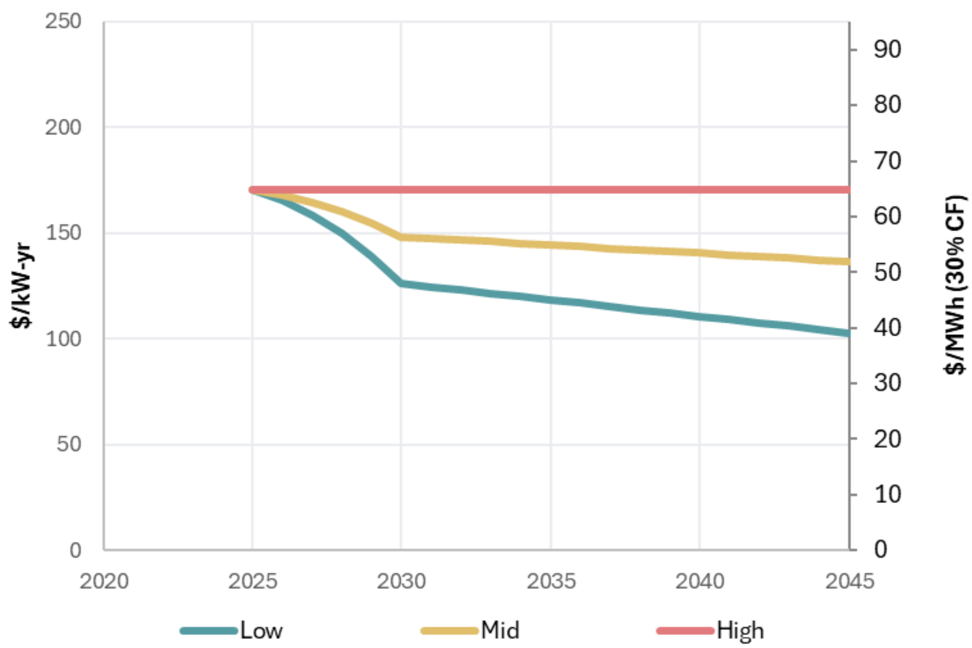


Table 5.2 shows capacity factors of the various wind and solar PV resource options in the 2026 IRP.

Table 5.2. Wind and Solar Capacity Factors by Location, All Simulated Years

Resource	Capacity Factor (%)
Solar – Central WA	25%
Solar – Northeast WA	24%
Solar – Idaho	24%
Solar – Oregon	24%
Wind – WA Gorge	30%
Wind – OR Gorge	30%
Wind – Idaho	29%
Wind – Montana	39%

Advanced Technologies

Incorporating a broader range of carbon-free resource technology types into the IRP study beyond the resource technologies that are currently commercially available on a utility scale adds diversity and value to a future power supply portfolio. However, at the time the current IRP inputs were finalized, a significant amount of uncertainty remained with respect to the commercial availability, timing, and pricing of these advanced technology resources. City Light separated these resources from the established resource technologies in the present IRP study to prevent those uncertainties from muddying final portfolio results. The advanced technologies City Light considered were long-duration energy storage, enhanced geothermal, SMRs, and green hydrogen peaker plants. These clean, firm resources will be an important component for City Light's future energy portfolio.

Table 5.3 provides more details on model assumptions for these advanced technologies.

Table 5.3. Advanced Technologies in the IRP Study

Technology	Location(s)	Data Sources and Notes
Long-Duration Energy Storage	On-system	Form Energy Modeled as 100-hour iron-air batteries 75% charging efficiency, 50% discharging efficiency 20-year expected life span
Enhanced Geothermal	Delivered to Mid-C	NREL ATB Modeled as a baseload resource 95% capacity factor
SMRs	Delivered to Mid-C	NREL ATB Modeled as a baseload resource 95% capacity factor
Green Hydrogen Peaker Plants	On-system	NREL ATB Modeled as new-frame combustion turbines Heat rate of 9.72 MMBtu/MWh

Long-Duration Energy Storage was modeled using publicly available performance parameters from Form Energy's 100-hour iron-air batteries. Specifically, the 2026 IRP assumed a 75% charging efficiency, a 50% discharging efficiency, and a 20-year expected life span of the system.

Enhanced geothermal and SMRs were modeled as baseload resources, both with 95% capacity factors, per NREL ATB. They were assumed to be delivered to Mid-C, so cost of transmission to Mid-C was included in the break-even analysis.

Green hydrogen peaker plants were modeled as new-frame combustion turbines with a heat rate of 9.72 MMBtu/MWh, per NREL ATB, and were assumed to be located on City Light's system. The cost of these peaker plants was assumed to include all costs associated with the production, transport, and storage of green hydrogen.

Break-even analyses were performed for each advanced resource technology type individually. The purpose of a break-even analysis is to determine the point at which a given advanced technology type would add value to a candidate portfolio. For more details on the break-even analysis methodology, see Appendix 11: Advanced Technology Break-even Analyses.

Market Purchases

City Light also has the option to purchase energy from the market in lieu of supplying energy from demand- or supply-side resources. Market purchases were valued according to the hourly wholesale market price forecast. Further details on the 2026 IRP's assumptions on availability and cost of market purchases are detailed in Appendix 6: Market Prices.

APPENDIX 6: MARKET PRICES

The 2026 Integrated Resources Plan (IRP) developed three scenarios (Mid, Low, and High) for hourly wholesale price forecasts at the Mid-Columbia (Mid-C) and California-Oregon Border (COB) market hubs. These forecasts were based on third-party S&P hourly price forecasts, Northwest Power and Conservation Council (Power Council) hydro-dependent price forecasts across 30 different hydro futures, and Intercontinental Exchange (ICE) forward-looking Mid-C prices. The 2026 IRP relies particularly on Power Council price data as they focus on modeling hydro conditions and operating constraints across the hydro-heavy Pacific Northwest, and the impact of hydro conditions and constraints on the wholesale energy market. Power Council prices were incorporated into all three price scenarios so that the 2026 IRP model would include the weather-driven joint distribution of hydroelectricity generation and wholesale market prices.

The methodology used to develop the three ensemble forecasts corresponding to the Low, Mid, and High price scenarios for Mid-C is described below.

Mid: This scenario reflects near-term market scarcity, long-term expectations that align with S&P projections, and monthly or hydrological year price variability that roughly corresponds to the Power Council's hydro modeling. To develop the Mid scenario, the 2026 IRP began with the S&P hourly prices and made the following adjustments:

- In years 2025–2030, monthly scalars were applied to Mid-C prices for all hours in which the ICE forward prices as of October 9, 2024, were blended with the hourly S&P prices. The scalars ramp down linearly so that average monthly prices in 2025 align with ICE forward prices and average monthly prices in 2030 align with S&P monthly averages.
- For each hydro year, a monthly price adder was applied based on the Power Council price data's monthly average price deviations for that hydro year.
- A price floor of $0/MWh was applied, due to S&P applying a minimum price of $0/MWh.

Low: This scenario reflects near term market scarcity, long-term expectations that align with the Power Council's projections, and monthly/hydro year price variability that roughly corresponds to the Power Council's hydro modeling. To develop the Low scenario, the 2026 IRP began with the Power Council's High Demand Mid Gas price forecast and made the following adjustments:

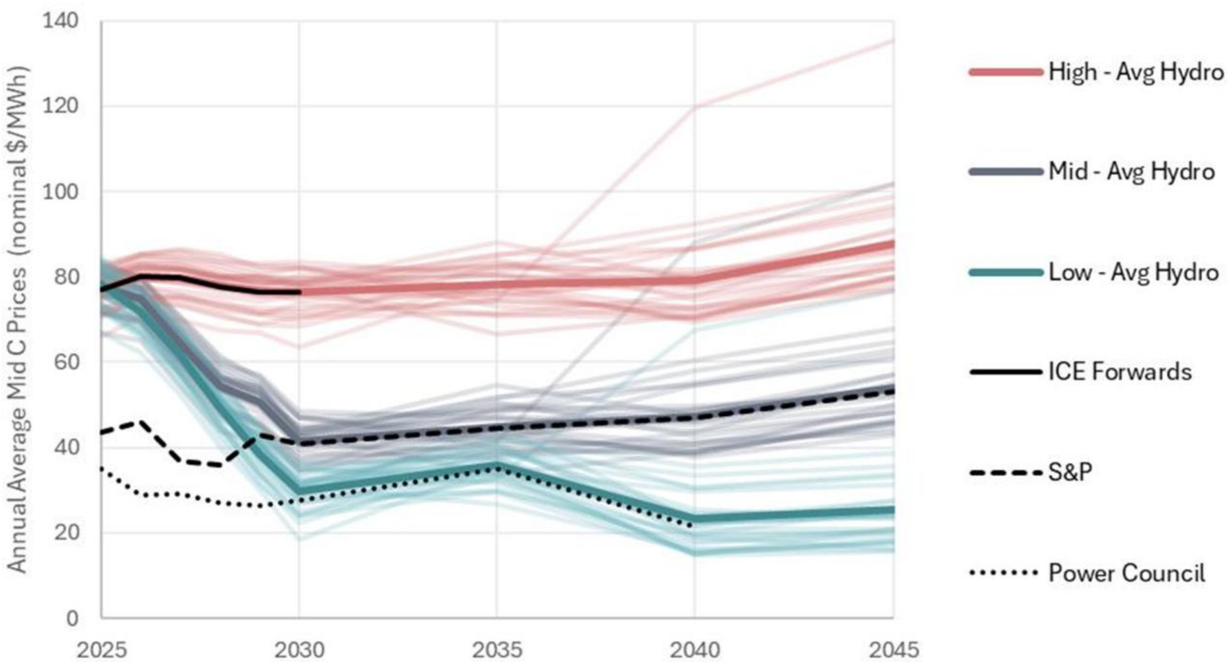
- In years 2025–2030, monthly scalars were applied to Mid-C prices in all hours that blend the ICE forward prices with the Power Council prices. The scalars ramp down linearly so that average monthly prices in 2025 align with ICE forward prices and average monthly prices in 2030 align with Power Council hydro-year-specific monthly averages. Prior to 2030, the scalars were applied based on average hydro conditions to maintain consistent hydro-based spreads across the price scenarios.
- A price floor of $0/MWh was applied, because the price floor for the S&P data for the Mid price scenario was also $0/MWh, and for purposes of a consistent methodology it was considered desirable to treat the Low scenario the same.

High: This scenario projects persistent scarcity into the future, and monthly/hydro year price variability that roughly corresponds to the Power Council's hydro modeling. To develop the High scenario, the 2026 IRP began with the ICE hourly prices and applied the same methodology used to develop the Mid scenario, with the following adjustments:

- Rather than ramping down the ICE forward price scalar between 2025 and 2030, ICE average monthly prices were applied for all years, including beyond 2030.
- For each hydro year, a monthly price adder was applied based on the Power Council price data's monthly average price deviations for that hydro year.

The resulting price forecasts are shown in Figure 6.1.

Figure 6.1. Mid-C Prices Across Hydro Futures



City Light evaluated several additional price forecasts from external entities and determined that the three price scenarios described above encompass the range of feasible Mid-C price forecasts.

Since City Light did not have access to hourly California market price forecasts, the team used the S&P Mid-C price forecasts as a starting point and adjusted the prices as follows:

- In hours when the S&P Mid-C price is $0/MWh, the California price is also assumed to be $0/MWh to avoid unrealistic arbitrage opportunities (e.g., to avoid making profit from importing excessive energy when prices are negative in California).
- In hours when the S&P Mid-C price is not $0/MWh, the monthly peak/off-peak price difference between the S&P COB market price and the S&P Mid-C market price is added to the hourly S&P Mid-C price.[29]

[29] Specifically, the average market price difference between COB and Mid-C for the month and peak period is calculated for hours where the Mid-C price is not $0/MWh. The price difference is then scaled upward by multiplying by the ratio of the total number of hours in the month and peak period divided by the hours included in the month and peak period excluding hours when Mid-C price is not $0/MWh. This

Market Reliance

The new resource buildout in the IRP model framework is highly dependent on assumptions of how much energy City Light can purchase in the market. This dependance is because new resource buildouts are primarily driven by resource adequacy, and many of the eligible new resources (even batteries for long-duration events) have fairly low capacity factors during resource adequacy events. Each megawatt of market purchases can therefore offset multiple megawatts of new resource buildouts needed to provide the same amount of capacity.

In the capacity expansion model, City Light tested limiting market purchases to both 200 MW and 300 MW in (and only in) hours where the region is resource constrained from meeting loads,[30] to avoid overly relying on the market and underbuilding needed resources while determining how different market purchase uncertainties affect new resource buildouts. To ensure resource adequacy, in production cost model and resource adequacy model runs, City Light limited market purchases to 200 MW in resource-constrained hours for all runs. The 200 MW value is consistent with the market reliance assumption used in the 2024 IRP; however, the 2024 IRP applied this constraint to all hours.

In hours when the region is not resource constrained, City Light limited total transactions (imports plus exports) to 1 GW in all hours, based on historical trading of around 500 MW.

Carbon and Renewable Energy Content Requirements

City Light has carbon emissions compliance requirements under Washington's Clean Energy Transformation Act (CETA) and Climate Commitment Act (CCA). Generally, demand- and supply-side resources are considered emissions free, while market purchases are treated as having an unspecified source, and therefore are assumed to have an emissions rate equal to the marginal resource in the market. Carbon prices are embedded in the wholesale market price forecasts and are therefore automatically applied to market purchases.

---

scaling ensures that the full average price differential between COB and Mid-C for the given period is accounted for. For example, if COB is on average $10/MWh cheaper than Mid-C in April peak hours in 2030, there are 400 peak hours and 40 of the Mid-C peak hours have prices of $0/MWh, then the price adjustment to COB would be *-$10/MWh * (400 hours / (400 – 40 hours)) = -$11.11/MWh*.

[30] Resource-constrained loads are based on the Power Council's modeling of hours with greatest loss of load probability (LOLP) in the region.

However, the social cost of greenhouse gas (SCGHG) may be higher than the market price for carbon. Consistent with the analysis performed in the 2022 and 2024 IRPs, the SCGHG was calculated and added after the fact to each 2026 IRP portfolio, based on each IRP portfolio's emissions and the social cost of carbon dioxide (CO_2) from the Utilities and Transportation Commission (UTC), as detailed in Appendix 4: Regulatory Requirements.

Minimum renewable energy requirements established by CETA and the Energy Independence Act (EIA, I-937) place constraints on the resource options and market reliance selected by the IRP model. These requirements are discussed in further detail in Appendix 4: Regulatory Requirements.

APPENDIX 7: TRANSMISSION

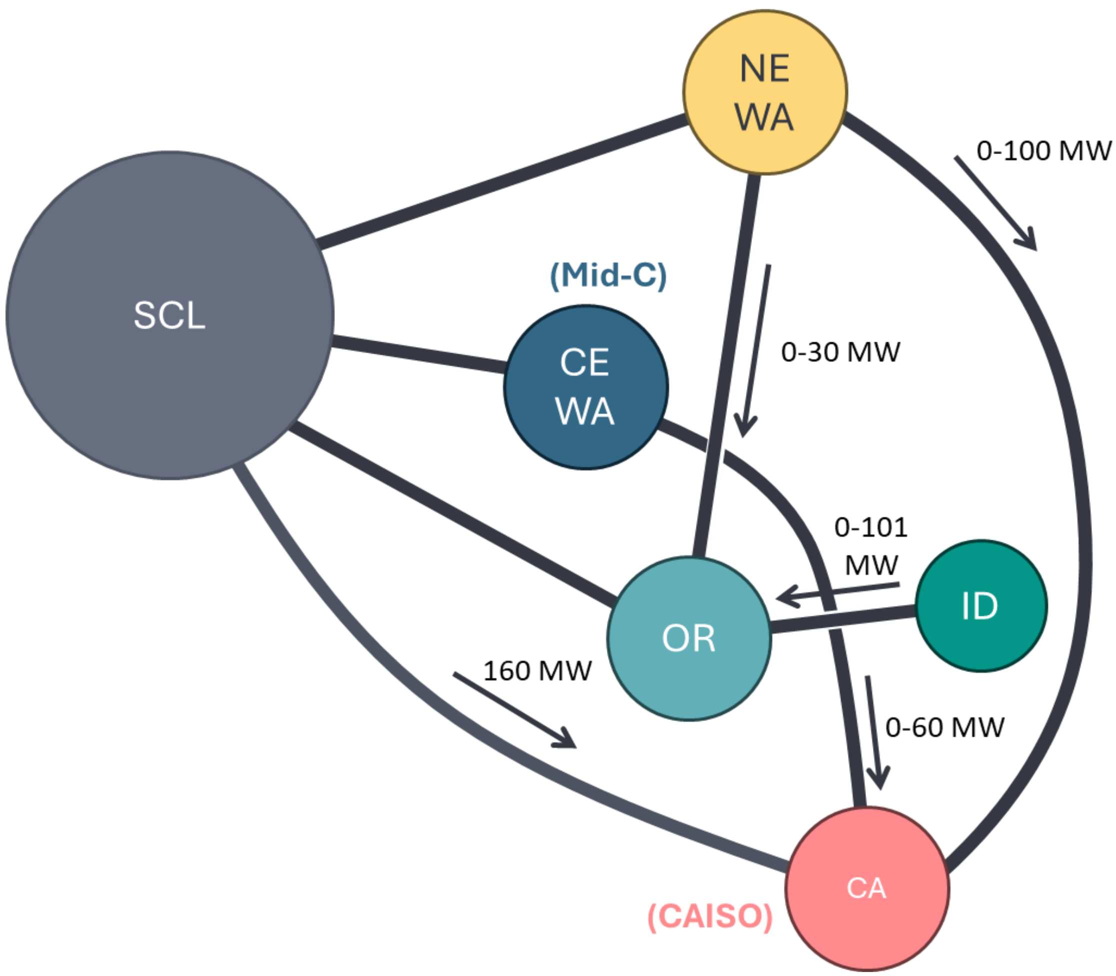
City Light implemented a zonal “pipe and bubble” model within GridPath with flow-gate-based constraints to represent relevant regional transmission in the 2026 IRP. The development and application of flow-gate-based constraints in a pipe and bubble transmission model differ from common practice. However, City Light decided this was necessary due to the unique circumstances the Pacific Northwest is facing in the transmission system.

Bonneville Power Administration (BPA) provides approximately 75% of the transmission serving the Pacific Northwest. The remaining 25% is owned by individual utilities. Typically, utilities and other load-serving entities in the Pacific Northwest secure long-term firm point-to-point (PTP) or Network Integration Transmission Service (NITS) transmission rights to deliver generation across BPA’s system to ensure reliable load service. Because weather-dependent resources cannot generating energy at their full capacity 100% of the time, the reserved transmission is not fully utilized at all times. This means transmission capacity remains reserved even when it is not being used to serve load. In particular, as utility-scale wind and solar resources have grown in the region and load-serving entities continue to reserve more transmission capacity than required to serve load, BPA’s transmission system has become largely oversubscribed. As a result, flows across key transmission paths in the region appear highly constrained at all times, even though most of the time, those paths are not *physically* constrained. Because transmission rights holders can resell some of their reserved transmission capacity, there is potential for transmission to be used more efficiently, which could prevent regional transmission from being underutilized, as well as mitigate the need for costly and slow transmission projects across the region.

Historically, planning studies have modeled long-term firm transmission paths as being fully subscribed when physically there is still significant flexibility left on those pathways. For this IRP, an alternate, more physically-based approach was selected that involves modeling the use of existing transmission flexibility within City Light’s own portfolio when evaluating its long-term transmission requirements. The model approximated the hourly physical constraints on the regional transmission system, rather than applying static firm constraints on an annual basis. To accomplish this, the model tracked when resources were generating and the resulting transmission impacts across key regional paths. The model then used this information to evaluate transmission congestion and physical constraints to determine whether City Light needed to acquire additional long-term transmission rights.

Figure 7.1 below shows the different zones included in GridPath where City Light has existing transmission rights, and the assumed connectivity capacities between them. An additional zone included in the model, Montana, is not pictured in the figure, since City Light does not currently have transmission rights from Montana to Mid-C for final delivery to City Light's balancing area. Transmission pathways in the figure with no label and connections in directions not indicated by arrows are assumed to be unconstrained. For example, the path from SCL to CAISO is assumed to be limited to 160 MW, but the path from CAISO to SCL is assumed to be unconstrained. Based on its current transmission portfolio, City Light does not anticipate any difficulty in securing transmission to deliver power from the regional hubs connected to its service territory, so no transmission limitations were imposed on power imports to City Light from regional hubs in the model; thus, transmission capacities for power imports to the SCL zone are unlabeled in the figure.

Figure 7.1. City Light's Existing Transmission Rights and Connectivity Capacities



Once GridPath's capacity expansion model built candidate portfolios, it tracked total flows from both existing resources and the selected candidate resources on an hourly basis in the production cost and resource adequacy models. Flows in the capacity expansion model were limited based on the quantity of transmission rights that City Light holds. In particular, for any flow going into the City Light zone to serve its own load, the model calculated the impact to flows across key constrained paths. When flows exceeded estimated transmission rights in City Light's existing portfolio, the model had two options:

1. The dispatch could change, meaning resources could be curtailed or the portfolio could be redispatched to respect the transmission constraints on the system.
2. If the constrained dispatch occurs in 2035 or later, the model was allowed to select and acquire additional transmission rights, using existing reference prices (see below). 2035 was the first year in which it was assumed that City Light could utilize newly acquired transmission, allowing the utility time to acquire or build new transmission over the next ten years. Transmission rights from the modeled Montana zone to the Mid-C balancing area could also be selected by the capacity expansion model if needed.

The capacity expansion model weighed both of the options above when encountering flow constraints into City Light's zone, to arrive at the least-cost, reliable portfolio over the entire study period.

New transmission contracts adding capacity between City Light and Oregon, and between City Light and Central Washington, were priced within the model according to the BPA BP-24 Long-Term Firm PTP rate of $19,766/MW-year estimated for 2024,[31] adjusted for inflation. Transmission connecting the Oregon and Idaho zones was set to Idaho Power's long-term firm PTP transmission rate at the time IRP inputs were finalized, which was $31,419/MW-year. Additional transmission connecting Montana to the Central Washington zone was priced at the BP-24 intertie rate of $6,288/MW-year. Data inputs for the IRP were finalized in late 2024, and the transmission rates were not updated for changes in rates between late 2024 and the submission of the IRP report.[32]

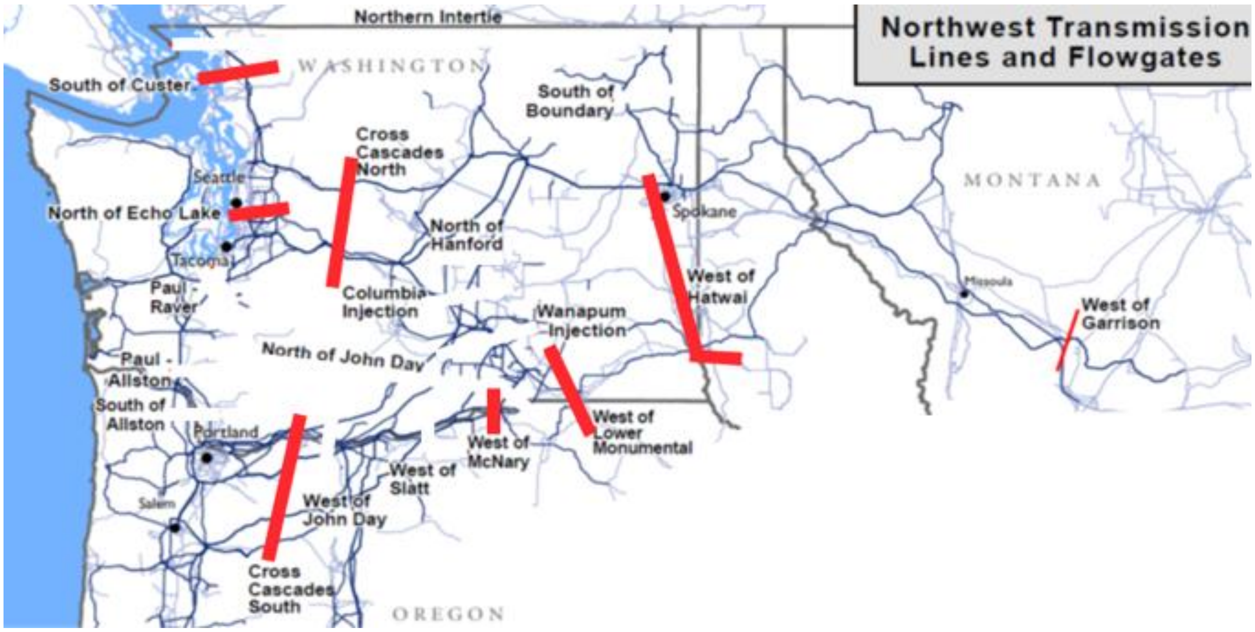
The map in Figure 7.2 provides an overview of some of the key flow paths, or "flow gates," that BPA monitors and plans around. The flow gates demarcated by red lines

---

[31] Based on the posted rate of $1.648/kW-month, converted to dollars per megawatt-year.
[32] For example, BPA's rates have been updated in proceedings.bpa.gov/Home/OpenDoc?fileId=8124. BPA's Long-Term Firm PTP rate has increased from $1.648/kW-month to $2.043/kW-month, although the increase is less dramatic when adjusting for inflation. The Montana intertie rate increased from $0.524/kW-month = $6,288/MW-year, to become $0.545/kW-month.

were found by Sylvan and City Light to be the key paths between established resources and City Light's balancing area.

Figure 7.2. BPA Paths and Flow Gates



The transmission model used in this IRP estimates physical flows across each of the key flow gates listed in Table 7.1. The estimates were established using Power Transfer Distribution Factor (PTDF) calculations from BPA's Long-Term Original Inventory Map for regional transmission paths, which City Light clustered into zones. PTDFs were available for all transmission paths relevant to City Light's system except the BPAPOWER to BPAT.SCL path, which was estimated using BPA's short-term PTDF calculator instead. PTDFs represent the approximate fraction of a given quantity of power flow that moves across each path when that quantity of power is injected into the grid at one location and withdrawn at another. For example, if 1 MW of power were injected into the Northeast Washington (NE_WA) zone and withdrawn at City Light's balancing area, the first column of Table 7.1 indicates that approximately 0.52 MW of power will flow across Cross Cascades North flow gate, and approximately 0.15 MW of power will flow across the North of Echo Lake flow gate, and so on.

To derive transmission constraints for energy flowing into City Light's territory, City Light started by clustering City Light's various firm transmission rights into ten zones, based on point of receipt (POR) and point of delivery (POD). City Light then used BPA's PTDFs to determine fractional flows across regional flow gates for each POR and POD pair. Flow gates showing minimal or negative flows across all of City Light's firm transmission pathways were eliminated as constraining flow gates, leaving nine constraining flow gates. The team performed k-means clustering for every integer *k* from *k*=2 through *k*=7 to investigate the impact of different reductions in problem size and identify flow gates that were of higher importance for the model to resolve. The team selected the groupings corresponding to *k*=7 to maintain the greatest amount of transmission flow gate resolution in the model.

City Light also derived the maximum capacity in megawatts at all key flow gates based on City Light's existing rights and the seven key modeled flow gates. If City Light were to use the maximum extent of its transmission rights simultaneously across each of the seven key modeled flow gates, the net impact at each flow gate would be the maximum capacity City Light would be permitted to use at any given time. These maximum flows are indicated in the right-most column of Table 7.1 and serve as maximum transmission capacities across each of the modeled key flow gates given City Light's existing portfolio of transmission rights.

The following example illustrates how the table can be used to identify modeled constraints on power flow:

- Suppose City Light attempts to transfer 1,000 MW from NE_WA to SCL and 1,000 MW from OR to SCL.
- When flowing 1,000 MW from the NE_WA zone to the SCL zone, the impact on the Cross Cascades North flow gate can be found by looking down the first column of the table to the Cross Cascades North row and calculating the product of the total power flow and the fractional impact indicated in the table: (1,000 MW * 0.52) means the impact of that exchange would result in 520 MW of increased power flow at Cross Cascades North.
- Similarly, the impact on the Cross Cascades North flow gate of flowing power from the OR zone to the SCL zone can be found in the third column of the table in the Cross Cascades North row and is equal to 0.73; the total impact of that second exchange on Cross Cascades North would be *1,000 MW * 0.73 = 730 MW*.
- The total impact on the Cross Cascades North flow gate of these simultaneous power flows is the sum, *520 MW + 730 MW = 1,250 MW*, which is less than the 1,341 maximum flow allowed at that flow gate. The maximum allowed flow can be found under the "Max Flow" column on the far right of the table, in the Cross Cascades North row (this number was derived from the impact on Cross Cascades North when all of City Light's current transmission rights are fully utilized).
- However, the same logic shows that at the West of McNary flow gate the increase in power would be *40 MW + 340 MW = 380 MW*, which is greater than City Light's 151 MW maximum flow limit.

- Even though the "Max Flow" constraint is not violated at Cross Cascades North, the constraint is violated at another location (in this case West of McNary), which means City Light is not allowed to import 1,000 MW from NE_WA and 1,000 MW from OR at the same time.

Table 7.1. Flow Gates Used to Model Transmission

Zone From	NE_WA	CE_WA	OR	CA	Max Flow (MW)
Zone To	SCL	SCL	SCL	SCL	
CROSS CASCADES N.	0.52	0.82	0.73	0.71	**1,341**
NORTH OF ECHO LAKE	0.15	0.34	0.36	0.36	**561**
SOUTH OF CUSTER	0.37	0.04	0.04	0.03	**425**
WEST OF HATWAI	0.57	0.07	0.08	0.04	**673**
WEST OF MCNARY	0.04	0.04	0.34	-0.12	**151**
WEST OF LOMO	0.14	0.10	0.01	-0.02	**255**
CROSS CASCADES S.	0.05	0.06	0.13	0.12	**161**

APPENDIX 8: MODEL FRAMEWORK

For the 2026 Integrated Resource Plan (IRP), City Light used the open-source grid analytics framework GridPath to better support an understanding of the utility's position within the changing energy landscape and the potential of supply-side energy resources. GridPath integrates the following models that make up the complete IRP analysis:

- Capacity expansion modeling: what resources to acquire
- Production cost modeling: how to dispatch resources within a modeled portfolio
- Resource adequacy analysis: how well the selected resources meet energy and capacity needs

Compared with the model framework used in prior IRPs at City Light, GridPath presents some notable advantages for modeling City Light's generation resource portfolio and candidate supply-side resource selections. First, in the present IRP, GridPath was able to dynamically dispatch flexible generation resources within one- and two-week periods while accounting for complex operational constraints at City Light's Skagit hydroelectric project. The previous 2024 IRP model could only optimize Skagit and Boundary resource generation within five-day intervals and could not fully account for operational constraints at Skagit.

Second, GridPath's capacity expansion model can utilize hourly capacity profiles of available resources, contracts, and market purchases to build optimal candidate portfolios. The previous 2024 IRP model could not incorporate capacity profiles at an hourly resolution and instead relied on stacking single-value effective load carrying capacities (ELCCs) for each candidate resource to meet resource adequacy requirements. The 2024 IRP model's ELCC value abstraction was not only expensive to compute for all existing and candidate resources, but the results were less informative and reliable in quantifying the contribution of energy storage resources.

Third, GridPath's zonal transmission module uses physics-based constraints at key flow gates in the region. This technique more realistically captures constraints placed on market availability by transmission availability to better guide cost-effective wholesale energy marketing activity. The previous 2024 IRP model was unable to effectively model transmission-based constraints. As a result, City Light's previous IRP studies could account for transmission only through sensitivity analyses that allowed for unlimited transmission but applied a range of transmission cost assumptions.

Finally, GridPath allows for wholesale energy market arbitrage, something that was not present in the 2024 IRP model. City Light's power marketers currently perform wholesale energy market arbitrage, so incorporating arbitrage into the model more accurately reflects the additional value that the energy resources provide to City Light.

The capacity expansion model was run for five investment years (2029, 2030, 2035, 2040, and 2045), representing periods when new resources could optionally be added to the system (i.e., the earliest a new resource can be added is 2029). For each investment period, the model used 32 representative days (one weekday and one weekend/holiday per month, plus the eight most resource-adequacy-constrained days spread across eight calendar months) at an hourly resolution to endogenously account for detailed operations and resource needs throughout the year. Market access was also included in the capacity expansion analysis. An assumption was made that market purchases will fill open positions in any hour to the extent that they are available and come at a lower cost than further resource additions. The capacity expansion model was constrained to allow zero expected unserved energy (EUE), because it explicitly includes only a fraction of the days in a full year. Zero EUE is a constraint that is much more stringent than what is implicitly allowed under resource adequacy metrics. This helped ensure that the resulting candidate portfolios would meet City Light's resource adequacy requirements through all hundreds of distinct simulated conditions for each of the twenty years in the study period, as explained in Appendix 9: Resource Adequacy. However, this incurs the risk that the model will build overly conservative, potentially overbuilt candidate portfolios.

The portfolios produced by the capacity expansion model were grouped into two clusters, from which a representative portfolio was selected from each for further analysis. In addition to the Current portfolio with no candidate resources added, the other resultant portfolios were the Small Diverse and Large Diverse portfolios. The Small Diverse portfolio allows a maximum of 300 MW of market purchases during resource-adequacy-constrained days to offset the capacity expansion model's potential to overbuild to meet the zero EUE constraint. This results in a smaller resource portfolio buildout. In comparison, the Large Diverse portfolio allows a maximum of only 200 MW of market purchases during resource-adequacy-constrained days, increasing the needed resource portfolio buildout. It is important to note that the assumption of differing access to the market was only introduced in the capacity expansion model to build a menu of options. In the production cost and resource adequacy modeling, market access was held constant at 200 MW in constrained hours.

In addition to the Current portfolio, which did not add any new resources, City Light created six candidate portfolios. These portfolios are further described in Appendix 10: Portfolio Outputs and Analysis.

- Small Diverse
- Large Diverse
- Large solar + storage
- Small solar + storage
- Large wind
- Small wind

The last four portfolios kept the total new energy generation from the new resources the same as their Small Diverse and Large Diverse counterparts[33] but met the new energy generation with only the resources indicated in their respective names. Studying the resource adequacy metrics and costs of "bookend" candidate portfolios, for which all the additional resources consisted of only one type, provided helpful perspective on the mix of types identified in the Small Diverse and Large Diverse portfolios.

The reliability of the Current portfolio and the six candidate portfolios for serving load in 2030 was evaluated through GridPath's resource adequacy model for 870 scenarios, comprising 29 historical weather year effects on City Light's load (1994–2023 calendar year data, trimmed to 29 hydro years)[34] crossed with 30 Northwest Power and Conservation Council (Power Council) hydro trajectories, for a total of 870 distinct hydro and load scenarios. The hydro scenarios determine inflows to City Light's hydro resources, generation from the Federal Columbia River Power System (FCRPS), variations to the hourly wholesale market prices, and regional loss-of-load risk (to inform hourly market availability constraints). The weather scenarios determine load and wind and solar generation profiles at several locations in the region.

The Current portfolio and six candidate portfolios were evaluated in the production cost model for a typical hydro year and typical load conditions over a total of 27 different cost conditions. These 27 conditions included three market price scenarios (low, mid, high), three wind resource capital cost conditions (low, mid, high), and three solar and storage resource capital cost conditions (low, mid, high).

[33] The total new energy generation was the same, but the installed capacity (MW) was not necessarily the same.

[34] A hydro or BPA fiscal year (FY) spans October of the preceding calendar year to September of the current calendar year. For example, FY 1995 spans October 1, 1994, to September 30, 1995. The 30 calendar years have data for only 29 hydro/FYs in full; in this case FY 1995 to FY 2023 (data preceding October of the first calendar year and following September of the last calendar year are unused).

Market Reliance

As explained in further detail in Appendix 6: Market Prices, the new resource buildout in the IRP model framework is sensitive to City Light's market reliance assumptions. On region-wide resource-adequacy-constrained days, City Light limited short-term (day-ahead or spot) wholesale energy market purchases to a maximum of 200 MW, which is consistent with the market reliance assumption used in the 2024 IRP. This market reliance assumption may be reevaluated in the future. As described in Appendix 6: Market Prices, different magnitudes of assumed market reliance or different time periods where there are market reliance constraints can significantly change the size of resource portfolio buildouts. This can be seen in the total capacity requirement differences in the Large Diverse portfolio, which allowed only 200 MW of market reliance on constrained days, and the Small Diverse portfolio, which allowed 300 MW of market reliance on constrained days.

Aside from the constraints on short-term market reliance during constrained periods, City Light did not assume market constraints on the ability to purchase energy from the market on a longer-term forward basis to cover resource adequacy capacity needs. Not putting constraints on the model to purchase energy on a longer-term forward basis causes the model to assume it can purchase from the market as much "firm capacity" (see Appendix 9: Resource Adequacy) as needed when the candidate portfolio is not adequate to meet resource adequacy needs. This assumption is helpful for understanding total resource needs, but may not be practicable.

Cost for Right to Call Capacity

Energy purchased to meet resource adequacy needs does not necessarily cost the same as energy purchased in short-term wholesale energy markets. This is because energy to ensure reliable load service must often be purchased in forward markets, which may carry a price premium reflective of providing certainty of available energy and associated capacity in the forward period.

The IRP model framework estimated the forward capacity price premium by using the Bonneville Power Administration's (BPA's) monthly demand charges. The capacity cost in the IRP model for each month was set to the BPA monthly demand charge times the maximum kilowatts of capacity met by forward purchases. BPA's demand charges are $138/kW-year, which is implied capacity premium of $15.75/MWh.[35]

[35] $138/kW-year after summing BPA monthly demand charges and converting to 2026 dollars. Implied capacity premium is from multiplying $138/kW-year * 1,000 kW/MW * 1 year/8,760 hours.

City Light believes estimating the value of capacity costs based on BPA demand charges is reasonable within the IRP model framework for several reasons. First, BPA's demand charges are based on an estimated cost to build a new capacity resource, referred to as the Cost of New Entry (CONE). Valuing capacity based on BPA's CONE is consistent with the methodology to price capacity used in several neighboring utilities' recent IRPs, where CONE capacities also have annual capacity costs comparable to BPA's demand charges. Second, City Light validated its capacity cost assumption by observing the differences between market forward and spot market energy prices, and assuming that the difference in pricing is due to the valuation of certainty of capacity of the forward purchases. These observations resulted in similar implied capacity premiums of roughly $15/MWh.

While the IRP model framework employs a capacity price premium based on the cost to build a new physical capacity resource, inclusion of capacity price premiums within the IRP does not necessarily represent procurement of physical capacity resources or direct purchase of capacity products. Instead, the cost of a physical capacity resource is simply used to set the implicit price premium for the right to firmly call on certain megawatt-hours during resource-adequacy-constrained events.

Transmission

The IRP model framework utilizes a zonal transmission topology model to realistically constrain energy and marketing availability to City Light, as opposed to the 2024 IRP model, which did not model transmission topology. Prior to 2035, the model constrains transmission based on City Light's existing transmission rights. Starting in 2035, the model allows City Light to purchase new transmission based on prevailing regional transmission rates. See Appendix 7: Transmission for further details on the transmission modeling.

APPENDIX 9: RESOURCE ADEQUACY

Resource adequacy is a measure of the ability of a portfolio of generation and transmission assets to meet the electric demands on a power system during all hours of the year and under all but the most extreme conditions. It is typically a probabilistic assessment, meaning that the analysis is performed over a large set of circumstances, such as varying weather conditions. In addition, criteria are set to provide a certain level of confidence in the system's ability to meet demand. Various metrics can be used to indicate how well a system meets demand, highlighting different types of stress on the system. The criterion selected for the 2026 IRP to determine whether a potential portfolio is resource adequate was 0.1 Loss of Load Expectation (LOLE), or an expected maximum of one loss of load day in 10 years. City Light chose the resource adequacy standard of 0.1 LOLE for the 2026 IRP because it is an industry standard and is used in the Western Resource Adequacy Program (WRAP).

In the worst-case scenarios, such as the one day in ten years when City Light finds itself in a shortfall event, emergency measures and resources may be available as a last resort; thus, one allowed day with loss of load does not necessarily mean that the power will go out in Seattle. However, to further bolster reliability, City Light used multiple additional resource adequacy metrics for each candidate portfolio to more fully understand the characteristics of loss of load occurrences. While City Light does not set a numeric standard for the other resource adequacy metrics, analyzing a variety of metrics provides a better understanding of the relative performance of each portfolio and lays a foundation for potentially adding additional numeric standards in future IRPs.

In theory, it is possible to set a lower LOLE and acquire enough resources to meet load under all but the most extreme and unlikely scenarios that only occur, for example, only once every 100 years; however, this would overbuild at a cost to ratepayers. Instead, a balance must be found between reducing resource adequacy metrics and reducing cost.

It is important to note that this analysis focuses on the ability of the generation resources and transmission system within a candidate portfolio to deliver power to Seattle's service territory. It does not consider whether the distribution grid is able to bring that power to customers. In actuality, most outages customers experience are due to failures in the distribution grid (e.g., a tree falling on a power line). Integrated system planning, which provides a more unified evaluation across the distribution grid, transmission system, and bulk system power, is a new concept that City Light is currently investigating. However, this 2026 IRP Report analysis looks at only outages due to energy deficits.

Resource adequacy metrics were calculated for the Current portfolio and each of the six candidate portfolios for the model years 2030 and 2035. The portfolios are described in more detail in Appendix 10: Portfolio Outputs and Analysis. For each year studied, the resource adequacy model ran the Current portfolio and each candidate portfolio through 870 distinct hourly simulations: one for each combination of 29 weather and 30 hydro futures. This reflects the year-to-year uncertainty in hydro resources, load and generation from weather-dependent resources, such as wind and solar. This model is described in more detail in Appendix 8: Model Framework. To calculate the resource adequacy metrics used in this analysis, the resource adequacy model recorded every hour that a given portfolio was not able to fully serve electric demand, along with the magnitude of the shortfall for each simulation. If the portfolio was unable to meet the criterion of 0.1 LOLE, additional firm capacity was added to that portfolio to bring it up to that standard.

In previous IRPs, City Light used the Monthly Loss-of-Load Event (MoLOLEv) metric of 0.2 MoLOLEv (no more than two events every 10 years for each month of January, July, August, and December). City Light decided to move away from this metric in favor of the more conservative 0.1 LOLE. As the energy landscape evolves, resource adequacy and the metrics used to evaluate it are becoming more important. A more holistic approach is necessary, and City Light will continue to evaluate what metric or metrics will be most useful moving forward.

Firm Capacity Additions

The candidate portfolios as built in the capacity expansion model consist of wind, solar PV, and short-duration battery resources. Wind and solar are weather-dependent generation sources. Short-duration batteries are not weather dependent, but with only four hours of storage duration, rely on weather-dependent resources to recharge once depleted. Building a resource adequate candidate portfolio using only these resources would be infeasible, as it would require an exponential amount of additional new-build utility-scale wind, solar PV, and short-duration battery projects to address the risk introduced by weather dependence and reduce the number of loss-of-load days. Instead, the portfolios were built by requiring no unserved energy during 32 representative days (see Appendix 8: Model Framework for more information) using wind, solar PV, and short-duration batteries. Then the resource adequacy model was run to identify how much additional firm capacity is needed each year for the Current portfolio and each candidate portfolio to become resource adequate, as shown in Table 9.1. For 2040 and 2045, only the Current portfolio was run through the resource adequacy model. For the other portfolios, firm capacity need was estimated using the base need from the Current portfolio and subtracting the estimated wind and solar capacity contributions based on the wind and solar–only portfolios for 2030 and 2035.

Table 9.1. Cumulative Firm Capacity Needs (MW) for Each Portfolio by Year

Portfolio	2030	2035	2040	2045
Current	78	315	567	828
Small Diverse	0	180	387	466
Small Wind	0	168	382	467
Small Solar	11	251	475	672
Large Diverse	0	0	275	314
Large Wind	0	0	269	305
Large Solar	0	181	433	616

There is uncertainty around when new advanced technology resources such as long-duration batteries, green hydrogen peaker plants, and non-emitting baseload resources will become commercially available at scale, and at what cost (see Appendix 5: Resource Options and Appendix 11: Advanced Technology Break-even Analyses), but this analysis does show that resource adequate portfolios comprising only established technologies will not be economically feasible in the near future. Clean, firm technology resources will be necessary to keep City Light's power supply portfolio resource adequate.

For example, in 2035 the Large Diverse portfolio is resource adequate without the need for additional firm energy. However, the Small Diverse portfolio did not meet City Light's resource adequacy standard, with seven loss-of-load days in ten years. To meet the resource adequacy standard, the Small Diverse portfolio required an additional 180 MW of firm capacity additions. When comparing the Large Diverse and the Small Diverse portfolios, the Large Diverse portfolio had an additional 1,000 MW of nameplate capacity of intermittent resources and short-duration batteries. This addition of 180 MW of firm capacity additions for the Small Diverse portfolio was enough to make up for the 1,000 MW addition that the Large Diverse portfolio had.

In the real world, firm capacity as modeled in the IRP can be thought of as any firm capacity product, or firm energy product with capacity components. These include baseload resources such as small modular reactors (SMRs) and enhanced geothermal systems, forward wholesale energy market purchases, or short-term contracts with firm energy provisions.

Metrics

The first set of metrics calculated for the analysis below shows the expected values of shortfall magnitude and frequency over all 870 simulated years, for a given portfolio. These metrics take into account both good and bad hydro and weather futures. Table 9.2 provides definitions of the metrics. These definitions are lightly modified versions of definitions provided by the Electric Power Research Institute (EPRI).[36]

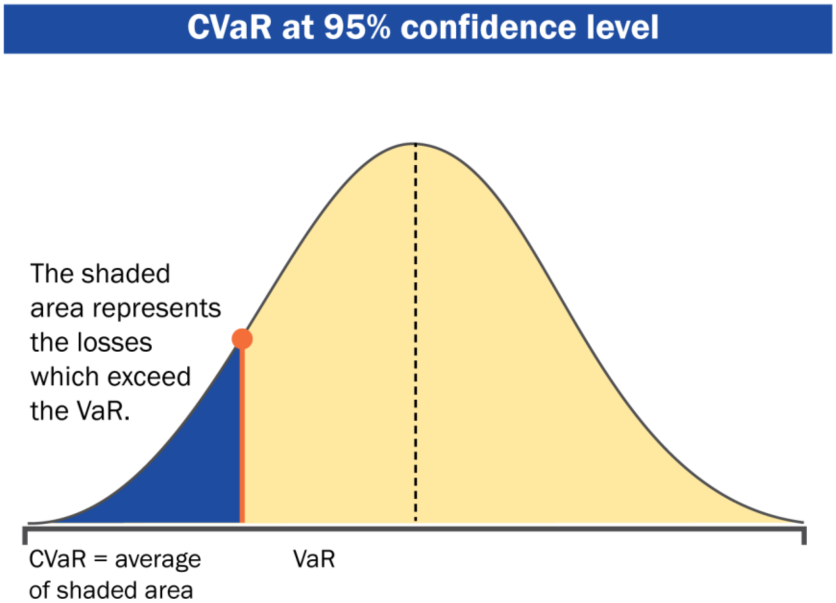
Table 9.2. Resource Adequacy Metrics and Definitions

Metric	Abbreviation	Units	Definition
Loss-of-Load Expectation	LOLE	days/year	Average event-days per year across all simulations
Loss-of-Load Hours	LOLH	hours/year	Average total event-hours per year across all simulations
Expected Unserved Energy	EUE	MWh/year	Average load not served per year due to shortfall events across all simulations
Loss-of-Load Events	LOLEv	Contiguous events/year	Average count of events per year across all simulations

These metrics as defined above refer to the expected value, but it is also important to look at the worst case for each metric to evaluate the risk of each metric for a given candidate portfolio. This can be done by calculating the Conditional Value at Risk (CVaR), for each metric (see Figure 9.1). Each metric listed above can be calculated for an individual year-long simulation rather than over all 870 year-long simulations taken together. The CVaR takes a certain percentage of the worst of the simulations based on these metrics and calculates the expected value (or average) of those simulations. This analysis calculated the CVaR95 (the worst 5% of simulations) and CVaR99 (the worst 1% of simulations) for each metric to show how the portfolio performs in the worst-case scenarios.

[36] EPRI. Metrics Explainers. msites.epri.com/resource-adequacy/metrics/metrics-explainers

Figure 9.1. Visualization of CVaR95



Results

The following results show the scenario comparison of each portfolio by annual metrics, monthly metrics, shortfall distribution, and individual events, with individual events defined by the period of time in which there is unserved energy. For example, consider a time window between 1 p.m. and 7 p.m. If an outage occurs between 1 p.m. and 4 p.m. with service restored between 4 p.m. and 6 p.m. followed by another outage from 6 p.m. to 7 p.m., then these outages would count as two separate events.

Annual Metrics

To obtain the metrics presented in this appendix, the resource adequacy model was run for two evaluations years: 2030 and 2035. Each table below represents analysis for one of the four metrics identified above (LOLE, LOLH, EUE, and LOLEv) as well as CVaR95 and CvaR99 for the two evaluation years. Table 9.3 through Table 9.6 show each portfolio without the additional firm capacity described in the Firm Capacity Additions section above. The shading represents the relative performance of each portfolio within a given study year. The darker shading indicates worse performance relative to the lighter shaded metrics.

*Table 9.3. Loss-of-Load Expectation (LOLE) in Days/Year - **Excludes** Capacity Additions*

Portfolio	2030			2035		
	LOLE	LOLE CVaR95	LOLE CVaR99	LOLE	LOLE CVaR95	LOLE CVaR99
Current	0.20	3.91	7.89	1.97	12.43	17.89
Small Diverse	0.09	1.86	6.00	0.68	7.45	10.78
Small Wind	0.09	1.68	5.78	0.56	6.73	10.00
Small Solar	0.12	2.36	6.67	1.12	8.95	11.22
Large Diverse	0.02	0.39	1.89	0.09	1.70	5.56
Large Wind	0.03	0.52	2.56	0.07	1.30	5.67
Large Solar	0.03	0.59	2.89	0.55	7.00	10.33

*Table 9.4. Loss-of-Load Hours (LOLH) in Hours/Year - **Excludes** Capacity Additions*

Portfolio	2030			2035		
	LOLH	LOLH CVaR95	LOLH CVaR99	LOLH	LOLH CVaR95	LOLH CVaR99
Current	3.40	67.25	131.89	31.87	198.41	257.22
Small Diverse	1.74	34.32	108.89	12.50	138.23	196.00
Small Wind	1.59	31.45	105.78	10.35	128.27	179.33
Small Solar	2.14	42.41	115.11	20.31	161.59	214.33
Large Diverse	0.40	7.91	38.67	1.69	33.34	110.67
Large Wind	0.53	10.55	51.56	1.26	24.98	110.78
Large Solar	0.51	10.02	49.00	9.83	124.20	188.33

*Table 9.5. Expected Unserved Energy (EUE) in MWh/Year - **Excludes** Capacity Additions*

Portfolio	2030			2035		
	EUE	EUE CVaR95	EUE CVaR99	EUE	EUE CVaR95	EUE CVaR99
Current	314	6,213	17,943	4,932	42,666	58,676
Small Diverse	92	1,825	7,961	1,137	16,825	28,519
Small Wind	84	1,662	7,122	920	14,488	25,973
Small Solar	139	2,740	11,085	2,517	29,208	44,109
Large Diverse	15	300	1,468	82	1,616	6,710
Large Wind	22	433	2,118	77	1,527	6,954
Large Solar	48	955	4,667	1,027	16,784	28,076

*Table 9.6. Loss-of-Load Events (LOLEv) in Contiguous Events/Year - **Excludes** Capacity Additions*

Portfolio	2030			2035		
	LOLEv	LOLEv CVaR95	LOLEv CVaR99	LOLEv	LOLEv CVaR95	LOLEv CVaR99
Current	0.20	4.05	9.78	2.33	19.66	29.33
Small Diverse	0.08	1.59	5.67	0.59	8.68	15.22
Small Wind	0.07	1.41	5.22	0.53	8.39	15.89
Small Solar	0.11	2.16	6.89	0.99	10.39	15.78
Large Diverse	0.01	0.27	1.33	0.06	1.18	4.33
Large Wind	0.02	0.45	2.22	0.05	0.91	4.22
Large Solar	0.04	0.80	3.89	0.41	6.20	11.11

Table 9.7 through Table 9.10 show metrics for each portfolio after the additional firm capacity has been included. The shading represents the relative performance of each portfolio within a given study year. The darker shading indicates worse performance relative to the lighter shaded metrics. Each table below represents analysis for one of the four metrics identified above (LOLE, LOLH, EUE, and LOLEv) as well as CVaR95 and CVaR99 for 2030 and 2035.

*Table 9.7. Loss-of-Load Expectation (LOLE) in Days/Year - **Includes** Capacity Additions*

Portfolio	2030			2035		
	LOLE	LOLE CVaR95	LOLE CVaR99	LOLE	LOLE CVaR95	LOLE CVaR99
Current	0.10	1.95	6.67	0.10	1.91	7.44
Small Diverse	0.09	1.86	6.00	0.10	1.98	7.33
Small Wind	0.09	1.68	5.78	0.09	1.86	7.33
Small Solar	0.10	1.95	6.67	0.10	1.95	7.44
Large Diverse	0.02	0.39	1.89	0.09	1.70	5.56
Large Wind	0.03	0.52	2.56	0.07	1.30	5.67
Large Solar	0.03	0.59	2.89	0.09	1.77	6.67

*Table 9.8. Loss-of-Load Hours (LOLH) in Hours/Year - **Includes** Capacity Additions*

Portfolio	2030			2035		
	LOLH	LOLH CVaR95	LOLH CVaR99	LOLH	LOLH CVaR95	LOLH CVaR99
Current	1.66	32.91	112.11	1.64	32.34	124.11
Small Diverse	1.74	34.32	108.89	1.68	33.25	119.00
Small Wind	1.59	31.45	105.78	1.50	29.59	113.22
Small Solar	1.71	33.80	113.67	1.72	33.98	123.44
Large Diverse	0.40	7.91	38.67	1.69	33.34	110.67
Large Wind	0.53	10.55	51.56	1.26	24.98	110.78
Large Solar	0.51	10.02	49.00	1.52	30.00	108.67

*Table 9.9. Expected Unserved Energy (EUE) in MWh/Year - **Includes** Capacity Additions*

Portfolio	2030			2035		
	EUE	EUE CVaR95	EUE CVaR99	EUE	EUE CVaR95	EUE CVaR99
Current	111	2,201	9,459	70	1,392	6,539
Small Diverse	92	1,825	7,961	58	1,152	5,332
Small Wind	84	1,662	7,122	59	1,161	5,297
Small Solar	117	2,321	9,991	58	1,154	5,511
Large Diverse	15	300	1,468	82	1,616	6,710
Large Wind	22	433	2,118	77	1,527	6,954
Large Solar	48	955	4,667	58	1,147	4,969

*Table 9.10. Loss-of-Load Events (LOLEv) in Contiguous Events/Year - **Includes** Capacity Additions*

Portfolio	2030			2035		
	LOLEv	LOLEv CVaR95	LOLEv CVaR99	LOLEv	LOLEv CVaR95	LOLEv CVaR99
Current	0.10	2.00	7.11	0.08	1.55	7.00
Small Diverse	0.08	1.59	5.67	0.10	2.02	9.00
Small Wind	0.07	1.41	5.22	0.09	1.70	7.67
Small Solar	0.09	1.84	6.56	0.08	1.64	6.78
Large Diverse	0.01	0.27	1.33	0.06	1.18	4.33
Large Wind	0.02	0.45	2.22	0.05	0.91	4.22
Large Solar	0.04	0.80	3.89	0.09	1.80	7.33

The worst performing portfolio across all metrics is the Current portfolio. This portfolio does not meet the resource adequacy standard of 0.1 LOLE, which means City Light is likely to experience more than one loss of load day in the next 10 years and will need to procure new resources to avoid this outcome and reliably meet future loads.

Of the six candidate portfolios, three are considered large, meaning they have more wind, solar PV, and short-duration battery resource additions than the portfolios considered to be small. The portfolios are described in more detail in Appendix 10: Portfolio Outputs and Analysis. The small portfolio group allowed for 300 MW of spot market imports during regional resource-adequacy-constrained hours, while the large portfolios allowed for 200 MW of spot market imports when building portfolios. In the rest of the analysis, only 200 MW were allowed.

The large portfolios show much better performance across resource adequacy metrics than the small portfolios; however, this better performance across these resource adequacy metrics suggests that the large portfolios could be overbuilt in study years 2030 and 2035. For example, Table 9.7 shows the LOLE results for each portfolio in 2030 and 2035. In 2030, the large portfolios have LOLEs of 0.02 and 0.03, which are significantly smaller than the resource adequacy standard of 0.1 LOLE. This difference in LOLE suggests that City Light has more resources than needed to ensure that it meets the necessary resource adequacy standard.

Within the small portfolios, the Small Wind portfolio has consistently better metrics. This is due to the higher capacity factor of wind, as compared to solar PV, and the timing of potential energy deficits City Light will face from increased load as a winter-peaking utility. In addition, City Light can currently purchase cheap solar power from California during the day, so adding solar to the portfolio may reduce arbitrage opportunities. In terms of resource adequacy metrics, the Small Diverse portfolio, with a mix of wind and solar PV resources, is only slightly worse than the Small Wind, and significantly better than the Small Solar portfolio.

Within the large portfolios, the Large Diverse portfolio with wind and solar PV projects has consistently better resource adequacy metrics through every study year in the IRP. This is likely because the increased generation from wind and solar PV projects improves the portfolio’s effectiveness in serving load. However, the marginal nameplate capacity of wind and solar PV resources produces diminishing returns in terms of reliability because of the weather-driven intermittency of these resources. High saturation of generation from one type of weather-driven renewable resource within a region also acts to suppress regional wholesale energy market prices. The combined impacts of low production in times of need and low market prices in times of high production are likely not fully captured here; City Light expects that the diverse portfolios will likely offer some unseen benefits over the wind portfolios as a result of their diversity.

The addition of firm capacity to bring each portfolio to the 0.1 LOLE standard decreases the expected (average) values of other resource adequacy metrics as well. The firm capacity can reduce the number of hours the portfolio is in deficit, meaning fewer total LOLH, and even if it does not completely remove the deficit, adding firm capacity reduces the amplitude of energy shortfalls, or EUE. Adding firm capacity also reduces the number of long energy shortfall events, but can have the effect of breaking up larger singular capacity shortfall events into multiple smaller ones. Overall, the expected LOLEv for the candidate portfolios decreases after capacity additions. In contrast, firm capacity additions have less of an effect on the metrics' CVaRs; while increased firm capacity ameliorates the worst-case LOLH and EUE, it leaves the most extreme scenarios relatively untouched in terms of frequency (LOLE and LOLEv).

Monthly Metrics

Calculating monthly metrics can demonstrate both seasonality and the changing characteristics of shortfalls month-to-month. The sum of the monthly metrics for one year equals the annual metric, which allows for comparison. For example, if the LOLE in January is 0.1 and in December is 0.1, the annual LOLE will be 0.2 assuming no other month has lost load.

Each figure below represents analysis for one of the four metrics identified above (LOLE, LOLH, EUE, and LOLEv) for one of the years evaluated (2030 and 2035). Figure 9.2 through Figure 9.9 show each portfolio without the additional firm capacity described in the Firm Capacity Additions section above. Months for which a metric was zero are not shown in the figure. For example, in Figure 9.2, none of the portfolios had a LOLE for the months of April through October in 2030.

*Figure 9.2. 2030 Loss-of-Load Expectation (LOLE) by Month – **Excludes** Capacity Additions*

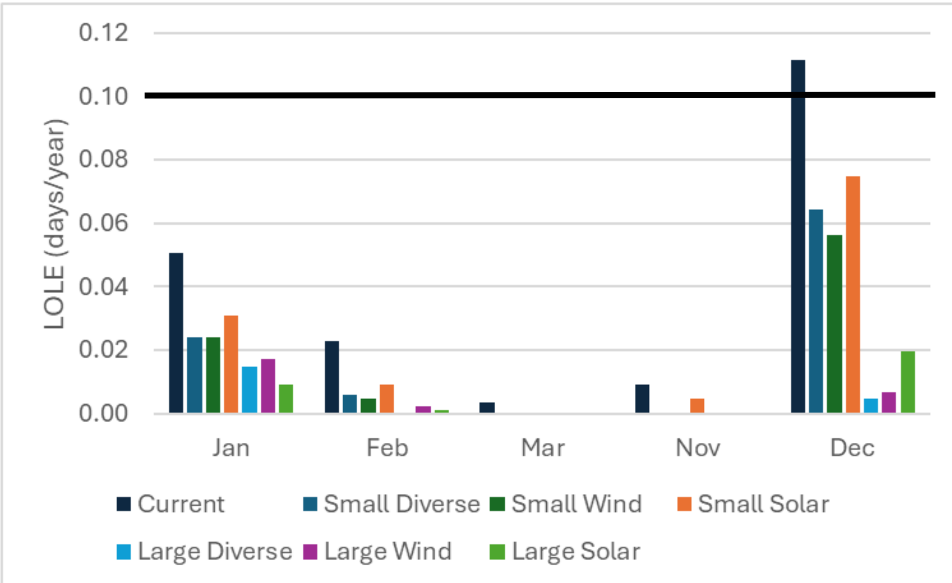


*Figure 9.3. 2035 Loss-of-Load Expectation (LOLE) by Month – **Excludes** Capacity Additions*

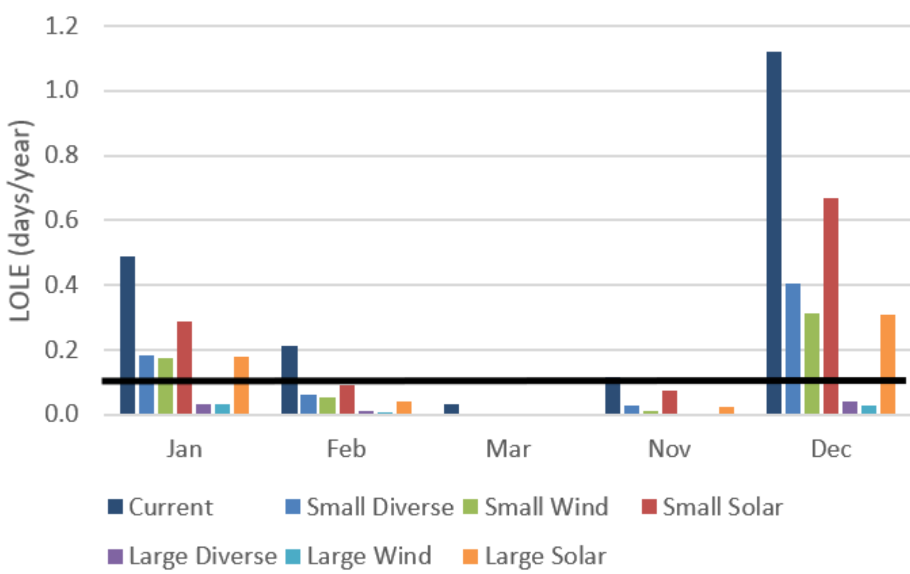


*Figure 9.4. 2030 Loss-of-Load Hours (LOLH) by Month – **Excludes** Capacity Additions*

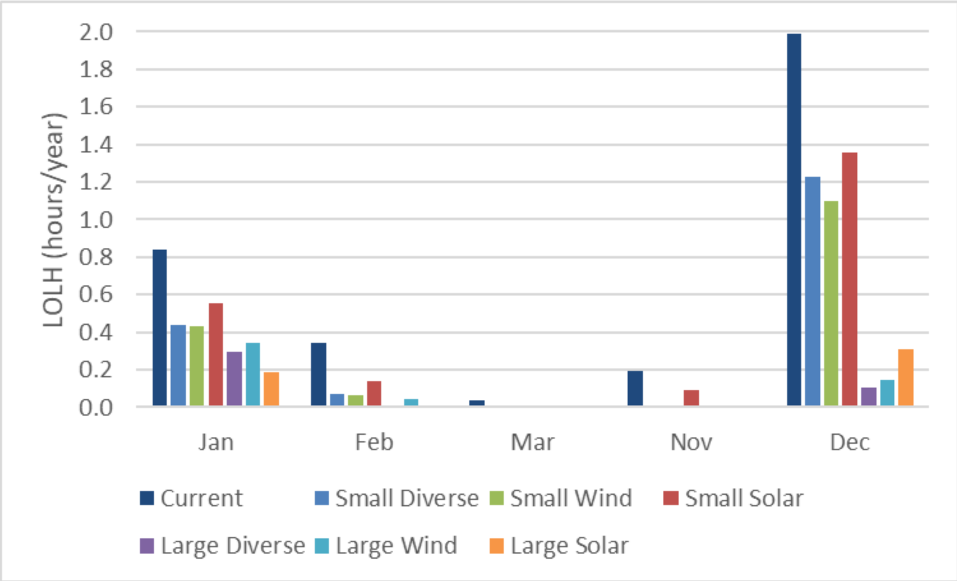


*Figure 9.5. 2035 Loss-of-Load Hours (LOLH) by Month – **Excludes** Capacity Additions*

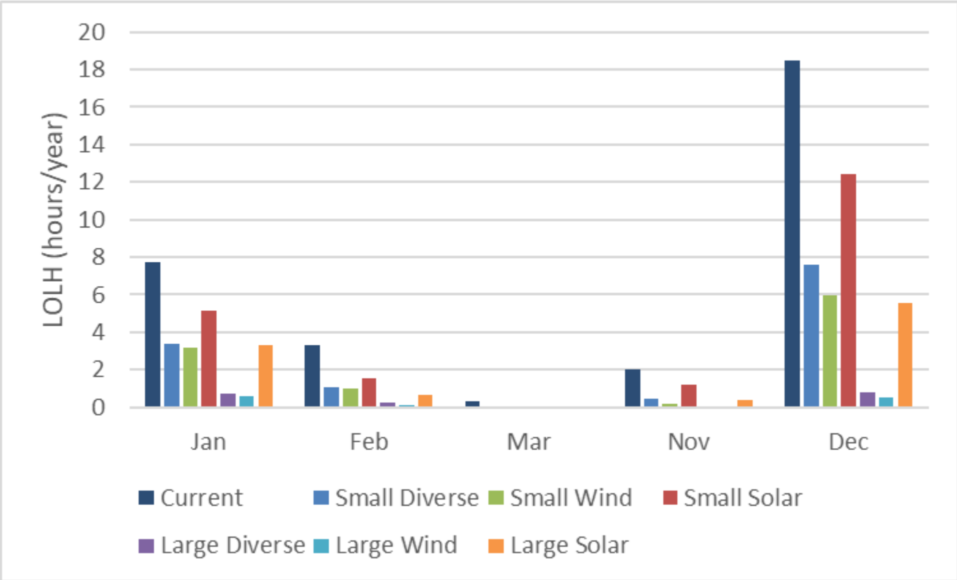


*Figure 9.6. 2030 Expected Unserved Energy (EUE) – **Excludes** Capacity Additions*

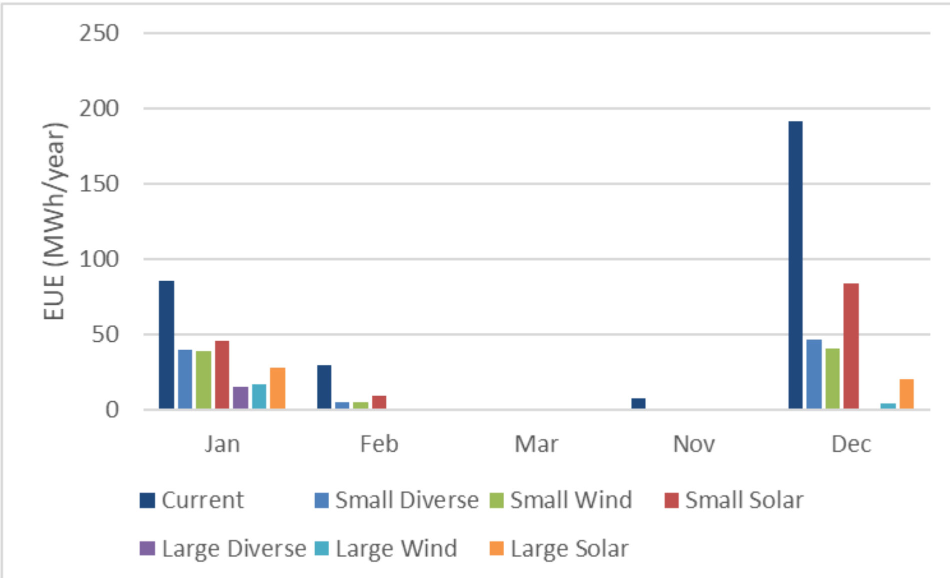


*Figure 9.7. 2035 Expected Unserved Energy (EUE) – **Excludes** Capacity Additions*

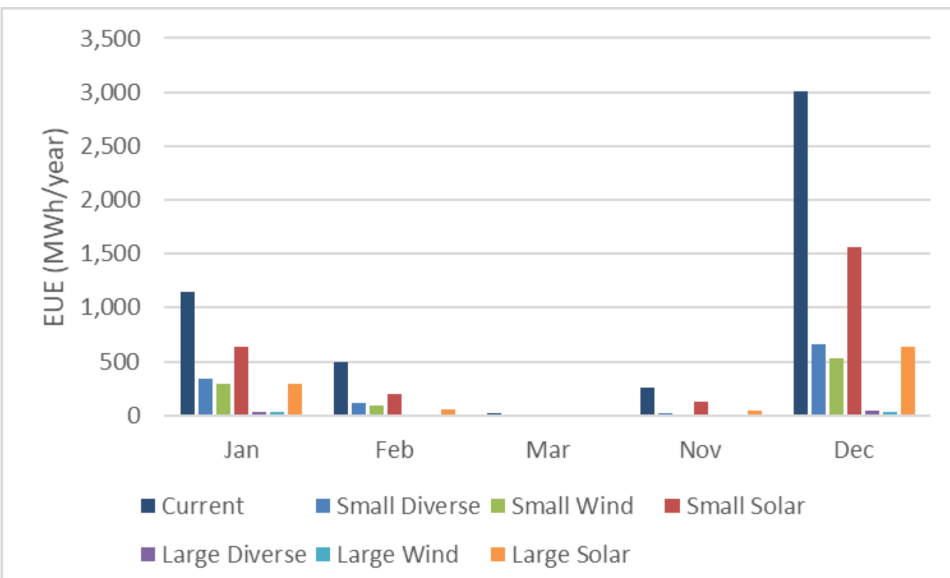


*Figure 9.8. 2030 Loss-of-Load Events (LOLEv) – **Excludes** Capacity Additions*

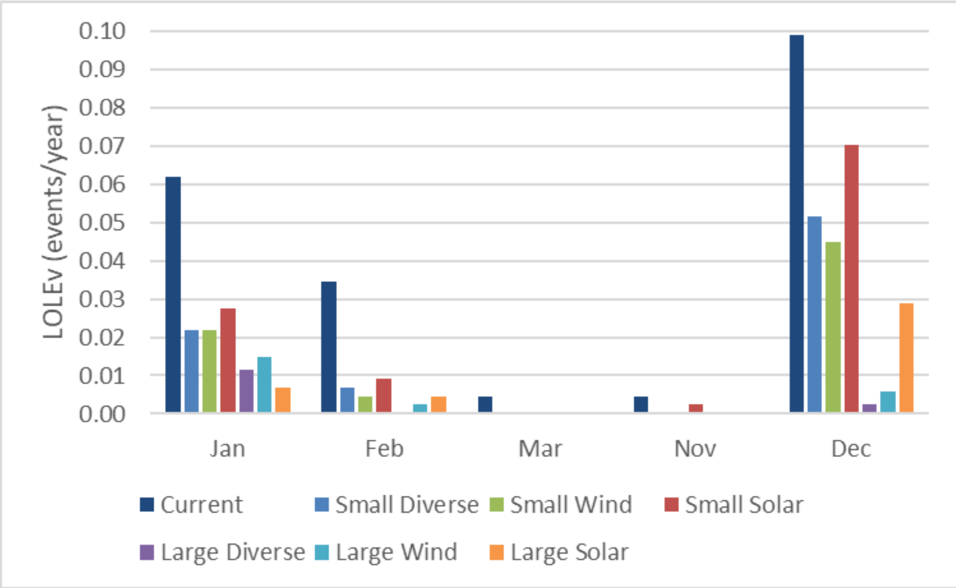
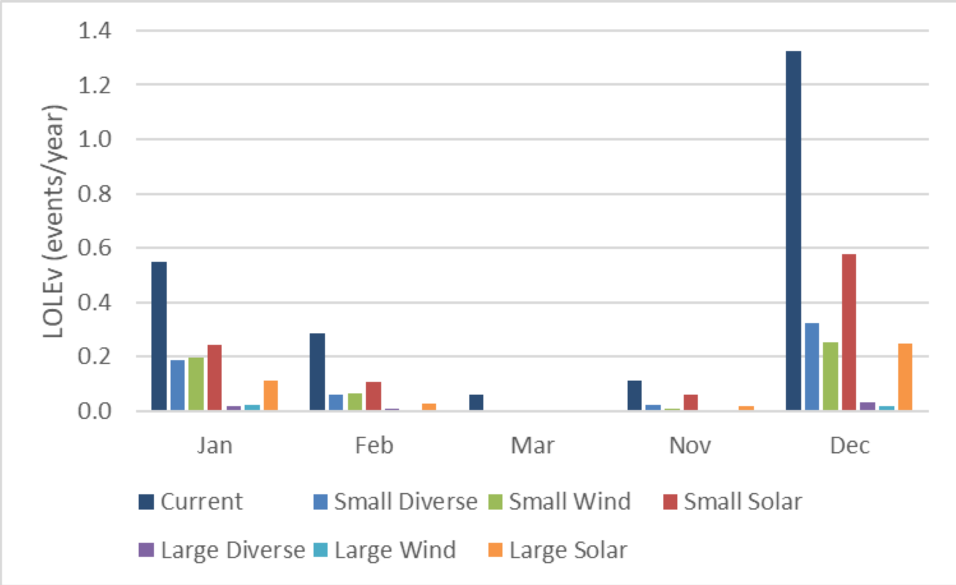


*Figure 9.9. 2035 Loss-of-Load Events (LOLEv) – **Excludes** Capacity Additions*



City Light can generally meet summer load due to its hydro generation projects in the Upper Skagit basin, and particularly its flexible operating range at Ross Lake. City Light is a winter-peaking utility, and its analysis shows that December has the greatest risk for a loss of load event (LOLEv), followed by January.

Within the small candidate portfolios, the Small Solar portfolio performs the worst across all resource adequacy metrics and months in the winter due to lower irradiance in the Pacific Northwest from both increased cloud cover and high latitude. The large candidate portfolios show less consistency across reliability metrics in the winter. In terms of LOLH and LOLEv, the Large Solar portfolio performs the best of the three large portfolios in January and the worst in December, but its EUE is worse in January than in December. This is likely due to more solar production in January during the day, but the lower capacity factor leads to an increase in total unserved energy. The Large Wind portfolio is consistently, but only slightly, worse in all metrics than the Large Diverse portfolio due to increased saturation of wind.

Figure 9.10 through Figure 9.17 represent analysis for one of the four metrics identified above (LOLE, LOLH, EUE, and LOLEv) for one of the years evaluated (2030 and 2035), with the inclusion of the additional firm capacity for each portfolio as listed in Table 9.1, including the Current portfolio. Months for which a metric was zero are not shown in the figure.

*Figure 9.10. 2030 Loss-of-Load Expectation (LOLE) by Month – **Includes** Capacity Additions*

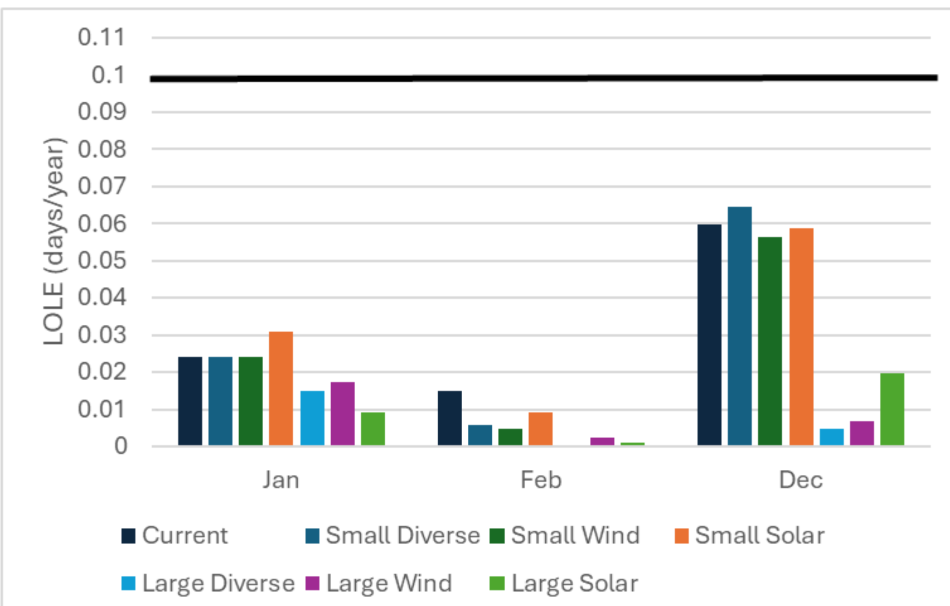


*Figure 9.11. 2035 Loss-of-Load Expectation (LOLE) by Month – **Includes** Capacity Additions*

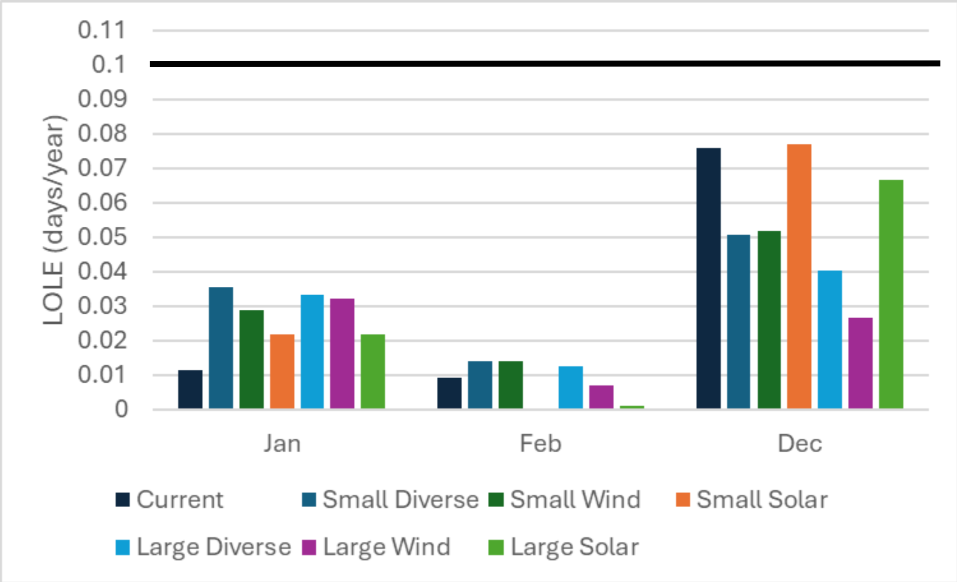


*Figure 9.12. 2030 Loss-of-Load Hours (LOLH) by Month – **Includes** Capacity Additions*

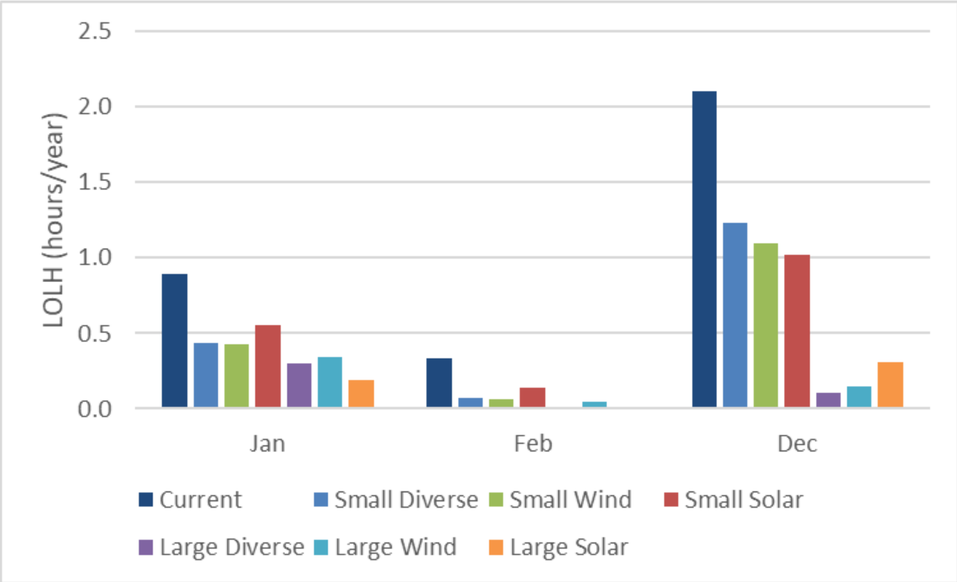


*Figure 9.13. 2035 Loss-of-Load Hours (LOLH) by Month – **Includes** Capacity Additions*

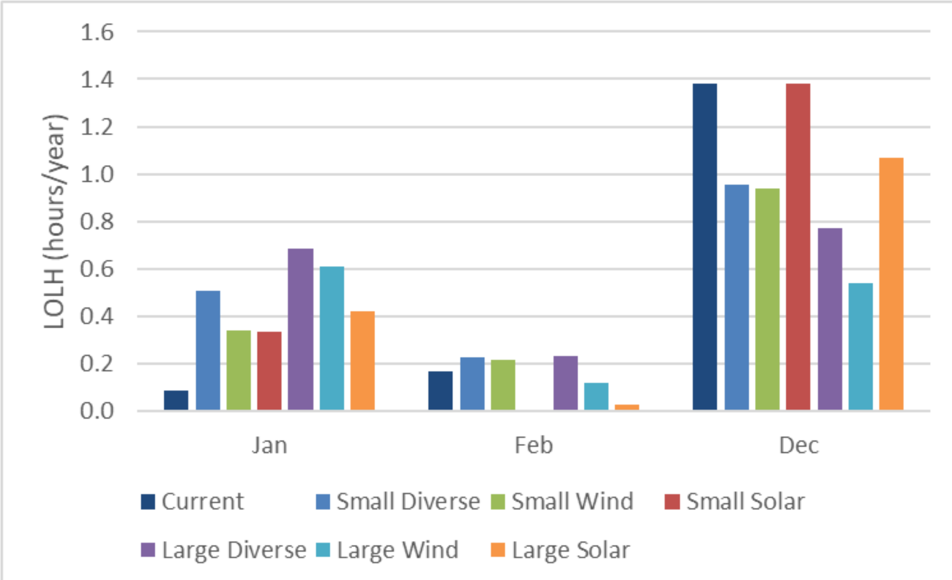


*Figure 9.14. 2030 Expected Unserved Energy (EUE) – **Includes** Capacity Additions*

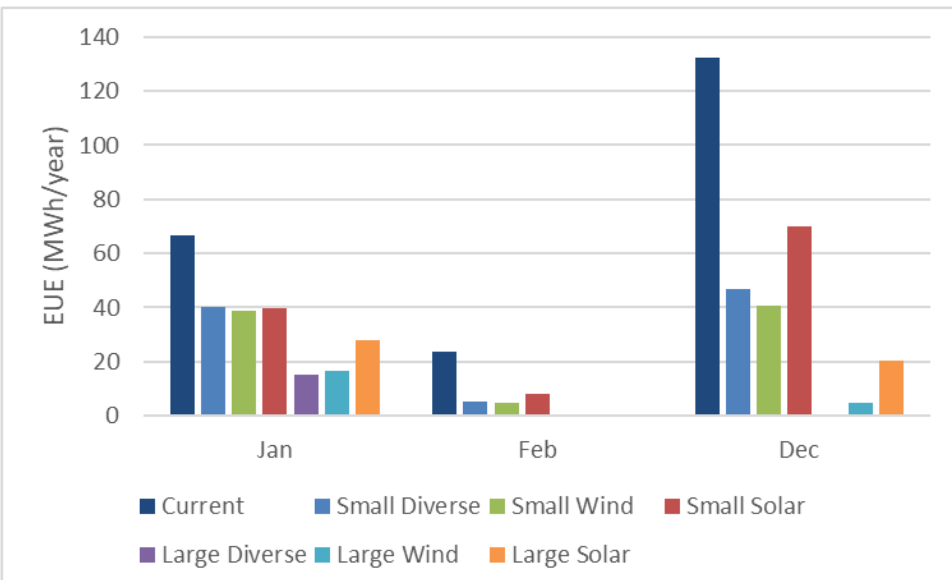


*Figure 9.15. 2035 Expected Unserved Energy (EUE) – **Includes** Capacity Additions*

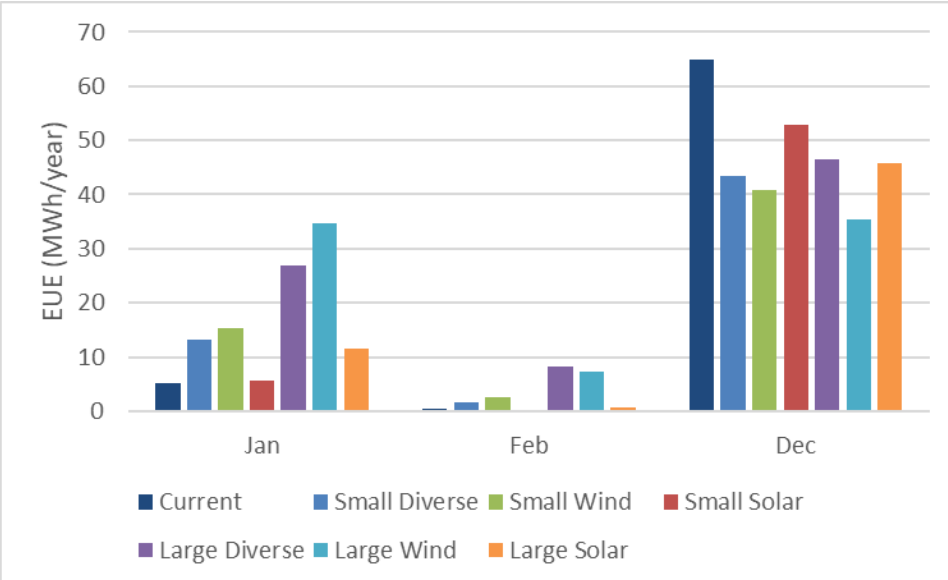


*Figure 9.16. 2030 Loss-of-Load Events (LOLEv) – **Includes** Capacity Additions*

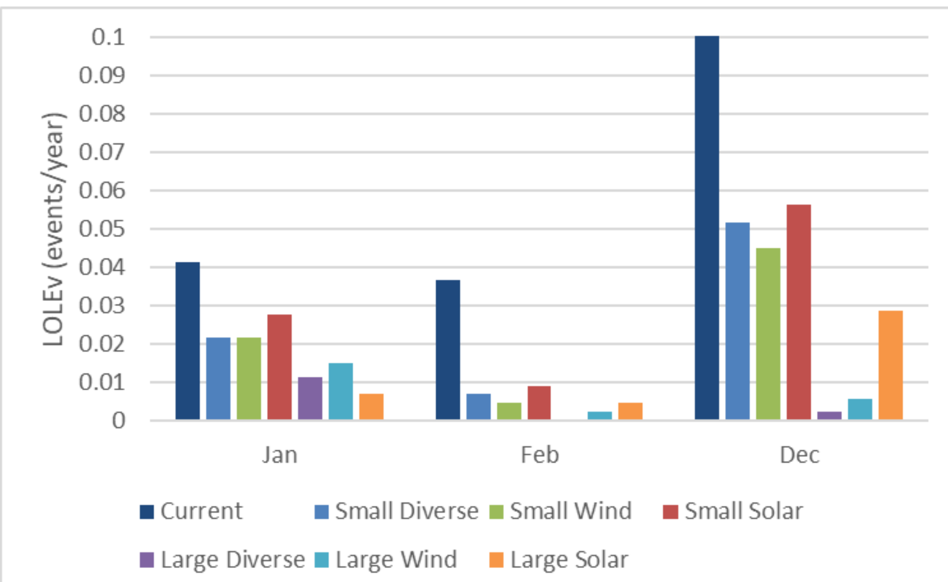
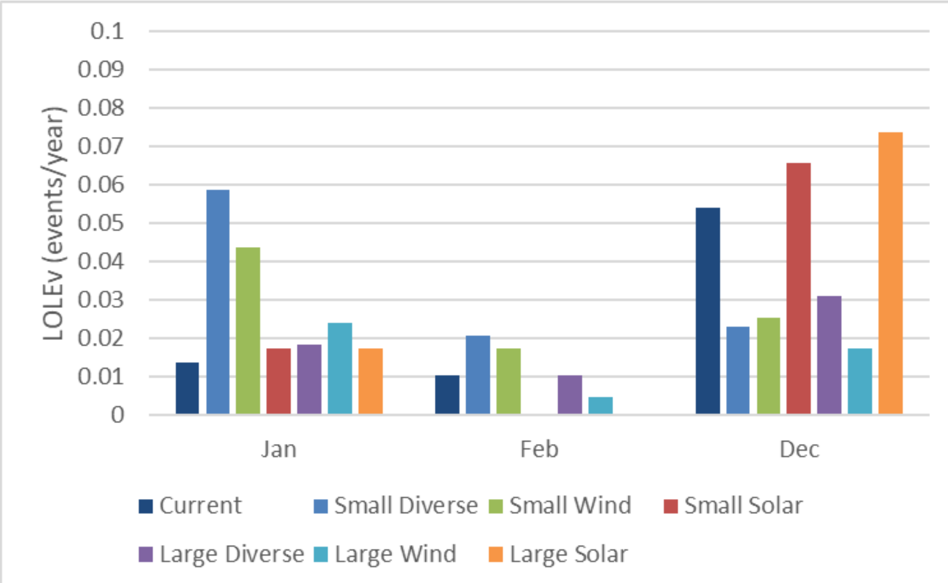


*Figure 9.17. 2035 Loss-of-Load Events (LOLEv) – **Includes** Capacity Additions*



Adding firm capacity eradicates all shortfalls in March and November of 2030 and 2035. The solar portfolios continue to show greater losses than their comparable diverse and wind portfolios, and December generally shows the largest losses across portfolios and metrics. January occasionally surpasses December with poor performing large portfolios in 2030 across all metrics however in 2035, December is by far the worst performing month across all metrics and portfolios except for a slightly higher January LOLE for the Large Wind portfolio and higher January LOLEv for the Small Diverse, Small Wind, and Large Wind portfolios.

Shortfall Distribution

Beyond looking at average and extreme conditions, it is also useful to explore the full distribution of events across the 870 simulations, in both duration and magnitude, from a resource adequacy perspective. Each simulation represents a combination of a weather and hydro year, with each year consisting of 8,760 hours. A single simulation run can have multiple noncontiguous periods with shortfalls, so it is possible to have frequencies exceeding 870. That is, if a simulation has a 10-hour shortfall followed by a 20-hour shortfall, the frequency for both the 7-to-12-hour and the 13-to-24-hour shortfall duration bins will increase in value by one, rather than the 25-to-48-hour shortfall duration bin increasing in value by one. Figure 9.18 through Figure 9.21 show event distributions with and without firm capacity additions. Note that the units on the y-axes of Figure 9.18 and Figure 9.19 are of different orders of magnitude and that the 2035 duration distribution shows a total frequency that is much higher than that of the 2030 distribution.

*Figure 9.18. 2030 Shortfall Duration Distribution – **Excludes** Capacity Additions*

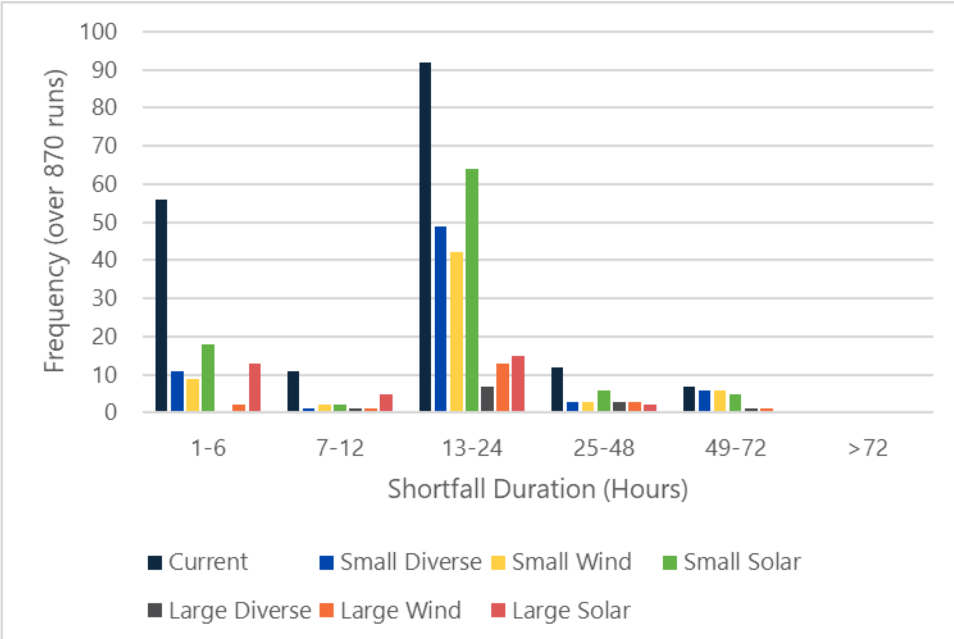


*Figure 9.19. 2035 Shortfall Duration Distribution – **Excludes** Capacity Additions*

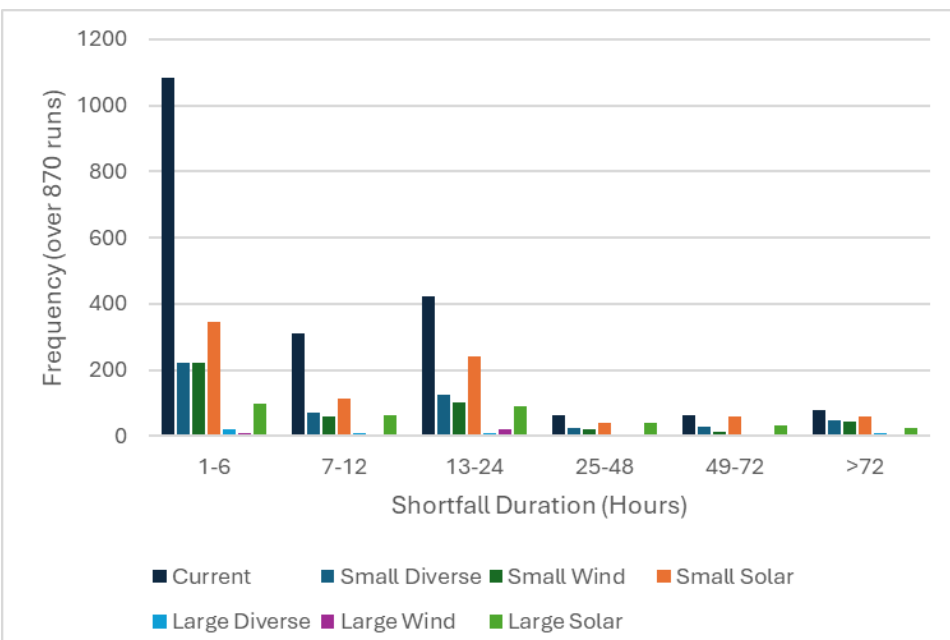


*Figure 9.20. 2030 Shortfall Duration Distribution – **Includes** Capacity Additions*

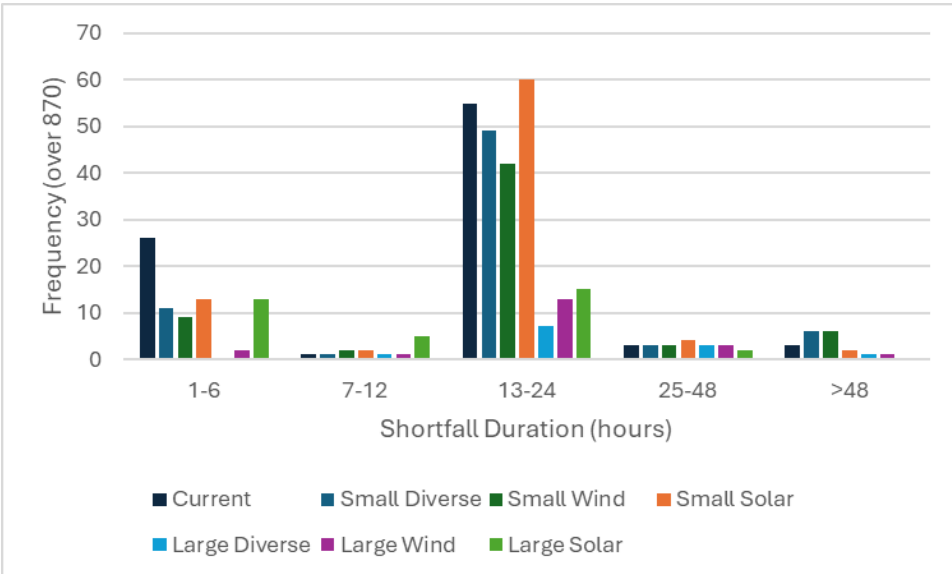
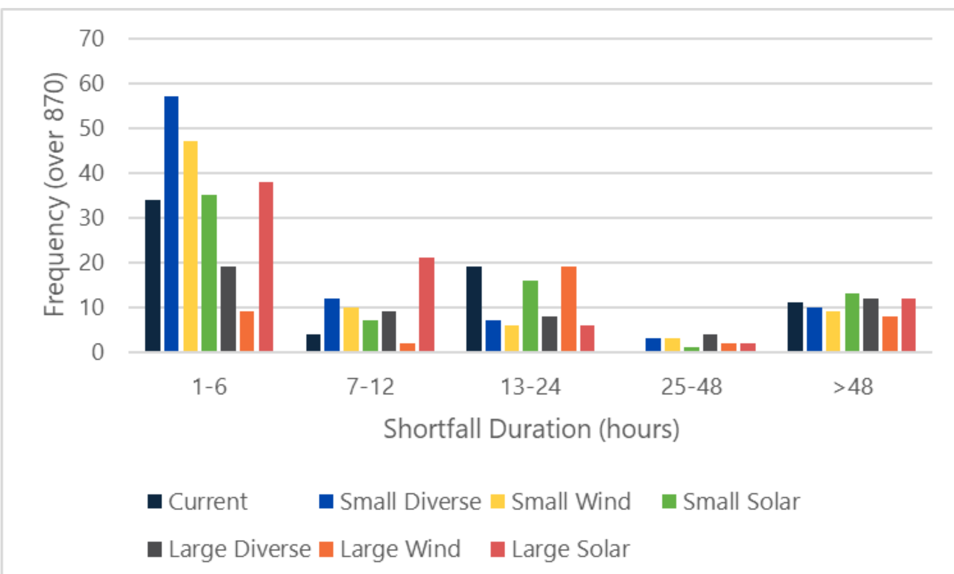


*Figure 9.21. 2035 Shortfall Duration Distribution – **Includes** Capacity Additions*



Without firm capacity additions, the frequency of short events greatly increases from 2030 to 2035, with the Current portfolio analysis for 2035 showing roughly 20 times the number of events lasting six hours or less (and half of these events lasting only one hour). In 2030, the majority of shortfalls last 12 to 24 hours across all portfolios without firm capacity additions, but by 2035, the majority of events are six hours or less except with the Large Wind portfolio, which has double the number of events from 12 to 24 hours. This pattern is seen in the distribution of shortfall duration within portfolios after firm capacity is added, although at a much smaller scale. This is likely due to the increased variability in both load and generation in 2035, which causes shorter and more frequent peaks in load and lows in weather-dependent generation. Wind, on the other hand, has a tendency to die out for longer periods of time than other resources, leading the Large Wind portfolio to have longer shortfalls.

Adding firm capacity mostly eliminates shortfalls lasting over 72 hours (three days) but may cause an increase in shorter duration events that occur very close to each other. Additionally, the number of events longer than two days in 2035 after capacity additions is fairly consistent across all portfolios, demonstrating that longer duration extreme events are hard to mitigate for all portfolio compositions given established commercially available resources.

Figure 9.22 and Figure 9.23 show the magnitude of events (in MWh) rather than the duration of the energy shortfalls, which highlights significant differences between the portfolios' reliability. The x-axis displays the magnitude ranges for the 870 scenarios' median-duration energy shortfall. Note that the units on the y-axes of the two figures are of different orders of magnitude. The 2035 shortfall frequencies easily exceed the 2030 shortfall frequencies in all magnitude bins, indicating growing generation resource needs over time.

*Figure 9.22. 2030 Shortfall Magnitude Distribution – **Excludes** Capacity Additions*

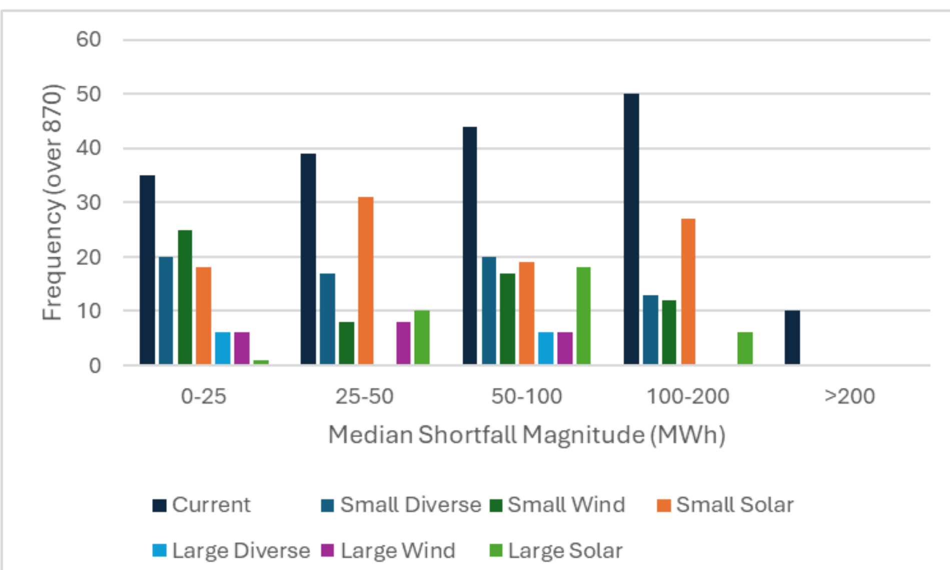
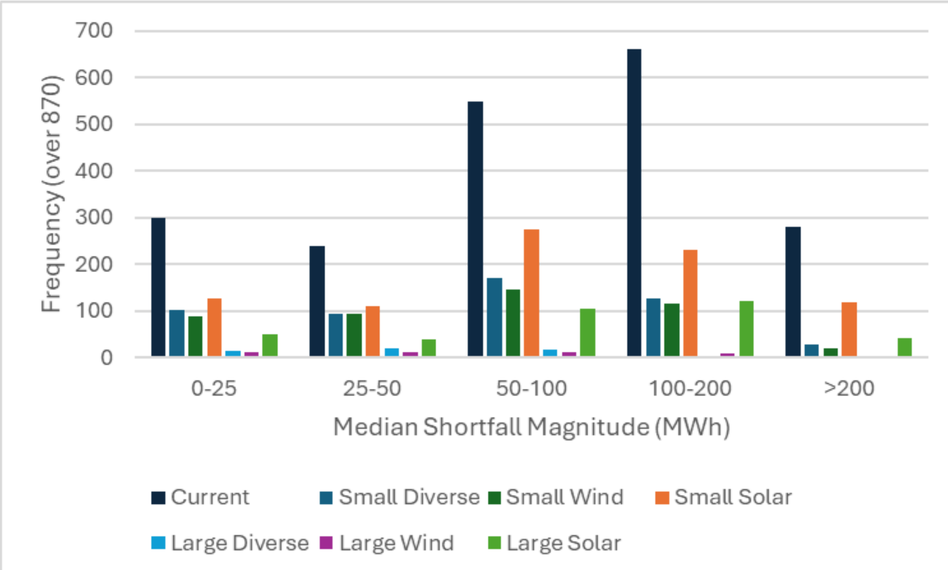


*Figure 9.23. 2035 Shortfall Magnitude Distribution – **Excludes** Capacity Additions*



In 2035, the frequency of higher magnitude events greatly outpaces that of smaller events across all portfolios. This is likely due to peak demand increasing faster than average load, resulting in greater shortfalls when they occur. This is especially true given the limited flexibility of established commercially available technologies. The trends of the annual metrics between portfolios show the solar portfolios having the highest event frequency, especially for events with a median magnitude between 50 MWh and 200 MWh; this is likely due to the lower capacity factor of solar.

Figure 9.24 and Figure 9.25 show the same analysis with the addition of firm capacity to the portfolios.

*Figure 9.24. 2030 Shortfall Magnitude Distribution – **Includes** Capacity Additions*

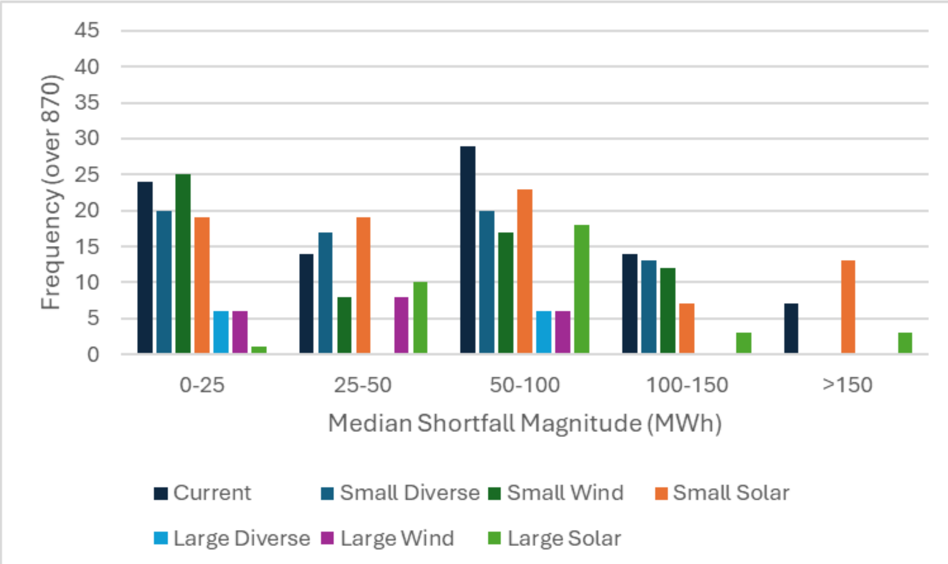
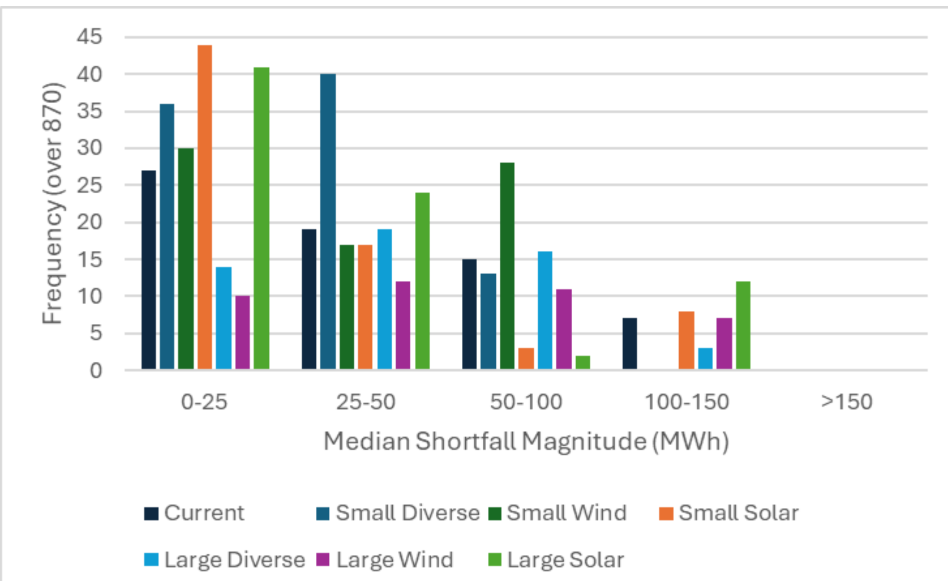


*Figure 9.25. 2035 Shortfall Magnitude Distribution – **Includes** Capacity Additions*

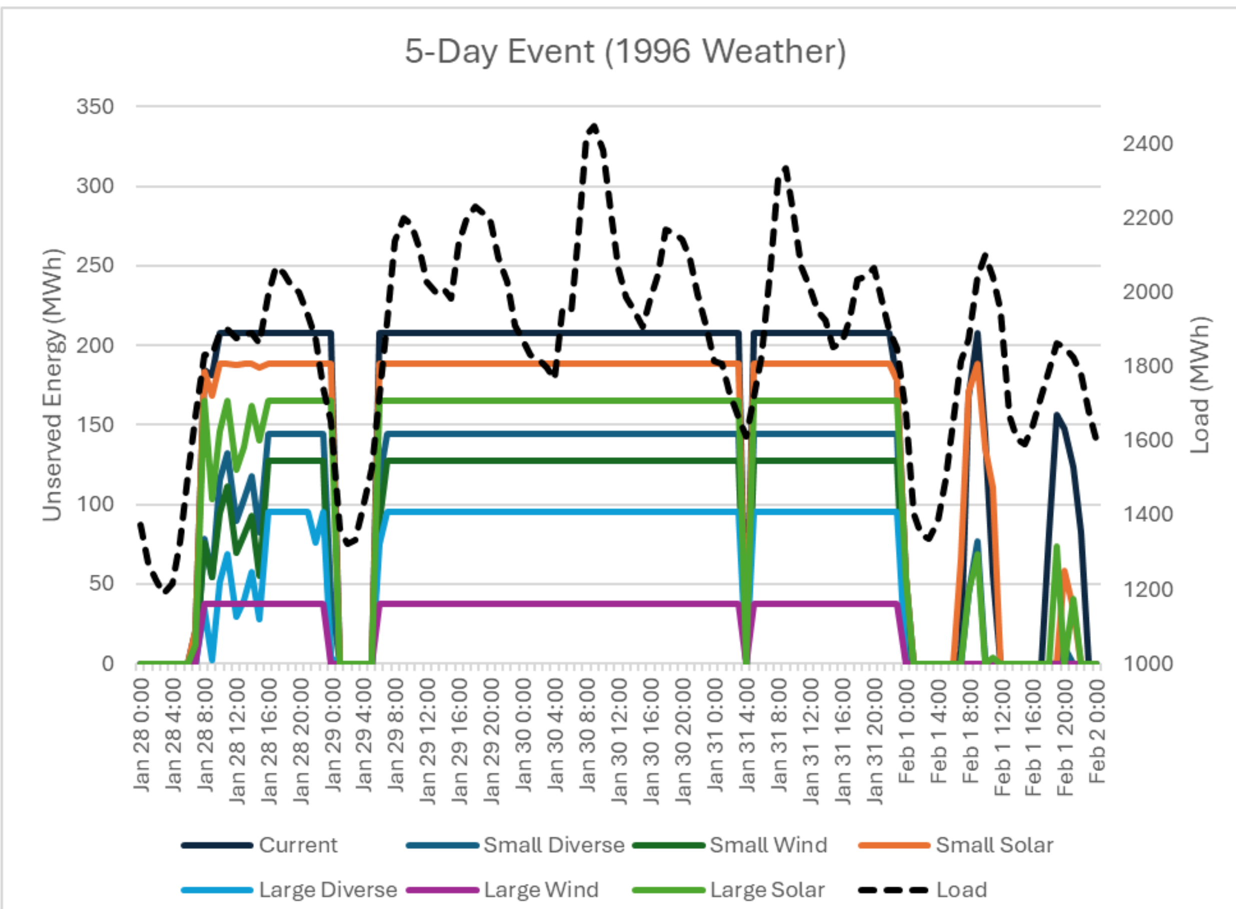


After capacity additions, the solar portfolios continue to have the most frequent and highest magnitude shortfalls of the seven portfolios. In 2035, the current, solar, and remaining large portfolios have a number of shortfall events between 100 MWh and 150 MWh. The large portfolios require less added capacity to bring the annual LOLE to 0.1, resulting in higher magnitude events if wind and solar generation is reduced from inclement weather.

Individual Event Analysis

While looking at summary metrics is useful for comparing portfolios, it can obfuscate important details about the types of events City Light may be facing in the future. When calculating resource adequacy metrics, an event is defined as a contiguous set of hours with some amount of energy shortfall. This means that a five-hour shortfall, followed by one hour without a shortfall, followed by another five-hour shortfall is considered to be two five-hour events. In reality, most would consider such an occurrence as one 11-hour event. Figure 9.26 shows a five-day period from a single simulation, specifically using 1996 weather and a single hydro year simulation. The y-axis on the left is unserved energy and on the right is load, both in megawatt-hours. The dotted line represents the load and corresponds to the right y-axis, and the solid lines represent the unserved energy of each portfolio in 2030 and correspond to the left y-axis. Most hours of the five days have some magnitude of energy deficit, but the model's calculations are based on five short events rather than one long event.

*Figure 9.26. Five-Day Event Comparing Load to Portfolio Shortfalls – **Excludes** Firm Capacity Additions*



For this specific event, the Current, Small Solar, and Large Solar portfolios without firm capacity additions have the highest shortfalls. The Small Diverse and Small Wind portfolios perform slightly better than the solar portfolios but still have shortfalls over 100 MWh. The Large Diverse portfolio is even better, managing to reduce the peak of the deficit to 95 MWh. The Large Wind portfolio performs best in this specific event at under 40 MWh, but if the wind dies down, the energy deficit will skyrocket. The flat peaks of unserved energy are due to the flexibility within City Light's Current portfolio since the model dispatches generation to reduce the maximum peak of unserved energy as much as the resources within it allow.

Sustained events like these are a large driver of many of the resource adequacy metrics. This one event occurs over five days and five contiguous sets of hours, affecting LOLE, LOLEv, and LOLH more than a single five-hour event would. The long duration also reduces City Light's ability to flex resources, resulting in increased EUE.

These types of events often occur in bad hydro years, when City Light's flexibility and capacity at Ross Dam is significantly reduced and the Pacific Northwest region, which is generally hydro-heavy, experiences concurrent energy deficits due to less available water. The long duration of the event provides limited ability for short-duration batteries to recharge, and the high peaks alongside sustained increased load prevent them from achieving more than flattening the magnitude of hourly shortfalls. Winter events like this also tend to coincide with decreased wind generation because cold weather events bring with them low temperature gradients, leading to stagnant air.

Specific types of supply- or demand-side resources will be necessary to remedy these types of events. Clean baseload resources, such as SMRs or enhanced geothermal systems, would almost guarantee (beyond unplanned outages) reducing the total energy shortfall. Long-duration batteries may have sufficient capacity to flex during the majority of a five-day event, reducing the total shortfall or the number of hours with shortfalls. Demand response programs that have a guaranteed capacity and ability to shift multiple days or even completely curtail energy usage may also be useful.

Resource Adequacy Conclusions

The results in this appendix demonstrate that of the portfolios analyzed, the Large Diverse portfolio most consistently meets the resource adequacy metrics analyzed. This appendix also highlights the need to study a wide range of resource adequacy metrics to develop a comprehensive view of the performance of each portfolio. For example, in 2030 both the Large Diverse and the Large Solar portfolios meet the 0.1 LOLE resource adequacy standard (both with and without firm capacity additions). However, the LOLE

CVaR values in that same year highlight the better performance of the Large Diverse portfolio over the Large Solar portfolio. City Light can employ mitigation measures to help ensure its ability to meet load, including selecting a portfolio that is not heavily reliant on a single resource (such as the wind or the solar + storage portfolios). Conducting extensive resource adequacy analysis to mitigate risk and fully understand how well a given portfolio performs provides guidance for picking a portfolio that performs well across a variety of metrics and would be robust enough to avoid the largest variety of loss of load events.

It is worth noting that in worst-case scenarios, when City Light encounters a shortfall event, contingency measures and emergency resources may be available. As such, using the 0.1 LOLE or one day with lost load resource adequacy metric does not guarantee a power outage in Seattle. It is only when a utility declares an energy emergency such as some utilities were forced to do during the MLK Day weekend cold snap in January 2024, that regional emergency resources become available to avoid the utility shedding load. This is also one of the anticipated benefits of joining WRAP. If despite all reasonable good faith efforts and planning City Light finds itself in an energy deficit with no energy available for purchase from the wholesale market, WRAP is designed to ensure that emergency energy reserves will be available from others in the region who are not experiencing the same strain on their systems.

Finally, the Federal Energy Regulatory Commission (FERC) license that governs City Light's hydroelectric operations on the Skagit River allows City Light to generate extra power using the water reserves in Ross Lake to serve firm load when no other options are available. Even though City Light can utilize these emergency measures to avoid load shed under worst-case conditions, these are not measures that should be relied upon on a planning basis. A LOLEv in the IRP represents a situation in which City Light would need to take emergency action due to an energy deficit position, which would likely help City Light avoid an actual load shed event, but would not guarantee this outcome.

APPENDIX 10: PORTFOLIO OUTPUTS AND ANALYSIS

As part of the 2026 IRP, City Light evaluated the costs and reliability of City Light's existing power supply portfolio over the 20-year study period, 2026–2045, with no new resource additions; this is referred to as the Current portfolio. City Light also evaluated six variants of the Current portfolio: three small portfolios and three large portfolios. To create these clusters, the team ran GridPath's capacity expansion model with two distinct sets of market access assumptions. The small portfolio group allowed for 300 MW of spot market imports during regional resource-adequacy-constrained hours, while the large portfolios allowed for 200 MW of spot market imports. The small and large portfolio groups each comprised three portfolio types: diverse, wind, and solar + storage (4-hour batteries). Diverse portfolios allow for both wind and solar + storage resources. To create the wind and solar + storage portfolios, these specific resource additions were scaled up from the diverse portfolios with annual renewable energy provided by the portfolios held constant.[37]

City Light evaluated the performance of each portfolio based on Seattle City Light's selected resource adequacy criterion and policy compliance.

The six candidate portfolios meet the following conditions:

- All six portfolios were built in the capacity expansion modeling phase to meet resource adequacy needs with the metric of 0.1 Loss of Load Expectation (LOLE), which is equivalent to one expected day every ten years.
- All portfolios meet I-937 policy requirements and Clean Energy Transformation Act requirements under hydro median conditions.

Table 10.1 describes City Light's current portfolio with no new resources and the six candidate profiles for the 2026 IRP. Table 10.2 through Table 10.7 present the composition and total nameplate capacities for each resource in 2030, 2035, 2040, and 2045 under each candidate portfolio. Each of these tables include firm capacity as a resource option. As described in Appendix 9: Resource Adequacy, after the candidate portfolios were built in the capacity expansion model, they were tested against the 0.1 loss of load event (LOLE) resource adequacy metric. If the portfolio was unable to meet the criterion of 0.1 LOLE, additional firm capacity was added to that portfolio to bring it up to that standard.

[37] Because different resources have different capacity factors, even though the energy generation is held constant within each cluster, the nameplate capacity of the portfolios within the clusters differs.

Table 10.1. 2026 IRP Portfolio Names

Portfolio	Description
Current	Existing portfolio
Small Diverse	Existing portfolio + wind + solar + storage
Small Wind	Existing portfolio + wind
Small Solar	Existing portfolio + solar + storage
Large Diverse	Existing portfolio + wind + solar + storage
Large Wind	Existing portfolio + wind
Large Solar	Existing portfolio + solar + storage

Table 10.2. 2026 IRP Small Diverse Portfolio Resource Additions In Study Years

Portfolio	2030	2035	2040	2045
Wind (MW)	282	457	668	1,743
Solar (MW)	119	119	119	119
Battery (MW)	10	10	189	345
Firm Capacity (MW)	0	180	387	466

Table 10.3. 2026 IRP Small Wind Portfolio Resource Additions In Study Years

Portfolio	2030	2035	2040	2045
Wind (MW)	376	574	799	1,840
Solar (MW)	0	0	0	0
Battery (MW)	0	0	0	0
Firm Capacity (MW)	0	168	382	467

Table 10.4. 2026 IRP Small Solar Portfolio Resource Additions In Study Years

Portfolio	2030	2035	2040	2045
Wind (MW)	0	0	0	0
Solar (MW)	477	712	989	2,338
Battery (MW)	87	130	311	1,404
Firm Capacity (MW)	11	251	475	672

Table 10.5. 2026 IRP Large Diverse Portfolio Resource Additions In Study Years

Portfolio	2030	2035	2040	2045
Wind (MW)	424	1,002	1,002	2,310
Solar (MW)	600	600	600	600
Battery (MW)	109	109	188	360
Firm Capacity (MW)	0	0	275	314

Table 10.6. 2026 IRP Large Wind Portfolio Resource Additions In Study Years

Portfolio	2030	2035	2040	2045
Wind (MW)	897	1,468	1,468	2,798
Solar (MW)	0	0	0	0
Battery (MW)	0	0	0	0
Firm Capacity (MW)	0	0	269	305

Table 10.7. 2026 IRP Large Solar Portfolio Resource Additions In Study Years

Portfolio	2030	2035	2040	2045
Wind (MW)	0	0	0	0
Solar (MW)	1,137	1,891	1,891	3,534
Battery (MW)	207	345	595	2,123
Firm Capacity (MW)	0	181	433	615

Metrics

The portfolios were evaluated according to five different metrics: Net Present Value (NPV), transmission capacity need, the social cost of greenhouse gas (SCGHG), the LOLE, and the Western Resource Adequacy Program (WRAP) requirements.

Net Present Value

The NPV, which is reported in millions of 2026 real dollars, contains the sum of all portfolio costs for resources (e.g., supply, transmission, firm capacity, energy conservation, demand response, customer solar, and renewable energy credit purchases), City Light's BPA power contract, and the SCGHG from 2026 to 2045

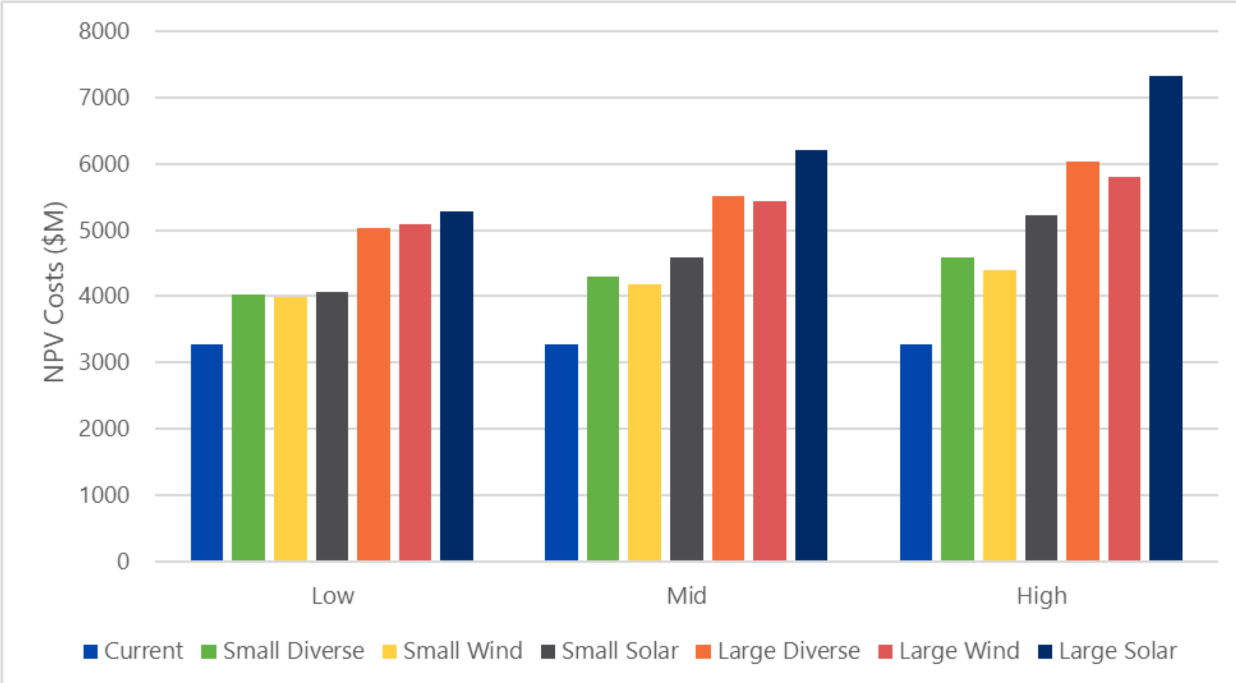
The inputs for the 2026 IPR NPV analysis were determined at the end of 2024. The energy industry is experiencing a particularly volatile operating environment and has experienced dramatic changes over the past year, which are not reflected in the analysis.

- The current Presidential administration repealed tax credits for many renewable energy resources, which will increase the cost to acquire these resources
- The current administration also repealed tax credits for electric vehicles
- The growing role of Artificial Intelligence has led to higher demand for data centers, which will increase load forecasts
- The picture of market availability in the northwest has radically shifted, with multiple studies identifying the possibility of resource shortages across the region during severe weather
- There has been further and accelerated development of clean, firm resources such as enhanced geothermal and small modular nuclear reactors.

City Light completes an IRP every two years and will complete additional in-depth analyses to capture these changes, as well as the increasing volatility across the industry, in the 2028 IRP Progress Report.

Figure 10.1 shows the NPV cost of each of the seven portfolios in three different future wholesale energy market-price scenarios: Low, Mid, and High (see Appendix 6: Market Prices for more detail about market prices). Of the seven portfolios, the NPV cost is lowest for the Current, Small Diverse, and Small Wind portfolios. The Current portfolio has the lowest cost of the seven portfolios; however, it is the only one that is not resource adequate.

Figure 10.1. 2026 IRP Seven Portfolio Annual Portfolio Costs



The remaining portfolios, particularly the Large Solar portfolio, are more expensive likely due to the increased addition of wind, solar, and battery resources. These resources are both expensive and lack dispatch flexibility to take advantage of wholesale market arbitrage opportunities. The higher capacity of wind, solar, and battery resources in the large portfolios is due to their limited market access in the capacity expansion model on regionally resource-adequacy-constrained days (200 MW) compared with the small portfolios (300 MW). It is impossible to know how much market availability will actually occur in the future during severe events when the market is likely to be constrained.

Transmission

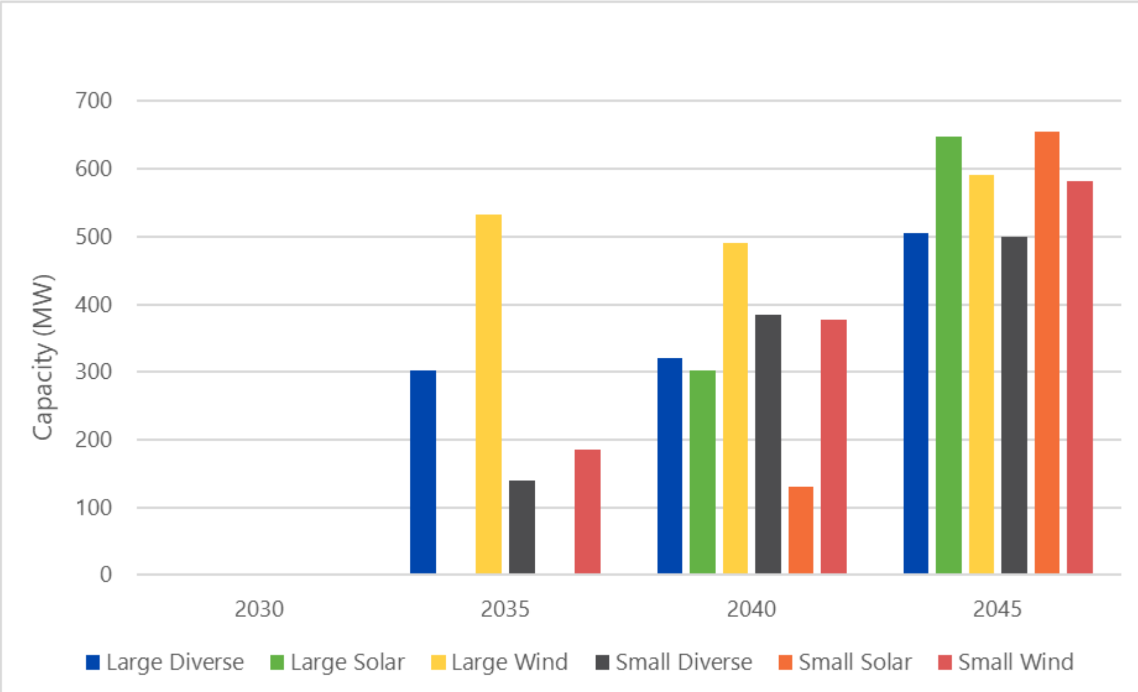
The transmission metric looks at the total estimated transmission capacity needed in each of the six IRP candidate portfolios. Due to uncertainty in available future transmission capacity, this metric can be viewed as a transmission risk level for each of the portfolios.

Figure 10.2 shows the transmission capacity needed for each portfolio in five-year intervals from 2030 to 2045. The model does not allow for additional transmission acquisition until 2035, but beginning in 2035 it can select five-year contracts as needed. Although the model does not allow for transmission acquisition until 2035, some portfolios could require transmission additions before the model allows. Both wind portfolios need the largest amount of cumulative transmission capacity from 2030 through 2045. While the solar + storage portfolios do not require additional transmission until 2040, their transmission capacity needs increase by 408% for the Small Solar portfolio and 113% for the Large Solar portfolio from 2040 to 2045.

Although the capacity expansion model selects similar magnitudes of wind and solar resources for the wind portfolios and the solar + storage portfolios, the model's results show that the wind resources require more transmission additions than the solar resources. The wind resources selected by the model are in the Gorge (Washington-Oregon border), Montana, and southern Idaho. Generation capacity produced by southern Idaho wind is assumed to be routed through Oregon before Seattle and Montana wind capacity is transmitted to Seattle through Mid-C. Since City Light has limited additional available transmission capacity along the Southern Idaho to Oregon and Montana to Mid-C transmission paths, the capacity expansion model requires transmission capacity additions to deliver this energy to Seattle.

In contrast, the new solar resources selected by the model are located exclusively in the NE_WA and CE_WA zones, both of which have direct paths to Seattle. As such, no additional transmission is needed to deliver these solar resources to Seattle's balancing area. The reason why additional transmission is required for the solar + storage portfolios is that the model selects batteries located in Idaho, and like the Idaho wind resources, storage capacity from these batteries is routed through Oregon before reaching Seattle. Of the diverse portfolios, the small one requires the least amount of added transmission capacity up to 2040, although both the Small Diverse and Large Diverse portfolios show increasing needs in later years.

Figure 10.2. IRP 2026 Six Portfolios' Annual Transmission Capacity

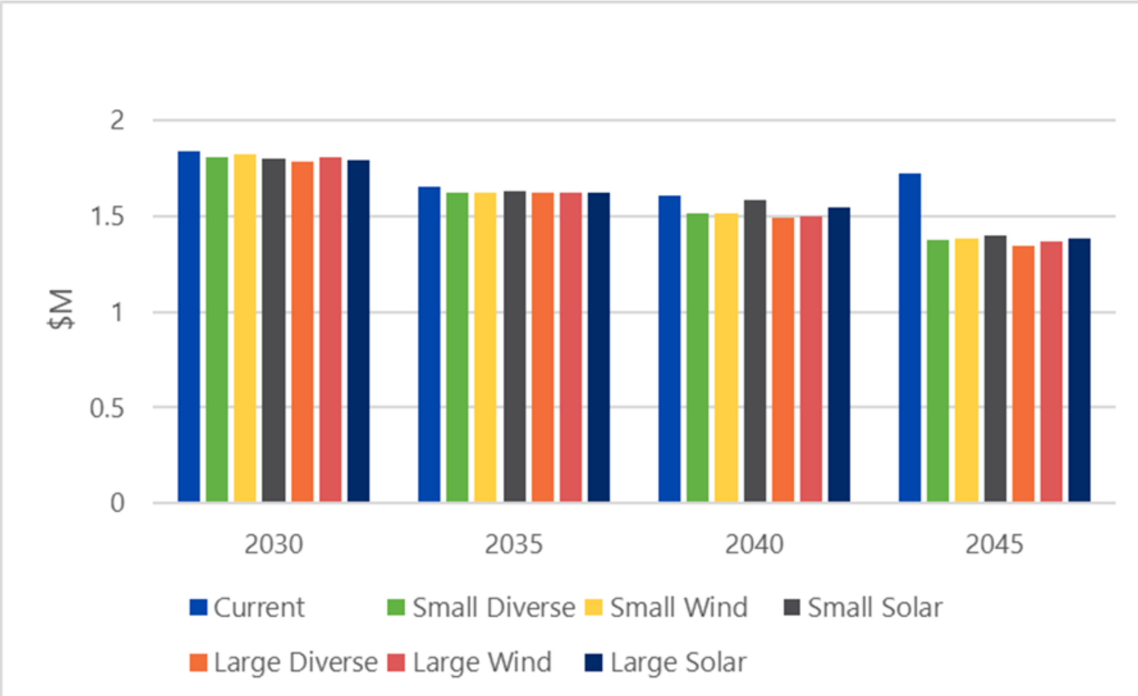


Social Cost of Greenhouse Gas

City Light is required to consider the SCGHG according to the Clean Energy Transformation Act (CETA). The SCGHG cost calculations for the seven portfolios incorporate the CETA-assigned emissions rate of 0.437 metric tons of carbon dioxide equivalent (CO_2e) per megawatt-hour of unspecified energy to express the SCGHG in 2026 dollars per metric ton of CO_2e. Unspecified energy enters the portfolio through a small portion of the BPA contract, some of City Light's long-term contracts, firm capacity additions, and spot market purchases as identified through the Production Cost Model runs. Refer to Appendix 4: Regulatory Requirements for more information.

Figure 10.3 shows the SCGHG for each of the seven portfolios in 2030, 2035, 2040, and 2045 under the Mid market-price scenario. For the six candidate portfolios, the SCGHG decreases over time in response to regional compliance mandates. This is because the capacity expansion and production cost models have constraints that are based on regional requirements, which affects how City Light interacts with the market. Because these portfolios have higher capacities, they have fewer spot market purchases. However, the Current portfolio's SCGHG remains relatively stable over the four study years and is significantly higher than that of the other candidate portfolios in 2045, because it requires more market purchases. For example, the Current portfolio is 28% higher than the Large Diverse portfolio in 2045.

Figure 10.3. IRP 2026 Seven Portfolios' Social Cost of Greenhouse Gas



WRAP

City Light is a participant in the Western Resource Adequacy Program (WRAP), which requires participating utilities to meet recent historic peak loads plus a planning reserve margin (PRM) percentage with the qualifying capacity contributions (QCCs) of owned and contracted-for resources. This subsection looks to see if the IRP portfolios allow City Light to comply with WRAP's requirements. WRAP estimates whether City Light has sufficient resources to contribute to its share of regional load during the region's 5% highest peak summer and winter hours (capacity critical hours). WRAP helps ensure that there is adequate regional capacity to meet regional need, but the amount and timing of resource adequacy needs of City Light may differ from those of the region. Because the IRP model builds its portfolio primarily to meet City Light's needs, the IRP model generally overbuilds resources with respect to the resources needed only to meet WRAP.

A challenge of estimating WRAP compliance is that peak loads and QCCs are dependent on data that does not yet exist; for example, the 2045 QCC of City Light's resources would be derived in part from the performance of those resources in 2040. Additionally, PRMs are currently set by WRAP for five years out. However, existing PRMs and QCCs combined with City Light's peak load forecast can provide a rough estimate of whether the IRP portfolios allow City Light to be compliant with WRAP.

PRMs for all years were assumed to be the same as the PRMs used for the WRAP Winter 2024–2025 and Summer 2025 seasons. QCCs of City Light's existing resources were also assumed to be equal to the QCCs in City Light's respective WRAP Winter 2024–2025 and Summer 2025 workbooks. For new resources, WRAP provides QCC values, which allow the nameplate capacity of new resources to be converted to equivalent QCCs.[38] Since these QCC values vary both by resource and WRAP subregion, each new resource selected in the IRP portfolios was binned into a WRAP subregion, and then the resource's nameplate capacity was multiplied by the QCC value for the respective resource type and subregion. The IRP resources for which WRAP does not provide a QCC value are the firm capacity additions. Firm capacity additions were assumed to provide perfect capacity (e.g., 100 MW of capacity additions would have a QCC value of 100 MW). In addition, all resource changes to the Current portfolio after Summer 2025, other than changes to City Light's BPA power contract and resources selected in the 2026 IRP, are ignored.[39]

Figure 10.4 through Figure 10.7 show the capacity position for the months when City Light has the worst capacity position, (i.e., the greatest capacity deficit or smallest surplus) for the given summer or winter season, year, and portfolio. For example, if a portfolio has a surplus capacity in the summer of 2030 of 100 MW, 300 MW, 400 MW, and 200 MW for June, July, August, and September, respectively, then the figure would show 100 MW (the smallest surplus) for summer 2030. If instead the values for the same four months were -200 MW, 100 MW, 400 MW, and -300 MW, the figure would show -300 MW (the greatest capacity deficit). Values that are positive indicate that City Light has a surplus across all months in the given season, whereas values that are negative indicate that City Light has a deficit in at least one month in the season.

[38] Specifically, the latest available QCC percentage was used, which was for the Winter 26-27 and Summer 2027 seasons.
[39] Resource changes after Summer 2025 include but are not limited to the new NewSun solar project and removal of the Columbia Ridge and Columbia Basin Hydro contracts.

Figure 10.4. IRP 2026 Seven Portfolios Summer Greatest Monthly Deficit/Smallest Surplus Without Firm Capacity Additions

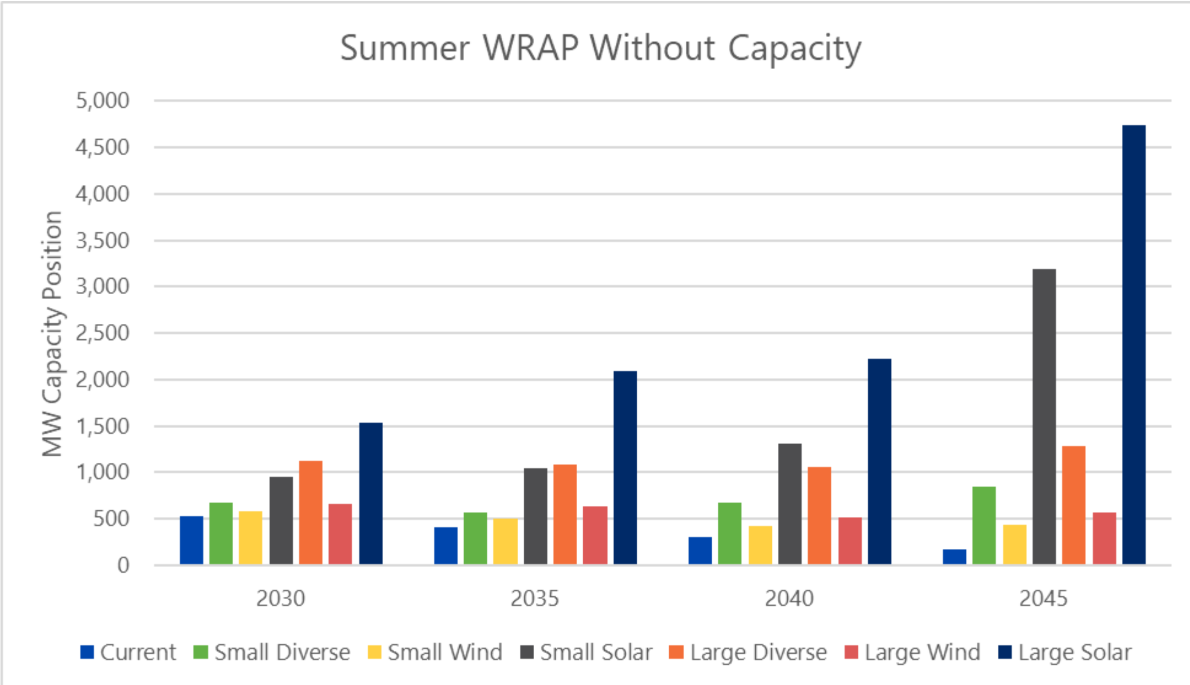


Figure 10.5. IRP 2026 Seven Portfolios Winter Greatest Monthly Deficit/Smallest Surplus Without Firm Capacity Additions

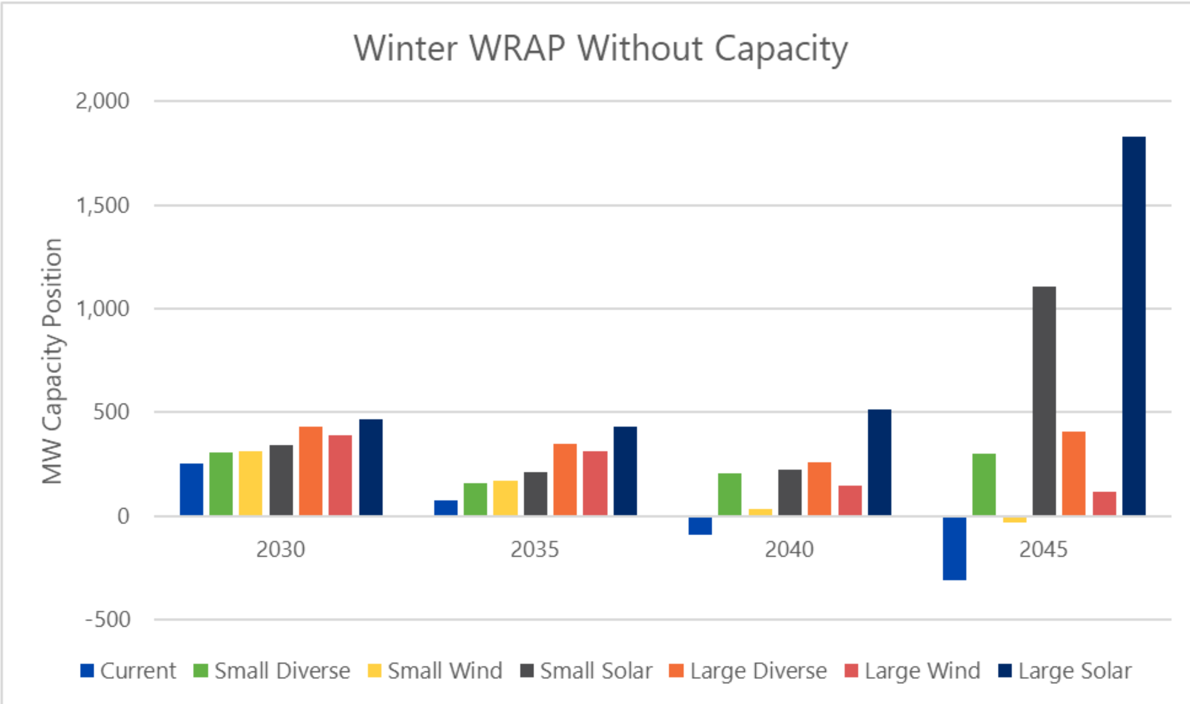


Figure 10.6. IRP 2026 Seven Portfolios Summer Greatest Monthly Deficit/Smallest Surplus with Firm Capacity Additions

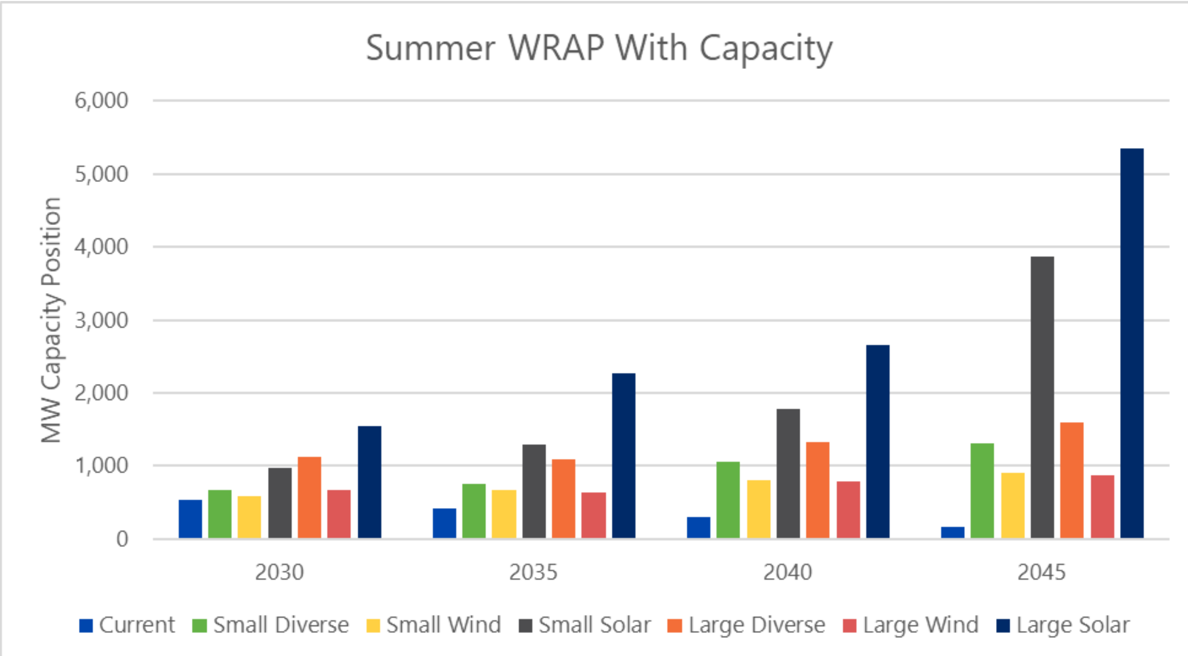


Figure 10.7. IRP 2026 Seven Portfolios Winter Greatest Monthly Deficit/Smallest Surplus with Firm Capacity Additions

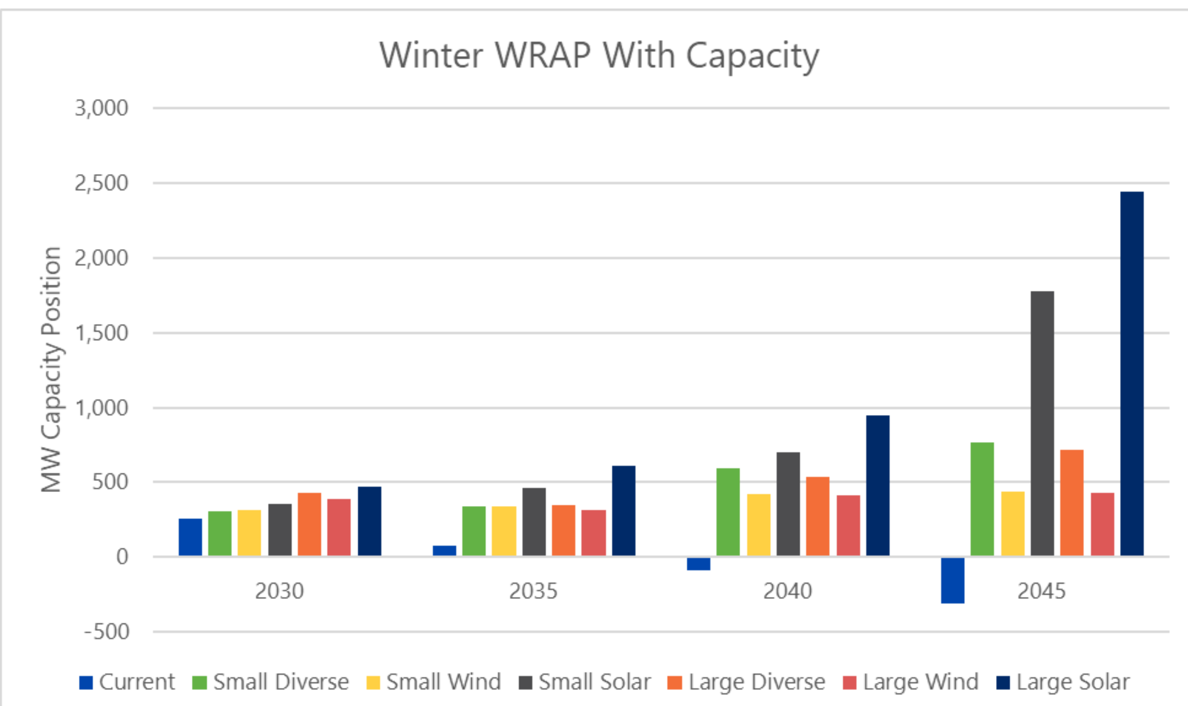


Figure 10.4 and Figure 10.5 show the smallest monthly surplus and the greatest monthly deficit for the seven portfolios without additional capacity in summer and winter, respectively. In the winter months the Current portfolio surplus decreases until 2040, at which point it enters a deficit. Small Wind enters a deficit in 2045. The surplus in both Large Solar and Small Solar increases over the years, while the surplus of the Large Wind portfolio steadily decreases. In the summer months none of the portfolios is ever in deficit. The Current portfolio steadily decreases but does not reach a deficit.

Figure 10.6 and Figure 10.7 show the greatest monthly capacity deficit and the smallest monthly capacity surplus for the seven candidate portfolios with additional generation in winter and summer, respectively. In winter, monthly surplus capacity increases over the years. By 2045, both the Large Solar and the Small Solar portfolios show more of a surplus than the remaining five portfolios due to the current high QCC accreditation of energy storage in WRAP. In contrast, the Current portfolio surplus decreases from 2030 to 2035 and in 2040 and 2045 is in deficit.

In the summer months, none of the portfolios is in deficit (although the surplus for all increases over time with the addition of new resources) and Figure 10.6 shows that under current QCC accreditation values solar and storage portfolios have a surplus that increases over the years. However, QCC accreditation of energy storage may decrease significantly in the future,[40] which means that the surplus provided by the solar and storage portfolios may actually be significantly closer to that of the other portfolios.

Overall, the seven portfolios are expected to be WRAP sufficient or nearly WRAP sufficient even prior to capacity additions for all years and for both winter and summer seasons. While uncertainty exists about actual WRAP PRM requirements and future QCC accreditation, after capacity additions all portfolios have a buffer of several hundred megawatts of capacity to account for the uncertainty. Under a sensitivity (not shown above) where PRMs are 50% greater than they currently are (i.e., WRAP requirements increase) and all new resource QCCs are derated by 33%, all portfolios were still or nearly WRAP sufficient, with no portfolio having a deficit greater than 11 MW. Therefore, meeting WRAP compliance is not a major factor in portfolio selection.

[40] For example, in the WRAP Forward Showing September 2, 2025, advanced assessment shows that in the separate SWEDE (Southwest/East Diversity Exchange) region of WRAP, energy storage QCCs decrease from approximately 100% in 2025 to 86% in 2027 due to oversaturation of short duration energy storage over that time period.

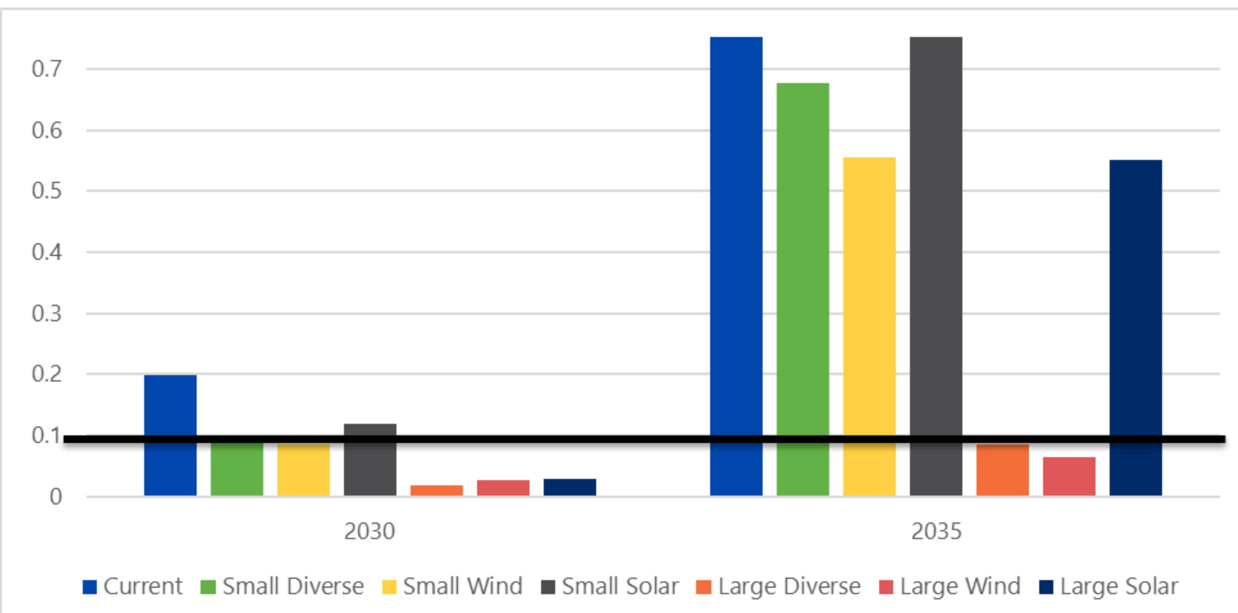
Resource Adequacy

Figure 10.8 shows the LOLE in 2030 and 2035 for each portfolio without adding firm capacity. The figure shows that only the large portfolios are resource adequate without additional capacity. In particular, the Current and small portfolios significantly exceed the maximum LOLE value allowed to meet City Light's resource adequacy standard in 2035.

Figure 10.9 shows the LOLE for each of the seven portfolios with firm capacity additions. Note that the quantity of added firm capacity for each portfolio was specifically calculated to equal the minimum required to make the portfolio resource adequate, and no firm capacity was added to portfolios that were already resource adequate.

In 2030, all the large portfolios are well below the standard of one day in ten years with lost load, indicating that in 2030 these portfolios are overbuilt. However, in 2035, these large portfolios are much closer to City Light's resource adequacy standard and are therefore more appropriate for the City Light system.

Figure 10.8. IRP 2026 Seven Portfolios Loss-of-Load Expectation without Additional Firm Capacity



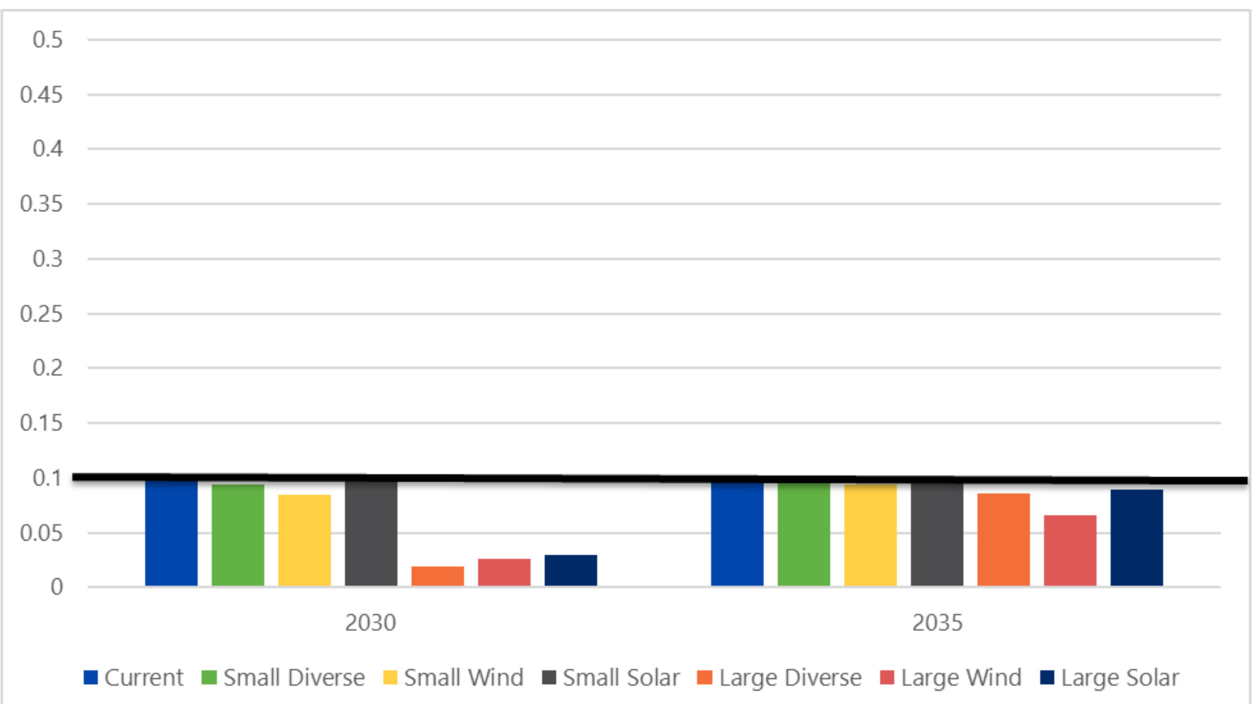
As Figure 10.8 shows, the additional wind, solar, and battery resources in each of the candidate portfolios (with the exception of Large Diverse and Large Wind) are not enough to ensure resource adequacy at a level of at most one loss-of-load day in ten years. To meet this standard, City Light added the minimum required firm capacity to each candidate portfolio, as shown in Table 10.8. These capacity additions could come from baseload resources, forward purchases, or contracts with firm energy provisions.

Table 10.8. 2026 IRP Seven Portfolio Firm Capacity Additions

Portfolio	2030	2035	2040	2045
Current	78	315	567	827
Small Diverse	0	180	387	466
Small Wind	0	168	382	467
Small Solar	11	475	475	672
Large Diverse	0	0	275	314
Large Wind	0	0	269	305
Large Solar	0	181	433	616

Figure 10.9 includes the firm capacity additions and shows each of the candidate portfolios now meeting the 0.1 LOLE threshold.

Figure 10.9. IRP 2026 Seven Portfolios Loss-of-Load Expectation with Additional Firm Capacity



While all candidate portfolios were required to meet the resource adequacy standard of a maximum of one day in ten years with lost load, further analysis is necessary to evaluate the overall reliability of each portfolio. For further resource adequacy analysis, please refer to Appendix 9: Resource Adequacy.

Portfolio Analysis Evaluation

Table 10.9 summarizes the key strengths and weaknesses of the seven portfolios. A more extensive reliability analysis of these portfolios is presented in Appendix 9: Resource Adequacy.

Table 10.9. 2026 IRP Seven Portfolio Strengths and Weaknesses

Portfolio Name	Strengths	Weaknesses
Small Diverse	• Lowest NPV overall among candidate portfolios • Diverse resource mix lowers cost and reliability risk	• Is not resource adequate on its own and requires firm capacity additions to meet resource adequacy standard earlier than large portfolios
Small Wind	• Low NPV value across all three price futures	• Relies solely on wind (lack of resource diversity significantly increases risk) • Large transmission acquisition need • Is not resource adequate on its own and requires firm capacity additions to meet resource adequacy standard earlier than large portfolios • Only portfolio that is in deficit in WRAP requirements before the end of the IRP study period
Small Solar	• Has low transmission acquisition need through 2045	• Relies solely on solar + storage (lack of resource diversity significantly increases risk) • Is not resource adequate on its own and requires firm capacity additions to meet resource adequacy standard earlier than Large portfolios • Among the highest of the candidate portfolios' SCGHG

Portfolio Name	Strengths	Weaknesses
Large Diverse	• Diverse resource mix lowers cost and reliability risk • Resource adequate through 2035; lower dependency on acquiring firm capacity products for future reliability • Lowest SCGHG through 2045	• Has a LOLE of 0.02 in 2030, indicating extra resources in the portfolio
Large Wind	• Resource adequate through 2035	• Has a LOLE of 0.03 in 2030, indicating extra resources in the portfolio • Relies solely on wind (lack of resource diversity significantly increases risk) • Large transmission acquisition needs
Large Solar	• Low transmission acquisition need through 2045	• Has a LOLE of 0.03 in 2030, indicating extra resources in the portfolio • Relies solely on solar + storage (lack of resource diversity significantly increases risk) • Among the highest of the candidate portfolios' SCGHG • Highest NPV across all three price futures

Recommendation

City Light finds that the portfolio attributes of the Large Diverse portfolio would be the best fit. While the existing resource scenario had the lowest NPV costs by a small margin, it did not meet City Light's resource adequacy requirement of 0.1 LOLE through the 20-year study period and represents the highest risk of loss of load. Under extreme load and hydro scenarios, City Light expects the Current portfolio would fall even further below the resource adequacy threshold, and relative costs would increase due to the higher market reliance necessary to serve load. City Light feels uncomfortable with recommending any of the wind or solar + storage variants, since a portfolio with a significant percentage of only wind or solar renewables presents significant challenges to balancing energy in real time and also creates additional resource procurement risk.

Furthermore, the Small Diverse portfolio requires significantly more firm capacity additions than the Large Diverse portfolio does and also has an additional 100 MW of market reliance. The Large Diverse portfolio is the 2026 IRP preferred portfolio. However, circumstances may change, City Light will continue to evaluate whether its plans should be altered every two years.

APPENDIX 11: ADVANCED TECHNOLOGY BREAK-EVEN ANALYSES

City Light analyzed an additional set of resource technologies, termed "advanced technologies" here, separately from the established new resource technologies (wind, solar PV, and short-duration BESSs) included in the primary IRP analysis. Advanced technologies are those that have not yet been extensively deployed at scale, even though the technological capabilities may already exist and they may have already been deployed at scale in a few instances. These technologies also tend to have much longer deployment times from investment to the first operational deliveries than wind, solar PV, and short-duration BESSs. Advanced technologies treated in this IRP include enhanced geothermal systems, small modular reactors (SMRs), long-duration energy storage, and green hydrogen peaker plants.

These technologies provide clean, firm power in the form of baseload or dispatchable power and will be critical to building a reliable and clean portfolio. A portfolio built only on wind, solar and short-duration batteries requires a high capacity volume to overcome the weather dependency of these resources, but is still not guaranteed to produce power when it is needed.

The advanced technology resources were treated separately because there remains uncertainty surrounding when these resources will become commercially available on a utility scale and what they will cost. City Light performed separate break-even analyses for each advanced technology type to determine the price at which adding an advanced technology resource would reduce the cost of the 2026 IRP's candidate portfolios.

Background

Resource Adequacy Need

Seattle City Light's existing power supply portfolio currently provides significant flexibility for meeting its system load, especially because of the seasonal reservoir storage available at its Skagit hydroelectric project. As discussed in more detail in Appendix 9: Resource Adequacy, the most significant drivers of new resource needs are long (multiday) resource adequacy events.

While established technology resources, namely utility-scale wind, solar PV, and short-duration BESSs, could hypothetically satisfy Seattle's resource needs during most conditions, relying on only these resource types during multiday events poses significant risks. In particular, the meteorological conditions that cause City Light's load to increase (multiday heat waves in summer and cold snaps in winter) also tend to cause low-wind conditions. These circumstances are compounded by the fact that the conditions that result in multiday heat waves in summer can also cause reduced solar irradiance. During winter cold snaps, skies are often clear, but solar irradiance is naturally diminished due to the low angle of the sun. If a multiday event occurred during an extended period of poor hydrological conditions, the region could experience low hydro, solar, and wind energy for multiple consecutive days, which would present a high risk of insufficient generation for serving loads directly or for recharging short-duration BESSs. Consequently, clean, firm advanced technology resources that are not weather dependent and therefore not at high risk of generating low or zero power during multiday heat and cold snap events would likely better meet City Light's resource adequacy needs.

Advanced Technology Types Considered

In the 2024 IRP Progress Report, City Light included enhanced geothermal systems and Oregon offshore wind as candidate resources in the portfolio expansion model. Incentives for development and work toward commercial deployment of offshore wind in the coastal waters of the Pacific Northwest have been significantly hampered by recent federal policies, which were considered not likely to change in the near future. Thus, City Light excluded offshore wind from the advanced technologies to be evaluated in the present work.

Due to demonstrated regional need for clean, firm resources, City Light chose to retain enhanced geothermal systems as a candidate resource for evaluation in the 2026 IRP break-even analyses, because as a baseload resource it is both clean and firm. Conventional geothermal plants require natural sources of heat far below the earth's surface to have pre-existing paths through cracked or porous rock. In these specific geological conditions, energy is relatively easy to harness when cool water is pumped underground and returns to the surface at a much higher temperature. However, these specific geological conditions are not common in the contiguous United States, especially in the Pacific Northwest. Enhanced geothermal systems still rely on harnessing energy from cool water pumped underground and heated by the Earth along its return, but unlike conventional geothermal plants, they can be built by drilling a deep well through nonporous subsurface rock. The pre-existing geological conditions enhanced geothermal systems require are much more common in the United States, which significantly expands the untapped potential for harnessing geothermal energy, including in the Pacific Northwest. Even if enhanced geothermal systems are build outside of the northwest, City Light would be able to deliver that resource to load, provided sufficient transmission capacity.

Similarly, based on the demonstrated regional need for clean, firm resources, City Light also added SMRs into the break-even analyses as another type of advanced technology that functions as a baseload resource. The other type of clean, firm resources City Light chose to include in the break-even analyses were green hydrogen peaker plants and long-duration energy storage (100 MWh), as these advanced technologies provide clean, firm dispatchable power. City Light evaluated these advanced technology types in the present IRP based on the steady technological progression of and positive economic outlook for these technologies. As with established resource technologies and enhanced geothermal systems, these advanced technology resources do not necessarily need to be developed in the Pacific Northwest; they only need sufficient transmission pathways to deliver the energy generated to the Pacific Northwest.

Firm Capacity Product Assumptions

City Light began its break-even analyses using the information provided by the Small Diverse and Large Diverse portfolios, which were both built using only established technology resources as candidates for portfolio expansion purposes. As discussed in the main 2026 IRP Report and in more detail in Appendix 9: Resource Adequacy, the Small Diverse candidate portfolio required City Light to procure specific amounts of firm capacity products in each year from 2031 through 2045 to meet its resource adequacy standard of at most one loss-of-load day in ten years. Similarly, the Large Diverse candidate portfolio required procurement of firm capacity products from 2036 through 2045 to achieve City Light's resource adequacy standard. This firm capacity is necessary because the Small Diverse and Large Diverse portfolios were built in the capacity expansion model using only single days in each calendar month with regionally extreme resource needs (also known as resource-adequacy-constrained days); as a result, the capacity expansion model did not capture more extensive resource needs for multiday resource-adequacy-constrained days. In contrast, the resource adequacy model included all hours across hundreds of modeled years and, as a result, captured the increased resource needs due to multiday resource-adequacy-constrained days. Table 11.1 summarizes the firm capacity additions required for each candidate portfolio at key modeled years.[41]

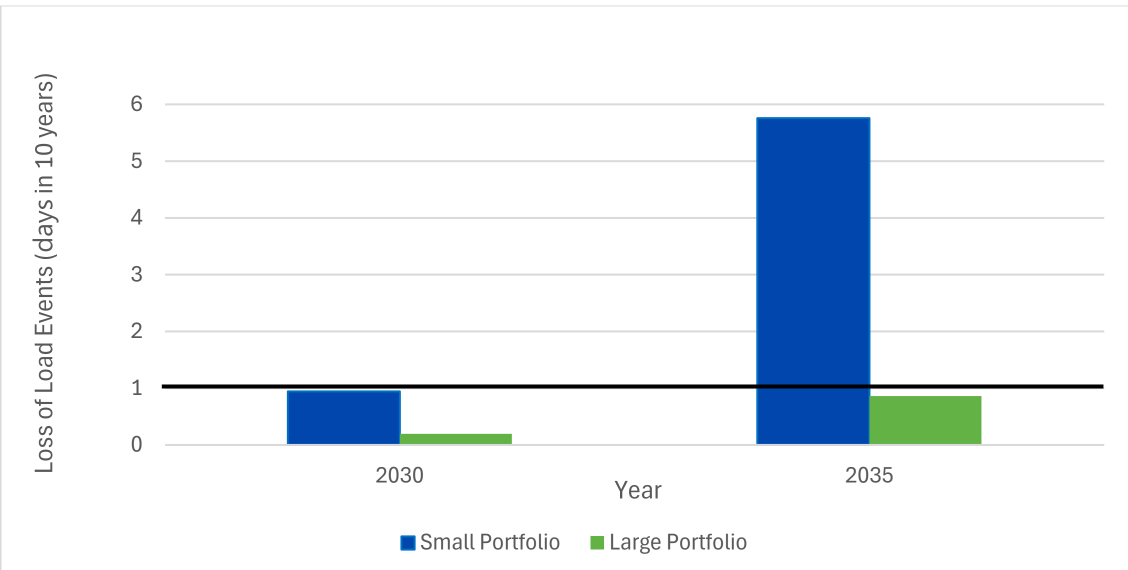
Table 11.1. Resource Adequacy–Required Firm Capacity Resource Additions by Year (MW)

Portfolio	2030	2035	2040	2045
Small Diverse	0	180	567	828
Large Diverse	0	0	387	314

[41] For years between modeled years, annual firm capacity requirements were linearly interpolated between the modeled years.

Figure 11.1 shows reliability in terms of Loss of Load Expectation (LOLE) of the Small Diverse and Large Diverse portfolios in 2030 and 2035 before any firm capacity additions. In 2030, the Small Diverse portfolio is just under City Light's resource adequacy standard of one loss-of-load day in ten years and is thus near-optimally sized for Seattle's system as modeled. The Large Diverse portfolio is far under this threshold in 2030, indicating that it is overbuilt. By 2035, the Large Diverse portfolio has 0.9 expected loss-of-load days in ten years, making it near-optimally sized for Seattle's system, while the Small Diverse portfolio in 2035 does not meet the resource adequacy standard without additional firm capacity. After 2035, both the Small Diverse and Large Diverse portfolios require increasing quantities of firm capacity to stay below the resource adequacy standard.

Figure 11.1. Portfolio Resource Adequacy Before Added Firm Capacity



The GridPath model limited market access on regionally resource-adequacy-constrained days; on those days, once market resources were exhausted, the model had to either build additional supply-side resources or purchase firm capacity products. For the advanced technology break-even analyses, City Light simulated a case in which the cost of firm capacity was consistent with the average cost of new resources built by the Large Diverse portfolio beyond the total new resource capacity of the Small Diverse portfolio. This approach is explained in greater detail in the following section.

Firm Capacity Price Estimates

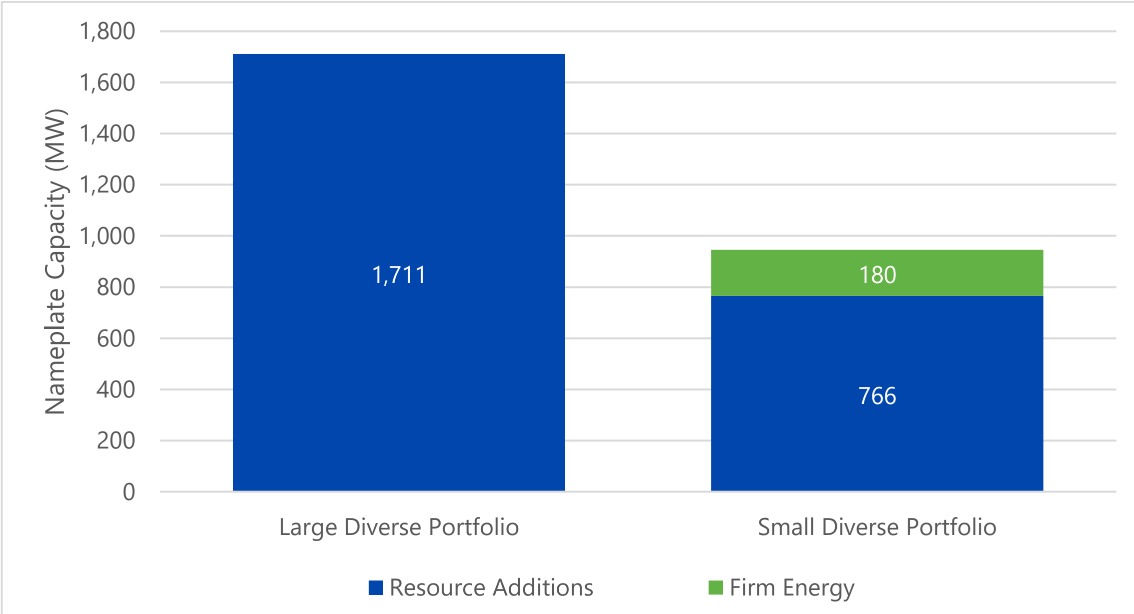
In the main 2026 IRP analysis, City Light assumed that firm capacity products were priced according to BPA's BP-24 demand charge rates of $138/kW per year.[42] City Light's subject matter experts consider this to be a best-case-scenario price, as it would be very low compared with the cost of buying wholesale energy products or building additional generation resources to meet City Light's additional energy and capacity needs. From an energy and capacity perspective, these firm capacity products could be replaced with equivalent energy products that have a capacity component, whether purchased from the wholesale energy market through forward transactions, procured via power purchase agreements (PPAs), or obtained by building out or acquiring renewable energy projects, albeit at a higher price point than that of the BP-24 demand charge rate.

City Light was especially interested in evaluating advanced technology resources that would offer an essentially constant or on-demand supply of energy. These resource types have the potential to offset a significant portion of the sizable magnitude of intermittent renewable energy resources identified in the IRP main report's preferred (Large Diverse) portfolio in future years. The intermittent renewable energy resources have a low capacity factor. Achieving the same megawatt-hours of generation requires a higher nameplate capacity than a resource with a higher capacity factor requires.

Figure 11.2 compares the Small Diverse and Large Diverse portfolios in 2035, demonstrating how just 180 MW of firm energy or firm capacity resources in the Small Diverse Portfolio can replace nearly 1,000 MW of nameplate capacity of intermittent renewables and short-duration batteries in the Large Diverse portfolio, while still meeting City Light's resource adequacy standard. For this reason, the potential cost savings of advanced technology resources are approximated as the marginal cost of new intermittent renewable resources, which is significantly higher than the BP-24 demand charge rate.

[42] After adjusting for inflation to 2026 dollars.

Figure 11.2. Large Diverse and Small Diverse portfolios' New Resource Additions in 2035.



To calculate the cost of new intermittent renewable resources (the cost of marginal capacity), City Light used the difference in the total portfolio costs excluding the additional firm capacity products (but inclusive of project capital costs, O&M, and net marketing revenue) between the Small Diverse and Large Diverse portfolios, divided by the difference in added firm capacity of the Small Diverse and Large Diverse portfolios, for each study year.[43] This resulted in estimated firm capacity costs by year as shown in Table 11.2.[44]

---

[43] The equation for the cost of marginal capacity was: *(large portfolio cost without added firm capacity - small portfolio cost without added firm capacity) / (small portfolio firm capacity - large portfolio firm capacity) = cost of marginal capacity*.

[44] For this analysis, these firm capacity costs indicate the average cost to procure intermittent renewable resource capacity in the last decade of the IRP study period; high firm capacity costs would make relatively expensive emerging technology projects look more appealing. Based on the resource adequacy analysis of the Large Diverse portfolio in the IRP, this method likely determines an appropriate upper-bound cost estimate for 2035, but may slightly underestimate the cost of marginal new-build capacity after 2035. This underestimation occurs because the Large Diverse portfolio almost exactly met City Light's resource adequacy standard of one loss-of-load day in ten years without any firm capacity additions in 2035 but required firm capacity additions after 2035 to continue meeting City Light's resource adequacy standard.

Table 11.2. Firm Capacity Prices Under the Mid-Market Price Scenario

Year	Firm Capacity Price ($/kW-year)
2035	484
2040	658
2045	686

As the Pacific Northwest becomes increasingly saturated with wind, solar and short-duration BESSs, each unit capacity addition of these resources contributes less to meet peak net loads. It is likely that City Light would find alternate means to procure firm capacity by 2035; even the estimated costs of firm capacity presented in Table 11.2 are high compared with forecast wholesale energy market prices, for example. Consequently, City Light was comfortable using these estimates as a reasonable upper-bound for firm capacity costs in the break-even analyses, described further in the Method section below. In such a future, it is likely that any advanced technologies that become commercially available at a utility-scale would compete to set the marginal price of firm capacity below the costs in Table 11.2.

Method

To perform the break-even analysis for each advanced technology resource type, City Light evaluated advanced technology resources in the context of the Small Diverse candidate portfolio without the addition of firm capacity products. City Light added 200 MW of one advanced technology type to the candidate portfolio starting in 2035 at zero capital cost. The portfolio was then run through the resource adequacy model to determine the minimum amount of firm capacity needed on top of the 200 MW of the advanced technology resource to allow the new advanced technology portfolio to meet City Light's resource adequacy standard. City Light then added that minimum amount of firm capacity to the new advanced technology portfolio. Table 11.3 shows the required firm capacity additions to the Small Diverse portfolio with 200 MW of the given advanced technology resource, by year, that are necessary for the portfolio to meet City Light's resource adequacy requirement of 0.1 LOLE.

Table 11.3. Firm Capacity Additions with 200 MW of Advanced Technology Resource

Year	None (Small Diverse Portfolio)	Green Hydrogen Peaker Plant	Baseload	Multiday Storage
2030	0	0	0	0
2035	180	0	0	0
2040	322	120	119	128
2045	420	196	196	214

Each advanced technology portfolio was run through GridPath's production cost model for the same typical weather and hydro year that was used in the main IRP work to evaluate the Small Diverse and Large Diverse candidate portfolios to determine the advanced technology portfolios' costs by year. The difference in total costs between the Small Diverse candidate portfolio, which consists of established resource technologies and firm capacity additions, and the new advanced technology candidate portfolio with any capacity additions necessary represents the total savings to the utility from adding 200 MW of that particular advanced technology to the portfolio. Thus, the value of firm capacity is a determining factor in calculating the break-even value.

Break-even values were calculated by dividing the annual levelized savings by the average annual megawatt-hour generation for advanced technology baseload resources (in the 2026 IRP these were enhanced geothermal systems and SMRs) or by the 200 MW nameplate capacity of the resource for dispatchable advanced technology resources (in the 2026 IRP, these were green hydrogen peaker plants and long-duration energy storage. This allowed City Light to determine the break-even value per megawatt-hour of enhanced geothermal systems and SMRs, and the break-even values per megawatt of long-duration energy storage and green hydrogen peaker plants.

Break-even Values Results and Discussion

The break-even value is the maximum price per unit energy, or per unit capacity, at which adding 200 MW-nameplate of an advanced technology resource would not result in increased costs to City Light, as compared to the Small Diverse portfolio; any price below the break-even value would result in net savings. To explore how the price of wholesale market energy affects the break-even values, City Light varied the calculation of marginal firm capacity using its low-, mid-, and high-wholesale market price forecast scenarios (see Appendix 6: Market Prices). In total, the break-even values capture the savings in capital costs and net marketing opportunity under the three wholesale market price forecast scenarios, as well as any additional curtailment costs.

To add context to the break-even analysis results presented below, we provide comparisons of the advanced technology resources' break-even values to the equivalent costs of established technology resources used in this IRP. This also generalizes our results so that the break-even values can be expressed in terms of established technology resource costs as they change over time.

Using the firm capacity costs by year in Table 11.2, the resulting break-even values for the baseload resources (enhanced geothermal and SMRs) are $94/MWh, $111/MWh, and $135/MWh for the low-, mid-, and high-market price forecasts, respectively. These values translate to 261%, 310%, and 375% of the expected capital cost in dollars per megawatt-hour of a solar PV project in 2035. Green hydrogen peaker plants' break-even values demonstrated minimal sensitivity to wholesale market price forecasts, but ranged from $650/kW-year to $677/kW-year for various green hydrogen fuel costs ranging from $0/MWh to $400/MWh. These were equivalent to between 1,663% and 1,732% of the expected capital costs in dollars per kilowatt-year of short-duration BESSs in 2035. Long-duration energy storage break-even values ranged from $677/kW-year to $726/kW-year for the various wholesale market price forecasts, which were equivalent to between 1,732% and 1,857% of the expected capital costs in dollars per kilowatt-year of new-build short-duration BESSs in 2035. Table 11.4 summarizes these break-even ranges.

Table 11.4. Breakeven Value Ranges

Advanced Technology Type	Lowest Break-even Value (2026 dollars)	Highest Break-even Value (2026 dollars)	Lowest Break-even Value (% of established tech cost in 2035)	Highest Break-even Value (% of established tech cost in 2035)
Baseload (Enhanced Geothermal, Small Modular Reactors)	$94/MWh	$135/MWh	261% of solar PV cost	375% of solar PV cost
Green Hydrogen Peaker Plants	$650/kW-year	$677/kW-year	1,663% of 4-hour BESSs cost	1,732% of 4-hour BESSs cost
Long-Duration Energy Storage	$677/kW-year	$726/kW-year	1,732% of 4-hour BESSs cost	1,857% of 4-hour BESSs cost

The break-even analysis results show that baseload resources were estimated to be worth about 2.5 to almost four times the cost of the equivalent nameplate capacity of solar resources (calculated over the full 2035–2045 period) when added to the portfolio in 2035. Baseload resources would provide energy to consistently serve City Light's load, regardless of daylight hours or variable weather conditions. This provides increased value over the intermittent, daytime-only power supplied by a typical solar PV plant, even east of the Cascade Mountains. However, baseload resources cannot easily be turned off when energy is not needed, which means excess energy may often be sold on the wholesale energy market at a net loss.

Green hydrogen peaker plants were found to be worth 16 to more than 17 times the cost of equivalent capacity of short-duration BESSs, and long-duration energy storage resources were found to be worth about 17 to more than 18 times the cost of the equivalent amount of short-duration BESSs in 2035. In contrast to baseload resources, both of these resource types can easily be cycled on and off and are therefore operated to provide additional energy only when economically advantageous. As a result, these resource types offer significantly more value relative to baseload and other resources present in the Small Diverse candidate portfolio by 2035. Additionally, recent resource adequacy studies in the Pacific Northwest have shown that multiday extreme weather events, such as the cold-snap in January 2024, pose the greatest reliability risks to the region, which further contributes to the value offered by both green hydrogen peaker plants and long-duration energy storage additions to City Light's power supply portfolio.

To help level-set the feasibility of relative break-even costs of green hydrogen peaker plants and long-duration energy storage, consider a hypothetical case where all loss-of-load events using only City Light’s existing power supply portfolio are 100 hours or longer. In such a case, for each nameplate megawatt of capacity, a long-duration energy storage provides 100 MWh of energy (i.e., each megawatt of storage capacity x 100 hours), compared to a short-duration BESS’s 4 MWh. In this case, a single megawatt of long-duration energy storage mitigates the energy shortfall better than short-duration energy storage by a factor of 25. In such a hypothetical case, the reported 1,730% to 1,860% of the value of the short-duration energy storage would actually *undervalue* long-duration energy storage.[45] In reality, many loss-of-load events last less than 100 hours, so the full 100-hour duration of the modeled long-duration energy storage is not fully utilized in every event. For this reason, it appears reasonable for the long-duration

[45] All other factors being equal, and assuming the value of lost load (VOLL) dwarfs the operational differences of the batteries.

energy storage value to see a reduction to about 1,730% to 1,860% of the value of short-duration energy storage.

Advanced Technology Concluding Assessment

Break-even values for each advanced technology type indicate City Light's best estimates of the maximum cost-per-unit (dollars per megawatt-hour or dollars per kilowatt-year) at which 200 MW nameplate of an advanced technology resource would add value to City Light's candidate portfolios.

These break-even values depend on both the wholesale energy market price forecasts and the future price of marginal firm capacity that advanced technology resources compete with. As both of these are difficult to predict out to a 20-year horizon, City Light calculated break-even values across low-, mid-, and high-market price futures. In these break-even analyses, firm capacity prices represent a future in which firm capacity (or firm energy) products are not available for purchase at a cost lower than the price to build new renewable energy projects; the cost of each marginal unit of capacity is expected to increase with time.

Based on the assumptions in the IRP, baseload advanced technology resources available for procurement starting in 2035 with costs at or below $94/MWh to $135/MWh would add value to City Light's power supply portfolio. The break-even value within this range would be determined by the actual cost of firm capacity products available in the wholesale market or through bilateral purchases at the time. Similarly, City Light would see value from a green hydrogen peaker plant priced at $650/kW-year to $677/kW-year at most, or from a long-duration energy storage offered for at most $677/kW-year to $726/kW-year.

City Light recognizes that these break-even values are sensitive to the modeling assumptions used. The cost of existing resources has shifted dramatically higher since the inputs to the IRP were finalized. This directly impacts the break-even value for advanced resources. City Light completes an IRP every two years and will complete a deeper analysis into the value of clean, firm and dispatchable resources for the next IRP.

Potential approaches to evaluating break-even values of new advanced technology resources in future IRP studies are summarized as follows:

- Offer a fixed amount of a new advanced technology into the capacity expansion model at zero cost and at a predetermined future year so that established technology resources may potentially be displaced or delayed in their selection for portfolio expansion.

- Vary capacities and availability dates in sensitivity studies.
- Run the production cost model for multiple weather scenarios per study year to inform the value of advanced technology resources when the system is under a range of stress levels.

Since the above approaches require non-negligible computational resources and time, the team can use the results presented here to inform further exploration of the uncertainty space, while being strategic about which expanded model runs would provide the most insight to City Light.

APPENDIX 12: COMMUNITY OUTREACH AND PUBLIC INVOLVEMENT PROCESS

City Light is proud to be a local, community-owned utility that is visible and actively involved in the communities it serves. Its commitment to racial diversity, social justice and the equitable provision of services to all is an important part of City Light's mission, vision, and values.

Community Outreach

City Light has taken a coordinated approach in outreach for large planning efforts by partnering with the City of Seattle Department of Neighborhoods (DON) to engage with communities throughout City Light's service area for feedback to inform the 2026 Integrated Resources Plan (IRP), the 2026 Clean Energy Improvement Plan (CEIP), and the 2027–2032 Strategic Plan. The ongoing public participation process, which continues to evolve, has included the following elements:

1. **Reviewing Existing Feedback:** City Light reviewed relevant community feedback provided via other strategic planning efforts (e.g. City Light's most recent Transportation Electrification Strategic Investment Plan and the City's Comprehensive Plan). This approach enabled us to be responsive to customers' and communities' existing feedback and identify gaps in and opportunities for community engagement.
2. **Hosting Community Conversations:** City Light has directly engaged with customers and community leaders through public meetings, focus groups, and community gatherings to inform the CEIP planning process.
3. **Engaging Trusted Community Partners:** City Light also met with community organizations and DON Community Liaisons, who work directly with highly impacted communities and vulnerable populations on issues including affordability, public health, environment, etc.
4. **Qualitative Research via Online Discussion Boards:** City Light has worked with a consultant to conduct a digital focus group of 35 City Light customers from diverse backgrounds oversampling those traditionally underrepresented in surveys such as Black, Indigenous, or People of Color (BIPOC); central/south Seattle residents; and younger respondents.

Outreach follows guidelines established by the equity-related sections of the CEIP and has been directly informed by the public participation process that targeted priority populations as identified by the Clean Energy Transformation Act (CETA) as Highly

Impacted Communities and Vulnerable Populations. Community feedback identified the following groups as those most vulnerable to or impacted by lack of access to power:

- Those who rely on electricity for medical devices, medication, and/or personal mobility (e.g., electric wheelchairs, breathing machines, insulin)
- Those who disproportionately experience and are more sensitive to extreme weather events (e.g., community elders, children)
- Those who are monolingual in a language other than English or have limited English proficiency
- Are lower-income and/or BIPOC living in franchise communities (e.g., White Center, Shoreline, Burien)

Key themes from community feedback have included: centering vulnerable communities in the planning process, increasing awareness about how City Light is preparing for the clean energy transition, exploring the use of renewables while protecting affordability, and ensuring that customers have equitable access to programs and services.

Public Involvement Process

City Light's IRP process includes frequent interaction and information-sharing with a panel of external IRP advisors. This external advisory panel consists of the following individuals:

- Roz Jenkins (formerly Steve Gelb), Emerald Cities Collaborative
- Dr. Angela Griffin, Byrd Barr Place
- Paul Munz, Bonneville Power Administration (BPA, retired)
- Jeremy Park, P.E. University of Washington
- Yuri Rodrigues, Seattle Pacific University
- Mike Ruby, Ph.D., P.E., Envirometrics, Inc.
- Charlee Thompson, NW Energy Coalition
- Elizabeth Osborne, Northwest Power and Conservation Council
- Austin Scharff, WA Department of Commerce
- Kevin Schneider, Pacific Northwest National Laboratory
- Terry Sullivan, King County
- John Ollis, Northwest Power and Conservation Council

The City Light IRP team held five online meetings with this advisory panel from 2024 to 2025, described in Table 12.1.

Table 12.1. 2026 IRP External Advisory Panel Meeting Schedule

Date	Meeting Subject
November 6, 2024	• SCL and Panel introductions • Context and Framing: IRP and DSMPA • IRP and DSMPA Milestones
January 15, 2025	• 2026 IRP Report Overview • 2026 IRP Load Forecast • IRP Input Assumptions: Transmission, BPA Product Choice, Resource Options, Wholesale Prices
April 2, 2025	• 2026 IRP and DSMPA Staggered Approach • 2026 DSMPA Preliminary Results • Existing Resources
July 17, 2025	• DSMPA Results
September 24, 2025	• IRP Results

The external IRP advisory panel provided feedback on the following topics.:

- Future plans for adding distribution analysis and creating an Integrated System Plan
- Need for clarifications on the electrification projections included in the load forecast
- Questions about various demand-side product modeling assumptions
- Questions about how battery technology may ease pressure during peaks
- Transmission modeling

City Light encourages members of the public to contact City Light at SCL_RPA@seattle.gov if they would like to be considered for this panel.

GLOSSARY OF TERMS

1-in-10 Peak: The peak hourly load expected to occur once every 10 years.

Achievable economic potential: The portion of achievable technical potential determined to be cost-effective by the IRP's optimization modeling, in which either bundles or individual energy efficiency measures are selected based on cost and savings. The cumulative potential for these selected bundles constitutes achievable economic potential.

Achievable technical potential: The portion of technical potential that could realistically be realized during the study's period, considering market barriers such as customer awareness, willingness to adopt measures, and historical program participation rates. It includes savings, regardless of the acquisition mechanism, that may be acquired through utility programs, improved codes and standards, and market transformation without considering cost-effectiveness.

aMW (average megawatts): Average power measured over a specified period of time. In long-term resource planning studies like the Integrated Resource Plan (IRP), the specified unit of time is often equal to one full year; in this case, 1 aMW over a year would equal 8,760 MWh.

Baseload resource: A resource that provides a relatively consistent and stable amount of power every hour that it is in operation. Often baseload resources are expensive and labor-intensive to cycle on and off, so baseload resources are assumed to be operating continuously, except during infrequent periods of planned maintenance.

BESS (Battery energy storage system): The technical term for batteries used to store utility-scale quantities of energy for use at a later period of time of greater need or value.

Candidate portfolio: a power supply portfolio that contains additional generation (and potentially also additional transmission) resources compared with the utility's existing power supply portfolio to help maintain reliable load service into a future period.

Capacity: The maximum power output that a generator can produce, or the maximum amount of power that can be transferred over a transmission line, under specified conditions. Capacity is a measure of power and is generally expressed in kilowatts (kW) or megawatts (MW). The relationship between capacity and energy is often expressed as $Energy = Capacity \times Time$. For example, a power plant with 1 MW of capacity operating for one hour produces 1 MWh of energy.

Capacity expansion model (or portfolio expansion model): A mathematical model used as part of the IRP process to determine the lowest-cost candidate portfolio required to meet future loads based on user-specified resource options and reliability requirements.

Clean Energy Implementation Plan (CEIP): As part of the Clean Energy Transformation Act (CETA), a CEIP describes the utility's near-term plan for making incremental progress toward meeting the long-term clean energy transformation targets outlined in the CETA while continuing to pursue all cost-effective, reliable, and feasible conservation and efficiency resources.

Clean Energy Transformation Act (CETA): Signed into law in 2019, CETA requires electric utilities to supply their Washington state customers with 100% renewable or non-emitting electricity by 2030, with no provision for offsets starting in 2045.

Conservation: According to the Northwest Power Act, conservation refers to any reduction in electric power consumption because of increases in the efficiency of energy use, production, or distribution.

Customer/customer classes: One or more categories of customers defined by rate tariff(s) published by Seattle City Light and approved by the Seattle City Council. Examples of customer classes are residential, industrial, and business general service (small, medium, large, and high demand).

Demand (electric): The load that is drawn from the source of supply over a specified interval of time (generally expressed in kilowatts, megawatts, or kilovolt-amperes).

Demand response: A voluntary and temporary change in consumers' use of electricity when the power system is stressed.

Demand-side management: The process of helping customers use energy more efficiently.

Demand-side management potential assessment (DSMPA): A Seattle City Light analysis of the amount of demand-side resources such as conservation, customer solar, and demand response that have economic, achievable potential within City Light's service territory. This analysis fulfills statutory requirements of Chapter 194-37 of the Washington Administrative Code (WAC), which requires that City Light identify all achievable, cost-effective conservation potential for the upcoming 10 years, and supports compliance with Washington State's Clean Energy Transformation Act (CETA). Targets set by City Light's DSMPA impact City Light's load projections and thus serve as inputs into the IRP.

Distribution: The transfer of electricity from the transmission network to the consumer. Distribution systems generally include the equipment to transfer power from the utility substation to the customer's meter.

Energy: The total amount of electricity produced or consumed over a specific duration. Typical units are kWh, MWh, and aMW. The relationship between capacity and energy is often expressed as $Energy = Capacity \times Time$. For example, a 1 MW power plant operating at full capacity for one hour produces 1 MWh of energy.

Energy efficiency measure: Implementation of an individual project or technology to reduce the consumption of energy at the same or an improved level of service. Often referred to as simply a "measure."

Energy Independence Act (EIA): Passed by Washington voters in 2006, this act requires electric utilities serving at least 25,000 retail customers to meet a certain percentage of their electrical load with renewable energy resources. Also known as I-937.

Greenhouse gas: Gases, such as carbon dioxide, nitrous oxide, methane, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride, that are transparent to solar (short-wave) radiation but opaque to long-wave (infrared) radiation, thus preventing long-wave radiant energy from leaving Earth's atmosphere. The trapped long-wave radiant energy has the net effect of warming Earth's atmosphere.

Generation: The act or process of producing electricity from other forms of energy.

Integrated Resource Plan (IRP): A comprehensive evaluation of future electric or natural gas resource plans that considers the full range of resources that are available and may be available in the future to provide adequate and reliable service to a customer's needs at the lowest possible risk-adjusted system cost. These plans are filed with the state Department of Commerce or public utility commissions on a periodic basis.

Kilowatt (kW): The unit of power that equals 1,000 watts.

Kilowatt-hour (kWh): A basic unit of electrical energy that equals one kilowatt of power applied for one hour. Equivalent to 3,412 BTU.

Megawatt (MW): The unit of power that equals one million watts or one thousand kilowatts.

Megawatt-hour (MWh): A basic unit of energy that equals one megawatt of power applied for one hour.

Nameplate Capacity: The maximum power output that a generator can produce (determined by the manufacturer) without exceeding design limits. Installed generator nameplate capacity is commonly expressed in megawatts (MW) and is usually indicated on a nameplate physically attached to the generator.

Northwest Power Act: On December 5, 1980, Congress passed the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), which authorized the four states of Idaho, Montana, Oregon, and Washington to form the Northwest Power and Conservation Council (Power Council) to ensure reliable power supply for the Pacific Northwest while protecting fish and wildlife impacted by hydropower dams and prioritizing environmentally sustainable energy.

Northwest Power and Conservation Council (Power Council): The Northwest Power Act established the Power Council and directs it to develop and maintain both a regional power plan and a fish and wildlife program to balance the environmental and energy needs of the Pacific Northwest. The Power Council prepares a Power Plan every five years to assure the region an adequate, efficient, economical and reliable power supply.

Peaker plant: A power plant that is expected to operate only for a small number of hours each year in order to help meet peak loads.

Power supply portfolio: In the IRP context, a collection of all generation resources, power contracts, demand-side management programs (e.g., energy conservation, demand response, customer solar), and transmission assets that a utility uses to serve its load. For example, City Light's existing portfolio comprises investments in demand-side management programs, City Light-owned hydropower resources, existing hydropower and renewable energy contracts from regional partners, and wholesale market purchases.

Power: The rate at which electrical energy is transferred in a circuit. Power can also be thought of as an instantaneous measure of energy. The standard unit of power is the watt (W). One MW is equal to 1,000,000 watts.

Production cost model: A model used as part of the IRP process to determine the resource controls and operations to meet load at lowest cost, subject to provided constraints and targets. The production cost model determines the total costs and revenues produced by a candidate portfolio that is composed of the resource selections determined by the IRP capacity expansion model and wholesale electricity marketing activity.

PV (Photovoltaic); The technical term for solar panels used to generate electricity.

Reliability: In the context of a long-term resource planning study such as the IRP, having sufficient resources to meet loads under a wide variety of plausible conditions. Often closely tied to "resource adequacy".

Revised Code of Washington (RCW): The laws that are currently in place in Washington state.

Resource adequacy: A measure of a load-serving entity, such as a utility like Seattle City Light, to consistently serve load using its power supply portfolio, even in extreme conditions such as extreme weather events.

Sector(s): A division of the economy for energy planning purposes. Energy efficiency programs generally serve the residential, commercial (e.g., retail stores, office, and institutional buildings), and industrial sectors.

Social Cost of Greenhouse Gas (SCGHG): The impact that emitting a greenhouse gas has on society, generally expressed as dollars of impact per ton of carbon dioxide warming equivalent ($/t$CO_{2e}$).

Technical potential: The total amount of energy efficiency that could be achieved within City Light's service territory, assuming that all feasible resource opportunities can be captured regardless of cost and market barriers, such as customer willingness to adopt. The potential is only limited by physical and operational constraints.

Transmission: The act or process of transporting electric energy by wire over long distances, generally accomplished by elevating the electric current to high voltages. In the Pacific Northwest, Bonneville Power Administration operates most of the high-voltage, long distance transmission lines.

Uncertainty: The range or interval of doubt surrounding a measured or calculated value within which the true value is expected to fall with some degree of confidence. Confidence increases as the range of uncertainty decreases.

Utilities and Transportation Commission (UTC): A three-member commission appointed by the governor and confirmed by the state Senate, whose mission is to protect the people of Washington state by ensuring that investor-owned utility and transportation services are safe, available, reliable, and fairly priced.

Western Resource Adequacy Program (WRAP): A western regional program that requires utilities to demonstrate that they have sufficient resources to meet their share of potential future regional peak load, to ensure that the western region meets a set resource adequacy standard. Resources are accredited for having the potential to meet future regional peak load by being assigned qualifying capacity contributions (QCCs).