EXHIBIT 42

Energy Secretary Ensures Washington Coal Plant Remains Open to Ensure Affordable, Reliable and Secure Power Heading into Winter

U.S. Secretary of Energy Chris Wright today issued an emergency order to ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity heading into the cold winter months.

Energy.gov

December 17, 2025

2 min

Emergency order addresses critical grid reliability issues, lowering risk of blackouts and ensuring affordable electricity access

WASHINGTON—U.S. Secretary of Energy Chris Wright today issued an emergency order to ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity heading into the cold winter months. The order directs TransAlta to keep Unit 2 of the Centralia Generating Station in Centralia, Washington available to operate. Unit 2 of the coal plant was scheduled to shut down at the end of 2025. The reliable supply of power from the Centralia coal plant is essential for grid stability in the Northwest. The order prioritizes minimizing the risk and costs of blackouts.

"The last administration's energy subtraction policies had the United States on track to experience significantly more blackouts in the coming years — thankfully, President Trump won't let that happen," said **Energy Secretary Wright**. "The Trump administration will continue taking action to keep America's coal plants running so we can stop the price spikes and ensure we don't lose critical generation sources. Americans deserve access to affordable, reliable, and secure energy to heat their homes all the time, regardless of whether the wind is blowing or the sun is shining."

According to DOE's Resource Adequacy Report, blackouts were on track to potentially increase 100 times by 2030 if the U.S. continued to take reliable power offline as it did during the Biden administration.

The North American Electric Reliability Corporation (NERC) determined in its 2025-2026 Winter Reliability Assessment that the WECC Northwest region is at elevated risk during periods of extreme weather, such as prolonged, far-reaching cold snaps.

This order is in effect beginning on December 16, 2025, and continuing until March 16, 2026.

Background:

The NERC Winter Reliability Assessment warns that "extreme winter conditions extending over a wide area could result in electricity supply shortfalls." With winter electricity demand continuing to rise, peak demand in the U.S. increased by 2.5% since last winter.

###

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December 16, 2025

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Just Launched: A Critical Materials Career Map

December 17, 2025

Tags:

STRENGTHEN GRID RELIABILITY AND SECURITY

EMERGENCY RESPONSE

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EXHIBIT 43

U.S. DEPARTMENT of ENERGY

Promises Made, Promises Kept

DOE is Delivering on President Trump's Agenda of American Energy Dominance.

Energy.gov

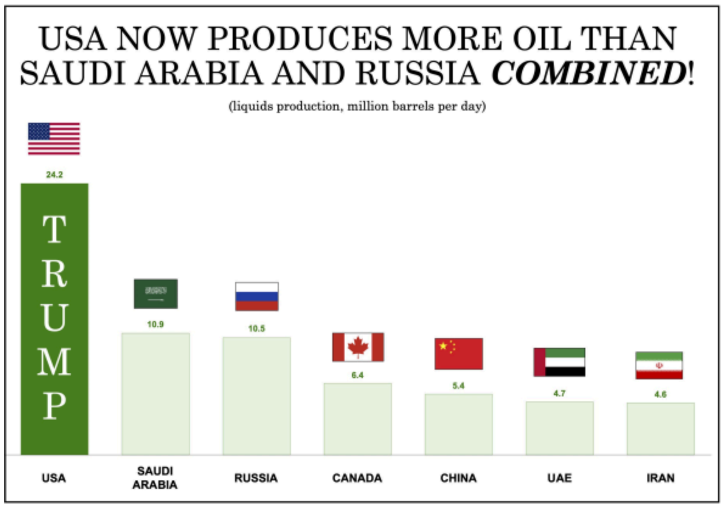
December 18, 2025

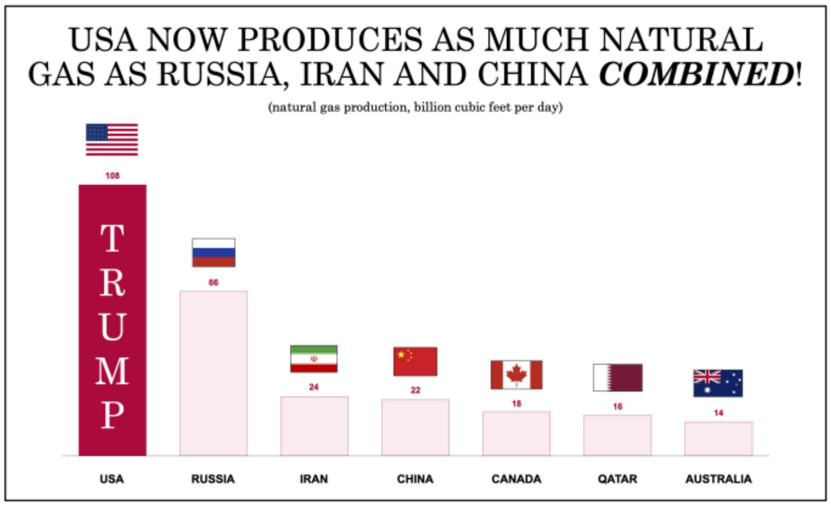
7 min

UNLEASHING THE GOLDEN ERA OF ENERGY DOMINANCE AND LOWERING PRICES

With President Trump and Secretary Wright's leadership, the Energy Department has ushered in an unprecedented era of energy dominance, resulting in record energy production and more affordable prices.

- Thanks to President Trump, gas prices are at a [4-year low]averaging about $2.90/gal. Savings for the American people will amount to over $500 million this Christmas.
- Never before in America's history has our Nation been more energy dominant: Thanks to President Trump's policies, America leads the world in oil and natural gas production, producing at all-time records.
- The U.S. now produces more oil than Saudia Arabia and Russia combined at 24.2 million barrels per day.
- The U.S. now produces as much natural gas as Russia, Iran and China combined at 108 billion cubic feet per day.





- On Day One, President Trump directed the Energy Department to end the Biden LNG export ban, delivering prosperity at home and peace abroad. Since January, The Energy Department has approved more LNG export capacity than the volume exported today by the world's second-largest LNG exporter.

- Since President Trump took office, prices for propane, kerosene, firewood and fuel oil are all down.
- Thanks to President Trump and the passage of the Working Families Tax Cut, the Energy Department is refilling and repairing the Strategic Petroleum Reserve (SPR) after the Biden administration recklessly drained and damaged it for political purposes.
- In May 2025, the Energy Department announced the largest deregulatory effort in the department's history, proposing the elimination of 47 regulations driving up costs for consumers, estimated to save Americans $11 billion in costs.
- In March 2025, the Energy Department withdrew four conservation standards, including standards on electric motors, ceiling fans, dehumidifiers and external power supplies, cutting red tape, restoring consumer choice and lowering costs for the American people.

PREVENTING BLACKOUTS AND REVERSING THE BIDEN ENERGY SUBTRACTION AGENDA

The previous administration's energy subtraction agenda threatened the reliability of the U.S. energy grid, which is why on Day One, President Trump declared a national energy emergency and made it a central mission of his administration to lower costs and stabilize the grid.

- Under the Biden administration, there were plans to shutter coal, natural gas and hydro-powered electricity plants. An Energy Department report released earlier this year showed that before President Trump's election, America was on track to experience a massive shortfall of reliable electricity generation and 100 times more blackouts in the next five years.
- Thanks to President Trump, the Energy Department is reversing those dangerous and costly energy subtraction policies. The Energy Department has issued 16 emergency orders, to maximize grid reliability, affordability and to keep power online and available that would have otherwise been shuttered. These emergency orders have been essential in keeping the lights on during periods of extreme weather and periods of peak demand.
- Thanks to President Trump, the Energy Department halted the Biden Administration's radical anti-hydroelectricity policy in the Columbia River Basin, which could have led to the shutdown of more than 3,000 megawatts of affordable, reliable and secure hydroelectric power – enough generation to power about 2.5 million homes.
- The Energy Department has provided overdue support to addressing Puerto Rico's grid crisis and delivering affordable, reliable, and secure energy to 3.2 million Puerto Ricans. In October 2025, the Energy Department reallocated $365 million in funding to help fix grid crisis and support commonsense repairs, helping more Puerto Ricans on a faster timeline.
- In September 2025, the Energy Department cancelled more than $13 billion in unobligated funds that were appropriated to advance the previous Administration's wasteful Green New Scam agenda and returned these funds to the U.S. Treasury.

ENDING THE WAR ON BEAUTIFUL, CLEAN COAL

While the last administration declared war on American coal, President Trump and DOE are fully committed to strengthening American coal-workers and coal's critical role in powering America.

- Thanks to President Trump, wages for coal workers are up and coal plants across the country are reversing plans to shut down. By the end of the year, more than 15 gigawatts of coal-powered electricity generation will have been saved, strengthening grid reliability and affordability.
- Following the President's Executive Order to "Reinvigorate America's Beautiful Clean Coal Industry," Secretary Wright issued five initiatives to expand and modernize the coal industry and support emerging technologies.
- The Energy Department reinstated the National Coal Council to provide expert guidance on the future of coal technologies and markets.

UNLEASHING THE NEXT AMERICAN NUCLEAR RENAISSANCE

For decades, the American nuclear industry has been smothered by bureaucratic red tape. Thanks to President Trump, the next American Nuclear Renaissance has arrived.

- DOE has taken numerous actions to accelerate the development of next generation nuclear technology and restore domestic supply chains to accomplish President Trump's goal of expanding American nuclear energy capacity from approximately 100 GW in 2024 to 400 GW by 2050.
  - In December 2025, the Energy Department awarded $800 million to TVA and Holtec to advance deployment of U.S. small modular reactors.
  - In November 2025, the Energy Department announced it closed a $1 billion loan to accelerate the restart of a Pennsylvania nuclear power plant that will deliver 850 megawatts of electricity.
  - In September 2025, the Energy Department selected four companies for Advanced Nuclear Fuel Line Pilot Projects in order to strengthen domestic supply chains for nuclear fuel.
  - In August 2025, the Energy Department made a second round of conditional commitments to provide high-assay low-enriched uranium to three U.S. companies to meet near-term fuel needs.
  - In August 2025, the Energy Department announced the 11 initial selections for President Trump's Nuclear Reactor Pilot Program to move their technologies toward deployment.
  - In July 2025, the Energy Department announced site selections for AI data center and energy infrastructure development on federal lands.
  - In July 2025, the Energy Department announced the start of a new pilot program to accelerate the development of advanced nuclear reactors and strengthen domestic supply chains for nuclear fuel.

ENSURING NATIONAL SECURITY BY REDUCING FOREIGN DEPENDENCE ON CRITICAL MINERALS

Thanks to President Trump, the Energy Department is reshoring American-made supply chains for critical minerals, making U.S. national security a priority by reducing U.S. dependence on foreign supply chains.

- In November 2025, DOE announced $355 million in funding opportunities for American industrial facilities capable of producing valuable minerals from existing industrial and coal byproducts and to establish Mine of the Future proving grounds for real-world testing of next-generation mining technologies.
- In December 2025, DOE announced $134 million in funding opportunities to enhance domestic supply chains for rare earth elements (REEs), to support projects that will commercialize the recovering and refining of REEs from unconventional feedstocks.
- The Energy Department announced it restructured a loan with Lithium Americas to further protect taxpayers and solidify the launch of the only domestic source of lithium carbonate here in America. The new terms provide the U.S. Government with 5% equity ownership in the form of Lithium America Corporation warrants.
- DOE's national labs have been able to develop technologies to extract critical minerals and rare earth elements from coal waste, and is partnering with the private industry to commercialize and

advance these technologies.

MODERNIZING AMERICA’S NUCLEAR DETERRENT

The Energy Department has prioritized national security by modernizing the U.S. nuclear enterprise that supports President Trump’s Peace Through Strength Agenda. These actions have ended years of neglect to keep our Nation safe and strategic readiness.

- Signed into law earlier this year, President Trump’s Working Families Tax Cut made more than $3 billion to accelerate the modernization efforts at the Energy Department’s National Nuclear Security Administration.
- Completed the manufacturing of the first B61-13 gravity bomb, the latest modification to the B61 family of nuclear weapons. The first unit was assembled almost a year before the original target date and less than two years after the program was first announced, making the B61-13 one of the most rapidly developed and fielded weapons since the Cold War.
- Completed the Last Production Unit (LPU) of the W88 Alteration (Alt) 370, a multiyear program to modernize the W88 nuclear warhead carried onboard Ohio-class ballistic missile submarines.
- NNSA announced two new supercomputers at Los Alamos National Laboratory, which will significantly advance U.S. national security, AI, and scientific research capabilities.

ACCELERATING AMERICA'S SCIENTIFIC CAPABILITIES

The Department of Energy is accelerating America's scientific engine. This means that technological innovation is designed, tested, and built in America using the brightest minds.

- On November 24, 2025, President Trump signed Executive Order 14363 directing the Department of Energy to lead its flagship AI initiative—the Genesis Mission—a national project combining America's world-leading private-sector AI capabilities with DOE's scientific data, facilities and expertise.

- DOE has already been working to accelerate science and innovation, to ensure U.S. has the technology to unleash the potential of harnessing nuclear fusion power in the U.S. In October 2025, DOE released its Fusion Science and Technology Roadmap (FS&T) Roadmap, as a national strategy to develop and commercialize nuclear fusion power in the most rapid, responsible time in history.

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December 19, 2025

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EXHIBIT 44

Administration of Donald J. Trump, 2025

Executive Order 14156—Declaring a National Energy Emergency
January 20, 2025

By the authority vested in me as President by the Constitution and the laws of the United States of America, including the National Emergencies Act (50 U.S.C. 1601 *et seq*.) ("NEA"), and section 301 of title 3, United States Code, it is hereby ordered:

Section 1. *Purpose*. The energy and critical minerals ("energy") identification, leasing, development, production, transportation, refining, and generation capacity of the United States are all far too inadequate to meet our Nation's needs. We need a reliable, diversified, and affordable supply of energy to drive our Nation's manufacturing, transportation, agriculture, and defense industries, and to sustain the basics of modern life and military preparedness. Caused by the harmful and shortsighted policies of the previous administration, our Nation's inadequate energy supply and infrastructure causes and makes worse the high energy prices that devastate Americans, particularly those living on low- and fixed-incomes.

This active threat to the American people from high energy prices is exacerbated by our Nation's diminished capacity to insulate itself from hostile foreign actors. Energy security is an increasingly crucial theater of global competition. In an effort to harm the American people, hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets. An affordable and reliable domestic supply of energy is a fundamental requirement for the national and economic security of any nation.

The integrity and expansion of our Nation's energy infrastructure—from coast to coast—is an immediate and pressing priority for the protection of the United States' national and economic security. It is imperative that the Federal government puts the physical and economic wellbeing of the American people first.

Moreover, the United States has the potential to use its unrealized energy resources domestically, and to sell to international allies and partners a reliable, diversified, and affordable supply of energy. This would create jobs and economic prosperity for Americans forgotten in the present economy, improve the United States' trade balance, help our country compete with hostile foreign powers, strengthen relations with allies and partners, and support international peace and security. Accordingly, our Nation's dangerous energy situation inflicts unnecessary and perilous constraints on our foreign policy.

The policies of the previous administration have driven our Nation into a national emergency, where a precariously inadequate and intermittent energy supply, and an increasingly unreliable grid, require swift and decisive action. Without immediate remedy, this situation will dramatically deteriorate in the near future due to a high demand for energy and natural resources to power the next generation of technology. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy and the integrity of our Nation's electrical grid. Our Nation's current inadequate development of domestic energy resources leaves us vulnerable to hostile foreign actors and poses an imminent and growing threat to the United States' prosperity and national security.

These numerous problems are most pronounced in our Nation's Northeast and West Coast, where dangerous State and local policies jeopardize our Nation's core national defense and security needs, and devastate the prosperity of not only local residents but the entire United States population. The United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy. In light of these findings, I hereby declare a national emergency.

Sec. 2. Emergency Approvals. (a) The heads of executive departments and agencies ("agencies") shall identify and exercise any lawful emergency authorities available to them, as well as all other lawful authorities they may possess, to facilitate the identification, leasing, siting, production, transportation, refining, and generation of domestic energy resources, including, but not limited to, on Federal lands. If an agency assesses that use of either Federal eminent domain authorities or authorities afforded under the Defense Production Act (Public Law 81–774, 50 U.S.C. 4501 *et seq.*) are necessary to achieve this objective, the agency shall submit recommendations for a course of action to the President, through the Assistant to the President for National Security Affairs.

(b) Consistent with 42 U.S.C. 7545(c)(4)(C)(ii)(III), the Administrator of the Environmental Protection Agency, after consultation with, and concurrence by, the Secretary of Energy, shall consider issuing emergency fuel waivers to allow the year-round sale of E15 gasoline to meet any projected temporary shortfalls in the supply of gasoline across the Nation.

Sec. 3. Expediting the Delivery of Energy Infrastructure. (a) To facilitate the Nation's energy supply, agencies shall identify and use all relevant lawful emergency and other authorities available to them to expedite the completion of all authorized and appropriated infrastructure, energy, environmental, and natural resources projects that are within the identified authority of each of the Secretaries to perform or to advance.

(b) To protect the collective national and economic security of the United States, agencies shall identify and use all lawful emergency or other authorities available to them to facilitate the supply, refining, and transportation of energy in and through the West Coast of the United States, Northeast of the United States, and Alaska.

(c) The Secretaries shall provide such reports regarding activities under this section as may be requested by the Assistant to the President for Economic Policy.

Sec. 4. Emergency Regulations and Nationwide Permits Under the Clean Water Act (CWA) and Other Statutes Administered by the Army Corps of Engineers. (a) Within 30 days from the date of this order, the heads of all agencies, as well as the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works shall:

> (i) identify planned or potential actions to facilitate the Nation's energy supply that may be subject to emergency treatment pursuant to the regulations and nationwide permits promulgated by the Corps, or jointly by the Corps and EPA, pursuant to section 404 of the Clean Water Act, 33 U.S.C. 1344, section 10 of the Rivers and Harbors Act of March 3, 1899, 33 U.S.C. 403, and section 103 of the Marine Protection Research and Sanctuaries Act of 1972, 33 U.S.C. 1413 (collectively, the "emergency Army Corps permitting provisions"); and
>
> (ii) shall provide a summary report, listing such actions, to the Director of the Office of Management and Budget ("OMB"); the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works; the Assistant to the President for Economic Policy; and the Chairman of the Council on Environmental Quality (CEQ). Such report may be combined, as appropriate, with any other reports required by this order.

(b) Agencies are directed to use, to the fullest extent possible and consistent with applicable law, the emergency Army Corps permitting provisions to facilitate the Nation's energy supply.

(c) Within 30 days following the submission of the initial summary report described in subsection (a)(ii) of this section, each department and agency shall provide a status report to the OMB Director; the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works; the Director of the National Economic Council; and the Chairman of the CEQ. Each such report shall list actions taken within subsection (a)(i) of this section, shall list the status of any previously reported planned or potential actions, and shall list any new planned or potential actions that fall within subsection (a)(i). Such status reports shall thereafter be provided to these officials at least every 30 days for the duration of the national emergency and may be combined, as appropriate, with any other reports required by this order.

(d) The Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works, shall be available to consult promptly with agencies and to take other prompt and appropriate action concerning the application of the emergency Army Corps permitting provisions. The Administrator of the EPA shall provide prompt cooperation to the Secretary of the Army and to agencies in connection with the discharge of the responsibilities described in this section.

Sec. 5. Endangered Species Act (ESA) Emergency Consultation Regulations. (a) No later than 30 days from the date of this order, the heads of all agencies tasked in this order shall:

> (i) identify planned or potential actions to facilitate the Nation's energy supply that may be subject to the regulation on consultations in emergencies, 50 C.F.R. 402.05, promulgated by the Secretary of the Interior and the Secretary of Commerce pursuant to the Endangered Species Act ("ESA"), 16 U.S.C. 1531 *et seq*.; and
>
> (ii) provide a summary report, listing such actions, to the Secretary of the Interior, the Secretary of Commerce, the OMB Director, the Director of the National Economic Council, and the Chairman of CEQ. Such report may be combined, as appropriate, with any other reports required by this order.

(b) Agencies are directed to use, to the maximum extent permissible under applicable law, the ESA regulation on consultations in emergencies, to facilitate the Nation's energy supply.

(c) Within 30 days following the submission of the initial summary report described in subsection (a)(ii) of this section, the head of each agency shall provide a status report to the Secretary of the Interior, the Secretary of Commerce, the OMB Director, the Director of the National Economic Council, and the Chairman of CEQ. Each such report shall list actions taken within the categories described in subsection (a)(i) of this section, the status of any previously reported planned or potential actions, and any new planned or potential actions within these categories. Such status reports shall thereafter be provided to these officials at least every 30 days for the duration of the national emergency and may be combined, as appropriate, with any other reports required by this order. The OMB Director may grant discretionary exemptions from this reporting requirement.

(d) The Secretary of the Interior shall ensure that the Director of the Fish and Wildlife Service, or the Director's authorized representative, is available to consult promptly with agencies and to take other prompt and appropriate action concerning the application of the ESA's emergency regulations. The Secretary of Commerce shall ensure that the Assistant Administrator for Fisheries for the National Marine Fisheries Service, or the Assistant Administrator's authorized representative, is available for such consultation and to take such other action.

Sec. 6. Convening the Endangered Species Act Committee. (a) In acting as Chairman of the Endangered Species Act Committee, the Secretary of the Interior shall convene the Endangered Species Act Committee not less than quarterly, unless otherwise required by law, to review and consider any lawful applications submitted by an agency, the Governor of a State, or any applicant for a permit or license who submits for exemption from obligations imposed by Section 7 of the ESA.

(b) To the extent practicable under the law, the Secretary of the Interior shall ensure a prompt and efficient review of all submissions described in subsection (a) of this section, to include identification of any legal deficiencies, in order to ensure an initial determination within 20 days of receipt and the ability to convene the Endangered Species Act Committee to resolve the submission within 140 days of such initial determination of eligibility.

(c) In the event that the committee has no pending applications for review, the committee or its designees shall nonetheless convene to identify obstacles to domestic energy infrastructure specifically deriving from implementation of the ESA or the Marine Mammal Protection Act, to include regulatory reform efforts, species listings, and other related matters with the aim of developing procedural, regulatory, and interagency improvements.

Sec. 7. Coordinated Infrastructure Assistance. (a) In collaboration with the Secretaries of Interior and Energy, the Secretary of Defense shall conduct an assessment of the Department of Defense's ability to acquire and transport the energy, electricity, or fuels needed to protect the homeland and to conduct operations abroad, and, within 60 days, shall submit this assessment to the Assistant to the President for National Security Affairs. This assessment shall identify specific vulnerabilities, including, but not limited to, potentially insufficient transportation and refining infrastructure across the Nation, with a focus on such vulnerabilities within the Northeast and West Coast regions of the United States. The assessment shall also identify and recommend the requisite authorities and resources to remedy such vulnerabilities, consistent with applicable law.

(b) In accordance with section 301 of the National Emergencies Act (50 U.S.C. 1631), the construction authority provided in section 2808 of title 10, United States Code, is invoked and made available, according to its terms, to the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works, to address any vulnerabilities identified in the assessment mandated by subsection (a). Any such recommended actions shall be submitted to the President for review, through the Assistant to the President for National Security Affairs and the Assistant to the President for Economic Policy.

Sec. 8. Definitions. For purposes of this order, the following definitions shall apply:

(a) The term "energy" or "energy resources" means crude oil, natural gas, lease condensates, natural gas liquids, refined petroleum products, uranium, coal, biofuels, geothermal heat, the kinetic movement of flowing water, and critical minerals, as defined by 30 U.S.C. 1606 (a)(3).

(b) The term "production" means the extraction or creation of energy.

(c) The term "transportation" means the physical movement of energy, including through, but not limited to, pipelines.

(d) The term "refining" means the physical or chemical change of energy into a form that can be used by consumers or users, including, but not limited to, the creation of gasoline, diesel, ethanol, aviation fuel, or the beneficiation, enrichment, or purification of minerals.

(e) The term "generation" means the use of energy to produce electricity or thermal power and the transmission of electricity from its site of generation.

(f) The term "energy supply" means the production, transportation, refining, and generation of energy.

Sec. 9. General Provisions. (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of OMB relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.

DONALD J. TRUMP

The White House,
January 20, 2025.

[Filed with the Office of the Federal Register, 11:15 a.m., January 28, 2025]

NOTE: This Executive order was published in the *Federal Register* on January 29.

Categories: Executive Orders : National energy emergency, declaration.

Subjects: Army Corps of Engineers, U.S.; Assistant Secretary of the Army for Civil Works; Council on Environmental Quality; Critical minerals, supply chain improvements; Energy grid infrastructure, improvement efforts; National Economic Council; National energy emergency declaration; National Security Adviser; Office of Management and Budget; Oil and gas drilling, Federal oversight and regulation; Oil and natural gas, domestic production; Secretary of Commerce; Secretary of the Army; Secretary of the Interior.

DCPD Number: DCPD202500123.

EXHIBIT 45

ECONOMY
+ENVIRONMENT

To: Policymakers, media, businesses, and other interested parties

From: Michael Timberlake, E2

Date: December 12 ,2025

Subject: Clean Economy Works: November 2025 Analysis

INTRODUCTION

This Clean Economy Works (CEW) analysis is part of E2's ongoing monthly tracking of large-scale clean energy project announcements, cancellations, closures, and downsizes across the United States. This analysis monitors private-sector investment in clean energy manufacturing, generation, and grid infrastructure projects since federal energy tax credits were passed in August 2022. The tracking excludes projects that began, were proposed, sited, or in anyway began development prior to the federal Inflation Redution Act (IRA), as well as those funded entirely by federal sources or lacking specific geographic data. CEW measures key indicators including investment value, job creation or losses, project types (manufacturing, generation, research and development), and distribution by sector, state, and congressional district.

Since 2025, this analysis began to include all project cancellations, closures, and downsizings going back to August 2022 due to rising business uncertainty about the future of U.S. clean energy policy, culiminating in the rollback and restriction of energy tax credits included in the federal tax and spending bill passed in July 2025. E2's methodology excludes temporary delays or ownership transfers that do not impact production capacity. E2's tracking of cancelled and closed projects includes developments that may not have been counted as an announcement because they had been proposed, announced, broken ground, or opened prior to August 2022.

This dataset provides a comprehensive look at the evolving U.S. clean energy economy—highlighting the impact of federal policy changes, supply chain dynamics, and market shifts on America's clean energy workforce and investment pipeline.

OVERVIEW

Clean energy project activity in November remained subdued, with companies announcing only five new large-scale manufacturing projects totaling $550 million in investment. While this marks a modest uptick in announcement activity over the previous few months, November also saw the lowest level of project abandonment in over a year. Still, the single cancellation—a $575 million battery storage project in Missouri—was enough to push losses above new investment again.

Through November, cancellations, closures, and downsizes continue to outpace new announcements nearly **three to one** in both capital investment and job impacts. In total, companies have abandoned more than **$32 billion** in clean energy investments and nearly **40,000 jobs** so far in 2025, compared to just **$12 billion** in new investment and **19,000** newly announced jobs.

The trends reinforce a central theme of the year: while U.S. clean energy manufacturing continues to expand in pockets, a growing number of companies are reversing course amid uncertainty over long-term federal policy signals—undermining the gains achieved after federal enery tax credits were passed in 2022 and threatening future U.S. global competitiveness.

CANCELLATION FINDINGS

November saw the **fewest cancellations since November 2024**, but the single project lost—a **$575 million** ICL Group battery storage manufacturing facility in Missouri—underscores the scale of capital at stake. The project's termination also eliminated **150 expected jobs**.

Battery and storage projects represent the largest single category of cancellations since August 2022, accounting

Fifty-two large-scale clean energy projects have been canceled, closed, or downsized in 2025—more than any previous year since E2 began tracking. These projects were expected to create at least **39,000 new jobs** and included **more than $32 billion** in planned investments that are now lost.

- **Manufacturing facilities** account for nearly all losses—accounting for **45 of the 51 projects abandoned in 2025** and **over 29,000 jobs** and **$24.2 billion** in investment lost.
- EV and battery/storage projects continue to drive the majority of cancellations: **24 EV projects** and **26 battery/storage projects** have been abandoned since 2025
- **Republican congressional districts** have experienced the greatest economic fallout: **37 canceled projects**, **21,916 lost jobs**, and **$16.9 billion** in abandoned investments compared with **25 projects**, **13,398 jobs**, and **$10.4 billion** in lost investment in **Democratic-held districts**, and **13 projects**, **4,378 jobs**, and **$4.6 billion** in lost investment where the specific district is yet to be the determined.

ANNOUNCEMENT FINDINGS

Companies announced five new clean energy manufacturing projects in November with a combined estimated investment of **$550 million** and **at least 1,800 jobs**. Activity was concentrated in the Southeast:

- **First Solar** announced a **$330 million** solar module manufacturing plant in South Carolina, the largest investment and jobs announcement of the month.
- **Georgia** emerged as the top state for new November activity, with **three projects** expected to create **700 jobs** and invest **$63 million**.
- Manufacturing continues to dominate new activity, representing **over 80 percent** of all projects tracked by E2.

Since E2 began tracking announcements in August 2022, 422 new large-scale propjects have been announced that are still continuing or are now operational. These projects are expected to invest more than $132 billion and employ at least 125,925 permanent workers once completed according to company estimates*.

CONCLUSION

November's project activity offers a mixed picture: modest new investment, comparatively low monthly cancellations, but continued net losses that signal persistent fragility across the U.S. clean energy manufacturing ecosystem. Companies announced five new projects totaling **$550 million**—including major solar and grid equipment investments in the Southeast—yet a single **$575 million** cancellation in Missouri was enough to push monthly losses above gains once again. This imbalance is emerging at a moment when U.S. clean energy manufacturing should be accelerating; instead, 2025 is now the weakest net year for clean energy industrial growth since E2 began tracking in August 2022.

This contrast highlights a sector increasingly sensitive to policy uncertainty. Even projects that had begun hiring or early development are being reconsidered, leaving communities with fewer jobs and delayed economic growth. At the same time, the continued flow of new manufacturing announcements in places like Georgia and South Carolina shows that some targeted, high-value investments will still continue to move forward.

Taken together, November's data show a clean energy manufacturing sector that remains active but volatile. Announcements continue, but cancellations are increasingly shaping the net outcome, reinforcing how quickly investment momentum can shift and how consequential individual project decisions are for jobs, supply chains, and local economies.

**Job and investment impacts from announcements and cancellations are based on company estimates or reporting on closed and downsized facilities. About one-third of all projects announced do not include either a job estimate or investment estimate.*

ABOUT THIS ANALYSIS

Announcements

Projects that began development, were proposed, or applied for local and state approval before the passage of the Inflation Reduction Act (IRA) are not included. This analysis also does not include investments in which the federal government has provided financial resources for the complete project, lease sales, projects in which an announcement was made but lacked specific geographic information, etc. Details on projects came from news reports on new and related projects; press releases from companies announcing new developments; and government announcements.

Cancellations, Closures, Downsizes

This tracking includes all projects, plants, operations, or expansions that were cancelled or closed since passage of the IRA in August 2022. This does not include announced layoffs that are not associated with a project downsizing unless there is a stated decease in production output. This list also does not include the transfer of project ownership, if production will continue under the new ownership, power purchasing agreements, or other similar type of announcements. Project delays or idling of facilities are not included unless there in an announced decrease in production or investment or unless the project will need to be restarted to proceed in the future.

APPENDICES

Tables detailing the 422 large-scale clean energy project announcements and 75 project cancellations, clsoures, and downsizes made since August 16, 2022 are below.

- **Appendix A |** Latest projects announced
- **Appendix B |** Latest project abandonments
- **Appendix C |** Projects announced by year 2022- 202
- **Appendix D |** Total projects abandoned by year 2022-2025
- **Appendix E |** Total projects announced by sector; Aug. 2022 –
- **Appendix F |** Total projects abandoned by sector; Aug. 2022 –
- **Appendix G |** Total projects announced by type; Aug. 2022 –
- **Appendix H |** Total projects abandoned by type; Aug. 2022 –
- **Appendix I |** Total projects announced by congressional district; Aug. 2022 –
- **Appendix J |** Total projects abandoned by congressional district; Aug. 2022 –
- **Appendix K |** Total projects announced by state; Aug. 2022 –
- **Appendix L |** Total projects abandoned by state; Aug. 2022 -

An updated list and map of the clean energy announcements a tracked by E2 can be found at https://e2.org/project-tracker.

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APPENDIX I | Latest project announcements

Date	Developer	State	Source	Sector	Type	Jobs	Investment
10/29	ElringKlinger	SC	Link	Battery/Storage	Manufacturing	294	$68,500,000
11/12	Hyosung	TN	Link	Grid, Transmission and Electrification	Manufacturing	240	$157,000,000
11/14	First Solar	SC	Link	Solar	Manufacturing	600	$330,000,000
11/14	Socomec	GA	Link	Grid, Transmission and Electrification	Manufacturing	300	$10,000,000
11/20	Georgia Transformer	GA	Link	Grid, Transmission and Electrification	Manufacturing	400	$40,000,000
11/24	NeoVolta	GA	Link	Battery/Storage	Manufacturing		$13,000,000

APPENDIX II | Latest project abandonments

Date	Developer	State	Source	Status	Sector	Type	Jobs Lost	Investment Lost
11/12	ICL Group	MO	Link	Canceled	Battery/Storage	Manufacturing	150	$574,000,000

APPENDIX III | total projects announced by year 2022-2025

Year	Projects	Investment Announced	Jobs Announced
2022	70	$40,369,500,000	28,831
2023	191	$64,144,200,000	59,165
2024	85	$15,863,729,000	18,820
2025	76	$11,992,750,000	19,109
Total	**422**	**$132,370,179,000**	**125,925**

APPENDIX IV | total projects cancelled, closed, downsized by year 2022-2025

Year	Projects	Investment Lost	Jobs Lost
2022	0	0	0
2023	9	$744,000,000	2,052
2024	14	$1,971,500,000	7,546
2025	52	$29,341,300,000	30,094
Total	**75**	**$32,056,800,000**	**39,692**

APPENDIX V | total projects announced by sector; Aug. 2022 —

Sector	Projects	Investment Announced	Jobs Announced
Battery/Storage	67	$40,580,000,000	26,647
Biofuel	1	$0	40
Energy Efficiency	1	$6,000,000	200
EV	153	$80,534,500,000	63,464
Geothermal	1	$0	0

Grid, Transmission and Electrification	51	$5,971,609,000	10,863
Hydrogen	20	$7,409,100,000	2,977
Semiconductor	0	$5,375,000,000	1,970
Solar	100	$18,450,870,000	33,533
Wind	28	$4,060,500,000	3,254

**totals will not match overall figures as some projects are categorized into multiple sectors*

APPENDIX VI | total projects cancelled, closed, downsized by sector; Aug. 2022 —

Sector	Projects	Investment Lost	Jobs Lost
Battery/Storage	31	$19,044,500,000	17,451
Biofuel	0	$0	0
Energy Efficiency	0	$0	0
EV	40	$18,074,800,000	24,354
Geothermal	0	$0	0
Grid, Transmission and Electrification	1	$150,000,000	600
Hydrogen	4	$1,460,000,000	1,080
Semiconductor	0	$0	0
Solar	9	$2,850,000,000	2,937
Wind	7	$1,500,000,000	2,960

**totals will not match overall figures as some projects are categorized into multiple sectors*

APPENDIX VII | total projects announced by type; Aug. 2022 —

Type	Projects	Investment Announced	Jobs Announced
Generation	50	$11,276,370,000	3,746
Manufacturing	344	$120,216,409,000	119,801
Recycling, Repair, and Maintenance	16	$148,500,000	872
R&D	9	$698,900,000	1,476

APPENDIX VIII | total projects cancelled, closed, downsized by type; Aug. 2022 —

Type	Projects	Investment Lost	Jobs Lost
Generation	9	$4,520,000,000	2,730
Manufacturing	65	$27,536,800,000	36,824
Recycling, Repair, and Maintenance	0	$0	0
R&D	1	$0	138

APPENDIX IX | total projects announced by congressional district; Aug. 2022 —

Party	Projects	Investment Announced	Jobs Announced
Republican	261	$106,255,329,000	90,605
Democratic	135	$22,486,700,000	31,240
Unknown	27	$3,628,150,000	4,080

APPENDIX X | total projects cancelled, closed, downsized by congressional district; Aug. 2022 —

Party	Projects	Investment Lost	Jobs Lost
Republican	37	$16,938,000,000	21,916
Democratic	25	$10,488,800,000	13,398
Unknown	13	$4,630,000,000	4,378

APPENDIX XI | total projects announced by state; Aug. 2022 —

State	Projects	Investment Announced	Jobs Announced
Alabama	10	$2,819,200,000	1,711
Arizona	12	$6,225,000,000	2,962
Arkansas	3	$250,000,000	525
California	17	$3,750,000,000	1,810
Colorado	5	$40,000,000	820
Connecticut	4	$24,800,000	100
Florida	6	$176,000,000	450
Georgia	38	$13,269,000,000	18,080
Illinois	12	$2,768,600,000	3,108
Indiana	12	$7,279,000,000	6,922
Iowa	4	$17,000,000	102
Kansas	3	$110,000,000	180
Kentucky	10	$4,558,900,000	2,761
Louisiana	7	$1,728,000,000	1,138
Maine	1	$6,000,000	200
Maryland	4	$316,370,000	325
Massachusetts	6	$45,700,000	1,041
Michigan	32	$10,119,800,000	9,249
Minnesota	5	$207,200,000	875
Mississippi	7	$2,291,950,000	2,990
Missouri	5	$250,000,000	591
Nebraska	1	n/a	n/a
Nevada	7	$6,600,000,000	5,250
New Hampshire	2	$16,300,000	n/a

New Jersey	1	n/a	n/a
New Mexico	7	$2,185,000,000	3,442
New York	13	$791,000,000	1,809
North Carolina	29	$20,365,259,000	11,695
North Dakota	1	n/a	n/a
Ohio	19	$7,093,300,000	4,934
Oklahoma	5	$4,270,000,000	1,310
Oregon	2	$43,000,000	n/a
Pennsylvania	8	$583,500,000	1,738
Puerto Rico	1	n/a	800
Rhode Island	1	n/a	n/a
South Carolina	35	$14,991,000,000	15,077
Tennessee	27	$5,784,300,000	5,754
Texas	34	$9,696,000,000	14,132
Utah	3	$1,000,000,000	0
Vermont	1	n/a	12
Virginia	11	$1,712,000,000	2,130
West Virginia	4	$1,335,000,000	850
Wisconsin	7	$242,000,000	462
Alabama	10	$2,819,200,000	1,711

APPENDIX XII | total projects cancelled, closed, downsized by state Aug. 2022-Oct. 2025

State	Projects	Investment Lost	Jobs Lost
Alabama	1	n/a	45
Arizona	5	$1,750,000,000	3,895
Arkansas	1	n/a	545
California	3	$2,200,000,000	438
Colorado	5	$840,000,000	1,912
Georgia	4	$3,362,000,000	1,327
Illinois	3	$3,270,000,000	2,655
Indiana	1	$2,203,000,000	1,740
Kansas	1	n/a	900
Kentucky	2	$814,000,000	692
Massachusetts	2	$370,000,000	100
Michigan	14	$7,727,300,000	9,829
	1	$574,000,000	150
Mississippi	1	$500,000,000	2,000
New Jersey	3	n/a	1,300
New York	8	$3,000,000,000	1,770

North Carolina	1	$1,400,000,000	1,062
Ohio	3	$800,000,000	2,520
Oklahoma	3	$320,000,000	2,500
Oregon	1	n/a	418
South Carolina	3	$1,700,000,000	1,520
Tennessee	3	$600,000,000	1,010
Texas	1	n/a	150
Virginia	2	$309,000,000	350
Washington	2	$15,000,000	264
West Virginia	1	$150,000,000	600

E2 is a national, nonpartisan group of business leaders, investors, and professionals from every sector of the economy who advocate for smart policies that are good for the economy and good for the environment. Our members have founded or funded more than 2,500 companies, created more than 600,000 jobs, and manage more than $100 billion in venture and private equity capital.

EXHIBIT 46

U.S. DEPARTMENT of ENERGY

Energy Department Announces Termination of 223 Projects, Saving Over $7.5 Billion

The U.S. Department of Energy today announced the termination of 321 financial awards supporting 223 projects, resulting in a savings of approximately $7.56 billion dollars for American taxpayers.

Energy.gov

October 2, 2025

2 min

WASHINGTON—The U.S. Department of Energy (DOE) today announced the termination of 321 financial awards supporting 223 projects, resulting in a savings of approximately $7.56 billion dollars for American taxpayers. Following a thorough, individualized financial review, DOE determined that these projects did not adequately advance the nation's energy needs, were not economically viable, and would not provide a positive return on investment of taxpayer dollars.

The awards were issued by the Offices of Clean Energy Demonstrations (OCED), Energy Efficiency and Renewable Energy (EERE), Grid Deployment (GDO), Manufacturing and Energy Supply Chains (MESC), Advanced Research Projects Agency-Energy (ARPA-E) and Fossil Energy (FE).

"On day one, the Energy Department began the critical task of reviewing billions of dollars in financial awards, many rushed through in the final months of the Biden administration with inadequate documentation by any reasonable business standard," **Secretary Wright** said. "President Trump promised to protect taxpayer dollars and expand America's supply of affordable, reliable, and secure energy. Today's cancellation's deliver on that commitment. Rest assured, the Energy Department will continue reviewing awards to ensure that every dollar works for the American people."

Of the 321 financial awards terminated, 26% were awarded between Election Day and Inauguration Day. Those awards alone were valued at over $3.1 billion.

In May 2025, Secretary Wright issued a Secretarial Memorandum entitled, "Ensuring Responsibility for Financial Assistance," establishing a new policy for evaluating financial awards. The policy authorized program offices to request additional information from awardees. It also required that awards be reviewed on a case-by-case basis to identify waste, safeguard taxpayer dollars, protect America's national security, and advance President Trump's commitment to deliver affordable, reliable, and secure energy for the American people.

Using this review process, DOE evaluated each of these awards and determined that they did not meet the economic, national security or energy security standards necessary to justify continued investment.

As outlined in the Secretary's memorandum, award recipients have 30 days to appeal a termination decision. Some of the projects included in this announcement have already begun that process.

###

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Energy Department Announces $365 Million in Funding to Provide Overdue Support to Puerto Rico's Power Grid

September 30, 2025

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October 15, 2025

Media Inquiries:

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EXHIBIT 47

U.S. DEPARTMENT of ENERGY

Energy Reliability and Resilience

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Energy reliability is the ability of a power system to consistently deliver power to homes, buildings, and devices—even in the face of instability, uncontrolled events, cascading failures, or unanticipated loss of system components. Energy resilience is the ability of the grid, buildings, and communities to withstand and rapidly recover from power outages and continue operating with electricity, heating, cooling, ventilation, and other energy-dependent services. Energy resilience increases energy reliability and renewable energy sources can help support a resilient, reliable energy system.

Resilient, reliable energy is critical to the well-being of every American. It keeps life-saving hospital equipment and communications systems operating, buildings at safe temperatures with good ventilation, and American workers to go about their business without interruption. Energy infrastructure—facilities or equipment used to generate, deliver, process, or produce energy—that can withstand and quickly recover from disruptions is resilient and reliable infrastructure.

A resilient and reliable power system reduces the likelihood of long-duration outages over large service areas, limits the scope and impact of outages when they do occur, and rapidly restores power after an outage.

What Makes Energy Resilient?

Power outages can be caused by extreme weather, breaches in cybersecurity, high energy demand that overloads the electric grid, failure of aging equipment, and physical interference with equipment. Grid disturbances are changes in electrical voltage and frequency on the grid that can lead to power outages.

A resilient electric grid distribution system uses local resources, such as solar panels and battery storage in homes and buildings, to quickly reconfigure power flows and recover electricity services during a disturbance. The approach to modernize the grid and increase resilience focuses on integrating distributed energy resources, advanced controls, grid architecture, and emerging grid technologies at a regional scale.

Strong resilience measures in building energy codes can also ensure that new construction and major renovation projects minimize energy use, maximize comfort, and enhance potentially life-saving resilience benefits. Building owners and operators, communities, and local and state governments can strategically plan to increase resilience using these resources.

What Makes Energy Reliable?

When we diversify our energy mix by adding more types of energy to the grid, we increase our energy reliability. The rise of renewable power, which comes from unlimited energy resources, like wind, sunlight, water, and the Earth’s natural heat, has the potential to vastly improve the reliability of the American energy system. Currently, renewable energy generates about 21% of all U.S. electricity, and that percentage is rising quickly.

A reliable electric grid distribution system can continue to deliver electricity to homes and buildings regardless of any disruptions or disturbances. The approach to modernizing the grid to increase resilience and reliability focuses on integrating distributed energy resources, advanced controls, grid architecture, and emerging grid technologies at a regional scale. DOE efforts, like the Energy Storage Grand Challenge Roadmap and the Long Duration Storage Shot, will increase resilience. DOE's Grid Modernization Initiative works with public and private partners to develop concepts, tools, and technologies needed to measure, analyze, predict, protect, and control the grid of the future.

Improving Reliability Through Energy Storage

Energy storage technologies can improve energy reliability by making surplus energy available whenever it is needed, such as during a power outage.

Pumped storage hydropower is responsible for most U.S. commercial energy storage capacity and has been used for more than 100 years. Wind energy and solar energy can be captured and stored for later use with batteries, and researchers are investigating geothermal energy storage.

Energy storage is also essential to efficient transportation. EERE invests in research and development of hydrogen storage and batteries to ensure on- and off-road vehicles can reliably move people and goods from one place to another.

The U.S. Department of Energy's Energy Storage Grand Challenge is a comprehensive program to accelerate the development, commercialization, and use of next-generation energy storage technologies. As part of this program, the Long Duration Storage Shot™ aims to, within the decade, reduce the cost of grid-scale energy storage by 90% for systems that can provide energy for at least 10 hours in duration.

Energy Reliability and Resilience News

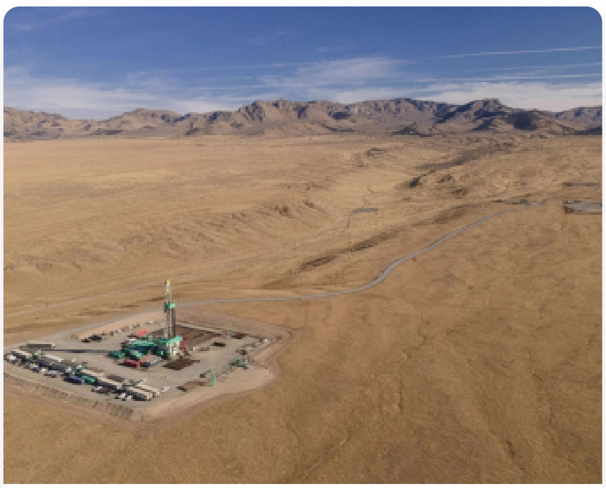

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EXHIBIT 48

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Washington, DC 20585

September 5, 2025

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RE: August 6, 2025 Submission

To Whom It May Concern:

Thank you for your August 6, 2025 submission on behalf of the Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York (collectively, the State AGs). The submission was titled "Motion to Intervene and Protective Request for Rehearing by the Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York" (Submission). It was not filed in any active docket.

On July 7, 2025, the U.S. Department of Energy (DOE) issued the Report on Strengthening U.S. Grid Reliability and Security (Resource Adequacy Report or RAR), fulfilling Section 3(b) of Executive Order 14262. The RAR presents a unified, transparent methodology for assessing the reliability of the bulk power system and identifying regions at elevated risk of resource inadequacy under projected load growth and plant retirement scenarios. DOE developed this approach in coordination with NERC and leading industry experts to provide a consistent, data-driven framework for informing federal reliability interventions, particularly as the grid faces surging demand from AI-driven data centers, reindustrialization, and electrification.

In the Submission, the State AGs seek rehearing of the RAR under section 313 of the Federal Power Act (FPA).[1] An application for rehearing under section 313 of the FPA[2] may be filed only by a "person, electric utility, State, municipality, or State commission" that is "aggrieved" by "an order issued by [DOE]."[3] If these prerequisites are not met, there is no basis for rehearing. Here, we note that the RAR is simply a report that details the current condition of the United States electrical grid. It contains no directives, nor does it impose legal duties upon any party, including the State AGs. As such, it cannot be considered an "order" by which the State AGs are "aggrieved" within the meaning of section 313 of the FPA, as would be required to request rehearing. Accordingly, DOE will take no action on the Submission.

Sincerely,

Tina Francone

Tina Francone
Director of the Grid Deployment Office, Acting

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[1] Submission at 1.
[2] 16 U.S.C. § 825*l*(a).
[3] *Id.*

EXHIBIT 49

UNITED STATES OF AMERICA
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order TransAlta Centralia Generation	Order No. 202-25-11

**DECLARATION OF DAVID C. GOMEZ
IN SUPPORT OF
MOTION TO INTERVENE, REQUEST FOR REHEARING,
AND MOTION TO STAY BY STATE OF WASHINGTON**

I, David C. Gomez, declare under penalty of perjury under the laws of the state of Washington that the following is true and correct:

1. I am now and at all times mentioned have been a citizen of the United States, over the age of 18 years, competent to make this declaration, and I make this declaration from my own personal knowledge and judgment. The statements contained herein are my own, and not binding on the Washington Utilities and Transportation Commission in a future proceeding.

2. I am employed by the Washington Utilities and Transportation Commission (Commission) as a Regulatory Analyst. I perform accounting and financial analysis of regulated utility companies, as well as legislative and policy analysis specifically in the area of power costs. I have over ten years of experience in my present position. I have a master's in business administration from the University of St. Thomas.

3. I presented testimony on behalf of Commission Staff in Commission Docket UE-121373 regarding the Centralia Coal Transition Power Purchase Agreement (PPA)

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between Puget Sound Energy (PSE) and TransAlta Centralia Generation LLC (TransAlta) as well as monitoring PSE's annual compliance filings over the twelve-year term of the PPA.

4. I have reviewed the U.S. Department of Energy's Order No. 202-25-11 (DOE Order) as it relates to the continued operation of TransAlta's Centralia Unit 2 (Plant) beyond its planned retirement date of December 31, 2025. I cannot attest to the current state of maintenance of the Plant to operate after December 31, 2025 in compliance with DOE's Order as this is an unregulated merchant plant. DOE's Order requires TransAlta to provide the DOE by December 30, 2025, "with information concerning the measures it has taken and is planning to take to ensure the operational availability of Centralia Unit 2 consistent with this Order." Ex. 1. However, I provide in this declaration my expert opinion of the Plant's economics in light of DOE's order using publicly available information. Ex. 49-1 (*Centralia Power Plan Profile*, S&P Global, Market Intelligence, https://www.capitaliq.spglobal.com/apisv3/spg-webplatform-core/powerplant/powerplantprofile?id=2232 (last visited Jan. 6, 2026)). S&P Global Market Intelligence provides coverage of operational power plant units that file data with the U.S. Energy Information Administration (EIA) or are larger than 1 MW in North America, and 5 MW outside of North America. On January 1st the Plant's output will be subject to the requirements of Washington State's Climate Commitment Act (CCA) which will necessitate TransAlta's acquisition of emission allowances equal to its CO_2 output.

5. The imposition of CCA requirements post December 31, 2025, will fundamentally change the Plant's economic dispatch relative to Mid-C hourly market prices. The Plant's variable costs are more than doubled when emission allowance costs are included. This changes the Plant's merit order to be on par with a gas peaker plant. For the purposes of setting power cost rates, Staff relies on weather normalized load and hydro assumptions to model and forecast future electric market prices. Under weather normalized

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conditions, the Plant would not be economical to operate at its pre-December 2025 capacity factor as it would generate less than 100 hours annually (between 1-6 percent capacity factor) and earn less than half of the revenue TransAlta would need to recover the Plant's annual fixed costs of approximately $18 million. Ex. 49-2 (*Centralia Plant Financials*, S&P, Global Market Intelligence, https://www.capitaliq.spglobal.com/apisv3/spg-webplatform-core/powerplant/PlantProductionCostDetail?ID=2232 (last visited Jan. 6, 2026)). This can significantly change with extreme cold or hot weather events coupled with low hydro conditions like the 8-day MLK 2024 event, which was an extreme weather event cause by a confluence of factors such as prolonged unusually cold temperatures coupled with a low hydro (70 percent of normal, normal being 100 percent) and renewable generation. This can result in a situation where TransAlta could more than recover their annual fixed costs operating as a peaker. Assuming that the Plant is available and can ramp up from a cold state in time to respond to the extreme weather event as cited on the DOE Order. By my estimates, using historical Mid-C prices and the Plant's variable costs above, the MLK 2024 event would have generated over $40 million in revenue for TransAlta. However, the Plant operating as a peaker introduces significant operational and reliability issues of their own not discussed or considered in DOE's Order.

6. The DOE Order states the following:

> As a coal-fired facility, it would be difficult for the Centralia Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if TransAlta were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

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Ex. 1. The citation from the DOE Order above confirms the risk of relying on the Plant to stand by as a peaker and assuming that it could resume operations on short notice. In fact, since 2021 there has been a material increase in coal plant weighted equivalent (WEFOR) forced-outage rates nationally driven in part by increased cycling of units to accommodate variable energy resources. Ex. 49-3 (Georgia Butler, *Legacy Coal Plants are Getting More Unreliable, Cycling increases and deferred maintenance lead to higher forced outage rates*, Data Center Dynamics, News (Jun. 24, 2024), https://www.datacenterdynamics.com/en/news/legacy-coal-plants-are-getting-more-unreliable/)).

7. Conversion of the Plant to gas reduces its variable costs above by almost 60 percent (inclusive of emissions) thereby increasing its capacity factor to almost 50 percent. In addition, the planned conversion of the Plant to natural gas provides a more dependable load following resource complimentary to the Pacific Northwest's increasing level of renewable generation. As such, the conversion of the Plant represents a lower risk/economical pathway towards contributing to regional adequacy. DOE's Order introduces uncertainty regarding the expected timeline for the Plant's conversion.

8. The DOE Order states the following:

> In its 2025–2026 Winter Reliability Assessment, NERC finds that the WECC Northwest region, which includes Montana, Oregon, Washington, and parts of northern California and northern Idaho, is at elevated risk during periods of extreme weather. The assessment notes that "there is sufficient capacity in the area for expected peak conditions; however, [balancing authorities] are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year.

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Ex. 1. The NERC assessment referenced in DOE's Order above does not account for the current forecast of hydro for the region. In the Pacific Northwest, hydro accounts for fifty percent of the regions power generation. The National Oceanic and Atmospheric Administration's Northwest River Forecast Center (NRFC) publishes 120-day forecasts (percent of average) hydrology which, along with mountain snowpack, is a leading indicator of near-term expected hydro generation. I examined NRFC's most recent forecast (December 29, 2025 – April 28, 2026) which shows the Northwest region's rivers at 114 percent of average (average being 100 percent). The Northwest's last major winter event (MLK 2024) occurred in a low water year (approximately 70 percent of average). Ex. 49-4 (Federal Hydro System Powers Region Through Artic Blast, Bonneville Power Administration (Jan. 31, 2024), https://www.bpa.gov/about/newsroom/news-articles/20240131-federal-hydro-system-powers-region-through-arctic-blast). In spite of this challenge, the Region weathered the event without loss of load largely as a result of the responsiveness of the Federal Dams and the Pacific DC Intertie (Path 65). As a result, I conclude that the regional balancing authorities are well positioned this winter to ride out an extreme weather event this winter which obviates the need to extend coal operations and potentially delay the conversion of the Plant.

DATED this 12th day of January, in Thurston County, Washington.

DAVID C. GOMEZ

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EXHIBIT 49-1

Centralia | Power Plant Profile

OWNER	ULTIMATE PARENT	OPERATING CAPACITY OWNERSHIP (%)	PLANNED CAPACITY OWNERSHIP (%)
TransAlta Energy Corp	TransAlta Corp	100.000	-

Operator

TransAlta Centralia Generation

Site Information

City or County	Lewis County
State, Province, or Admin Region	Washington
Country	USA
NERC Region and Subregion	WECC/NWPP (100.00%)
Planning Area	Bonneville Power Administration (50.00%) Puget Sound Energy, Inc. (50.00%)
Balancing Authority	Bonneville Power Administration (50.00%) Puget Sound Energy, Inc. (50.00%)
Interconnected Utility	Bonneville Power Admin
Water Source	Skookumchuck River
Other Plants at Site	Centralia Gas

Recent News & Notes

EXCLUSIVE US coal producers cheer DOE use of emergency orders, hope for more in 2026 2 days ago

EXTRA The Daily Dose: BP names next CEO; PJM capacity prices clear at record highs 12/18/2025

EXTRA DOE orders Washington state's last coal plant to keep operating 12/17/2025

EXTRA US House moves to give FERC authority to delay generator retirements for 5 years 12/17/2025

TransAlta signs tolling deal to convert Wash. coal-fired plant to natural gas 12/9/2025

Plant Description

Operating Status	Operating
Current Operating Capacity (MW)	670.0
Prime Mover	Steam Turbine
Primary Fuel	Subbituminous Coal
Secondary Fuel	Distillate Fuel Oil
Fuel Group(s)	Coal, Oil
Fuel Conversion Status	Proposed
Co-Fired Units?	No
Fuel Switching Units?	No
Year First Unit in Service	1971
Cogenerator?	No
Offshore?	No
Regulatory Status	Merchant Unregulated

Summary Operating Data - 2024

Operating Capacity (MW)	670.0
Net Generation (MWh)	2,831,744
Heat Rate (Btu/kWh)	11,750
Capacity Factor (%)	48.12
Total Operating & Maintenance Expense per MWh ($/MWh)	35.30

Unit Details

				CAPACITY (MW)				
UNIT NAME	GENERATION TECHNOLOGY	TECHNOLOGY DETAIL	UNIT NAMEPLATE CAPACITY (MW)	SUMMER NET CAPACITY (MW)	WINTER NET CAPACITY (MW)	PRIMARY FUEL	OPERATING STATUS	ONLINE DATE
1	Steam Turbine (ST)	Subcritical	729.9	670.0	670.0	Refined Coal	Retired	Dec - 1971
2	Steam Turbine (ST)	Subcritical	729.9	670.0	670.0	Subbituminous Coal	Operating	1971

Unit Fuel Conversions

UNIT NAME	FUEL CONVERSION STATUS	OLD FUEL	NEW FUEL	ONLINE DATE
2	Proposed	Coal	Gas	Dec - 2028

Project Summary

PHASE	PROJECT TYPE	GENERATION TECHNOLOGY	TECHNOLOGY BREAKOUT	CURRENT DEVELOPMENT STATUS	NEW CAPACITY (MW)	PRIMARY FUEL	ESTIMATED COMPLETION DATE	ESTIMATED PROJECT COSTS ($000)	ESTIMATED PROJECT COST ($/KW)
1	Environmental	Steam Turbine (ST)	Retrofit of Mercury Control	Completed	1,340.0	Subbituminous Coal	2012	NA	NA
2	Environmental	Steam Turbine (ST)	Retrofit of NOx Control	Completed	1,340.0	Subbituminous Coal	Jan - 2013	NA	NA
3	Generation	Steam Turbine (ST)	Retirement of 1 ST	Completed	(670.0)	Refined Coal	Dec - 2020	NA	NA

Power Purchase Agreements

COUNTERPARTY	CONTRACTED (MW)	CONTRACT START DATE	CONTRACT END DATE	CONTRACT TERM (YEARS)
Puget Sound Energy, Inc.	180.0	Dec - 2014	Dec - 2015	1

COUNTERPARTY	CONTRACTED (MW)	CONTRACT START DATE	CONTRACT END DATE	CONTRACT TERM (YEARS)
Puget Sound Energy, Inc.	280.0	Dec - 2015	Dec - 2016	1
Puget Sound Energy, Inc.	300.0	Dec - 2024	Dec - 2025	1
Puget Sound Energy, Inc.	380.0	Dec - 2016	Dec - 2024	8
Puget Sound Energy, Inc.	670.0	Dec - 2028	Dec - 2044	16

S&P Global Market Intelligence guarantees coverage of operational power plant units that file data with the EIA or are larger than 1 MW in North America, and 5 MW outside of North America. S&P Global Market Intelligence does not comprehensively cover operational plants below this threshold. S&P Global Market Intelligence comprehensively covers power projects (generation or environmental) with units over 1 MW within North America, and over 5 MW outside of North America, which supply more than 50% of power generated to the grid.

Due to the variability of sources reporting values on in-development projects, S&P Global Market Intelligence accuracy on the following fields is guaranteed to be within 10%: unit capacity (nameplate, summer and winter) and project costs (minimum and maximum). Online date is guaranteed within 6 months for operational plants.

S&P Global Market Intelligence guarantees coverage on Power Purchase Agreements for plants first tracked after Jan - 2011 and with a unit greater than 100 MW.

EXHIBIT 49-2

Centralia | Plant Financials

Periods : Last Five Years

	2020 Y	2021 Y	2022 Y	2023 Y	2024 Y
Operational Statistics					
Operating Capacity (MW)	1,340.00	670.00	670.00	670.00	670.00
Summer Peak Capacity (MW)	1,340.00	670.00	670.00	670.00	670.00
Winter Peak Capacity (MW)	1,340.00	670.00	670.00	670.00	670.00
Net Generation (MWh)	5,149,037	3,114,315	3,555,037	4,143,372	2,831,744
Capacity Factor (%)	43.75	53.06	60.57	70.60	48.12
Heat Rate	11,257	11,414	11,501	11,627	11,750
SNL Modeled Production Costs					
Non-Fuel Non-Allowance Variable O&M Cost ($)	18,440,313	11,188,086	12,025,278	13,028,773	12,577,837
Allowance Costs ($)	NA	NA	NA	NA	NA
Non-Fuel Variable O&M Cost ($)	18,440,313	11,188,086	12,025,278	13,028,773	12,577,837
Fuel Costs ($)	114,125,790	70,634,313	95,722,104	101,293,372	69,505,534
Variable O&M Cost ($)	132,566,103	81,822,399	107,747,382	114,322,145	82,083,371
Non-Fuel Variable O&M Costs per MWh ($/MWh)	3.58	3.59	3.38	3.14	4.44
Fuel Cost per MWh ($/MWh)	22.16	22.68	26.93	24.45	24.55
Fixed O&M Cost ($)	33,681,845	16,279,612	16,790,063	17,714,338	17,873,181
Fixed O&M Cost per kW-Year ($/kW-year)	25.14	24.30	25.06	26.44	26.68
Total Operating & Maintenance Expense ($)	166,247,948	98,102,011	124,537,445	132,036,483	99,956,553
Total Operating & Maintenance Expense per MWh ($/MWh)	32.29	31.50	35.03	31.87	35.30

Note: S&P Global Market Intelligence reports generation and fuel consumption at the power plant and prime mover level, gathered from the Energy Information Administration forms 923 and 906 (EIA 923/906). Data from these forms is provided in both a preliminary/monthly report and a final annual report. The EIA does not provide a formal deadline for publication. Monthly reports are published 3 to 6 months after month-end, and annual data may not be published for 24 months from year-end.

In the case of pumped storage facilities, Net Generation (MWh) represents the total generation before energy used for pumping.

Additional data is sourced from the Federal Energy Regulatory Commission Form 1 (FERC Form 1) and the Environmental Protection Agency's Continuous Emissions Monitoring Systems (CEMS). In the absence of current-year filings, S&P Global Market Intelligence utilizes regression analysis to generate cost estimates. Inputs to the model are taken from the EIA 923, FERC Form 1 and CEMS.

EXHIBIT 50

UNITED STATES OF AMERICA
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order TransAlta Centralia Generation	Order No. 202-25-11

**DECLARATION OF ANDREW REEVES
IN SUPPORT OF
MOTION TO INTERVENE, REQUEST FOR REHEARING,
AND MOTION TO STAY BY STATE OF WASHINGTON**

I, Andrew Reeves, declare under penalty of perjury under the laws of the state of Washington that the following is true and correct:

Background and Qualifications

1. I am a regulatory analyst for the Public Counsel Unit of the State of Washington Attorney General's Office. I am submitting this affidavit on behalf of the State of Washington in support of its petition for rehearing on the Department of Energy (DOE) Order 202-25-4. I advocate for ratepayers in utility rate cases and perform financial and regulatory analysis on energy filings. Previously, I worked for Seattle City Light on energy affordability programs. I earned a Master of Public Administration from the University of Washington in 2020.

Purpose of This Declaration

2. The purpose of this declaration is to explain the existing reliability safeguards for both investor-owned utilities and public electric utilities in the State of Washington. As discussed later, individual utilities and the region have taken steps to maintain a necessary level of reliability while planning for transition to a clean energy future.

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<u>Are there Safeguards Already in Place for Region-Wide Extreme Weather Events?</u>

3. Washington utilities and oversight agencies manage reliability during extreme-weather events in several ways including individual utility Integrated Resource Plans (IRP), access to the Western Energy Imbalance Market, and the Western Resource Adequacy Program.

4. The Western Energy Imbalance Market (WEIM) is a market platform for balancing authorities in the West that enables real-time supply and demand resource balancing. Ex. 50-8 (*Western Energy Imbalance Market (WEIM)*, Western Energy Markets (Jan. 12, 2026)). WEIM launched in 2014 and includes 22 participants, representing 79 percent of the load of the Western Interconnection. Ex. 50-9 (*Western Energy Imbalance Market Fact Sheet*, Cal. Indep. Sys. Operator (June 6, 2024)).

5. The Western Resource Adequacy Program (WRAP) is a regional reliability planning and compliance program. Ex. 50-10 (David Pennington, *WRAP Area Map*, Western Power Pool (last modified Oct. 31, 2025), https://www.westernpowerpool.org/news/wrap-area-map (last visited Jan. 12, 2026)). WRAP includes 16 members ranging from British Columbia to Arizona and includes the Bonneville Power Administration, Arizona Public Service Company, Avista Corp, and Puget Sound Energy.

6. First, Washington utilities are required to develop an IRP every four years, with progress every two years, that plans for both resource adequacy and a reduction in greenhouse gas emissions under state law. *See* RCW 19.280.030. These plans include, among other things:

a) An assessment and 20-year forecast of the availability of and requirements for regional generation and transmission capacity to provide and deliver electricity to the utility's customers;

b) A determination of resource adequacy metrics; and

c) The integration of demand forecasts, resource evaluations, and resource adequacy requirement into a long-range assessment describing the implementation of the

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Clean Energy Transition Act (CETA) at the lowest reasonable cost and risk to the utility and its customers, while maintaining and protecting the safety, reliable operation, and balancing of its electric system. *See* RCW 19.280.300.

7. IRPs are intended to ensure utilities have the resource portfolio necessary to have the capacity to reliably meet system demand at any given time. These plans have already considered the closing of the Centralia Coal Plant, the implementation of CETA, and changing weather patterns in their analysis of peaking capacity resources Ex. 50-1 at 8.19 (pdf 209) (*2023 Electric Progress Report*, Puget Sound Energy (Dec 17, 2025)).

8. To identify the resources necessary to meet peak demand, utilities run a variety of simulations to replicate various load growth scenarios. Scenarios include changes to population and economic forecasts, changes to weather forecasts, market risk assessments, and cost and rate projections. Ex. 50-2 (*2025 Electric Integrated Resource Plan*, Avista Corp., Dec 31, 2026); Ex. 50-3 (*2021 PSE Integrated Resource Plan*, Puget Sound Energy (Dec 31, 2025)). Planning margins for these scenarios ensure the utilities will be prepared for significant extreme weather events.

9. As part of the weather forecasting, utilities are implementing effects due to climate change into weather, precipitation, and resource forecasting in the near- and long-term outlooks. Additionally, IRPs include specific hydroelectric generation forecasting that directly address the concerns raised in Order 202-25-4. For example, in its 2025 IRP, Avista Corporation, a Washington based company with approximately 418,000 electricity and 382,000 natural gas customers forecasts an increase in hydroelectric generation for the winter months over the next 30 years Ex. 50-2; Ex. 50-11 (*Investor Overview*, Avista Corp.).

10. In the near-term, utilities can conserve their hydropower resources for use in peak winter events. The National Weather Service predicts a wetter-than-average winter season for 2026, improving drought conditions. Ex. 64 (National Weather Service, "Winter Outlook 2025-2026," (Dec 31, 2025)). One example is Seattle City Light, a public utility delivering

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electricity to over 500,000 customers. In a winter preparedness meeting in November 2025, Seattle City Light stated their intention to save hydropower resources for peak winter events Ex. 50-4 (*Summary of the 2025 Winter Preparedness Resource Adequacy Meeting*, Washington Utilities and Transportation Commission (Dec 31 2025)).

11. In the long-term, utilities are including the conversion of the Centralia Coal Plant to natural gas as an important resource for reliable capacity moving forward. *See* Ex. 20 (TransAlta, "TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion," Dec 31, 2025). Any delays to the transition could risk reliability challenges in 2028 and beyond.

12. Second, Washington utilities have planned for immediate changes in demand and supply, participating in the Western Energy Imbalance Market (WEIM) to manage real-time power needs. The WEIM connects Northwest utilities with utilities in the desert Southwest and other regions, allowing for energy to be passed across a wide geographic area, providing insulation against extreme weather events affecting a region. Ex. 50-8.

13. In January 2024, the region experienced an extreme cold weather event, with over 450 local storms and significantly low temperatures in sections of the region Ex. 50-5 (National Weather Service, "The Month In Review – January 2024," Dec 31, 2025). The WEIM was used to great effect, importing energy from regions not affected by extreme weather to meet increased energy demand Ex. 50-6 (*Assessment of January 2024 Cold Weather Event*, Western Power Pool (Dec 31, 2025)).

14. The E3 report, which Energy cites in its Order, estimates firm imports for capacity contribution at 3,750 MW, but January 2026 discussions with the E3 staff who authored the report indicated that this was a middle-of-the-road estimate and that the actual number could be higher. Ex. 3 at 9 (E3, Resource Adequacy and the Energy Transition in the Pacific Northwest). In fact, during the January 2024 cold weather event, the Western Power Pool (WPP) estimated that the Northwest imported roughly 4,900 MWs from the Desert

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Southwest and Rockies region. An increase to this level of imports would greatly improve the Northwest reliability's position in the analysis.

15. Third, California ISO's (CAISO) Reliability Coordinator (RC West) determines measures to prevent or mitigate system emergencies in day-ahead or real-time operations. Ex. 50-12 (Cal. Indep. Sys. Operator, *RC West*, CAISO); Ex. 50-7 (*Procedure No. RC0410 System Emergencies*, CAISO,). RC West can issue energy emergency alerts to help ensure energy is directed toward the needed utilities. If these are activated, the reliability coordinator can work with the balancing authority under the alert to ensure all generation is active, verify demand-side management has been activated, alert all other balancing authorities and market participants of the status, and evaluate mitigation options such as redispatching generation, cancelling or recalling transmission and generation outages, and managing generation to address capacity, among others.

16. The reliability coordinator is also responsible for reviewing balancing authority operating plans that address extreme weather events such as unanticipated high load due to extreme cold temperatures. In the January 2024 cold weather event, four entities were placed into different levels of emergency to help maintain reliability across the region. Ex. 50-8.

17. Finally, Washington utilities are voluntarily participating in the Western Resource Adequacy Program (WRAP), WRAP can ensure more reliable service and a more accurate resource adequacy picture region wide. Ex. 50-10. Utilities are already incorporating WRAP metrics in their IRPs and see the possibility to obtain better reliability from the market through WRAP coordination. Ex. 50-2.

18. The region's utilities have not left reliability to chance. Because utilities extensively plan, stress-test assumptions, and participate in regional markets, the forced operation of Centralia as a coal plant does not provide meaningful assurance beyond what already exists. Utilities have already planned for the closure of the plant, and forced operation

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that causes delays to a possible natural gas transition could risk resource adequacy far into the future.

I declare under penalty of perjury under the laws of the state of Washington that the foregoing is true and correct, to the best of my knowledge.

DATED this 13th day of January, in Seattle, Washington.

ANDREW REEVES

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EXHIBIT 50-1

2023 ELECTRIC PROGRESS REPORT

CHAPTERS 1–9

PUGET SOUND ENERGY

2023 ELECTRIC PROGRESS REPORT

TABLE OF CONTENTS

PUGET SOUND ENERGY

About PSE

As Washington State's oldest local energy company, Puget Sound Energy serves more than 1.2 million electric customers and more than 900,000 natural gas customers in ten counties. Our service territory includes the vibrant Puget Sound area and covers more than 6,000 square miles, stretching from south Puget Sound to the Canadian border, and from central Washington's Kittitas Valley west to the Kitsap Peninsula.

A subsidiary of Puget Energy, PSE meets the energy needs of its customers, in part, through incremental, cost-effective energy efficiency, procurement of sustainable energy resources, and far-sighted investment in the energy-delivery infrastructure. PSE employees are dedicated to providing great customer service and delivering energy that is safe, dependable and efficient. For more information, visit pse.com.

Our electric service territory includes all of Kitsap, Skagit, Thurston, and Whatcom counties, and parts of Island, King (not Seattle), Kittitas and Pierce (not Tacoma) counties.

Our natural gas service territory includes: Parts of King (not Enumclaw), Kittitas (not Ellensburg), Lewis, Pierce, Snohomish, and Thurston counties

Figure 1.1 below shows PSE's electric and gas service territories.

Figure 1.1 Puget Sound Energy Natural Gas and Electric Service Territories

Table of Contents: Chapters

Chapter Six: Demand Forecasts

Chapter 7: Resource Adequacy Analysis

Chapter 8: Electric Analysis

DEFINITIONS & ACRONYMS

Term/Acronym	Definition
A4, A5	A standard for converting gases to carbon dioxide equivalents using the Intergovernmental Panel on Climate Change global warming protocols.
AARG	Average annual rate of growth
AB 32	California Global Warming Solutions Act of 2006, which mandates a carbon price to be applied to all power generated in or sold into that state.
AC	Alternating current
ACE	Area Control Error
ACE Rule	Affordable Clean Energy Rule. Adopted in 2018, EPA's replacement for the Clean Power Plant Rule.
ADMS	Advanced Distribution Management System, a computer-based, integrated platform that provides the tools to monitor and control distribution networks in real time
AECO	Alberta Energy Company, a natural gas hub in Alberta, Canada
AMI	Advanced metering infrastructure
AMI	Area median income
AMR	Automated meter reading
aMW	The average number of megawatt-hours (MWh) over a specified time period; for example, 175,200 MWh generated over the course of one year equals 20 aMW (175,200 / 8,760 hours).
AOC	Administrative Order of Consent
ARMA	Autoregressive moving average
ATB	Annual Technology Baseline, an annual, publically available report published by NREL, and presents a consistent set of electricity generating technology cost and performance data
ATC	Available transmission capacity
AURORA	One of the models PSE uses for electric resource planning. AURORA uses the western power market to produce hourly electricity price forecasts of potential future market conditions. AURORA is also used to test electric portfolios to evaluate PSE’s long-term revenue requirements.
BA	Balancing Authority, the area operator that matches generation with load
BAA	Balancing Authority area
BACT	Best available control technology, required of new power plants and those with major modifications, pursuant to EPA regulations
Balancing reserves	Reserves sufficient to maintain system reliability within the operating hour; this includes frequency support, managing load and variable resource forecast error, and actual load and generation deviations. Balancing reserves must be able to ramp up and down as loads and resources fluctuate instantaneously each hour.
BART	Best available retrofit technology, an EPA requirement for certain power plant modifications
Base Scenario	In an analysis, a set of assumptions that is used as a reference point against which other sets of assumptions can be compared. The analysis result may not ultimately indicate that the Base Scenario assumptions should govern decision-making.

Term/Acronym	Definition
Baseload combustion turbines	Baseload combustion turbines are designed to operate economically and efficiently over long periods of time. Generally combined-cycle combustion turbines (CCCTs).
Baseload resources	Baseload resources produce energy at a constant rate over long periods at lower cost relative to other production facilities; typically used to meet some or all of a region's continuous energy need.
BAU	Business-as-usual
Bcf	Billion cubic feet
BEM	Business Energy Management sector, for electric energy efficiency programs.
BES	Bulk electric system
BESS	Battery energy storage system
BIPOC	Black, Indigenous, and People of Color
BPA	Bonneville Power Administration
BSER	Best system of emissions reduction, an EPA requirement for certain power plant construction or modification.
BTU	British thermal units
CAA	Clean Air Act
CAISO	California Independent System Operator
capacity factor	The ratio of the actual generation from a power resource compared to its potential output if it was possible to operate at full nameplate capacity over the same period of time.
CAPEX	Capital expenditures required to achieve commercial operations of a generation plant. CAPEX may vary by resource type.
CAP	Corrective action plan, a series of operational steps used to prevent system overloads or loss of customer power
CAR	Washington State Clean Air Rule
CARB	California Air Resources Board
CBI	Customer benefit indicator
CCA	Climate Commitment Act
CCCT	Combined-cycle combustion turbine. Baseload generating plant that consists of one or more combustion turbine generators equipped with heat recovery steam generators that capture heat from the combustion turbine exhaust and use it to produce additional electricity via a steam turbine generator.
CCR	Coal combustion residuals
CCS	Carbon capture and sequestration
CDD	Cooling degree day
CEAP	Clean Energy Action Plan
CEC	California Energy Commission
CEIP	Clean Energy Implementation Plan
CETA	Clean Energy Transformation Act
CFS	Conditional Firm Service, a new transmission product offered by BPA.

Term/Acronym	Definition
CHP	Combined heat and power
CI	Confidence interval
CIA	Cumulative impact analysis
CIA	Community impact assessment
C&I	Commercial and industrial
CNG	Compressed natural gas
CO^2	Carbon dioxide
CO2e	Carbon dioxide equivalents
COE	U.S. Army Corps of Engineers
Contingency reserves	Reserves added in addition to balancing reserves; contingency reserves are intended to bolster short-term reliability in the event of forced outages and are used for the first hour of the event only. This capacity must be available within 10 minutes, and 50 percent of it must be spinning.
CPA	Conservation potential assessment
CPI	Consumer price index
CPP	federal Clean Power Plan
CPP	Critical Peak Pricing or dynamic pricing
CPUC	California Public Utilities Commission
CRAG	PSE's Conservation Resource Advisory Group
C&S	Codes and standards
CT	Combustion turbine
CVR	Conservation voltage reduction
DA	Distribution automation
DE	Distribution efficiency
DER	Distributed energy resources
Demand response	Flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.
Demand-side resources	These resources reduce demand. They include energy efficiency, distribution efficiency, generation efficiency, distributed generation and demand response.
DER	Distributed energy resources. Electricity generators like rooftop solar panels that are located below substation level.
DERMS	Distributed Energy Resource Management System
Deterministic analysis	Deterministic analysis identifies the least-cost mix of demand-side and supply-side resources that will meet need, given the set of static assumptions defined in the scenario or sensitivity.
DG	Distributed generation
Distributed energy resources	Small-scale electricity generators like rooftop solar panels, located below substation level.
DLC	Direct load control, one of several demand response programs

Term/Acronym	Definition
DMS	Distribution management system
DNV	An energy consultant
DOE	U.S. Department of Energy
DOH	Washington State Department of Health
DR	Demand response
DSM	Demand-side measure
DSM	Demand-side management
DSO	Dispatcher Standing Order
DSP	Delivery System Planning
DSR	Demand-side resources
Dth	Dekatherms
Dual fuel	Refers to peakers that can operate on either natural gas or distillate oil fuel.
EAG	PSE's Equity Advisory Group
EDAM	Extended day-ahead market
EE	Energy efficiency
EEI	Edison Electric Institute
EHD	Environmental health disparities
EHEB	Economic, Health and Environmental Benefits Assessment
EIA	U.S. Energy Information Agency
EIA	Washington State Energy Independence Act
EIM	The Energy Imbalance Market operated by CAISO
EIS	Environmental impact statement
EITEs	Energy-intensive, trade-exposed industries
ELCC	Effective load carrying capacity. The peak capacity contribution of a resource calculated as the change in capacity of a perfect capacity resource that results from adding a different resource with any given energy production characteristics to the system while keeping the 5 percent LOLP resource adequacy metric constant.
EMC	PSE's Energy Management Committee
Energy need	The difference between forecasted load and existing resources.
Energy storage	A variety of technologies that allow energy to be stored for future use.
EPA	U.S. Environmental Protection Agency
EPR	Electric Progress Report
EPRI	Electric Power Research Institute
EPS	Washington state law RCW 80.80.060(4), GHG Emissions Performance Standard
ERU	Emission reduction units. An ERU represents one MtCO2 per year.
ESP	Electric service platform
ESS	Energy storage systems

Term/Acronym	Definition
EUE	Expected unserved energy, a reliability metric measured in MWhs that describes the magnitude of electric service curtailment events (how widespread outages may be).
EV	Electric vehicle
FERC	Federal Energy Regulatory Commission
FIP	Final implementation plan
FLISR	Fault Location, Isolation, Service Restoration
FPL	Federal poverty level
FSC	Floating surface collector
GDP	Gross domestic product
GENESYS	The resource adequacy model used by the Northwest Power and Conservation Council (NPCC).
GHG	Greenhouse gas
GIS	Geographic Information System
GPM	Gas portfolio model
GRC	General Rate Case
GTN	Gas Transmission Northwest
GW	Gigawatt
HB 1257	Clean Buildings for Washington Act
HDD	Heating degree day
HDR	Energy consultant
HIC	Highly impacted communities
HILF	High-impact, low-frequency events
HVAC	Heating, ventilating and air conditioning
I-937	Initiative 937, Washington state's renewable portfolio standard (RPS), a citizen-based initiative codified as RCW 19.285, the Energy Independence Act.
IAP2	International Association of Public Participation
iDOT	Investment Optimization Tool. An analysis tool that helps to identify a set of projects that will create maximum value.
IGCC	Integrated gasification combined-cycle, generally refers to a model in which syngas from a gasifier fuels a combustion turbine to produce electricity, while the combustion turbine compressor compresses air for use in the production of oxygen for the gasifier.
IIJA	Infrastructure Investment and Jobs Act
Intermittent resources	Resources that provide power that offers limited discretion in the timing of delivery, such as wind and solar power.
IOU	Investor-owned utility
IPP	Independent power producer
IRA	Inflation Reduction Act
IRP	Integrated resource plan

Term/Acronym	Definition
ISO	Independent system operator
ITA	Independent technical analysis
ITC	Investment tax credit
KORP	Kingsvale-Oliver Reinforcement Project pipeline proposal
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hours
LAES	Liquid air energy storage
LNG	Liquified natural gas
Load	The total of customer demand plus planning margins and operating reserve obligations.
LOLE	Loss of load expectation, a reliability metric that measures the number of days per year with loss of load due to load exceeding available system capacity.
LOLH	Loss of load hours (or loss of load energy), a reliability metric that measures the duration of electric service curtailment events (how long outages may last).
LOLP	Loss of load probability, a reliability metric that measures the likelihood of an electric service curtailment event happening.
LP-Air	Vaporized propane air
LSR	Lower Snake River Wind Facility
LTCE	Long-term capacity expansion model
LTF	Long-term firm transmission
LTF PTP	Long-term firm point-to-point transmission
MATS	Mercury Air Toxics Standard
MDEQ	Montana Department of Environmental Quality
MDQ	Maximum daily quantity
MDth	One thousand dekatherms or 10,000 therms
MEIC	Montana Environmental Information Center
MESA	Modular Energy Storage Architecture. A protocol for communications between utility control centers and energy storage systems.
Mid-Columbia (Mid-C) market hub	The principle electric power market hub in the Northwest and one of the major trading hubs in the WECC.
MIP	Mixed integer programming, a mathematic optimization technique with combines elements of linear programming and integer programming
MMBtu	Million British thermal units
MMtCO2e	Million metric tons of CO2 equivalent
MSA	Metropolitan statistical area
MSCG	Morgan Stanley Commodities Group
MW	Megawatt

Term/Acronym	Definition
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards, set by the EPA, which enforces the Clean Air Act, for six criteria pollutants: sulfur oxides, nitrogen dioxide, particulate matter, ozone, carbon monoxide and lead.
Nameplate capacity	The maximum sustained output capacity of an electric-generating resource.
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
Net maximum capacity	The capacity a unit can sustain over a specified period of time – in this case 60 minutes – when not restricted by ambient conditions or deratings, less the losses associated with auxiliary loads.
Net metering	A program that enables customers who generate their own renewable energy to offset the electricity provided by PSE.
NGV	Natural gas vehicles
NO2	Nitrogen dioxide
NOAA	National Oceanic and Atmospheric Administration
NOS	Network Open Season, a BPA transmission planning process.
NO_x	Nitrogen oxides
NPCC	Northwest Power & Conservation Council
NPV	Net present value
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NRF	Northwest Regional Forecast of Power Loads and Resources, the regional load/balance study produced by PNUCC.
NSPS	New source performance standards, new plants and those with major modifications must meet these EPA standards before receiving permit to begin construction.
NSRDB	NREL's National Solar Radiation Database
NTTG	Northern Tier Transmission Group
NUG	Non-utility generator
NWA	Non-wires analysis
NWE	NorthWestern Energy
NWGA	Northwest Gas Association
NWP	Northwest Pipeline
NWPP	Northwest Power Pool
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OMS	Outage management system
OTC	Once-through cooling
PACE	PacifiCorp East

Term/Acronym	Definition
PACW	PacifiCorp West
PCA	Power cost adjustment (electric)
PCORC	Power cost only rate case
Peak capacity contribution	The nameplate capacity of a particular resource multiplied by the ELCC for that resource. For example, 100 MW of eastern Washington solar nameplate capacity, which has a summer ELCC of 54%, has a summer peak capacity contribution of 54 MW.
Peak need	Electric or gas sales load at peak energy use times.
Peaker or peaking plants	Peaker is a term used to describe generators that can ramp up and down quickly in order to meet spikes in need. They are not intended to operate economically for long periods of time like baseload generators.
Peaking resources	Quick-starting electric generators that can ramp up and down quickly in order to meet short-term spikes in need, or gas sales resources used to meet load at times when demand is highest.
PEFA	ColumbiaGrid's planning and expansion functional agreement, which defines obligations under its planning and expansion program.
PEV	Plug-in electric vehicle
PG&E	Pacific Gas and Electric Company
PGA	purchased gas adjustment
PGE	Portland General Electric
PHES	Pumped hydroelectric energy storage
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES Act	Pipeline Inspection, Protection, Enforcement, and Safety Act (2006)
Planning reserve margin or PRM	These are amounts over and above customer peak demand that ensure the system has enough flexibility to handle balancing needs and unexpected events.
Planning standards	The metrics selected as performance targets for a system's operation.
PLEXOS	An hourly and sub-hourly chronological production simulation model that utilizes mixed-integer programming (MIP) to simulate unit commitment of resources at a day-ahead level, and then simulate the re-dispatch of these resources in real time to match changes in supply and demand on a 5-minute basis.
PM	Particulate matter
PNNL	Pacific Northwest National Laboratory
PNUCC	Pacific Northwest Utilities Coordinating Committee
PNW	Pacific Northwest
POI	Point on interconnection
POD	Point of delivery
Portfolio	A specific mix of resources to meet gas sales or electric load.
PPA	Purchased power agreement. A bilateral wholesale or retail power short-term or long-term contract, wherein power is sold at either a fixed or variable price and delivered to an agreed-upon point.
PRP	Pipeline replacement program

Term/Acronym	Definition
PSCAA	Puget Sound Clean Air Agency
PSE	Puget Sound Energy
PSEM	Puget Sound Energy Merchant, the part of PSE responsible for obtaining and scheduling the transmission needed to serve PSE loads.
PSIA	Pipeline Safety Improvement Act (2002)
PSRC	Puget Sound Regional Council
PTC	Production Tax Credit
PTP	Point-to-point transmission service, meaning the reservation and transmission of capacity and energy on either a firm or non-firm basis from the point of receipt (POR) to the point of delivery (POD).
PTSA	Precedent Transmission Service Agreement
PUD	Public utility district
Pumped hydro or PHES	Pumped hydro facilities store energy in the form of water, which is pumped to an upper reservoir from a second reservoir at a lower elevation. During periods of high electricity demand, the stored water is released through turbines to generate power in the same manner as a conventional hydropower station.
PV	Photovoltaic
R&D	Research and development
RA	Resource adequacy
RAM	Resource Adequacy Model. RAM analysis produces reliability metrics (EUE, LOLP, LOLH) that allow us to assess physical reliability.
Rate base	The amount of investment in plant devoted to the rendering of service upon which a fair rate of return is allowed to be earned. In Washington state, rate base is valued at the original cost less accumulated depreciation and deferred taxes.
RCRA	Resource Conservation Recovery Act
RCW	Revised Code of Washington
RCW 19.285	Washington State's Energy Independence Act, commonly referred to as the state's renewable portfolio standard (RPS)
RCW 80.80	Washington State law that sets a generation performance standard for electric generating plants that prohibits Washington utilities from building plants or entering into long-term electricity purchase contracts from units that emit more than 970 pounds of GHGs per MWh.
REC	Renewable energy credit. RECs are intangible assets, which represent the environmental attributes of a renewable generation project – such as a wind farm – and are issued for each MWh of energy generated from such resources.
RECAP	Renewable Energy Capacity Planning, E3's resource adequacy analysis model
REC banking	Washington's renewable portfolio standard allows for RECs unused in the current year to be "banked" and used in the following year.
Redirected transmission	Moving a primary receipt point on BPA's system. According to BPA's business practice, PSE can redirect an existing long-term or short-term, firm or non-firm transmission that it

Term/Acronym	Definition
	has reserved on BPA's transmission system. BPA will grant the redirect request as long as there is sufficient capacity on the system to accommodate the change.
Regulatory lag	The time that elapses between establishment of the need for funds and the actual collection of those funds in rates.
REM	Residential Energy Management sector, in energy efficiency programs.
Repowering	Refurbishing or renovating a plant with updated technology to qualify for Renewable Production Tax Credits under the PATH Act of 2015.
Revenue requirement	Rate Base x Rate of Return + Operating Expenses
RFP	Request for proposal
RFQ	Request for quote
RHA	Renewable Hydrogen Alliance
RICE	Reciprocating internal combustion engine – also referred to as recip peakers.
RNG	Renewable natural gas
RPS	Renewable portfolio standard. A requirement that electricity retailers acquire a minimum percentage of their power from renewable energy resources. Washington state mandates 3 percent by 2012, 9 percent by 2016 and 15 percent by 2020.
RTO	Regional transmission organization
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAM	NREL's System Advisor Model
SAP	Systems Applications and Products in Data Processing
SCADA	Supervisory control and data acquisition that provides real-time visibility and remote control of distribution equipment
SCCT	Simple-cycle combustion turbine, a generating unit capable of ramping up and down quickly to meet peak resource need. Also called a peaker.
Scenario	A consistent set of data assumptions that defines a specific picture of the future; takes holistic approach to uncertainty analysis.
SCC	Social cost of carbon, also called SCGHG, social cost of greenhouse gases
SCGHG	Social cost of greenhouse gases
SCR	Selective catalytic reduction
SEIA	Solar Energy Industries Association
SENDOUT	The deterministic gas portfolio model used to help identify the long-term, least-cost combination of integrated supply- and demand-side resources that will meet stated loads.
Sensitivity	A set of data assumptions based on the Reference Scenario in which only one input is changed. Used to isolate the effect of a single variable.
SEPA	Washington State Environmental Policy Act
SIP	State Implementation Plan

Term/Acronym	Definition
SMR	Small modular reactor
SNCR	Selective non-catalytic reduction
SO2	Sulfur dioxide
SOFA system	Separated over-fire air system
Solar PV	Solar photovoltaic technology
Stochastic analysis	Stochastic risk analysis deliberately varies the static inputs to the deterministic analysis, to test how different portfolios perform with regard to cost and risk across a wide range of potential future power prices, natural gas prices, hydro generation, wind generation, loads, plant forced outages and CO2 prices.
Supply-side resources	Resources that generate or supply electric power, or supply natural gas to natural gas sales customers. These resources originate on the utility side of the meter, in contrast to demand-side resources.
T&D	Transmission and distribution
TailVar90	A metric for measuring risk defined as the average value of the worst 10 percent of outcomes.
TCPL-Alberta	TransCanada's Alberta System (also referred to as TC-AB)
TCPL-British Columbia	TransCanada's British Columbia System (also referred to as TC-BC)
TC-Foothills	TransCanada-Foothills Pipeline
TC-GTN	TransCanada-Gas Transmission Northwest Pipeline
TC-NGTL	TransCanada-Nova Gas Transmission Pipeline
TEPPC	WECC Transmission Expansion Planning Policy Committee
TF-1	Firm gas transportation contracts, available 365 days each year.
TF-2	Gas transportation service for delivery or storage volumes generally intended for use during the winter heating season only.
thermal resources	Electric resources that use carbon-based or alternative fuels to generate power.
TOP	Transmission operator
Transmission capacity	Defines the quantity of generation development available in specific geographic regions.
Transmission costs	Transmission costs model the cost of transmitting power from a generating resource to PSE's service territory
Transmission losses	This refers to energy lost to heat as power is carried from one location to another.
Transmission redirect	"Redirecting" transmission means moving a primary receipt point on BPA's system. According to BPA's business practice, PSE can redirect an existing long-term or short-term, firm or non-firm transmission that it has reserved on BPA's transmission system. BPA will grant the redirect request as long as there is sufficient capacity on the system to accommodate the change.
Tranche	A capacity segment on ELCC saturation curve
Transport customers	Customers who acquire their own natural gas from third-party suppliers and rely on the natural gas utility for distribution service.

Term/Acronym	Definition
TSR	Transmission service request
TSEP	Bonneville Power Administration's transmission service request study and expansion process.
UPC	use per customer
VectorGas	An analysis tool that facilitates the ability to model price and load uncertainty.
VERs	Variable energy resources
VPP	Virtual power plant
VVO	Volt-var optimization
WAC	Washington Administrative Code
WACC	Weighted average cost of capital
WCI	Western Climate Initiative
WCPM	Wholesale Purchase Curtailment Model
WECC	Western Electricity Coordinating Council
WECo	Western Energy Company
WEI or Westcoast	Westcoast Energy, Inc.
Wholesale market purchases	Generally short-term purchases of electric power made on the wholesale market.
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
ZLD	Zero liquid discharge

EXECUTIVE SUMMARY
CHAPTER ONE

PSE PUGET SOUND ENERGY

Contents

1. Introduction

Puget Sound Energy (PSE) is Washington State's largest and oldest utility, serving 1.5 million customers in ten counties over 6,000 square miles. History reflects how PSE has shared customers' environmental concerns over the years while balancing expectations for uncompromised reliability, affordability, and safety. Puget Sound Energy was an early leader in clean energy — from our oldest hydroelectric facility, Snoqualmie Falls built in 1898, to our first wind facility, Hopkins Ridge, developed in 2005, to establishing a pathway to remove coal-fired generation by the end of 2025. Our commitment to clean energy and reducing greenhouse gas emissions has only strengthened in recent years, as evidenced by our support of the passage of the Clean Energy Transformation Act (CETA) and the Climate Commitment Act (CCA).

In this 2023 Electric Progress Report (2023 Electric Report or report), we identified the need to build and/or acquire a significant amount of resources to comply with the CETA and meet resource adequacy requirements — more than 6,700 megawatts (MW) of nameplate capacity by 2030. This report outlines the resources and actions to get us there.

A Series of Firsts

This document is PSE's first electric progress report. A product of the CETA, it is designed to streamline reporting as we work toward our clean energy goals. This report is also our first opportunity to reinforce the commitments in PSE's 2021 Clean Energy Implementation Plan (CEIP), which includes eliminating coal-fired resources by 2025, achieving greenhouse gas neutrality by 2030, and supplying 100 percent renewable and non-emitting electric energy by 2045.

This is the first resource plan to incorporate climate change temperature predictions in the analysis, and this made an unmistakable mark on our resource needs. As a result of this analysis, we learned that even though the summer peak is increasing, PSE is still a winter peaking utility. Although our most significant peak demand will still occur in winter, we must also account for summer peaks. The resources we rely on to get us through cold winter nights will not be the same as those that get us through hot summer days.

This report also expands our approach to quantifying customer benefits in the analysis to ensure a more equitable transition to clean energy. The resulting resource plan is far more diverse and relies more on clean, intermittent resources such as wind, solar, and storage. The plan also reduces market reliance compared to prior resource plans because we recognize that recent significant changes in the wholesale electric market make it increasingly risky and unreliable to rely on the market. Although markets will continue to play a critical role in optimizing PSE's portfolio, we can no longer rely on traditional energy markets to meet peak capacity needs.

An All-of-the-above Approach

All these factors drove us to look at our portfolio of resources in new and diverse ways. The portfolio builds a wide range of new renewable and storage resources — an all-of-the-above approach — at an unprecedented scale and pace. The amount of new, non-emitting generation resources PSE will need by 2030 is more than we have accumulated in our 100-year history. It will require us to develop resources rapidly while we adhere to our procurement principles and policies to meet our CETA goals.

Our analysis also revealed that we will need significant grid improvements that allow increasing amounts of intermittent resources to work in concert. The grid will require considerable development in transmission capacity to bring utility-scale wind and solar to our region and allow the rapid advancement of new and emerging technologies such as green hydrogen.

Our plan illustrates significant investment in wind and solar resources combined with energy storage will shape the foundation of the energy system of the future. We also assume that technologies emerging over the coming 15 years will help us maintain a reliable system. We are not pursuing a single long-term technology solution but will explore multiple emerging technologies in the coming years. We will take a pragmatic, diversified approach and engage with others in the region to take concrete steps to move multiple technologies forward. We will work together to ensure that future resources are available to maintain the reliability and affordability our customers expect as we create a cleaner and more equitable system.

Mitigating Risk

There is a risk that some of these technologies will not emerge as viable at the pace we need. We are mitigating that risk in several ways. For example, we assumed multiple fuel options for peaking facilities. We are active partners in establishing Washington as a green hydrogen leader, which includes working with Fortescue Future Industries and other regional interested parties to explore the development of a hydrogen production facility at the former Centralia coal mine in Centralia, Washington.[1] Although not part of the preferred portfolio, we see advanced nuclear reactors as potentially a necessary part of our region's future energy supply mix and will continue to investigate the technology as a potential fit for future PSE resource needs. Puget Sound Energy and the region will need emerging resources like hydrogen hubs and/or advanced nuclear reactors to become commercially viable to help integrate renewables and ensure a reliable grid in the future. For that reason, PSE intends on taking an active role in exploring such technologies to help ensure progress is made toward meeting the needs of our customers and successfully meeting the requirements of state policy.

We are proud to be the Pacific Northwest's largest utility producer of renewable energy, but we know that our journey toward an equitable clean energy future has only begun. The resource plan included in this 2023 Electric Report is another critical next step highlighting the opportunities for PSE to continue leading the way on renewable energy for our state and region.

2. Resource Planning Foundations

This 2023 Electric Report is an update to the 2021 Integrated Resource Plan (IRP) required under Washington Utilities and Transportation Commission (WUTC) rules for electric investor-owned utilities as of December 2020.[2] Those changes require electric utilities to file an electric IRP every four years and an update, or progress report, two

[1] https://ffi.com.au/news/centralia/
[2] WAC 480-100-625

years later. This 2023 Electric Report is a planning exercise that evaluates how PSE will meet customer electric supply needs. The analysis considers policies, costs, changing economic conditions, and the existing energy system to develop a plan to meet the needs of our customers at the lowest reasonable cost over the next 20+ years.

Throughout the resource planning process for this report, we focused on the following key objectives, which lay the foundation for this and all future resource plans:

- Build a reliable, diversified power portfolio of non-emitting resources
- Ensure an equitable clean energy transition for all PSE customers
- Ensure resource adequacy while delivering a clean energy transition
- Ensure resource planning aligns with PSE's Clean Energy Implementation Plan (CEIP) to meet our interim targets and CETA obligations

Recognizing that the 2023 Electric Report does not make resource or program implementation decisions is important. The report is a long-term view of what resources appear to be cost-effective while maximizing benefits and minimizing burdens, based on the best information we have today about the future. The forecasts and resource additions in the 2023 Electric Report will change in future IRPs as technology advances, customer use patterns change, clean fuel options evolve, resource costs change, the wholesale energy market evolve, and new policies are established.

3. Change Drivers

We developed this report during a time of extraordinary change as policymakers, the utility industry, and the public confront the challenge of climate change and the necessity to transition to a clean and equitable energy future. The following describes four areas of focus that impact the resource plan described in this report.

3.1. Address Regulatory Changes

The 2023 Electric Report includes updates in response to new legislation enacted since the 2021 IRP. These updates include the Climate Commitment Act, updates to CETA rules, Washington State building code efficiency improvements, and portions of the Inflation Reduction Act (IRA). We incorporated as much of the IRA as possible, resulting in an estimated savings of approximately $10 billion over the next 20+ years from production and investment tax credits. However, because the law was enacted late in our planning process, we could not consider all the nuances of the bill, nor could we incorporate the policies and rules the federal government has not developed yet to implement the IRA. We will continue to analyze and integrate the impacts of the IRA for the 2025 IRP.

➔ A complete discussion of the legislative policy updates is in Chapter Four: Legislative and Policy Change.

3.2. Embed Equity

The 2023 Electric Report represents our continued progress in a journey to embed equity into the resource planning process. We began incorporating equity in 2021 by assessing highly impacted communities and developing initial customer benefit indicators. Since then, we've made progress by defining vulnerable populations and creating customer benefit indicators with input from interested parties, including the Equity Advisory Group (EAG) formed during the 2021 CEIP process. We recognize this is one step of many toward ensuring an equitable clean energy transition. Equity is complex to measure and assess, especially in energy system planning. However, we continue to refine our analysis and work with interested parties to embed equity throughout the resource planning process.

CETA requires that all customers benefit from the transition to clean energy through the equitable distribution of energy and non-energy benefits and the reduction of burdens to vulnerable populations and highly impacted communities.

For this report, we expanded the 2021 IRP approach to building a preferred portfolio to include a portfolio benefit analysis using customer benefit indicators (CBIs) developed for the 2021 CEIP with extensive input from the EAG. Our goal in using customer benefit indicators (CBIs) is to identify a preferred portfolio that balances customer benefits with portfolio costs while reducing burdens to vulnerable populations and highly impacted communities. Our approach is evolving and will continue to improve and develop for the 2025 IRP and future CEIP cycles.

➔ Details on the portfolio benefits analysis are in Chapter Five: Key Analytical Assumptions.

3.3. Incorporate Impacts of Climate Change

The 2023 Electric Report incorporates climate change in the base energy and peak demand forecast for the first time. We heard from interested parties that it is vital to incorporate climate change because it affects future demand, and we agree. We included climate change in the base demand forecast, the resource adequacy analysis, and stochastic scenarios. Before this report, PSE used temperatures from the previous 30 years to model the expected normal temperature for the future. This approach was a common utility practice but did not recognize predicted climate change impacts on temperatures. We used climate change projections, modeled recently by climate change scientists for the region in time for this 2023 Electric Report, to calculate a normal temperature assumption that reflects climate change. No industry standards or best practices for incorporating climate change into a demand forecast exist. Including climate change in this report for the first time is a significant milestone, but we recognize this methodology needs to be refined and will evolve in future planning efforts.

➔ Please refer to Chapter Six: Demand Forecast for details regarding how we incorporated climate change into our demand forecast.

3.4. Reduce Market Reliance

The supply and demand fundamentals of the wholesale electric market have changed significantly in recent years. The availability of dispatchable generation resources is declining, and market power prices and volatility are increasing. These factors make reliance on the Western Interconnect market increasingly risky, so we plan to decrease market reliance during high demand peak hours, from almost 1,500 MW to zero MW by 2029.

For decades, PSE's customers have benefitted from an over-supplied market. Under such conditions, firm capacity was available at a low cost. The market outlook is different today. While markets will continue to play a critical role in optimizing PSE's portfolio, we can no longer rely on traditional energy markets to meet peak capacity needs.

The future of electricity consists of a diversified portfolio of non-emitting resources. A diverse portfolio reduces vulnerabilities due to market price, supply fluctuations, and political unrest. Having multiple, reliable generating resources allows a utility to continue to provide power without disruption if one energy source fails. A diverse energy portfolio reduces environmental impacts, improves reliability, and promotes innovation to meet our customers' needs. Resource diversity is the key to reducing emissions while preserving reliability and affordability.

➔ We provide more details on the various portfolios considered in Chapter Eight: Electric Analysis.

3.5. Accessibility and Plain Language

While creating the 2023 Electric Progress Report, we took measures to improve the accessibility of our written documents, public meetings, and website content. In this and future documents, we are committed to removing participation barriers and attracting more members of the public into the resource planning process. We are continuously evaluating our content and working to improve readability and accessibility for all while encouraging interested members of the public to get involved in our planning processes.

➔ Appendix A: Public Participation contains additional detailed information about public feedback in this IRP cycle.

4. Preferred Portfolio

The preferred portfolio, which requires over 6,700 MW of new generation by 2030, is a portfolio of diverse resources that can fulfill our CETA commitments and achieve carbon neutrality by 2030 and a carbon-free electric energy supply by 2045. As described in Table 3.1, this portfolio significantly increases conservation, demand response, renewable resources, and energy storage. However, given the large amounts of variable energy resources such as wind and solar, and energy-limited resources such as energy storage, we rely on newer technologies, specifically hydrogen, as a fuel to meet peak energy needs to achieve a carbon-free energy supply by 2045 while maintaining reliability and resource adequacy.

We acknowledge the risk of relying on an uncertain fuel source, so we intentionally diversified this portfolio to reduce risk. Additionally, in future IRP cycles, we will continue to evaluate and consider emerging technologies, including green hydrogen and advanced nuclear small modular reactors (SMR).

Table 1.1: Electric Preferred Portfolio, Resource Additions (Nameplate Capacity)

Resource Additions (Nameplate MW)	Total by 2030	Total by 2045
Demand-side Resources	**618**	**1,265**
Conservation[1]	281	818
Demand Response	337	446
Distributed Energy Resources	**739**	**2,392**
DER Solar	552	2,124
Net Metered Solar	*284*	*1,393*
CEIP Solar	*79*	*79*
New DER Solar	*189*	*652*
DER Storage[2]	187	267
Supply-side Resources	**5,360**	**11,174**
CETA-compliant Peaking Capacity[3]	711	1,588
Wind	1,400	3,650
Solar	700	2,290
Green Direct	100	100
Hybrid (Total Nameplate)	1,450	1,748
Hybrid Wind	*600*	*800*
Hybrid Solar	*400*	*398*
Hybrid Storage	*450*	*550*
Biomass	-	-
Advanced Nuclear (SMRs)	-	-
Standalone Storage	1,000	1,800
Total	**6,717**	**14,830**

Notes:

1. Conservation in winter peak capacity includes energy efficiency, codes and standards, and distribution efficiency.
2. Distributed Energy Resources (DER) storage includes CEIP storage additions, non-wires alternatives, and distributed storage additions.
3. CETA-qualifying peaking capacity is functionally like natural gas peaking capacity but operates using non-emitting hydrogen or biodiesel fuel. We describe CETA-qualifying peaking capacity in Chapter Five: Key Analytical Assumptions and present alternative fuel assumptions in Appendix D: Generic Resource Alternatives.

➔ Please see Chapter Three: Resource Plan for a complete description of the preferred portfolio.

CLEAN ENERGY ACTION PLAN

CHAPTER TWO

PUGET SOUND ENERGY

Contents

1. Introduction

Washington State's Clean Energy Action Plan (CEAP) is a new aspect of Puget Sound Energy's (PSE's) Integrated Resource Plan (IRP) process. Introduced in the Clean Energy Transformation Act (CETA) in 2019, the CEAP identifies steps utilities can take over the next 10 years to meet the requirements of CETA. This is PSE's first Electric Progress Report and the first to include a CEAP update. As with any new requirement or assessment, the CEAP will evolve, and future IRPs will benefit from the lessons we learned in previous planning processes.

Puget Sound Energy is committed to achieving the requirements of CETA and carbon neutrality by 2030 and a carbon-free electric energy supply by 2045, and the CEAP presented here reflects these goals. Bridging PSE's Clean Energy Implementation Plan (CEIP) and IRP, the CEAP informs our decisions about specific and interim targets and actions over ten years, per RCW 19.280.030[1].

Table 2.1 presents near-term renewable and non-emitting — or clean energy — targets starting in the 2021 IRP and progressing through this progress report. The 2021 IRP established a clean energy target with a linear ramp from existing renewable energy generation to the 80 percent target in 2030. The 2021 CEIP expanded this target to make aggressive progress near-term toward the 80 percent goal. This 2023 Electric Progress Report (2023 Electric Report) retains the 63 percent clean energy target for 2025 established in the 2021 CEIP; however, given an increase in the load forecast, this report's resource plan requires additional renewable and non-emitting generation to meet the same target.

Table 2.1: Renewable and Non-emitting Energy Targets for 2025

Document	Clean Energy Target[1] by 2025 (%)	Clean Energy Generation to Meet Target[1] (MWh)
2021 IRP	56	10,046,493
2021 CEIP	63	11,381,593
2023 Progress Report	63	12,324,846

Notes: Clean energy targets represent a percent or quantity (MWh) of renewable or non-emitting energy of delivered load. The delivered load is adjusted for projected future demand-side resources (conservation, demand response, select distributed energy resources), PURPA contracts, and voluntary renewable programs.

2. Requirements

The 2021 IRP marked a significant departure from past IRPs largely due to CETA. The new rules, WAC 480-100-620 (12),[2] outline the requirements for this report. The utility must develop a 10-year clean energy action plan for implementing RCW 19.405.030[1]□ .

In this CEAP, the utility must include the following:

- A 10-year action plan that is the lowest reasonable cost (see section 3)

[1] RCW 19.280.030
[2] WAC 480-100-620

- Establish resource adequacy requirement (see section 3.2)
- Identify any need to develop new or to expand or upgrade existing bulk transmission and distribution facilities (see section 5)
- Identify cost-effective conservation potential assessment (CPA) (see section 3.1)
- Identify how the utility will meet the requirements of the clean energy transformation standards (see section 4)
- Identify potential cost-effective demand response (see section 3.4)
- Identify renewable resources, non-emitting electric generation, and distributed energy resources and how they contribute to meeting the resource adequacy requirement (see section 3.3)
- Identify the nature and extend for alternative compliance reliance (see section 6)
- Incorporate the social cost of greenhouse gasses as a cost adder (see section 7)

3. Ten-year Resource Additions

From the 2023 Electric Progress Report 22-year period, Table 2.1 summarizes the 10-year outlook for the resource mix in PSE's preferred portfolio. The portfolio benefit analysis, which considers the equitable distribution of benefits and how burdens may be reduced over the CEAP's ten-year horizon, informed our final selection of resources while ensuring the preferred portfolio met PSE's peak capacity, energy and renewable needs, and addressed market risk.

Table 2.2: 10-year Annual Incremental Resource Additions Preferred Portfolio

Resource	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total 2024–2033
Conservation[1]	33	32	44	36	36	60	41	42	78	43	445
Demand Response	71	65	71	47	49	16	17	17	17	16	387
DER Solar[2]	97	75	51	70	73	93	91	98	98	102	850
Net Metered Solar	*38*	*21*	*21*	*40*	*40*	*61*	*61*	*67*	*67*	*71*	*490*
CEIP Solar	*55*	*24*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*79*
New DER Solar	*4*	*30*	*30*	*30*	*33*	*32*	*30*	*31*	*31*	*31*	*281*
DER Storage[3]	21	18	29	32	29	28	30	28	4	4	223
CETA-qualifying Peaking Capacity[4]	237	0	237	0	237	0	0	0	0	0	711
Wind	300	300	500	0	0	0	400	200	100	100	1,900
Solar	100	0	0	0	200	400	0	0	0	0	698
Hybrid Total	150	150	400	0	150	600	0	0	0	0	1449
Hybrid Wind	*0*	*100*	*200*	*0*	*100*	*200*	*0*	*0*	*0*	*0*	*600*

Resource	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total 2024–2033
Hybrid Solar	*100*	*0*	*100*	*0*	*0*	*200*	*0*	*0*	*0*	*0*	*399*
Hybrid Storage	*50*	*50*	*100*	*0*	*50*	*200*	*0*	*0*	*0*	*0*	*450*
Standalone Storage	0	100	600	300	0	0	0	0	100	100	1,200
Total	1010	740	1932	485	774	1198	579	385	396	364	7,862

Notes:

1. Conservation in winter peak capacity includes energy efficiency, codes and standards, and distribution efficiency.
2. Distributed Energy Resources (DER) solar includes customer solar photovoltaic (PV), Clean Energy Implementation Plan (CEIP) solar additions, non-wires alternatives, and ground and rooftop solar additions.
3. Distributed Energy Resources (DER) storage includes CEIP storage additions, non-wires alternatives, and distributed storage additions.
4. CETA-qualifying peaking capacity is functionally similar to natural gas peaking capacity but operates using non-emitting hydrogen or biodiesel fuel. We describe CETA qualifying peaking capacity in Chapter Five: Key Analytical Assumptions and present alternative fuel assumptions in Appendix D: Generic Resource Alternatives.

3.1. Conservation Potential Assessment

We analyzed demand-side resource (DSR) alternatives in a conservation potential assessment (CPA) to develop a supply curve used as an input to the portfolio analysis. Then the portfolio analysis determines the maximum amount of energy savings the model captured without raising the overall electric portfolio cost. This study identified the cost-effective level of conservation, which includes non-energy benefits from the portfolio benefit analysis to include in the portfolio. We evaluated the amount of cost-effective conservation to meet the portfolio's capacity and energy needs, optimizing the lowest cost and considering distributed and centralized resources.

➔ See Appendix E: CPA and Demand Response Assessment for the full CPA Assessment. A complete discussion of how we chose the conservation levels for the preferred portfolio is in Chapter Three: Resource Plan.

Figure 2.3: 10-year Achievable Technical Potential Conservation Savings (Energy aMW and Peak MW)

Demand-side Resources	Total Savings (aMW)	Winter Peak Savings (MW)	Summer Peak Savings (MW)
Energy Efficiency	167	214	212
Distribution Efficiency	11	11	10
Codes and Standards	159	196	245

3.1.1. Impacts and Actions

This electric report informs the target setting process and, through this analysis, we identified 10-year savings of 167 aMW as cost-effective. We will use this to inform the draft 2023 Energy Independence Act (EIA) target for the 2024-

2025 biennium after adjusting for intra-year ramping and savings at the meter. Under the EIA, utilities must pursue all cost-effective, reliable, and feasible conservation. Puget Sound Energy fulfills these requirements by undertaking additional analysis to identify the conservation potential over 10 years and set two-year targets. Setting the final two-year targets is part of PSE’s biennial conservation plan process, which will take place over the next few months and builds on the information in this electric progress report.

3.2. Resource Adequacy

We must meet capacity need over the planning horizon with firm capacity resources or contractual arrangements to maintain reliability. All resources, including renewable resources, distributed energy resources, and demand response, contribute to meeting the capacity needs of PSE’s customers, but they make different kinds of contributions.

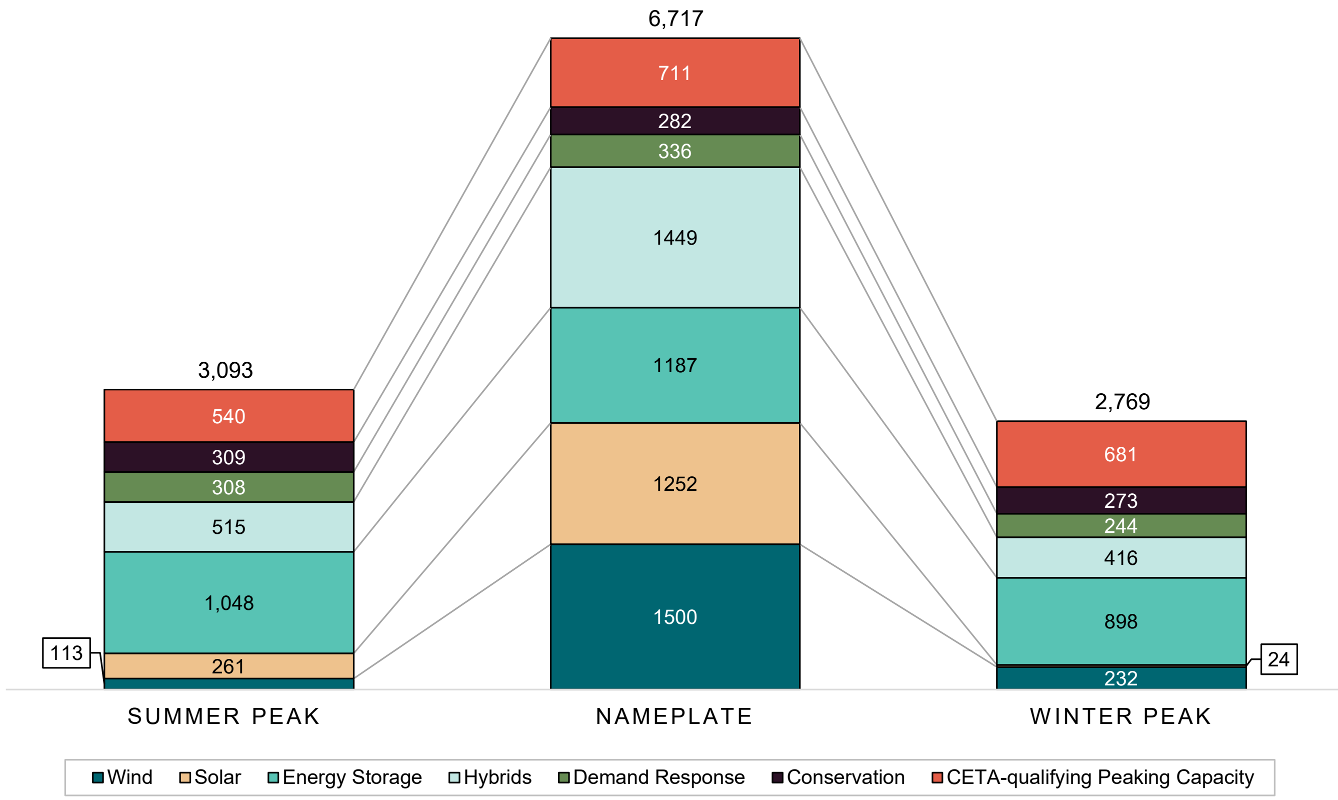
We have established a five percent loss of load probability (LOLP) resource adequacy metric to assess physical resource adequacy risk. The LOLP analysis measures the likelihood of a load curtailment event in any given simulation regardless of the frequency, duration, and magnitude of the curtailment(s). Therefore, the possibility of capacity being lower than the load anytime in the year cannot exceed five percent.

Assessing the peak capacity each resource can reliably provide is an integral part of resource adequacy analysis. To quantify the peak capacity contribution of renewable resources (wind, hydro, and solar) and other resources (thermal, storage, demand response, and contract), we calculate the effective load-carrying capacity (ELCC) for each of those resources. The ELCC of a resource is unique to each utility and dependent on load shapes and supply availability, so it is hard to compare the ELCC of PSE’s resources with those of other entities.

We analyzed summer and winter peak capacity for this report, and the analysis indicated that the winter peak is higher than the summer peak. With the increase of renewable energy and energy storage in the portfolio, those resources contribute to the summer peak need better than the winter. For example, solar has a four percent peak capacity contribution in the winter but a 55 percent contribution in the summer. We added solar to the portfolio because it meets the CETA requirement and the summer peak need, but it does very little to meet the winter peak need.

Because the peak capacity contribution of each resource does not match the nameplate energy values, we need more resources to meet the peak need. For example, solar's 24 MW winter peak capacity contribution requires over 1,200 MW of installed nameplate capacity. After adjusting for peak capacity contribution, 6,717 MW of new resources installed nameplate capacity equals 3,093 MW summer peak capacity and 2,769 MW winter peak capacity, as detailed in Figure 2.1.

Figure 2.1: Nameplate Capacity Adjusted to Peak Capacity Contributions (MW) for 2030



➔ See Chapter Seven: Resource Adequacy Analysis and Appendix L: Resource Adequacy for a complete description of the resource adequacy modeling.

3.3. Renewable and Non-emitting Resources

We modeled several types of renewable and non-emitting utility-scale resources for this Electric Progress Report. Supply-side resources provide electricity to meet the load. These resources originate on the utility side of the meter. These resources include wind, solar, pumped hydro energy storage, battery energy storage, hybrid resources (combination of wind, solar, and battery), combustion turbines using alternative fuels such as biodiesel and hydrogen, and advanced nuclear small modular reactors (SMR).

Distributed energy resources (DER) are small, modular energy generation and storage technologies installed on the distribution systems rather than the transmission system. Distributed Energy Resources are typically under 10 MW and provide a range of services to the power grid. These resources include wind, solar, storage, and demand response technologies and may be networked to virtual power plants (VPPs). This report included demand response, distributed solar, and distributed storage programs as generic DERs.

➔ A full description of resources modeled for this progress report is in Appendix D: Generic Resource Alternatives, with a brief description in Chapter Five: Key Analytical Assumptions.

3.3.1. Impacts and Actions

Biodiesel

Biodiesel is a commercially available fuel that can be combusted in existing and new peaking plants. Biodiesel provides a carbon-neutral alternative to existing backup fuels like petroleum-derived diesel. Biodiesel is energy-dense and can be stored on site for short periods — one to two months — to provide reliability in the event green hydrogen or renewable natural gas supplies are exhausted or unavailable.

We will continue to monitor and engage with regional biodiesel manufacturers to determine the limits of biodiesel fuel supply. We anticipate a shift in biodiesel supply as the transportation sector is rapidly electrified and alternative fuels, such as biodiesel, become increasingly available to other industries.

Renewable Diesel

Renewable diesel — frequently referred to as R99 — is a commercially available fuel that can be combusted in various existing and new peaking plants. R99 provides a carbon-neutral alternative to existing backup fuels like petroleum-derived diesel. R99 is energy dense and can be stored on site (for periods measured in years) to provide reliability if green hydrogen or renewable natural gas supplies are exhausted or unavailable. Puget Sound Energy successfully tested R99 fuel in the Crystal Mountain generator and is coordinating with authorities to test R99 in a Frederickson generator in 2023.

We will continue to monitor and engage with regional R99 manufacturers to determine the limits of the R99 fuel supply. We anticipate an increase in R99 supply in 2024 as the transportation sector is rapidly electrified and alternative fuels, such as R99, become increasingly available to other industries.

Biodiesel and renewable diesel are derived from non-petroleum feedstocks like vegetable oil, animal fats, municipal waste, agricultural biomass, and woody biomass. Biodiesel is produced using a transesterification separation method, and renewable diesel uses a hydrogenation process. Renewable diesel meets all of the ASTM–D975 specifications. Renewable diesel can be blended with or replace petroleum-derived diesel without affecting engine operations or air operating permit requirements. Renewable diesel has a carbon intensity of approximately 60 percent less than petroleum diesel and reduced NOx, particulate matter, and VOC emissions.

Hydrogen

Green hydrogen has the potential to aid in the decarbonization of the electric sector without compromising reliability standards. Electrolyzers convert surplus renewable energy to hydrogen gas stored for long periods until needed during a peak event. During a peak event, green hydrogen is combusted with either existing retrofitted equipment or at new peaking plants. Until recently, high costs have dissuaded the development of hydrogen infrastructure for the energy sector, but production tax credits included in the Inflation Reduction Act have the potential to put green hydrogen in cost-parity with more conventional fuels.

Puget Sound Energy aims to be a leader in developing hydrogen infrastructure to bring the benefits of green hydrogen to the Pacific Northwest. Puget Sound Energy holds a place on the board of the Pacific Northwest Hydrogen Association[3], which is seeking to establish a network of suppliers, storage, and off-takers in the region as part of the Department of Energy's Hydrogen Hub (H2Hub) Funding Opportunity as part of the Infrastructure Investment and Jobs Act (IIJA). In addition to our work with Pacific Northwest Hydrogen Association, we are also working with Fortescue Future Industries and other regional interested parties to explore the development of a hydrogen production facility at the former Centralia coal mine in Centralia, Washington[4].

Beyond these initial efforts, we may explore pilot programs soon to learn more about blending hydrogen in existing, retrofitted, and new peaking plants. We will also continue to research fuel supply and security considerations.

Advanced Nuclear and Other Emerging Technologies

Clean energy dispatched on demand will be a key element of a decarbonized power grid. Energy storage, such as batteries, improves the ability of wind and solar resources to follow demand, but the energy-limited nature of energy storage systems constrains their effectiveness in longer-duration peak events. We are currently missing cost-effective clean energy resources, which follow load and generate power through long-duration peak events. Several emerging resources have the potential to fill this niche but require advancements in operability and commercial availability. We will continue to monitor the development of technologies such as advanced nuclear small module reactors (SMR), carbon capture and sequestration, and deep-well geothermal.

Energy Storage

Energy storage will be an essential component of a decarbonized power system to shift variable energy resources and load. As energy storage is added to PSE's system, we will learn how to use this new resource to optimize operational efficiency. We are reviewing energy storage submittals as part of the ongoing 2021 All-Source Request for Proposal (RFP).

We will also monitor advances in energy storage technology, such as new battery chemistries and long-duration batteries, or other storage mediums, such as gravity- or compression-based storage systems. We will evaluate these technologies as they become commercially viable.

3.4. Demand Response

Demand response programs are voluntary, and once enrolled, customers usually receive notifications in advance of forecasted peak usage times, requesting them to reduce their energy use. Some programs require action by the customer; others can be largely automated and are usually referred to as direct load control programs. For example, an

[3] https://pnwh2.com/
[4] https://ffi.com.au/news/centralia/

automated program might warm a customer's home or property earlier than usual with no action required on the part of the customer.

One example of a program that requires customer action is asking a wastewater plant to curtail pumping during certain peak energy need hours if they can. Because customers can always opt out of an event, demand response programs include some risk. If PSE relies on a certain amount of load reduction from demand response to handle a peak event, but customers opt out, we must use generating resources to fill the customer's needs.

We organized demand response programs modeled for this 2023 Electric Report in four categories:

- Behavioral Demand Response
- Commercial and Industrial (C&I) Curtailment
- Direct Load Control (DLC)
- Dynamic Pricing or Critical Peak Pricing (CPP)

➔ See Appendix E: Conservation Potential and Demand Response Assessments for the full CPA Assessment. We included a complete discussion of how we chose the demand response programs for the preferred portfolio in Chapter Three: Resource Plan Decisions.

Figure 2.4 lists the estimated 10-year achievable technical potential for demand response programs modeled for this report's residential, commercial, and industrial sectors. The table shows the attainable potential of each demand response program in MW, and the winter and summer peak need it fills to illustrate the total potential impact of demand response on system peak.

Table 2.4: 10-year Achievable Technical Potential Demand Response Programs for Model Year 2033 (MW)

Program	Category	Nameplate	Winter Peak	Summer Peak
Signal-capable Standard Water Heater[1]	Residential	74	61	51
Signal-capable Electric Heat Pump Water[1]	Residential	16	14	9
Signal-capable Heating, Ventilation, and Air Conditioning[1]	Residential, Commercial	102	73	98
Bring Your Own Smart (Internet-connected) Thermostat	Residential, Commercial	83	65	64
Signal-capable Electric Vehicle Charger[1]	Residential	21	15	20
Reduced (Lower) Electric Usage at Utility's Request	Commercial, Industrial	20	14	21
Time of Day Rates (Optional)	Residential, Commercial, Industrial	58	33	77
Electric Rate Allowing Electricity Cut Off in Periods of High Demand	Commercial	12	9	11

Note:
1. Capable of receiving internet, cellular, or radio signals.

3.4.1. Impacts and Actions

Distributed energy resources, including demand response, are a significant component of PSE's preferred portfolio from the 2023 Electric Progress Report and represent a piece of our strategy to achieve the targets laid out under CETA. Puget Sound Energy issued a DER Request for Proposal (RFP) in 2022. We are still working through the analysis and will have an updated target in the 2023 CEIP Biennial update.

4. Equitable Transition to Clean Energy

The Clean Energy Transformation Act (CETA) sets out important new expectations for the clean energy transition: that utilities must ensure that all customers benefit from the transition to clean energy.

4.1. Assess Current Conditions

To move toward an equitable transition to clean energy, we performed an economic, health, and environmental benefits (EHEB) assessment (the assessment) in 2021 to guide us as we developed our CEAP and CEIP. The purpose of the assessment was two-fold: first, to use the definitions we provided in our CEIP for named communities to identify highly impacted communities and vulnerable populations within our service area, and second, to measure disparate impacts to these communities using specific customer benefit indicators.

➔ See the updated assessment in Appendix J: Economic, Health, and Environmental Assessment of Current Conditions.

The initial qualitative and quantitative customer benefit indicators we developed through the assessment provide a snapshot of the economic, health, environmental, and energy security and resiliency impacts of resource planning on highly impacted communities and vulnerable populations within PSE's service territory. PSE built upon those initial customer benefit indicators in the assessment in developing its CEIP. Due to the timing of the IRP process and the CEIP adjudication, the proposed customer benefit indicators included in the CEIP may change based on the upcoming Washington Utilities and Transportation Commission decision on PSE's CEIP and in the future through public participation and input from PSE's Equity Advisory Group. The customer benefit indicators help measure progress toward achieving an equitable distribution of benefits and reducing burdens.

4.2. Customer Benefit Indicators

A key component to ensuring the equitable distribution of burdens and benefits and a reduction of burdens to vulnerable populations and highly impacted communities in the transition to a clean energy future is to include customer benefit indicators (CBIs) in the preferred portfolio development process. For this 2023 Electric Progress

Report, PSE used the CBIs established in the 2021 CEIP through extensive public participation and consultation with our equity advisory group.

We expanded on applying CBIs to the portfolio analysis with input from interested parties. First, we linked CBIs to specific portfolio modeling outputs to reflect customer benefit indicators in developing the preferred portfolio. We then combined these outputs into broader CBI areas, providing a context for interpreting the portfolio outputs. We indexed each portfolio from the sensitivity analyses on how well it performed in each CBI area to understand which benefits or burdens it may confer on our customers. Portfolios had to score well in several CBI areas to be considered in a preferred portfolio.

➔ See Chapter Three: Resource Plan, Chapter Eight: Electric Analysis, and Appendix H: Electric Analysis and Portfolio Model for more detail on the customer benefit indicator framework.

In summary, we have taken several actions that put us on a pathway to ensure all customers benefit from the transition to clean energy:

- Developed a public participation plan for the CEIP to obtain input on the equitable distribution of benefit and burdens
- Established the Equity Advisory Group
- Refined customer benefit indicators and metrics with the EAG and the CEIP public participation process
- Updated the portfolio benefits analysis to incorporate the customer benefit indicators and related metrics in the 2023 Electric Progress Report and future IRPs or CEIPs

Identifying and using customer benefit indicators is a developing process. Future IRPs will benefit from more input from the Equity Advisory Group (EAG) and the CEIP public participation process.

4.3. Vulnerable Populations and Highly Impacted Communities

As part of our work for the CEAP, we reviewed the CBI baseline data, often broken down into metrics for vulnerable populations and highly impacted communities, published in the 2021 CEIP. This report provides more detailed information about the 2020 and 2021 CBI data.

We will publish the metrics for 2022 for all CBI data included in Appendix J: Economic, Health and Environmental Assessment of Current Conditions of this report in our 2023 biennial CEIP update. We incorporate vulnerable populations and highly impacted communities in the IRP process by considering these groups while developing the achievable technical potentials for energy efficiency programs as part of the CPA discussed in Appendix E: Conservation Potential and Demand Response Assessments. The generic supply side resources we studied as part of the IRP lack detailed enough geographic information to establish relationships between resource selection and impacts on named communities.

➔ See Appendix J: Economic, Health, and Environmental Assessment of Current Conditions for details on the changes to the analyses.

5. Resource Deliverability

We will work to optimize our use of PSE's existing regional transmission portfolio to meet our growing need for renewable resources in the near term. However, the Pacific Northwest transmission system may need significant expansion, optimization, and possible upgrades in the long term to keep pace. The main areas of high-potential renewable development are east of the Cascades (Washington and Oregon), in the Rocky Mountains (Montana, Wyoming), in the desert southwest (Nevada, Arizona), and in California. Table 2.5 shows the regional transmission need for new resources outside PSE.

Table 2.5 Regional Transmission Need Based on 2023 Preferred Portfolio (MW)

Region	2030 (MW)	2033 (MW)
East of the Cascades (Central and Eastern Washington)	3,449	3,447
Rocky Mountain Region (Montana and Wyoming)	400	800
Cross Cascades Total	3,849	4,247
British Columbia	0	0

➔ See Appendix J: Regional Transmission Resources from the 2021 IRP on specific opportunities for expanding transmission capabilities and regional efforts to coordinate transmission planning and investment. The 10-year delivery system plan is in this report's Appendix K: Delivery System Planning.

Our delivery system needs investments to deliver energy to our customers from the edge of PSE's territory and to support DERs within the delivery grid. The delivery system 10-year plan described in Appendix K: Delivery System Planning identifies work needed to ensure safe, reliable, resilient, smart, and flexible energy delivery to customers, regardless of resource fuel source. This work includes specific upgrades to the transmission system to meet NERC compliance requirements, other evolving regulations related to DER integration and markets, and distribution system upgrades to enable higher DER penetration. Specific delivery system investments will become known when energy resources, whether centralized or DERs, begin siting through the established interconnection processes. The readiness of the grid and customers for DER integration will decrease the cost of interconnection and increase the number of viable locations. Proactive investments in grid modernization are also critical to support the clean energy transition and maximize benefits. We summarized the key investment areas in the following section.

5.1. Impacts and Actions

Puget Sound Energy is pursuing the acquisition of new additional transmission capacity and optimization of existing transmission capacity rights required to facilitate the delivery of its preferred resource portfolio. We are exploring ongoing opportunities to contract with the Bonneville Power Administration (BPA) for additional transmission rights by submitting transmission service requests (TSRs) and participating in BPA's annual cluster study. The BPA annual cluster study results may trigger requirements for funding BPA system reinforcement projects needed to award the requested TSR(s). Funding these reinforcement projects will be critical to adding capacity to the regional transmission system and projects delivering to PSE's system.

Puget Sound Energy seeks to repurpose specific portions of our transmission portfolio to enhance our value to align with the preferred resource portfolio. Existing Mid-C transmission capacity allocated for market purchases could be strategically redirected for new renewable projects and projects delivering to Mid-C. Colstrip Units 3 & 4 transmission rights could be repurposed for new Montana resource deliveries. In addition, standalone PSE generation facilities could be further developed to co-locate with new renewable projects for optimized energy delivery over shared transmission (e.g., Lower Snake River, Wild Horse, Goldendale).

6. Achieving CETA Compliance: 100 Percent Greenhouse Gas Neutral by 2030

Under CETA, utilities can meet up to 20 percent of the 2030 greenhouse gas neutral standard with an alternative compliance option. Utilities can use these alternative compliance options from January 1, 2030, to December 31, 2044. An alternative compliance option includes any combination of the following:

- Investing in energy transformation projects that meet criteria and quality standards developed by the Department of Ecology, in consultation with the Department of Commerce and the Commission
- Making an alternative compliance payment in an amount equal to the administrative penalty
- Purchasing unbundled renewable energy credits (RECs)

For this report, we modeled unbundled RECs to achieve CETA compliance 2030–2044, where renewable and non-emitting energy could be less than 100 percent of delivered energy annually. The preferred portfolio only incurs one alternative compliance payment in 2030 of $3.18 million worth of unbundled RECs to make up for 3.4 percent of delivered energy. For all future years of the CEAP horizon, the preferred portfolio meets the 100 percent standard without the need for alternative compliance options.

➔ See Chapter Five: Key Analytical Assumptions for a discussion on alternative compliance assumptions and costs. Appendix I: Electric Analysis Inputs and Results for portfolio modeling results.

7. Social Cost of Greenhouse Gases

The social cost of greenhouse gases (SCGHG) was included per WAC 480-100-620(12)(i).[2]

➔ General assumptions for the SCGHG are in Chapter Five: Key Analytical Assumptions, and a detailed modeling description of the SCGHG is in Appendix G: Electric Price Models.

RESOURCE PLAN
CHAPTER THREE

PUGET SOUND ENERGY

Contents

1. Introduction

This chapter presents Puget Sound Energy's preferred portfolio for the 2023 Electric Progress Report (2023 Electric Report). Our preferred portfolio is the result of robust Integrated Resource Plan (IRP) analyses developed with input from interested parties. Informed by our deterministic portfolio, risk, and portfolio benefit analyses, this portfolio meets the Clean Energy Transformation Act (CETA) requirements.

Puget Sound Energy is the Pacific Northwest's largest utility producer of renewable energy. We currently own and contract more than 10 million MWh of renewable and non-emitting energy, and we forecast this will grow to more than 30 million MWh by 2045.

Throughout the resource planning process for the 2023 Electric Report, we focused on the following key objectives, which lay the foundation for this and all future resource plans:

- Achieve the renewable energy targets under CETA — meet at least 80 percent of PSE's demand with renewable and non-emitting energy and achieve carbon neutrality by 2030, and meet 100 percent of PSE's demand with renewable and non-emitting resources by 2045.
- Build a reliable, diversified power portfolio of renewable and non-emitting resources.
- Continue to be a clean energy leader in the Pacific Northwest and beyond.
- Ensure an equitable transition to clean energy for all PSE customers.
- Ensure our resource planning aligns with PSE's Clean Energy Implementation Plan (CEIP) to meet our interim targets and CETA obligations.
- Ensure resource adequacy while transitioning to clean energy.

We used three distinct types of analysis to develop, refine, and identify the preferred portfolio:

1. The deterministic portfolio analysis solves for the least-cost solution and assumes perfect foresight about the future.
2. The risk analysis examines the preferred portfolio's performance concerning uncertainty in hydroelectric, wind and solar conditions, electric and natural gas prices, customer demand, and unplanned plant-forced outages.
3. The portfolio benefit analysis incorporates equity into the IRP process by measuring potential equity-related benefits to customers within a given portfolio. Because the IRP process is inherently forward-looking, this analysis seeks to identify portfolios containing a mix of electric resources that can enable more equitable customer outcomes in the future. It is important to note the IRP process generally lacks the detail to assess specific existing or future programs and actions that address equity. However, the IRP process can provide a pathway that ensures we acquire the electric resources necessary to implement more equitable programs and measures.

➔ See Chapter Five: Key Analytical Assumptions and Chapter Eight: Electric Analysis for details on these analyses, including methodologies and results.

We present this chapter in the following three sections. Section 2 summarizes the preferred portfolio and describes how the resource additions will meet our projected demand growth. Section 3 describes the contributors to our near-term capacity deficit and how this drives the resource additions in the preferred portfolio. Section 4 presents our process for developing and selecting a preferred portfolio and includes our portfolio benefit analysis results.

2. Preferred Portfolio

Puget Sound Energy is committed to reaching the CETA goals and achieving greenhouse gas (GHG) neutrality by 2030 and a GHG-free electric energy supply by 2045. The electric resource plan shows our current path to meet CETA commitments. Our plan prioritizes delivering cost-effective, reliable conservation and demand response and distributed and centralized renewable and non-emitting resources to our customers at the lowest reasonable cost. The plan reduces direct PSE emissions and achieves GHG neutrality by 2030 through clean energy investments.

We have made many updates and changes since PSE's 2021 IRP. The preferred portfolio resource additions for the 2023 Progress Report include significant increases in renewable resources to meet the CETA requirements and peak demand. We provide a detailed discussion of these changes in Chapter Eight: Electric Analysis and the following summary:

- Capacity Resources: We saw increased capacity resources due to increasing peak demands over the 2021 IRP and reduced market reliance. With the increased peak capacity contribution and lower resource costs, we saw more energy storage resources added to the 2023 preferred portfolio than the 2021 IRP preferred portfolio.

- Clean Energy Resources: Overall, there is an increase in renewable resource additions to meet CETA requirements due to the increase in the demand forecast. A complete discussion of changes to the demand forecast is in Chapter Six: Demand Forecasts.

- Conservation: Overall, the 2023 Progress Report CPA potential is down from the 2021 IRP by approximately 13 percent by 2045. The reduction in the CPA is due to the newly incorporated impact of climate change assumptions, which reduced savings in the later years of the study, and a new statutory provision requiring the state to adopt more efficient building energy codes to achieve a 70 percent reduction by 2031. We added the impact of this statute, which moved some of the potential from energy efficiency into codes and standards, and the updated building stock assessments, which have more efficiency penetration compared to the last stock assessment.

- Distributed Energy Resources: The 2023 progress report is consistent with the CEIP targets through 2025, and then we see an increase in net-metering solar based on the new forecast from current trends and economics, including rebates from the inflation reduction act.

This section presents the preferred portfolio, describes how the combination of resource additions will meet our projected demand growth, and explains how diversifying resource technology is paramount to reducing technology risk. The preferred portfolio further clarifies the following near-term and long-term priorities.

Near-term Priorities (2024–2029):

- Add diverse commercially available resources to meet CETA energy and resource adequacy needs
- Add utility-scale and distributed resources to achieve the renewable or non-emitting energy targets specified in PSE's 2021 CEIP
- Begin commercial activity to acquire bulk transmission to transport renewable energy from distant renewable energy zones to our customers
- Begin shifting our planning frameworks to align with WRAP requirements as more long-term information becomes available
- Continue to acquire conservation resources
- Continue to develop and refine methods to embed equity into resource decisions.
- Continue to participate in the Western Resource Adequacy Program (WRAP) on an operational basis
- Explore commercial opportunities for advanced nuclear small modular reactors (SMR) capacity and other non-emitting technologies
- Lead and actively participate in developing the region's hydrogen hub infrastructure
- Pursue demand response programs that can effectively help lower peak demand
- Reduce reliance on short-term market purchases in response to the changing western energy market

Long-term Priorities (2030–2045):

- Complete acquisition and development of additional transmission capacity (e.g., Cross Cascades, Idaho, Wyoming, Montana, B.C.) to deliver additional clean energy to our customers
- Develop and acquire generating resources that take longer to develop to meet CETA non-emitting generation obligations while maintaining resource adequacy and peak demand.
- Examine repowering or upgrading existing thermal resources and renewable generation to better position PSE to achieve the 2045 goal of an emission-free generation portfolio.
- Explore new capacity options to drive diversity in our energy supply

2.1. Resource Additions Summary

Table 3.1 describes our preferred portfolio of resource additions. With this combination of conservation, demand response, renewable resources, energy storage, and CETA-qualifying peaking capacity, PSE will reach GHG neutrality by 2030. However, given the large amounts of variable energy resources, such as wind and solar, and energy-limited resources, such as energy storage, we will need to rely on newer technologies, such as hydrogen, to reach a GHG-free energy supply by 2045 while maintaining reliability and resource adequacy. Although the high cost of advanced nuclear SMR deterred us from having it in the preferred portfolio, we will continue to monitor the technology.

Table 3.1: Electric Preferred Portfolio, Resource Additions Incremental Nameplate Capacity (MW)

Resource Type	2024–2025 Incremental	2026–2030 Incremental	2030 Cumulative	2031–2045 Incremental	2045 Cumulative
Demand Side Resources	**201**	**417**	**618**	**646**	**1,265**
Conservation[1]	65	216	281	537	818
Demand Response	136	201	337	110	446
Distributed Energy Resources	**212**	**527**	**739**	**1,652**	**2,392**
DER Solar	172	380	552	1,572	2,124
Net Metered Solar	*59*	*225*	284	*1,109*	*1,393*
CEIP Solar	*79*	-	79	-	*79*
New DER Solar	*34*	*155*	*189*	*463*	*652*
DER Storage[2]	40	147	187	80	267
Supply Side Resources	**1,337**	**4,023**	**5,360**	**5,814**	**11,174**
CETA-qualifying Peaking Capacity[3]	237	474	711	877	1,588
Wind	600	800	1400	2,250	3,650
Solar	100	600	700	1,590	2,290
Green Direct	-	100	100	-	100
Hybrid (Total Nameplate)	300	1,150	1450	298	1,748
Hybrid Wind	*100*	*500*	*600*	*200*	*800*
Hybrid Solar	*100*	*300*	*400*	-	*398*
Hybrid Storage	*100*	*350*	*450*	*100*	*550*
Biomass	-	-	-	-	-
Nuclear	-	-	-	-	-
Standalone Storage	100	900	1000	800	1,800
Total	**1,750**	**4,967**	**6,717**	**8,112**	**14,830**

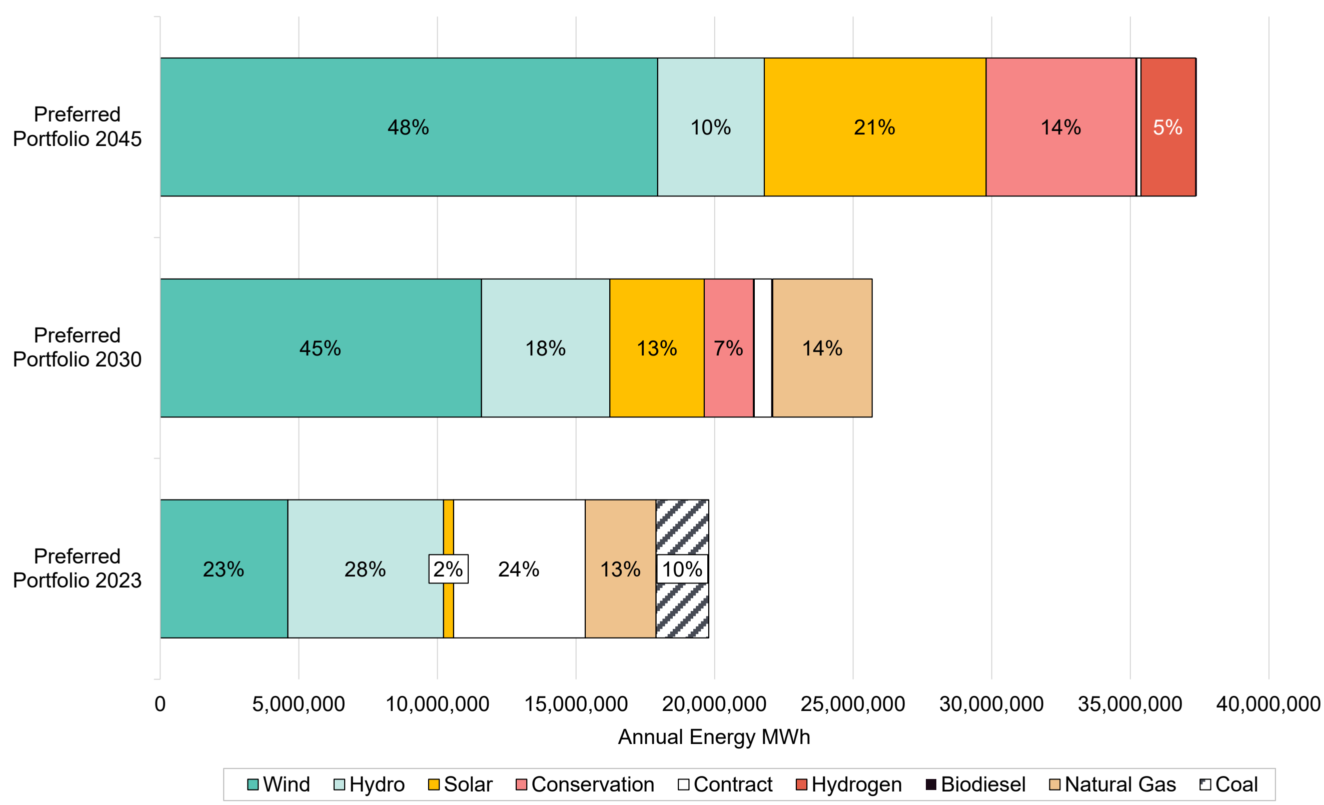
Notes:

1. Conservation in winter peak capacity includes energy efficiency, codes and standards, and distribution efficiency.
2. Distributed Energy Resources (DER) storage includes CEIP storage additions, non-wires alternatives, and distributed storage additions.
3. CETA-qualifying peaking capacity is functionally like natural gas peaking capacity but operates using non-emitting hydrogen or biodiesel fuel.

Figure 3.1 illustrates the projected annual energy production in 2023 and the future with the preferred portfolio. Wind resources are the largest share of capacity additions in the preferred portfolio, accounting for 36 percent of all energy-producing resources added to the planning horizon. However, wind resources produce 48 percent of the total annual energy in 2045, far more than its nameplate capacity indicates. Conversely, CETA-qualifying peaking capacity accounts for 13 percent of nameplate capacity (excluding storage) added by 2045 but supplies only 6 percent of the annual energy in 2045. Figure 3.1 illustrates that with the preferred portfolio, solar and wind remain the primary energy supply for meeting CETA, supplying nearly 70 percent of the portfolio's

CETA qualifying peaking capacity is functionally like natural gas peaking capacity but operates using non-emitting hydrogen or biodiesel fuel. We describe CETA qualifying peaking capacity in Chapter Five: Key Analytical Assumptions, and present alternative fuel assumptions in Appendix D: Generic Resource Alternatives. **RCW 19.405.020 (34)** annual energy in 2045. While CETA-qualifying peaking capacity resources are essential for resource adequacy, as discussed later in this chapter, they don't contribute substantially to the CETA-qualifying energy need.

Figure 3.1: Forecasted Annual Energy Production (Excluding Storage Dispatch)



2.2. Meeting Future Growth

The 2023 Electric Report shows we will meet future sales growth by combining utility-scale, demand-side (conservation), and distributed energy resources (DERs) described in Table 3.1. Distributed energy resources include storage systems, solar generation, or demand response that provides specific benefits to the transmission and distribution systems and simultaneously supports resource needs. The role of DERs in meeting system needs is changing, and the planning process is evolving to reflect that change. Distributed Energy Resources make lower peak capacity contributions and have higher costs. However, they are essential in balancing utility-scale renewable investments, transmission constraints, and local distribution system needs. The 2023 analysis also shows these resources enable larger equity benefits.

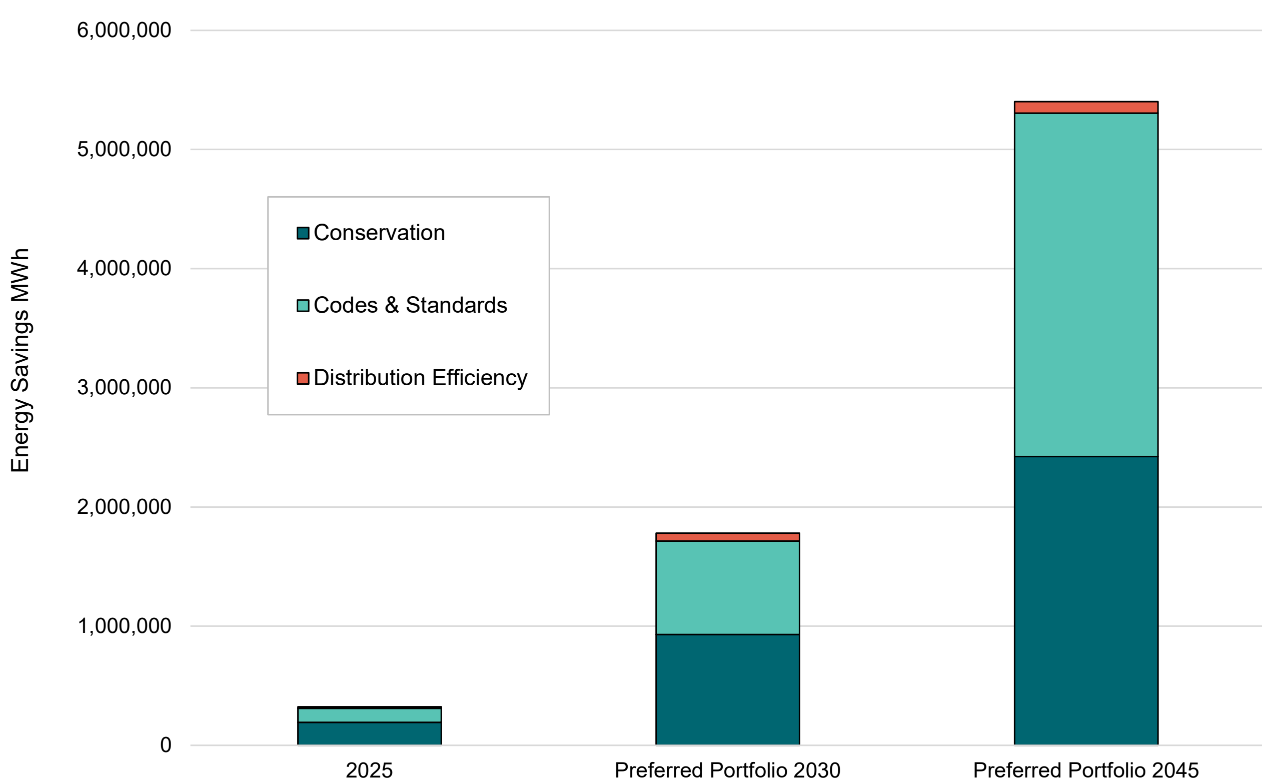
In the following section, we detail how the combination of resources in this plan will meet demand growth.

2.2.1. Conservation

For this analysis, conservation includes new energy efficiency measures, new codes and standard gains in efficiency, and distribution efficiency. Figure 3.2 describes the new energy savings from the preferred portfolio conservation measures.

➔ Appendix E: Conservation Potential Assessment contains a detailed discussion of the building codes and energy efficiency measures we modeled.

Figure 3.2: Preferred Portfolio Conservation Savings (MWh)

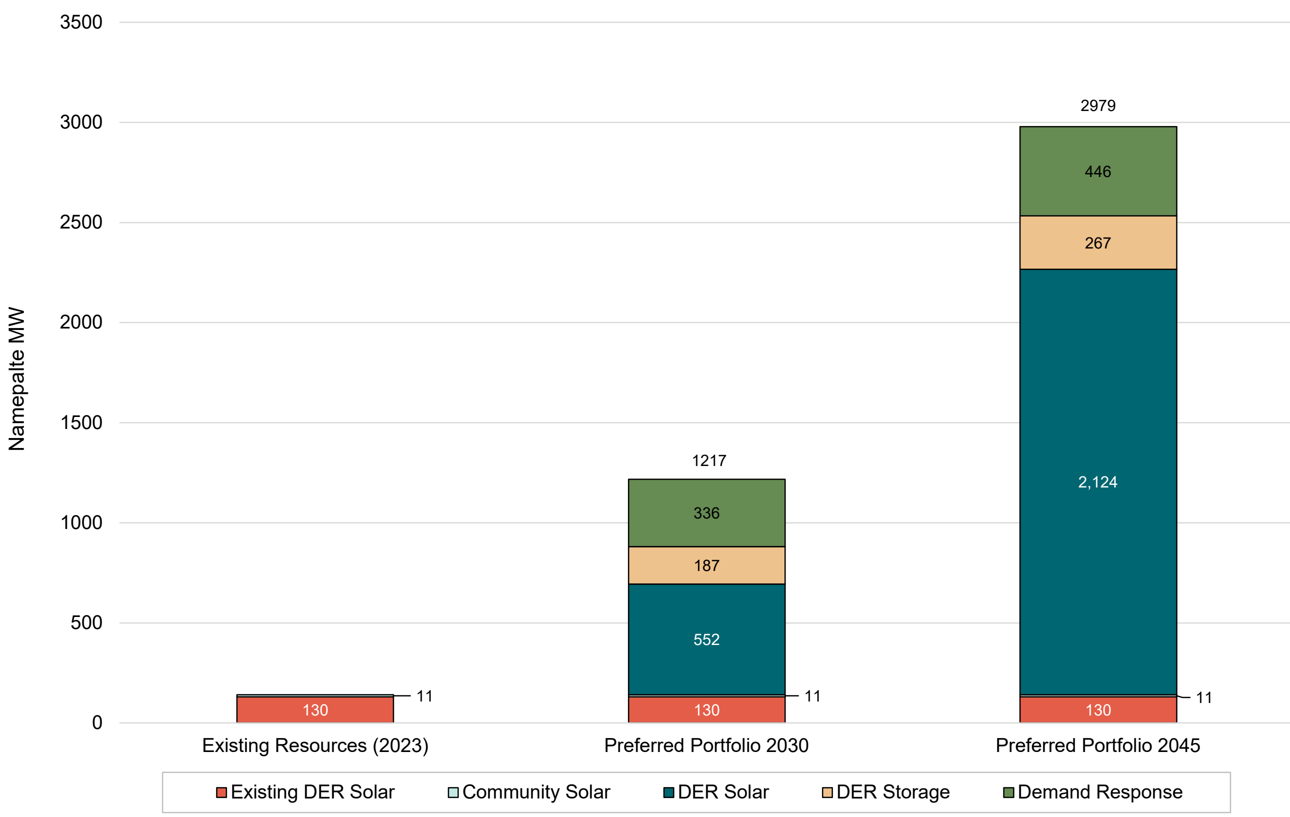


2.2.2. Distributed Energy Resources

Distributed energy resources are any resources located below the substation level. The customer or PSE can install DER. We included demand response, solar, and energy storage as distributed resources for this analysis. Our system includes 130 MW of customer-installed rooftop solar through net metering and 11 MW of community solar. We estimate we will add 552 MW of distributed solar and 187 MW of storage to the portfolio by 2030, growing to 2,124 MW of solar and 267 MW of energy storage by 2045. Demand response programs are peak savings options offered to customers, including direct load control for indoor heating and air conditioning thermostats and water heaters, managed electric vehicle charging, and critical peak pricing. Some distributed resources cost more than utility-scale programs but potentially enable larger equity benefits. Thoughtfully implemented, distributed resources can enable more equitable outcomes for customers in the clean-energy transition. We considered DERs necessary when developing our preferred resource plan, as discussed in Section 4 of this chapter.

Figure 3.3 shows the distributed resource capacity added to the preferred portfolio.

Figure 3.3: Preferred Portfolio Distributed Resource Additions (Nameplate MW)



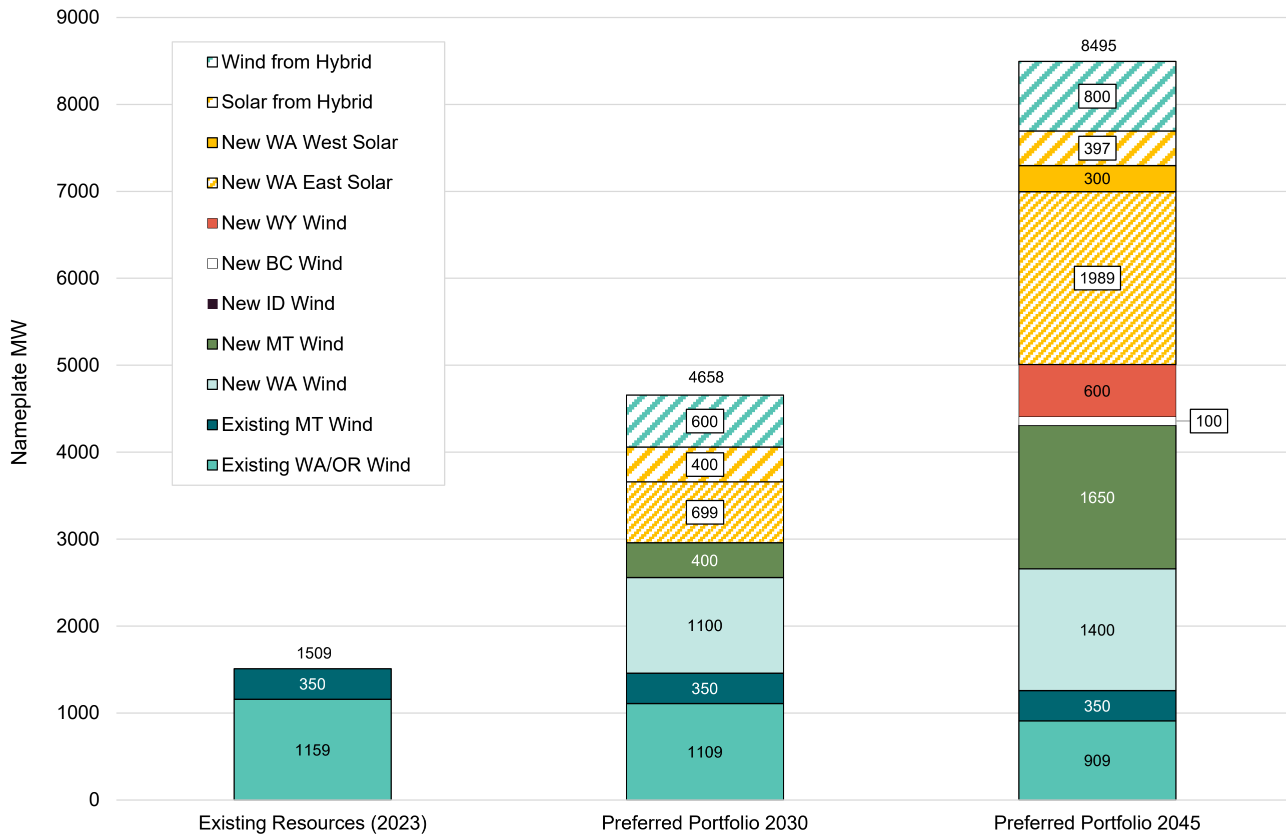
2.2.3. Clean Energy Resources

Qualifying clean energy (renewable and non-emitting) resources under CETA include wind, solar, advanced nuclear SMR, and alternative fuels such as biodiesel and hydrogen. Along with distributed energy resources, we must add many large utility-scale resources to the portfolio to meet the clean energy requirements. Figure 3.4 presents the utility-scale renewable resource additions in the preferred portfolio.

The scale and diversity of renewables PSE needs will require access to renewables outside Washington State and around the Pacific Northwest region, such as Montana, Wyoming, Idaho, and British Columbia. We will work to optimize our existing regional transmission portfolio to meet our growing need for renewable resources in the near term. However, the Pacific Northwest transmission system likely will need to be significantly expanded, optimized, and possibly upgraded to keep pace with the growing demand for clean energy. Puget Sound Energy will have to invest in the transmission system to deliver energy to customers from the edge of our territory and support the integration of distributed energy resources and demand response within the delivery grid.

The preferred portfolio adds almost 3,200 MW of new wind and solar resources to meet the CETA clean energy requirements by 2030. Of the 3,200 MW of wind and solar additions, 2,800 MW are resources in Washington State that will need cross-Cascades transmission. The remaining 400 MW are in Montana and will use Montana transmission.

Figure 3.4: Preferred Portfolio Wind and Solar Additions (MW)



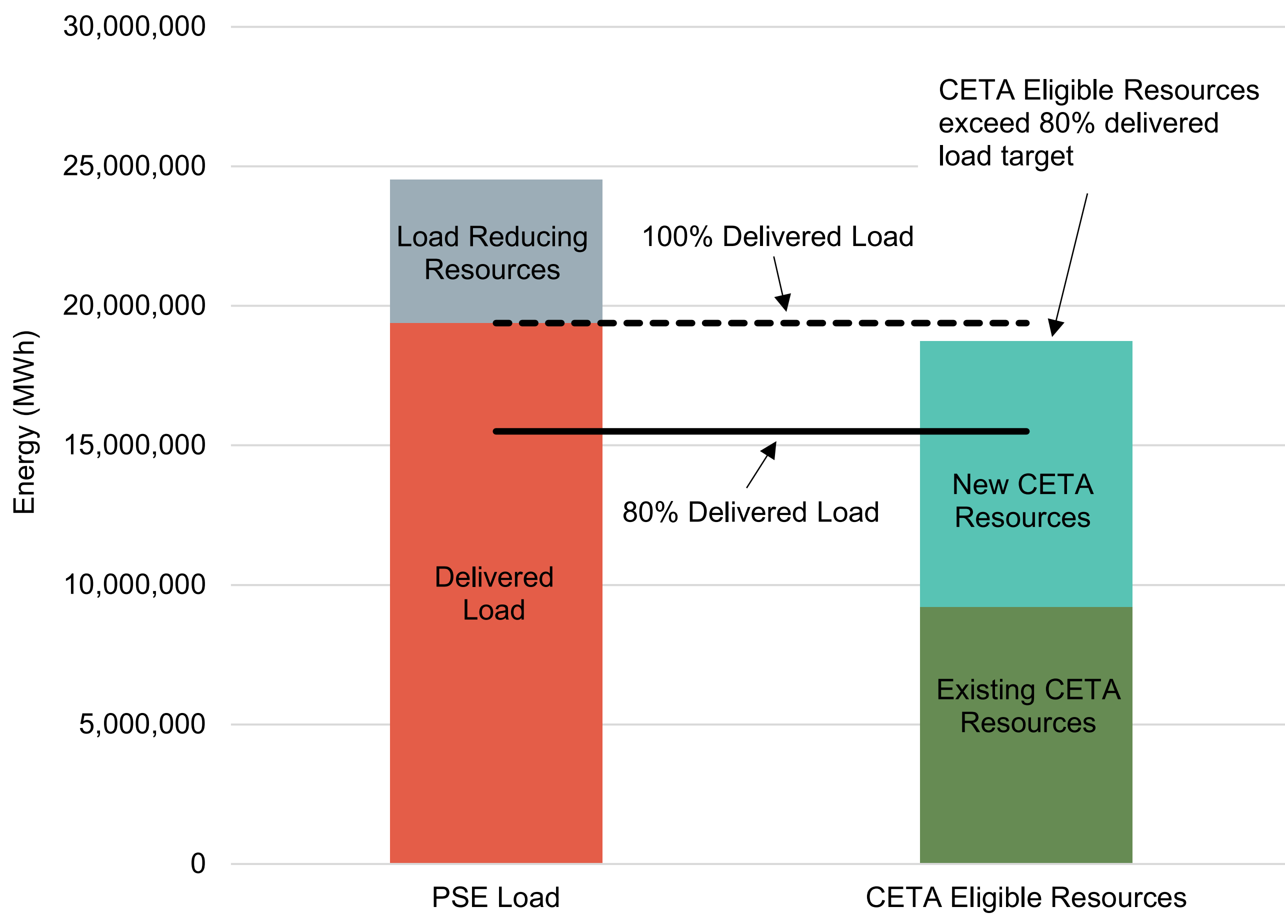
Risk of Meeting CETA Requirements

In 2030, we must meet at least 80 percent of retail sales with renewable or non-emitting resources. Figure 3.5 is the breakdown of the 2030 CETA requirement. As we can see from the chart, the preferred portfolio is well above the 80 percent requirement. For CETA compliance, we take the requirement on the adjusted retail sales after conservation, demand response, PURPA contracts[1], and voluntary renewable programs, including solar net-metering, Green Direct, and community solar. The gray bar in the chart represents the load-reducing resources, and the red bar is retail sales

[1] Public Utility Regulatory Policy Act (PURPA) qualifying facilities (QFs) are smaller generating units that use renewable resources, such as solar and wind energy, or alternative technologies, such as cogeneration.

after adjustment for load-reducing resources. The top of the red bar would be 100 percent, and the black line is 80 percent of the retail sales.

Figure 3.5: CETA Compliance in 2030 (Annual Energy MWh)



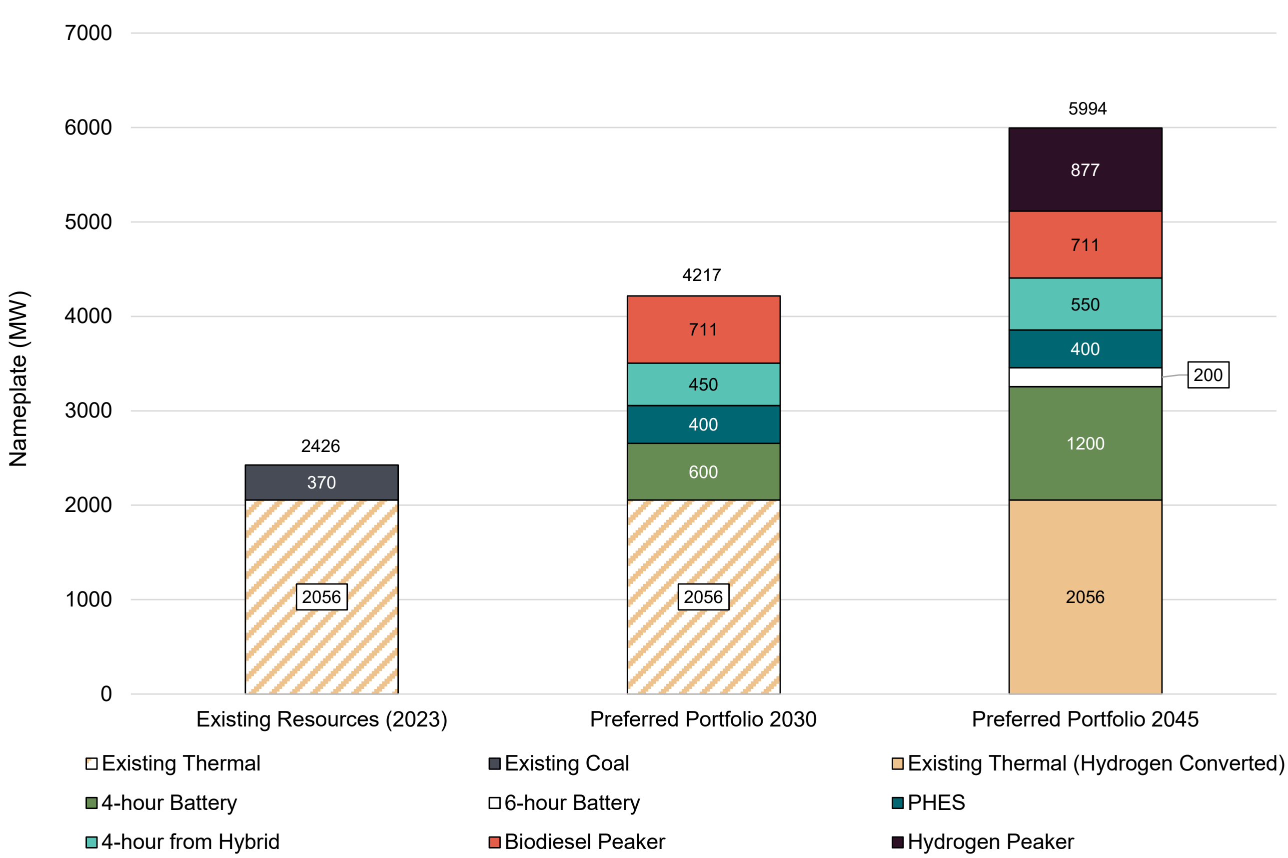
As part of the stochastic risk analysis, one of the future risks tested was whether the preferred portfolio would meet the CETA requirements under different conditions, such as changes in the demand forecast, hydroelectric generation, wind generation, and solar generation. Under all these conditions, renewable resource generation stays well above the base target for annual energy, ranging in 2030 from 80 percent at the lowest to 124 percent on the highest end, with half of the forecasted simulations in the range of 93 percent to 105 percent.

➔ Chapter Eight: Electric Analysis presents a complete discussion of the stochastic portfolio analysis.

2.2.4. Capacity Resources

Qualifying resources under CETA analyzed in this report include peaking capacity, energy storage, and advanced nuclear SMR. The peaking capacity we modeled includes CETA-qualifying fuels such as biodiesel and hydrogen, referred to herein as CETA-qualifying peaking capacity. We assumed hydrogen fuel would be available starting in 2030. We assumed natural gas to hydrogen blending would begin at 30 percent hydrogen in 2030 and increase to 100 percent by 2045. We left more than 2,000 MW of existing thermal resource capacity in the portfolio and converted it to hydrogen to maintain system reliability through resource adequacy. We modeled existing thermal resources with an option to retire them economically or convert them to hydrogen starting in 2030. As shown in Figure 3.6, the model added three additional peakers that will use biodiesel as fuel by 2030 and more than 800 MW of new hydrogen peakers by 2045. The model selected 1,450 MW of new energy storage by 2030, growing to 2,350 MW by 2045 to help meet resource adequacy and ancillary services. Energy storage resources are not energy-producing resources; they store the energy produced from other resources to be available during peak hours.

Figure 3.6: Preferred Portfolio CETA-qualifying Capacity Additions (Nameplate MW)



Hydrogen Fuel Risk

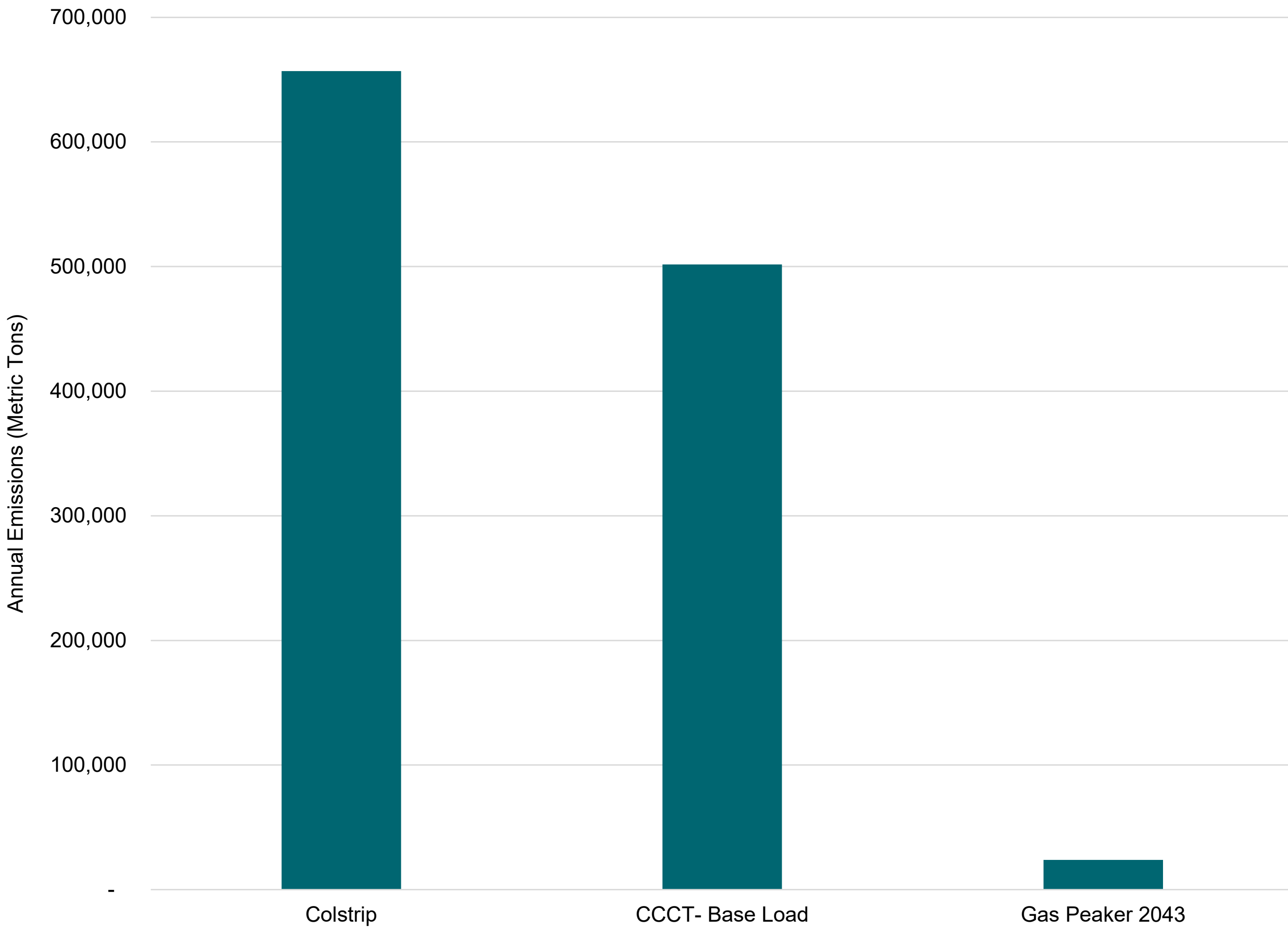
Green hydrogen has the potential to aid in the decarbonization of the electric sector without compromising reliability standards. Electrolyzers convert surplus renewable energy to hydrogen gas, which is stored for long periods until it is needed during a peak event. During a peak event, green hydrogen is combusted with either retrofitted existing equipment or at new peaking plants. Until recently, high costs have dissuaded development of hydrogen infrastructure for the energy sector, but production tax credits included in the Inflation Reduction Act have the potential to put green hydrogen in cost-parity with more conventional fuels.

In the preferred portfolio, the new hydrogen peakers start in 2039, giving us several years to understand the fuel supply before making resource acquisitions. Integrated Resource Plan meeting participants asked, "What if PSE built peakers assuming they blend to full hydrogen, but hydrogen is not available as planned?" First, we would not start building or acquiring a hydrogen peaker until 2035, which gives us more time to understand the hydrogen supply and availability. Second, we can build dual-fueled peakers using biodiesel as a backup fuel. Puget Sound Energy has eight peaking units with a backup fuel supply. We are experts in the process and requirements to set up and maintain a backup fuel supply. Like the existing peaker units, the backup is available in a tank on the property in case of primary fuel supply interruptions. Puget Sound Energy holds a place on the board of the Pacific Northwest Hydrogen Association and is working with other regional parties to explore development of a hydrogen production facility at the former Centralia coal mine in Centralia, Washington.

➔ A discussion of the work that PSE is doing on Hydrogen is in Chapter Two: Clean Energy Action Plan.

Finally, we looked at what would happen in a worst-case scenario where the frame peaker had to run on natural gas. In this event, for the limited hours the plant must run for peak contribution, the equivalent forecasted emissions would be 16,000 metric tons annually. Figure 3.7 illustrates the equivalent emissions on an equal-sized coal-fired plant (Colstrip) and a combined cycle combustion turbine (CCCT) baseload gas plant for comparison.

Figure 3.7: Annual Greenhouse Gas Emissions based on equivalent 237 MW (Metric tons CO2e)



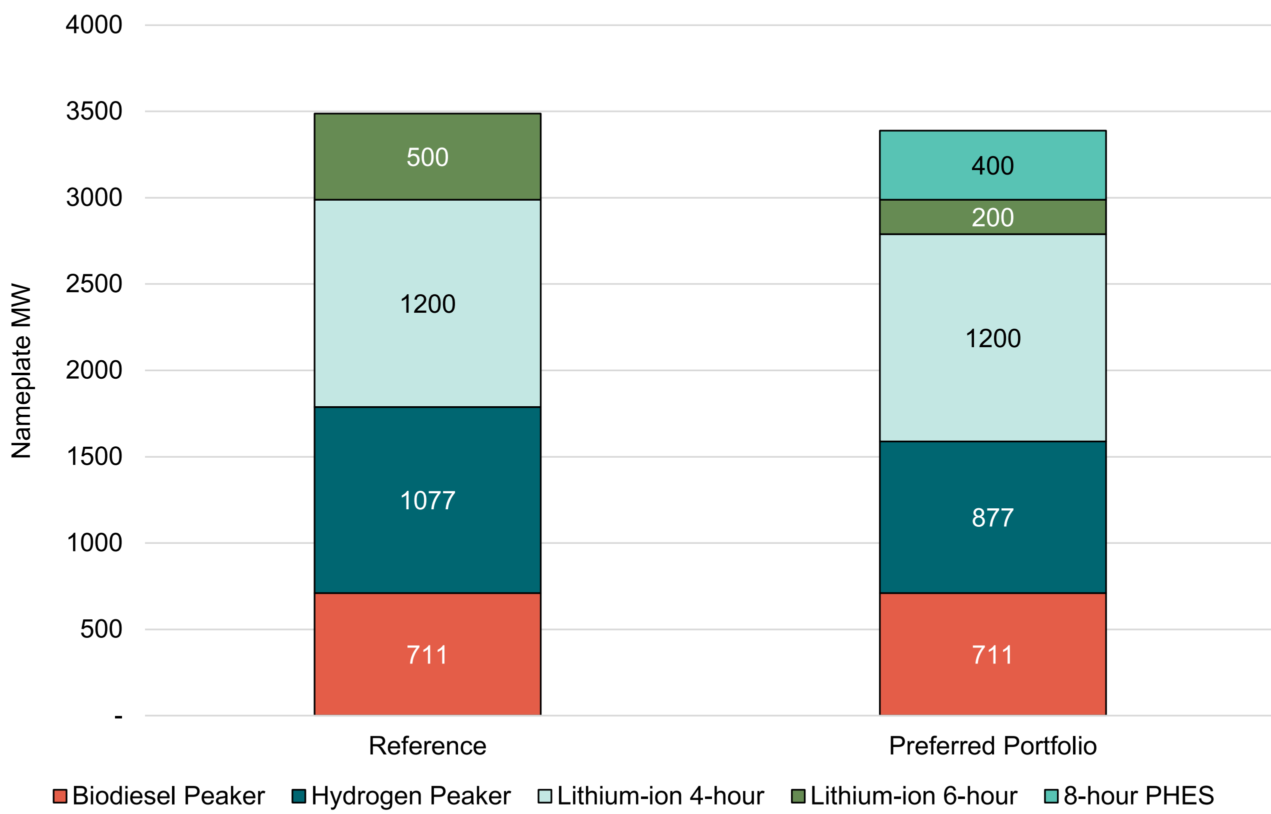
2.3. Diversifying the Portfolio

As PSE and the region seek to decarbonize systems, the future of electricity is a diverse portfolio of renewable and non-emitting resources. A diverse energy mix is essential for energy security because it is less dependent on a single fuel source, reducing vulnerabilities due to market price, supply fluctuations, and political unrest. Multiple, reliable generation sources allow a utility to provide power without disruption if one energy source fails. A diverse portfolio can reduce environmental impacts, improve reliability, and promote innovation to meet the needs of more than 1.5 million PSE customers. Resource diversity is the key to reducing emissions while preserving reliability and affordability.

The initial least-cost reference portfolio we developed for the 2023 Electric Report relies primarily on a few resources because we designed the model to select the lowest-cost resources available. However, we need to consider factors such as risk and feasibility when considering resources to include in the preferred portfolio. For example, the least-cost reference portfolio relies heavily on 4-hour batteries and hydrogen as a fuel because 4-hour batteries are the lowest-cost energy storage resource, and hydrogen is the lowest-cost, CETA-qualifying fuel source for thermal resources. To develop the preferred portfolio, we adjusted the least-cost reference portfolio to bring more diversity and lower its inherent technology and feasibility risks.

Figure 3.8 shows how we adjusted the storage resources in the preferred portfolio from the reference case to create a diverse portfolio that relies on multiple resources to meet demand. Figure 3.8 shows how diversifying storage resources results in less hydrogen peaker capacity.

Figure 3.8: New Energy Storage and Peaking Capacity Nameplate Additions by 2045 (MW)



Energy Storage

The least-cost reference portfolio will add 1,000 MW of four-hour batteries by 2030 because they are the lowest-cost energy storage resources. We adjusted the types of energy storage resources for the preferred portfolio to include more diverse technologies. For the preferred portfolio, we added 200 MW of pumped hydroelectric energy storage (PHES) in Montana and 400 MW of new Montana wind along with the existing 350 MW of wind. We added 200 MW of PHES in the Pacific Northwest to the preferred portfolio for 400 MW of PHES. The remaining energy storage is a mix of four-hour and six-hour batteries.

Advanced Nuclear Small Modular Reactors

In the least-cost reference portfolio, we modeled building more than 800 MW of new hydrogen peakers by 2045 in addition to the 2,000 MW of existing resources converted from natural gas to hydrogen. By 2045, we projected hydrogen to account for 36 percent of the peak capacity contribution. This least-cost reference portfolio relies heavily on a single fuel source with an unknown supply, creating risk. To diversify the portfolio, we can explore other technologies, such as advanced nuclear SMR, to include in future preferred portfolios. There are many unknowns around new advanced nuclear SMR technology. Although the high cost of advanced nuclear SMR deterred us from having it in the preferred portfolio, we will continue to monitor the technology. As advanced nuclear SMR technology matures, it could be a resource to help reduce the risks of relying on only a few technologies and a way to meet the CETA 100 percent requirement by 2045.

3. Resource Adequacy

The Pacific Northwest electricity industry is transitioning as governments and system planners implement major decarbonization policies. Operators and utilities are retiring significant quantities of coal-fired capacity while adding new renewable generation resources. As a result, PSE and other utilities are rethinking how we plan our systems, especially concerning resource adequacy. As we transition to 100 percent clean energy by 2045, we must ensure customers have reliable electricity and smoothly transition to a decarbonized system.

The resource adequacy analysis for this 2023 Electric Report resulted in a capacity deficit of 2,629 MW, more than double the 2021 IRP capacity deficit projected for 2029. This large deficit drives the large capacity additions in the preferred portfolio. This section describes the elements contributing to this deficit, including updates to the planning reserve margin, our reduction in market reliance, and variable resource peak capacity contributions.

3.1. Planning Reserve Margin Updates

The resource adequacy analysis for this 2023 Electric Report led us to increase the planning reserve margin to 23.8 percent in 2029, resulting in a capacity deficit of 2,629 MW. Two main elements contributed to the rise in the planning reserve margin:

- Climate change data in the load forecast and peak temperatures — when we accounted for average temperature trends, it only slightly lowered the one-in-two winter peak and increased the summer peak. Although summer peak temperatures increased, they do not come close to the winter peak level in this

2023 Electric Report's planning horizon. However, temperature volatility increased, which we accounted for in the resource adequacy and contributed to the overall increase in the planning reserve margin.

- Increase in peak demand — although the one-in-two winter peak lowered slightly, the updated electric vehicle (EV) forecast increased the demand. The increase in peak from the EV forecast was larger than the decrease from the climate change data, resulting in an overall increase to the one-in-two peak demand.

Climate change data also showed changes in the duration and frequency of loss of load events, which affected the capacity deficit. The data showed a decrease in event duration, less frequent events in the winter and more frequent events in the summer. Including climate change data increased the effective load-carrying capacity (ELCC) for solar and shorter-duration storage resources (those that discharge energy at the rated power output for less than 10 hours). Climate change data also shows the historical spring runoff is happening earlier in the year, which changes hydropower availability and the profile of hydroelectric generation and leaves less water for the summer.

3.2. Reduced Market Reliance

The western energy market has had surplus capacity for more than a decade. Given PSE's available firm transmission to the Mid-Columbia market hub, purchasing energy supply from the regional power market has been a cost-effective way to meet demand. However, the supply and demand fundamentals of the wholesale electric market have changed significantly in recent years in two important ways: supplies have tightened, and pricing volatility has increased.

In response to these changing conditions, we plan to replace short-term market supplies with firm resource adequacy qualifying capacity contracts compliant with CETA, meet our resource adequacy requirements, and align with a potential regional resource adequacy program. The preferred portfolio includes added firm capacity resources and reduced short-term market purchases.

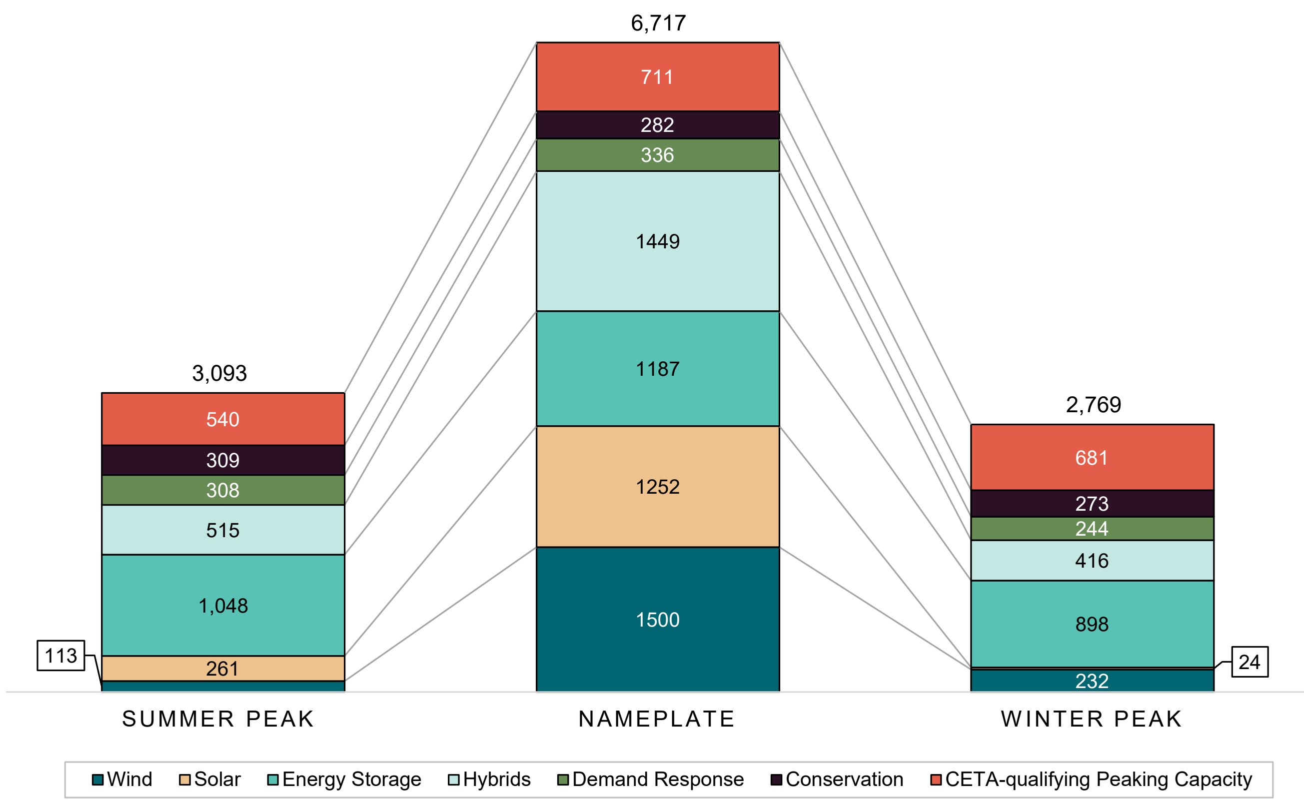
Our approach allows us to survey the market for available resource adequacy qualifying agreements and enables us to develop regional resource adequacy program requirements to help inform PSE's future needs. Given the tightening of energy markets and our preparations for possible participation in the Western Resource Adequacy Program (WRAP), we plan to reduce PSE's reliance on short-term wholesale market purchases.

This approach has challenges, such as permitting and building generating and storage resources and transmission to meet growing demands in an increasingly complex permitting landscape. Although those challenges are real, we are confident the resource plan in this 2023 Electric Report indicates a path to reach our clean energy goals and achieve the clean energy future our customers expect.

3.3. Peak Capacity Contribution

Electric resources, particularly variable resources such as solar and wind, rarely perform at nameplate capacity during peak need. Therefore, ensuring resource adequacy relies on evaluating a resource's peak capacity contribution, which is the nameplate capacity combined with the ELCC. After adjusting for the peak capacity contribution of each resource, we need more resources to meet the peak need than the nameplate capacity suggests. For example, solar's 24 MW peak capacity contribution requires over 1100 MW of installed nameplate capacity. After adjusting for peak capacity contribution, over 6,700 MW of new resources installed nameplate capacity adjusts to over 3,000 MW summer peak capacity and over 2,700 MW winter peak capacity, as detailed in Figure 3.9.

Figure 3.9: Nameplate Capacity Adjusted to Peak Capacity Contributions (MW)



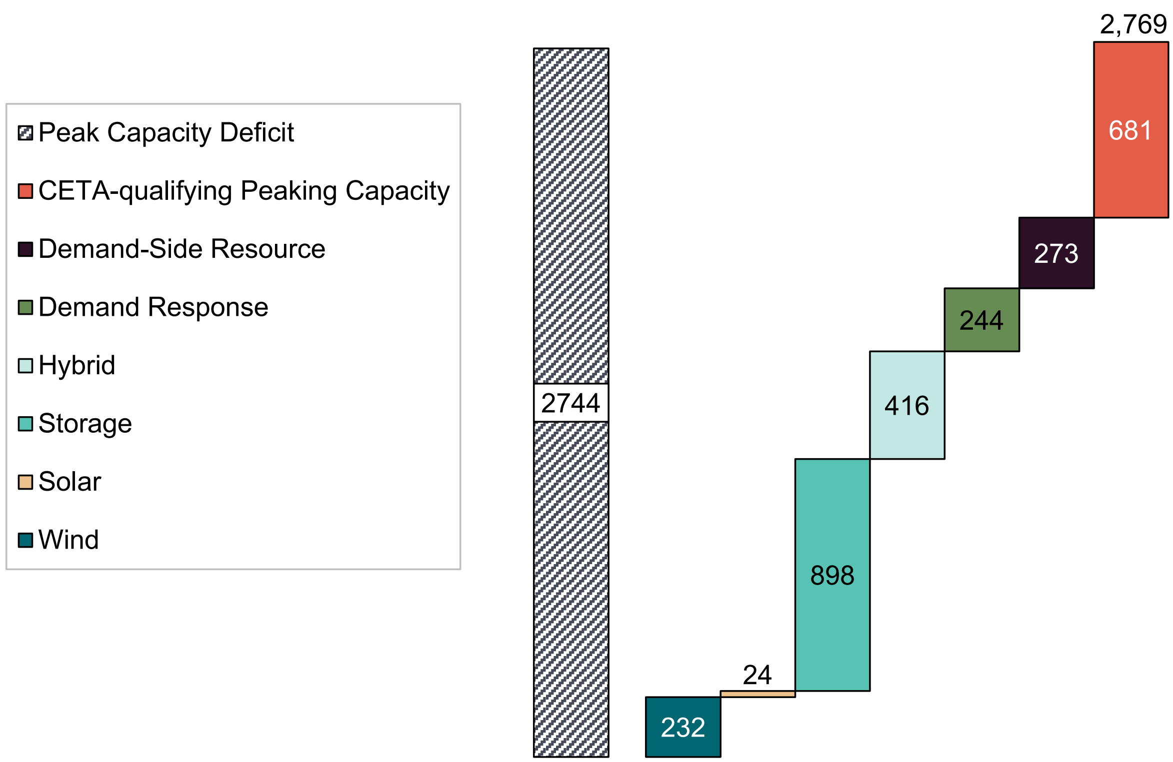
3.3.1. Winter Peak Drives Resource Capacity Additions

We analyzed summer and winter peak capacity. Consistent with prior years, the winter peak is higher than the summer peak. We noted that the increase of renewable energy and energy storage in the preferred portfolio contributed to meeting the summer peak need better than they contributed to the winter. For example, solar has a four percent peak capacity contribution in the winter but a 55 percent contribution in the summer. We added solar to the portfolio because it meets the CETA requirement and the summer peak need, but it does very little to meet the winter peak need. Given that the preferred portfolio meets the 2030 CETA target and renewable resource additions meet the summer peak capacity need, the winter peak need drives new peaking capacity in the preferred portfolio. The preferred portfolio builds 711 MW of CETA-qualifying peaking nameplate capacity by 2029 (Table 3.1), and assuming a 96 percent ELCC in winter (see Appendix D: Generic Resource Alternatives for operating assumptions), this adds 681 MW of peaking capacity. These additions balance the winter peak and create more than 250 MW summer peak surplus.

Figure 3.10 shows the breakdown of the effective winter peak capacity contribution for new resources. Note that this figure combines the nameplate capacities provided in Table 3.1 with respective ELCCs found in Appendix D: Generic Resource Alternatives.

➔ Please see Chapter Seven: Resource Adequacy Analysis for a detailed winter and summer peak needs discussion.

Figure 3.10: Meeting Winter Peak Need for 2030 — New Resource Additions Effective Capacity (MW)



4. Developing the Preferred Portfolio

This section describes how we developed candidate diversified portfolios. We also discuss the trends we observed across all candidate diversified portfolios in the near- and long-term and evaluate the costs of each candidate diversified portfolio. Finally, we present the results of our portfolio benefit analysis and summarize the selection of our preferred portfolio.

4.1. Candidate Diverse Portfolios

The first step to developing a preferred portfolio is to start with a least-cost portfolio. A least-cost portfolio meets constraints in a lowest-cost way. These constraints are:

- CETA renewable and clean-energy requirements
- Hourly customer demand for the year
- Peak capacity plus a planning reserve margin
- Reduced market reliance at peak
- Transmission access for new resources

The least-cost portfolio gave us a starting point which we then adjusted to identify a feasible portfolio of diverse resources that consider equity and create customer benefits while maintaining reliability and affordability. We refined the least-cost portfolio to maximize benefits and reduce burdens to vulnerable populations and highly impacted communities consistent with CETA. Figure 3.11 shows a progression of diversified portfolios ranging from the least diverse portfolio (11 A1) to the most diverse portfolio (11 A5), with each step adding a scheduled resource to increase the portfolio's diversity. We modeled portfolios 11 B1 and 11 B2 at the request of interested parties to exclude advanced nuclear SMR additions and are like the least and most diversified portfolios (11 A1 and 11 A5)

To create a diverse portfolio, we:

1. Start with the least cost reference portfolio,
2. Make incremental changes to the portfolio to test the sensitivity of the adjustment to resource builds and portfolio cost,
3. Create a portfolio with different options from part 2, considering equity, cost, feasibility, reliability, and diversity of energy supply.

Figure 3.11: Components of the Diverse Portfolios

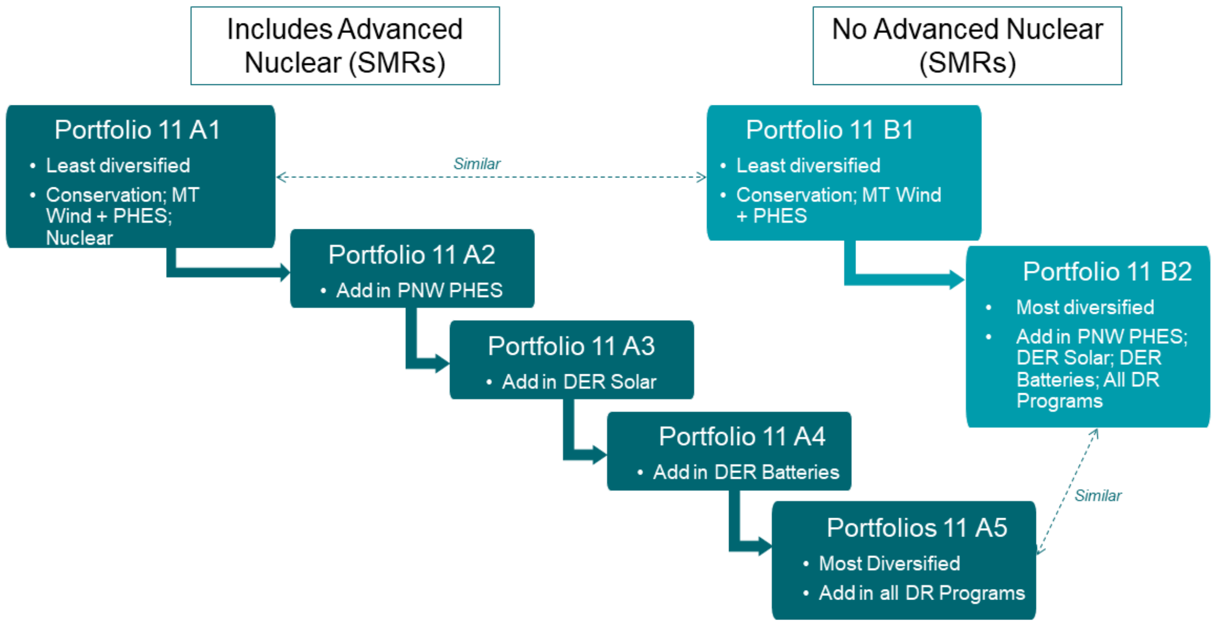
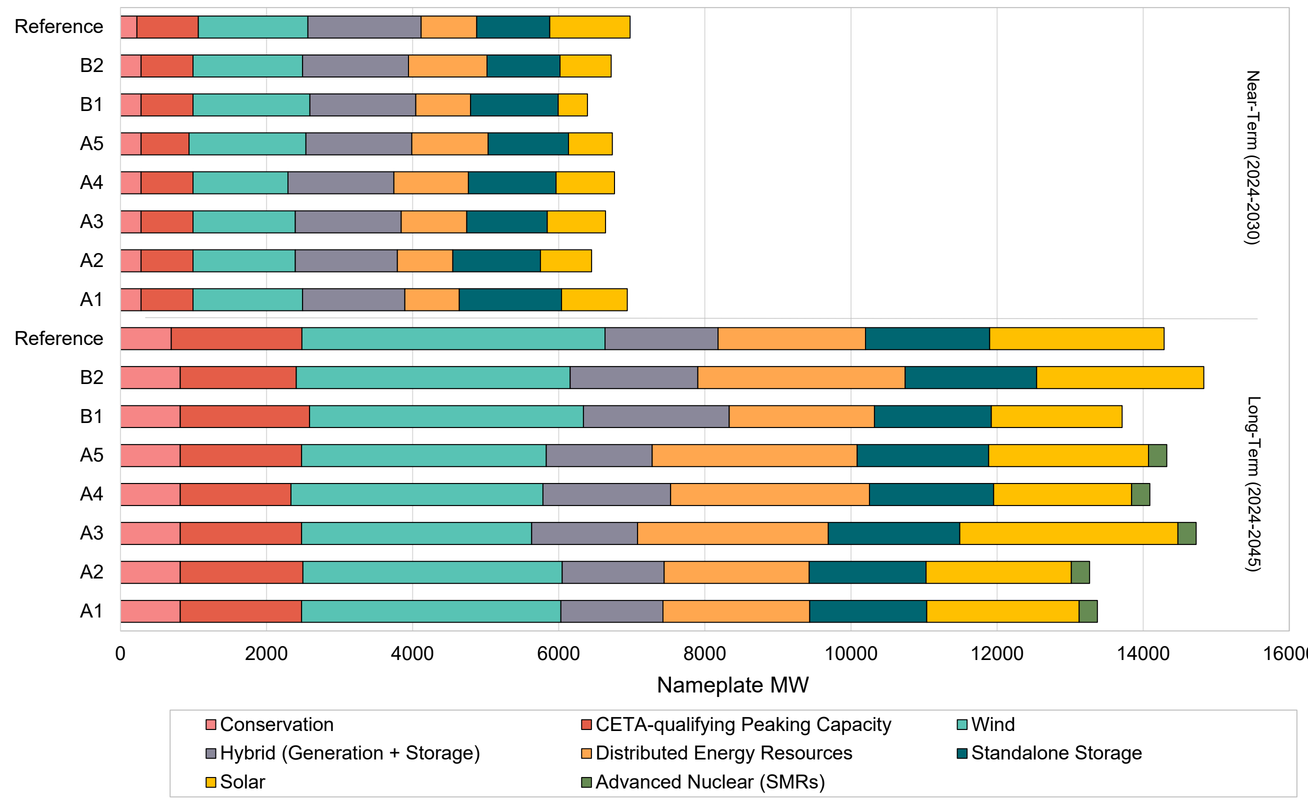


Figure 3.12 shows a breakdown of nameplate resource additions by portfolio. The portfolios are very similar in the near term (2024–2030). Puget Sound Energy needs many resources to meet CETA and resource adequacy, and there are few commercially available technologies today. All the diverse portfolios have equal amounts of conservation and CETA-qualifying peaking capacity, with the rest of the resources comprising demand response, wind, solar, energy storage, or a hybrid of renewable resources plus energy storage. For the longer term (2031–2045), the resource mix becomes more distinct between portfolios, although the need for conservation and CETA-qualifying peaking capacity is a stable addition across all portfolios.

Figure 3.12: Resource Builds (Nameplate MW)

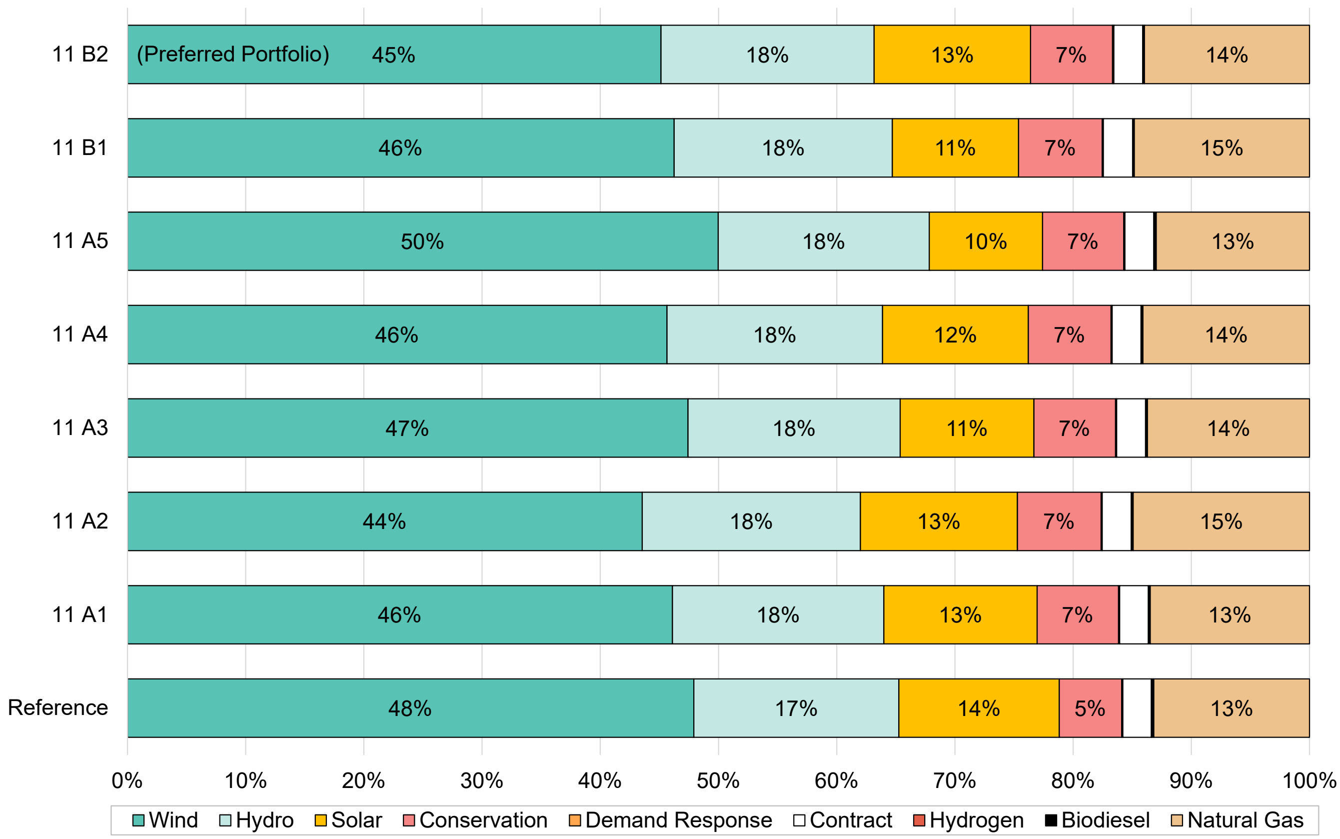


4.1.1. Near-term Resources (2024–2029)

The utility-scale and demand-side resource builds in the near term are similar across the diversified portfolios. In all the diversified portfolios, we need three peaking generation facilities by 2030 to maintain reliability as we add new variable resources. By 2030, we will add almost 1,500 MW of new energy storage to help meet resource adequacy and ancillary services. Energy storage resources are not energy-producing; they just store the energy produced from other resources, so it is available during peak hours. Given that we added more than 3,000 MW of variable energy resources by 2030 to meet the CETA requirements, we will need the energy storage resources to help store energy in low-demand hours to be used later in high-demand hours. The primary difference between the diversified portfolios is the amount of distributed energy resources. We listened to interested parties and PSE's Equity Advisory Group (EAG) and heard the importance of adding more distributed resources to the portfolio and increasing customer participation in these programs. However, no matter which portfolio we use for the preferred portfolio, the near-term resources are the same for utility-scale resources: we need to meet CETA requirements and resource adequacy, and there are limited options available to achieve these needs in the next six years.

Figure 3.13 presents each diversified portfolio's 2030 annual energy production by fuel type.

Figure 3.13: Annual Energy 2030 — Percent of Generation by Fuel Type

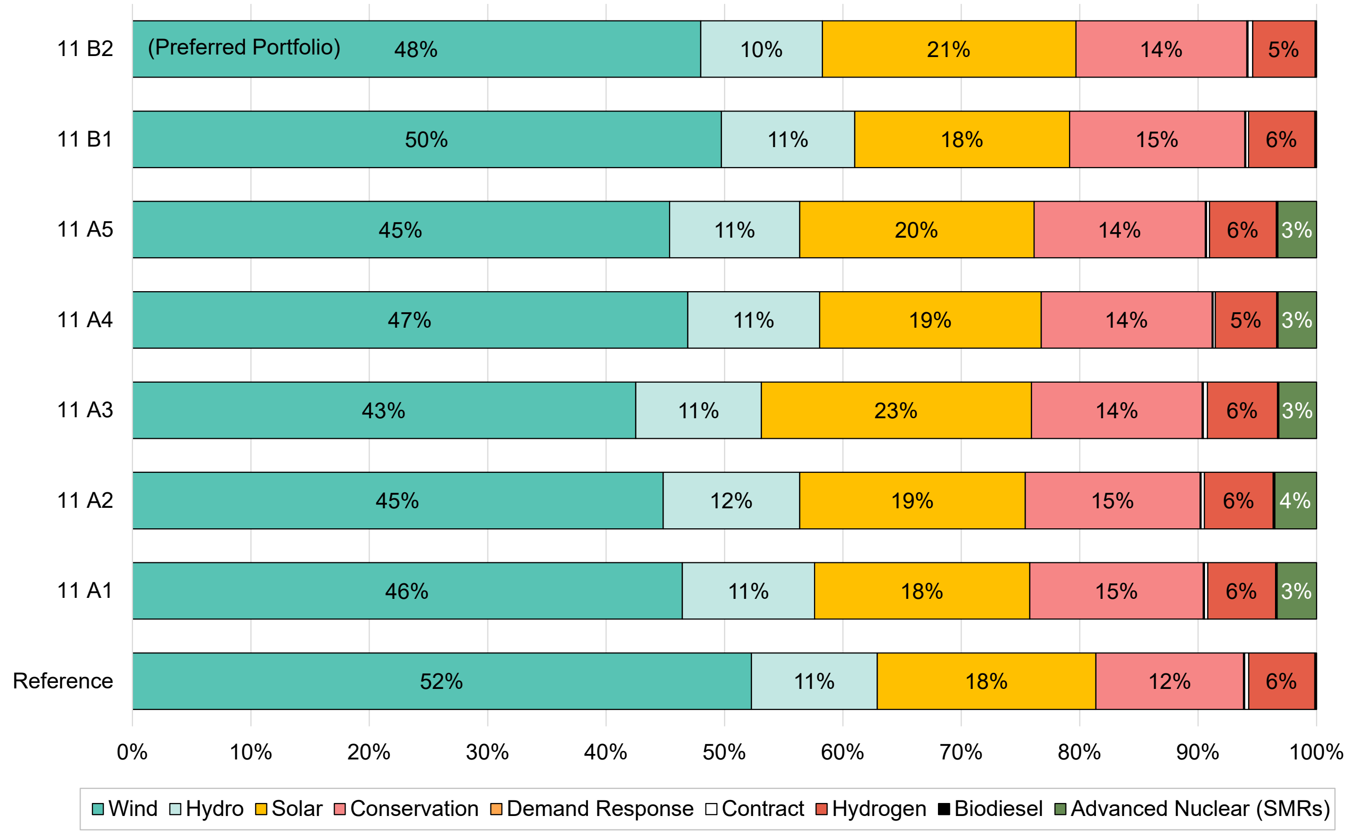


4.1.2. Long-term Resources (2030–2045)

As we look further into the future, the resources become less certain. Technological advancements are needed to achieve 100 percent clean energy by 2045. These advances could involve using alternative fuels such as hydrogen in combustion turbines or through advanced nuclear SMR technology. Both options are promising but present unique risks and costs. We will continue to explore these and other resource options in subsequent and future IRP cycles. Regardless of the technologies available long-term, it does not change near-term resources and resource options.

Figure 3.14 presents each diversified portfolio's 2045 annual energy production by fuel type.

Figure 3.14: Annual Energy 2045 – by Fuel Type (percent of generation)



4.1.3. Portfolio Costs

The portfolio costs include all those associated with construction, interconnection, transmission, fuel, and operations and maintenance of new generating resources, along with the costs to operate and maintain existing resources. We divided the portfolio costs into near-term resource additions before 2030 (Table 3.3) and longer-term, 21-year decisions for 2045 (Table 3.4). Figure 3.15 shows the annual portfolio costs for 2024–2029; annual portfolio costs for the entire planning period of 2024-2045 are in Chapter Eight: Electric Analysis.

In the near term, the combination of increasing distributed resources, conservation, demand response, and diversifying the portfolio delays adding one peaking generation facility until after 2030 but increases the cost over the reference case by $700–$880 million in the next six years.

Figure 3.15: Annual Portfolio Costs with Emissions 2024–2029 ($ Billions)

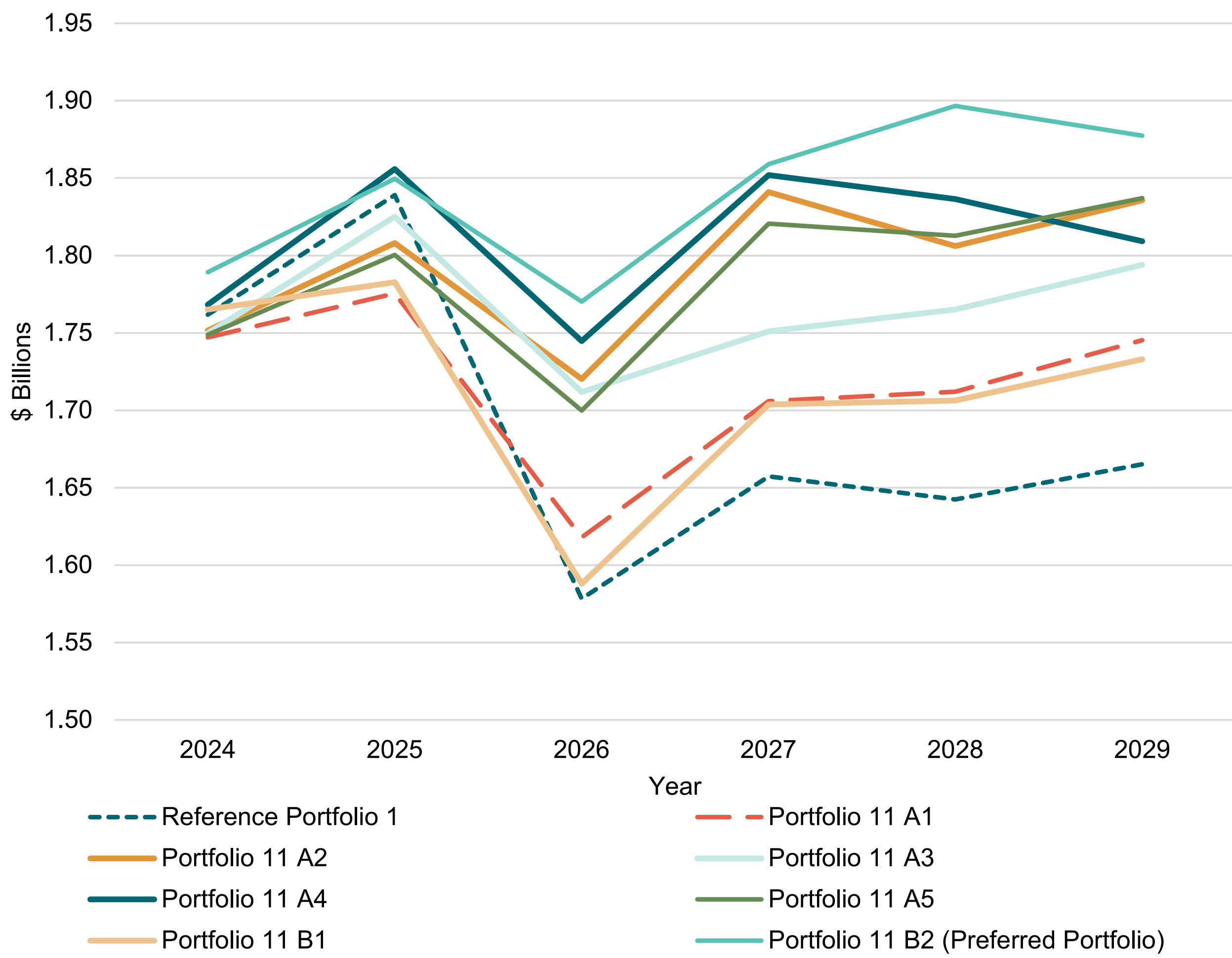


Table 3.3: Near-term (6-year) Net Present Values — 2024–2029 ($ Billions)

Portfolio	Portfolio Cost with SCGHG	Portfolio Cost without SCGHG	Social Cost of Greenhouse Gases (SCGHG)
Reference	8.14	6.05	2.08
11 A1	8.24	6.49	1.75
11 A2	8.59	6.70	1.89
11 A3	8.47	6.67	1.80
11 A4	8.68	6.75	1.93
11 A5	8.55	6.75	1.80
11 B1	8.22	6.32	1.91
11 B2 (Preferred Portfolio)	8.81	6.93	1.88

In the long-term, adding these distributed resources to the portfolio increases the cost over the reference case by $1.7 - $2.8 billion, as seen in portfolios 11 B1 and 11 A5, respectively (Table 3.4).

Diversifying the portfolio and increasing equity metrics through increased distributed resources, as described in Section 2.4.2, increases the cost of the portfolio both in the near- and long-term time horizon.

Table 3.4: Long-term (21-year) Net Present Values — 2024–2045 ($ Billions)

Portfolio	Portfolio Cost with SCGHG	Portfolio Cost without SCGHG	Social Cost of Greenhouse Gases (SCGHG)
Reference	17.61	20.85	3.24
11 A1	20.01	22.83	2.82
11 A2	20.32	23.25	2.93
11 A3	20.44	23.27	2.83
11 A4	20.74	23.64	2.90
11 A5	20.89	23.67	2.78
11 B1	18.09	21.09	3.00
11 B2 (Preferred Portfolio)	19.56	22.51	2.95

➔ Chapter Eight: Electric Analysis presents a complete discussion of portfolio sensitivity cost.

4.2. Portfolio Benefit Analysis

The Clean Energy Transformation Act requires utilities to consider equity and ensure all customers benefit from the transition to clean energy. However, AURORA, a traditional production cost model we use for portfolio modeling, only solves the least-cost solution. Therefore, we developed and used a portfolio benefit analysis tool to support our understanding of equity-related benefits and the associated costs within each portfolio and inform our work as we strive to select a portfolio best suited to enable equitable customer outcomes while also considering the cost. The preferred portfolio provides the best pathway to improve equitable outcomes of all our portfolios evaluated in this 2023 Electric Report. This outcome was driven primarily by increasing customer opportunities to participate in distributed energy and demand response programs.

The portfolio benefit analysis tool measures potential equity-related benefits to customers within a given portfolio and the tradeoff between those benefits and overall cost. We evaluated these benefits using quantitative customer benefit indicators (CBIs) and their metrics. Customer Benefit Indicators are quantitative and qualitative attributes we developed for the 2021 CEIP in collaboration with our Equity Advisory Group (EAG) and interested parties. These CBIs represent some of the focus areas in CETA related to equity, including energy and non-energy benefits, resiliency, environment, and public health.

For this 2023 Electric Report, we evaluated each portfolio using a subset of the CBIs proposed in the 2021 Clean Energy Implementation Plan, which as of this date, is still pending Washington Utilities and Transportation Commission (Commission) approval. We selected the subset of CBIs based on whether the AURORA modeling tool could quantitatively evaluate them, i.e., AURORA already had a comparable metric. The CBIs we included in the portfolio benefit analysis are:

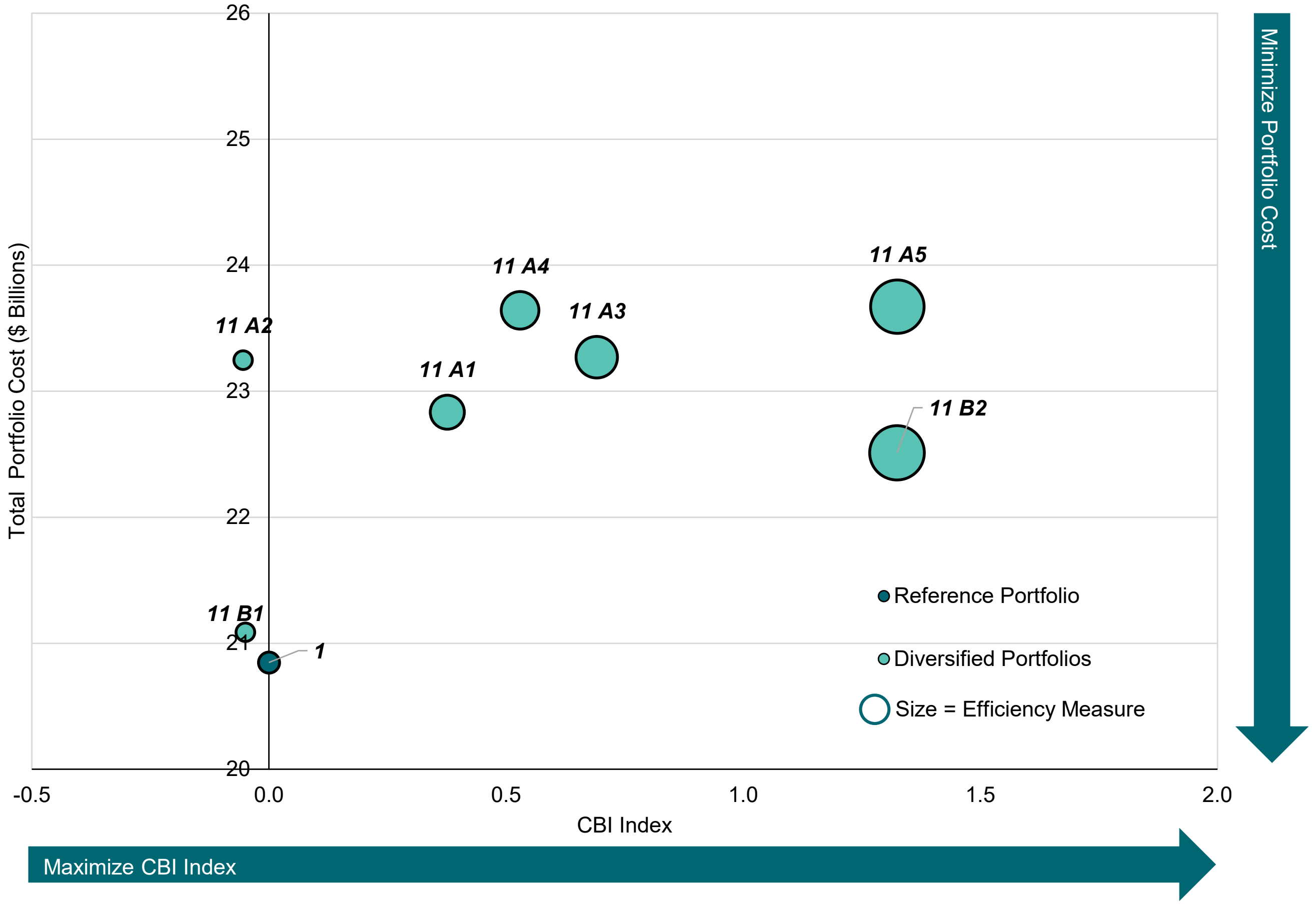
- **Improved access to reliable, clean energy** — measured by customers with access to distributed storage resources.
- **Improved affordability of clean energy** — measured by the total portfolio cost.
- **Improved outdoor air quality** — measured by sulfur oxides, nitrogen oxides, and particulate matter generated per portfolio.
- **Increase the number of jobs** — measured by the number of estimated jobs generated for each portfolio.
- **Increases participation in Energy Efficiency, Distributed Energy Resources, and Demand Response Programs** — measured by energy efficiency capacity added and the number of customers projected to participate in distributed energy resources and demand response programs.
- **Reduced greenhouse gas emissions** — measured by the total amount of CO_2-eq[2] generated per portfolio.
- **Reduced peak demand** — measured by the decrease in peak demand achieved via demand response programs.

The portfolio benefit analysis generates a CBI index for each portfolio, an aggregate measure of these CBIs (sans the portfolio cost) normalized to the reference, least-cost portfolio. A higher CBI index indicates that a portfolio enables more equity-related benefits than the reference portfolio. The CBI index juxtaposes each portfolio's total cost (direct and externality costs). The plot (Figure 3.11) illustrates the tradeoff between increasing portfolio benefits and the associated metrics and costs. Compared to the reference portfolio, the most efficient portfolios have the highest CBI indices with minimal increase in portfolio cost and sit closest to the bottom right corner of the plot.

Figure 3.16 shows the results generated by the portfolio benefit analysis tool for all diversified portfolios analyzed in this 2023 Electric Report. We can see portfolio 11 B2 is the most efficient of the diversified portfolios because it lies furthest to the right with the highest CBI index, one of the reasons we selected portfolio 11 B2 as the preferred portfolio. It has the highest overall CBI index at 1.32 and is the most diversified portfolio without advanced nuclear SMR that we evaluated in the 2023 Electric Report.

[2] CO2-eq or CO2-equivelant is a measure used to compare the emissions from various greenhouse gases based on their global-warming potential (GWP). Using the GWP, other greenhouse gases are converted to the equivalent amount of carbon dioxide.

Figure 3.16: Portfolio Benefit Analysis Tool Results



The high CBI index of portfolio 11 B2 comes from improvements in all the CBIs we considered in this analysis except for jobs, which varied slightly from the reference portfolio by less than half a standard deviation (index = -0.41). The benefits in the preferred portfolio include some of the highest potential customer participation numbers for DER solar, DER storage, and demand response programs at 87,492, 18,524, and 750,943 participants, respectively. Compared to the reference portfolio, the preferred portfolio also reduces greenhouse gas and other harmful emissions (Table 3.2).

Table 3.2: Portfolio CBI Metrics

CBI Metric	1 Reference	11 A5 Diversified Portfolio	11 B2 Diversified Portfolio
Cost ($, Billions)	20.85	23.67	22.51
GHG Emissions (Short Tons)	48,824,734	41,543,008	44,372,601
SO_2 Emissions (Short Tons)	28,841	28,836	28,759
NO_x Emissions (Short Tons)	11,426	10,307	10,805
PM Emissions (Short Tons)	9,036	8,873	8,940
Jobs (Total)	45,736	40,757	43,795
Energy Efficiency Added (MW)	695	818	818

CBI Metric	1 Reference	11 A5 Diversified Portfolio	11 B2 Diversified Portfolio
DR Peak Capacity (MW)	291	320	320
DER Solar Participation (Total New Participants)	12,115	83,903	87,492
DR Participation (Total New Participants)	513,238	750,943	750,943
DER Storage Participation (Total New Participants)	8,125	18,524	18,524

The results of the portfolio benefit analysis indicate that increasingly distributed and demand-side resources significantly increase the potential for more equitable outcomes for customers. Compared to the reference portfolio, portfolio 11 B2 has the following additions:

- **Conservation** — increases to 371 MW by 2045, 113 MW above the least-cost conservation.
- **Demand Response** — increases to 446 MW by 2045, an increase of 41 MW above the least-cost portfolio.
- **Distributed solar** — added 30 MW per year from 2026–2045, a total of 630 MW added by 2045 above the least cost portfolio.
- **Distributed storage** — added 25 MW per year from 2026–2031, a total of 150 MW added distributed storage above the least cost portfolio.

Portfolio 11 B2 achieved the highest CBI index of all portfolios evaluated in this 2023 Electric Report. In pursuing this portfolio, we will adopt a pathway forward for acquiring the resources necessary for a more equitable distribution of customer energy and non-energy burdens and benefits.

4.3. Portfolio Selection

We chose portfolio 11 B2 as the preferred portfolio because it presents a diverse mix of centralized renewable and non-emitting resources, reliable conservation, demand response, and distributed resources, and enables the most equity-related benefits of all the portfolios we evaluated. Furthermore, this portfolio reduces direct PSE emissions, achieves carbon neutrality by 2030, and is non-emitting by 2045. This portfolio is higher cost than most of the other diversified portfolios we evaluated. However, this outcome was driven primarily by increasing customer opportunities to participate in distributed energy and demand response programs, which we determined with feedback from PSE's EAG and other interested parties, were essential components of a preferred portfolio.

LEGISLATIVE AND POLICY CHANGE

CHAPTER FOUR

PUGET SOUND ENERGY

Contents

1. Introduction

Policy changes and the subsequent legislative changes in the energy sector have increased rapidly in the last five years. Puget Sound Energy (PSE) continues to respond to the quickly shifting landscape with plans that guide the resource acquisition process. This chapter outlines recent state and federal energy legislative and policy changes and how they informed the development of the 2023 Electric Progress Report (2023 Electric Report).

On the state level, we incorporated rules from the Clean Energy Transformation Act (CETA), the Climate Commitment Act (CCA), and new building codes. We also included the impacts of the federal Inflation Reduction Act (IRA) in this report.

2. Clean Energy Transformation Act

Clean Energy Transformation Act requires utilities to meet the following mandates:

- One hundred percent of retail utility sales must be greenhouse gas neutral by 2030, with 80 percent of those sales met with renewable and non-emitting resources and 20 percent with other clean investment options, which may include unbundled renewable energy credits.
- Renewable and non-emitting resources must meet one hundred percent of retail utility sales by 2045.
- Utilities must eliminate coal from their allocation of electricity to Washington retail customers after 2025.

This chapter addresses CETA rulemaking enacted after the 2021 IRP was published.

2.1. Washington Utilities and Transportation Commission

The Washington Utilities and Transportation Commission (Commission) concluded one CETA rulemaking in 2022, which established rules for electricity purchases from centralized markets, the prohibition of double counting, and the treatment of energy storage. The rules include additional contracting requirements, reporting contracts, and detail other data PSE must submit to the Commission.

2.1.1. Market Purchases and Double Counting

In the Market Purchases and Double Counting Rulemaking, the Commission issued an order on June 29, 2022, establishing rules for energy storage and prohibiting the double counting of clean energy attributes. This order also creates contracting and annual reporting requirements for data associated with the utility's resources and operations.

These rules require that PSE demonstrate compliance with the clean energy standards in CETA by acquiring electricity and associated renewable energy credits (RECs) or non-power attributes. Puget Sound Energy must show that we can deliver clean electricity to our system. We must also report on the source and characteristics of the electricity claimed for compliance.

This new rule did not affect modeling for the 2023 Electric Report.

2.1.2. Impact and Actions

As part of this report, we count the generation from CETA-qualifying renewable and non-emitting resources to meet CETA requirements, including wind, solar, nuclear, and renewable fuels (biodiesel and hydrogen), along with load reducers such as conservation, demand response, and customer voluntary renewable programs. Energy storage resources, such as batteries and pumped hydro storage, are treated as non-generating resources. Energy storage allows us to shift renewable energy to times of greater need, so the renewable energy used to charge those storage facilities is counted toward CETA requirements.

➔ A full description of PSE's existing CETA-qualifying resources is in Appendix C: Existing Resource Inventory, and a description of the new resources we modeled is available in Chapter Five: Key Analytical Assumptions and Appendix D: Generic Resource Alternatives.

In its order, adopting rules for market purchases, double counting, and other issues related to CETA, the Commission said further rulemaking and deliberation is needed regarding its interpretation of electricity use to ensure consistency and reliability across Washington's energy market and among electric utilities. PSE will incorporate these topics into our planning processes as appropriate as the Commission completes their rulemaking processes.

2.1.3. Incorporating Equity in Resource Planning

The CETA requires that "all customers are benefiting from the transition to clean energy through the equitable distribution of energy and nonenergy benefits and the reduction of burdens to vulnerable populations and highly impacted communities."[1] Equity is complex to measure and assess, especially in energy system planning; it is an important and new area to develop for resource planning since the enactment of CETA.

2.1.4. Impact and Actions

While PSE has considered equity in its low-income conservation programs in the past, the 2021 IRP saw a significant expansion of equity considerations. The 2021 IRP expanded its consideration of equity through the Economic, Health and Environmental Benefits Assessment (linked below) and the Customer Benefits Analysis (described in Chapter 3: Resource Plan. Since the 2021 IRP, we formed and convened an Equity Advisory Group (EAG) and engaged with this and other advisory groups, community-based organizations, and customers to better understand clean energy values in developing the 2021 Clean Energy Implementation Plan (CEIP). Input from these conversations shaped how we approached equity in this report.

The EAG comprises representatives from various community advocacy interests to advise PSE on the equitable transition to clean energy. The EAG also includes frontline customers. We encourage participation from environmental justice and public health advocates, tribes, and representatives from highly impacted communities and vulnerable populations. In the 2021 CEIP, the EAG initially advised on equity elements related to understanding the

[1] RCW 19.405.060

benefits and burdens customers may face, defining vulnerability factors, guiding principles for program implementation, and helped develop customer benefit indicators used in this report.

We revised and updated the customer benefits analysis used in the 2021 IRP to enhance the portfolio benefit analysis in this 2023 Electric Report. The portfolio benefit analysis incorporates a revised set of customer benefit indicators developed in the 2021 CEIP through collaboration among PSE staff, the EAG, and interested parties. The portfolio benefit analysis also incorporates methodological updates, informed by discussion with interested parties, to better quantify the distribution of portfolio-level metrics related to the customer benefit indicators. A full description of the portfolio benefit analysis and its results is available in Chapter Eight.

We also updated the Economic, Health, and Environmental Benefits Assessment in the 2023 Electric Report to reflect recent developments in identifying named communities. Named communities are customers burdened by social, economic, health, and environmental impacts, including highly impacted communities and vulnerable populations. We defined Highly Impacted Communities in our Department of Health Cumulative Impact Analysis, which we updated in August 2022. Puget Sound Energy staff collaborated with the EAG to define Vulnerable Populations as part of the 2021 CEIP and we used that definition in this report.

➔ A full description of the Economic, Health, and environmental Benefits assessment and its results is available in Appendix J: Economic, Health and Environmental Assessment of Current Conditions.

2.2. Clean Energy Implementation Plan

The Clean Energy Implementation Plan (CEIP) is a state-mandated four-year roadmap guiding PSE's clean energy investments for 2022–2025.

2.2.1. CEIP Overview

Consistent with CETA rules, we filed the company's first CEIP in December 2021. The plan illustrated our path toward meeting the requirements of CETA and the specific actions we will take from 2022–2025 to meet those goals. The CEIP proposed an interim target of serving customers with 63 percent clean, CETA-eligible renewable resources by the end of 2025. The CEIP also proposed targets and specific actions that include:

- 23.7 MW of Demand Response
- 25 MW of Distributed Energy Resources (DER) storage
- 50 MW of utility-scale storage
- 80 MW of DER solar,
- 1,073,434 MWh of energy efficiency, as determined in the 2022–2023 Biennial Conservation Plan

By rule, the Commission can approve, deny, or approve with conditions the filed CEIP. We are still waiting for a decision from the Commission on PSE's CEIP. However, we continue moving forward on specific actions to implement the CEIP by the end of 2025. These efforts include ongoing public participation with advisory groups and interested parties, completing the All-source and DER/DR resource acquisition processes, and beginning to develop tariff filings for new DER programs.

We used the 2021 IRP as the foundation for Puget Sound Energy's first CEIP. We will use the 2023 report to inform the 2023 biennial CEIP update. The 2023 report includes critical updates to the inputs and assumptions used in the AURORA modeling, which will directly feed into the 2023 biennial CEIP Update. The 2023 Electric Report rules (WAC 480-100-625)[2] require updates for the following items: load forecast, conservation, resources costs, state and federal requirements, significant economic and market changes, and other elements identified in the CEIP.

➔ See Chapter Eight: Electric Analysis for a discussion on substantive changes for the 2023 Electric Report.

2.2.2. Impact and Actions

The 2023 Electric Report includes the following CEIP targets and actions:

- 25 MW of Distributed Energy Resources (DER) storage
- 80 MW of DER solar
- Updates to the customer benefit indicators

We did not include targets for energy efficiency and demand response from the 2021 CEIP since we conducted a new conservation potential assessment and demand response assessment for the 2023 Electric Report. We used the new assessments to create new economic and achievable energy efficiency and demand response resource options in the preferred portfolio.

Another critical CETA goal bridging the 2023 Electric Report to the 2023 biennial CEIP update is including and embedding equity in decision-making and resource selection, via the revised customer benefit indicators and the portfolio benefit analysis, as described in Section 2.1.2 and detailed in Chapter Eight.

2.3. Climate Change

Under WAC 480-100-620 (10)(b), "at least one scenario must be a future climate change scenario. This scenario should incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change."[3] Temperature data that reflects climate change is a critical piece of our planning analysis. This crucial information impacts the demand forecast and influences how much energy PSE will need to serve our customers.

[2] WAC 480-100-625
[3] WAC 480-100-620

2.3.1. PSE Actions

The 2023 Electric Report is our first effort incorporating climate change data into the baseline forecast. We incorporated climate change in two key aspects of the analysis. First, we included climate change in the load forecast, as described in Chapter Six: Demand Forecast. We also included climate change impacts on regional loads and hydro generation in this report. We also included climate change in the resource adequacy analysis, the planning reserve margin, and the peak capacity contribution of resources, as described in Chapter Seven: Resource Adequacy.

2.4. Department of Health Cumulative Impact Analysis

The Clean Energy Transformation Act (CETA) directs the DOH to develop a CETA Cumulative Impact Analysis (CIA) of the impacts of climate change and fossil fuels on population health to designated highly impacted communities. The DOH released an initial CIA in February 2021 and an update in August 2022.

2.4.1. Impact and Actions

We used the results of the CIA to inform planning in our transition to clean energy. The CIA helps us identify, measure, and track equity-related metrics in several ways. Primarily, the CIA directs which communities we should geographically identify as highly impacted. Highly impacted communities may experience more public health and environmental burdens than other segments of our service area. Identifying, measuring, and tracking equity-related metrics in highly impacted communities helps us move toward an equitable transition to clean energy. By highlighting these highly impacted communities, we can identify disparities within our service territory, target specific actions to alleviate existing burdens, and benefit frontline communities.

The CIA also provides valuable data to support equity-related analysis. The DOH Environmental Health Disparities Map is a component of the CIA that offers a range of environmental and public health metrics that we use in our Environmental, Health, and Economic Benefits and Burdens Analysis.

➔ More information is available in the Environmental, Health, and Economic Benefits and Burdens Analysis in Appendix H: Electric Analysis and Portfolio Model.

2.5. Department of Ecology

The Washington State Department of Ecology is responsible for adopting rules that provide methods for assigning greenhouse gas emission factors for electricity and establishing a process to determine what types of projects may be eligible as energy transformation projects under CETA.

Ecology adopted a new rule on January 6, 2021, that establishes: WAC-173-446[4]

- A general process to determine eligible energy transformation projects

[4] https://ecology.wa.gov/Regulations-Permits/Laws-rules-rulemaking/Rulemaking/WAC-173-446

- A process and requirements for developing standards, methodologies, and procedures to evaluate energy transformation projects
- The default unspecified emissions factor in CETA

2.5.1. Impact and Actions

We did not evaluate any specific energy transformation projects as alternative compliance in this 2023 Electric Report. Instead, we bound the cost of alternative compliance measures using a forecast of renewable energy credit purchases to represent the lower bound and a 100 percent renewable portfolio by 2030 to represent the upper bound.

➔ A full description of the alternative compliance assumptions and methodology is available in Chapter Five: Key Analytical Assumptions.

We use the unspecified emission factor for the emission rate of the unspecified market purchases in the portfolio.

➔ You will find an accounting of the emissions from generating thermal resources and unspecified market purchases in the results from Chapter Eight: Electric Analysis and App_I_Input_Carbon_Prices spreadsheet from Appendix H: Electric Analysis and Portfolio Model.

3. Climate Commitment Act

In 2021, the Washington State Legislature passed the Climate Commitment Act (CCA) establishing a comprehensive cap-and-invest program to reduce statewide greenhouse gas (GHG) emissions through a price on emissions. The law directs Ecology to develop rules to implement and administer the program beginning January 1, 2023. As part of this process, Ecology adopted the final program rules on September 29, 2022. Puget Sound Energy is preparing to comply with this state law in alignment with our Beyond Net Zero Carbon (BNZC) commitments and aspirations.

3.1. Program Overview

The cap-and-invest program sets an overall cap on state GHG emissions, which declines over time in line with the state's statutory GHG emissions limits. Covered entities must report their GHG emissions to Ecology and obtain allowances to cover them. An allowance is a mechanism created by the Ecology equal to one metric ton of GHG emissions and may be directly distributed by Ecology, purchased at auction, or traded with others in the program. The program aims to establish a greenhouse gas emissions price and create a marketplace for covered entities to find the most efficient means to reduce emissions. The CCA mandates the state to equitably invest revenues raised through state-run allowance auctions in projects that reduce emissions and address climate resiliency and environmental justice, among other priorities.

3.2. Impacts and Actions

As an electric and natural gas utility, PSE is covered under the CCA. We will report emissions and have annual compliance obligations under the program.

Electric utilities subject to CETA are allocated no-cost allowances to mitigate the cost burden of the CCA program on electric customers until 2045. Allocations must be consistent with a supply and demand forecast approved by the Commission. Utilities may consign allowances to auction for the benefit of ratepayers, deposit them for compliance, bank them for future compliance, or a combination of these actions. All proceeds from the consignment of allowances must benefit ratepayers with priority to mitigating rate impacts to low-income customers.

Natural gas utilities must also comply with the CCA, and how they do may impact electric utilities, such as through a shift to more electrification of customer end uses. Our 2023 Gas Utility IRP includes an electrification analysis citing impacts on possible future electric infrastructure requirements. The 2023 Gas IRP analysis highlights the importance of a dual-fuel energy system as we transition to a low-carbon economy. Since this is a progress and an update of assumptions from the 2021 IRP, the results for the electrification scenarios are in the 2023 Gas Utility IRP; such studies are beyond the scope of this 2023 Electric Report. Combining this analysis with the 2023 Gas IRP also allowed us to better integrate the analysis between the electric and gas portfolios. We anticipate electrification analysis may influence future electric IRPs.

Puget Sound Energy must comply with the CCA; as a result, we expect price impacts for all our customers. We will work hard to mitigate those impacts through decarbonization efforts to manage our allowances.

In this progress report, we modeled CCA prices as a direct cost applied to economic dispatch on greenhouse gas emissions to reflect the opportunity cost of emission allowances introduced by the CCA. A full explanation of the methodology and assumptions we used to model the impacts of the CCA is available in Chapter Five.

Please visit the Washington State Department of Ecology's CCA rulemaking website to learn more about this state program.

4. Energy Efficiency Technology, Codes and Standards, and Electrification

Energy efficiency technology and changing codes and standards impact customer choices and energy efficiency programs. For example, when federal minimum lighting performance standards included screw-in LED lighting, PSE could no longer offer LEDs as energy efficiency program offerings. Although LEDs continue to achieve savings, we can no longer take credit for those savings in our incentive programs.

The two energy codes that impact our customers, the Washington State Energy Code (WSEC) and the Seattle Energy Code, are transitioning to focus on greenhouse gas emissions and energy efficiency. These changes emphasize the electrification of systems formerly fueled by natural gas. Since February 2021, the 2018 WSEC no longer gives builders efficiency credits for new single-family homes that install natural gas space or water heating; instead, it gives them credits for installing electric heat pumps for heat and hot water.

4.1. Impact and Actions

The codes and standards included in the 2023 Electric Report CPA and demand forecast include:

- 2018 WSEC
- Provision of RCW 19.27A.160

In 2021, the Seattle Energy Code[5] created significant barriers to using natural gas for space and water heating in new commercial and multi-family buildings. With few exceptions, new buildings will use various types of heat pump technology to meet the demands of these systems. The Seattle Energy Code will affect the gas utility that serves the city of Seattle, but the change in demand for electricity will impact Seattle City Light, the electric utility for the city of Seattle, and will not affect PSE's electric system.

Another provision included in the 2023 Electric Report CPA is a statutory requirement (RCW 19.27A.160) that directs the WSEC revision process to achieve a 70 percent reduction in energy consumption by 2031 compared to a 2006 code baseline.[6]

➔ See Appendix E: Conservation Potential and Demand Response Assessment for details on the CPA.

The Washington State Building Codes Council (WSBCC) has proposed mandating builders install electric heat pumps in new commercial buildings and multi-family homes instead of natural gas heating and cooling technologies. The WSBCC is also developing residential building codes, which would encourage using electric heat pumps in new residential buildings and penalize using natural gas heating appliances. These proposals are currently under consideration for adoption as part of the WSEC. Although not modeled in this analysis these changes would likely affect PSE by increasing the electric energy and peak demand more than forecasted. The amount of difference in the peak demand forecast will be affected by the technology installed in these new buildings.

Washington State issued the WSBCC proposed code updates after we conducted the 2023 Electric Report CPA so, it is not included in this report.

5. Inflation Reduction Act

The Inflation Reduction Act (IRA) was passed and signed into law in August 2022 and represented the single most significant federal investment in clean energy and climate-focused solutions in U.S. history — approximately $370

5 The cities of Bellingham and Shoreline also passed similar gas bans in their jurisdictions in 2022.
6 RCW 19.27A.160

billion. The IRA addresses climate change by providing tax incentives and consumer rebates to move project developers and households toward lower-carbon or zero-carbon technologies. The two main incentives applicable to renewable projects are the Production Tax Credits (PTCs) and Investment Tax Credits (ITCs), both scheduled to phase out before the IRA was enacted.

Production Tax Credits provide an energy tax credit ($/MWh) for the first 10 years of energy output after a utility places a project in service. Before the IRA was enacted, PTCs had expired for any new projects placed in service in 2022 and beyond. The IRA bill extends PTCs to 100 percent for eligible projects placed in service before the end of 2032[7]; solar projects have also been added back into the eligible technology definitions of the PTC for the first time since 2005. The IRA also gives taxpayers new authority to transfer their credits to parties with tax appetite, providing taxpayers an additional means to monetize earned credits.

Investment Tax Credits provide an energy tax credit based on the percentage of the investment in the project. Before the IRA was enacted, the old ITC rate for projects placed in service in 2022 had phased down to 10 percent. The IRA increased the ITC rate to 30 percent through 2032[8]. Taxpayers will also have new authority to transfer their credits to parties with tax appetite, giving taxpayers an additional monetization option for earned credits.

Previously, the ITC for battery storage projects was restricted to only battery storage projects paired with solar or other renewable energy generation assets in a hybrid configuration. The IRA now extends the ITC to cover all stand-alone energy storage applications. This change ensures the tax credits support a more flexible system because the battery can charge from the grid and its paired solar project.

The IRA provides more long-term certainty in investment decisions by providing 10 years of energy tax incentive eligibility and enhanced tools to accelerate or support credit monetization. Where previous tax rules for PTC (wind) and ITC (solar) were technology-specific, the new tech-neutral credit may allow the entity receiving the credit to choose the most efficient incentive type. The rules also provide bonuses for where and how projects are built. The rules give project developers incentives to utilize domestically sourced materials, drive economic opportunity by placing projects in service in low-income communities, and leverage an existing workforce in census tracts deemed energy communities where new clean energy developments may impact fossil-fuel extraction and generation activities.

5.1. Impact and Actions

We included the updated and extended PTC and ITC tax credits in the 2023 Electric Report analysis. We also extended the ITC to stand-alone energy storage — batteries, pumped hydro storage, and nuclear. The inclusion of the IRA in the analysis results in over $10 billion in projected savings to the customer.

Many other provisions in the IRA may impact electricity demand. For example, electric vehicle adoption rates may increase due to provisions of the IRA that provide buyer and charging facility owners tax incentives, incentives to help

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[7] The existing PTC and ITC are extended at full value through 2024. After 2024, the existing PTCs and ITCs will expire. In their place, functionally similar clean energy production tax credits and clean energy investment tax credits take effect with broader flexibility to capture a greater number of eligible technology neutral energy sources. The new credits are similar value and definition to the prior credits if prevailing wage and apprenticeship requirements are met. Taxpayers are allowed to elect which credit they choose when placing an eligible project into service.

[8] See footnote 3.

consumers add rooftop solar and battery storage options, rebates intended to help low and moderate-income households achieve higher levels of energy efficiency and a host of other provisions. However, because the law was enacted late in our planning process, we could not add these policies to our demand forecast and could not consider all the nuances of the bill.

KEY ANALYTICAL ASSUMPTIONS

CHAPTER FIVE

PUGET SOUND ENERGY

Contents

1. Introduction

This chapter describes the forecasts, estimates, and assumptions Puget Sound Energy developed for the 2023 Electric Progress Report (2023 Electric Report). These assumptions span the horizon from 2024-2045 for the 2023 Electric Report. Additional details of the analyses are in Chapter Eight: Electric Analysis and in the related appendices.

This section on electric analysis includes the assumptions we used to create different economic conditions and operational considerations that affect portfolio costs and risks. Inputs included the electric demand forecast, price assumptions for natural gas and CO_2 costs, assumptions about cost and characteristics for existing and generic resources, and transmission considerations. We also included delivery system planning assumptions.

Next, we described electric portfolio sensitivities. Sensitivities start with the optimized, least-cost reference portfolio and change resource assumptions, environmental regulations, or other conditions to examine the effect of each change on the portfolio. We used these sensitivities to help build the preferred portfolio.

Last, we described our considerations for modeling electric supply-side resources as power purchase agreements or ownership agreements in the technology model section.

2. Electric Portfolio Analysis Assumptions

We analyzed a single reference case scenario for this 2023 Electric Report. A single scenario contrasts with a full Integrated Resource Plan (IRP), where multiple scenarios are typically analyzed to test how different economic conditions impact the portfolio optimization results. Instead of numerous scenarios, we used stochastic analysis for this 2023 Electric Report to measure the robustness of the preferred portfolio across a range of economic conditions.

The following section features the primary assumptions for the reference scenario.

2.1. Embed Equity with the Portfolio Benefit Analysis Tool

AURORA, the production cost model software we used for portfolio modeling in this report, is designed to find the lowest-cost portfolio given a set of constraints. Therefore, one of the best ways to influence the results of the AURORA portfolio model is to alter the cost of resources. For example, we incorporated the SCGHG in the AURORA portfolio model as an externality cost, which increases the cost of emitting resources, discouraging the model from including emitting resources in the final portfolio selection. Unfortunately, equity metrics do not have a specified dollar value, like the SCGHG, that we can incorporate into the portfolio model.

We needed another method to embed equity into the portfolio analysis and the 2023 Electric Report, so we created the portfolio benefit analysis tool. This new tool provides a measure of equity-related metrics outside the AURORA model that we can use to inform the portfolio development iteratively.

The portfolio benefit analysis tool is a spreadsheet-based model that relates the relative value added from improving Customer Benefit Indicators (CBIs) with the cost of a given portfolio. The portfolio benefit analysis tool builds on the approach we used in the 2021 IRP to incorporate equity. The tool allowed us to add interested party input to inform our process for the 2023 Electric Report. We anticipate we will continue improving how we incorporate CBIs in portfolio modeling. We describe the methodology we deployed in the portfolio benefit analysis tool in Appendix H: Electric Analysis and Portfolio Model, the portfolio benefit analysis tool Excel workbook that contains the data and the numerical analysis results in Appendix I: Electric Analysis Inputs and Results, and a discussion of the results in Chapter Eight: Electric Analysis.

2.2. Puget Sound Energy Customer Demand

The 2023 Electric Report demand forecast used in the analysis represents an estimate of energy sales, customer counts, and peak demand over 22 years.[1] Significant inputs include the following:

- Demographic changes
- Impacts of climate change
- Information about regional and national economic growth
- Known large load additions or deletions
- Prices
- Seasonality and other customer usage and behavior factors
- Weather

Figure 5.1 shows the electric peak demand and annual energy demand forecasts without the effects of conservation. The forecasts include sales (delivered load) plus system losses, which we represented in average energy demand over the year. The electric peak demand forecast is for a one-hour low temperature in winter at Sea-Tac airport, which we represented in total demand need at peak.

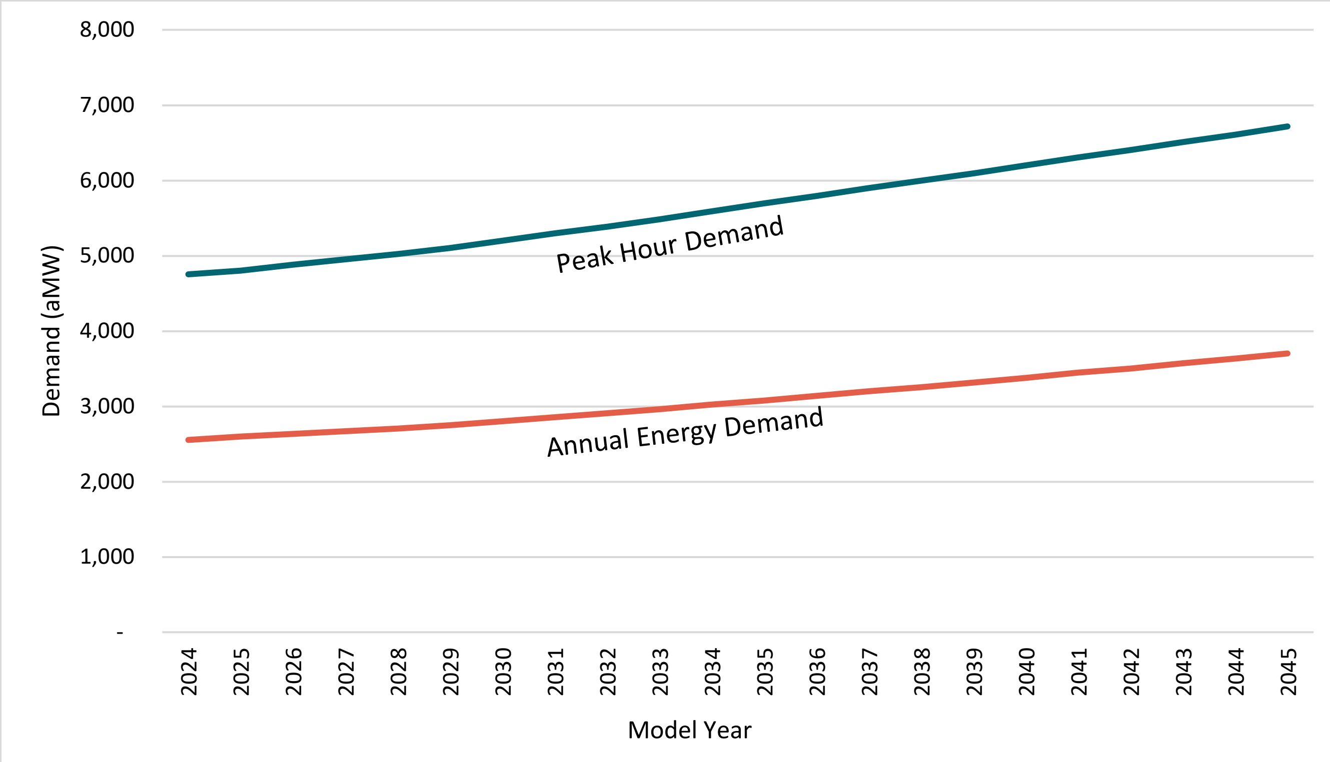
Why don't demand forecasts in rate cases and acquisition discussions match the IRP forecast?

The IRP analysis takes 12 to 18 months to complete. Demand forecasts are so central to the analysis that they are one of the first inputs we develop. By the time the IRP is completed, we may have updated our demand forecast. The range of possibilities in the IRP forecast is sufficient for long-term planning purposes, but we will always present the most current forecast for rate cases or when making acquisition decisions.

➔ See Chapter Six: Demand Forecasts, for a detailed discussion of the demand forecasts and Appendix F: Demand Forecasting Models, for the analytical models used to develop them.

[1] For long-range planning, customer demand is expressed as if it were evenly distributed throughout PSE's service territory, but, demand grows faster in some parts of the service territory than others.

Figure 5.1: 2023 Progress Report Electric Annual Energy and Peak Hour Demand Forecasts



2.3. Natural Gas Price Inputs

For natural gas price assumptions in this 2023 Electric Report, we used a combination of forward-market prices and fundamental forecasts acquired in spring 2022 from Wood Mackenzie.[2]

- Beyond 2030, we used the Wood Mackenzie long-run natural gas price forecasts published in May 2022.
- For 2029 and 2030, we used a combination of forward market prices from 2028 and selected Wood Mackenzie prices from 2031 to minimize abrupt shifts when transitioning from one dataset to another.
- From 2022–2028, we used the three-month average of forward-market prices from May 12, 2022. Forward market prices reflect the price of natural gas purchased at a given time for future delivery.
- In 2029, the monthly price is the sum of two-thirds of the forward market price for that month in 2028 plus one-third of the 2031 Wood Mackenzie price forecast for that month.
- In 2030, the monthly price is the sum of one-third of the forward market price for that month in 2028 plus two-thirds of the 2031 Wood Mackenzie price forecast for that month.

We used three natural gas price forecasts, mid, low, and high, to develop a range of gas prices for the stochastic analysis. However, we used only the mid natural gas prices in the reference scenario for this 2023 Electric Report.

[2] Wood Mackenzie is a well-known macroeconomic and energy forecasting consultancy whose gas market analysis includes regional, North American, international factors, Canadian markets, and liquefied natural gas exports. Under our agreement with Wood Mackenzie seasonal and annual natural gas price trends are confidential and cannot be shared as part of this report.

2.3.1. Mid Natural Gas Prices

The mid natural gas price forecast uses the three-month average of forward market prices from May 12, 2022, and the Wood Mackenzie fundamentals-based long-run natural gas price forecast published in May 2022. We used the mid natural gas price forecast in the reference case for this 2023 Electric Report.

2.3.2. Low Natural Gas Prices

We developed the low natural gas price forecast using monthly adjustment factors applied to the mid natural gas price forecast. We obtained adjustment factors from the ratio of the low and mid natural gas price forecasts provided in the Northwest Power and Conservation Council's 2021 Power Plan. We used the low natural gas price forecast to develop the stochastic inputs for this 2023 Electric Report.

2.3.3. High Natural Gas Prices

We developed the high natural gas price forecast using monthly adjustment factors applied to the mid natural gas price forecast. We obtained adjustment factors from the ratio of the high and mid natural gas price forecasts provided in the Northwest Power and Conservation Council's 2021 Power Plan. We used the high natural gas price forecast to develop the stochastic inputs for this 2023 Electric Report.

Figure 5.2 illustrates the range of 22-year levelized natural gas prices used in this analysis compared to the 22-year levelized natural gas prices PSE used in the 2021 IRP.

Figure 5.2: Levelized Natural Gas Prices Used in Scenarios, 2023 Progress Report vs. 2021 IRP (Sumas Hub, 22-year Levelized, Nominal $)

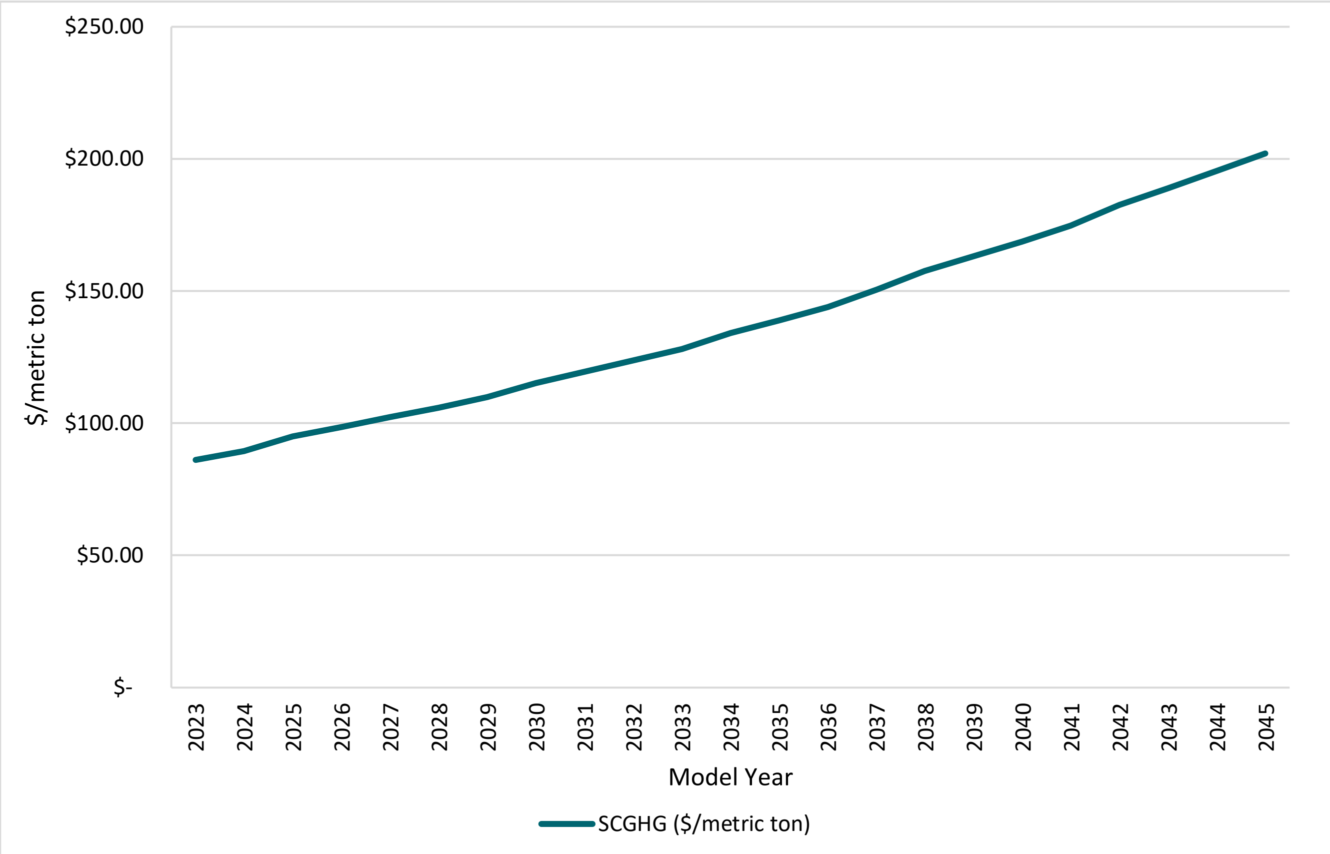
2.4. Carbon Dioxide Price Inputs

We modeled the Social Cost of Greenhouse Gases (SCGHG) and an allowance price for the Climate Commitment Act (CCA) in the 2023 Electric Report. In the following sections, we provide each price's forecasts and applications.

2.4.1. Social Cost of Greenhouse Gases

The SCGHG cited in the Clean Energy Transformation Act (CETA) comes from the Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document, August 2016 update. It projects a 2.5 percent discount rate, starting with $62 per metric ton (in 2007 dollars) in 2020. The document lists the CO_2 prices in real dollars and metric tons. We adjusted the prices for inflation (nominal dollars) resulting in a cost range from $86 per ton in 2023 to $202 per ton in 2045, as shown in Figure 5.3.

Figure 5.3: Social Cost of Greenhouse Gases in the 2023 Progress Report



We applied the SCGHG as a planning adder on emitting resources, so the SCGHG is applied when we optimize build decisions for new resources and retirement decisions for existing emitting resources. The reference case models the SCGHG as a fixed cost adder, which does not impact the dispatch schedule of emitting resources. However, we include a sensitivity that models the SCGHG as dispatch cost.

➔ See Appendix H: Electric Analysis and Portfolio Model for the complete discussion of how we modeled the SCGHG.

2.4.2. Upstream Carbon Dioxide Emissions for Natural Gas

The upstream emission rate represents the carbon dioxide, methane, and nitrous oxide releases associated with natural gas extraction, processing, and transport along the supply chain. We converted these gases to carbon dioxide equivalents (CO_2e) using the Intergovernmental Panel on Climate Change Fourth Assessment (AR4) 100-year global warming potentials (GWP) protocols.[3]

[3] The Environmental Protection Agency and the Washington Department of Ecology direct reporting entities to use the AR4 100-year GWPs in their annual compliance reports, as specified in Table A-1 at 40 CFR 98 and WAC 173-441-040.

For the cost of upstream CO_2 emissions, we used emission rates published by the Puget Sound Clean Air Agency[4] (PSCAA). The PSCAA used two models to determine these rates, GHGenius[5] and GREET.[6] Emission rates developed in the GHGenius model apply to natural gas produced and delivered from British Columbia and Alberta, Canada. The GREET model uses U.S.-based emission attributes and applies to natural gas produced and delivered from the Rockies basin. Table 5.1 provides the results of the GHGenius and GREET models.

Table 5.1: Upstream Natural Gas Emissions Rates

Model	Upstream Segment	End-Use Segment (Combustion)	Emission Rate Total	Upstream Segment CO2e (%)
GHGenius	10,803 g/MMBtu	+ 54,400 g/MMBtu	= 65,203 g/MMBtu	19.9
GREET	12,121 g/MMBtu	+ 54,400 g/MMBtu	= 66,521 g/MMBtu	22.3

Note: End-use Combustion Emission Factor: EPA Subpart NN.

The upstream segment of 10,803 g/MMBtu is converted to 23 lb/MMBtu and then applied to the emission rate of natural gas plants for the SCGHG emissions. We did not apply the upstream emission rate to the CCA allowance price.

2.4.3. Climate Commitment Act Allowance Price

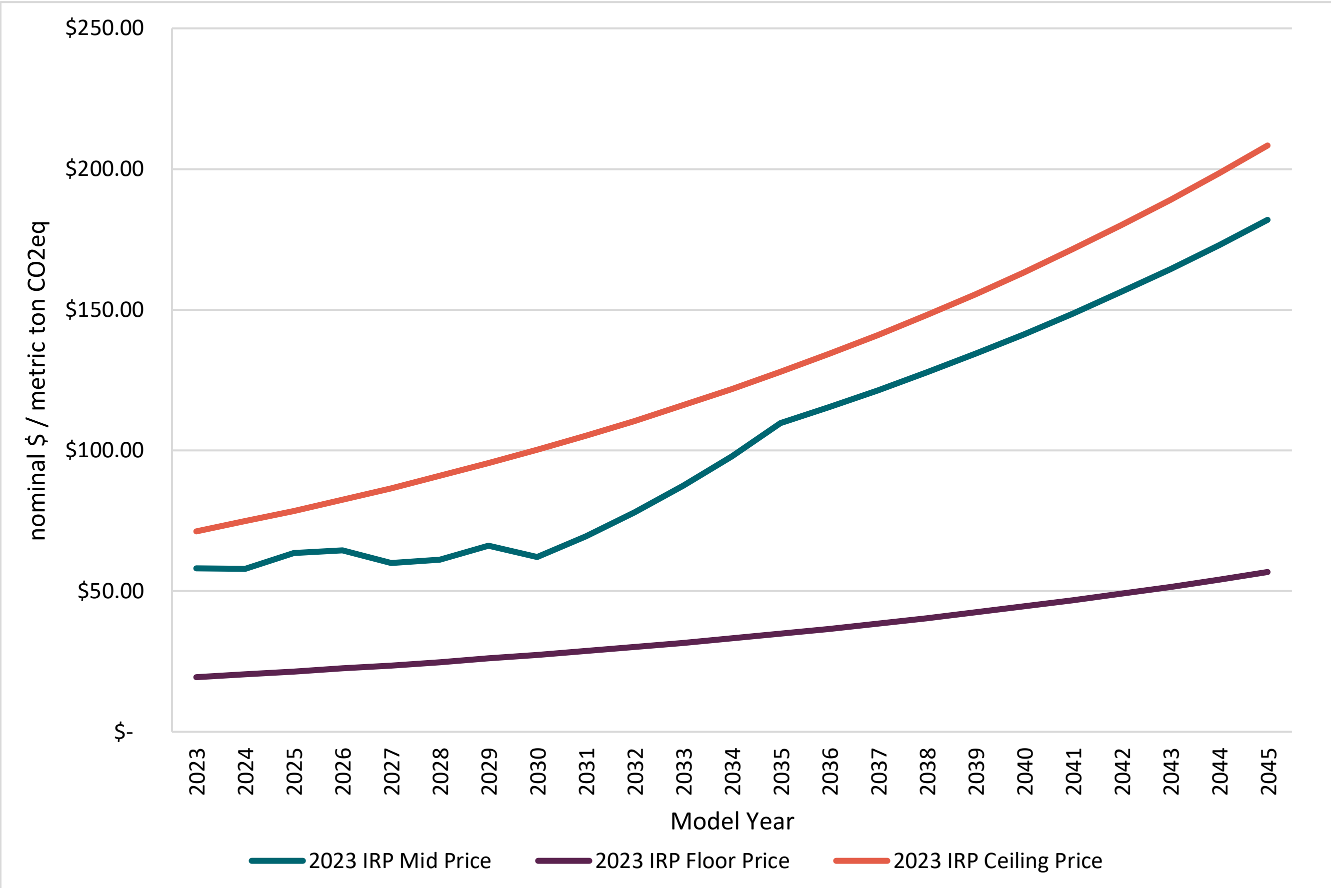
The Washington State legislature passed the CCA in 2021; it goes into effect in 2023. The CCA is a cap-and-invest bill that places a declining limit on the quantity of greenhouse gas emissions generated within Washington State and establishes a marketplace to trade allowances representing permitted emissions. The resulting market establishes an opportunity cost for emitting greenhouse gases. We added an emission price to greenhouse gas emissions in the electric price forecast model for emitting resources within Washington State to model this opportunity cost. In the price forecast model, we only added the emission price to Washington State emitting resources to ensure the model reflects any change in dispatch without impacting that of resources outside Washington State not subject to the rule. To accurately reflect all costs imposed by the CCA, we added a hurdle rate on transmission market purchases to the PSE portfolio model to account for unspecified market purchases using the CCA price forecast at the unspecified market emission rate 0.437 metric tons of CO_2eq per MWh (RCW 19.405.070).[7]

Figure 5.4 shows the emission prices we used to model the CCA allowance price, an ensemble of two price forecasts from the Washington Department of Ecology (Ecology) and the California Energy Commission (CEC). Ecology issued an analysis of the CCA, which included estimated allowance price forecasts across a range of program and market assumptions.[8] We suggest a linkage to the California carbon market is a likely scenario; therefore, we adopted an ensemble pricing scheme that begins with pricing at the rate specified by the Ecology CA Linkage 2030 case, then

4 Proposed Tacoma Liquefied Natural Gas Project, Final Supplemental Environmental Impact Statement, Ecology and Environment, Inc., March 29, 2019.
5 GHGenius. (2016). GHGenius Model v4.03. Retrieved from http://www.ghgenius.ca.
6 GREET. (2018). Greenhouse gases, Regulated Emissions and Energy use in Transportation; Argonne National Laboratory.
7 RCW 19.405.070
8 Preliminary Regulatory Analyses for Chapter 173-446 WAC, Climate Commitment Act Program

transitions to the CEC 2021 Integrated Energy Policy Report[9] allowance price forecast for the remainder of the modeling horizon.

Figure 5.4: Climate Commitment Act Allowance Pricing in the 2023 Progress Report



2.5. Climate Change

This 2023 Electric Progress Report is the first time Puget Sound Energy has included the influence of climate change on demand and hydroelectric conditions in the Pacific Northwest (PNW) in an electric progress report. We adapted inputs incorporating climate change from the NPCC's 2021 Power Plan analysis. As the basis for their analysis, the NPCC evaluated 19 climate change scenarios developed by the River Management Joint Operating Committee (RMJOC)[10], Part II, and selected three scenarios representing a range of possible climate outcomes. Puget Sound Energy adopted these same three climate change scenarios:

- CanESM2_RCP85_BCD_VIC_P1, coded as A.
- CCSM4_RCP85_BCD_VIP_P, coded as C.
- CNRM-CM5_RCP85_MACA_VIC_P3, coded as G.

9 2021 Integrated Energy Policy Report (ca.gov)
10 https://usace.contentdm.oclc.org/digital/collection/p266001coll1/id/9936

The three climate change scenarios we adopted uniquely impact the PNW load and hydroelectric input assumptions. Incorporating these disparate impacts into a single deterministic forecast presented significant modeling challenges. Therefore, the 2023 Electric Progress Report analysis averaged the effects of each climate change scenario to develop a single climate change case, which retains trends in all three climate change scenarios.

➔ For more information on assumptions for incorporating climate change, see Chapter Six: Demand Forecast.

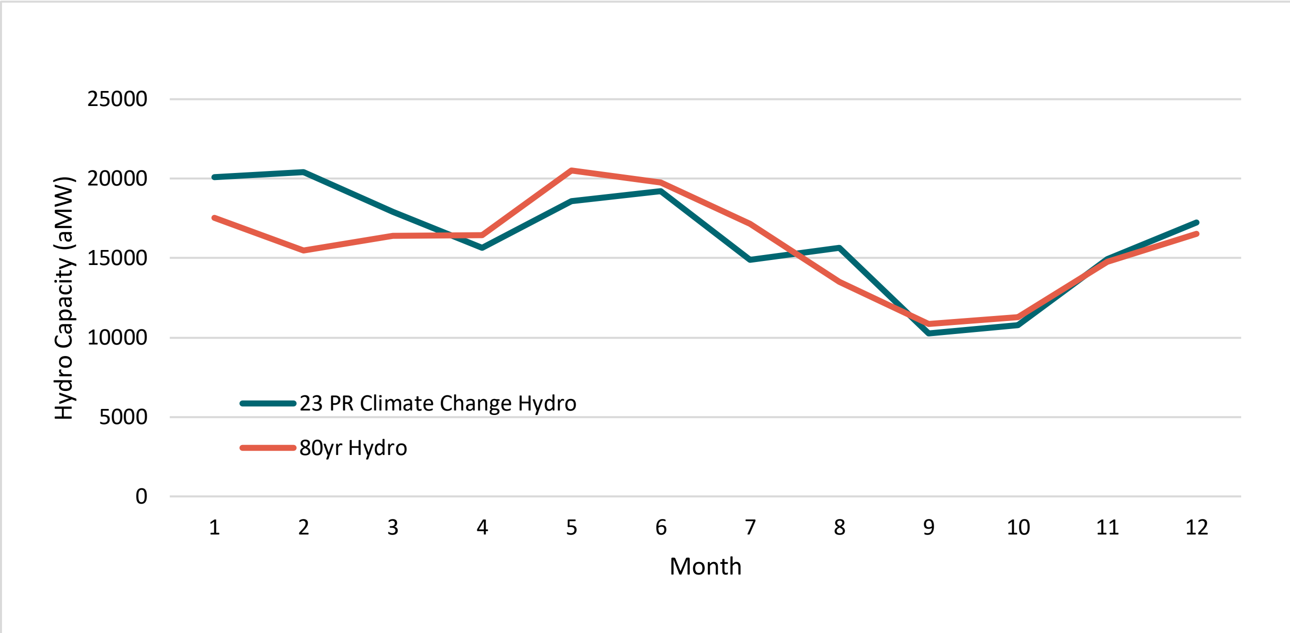
2.5.1. Hydroelectric Assumptions

We adapted the climate change hydroelectric forecast from the regional demand forecast created by the NPCC for the 2021 Power Plan. The hydroelectric forecast represents an average of all three climate change scenarios and an average of the hydroelectric conditions for the 30-year timespan of the climate change scenarios. We calculated hydroelectric capacity based on expected hydroelectric output from the GENESYS[11] regional resource adequacy model using streamflow data representative of the climate change scenarios.

We held the average hydroelectric forecast fixed for all the modeled years. Figure 5.5 presents the climate change hydroelectric forecast compared to the 80-year historic hydroelectric average forecast we used in the 2021 IRP. The forecasts are similar, but the climate change forecast trends toward more hydroelectric generation in the winter and less generation for the remainder of the year. This plot represents the PNW average hydroelectric capacity; trends for individual hydroelectric facilities will vary.

[11] https://www.nwcouncil.org/2021powerplan_genesys-model/

Figure 5.5: Pacific Northwest Climate Change Hydroelectric Forecast, Average of All Hydroelectric Facilities



2.6. Electric Price Inputs

We must create a wholesale electric price forecast as an input to the portfolio model to represent the wholesale power market. In this context, electric price does not mean the rate charged to customers; it means the price to PSE of purchasing (or selling) one megawatt (MW) of power on the wholesale market, given the prevailing economic conditions. This wholesale electric price forecast is an essential input since market purchases make up a substantial portion of PSE's existing electric resource portfolio.

Creating a wholesale electric price forecast requires performing WECC-wide AURORA model runs. The AURORA database starts with inputs and assumptions from the Energy Exemplar 2020 WECC Zonal database v1.0.1. We then include updates such as regional demand, natural gas prices, CO_2 prices, clean energy policies, and resource retirements and builds.

Figure 5.6 presents the annual average electric price forecast used in the 2023 Progress Report.

➔ See Appendix G: Electric Price Models for a detailed description of the methodology used to develop wholesale electric prices

Figure 5.6: Mid-C Wholesale Electric Price Annual Average Price Forecast Over Time (Nominal $/MWh)

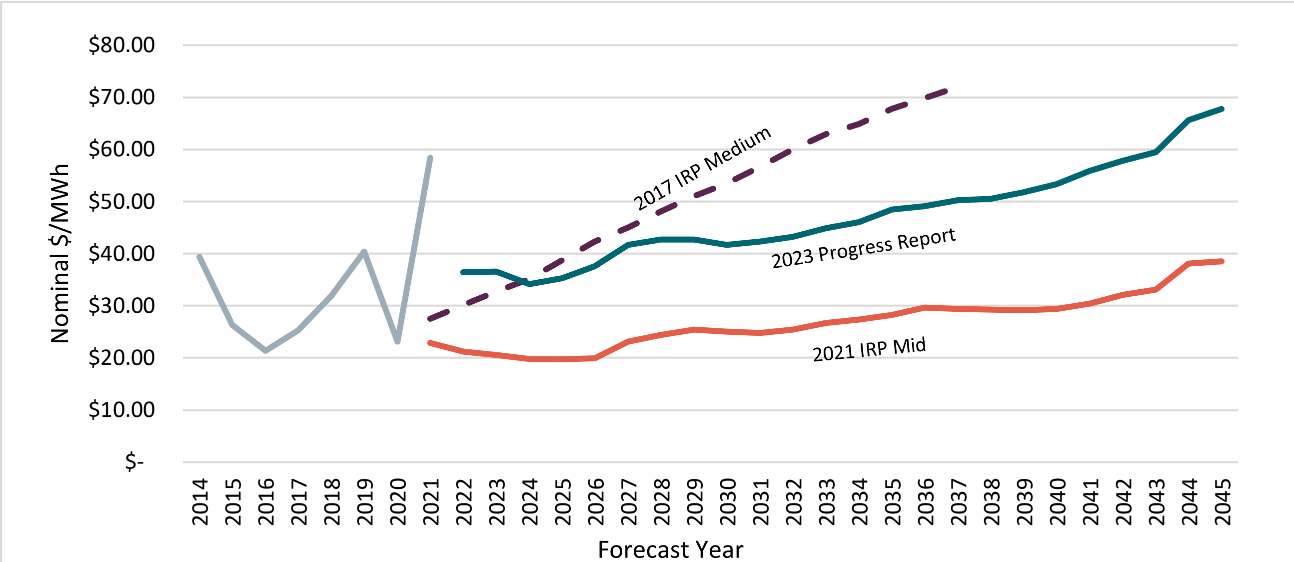
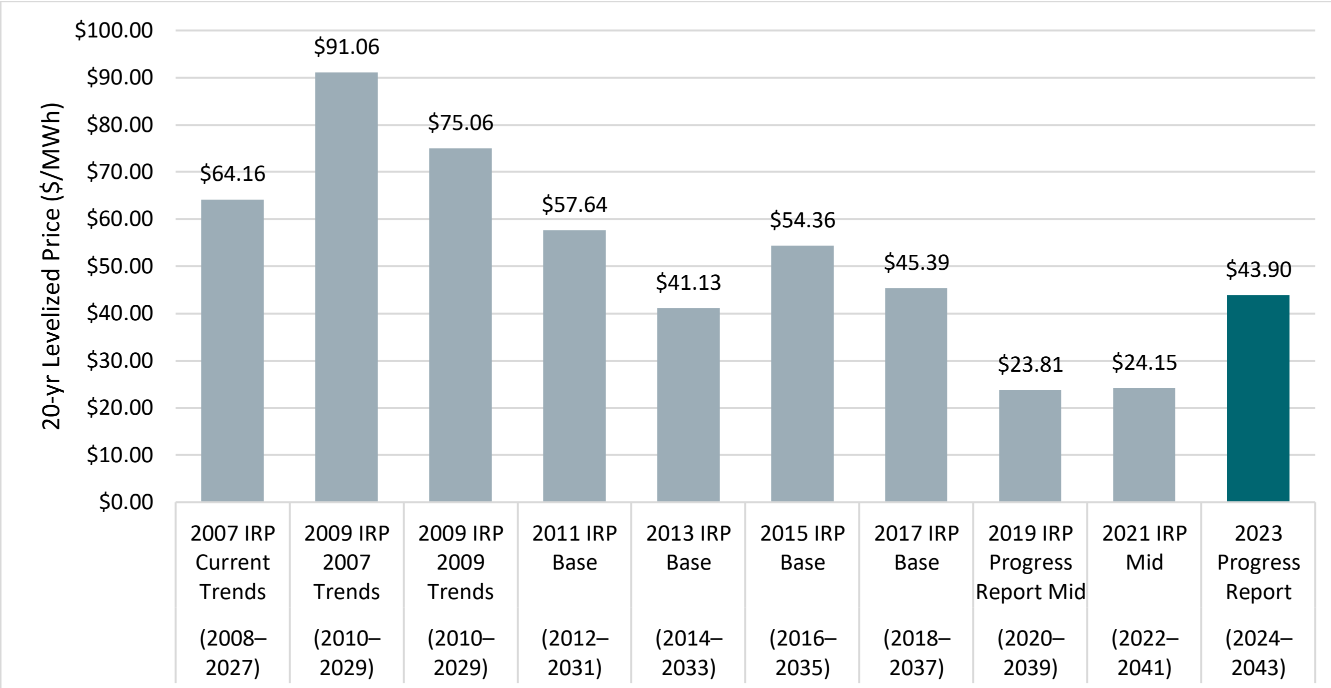


Figure 5.7 compares the 2023 electric price forecast to past IRP electric price forecasts. In previous IRPs, the downward revisions in forecast power prices corresponded to those in natural gas prices. In the 2021 IRP, the large increase in renewable resources in the region required by new clean energy regulations drives much of the downward revision in forecasted power prices. The 2017 IRP base scenario included CO_2 as a tax, whereas the 2021 IRP includes the social cost of greenhouse gases as an adder to resource decisions. The increase in electric prices in the 2023 Electric Progress Report is from several significant model updates, including increased natural gas prices, increased storage resources, revised methodology on clean energy policy modeling, and the addition of carbon allowance pricing from the CCA.

➔ Please find more details on the impacts of these updates in Appendix G: Electric Price Models.

Figure 5.7: Comparison of 2023 20-year Levelized Electric Prices Compared to Past IRPs ($/MWh)



2.7. Electric Resource Assumptions

We modeled the following generic resources as potential portfolio additions in this IRP analysis.

➔ See Appendix D: Generic Resource Alternatives, for detailed descriptions of the supply-side resources listed here and Appendix E: Conservation Potential Assessment and Demand Response Assessment, for detailed information on demand-side resource potentials.

2.7.1. Demand-side Resources

Demand-side resources contribute to meeting energy-need by reducing demand. An integrated resource plan includes both supply- and demand-side resources. We accounted for the contribution that demand-side programs make to meeting resource needs as a reduction in demand for the IRP analysis. Demand-side resources include energy efficiency measures (also referred to as conservation), generation efficiency measures, and distribution efficiency measures.

Energy Efficiency Measures

Energy efficiency measures reduce the level of energy used to accomplish a given amount of work. We group the wide variety of energy efficiency measures available into three categories: retrofit programs that have shorter lives; lost opportunity measures that have longer lives, such as high-efficiency furnaces; and codes and standards that drive down energy consumption through government regulation. Codes and standards impact the demand forecast but have no direct cost to utilities. Energy efficiency also includes small-scale electric distributed generation, such as combined heat and power.

Generation Efficiency

Generation efficiency comes from improvements at PSE generating plants.

Distribution Efficiency

Distribution efficiency comes from voltage reduction and phase balancing. Voltage reduction is reducing the voltage on distribution circuits to reduce energy consumption. Phase balancing can reduce energy loss by eliminating total current flow losses.

2.7.2. Distributed Energy Resources

Distributed Energy Resources (DER) are small, modular energy generation and storage technologies installed on the distribution systems rather than the transmission system. Distributed Energy Resources are typically under 10 MW and provide a range of services to the power grid. These resources include wind, solar, storage, and demand response technologies and may be networked to form Virtual Power Plants (VPPs). We included demand response, distributed solar, and distributed storage programs as generic DERs in this 2023 Electric Report.

Demand Response

Demand response resources are like energy efficiency in that they reduce customer peak load, but unlike energy efficiency, they are also dispatchable. These programs involve customers curtailing load when needed. The terms and conditions of demand response programs vary widely.

Distributed Solar Generation

Distributed solar generation refers to small-scale rooftop or ground-mounted solar panels close to the customer's load source. We modeled distributed solar as a residential-scale resource in western Washington. We summarize the capacity factors for solar resources modeled in Table 5.2. Consulting firm DNV provided the solar production profile data used in the AURORA model.

Table 5.2: Distributed Solar Capacity Factors

Solar Resource	Configuration	Capacity Factor (annual average, %)
DER Ground Solar	Residential-scale, fixed-tilt, ground mounted	17
DER Rooftop Solar	Residential-scale, fixed-tilt, rooftop mounted	17

Distributed Battery Energy Storage

Distributed battery energy storage systems refer to small-scale lithium-ion battery installations close to the customer's load. We modeled distributed storage as a residential-scale, three-hour duration battery with a nameplate capacity of 5 MW.

Non-wires Alternatives

We consider non-wires alternatives when developing solutions to specific, long-term needs identified in the transmission and distribution systems. The resources we study benefit from the capacity to address system deficiencies while supporting resource needs. We can deploy them across the transmission and distribution systems, providing flexibility in addressing system deficiencies. The non-wires alternatives we considered during the planning process include energy storage systems and solar generation.

2.7.3. Supply-side Resources

Supply-side resources provide electricity to meet the load. These resources originate on the utility side of the meter and include wind, solar, pumped hydroelectric energy storage, battery energy storage, hybrid resources (combination of wind, solar, and battery), combustion turbines, and advanced nuclear small modular reactors (SMR). The following section describes the supply-side resources applied to this 2023 Electric Report.

Wind

We modeled wind in seven locations throughout the northwest United States, including eastern Washington, central Montana, eastern Montana, Idaho, eastern Wyoming, western Wyoming, and offshore Washington. A summary of capacity factors for each wind resource is in Table 5.3. Consulting firm DNV provided the wind production profile data used in the AURORA model.

Table 5.3: Wind Capacity Factors

Wind Resource	Capacity Factor (annual average, %)
British Columbia	40.9
Eastern Washington	37.2
Central Montana	41.3
Eastern Montana	47.7
Idaho	15.0
Eastern Wyoming	46.4
Western Wyoming	36.1
Offshore Washington	42.1

Solar

We modeled solar as a centralized, utility-scale resource at several locations throughout the northwest United States and as a distributed, residential-scale resource in western Washington. A summary of the capacity factors for utility scale solar resources modeled is in Table 5.4. Consulting firm DNV provided the solar production profile data used in the AURORA model.

Table 5.4: Solar Capacity Factors

Solar Resource	Configuration	Capacity Factor (annual average, %)
Idaho	Utility-scale, single-axis tracker	27.3
Eastern Washington	Utility-scale, single-axis tracker	25.0

Solar Resource	Configuration	Capacity Factor (annual average, %)
Western Washington	Utility-scale, single-axis tracker	20.2
Eastern Wyoming	Utility-scale, single-axis tracker	28.9
Western Wyoming	Utility-scale, single-axis tracker	30.0

Energy Storage

Energy storage encompasses a range of technologies capable of converting kinetic energy into stored potential energy for later use. Energy storage removes the need for electricity generation to match the energy demand instantaneously. As such, energy storage can help to mitigate some of the challenges associated with variable energy resources such as wind and solar. A wide variety of energy storage technologies exist and span a range of development conditions from theoretical to commercially available. We discuss the current status of several storage technologies in Appendix D: Generic Resource Alternatives. We modeled a subset of commercially mature and well-characterized storage technologies for this 2023 Electric Report, including two-hour, four-hour, and six-hour lithium-ion batteries and eight-hour pumped hydroelectric storage. Generic Resource Alternatives. We modeled a subset of commercially mature and well-characterized storage technologies for this 2023 Electric Report, including two-hour, four-hour, and six-hour lithium-ion batteries and eight-hour pumped hydroelectric storage.

Baseload and Peakers

Baseload generators are designed to operate economically and efficiently over long periods of time, defined as more than 60 percent of the hours in a year.

Peaker is a term used to describe generators that can ramp up and down quickly to meet spikes in need. Unlike baseload resources, they are not intended to operate economically for long periods of time.

Hybrid Resources

In addition to stand-alone generation and energy storage resources, we modeled hybrid resources, which combine two or more resources at the same location to take advantage of synergies between the resources. We modeled three types of hybrid resources: eastern Washington solar + four-hour lithium-ion battery, eastern Washington wind + four-hour lithium-ion battery, and eastern Washington wind + solar + four-hour lithium-ion battery.

Baseload Thermal Plants

Baseload thermal plants or combined-cycle combustion turbines (CCCT) are F-type, 1 x 1 engines with wet cooling towers. We assumed they would generate 348 MW plus 19 MW of duct firing and be in PSE's service territory. We designed and intended these resources to operate at base load, defined as running more than 60 percent of the hours in a year.

Frame Peakers

Frame peakers or simple-cycle combustion turbines (SCCT) are F-type, wet-cooled turbines. We assumed they would generate 237 MW and be in PSE's service territory. We modeled these resources with either natural gas or an alternative fuel as the fuel source.

Recip Peakers

Recip peakers, or reciprocating engines, are small 18.2 MW engines with wet cooling located in PSE's service territory. We modeled these resources with either natural gas or an alternative fuel as the fuel source.

Alternative Fuels

In addition to natural gas, this 2023 Electric Report includes low-carbon alternative fuels, including hydrogen and biodiesel. Given current incentives in the Inflation Reduction Act,[12] green hydrogen fuel may become cost-effective compared to natural gas after accounting for the social cost of greenhouse gases and the impacts of the CCA. Biodiesel may also provide a viable, low-carbon alternative fuel for capacity resources during peak critical hours.

➔ We provide a description and the modeling assumptions used for these alternative fuels in Appendix I: Electric Analysis Inputs and Results.

Advanced Nuclear Small Modular Reactor

We modeled advanced nuclear (SMR) for the first time in the 2023 Electric Report. An SMR is a cluster of relatively small nuclear reactors at the same site that share land and infrastructure, although each reactor may be operated independently. The reactor technology is similar to that used in nuclear-powered submarines. While the exact specifications for SMR systems can vary, we chose to model this resource with a configuration of up to a 50MW module for this 2023 Electric Progress Report.

➔ We provide a complete description of SMR technology in Appendix D: Generic Resource Alternatives.

2.8. Electric Resource Cost Assumptions

We sourced generic resource capital cost assumptions from the National Renewable Energy Laboratory (NREL) 2022 Annual Technology Baseline (ATB)[13] for most resources in the 2023 Electric Report, consistent with our Clean Energy Implementation Plan (CEIP). This method is different from the approach we took in the 2021 IRP, which used different generic resource cost assumptions. The NREL did not include reciprocating peaker technology in the 2022 ATB; therefore, we sourced capital cost data for this generic resource from the U.S Energy Information Administration's (EIA) Annual Energy Outlook (AEO) for 2022 (2022 AEO).

Interconnection costs are not included as part of the capital cost for generic resources in the 2022 ATB or 2022 AEO and can account for a significant portion of the capital cost of some resource types. We added interconnection cost

[12] https://www.congress.gov/bill/117th-congress/house-bill/5376/text
[13] https://atb.nrel.gov/electricity/2022/technologies

estimates to each resource type based on the spur line length needed to interconnect each generic resource to the transmission grid to account for this omission.

We expect generic resource capital costs to decline as technology advances push costs down. The declining cost curves applied to different resource alternatives come from the 2022 ATB. The 2022 ATB provides three cost curves for each resource: low, mid, and constant technology cost scenarios. We selected the mid-technology cost scenario for the IRP cost curves, representing the most likely future cost projection.

We sourced generic resource O&M costs from the 2022 ATB for all generic resource technologies except thermal technologies. We sourced generic CCCT and frame peaker fixed O&M from averaging our existing costs, as reported in the 2021 FERC Form 1s. We adopted the fixed O&M that were reported for the Port Westward 2 facility as the generic reciprocating peaker fixed O&M.[14] We adopted variable O&M from the CAISO Variable Operations and Maintenance Cost Review, Final Proposal.[15]

The 2022 ATB did not provide O&M costs for most hybrid configurations presented in the 2023 Electric Report. We combined the fixed O&M for each component within the hybrid system to calculate these costs and used the respective capacities to generate a weighted average. The 2022 ATB provided a fixed O&M cost associated with a solar plus four-hour li-ion battery storage hybrid system, which is higher than the weighted average. Though the literature indicated this O&M was based on stand-alone solar and battery fixed O&M, NREL did not present the precise method of combining these costs in the 2022 ATB. To maintain consistency with other hybrid systems in the 2023 Electric Report, we used a weighted average for the solar plus battery storage hybrid resource. We show all hybrid resource fixed O&M as a time series.

➔ See Appendix D: Generic Resource Alternatives, for a more detailed description of resource cost assumptions, including transmission and natural gas transport assumptions.

Table 5.5 summarizes generic resource cost assumptions.

Table 5.5: New Resource Generic Cost Assumptions

IRP Modeling Assumptions (2020 $)	Nameplate (MW)	First Year Available	Fixed O&M ($/kW-yr)	Variable O&M[1] ($/MWh)	CAPEX ($/kW)[2]	Intercon-nection[2,3]	Total[2]
CCCT	348	2024	22.67	6.16	963	22	987
Frame Peaker	237	2024	9.52	1.02	879[4]	26	944
Recip Peaker	219	2024	14.53	1.16	2019	26	2045
WA Utility Solar East & West	100	2024	19.35	0.00	1074	156	1230
Idaho Utility Solar	400	2026	19.35	0.00	1074	463	1537

[14] https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/home
[15] https://stakeholdercenter.caiso.com/StakeholderInitiatives/Variable-operations-maintenance-cost-review

IRP Modeling Assumptions (2020 $)	Nameplate (MW)	First Year Available	Fixed O&M ($/kW-yr)	Variable O&M[1] ($/MWh)	CAPEX ($/kW)[2]	Intercon-nection[2,3]	Total[2]
WY Utility Solar East & West	400	2026	19.35	0.00	1074	463	1537
DER Solar — Rooftop and Ground-mounted WA West	5	2024	25.48	0.00	2,287	0	2,287
Offshore Wind	100	2030	70.78	0.00	4,137	590	4,728
BC Wind	100	2024	41.79	0.00	1,308	422	1,730
WA Wind	100	2024	41.79	0.00	1,308	156	1,464
MT Wind	100	2024	41.79	0.00	1,308	1,164	2,472
ID Wind	400	2026	41.79	0.00	1,308	463	1,772
WY Wind	400	2026	41.79	0.00	1,308	463	1,772
Pumped Storage — WA, OR, Closed Loop, 8-hour	100	2029	17.82	0.51	3,404	506	3,910
Pumped Storage — MT Closed Loop 8-hour	100	2029	17.82	0.51	3,404	198	3,602
Battery 2-hour Li-Ion	100	2024	20.12	0.00	746	58	804
Battery 4-hour Li-Ion	100	2024	32.76	0.00	1,256	58	1,314
Battery 6-hour Li-Ion	100	2024	45.49	0.00	1,765	58	1,823
DER Batteries 3-hour	5	2024	98.06	0.00	3,923	0	3,923
Wind + Battery	150	2024	38.35	0.00	1,093	217	1,310
Solar + Battery WA	150	2024	23.39	0.00	976	170[5]	1,147
Wind + Solar + Battery WA	250	2024	30.69	0.00	932	257[5]	1,190
Biomass	15	2024	151.00	5.80	4,332	573[5]	4,906
Advanced Nuclear SMR	50	2028	114.00	2.84	10,918	13	10,930

Notes:

1. Variable O&M costs do not include the cost of fuel for thermal resources.
2. Capital Costs, Vintage 2023. CAPEX (capital expenditures) required to achieve commercial operations of a generation plant. CAPEX may vary by resource type.
3. Interconnection costs consist of the transmission, substation, and natural gas pipeline infrastructure. The interconnection cost of offshore wind only includes onshore interconnection, and we included marine cable costs in the capital cost of the resource.
4. Frame peaker CAPEX includes costs for on-site biodiesel storage
5. Wind + Battery and Solar + Battery resources received a 40 percent interconnection cost-benefit, and the Wind + Solar + Battery resource received a 55 percent interconnection cost-benefit.

➔ See Appendix D: Generic Resource Alternatives for cost curve charts broken out by renewable, energy storage, and thermal resource type. See Appendix D: Generic Resource Alternatives for cost curve charts broken out by renewable, energy storage, and thermal resource type.

2.9. Flexibility Considerations

The 2023 Electric Report flexibility study reflects the financial impacts of the sub-hourly flexibility analysis in the portfolio analysis. Different resources have different sub-hourly operational capabilities. Even if the portfolio has adequate flexibility, various resources can impact costs and how the portfolio operates. For example, batteries could avoid the dispatch of thermal plants form ramping up and down.

For the sub-hourly flexibility analysis, we used a model called PLEXOS. First, we created a current portfolio case based on PSE's existing resources. We started the current portfolio case by making a simulation that reflects a complete picture of PSE as a Balancing Authority (BA) and our connection to the market. We represented PSE's Balancing Authority Area (BAA) load and generation on a day-ahead and real-time, 15-minute basis. We also included opportunities to make purchases and sales at the Mid-C trading hub in hourly increments and the Energy Imbalance Market (EIM) in 15-minute increments. For this analysis, we simulated 2029 for both hour-ahead and real-time and then took the difference in total portfolio cost between the two simulations.

We tested the impact of a range of potential new resources, each individually added to the current portfolio. If the dispatch cost of the portfolio with the new addition is lower than the existing portfolio case cost, we identified the cost reduction as a benefit of adding the new resource.

Table 5.6 shows the cost savings associated with each resource. For example, a CCCT has a cost savings of $5.17/kW-year. We applied these cost savings back to the fixed O&M of the generic resource as a reduction to the cost.

Table 5.6: Sub-hourly System Flexibility Cost Savings

Resource	Flexibility Cost Savings ($/kW-yr)
CCCT	5.17
Frame Peaker	9.65
Recip Peaker	28.14
Lithium-ion battery 2-hour	7.43
Lithium-ion battery 4-hour	47.21
Lithium-ion battery 6-hour	8.58
Pumped Storage Hydroelectric 8-hour	2.82
Demand Response	19.39

➔ See Appendix H: Electric Analysis and Portfolio Model, for a detailed description of the methodology used to develop the flexibility benefit.

2.10. Regional Transmission Constraints

Transmission constraints are a set of limits imposed on the IRP portfolio model, which seeks to model real-world transmission limitations within the WECC. These constraints include capacity limitations, transmission losses, and transmission costs.

2.10.1. Transmission Capacity Constraints

Transmission capacity constraints have become a vital modeling consideration as we transition away from thermal resources and toward clean, renewable resources to meet the goals of CETA. In contrast to thermal resources such as CCCTs and frame peakers, which we can generally site in locations convenient to transmission, produce power at a controllable rate, and dispatch as needed to meet shifting demand, renewable resources are site-specific and produce power intermittently. The limiting factors of renewable resources have two significant impacts on the power system: 1) we must acquire a greater quantity of renewable resources to meet the same peak demand as thermal resources, and 2) the best renewable resources to meet PSE's loads may not be located near our service territory. A wind farm in one location will produce a different amount of power than the same wind farm in another place. This situation makes it essential to consider whether there is enough transmission capacity to carry power from remote renewable resources to our service territory.

2.10.2. Assumptions

To model transmission capacity constraints, we created eight resource group regions and set limits on the generation capacity built in each region. We based resource group regions on the geographic relationships of the generic resources modeled in the 2023 Electric Report. Table 5.7 summarizes the resource group regions and the generic resources available in each group.

Table 5.7: Resource Group Regions and Generic Resources Available in Each Region

Generic Resource	PSE Territory[1]	Eastern Washington	Central Washington	Western Washington	Southern Washington / Gorge	British Columbia	Montana	Idaho & Wyoming
CCCT	X							
Frame Peaker	X							
Recip Peaker	X							
WA Solar East — Utility Scale		X	X		X			
WA Solar West — Utility Scale	X							
Idaho Solar — Utility Scale								X
WY Solar East — Utility Scale								X
WY Solar West — Utility Scale								X
DER WA Solar — Rooftop	X							
DER WA Solar — Ground	X							
WA Wind		X	X		X			
BC Wind						X		
MT Wind East							X	
MT Wind Central							X	
ID Wind								X
WY Wind East								X
WY Wind West								X
Offshore Wind				X				
Pumped Storage		X	X		X			
Battery 2-hour Li-Ion	X							
Battery 4-hour Li-Ion	X							
Battery 6-hour Li-Ion	X							
Solar + battery		X			X			
Wind + battery		X			X			
Solar + wind + battery		X			X			
Wind + pumped storage							X	
Biomass	X			X				
Advanced Nuclear SMR		X						

Note:

1. Not including the PSE IP Line (cross Cascades) or Kittitas area transmission, which is fully subscribed

We based capacity limits on our experience with available transmission capability (ATC) on the Bonneville Power Administration's (BPA) system, the results of BPA transmission service requests (TSRs), recent BPA TSR Study and Expansion Process (TSEP) Cluster Studies (2020, 2021, & 2022), regional transmission studies by Northern Grid, and dialogue with regional power sector organizations. Transmission planning, building, and acquisition are complex processes with various possible outcomes; therefore, we developed a range of plausible transmission limits and timelines for each region. To structure these ranges, we organized the transmission limits into tiers; uncertainty increases from tier to tier based on our ability to acquire that quantity of transmission.

The tiers include:

- **Tier 1:** Transmission capacity that we could likely acquire in 2023–2025. This transmission capacity draws primarily from repurposing our existing BPA transmission portfolio.
- **Tier 2:** Transmission capacity that we could acquire in 2025–2030 but is less certain than Tier 1. This transmission capacity adds new transmission resources to our portfolio. Tier 2 includes all Tier 1 transmission.
- **Tier 3:** Transmission capacity that we could acquire beyond 2030. Acquisition of Tier 3 transmission is less certain than Tiers 1 and 2. Capacity added in Tier 3 would likely come from adding long lead-time, major transmission system upgrades, or new transmission resources to PSE's portfolio. Tier 3 includes all Tier 1 and 2 transmission.
- **Tier 4:** Tier 4 represents a generally unconstrained transmission system.

In this report's reference case, we modeled transmission limits by tier with increasing transmission limits over time. By 2040, transmission will be unconstrained. In the context of this report, unconstrained transmission signifies there is enough time to acquire or build new transmission resources to match the resource mix provided by the model.

Table 5.8 summarizes the transmission limits by tier for each resource group region.

Table 5.8: Transmission Capacity Limitations by Resource Group Region (Added Transmission MW by Tier)

Resource Group Region	Tier 1 (by 2025)	Tier 2 (by 2030)	Tier 3 (by 2035)	Tier 4 (by 2040)
PSE territory (a)	(b)	(b)	(b)	(b)
Eastern Washington	640	2,310	2,510	Unconstrained
Central Washington	250	600	850	Unconstrained
Western Washington	0	100	635	Unconstrained
Southern Washington/Gorge	340	2,010	2,390	Unconstrained
British Columbia	200[c]	200[c]	200[c]	Unconstrained
Montana	0	400[c]	400[c]	Unconstrained
Idaho and Wyoming	0	400	600	Unconstrained
TOTAL	1,430	6,020	7,585	Unconstrained

Notes:

a. Not including the PSE IP Line (cross Cascades) or Kittitas area transmission, which is fully subscribed.
b. Not constrained in the resource model, assumes adequate PSE transmission capacity to serve future load.
c. Indicates we rounded transmission constraints to align with generic resource capacity ranges.

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The rationale for each transmission capacity limitation by resource group region follows.

Eastern Washington

Through BPA Cluster Study requests, we may obtain 150, 600, or 650 MW for transmission to the Lower Snake River region for Tiers 1, 2, and 3, respectively. By co-locating a 150 MW solar resource at an existing wind facility, we could add 150 MW of Tier 1 transmission. We may acquire an additional 340 or 1,230 MW for Tiers 1 and 2, respectively, of third-party BPA transmission from developer submittals and resource retirements.

Central Washington

We may obtain 250, 500, or 750 MW of transmission for Tiers 1, 2, and 3, respectively, using a portion of the existing 1,500 MW of Mid-C transmission we currently use for market purchases for dual purposes. An additional 100 MW of transmission may be available in Tier 1 to deliver Kittitas area solar via the Grant County PUD system.

Western Washington

We assume no additional transmission is available in Tier 1. Tier 2 may add 100 MW of BPA transmission after the TransAlta purchased power agreement (PPA) expires in 2025. Tier 3 may add 335 MW of dual-purpose transmission to prioritize renewable generation from the Mint Farm CCCT region. Tier 3 may add 200 MW of third-party transmission rights from developer submittals, resource retirements, or offshore wind development.

Southern Washington / Gorge

We may obtain 340 or 1,230 MW for Tiers 1 and 2, respectively, of third-party BPA transmission rights from developer submittals or resource retirements. Tiers 2 and 3 may also add 330 MW of dual-purpose transmission (Tier 2 100 MW, Tier 3 230 MW) to prioritize renewable generation co-located with the Goldendale CCCT.

British Columbia

We may obtain up to 160 MW of long-term transmission from BC Hydro by 2025. Any additional transmission between PSE and British Columbia would require a transmission study and likely system upgrades.

Montana

We may obtain 370 MW for Tier 2 of transmission from repurposing transmission freed up by removing Colstrip Units 3 & 4 from the PSE portfolio.

Wyoming / Idaho

Puget Sound Energy may pursue transmission capacity on the Boardman-to-Hemingway (B2H) and Gateway West projects, adding 400 or 600 MW of transmission for Tiers 2 and 3, respectively.

Puget Sound Energy Territory

For the 2023 Electric Report, we assumed that the PSE system in western Washington is unconstrained. This assumption does not include PSE IP Line (cross Cascades) or Kittitas area transmission, which is fully subscribed. This assumption holds because of a robust delivery system planning approach and the resulting long-range delivery system infrastructure plan, including transmission and distribution system upgrades.

2.10.3. Transmission Loss Constraints

Transmission loss constraints model energy lost to heat as power flows through the transmission line. Many factors, including distance, line material, and voltage, impact the magnitude of transmission line losses. The BPA assumes a flat 1.9 percent line loss across its transmission network. A line loss study conducted between PSE and the Colstrip substation found the line loss to be approximately 4.6 percent. Lacking a similar study for transmission to Wyoming and Idaho, we assumed a similar loss given the similar distance. Table 5.9 summarizes the transmission line losses assumed by the resource group region.

Table 5.9: Average Transmission Line Losses by Resource Group Region

Resource Group Region	Line Loss (%)
Eastern Washington	1.9
Central Washington	1.9
Western Washington	1.9
Southern Washington/Gorge	1.9
British Columbia	1.9
Montana	4.6
Idaho and Wyoming	4.6

2.10.4. Transmission Cost Constraints

Transmission cost is another factor used in the PSE portfolio model to constrain resource-build decisions. Transmission costs include a fixed component measured in dollars per kilowatt per year ($/kW-year) and a variable component measured in dollars per megawatt-hour ($/MWh). Fixed transmission costs include wheeling tariffs and balancing service tariffs, among others. Wheeling tariffs will vary by region depending on the number of wheels required to return power to our service territory. Balancing service tariffs vary by resource type; wind balancing service tariffs are usually more expensive than solar balancing serving tariffs, given the greater inter-hour variability of wind resources. Variable transmission costs are primarily composed of spinning and supply reserve requirement tariffs and may include other penalties or imbalance tariffs. Table 5.10 summarizes fixed and variable transmission costs by generic resource type.

We based the wheeling tariffs from Idaho and Wyoming on tariff service over Gateway West, Boardman to Hemingway, and the BPA main grid. For transmission cost modeling, we assumed the cost of three wheels (PacifiCorp, Idaho Power, and BPA) with a reduction to two wheels (PacifiCorp and BPA) after the Gateway West segments are fully completed (estimated 2030 according to PacifiCorp IRP).

Table 5.10: Transmission Costs by Generic Resource Type (in 2020 $)

Generic Resource	Fixed Transmission Cost ($/kW-year)	Variable Transmission Cost ($/MWh)
CCCT	0.00[a]	0.00
Frame Peaker	0.00[a]	0.00
Recip Peaker	0.00[a]	0.00
WA Solar East — Utility-scale	27.80	0.26
WA Solar West — Utility-scale	5.24	0.26
Idaho Solar — Utility-scale	57.66	0.26
WY Solar East — Utility-scale	101.12[b]	0.26
WY Solar West — Utility-scale	101.12[b]	0.26
DER WA Solar — Rooftop	0.00[a]	0.26
DER WA Solar — Ground-mount	0.00[a]	0.26
WA Wind	31.21	0.26
BC Wind	61.69	0.26
MT Wind — East	59.10	0.26
MT Wind — Central	59.10	0.26
ID Wind	61.07	0.26
WY Wind East	97.31[b]	0.26
WY Wind West	97.31[b]	0.26
Offshore Wind	31.21	0.26
WA/OR Pumped Storage	22.58	0.26
MT Pumped Storage	50.47	0.26
Battery 2-hour Li-ion	0.00[a]	0.00
Battery 4-hour Li-ion	0.00[a]	0.00
Battery 6-hour Li-ion	0.00[a]	0.00
Solar + Battery	27.80	0.26
Wind + Battery	31.21	0.26
Solar + Wind + Battery	31.21	0.26
Wind + Pumped Storage	59.10	0.26
Biomass	22.58	0.26
Advanced Nuclear SMR	22.58	0.26

Notes:

a. Fixed transmission cost is not applied because we assumed the resource would be built within the PSE service territory.

b. Wyoming transmission cost reflects wheel through Idaho Power territory, reduction in cost modeled in 2030 when Gateway West transmission becomes available. See Appendix H: Electric Analysis and Portfolio Model for further details on modeled transmission cost.

2.11. Electric Delivery System Planning Assumptions

Puget Sound Energy uses a structured approach to developing infrastructure plans that support various customer needs, including effective DER integration. Our process and the associated planning assumptions are in Figure 5.8 and Table 5.11, respectively.

Figure 5.8: Delivery System Planning Operating Model

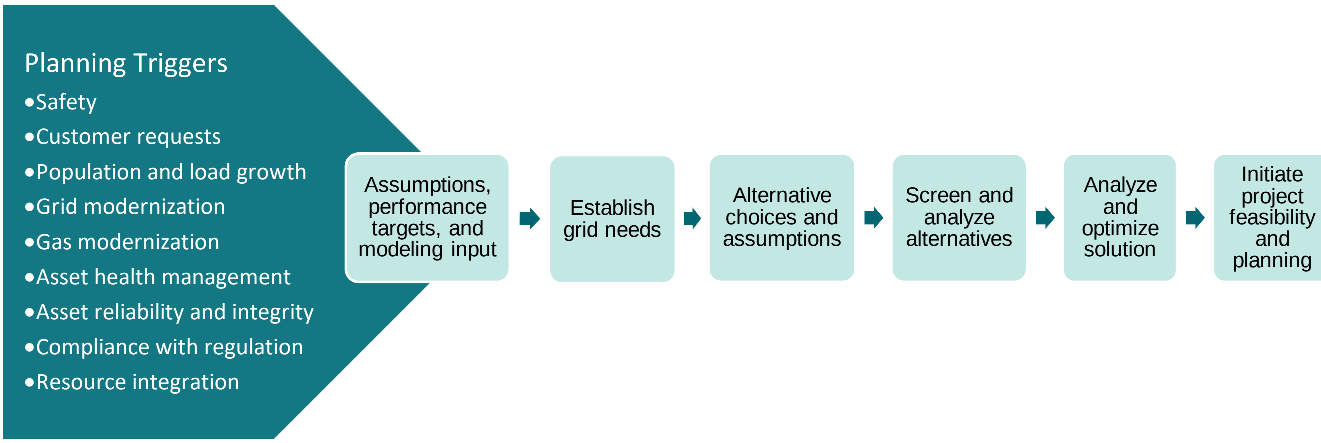


Table 5.11: Delivery System Planning Assumptions

Assumptions	Description
Demand and Peak Demand Growth	Uses county-level demand forecast applied based on historic load patterns of substations with known point loads adjusted for
Energy Efficiency	Highly optimistic 100% targets included (PSE benchmarking with peers in 2021)
Resource Interconnections	Interconnection requests with completed Large/Small Generator Interconnection Agreements included
Aging Infrastructure	Known concerns included in the analysis
Interruptible / Behavior-based Rates	Known opportunities to curtail during peak included
Distributed Energy Resources	Known controllable devices are included (most current solar and battery systems are not controllable to manage peak reliably to date)
System Configurations	As designed
Compliance and Safety Obligations	Meet all regulatory requirements, including NESC, NERC, and WECC, along with addressing voltage regulation, rapid voltage change, thermal limit violations, and protection limits

2.11.1. Delivery System Planning Non-wires Alternatives Forecast

We included a distributed energy resources forecast in the 2023 Electric Report that evaluates where we identified DERs as a potential non-wires solution for meeting delivery system needs. We then extrapolated the forecast based on load growth assumptions. As needs arrive on the planning horizon, further analysis relative to specific values and potential will test these assumptions.

The non-wires alternatives we considered during the delivery system planning (DSP) process include demand response, targeted energy efficiency, energy storage systems, and solar generation, among others. We considered these resources independently and as part of hybrid resource combinations with traditional infrastructure improvements to optimize the solution. Initial analyses suggest that cost-effective solutions align with needs primarily driven by capacity or resiliency. As we continue integrating DER into system solutions, we must answer critical questions about DER's operational flexibility and associated cyber-security considerations.

We used the following assumptions to develop a DER forecast to solve identified system needs over the 0-to-10-year time frame.

- Based on industry knowledge and consultant input for summer needs, we determined 3 to 4 MW was a reasonable size for utility-scale photovoltaic (PV).
- Due to the practical sizing of DER solutions, we did not consider projects with needs larger than 20 MW.
- We applied average historical percentages to determine energy efficiency, demand response, and energy storage potential.

We used the same assumptions for needs identified in the 10- to 20-year timeframe but extrapolated the value based on the load forecast (i.e., years with lower forecasted load growth would require fewer, smaller-scale projects to meet system needs versus years with larger forecasted load growth). We made additional considerations to account for the planning process. We assumed the needs we identified before 2023 would take two to three years to complete based on a new planning process and the learning curve associated with implementing new technologies. We assumed the needs identified after 2023 would be built when it first appeared on the system as the planning process matures and we gain experience siting DER. Figure 5.9 presents the forecast of DER resources added to the system as non-wires alternatives.

Figure 5.9: Forecasted DER Installation by Year and Type

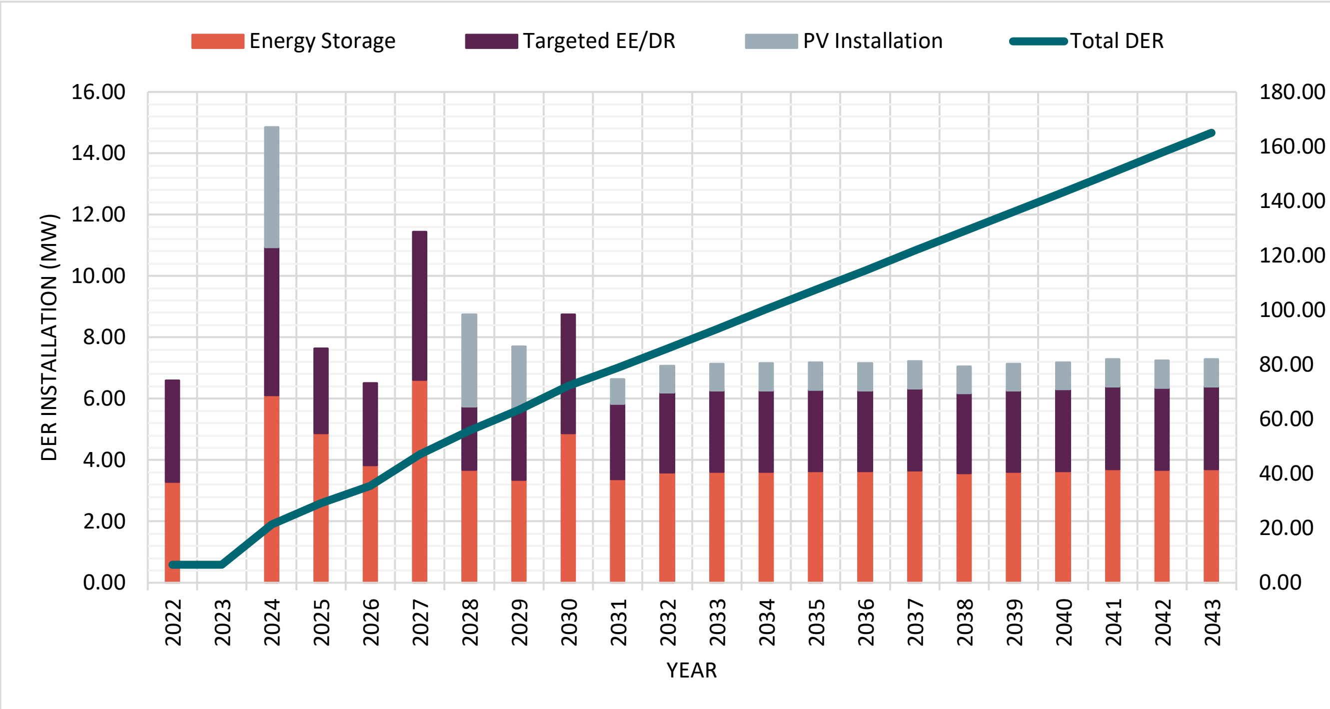


Table 5.12 presents the projected transmission and distribution deferrals resulting from the non-wires alternatives DER additions.

Table 5.12: Projected T&D Deferral by Project Type by 2040

Project Type	Energy Storage (MW)	Targeted EE/DR (MW)	PV Installation (MW)	Total DER (MW)
Planned Transmission System Projects[1]	7.1	6	0	13.1
Planned Substation Capacity Projects	17.6	12.4	3.9	33.9
Future Potential System Needs	59	42.6	16.4	118
Total	83.7	61	20.3	165

Note: [1]As identified in the PSE Plan for Attachment K

We modeled the energy storage and solar PV forecasts in the AURORA portfolio model as generating resource to represent the DSP non-wires alternatives. We included the targeted energy efficiency/demand response forecast as part of the cost-effective energy efficiency and demand response evaluation the model.

2.12. Transmission and Distribution Benefit

The transmission and distribution (T&D) benefit, also known as an avoided cost, is a benefit added to resources that reduce the need to develop new transmission and distribution lines. The T&D benefit is our forward-looking estimate of T&D system costs under a scenario where electrification requirements and electric vehicles drive substantial electric load growth. Studies of the electric delivery system identified capacity constraints on the transmission lines, substations, and distribution lines that serve PSE customers from increased load growth due to electrification and electric vehicle adoption. We used the estimated cost for the infrastructure upgrades required to mitigate these capacity constraints and the total capacity gained from these upgrades to calculate the benefit value. The 2023 Electric Progress Report included a T&D benefit of $74.70/kW-year for DER batteries. This estimated $74.70/kW-year is forecasted based on our additional transmission and delivery system needs under such a scenario. This increase is a significant change from the $12.93/kW-year we used in the 2021 IRP which used backward-looking metrics instead of the revised forward-looking scenario described.

2.13. Electric Generation Retirements

We modeled the economic retirement of existing thermal resources for this 2023 Electric Report. We assumed Colstrip would be removed from PSE’s portfolio by December 31, 2025; based on economics, the model can retire Colstrip earlier. We assumed the other thermal plants would run through the planning horizon but could retire early based on economics.

When determining the retirement of a generating plant, the model looks at the economics of the power plant for meeting loads and peaks. The generating plants' valuation process considers emission and variable costs (fuel, operations, and maintenance), fixed costs (including ongoing capital for upkeep and maintenance), and decommissioning costs.

2.14. Achieving CETA Compliance: 100 Percent Greenhouse Gas Neutral by 2030

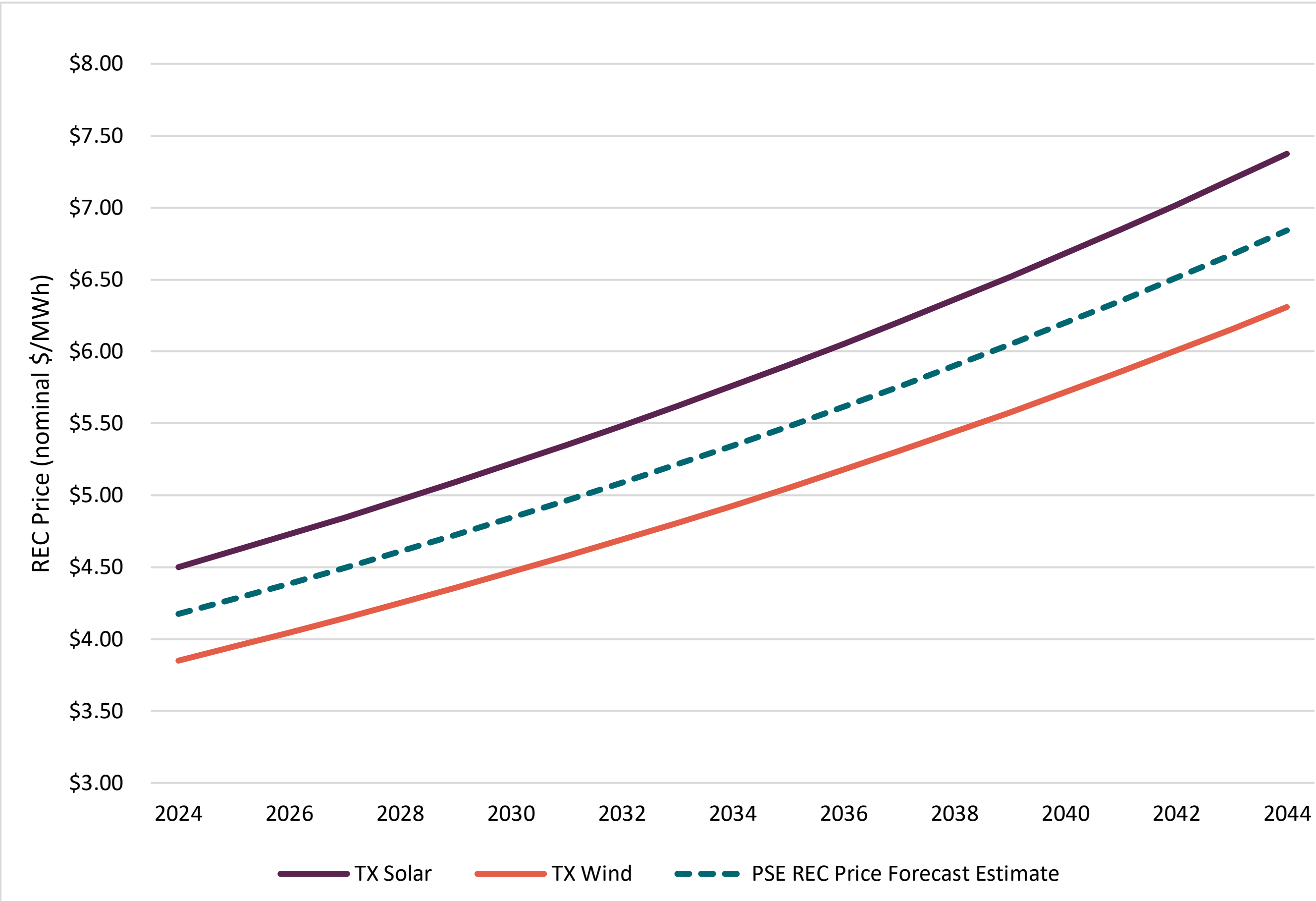
The CETA requires 100 percent greenhouse gas (GHG) neutrality by 2030, with a minimum of 80 percent of energy delivered met with renewable or non-emitting resources and the remaining energy delivered met by alternative options. Options for meeting the up to 20 percent remaining energy delivered include:

- Investing in energy transformation projects that meet criteria and quality standards developed by the Department of Ecology, in consultation with the Department of Commerce and the Commission
- Making an alternative compliance payment in an amount equal to the administrative penalty
- Purchasing carbon offsets
- Purchasing unbundled renewable energy credits

This 2023 Electric Report evaluated two methods to reach 100 percent GHG neutrality by 2030. For the first option, we assumed that we would purchase unbundled renewable energy credits (RECs) for up to 20 percent of the load not met by renewable generation starting in 2030 and decreasing to zero in 2045. The quantity of unbundled RECs purchased depends on the quantity of delivered energy not met by CETA-compliant resources. For example, if a given portfolio generated 85 percent of delivered energy with CETA-compliant resources in 2030, the remaining 15 percent would be compensated by purchasing unbundled RECs to achieve greenhouse gas-neutral compliance.

We reviewed REC markets nationwide to determine a suitable price forecast for unbundled RECs. The Texas wind and solar REC markets represent a stable, high-volume market with years of data available for review. Therefore, we selected an average of the Texas wind and solar REC price forecast as the REC price for achieving GHG neutrality compliance through the purchase of unbundled RECs. Figure 5.10 shows the Texas REC prices over the modeling horizon.

Figure 5.10: Forecasted Renewable Energy Credit Price Purchased to Achieve GHG Neutrality in Nominal $ per MWh



For the second option, we wanted to understand the impact of meeting 20 percent of the load with renewable resources to meet 100 percent of PSE's load with renewable resources by 2030. We modeled sensitivity 12 which retires all existing natural gas generation by 2030 and allows for addition of only renewable resources, thereby achieving 100 percent renewable energy by 2030.

➔ See Chapter Eight: Electric Analysis for the results of sensitivity 12 in detail.

We may meet actual compliance through other mechanisms that we are still developing. We will determine these mechanisms in the first CEIP that includes 2030, the year the greenhouse gas neutral standard takes effect. We will analyze these mechanisms as the Department of Ecology develops guidance on assigning greenhouse gas emission factors for electricity, establishes a process for determining what types of projects qualify as energy transformation projects, and includes other options such as transportation electrification.

3. Electric Portfolio Sensitivities

Sensitivity analysis is an essential component of the IRP process. After generating a reference portfolio, which is the optimized, least-cost set of resources to meet the base set of constraints, we model sensitivities that change a resource, environmental regulation, or condition to examine the effect of the change on the portfolio.

The portfolio modeling process is complex, with no shortage of potential sensitivities to investigate. In this 2023 Electric Report, we included key sensitivities necessary to develop a preferred portfolio in the analysis. We started with sensitivities that changed a single resource or assumption, such as adding more conservation programs or scheduled addition of pumped hydroelectric storage resources. These simple sensitivities provide context for how a given resource, which may not be part of the least-cost portfolio, may provide value, such as reduced greenhouse gas emissions or increased equity benefits. We then combined several of these simple changes to create diversified portfolios.

Diversified portfolios layer several minor changes to create a portfolio that provides even greater potential benefits. We modeled several diversified portfolios ranging from two to six small changes. These diversified portfolios become the candidate portfolios from which we will select a preferred portfolio based on its attributes related to cost, equity benefits, and feasibility.

The following sections provide an overview of the assumptions made for each sensitivity analyzed in this report. We provide their results and discussion in Chapter Eight: Electric Analysis. .

3.1. Reference Portfolio

The reference portfolio is a least-cost, CETA-compliant portfolio that allows the AURORA long-term capacity expansion model to optimize resource selection with as few constraints as possible. The reference portfolio is a basis against which to compare other portfolios. We used the assumptions described in the Electric Portfolio Analysis Assumptions section to develop the reference portfolio. We refer to the reference portfolio as sensitivity 1 throughout this report.

3.2. Conservation Alternatives

Adding higher conservation measures, we analyzed two sensitivities to assess portfolio builds and cost changes.

- Reference: 258 MW of new conservation will be added to the reference portfolio by 2045.
- Sensitivity 2: This sensitivity increases new conservation measures to 486 MW by 2045, an increase of 228 MW above the reference portfolio conservation.
- Sensitivity 3: This sensitivity increases new conservation measures to 382 MW by 2045, an increase of 123 MW above the reference portfolio conservation.

The reference, sensitivity 2 and sensitivity 3 portfolios all have codes and standards included for 437 MW by 2045. New energy efficiency up to bundle 3 was selected in reference portfolio for 258 MW by 2045. Although we did not select a distribution efficiency in the reference portfolio, we included a forecasted addition of distribution efficiency in sensitivity 2 and sensitivity 3 for a total of 11 MW by 2045. We included a forecasted addition of 475 MW by 2045 of energy efficiency in sensitivity 2 by having all measures through conservation bundle 10. We included a lower amount of the forecasted addition of 371 MW by 2045 of energy efficiency in sensitivity 3 by including all measures through conservation bundle 7. Table 5.13 shows the forecasted additions for demand-side resources for the portfolios.

Table 5.13: Demand-side Resources (MW for Reference, Sensitivity 2 Bundle 10, and Sensitivity 3 Bundle 7)

MW by 2045	1 Reference	2 Bundle 10	3 Bundle 7
Codes and Standards	437	437	437
New Distribution Efficiency	0	11	11
New Energy Efficiency	258	475	371
Total	695	923	818

3.3. Distributed Energy Resources Alternatives

We analyzed two sensitivities to assess changes in portfolio builds and costs with additional distributed energy resources (DERs).

- Reference: 1,494 MW of distributed solar and 117 MW of distributed storage will be added to the reference portfolio by 2045.
- Sensitivity 4: This sensitivity adds 600 MW of additional distributed solar by 2045, resulting in 2,094 MW of distributed solar by 2045.
- Sensitivity 5: This sensitivity adds 150 MW of additional distributed storage by 2045, resulting in 267 MW of distributed storage by 2045.

The reference portfolio, sensitivity 4 and sensitivity 5, all include DER forecasts for customer-sited solar, non-wires alternatives, and new programs identified in the CEIP. Based on the results of the reference portfolio, we did not find it economical to add any additional DERs due to the higher cost relative to utility-scale resources. Sensitivity 4 explores the impact of adding distributed solar above the established forecasts by adding 30 MW of distributed rooftop solar each year from 2026 to 2045. Sensitivity 5 examines the impact of adding distributed storage above the established forecast by adding 25 MW of distributed battery storage each year from 2026 to 2031.

3.4. Pumped Hydroelectric Storage Alternatives

We analyzed three sensitivities to assess changes in portfolio builds and cost by adding pumped hydroelectric storage (PHES) resources.

- Reference: PHES is selected on an economic basis, resulting in zero MW of PHES added to the reference portfolio.

- Sensitivity 6: This sensitivity adds 200 MW of Montana PHES and 400 MW of eastern Montana wind in 2026.
- Sensitivity 7: This sensitivity adds 200 MW of Montana PHES, 200 MW of central Montana wind, and 200 MW of eastern Montana wind in 2026.
- Sensitivity 8: This sensitivity adds 200 MW Pacific Northwest PHES in 2026.

Energy storage is a critical component of a CETA-compliant portfolio. The reference portfolio selected battery storage as a cost-effective storage resource. We explored diversifying the portfolio by adding PHES and battery energy storage in sensitivities 6, 7, and 8.

In sensitivities 6 and 7, we added 200 MW of Montana PHES in 2026. Energy from Montana resources currently gets to PSE via the Colstrip transmission line. The Colstrip transmission line has an available capacity of 750 MW for PSE to use. Given this restriction, we decided to overbuild Montana resources to provide surplus energy to charge the PHES resource and simultaneously maximize the throughput of energy over the Colstrip line to PSE. In sensitivity 6, we added 400 MW of eastern Montana wind to the existing 350 MW of Clearwater wind. In sensitivity 7, we added 200 MW of eastern Montana wind and 200 MW of central Montana wind in addition to the existing 350 MW of Clearwater wind. The Montana PHES and wind resources have a combined maximum output of 750 MW (the Colstrip transmission capacity limit), and excess energy is stored in the PHES resource.

In sensitivity 8, we added 200 MW of Pacific Northwest PHES in 2026. Since transmission capacity is less constrained in Washington and Oregon, we did not model any resource overbuild in sensitivity 8.

3.5. Advanced Nuclear Small Modular Reactors

We analyzed a sensitivity that added advanced nuclear SMR to the portfolio to assess changes in builds and cost.

- Reference: Advanced nuclear SMR is selected on an economic basis, resulting in zero MW of advanced nuclear SMR added to the reference portfolio.
- Sensitivity 9: This sensitivity adds 250 MW of advanced nuclear SMR in 2032.

The reference portfolio is updated to include a forecast in 2032 of 5 units of 50 MW advanced nuclear SMR resources for 250 MW. This advanced nuclear SMR provides a combination of dispatchability, reliability, and emission-free production benefits, making it an attractive alternative to traditional peaking resources as we move toward a zero-emissions portfolio.

3.6. No New Thermal Resources Before 2030

We analyzed a sensitivity where new thermal resources were unavailable before 2030 to assess changes in builds and cost.

- Reference: Thermal resources include natural gas peakers, blended natural gas and hydrogen peakers, and biodiesel peakers available for economical addition throughout the modeling horizon.
- Sensitivity 10: This sensitivity limited the availability of thermal resources before the year 2030. After 2030, we permitted natural gas, blended natural gas and hydrogen and biodiesel peakers in the portfolio.

This sensitivity aims to reduce the amount of thermal, or combustion, resources added to portfolio. No combustion resources are permitted to be added to the portfolio before the year 2030.

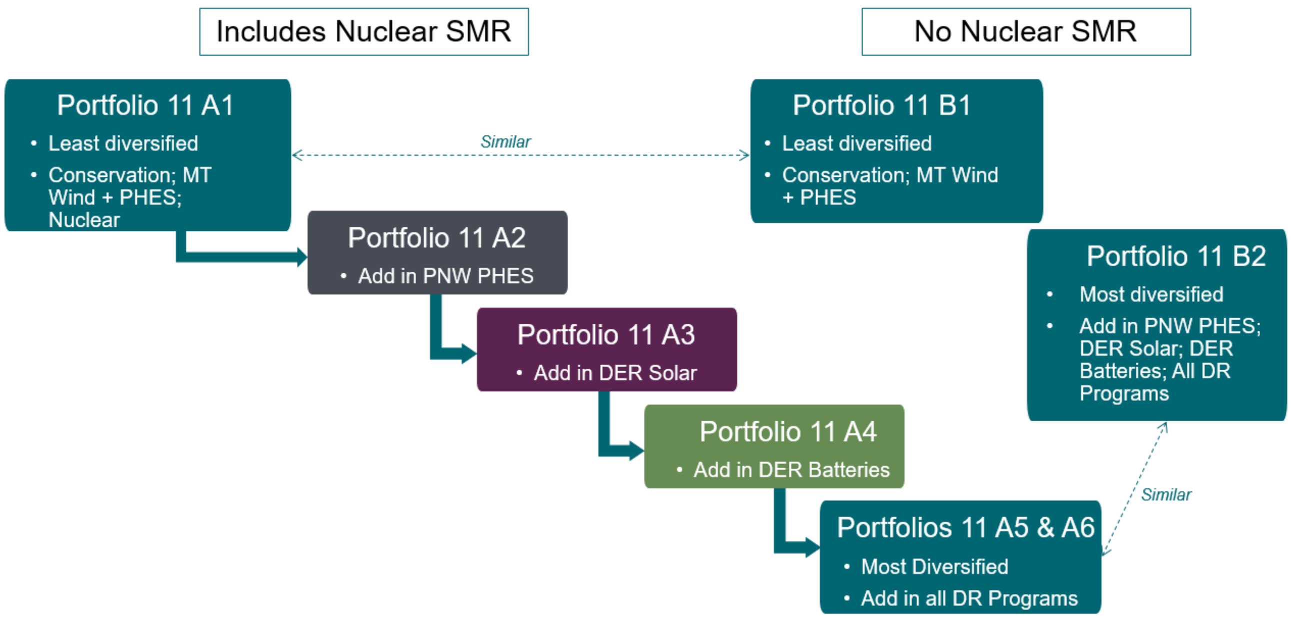
3.7. Diversified Portfolios

In comparison to the least-cost reference portfolio, the diversified portfolios broaden the resource additions, lower the technology and feasibility risks, and seek to maximize equity-related benefits. All diversified portfolios are based on the least-cost reference portfolio. Portfolios 11 A1 through 11 A5 explore layering in combinations of sensitivities 3 through 9. At the request of interested parties, portfolios 11 B1 and 11 B2 replicate the least and most diversified portfolios, 11 A1 and 11 A5, respectively, but without adding advanced nuclear SMR technology to the portfolio.

- Reference: New resources are acquired when cost-effective and needed.
- Sensitivity 11 A1: This sensitivity is the least diversified portfolio we developed in this report and therefore serves as the baseline diversified portfolio. Built on the least-cost reference portfolio, this portfolio increases conservation to 371 aMW by 2045 (Sensitivity 3), adds 400 MW of eastern Montana wind and 200 MW of Montana PHES in 2026 (Sensitivity 6), and adds 250 MW of advanced nuclear SMR in 2032 (Sensitivity 9).
- Sensitivity 11 A2: Same as 11 A1 but adds 200 MW of Pacific Northwest PHES in 2026 (Sensitivity 8).
- Sensitivity 11 A3: Same as 11 A2 but adds 30 MW of distributed solar resources annually from 2026 through 2045 (Sensitivity 4).
- Sensitivity 11 A4: Same as 11 A3 but adds 25 MW of distributed battery resources annually from 2026 through 2031 (Sensitivity 5).
- Sensitivity 11 A5: Same as 11 A4 but adds all demand response programs.
- Sensitivity 11 B1: Same as 11 A1 but without advanced nuclear SMR.
- Sensitivity 11 B2: Same as 11 A5 but without advanced nuclear SMR.

Figure 5.11 illustrates the relationships between the diversified portfolios we explored in this report.

Figure 5.11: Diversified Portfolio Schema



3.8. 100 Percent Renewable and Non-emitting by 2030

This sensitivity examines the impacts of retiring all existing thermal resources by 2030 and removing the ability to build any new thermal regardless of fuel type.

- Reference: The baseline assumes we will transition existing thermal to a 30 percent hydrogen blend starting in 2030 and ramp up to 100 percent hydrogen by 2045. New thermal fueled by natural gas, biodiesel, and hydrogen are all available as new resource options.
- Sensitivity 12: All existing thermal is retired on a ramped schedule from the late 2020s to 2030. All thermal resource options, including alternative fuels, are excluded from the modeling scenario producing a portfolio that is effectively 100 percent non-emitting by 2030.

We initially assumed we would retire existing thermal options for this sensitivity and remove new thermal options. However, we needed to adjust other assumptions to facilitate the long-term capacity expansion model. Those adjustments included removing all transmission capacity constraints, expanding available quantities of each resource type, and allowing the model to build advanced nuclear SMR in 2025. We made these changes to increase access to additional resources over the reference portfolio to help meet the large capacity deficit early in the modeling horizon.

With these changes implemented, the model solved in the preliminary stages when sampling settings were relatively coarse. But when we increased the sampling resolution for the final sensitivity run, the model could not converge on a solution.

3.9. High Carbon Price

We analyzed this sensitivity to explore the impact of a higher-than-expected greenhouse gas allowance price in the market established by the Climate Commitment Act.

- Reference: We modeled an ensemble allowance price as a direct cost on greenhouse gas emissions using the Washington Department of Ecology Linkage to California from 2024 to 2029, transitioning to the mid allowance price forecast created by the California Energy Commission in 2030.
- Sensitivity 13: We used the Washington Department of Ecology price ceiling as the allowance price as a direct cost of greenhouse gas emissions.

Figure 5.4 illustrates the relationship between the PSE ensemble price and the Department of Ecology ceiling price as described in Section 2.4 of this Chapter.

3.10. No Hydrogen Fuel Available

This sensitivity examines a future where green hydrogen fuel is unavailable for the electric sector.

- Reference: Hydrogen fuel blending at a rate of 30 percent in 2030 and increasing to 100% by 2045 is available for new blended fuel peakers and existing natural gas plants.
- Sensitivity 14: Hydrogen is unavailable, so existing natural gas plants burn only natural gas, and blended fuel peakers are not available for economic addition to the portfolio.

Interest and commercialization of large-scale green hydrogen production are at an all-time high, largely thanks to production and investment tax credits established by the Inflation Reduction Act. However, green hydrogen production is not guaranteed to materialize in the volumes needed to support the electric power sector. This sensitivity assumes a future with no green hydrogen for combustion in existing or new peaking resources modeled in this report.

3.11. Social Cost of Greenhouse Gases in Dispatch

This sensitivity compares different methodologies to apply the SCGHG as externality or dispatch costs and their effect on portfolios.

- Reference: We modeled the SCGHG as an externality cost in the long-term capacity expansion (LTCE) model. We omitted the SCGHG in the dispatch decision for emitting resources in the LTCE run.
- Sensitivity 15: We modeled the SCGHG as dispatch cost in the long-term capacity expansion model. We included the SCGHG in the dispatch decision for emitting resources in the LTCE run.

We omitted the SCGHG in the dispatch decision for emitting resources in the hourly dispatch run for the Baseline and Sensitivity 15. Figure 5.3 provides the social cost of greenhouse gases.

4. Purchasing Versus Owning Electric Resources

The 2023 Electric Report determines the supply-side capacity, renewable energy, and energy need, which sets the supply-side targets for future detailed planning in the Clean Energy Implementation Plan and the acquisition process. The Request for Proposal (RFP) processes for demand-side and supply-side resources are just one source of information for making acquisition decisions. We also considered market opportunities outside the RFP and resource-build decisions when making prudent resource acquisition decisions. The 2023 Electric Report assumes ownership of supply-side resources since the cost of power purchase agreements (PPA) is confidential.

In build-versus-buy, build refers to resource acquisitions involving asset ownership. Ownership could occur anywhere along the development cycle of a project. The company could develop or purchase the project anytime during the development cycle. Buy refers to purchasing the output of the plant through a PPA.

In general, quantitative and qualitative evaluations for build-and-buy proposals are conducted similarly in the Request for Proposal process to meet the company's needs, consistent with WAC 480-107,[16] solving for the lowest reasonable cost for customers. We evaluate qualitative project risks in the same way for both acquisitions. Quantitative evaluations for build options include ownership costs such as operating expenses, depreciation, and return on invested capital. Developers embed similar costs in the total price of PPAs, but we have no visibility on the breakdown of those costs.

The supplier of the PPA makes the financial investment for the utility. Rating agencies view PPAs as a financial obligation to the utility, representing a debt-financed capital investment in generation capacity. Rating agencies add/impute debt to the balance sheet to reflect the financial obligations to account for the company's credit exposure. The request for proposal (RFP) process includes an adjustment for imputed debt for PPAs to account for the impact on credit ratings. The cost of imputed debt is a consideration in the evaluation process but is not recoverable in rates.

The CETA provides a provision allowing for a return on expenses incurred from the PPA of no less than the authorized cost of debt and no greater than the rate of return. We did not include the PPA return in the evaluation process. The statutorily authorized PPA return has yet to be requested or approved in a General Rate Case proceeding.

Several factors could influence pricing differences between the buy and build scenarios. Independent power producers (IPP) have tax advantages over utilities since the tax rules differ. A carve-out in the tax code allows IPPs to depreciate the cost of investments upfront, whereas utilities depreciate the cost over time. This situation provides a tax shield on the front end to IPPs. Independent power producers are also more able to maximize the benefits of investment tax credits. The tax code limits the utilities' ability to fully utilize ITC for the customer benefit on ITCs on solar. Developers have more flexibility in how they finance projects with their capital structure. In the build scenario, our equipment selection and design specifications must meet PSE standards for ownership, whereas a supplier might be more inclined to be driven by cost. We can better control how the plant operates and be good community stewards when we own it.

[16] WAC 480-107

DEMAND FORECASTS

CHAPTER SIX

PUGET SOUND ENERGY

Contents

1. Introduction

The demand forecasts Puget Sound Energy (PSE) developed for this 2023 Electric Progress Report (2023 Electric Report) calculate the amount of electricity required to meet customers' needs over the more than 20-year study period, 2024–2045. These forecasts focus on two dimensions of demand: energy demand and peak demand.

- Energy demand is the total electricity needed to meet customer needs yearly (megawatt hours [MWh], or average megawatts [aMW]).
- Peak demand is the single highest hour of electricity demanded by customers each season, winter or summer (MW).

Puget Sound Energy incorporated crucial climate change data into the demand forecast for the first time in this report. We heard from interested parties that climate change is important because it affects future demand and needs, and we agree. We included climate change in the base demand forecast and in other analyses such as the stochastic scenarios.

Climate change already affects how our electricity customers use energy, and we expect that impact will increase. We expect summer and winter average and peak temperatures to get warmer. The energy and peak demand forecasts now incorporate climate change temperature effects. We also incorporated climate change in the resource adequacy (RA) analysis, the stochastic scenarios, and the conservation potential assessment (CPA). Including climate change in energy planning is crucial since it affects our customers.

Overall, we expect electric energy demand, before additional demand-side resources (DSR) identified in the 2023 Electric Report's base demand forecast, to grow at an average annual growth rate (AARG) of 1.8 percent from 2024 to 2045. This growth rate increased our forecast from 2,551 aMW in 2024 to 3,699 aMW in 2045, faster than the 1.2 average annual energy growth rate forecasted in the 2021 Integrated Resource Plan (IRP).

We expect base peak demand before additional DSR to increase at a 1.7 percent annual growth rate, from 4,753 MW in 2024 to 6,717 MW in 2045. This rate is also faster than the 1.2 percent average annual growth rate forecasted in the 2021 IRP and resulted in higher total peak demand at the end of the study period. New customers and electric vehicles are the principal drivers of the growth. Demand from customers using electric vehicles increases residential and commercial use per customer across the entire forecast period.

The 2023 Electric Report base demand forecasts also include the effects of climate change. Warming temperatures decrease energy usage in the winter and increase it in the summer. That phenomenon increases both the winter and summer normal peak temperatures; therefore, the peak forecast includes demand decreases in the winter and increases in the summer.

Table 6.1: Drivers Included and Not Included in the Base Demand Forecasts

Drivers	Demand Forecast Before Additional DSR	Demand Forecast After Additional DSR
Climate change temperatures	Yes	Yes
PSE energy efficiency programs for 2022–2023	Yes	Yes
Codes and standards effects through 2023	Yes	Yes
Demand-side solar installed through 2023	Yes	Yes
PSE energy efficiency programs for 2024 and beyond	No	Yes
Codes and standards for 2024 and beyond (Including Bellingham natural gas ban)	No	Yes
Demand-side solar installed in 2024 and beyond	No	Yes
Electric vehicle legislation: Zero Emission Vehicle (2020) and Clean Fuel Standard (2021)	Yes	Yes
Electric vehicle legislation: Clean Cars 2030 goal (2022)	No	No
Effects of the Climate Commitment Act or additional electrification	No	No
Inflation Reduction Act effects from the investment tax credit (ITC) on behind-the-meter solar	No	Yes
Inflation Reduction Act effects for DSR projects other than solar	No	No

We prepared stochastic draws in addition to the base demand forecast to model a range of potential economic conditions, weather conditions, and modeling variance in the 2023 Electric Report analysis. These draws included variations in temperature, economic and demographic drivers, electric vehicles, and demand model uncertainty. We also used modeled climate change temperatures to project a distribution of possible future temperature-sensitive demand, thereby modeling a more comprehensive range of warmer and colder conditions than the base demand forecast.

Demand and *load* are often used interchangeably in the energy industry, but they refer to different concepts. In this IRP demand refers to the energy needed to meet customers' needs during a calendar year, including losses, and load refers to demand plus the planning margin and operating reserves required to ensure the reliable and safe operation of the electric system.

1.1. Impacts of Demand-side Resources

When we applied forward projections of additional DSR savings, as shown in Table 6.2, we reduced demand significantly. However, it is necessary to start with forecasts that do not already include forward projections of DSR savings to identify the most cost-effective amount of DSR to include in the resource plan. Throughout this chapter, charts and tables labeled before additional DSR have only DSR measures implemented before the study period begins in 2024. Charts labeled after additional DSR include the cost-effective amount of DSR we identified in the 2023 Electric Report.

1.1.1. Demand Before Demand-side Resources

Why does PSE forecast demand before DSR? The demand forecast before DSR shows us the problem. What if no one acted to change how we use energy? That is not a future we anticipate. Demand-side resources like energy efficiency and demand management programs change energy use. We expect to continue incentivizing DSR. Federal, state, and local governments will continue changing energy codes and standards, and we expect consumers to continue putting solar panels on their roofs. But how much of this will occur, and how will it change the demand forecast? To answer this question, we assume no DSR and treat DSR as a resource in the modeling process. This methodology is industry standard and set forth by WAC 480-100-620[1] as part of the content of an integrated resource plan.

Table 6.2: Effect of Demand-side Resources on Demand Forecasts

2023 Electric Report Base Demand Forecast in 2045	Before Additional DSR	After Additional DSR
Electric Energy Demand (aMW)	3,699	2,949
Electric Peak Demand (MW)	6,717	5,867

2. Climate Change

This 2023 Electric Report marks the first time PSE incorporated climate change into the base energy and peak demand forecasts. Before this 2023 Electric Report, we used temperatures from the previous 30 years to model the expected normal temperature for the future. We then held this normal temperature constant for each future model year. This approach to forecasting is a common utility practice, but it does not recognize predicted climate change. This section provides a detailed description of our approach to developing a normal temperature assumption.

2.1. Priorities First

Puget Sound Energy heard and heeded the clear message from interested parties that climate change is a high priority, and we should incorporate its effects into our planning processes. It is essential to consider climate change in resource planning because PSE customers use electricity to heat in the winter and keep cool in the summer. Over time, we expect less overall heating demand and more cooling demand because of a general average warming trend. We used regional data recently developed by climate change scientists to calculate a normal temperature assumption that reflects climate change.

There are currently no industry standards or best practices for incorporating climate change into a demand forecast. The team at PSE is excited to include climate change in this report and participate in future refinements and the evolution of this methodology.

[1] WAC 480-100-620

We are incorporating climate change into the demand forecast in several ways:

- Energy demand forecast
- Peak demand forecast
- Resource adequacy (RA) analysis
- Stochastic analysis

The climate projections used in the forecast were part of a recent study conducted by the River Management Joint Operating Committee (RMJOC). The RMJOC consists of the Bonneville Power Administration, the U.S. Army Corps of Engineers, and the U.S. Bureau of Reclamation. This committee worked with climate scientists to produce many downscaled climate and hydrologic models for the Northwest region as part of their long-term planning.[2] The RMJOC chose 19 downscaled models. Each model is on the representative concentration pathway (RCP) of 8.5. An RCP is a forecast of the amount of warming to the Earth. RCP 8.5 is a high yet common warming forecast used by climate scientists. It represents more warming than other common warming forecasts, such as RCP 4.5 or 6.0.

The Northwest Power and Conservation Council (NWPCC) chose three of these 19 models to work with: CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA. The NWPCC chose these three models because they reflect a wide range of temperatures and hydrologic conditions over time. We used the three climate model projections selected by the NWPCC.

2.2. Determine Climate Change Normal Temperatures

This 2023 Electric Report marks the first time PSE incorporated climate change in the demand forecast and other aspects of planning. Since there is no industry standard approach to integrating climate change, we had to establish how to incorporate this data into our forecasts. The following section explains how we approached the challenge and the questions we asked. We also presented these questions and the analysis results to interested parties on January 20, 2022, and asked them for feedback on our approach.

2.2.1. What is Normal and Why Do We Need It?

When PSE models demand, we study the relationship between historical demand and historical temperatures because the temperature significantly impacts demand. Then, to create a demand forecast, PSE must make assumptions about future temperatures to create a future demand forecast. We refer to the assumed future temperatures as normal temperatures. For energy forecasting, the average heating degree day (HDD) and/or cooling degree day (CDD) for a month expresses the new normal temperature. We used a one-in-two occurrence of a given temperature to forecast peak demand.

We wanted to achieve three goals when we created new normal temperatures:

1. Develop an objective temperature normal, which included deciding what data to use.

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[2] River Joint Management Operating Committee (RMJOC): Bonneville Power Administration, United State Army Corps of Engineers, United Stats Bureau of Reclamation (2018). Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part 1:Hydroclimate Projections and Analyses.

2. Incorporate future temperature trends into the assumptions for the base demand forecasts. We provided a scenario in the 2021 IRP with climate change temperatures, but incorporated a more comprehensive approach in this 2023 Electric Report's base demand energy and base demand peak forecasts.
3. Produce the demand forecast in the framework necessary for planning. The 2023 Electric Report's analyses have specific input requirements. For example, we could have run the demand forecast with the climate projections from each of the three models, but this would have created three base forecasts. Instead, we created one demand forecast so we did not have to run the 2023 Electric Report analyses three times.

2.2.2. Choose the Data

We considered the following questions when we decided what data to use to define a new normal temperature:

1. How many years of data should we include when calculating a new normal?

   For the base energy demand forecast, we have historically used the last 30 years of temperatures to determine the normal. This approach created a relatively stable normal, with minor changes yearly. Forecasts that use five- or 10-year derived normal can have much larger swings in the year-to-year normal, creating difficulties for planning. We wanted to avoid this difficulty, so we opted to use a 30-year calculation centered on the year of interest. We used temperatures from the prior 15 and the coming 15 years for each forecast year in the analysis. We performed this calculation for each year of the forecast.

2. Should we use one climate model to predict future temperatures or all three models the NWPCC chose to create the normal?

   Since NWPCC used three models representing a wide range of possible climate outcomes, using all the climate models allowed us to capture a broad range of possible outcomes, so we used all three.

3. Should the forecasted new normal temperature include historical data, climate model projections, or some combination of the two?

   Recent historical data is a way to link climate change projections to what has occurred recently in the region. Incorporating recent data can help determine where the forecast should start. For example, in 2021, the region saw unprecedented hot temperatures, including 107⁰ Fahrenheit at Sea-Tac Airport on June 28, 2021. However, the climate models did not predict a temperature this high until 2035. Based on this assessment, the team at PSE used historical data and forecasted temperatures to calculate a new normal temperature.

4. Should the forecast of normal temperatures be flat, as in past IRPs, or should the forecast reflect a trend?

   We wanted to reflect average temperatures warming over time, so the normal energy forecast reflected this with increasing average temperatures in the winter and increasing average temperatures in the summers.

2.3. Normal Temperature for Energy Demand Forecast

We incorporated the normal temperatures into the base energy demand forecast models through heating degree days (HDDs) and cooling degree days (CDDs). We used the HDDs and CDDs to model future energy demand. HDDs and CDDs are standard ways to express temperatures and are used to estimate how much heating or cooling a customer may operate in response to a given daily temperature. We calculate degree days using a base temperature, typically 65°F, and the average daily temperature. For HDDs, we calculate the value as the amount the daily temperature is below 65°F, and for CDDs, it is the amount the daily temperature is above 65°F. For example, a 70°F-day will have 5 CDDs and 0 HDDs, while a 30°F-day will have 35 HDDs and 0 CDDs, using a base of 65°F. The team used the three climate models described and historical temperatures to create HDDs and CDDs. The climate models and the historical data are from NOAA's Sea-Tac Airport station.

Previously, we calculated HDDs and CDDs using the most recent 30 years of historical temperatures and used that static calculation through the forecast period, creating a flat normal temperature. For the 2023 Electric Report, we calculated the HDDs and CDDs for each year of the forecast using a different set of temperatures. We calculated HDDs and CDDs for each forecast year using temperatures from the prior 15 and the future 15 years, including the year of interest. If the previous 15 years included years where historical temperatures were available, we used historical data. We used temperatures from each of the three climate models for future years. Figures 6.1 and 6.2 show examples of the old and new normal temperatures, which include climate change.

Figure 6.1: Heating Degree Days, Previous Normal Temperature, and Current Normal Temperature Assumptions (HDD base temperature 65)

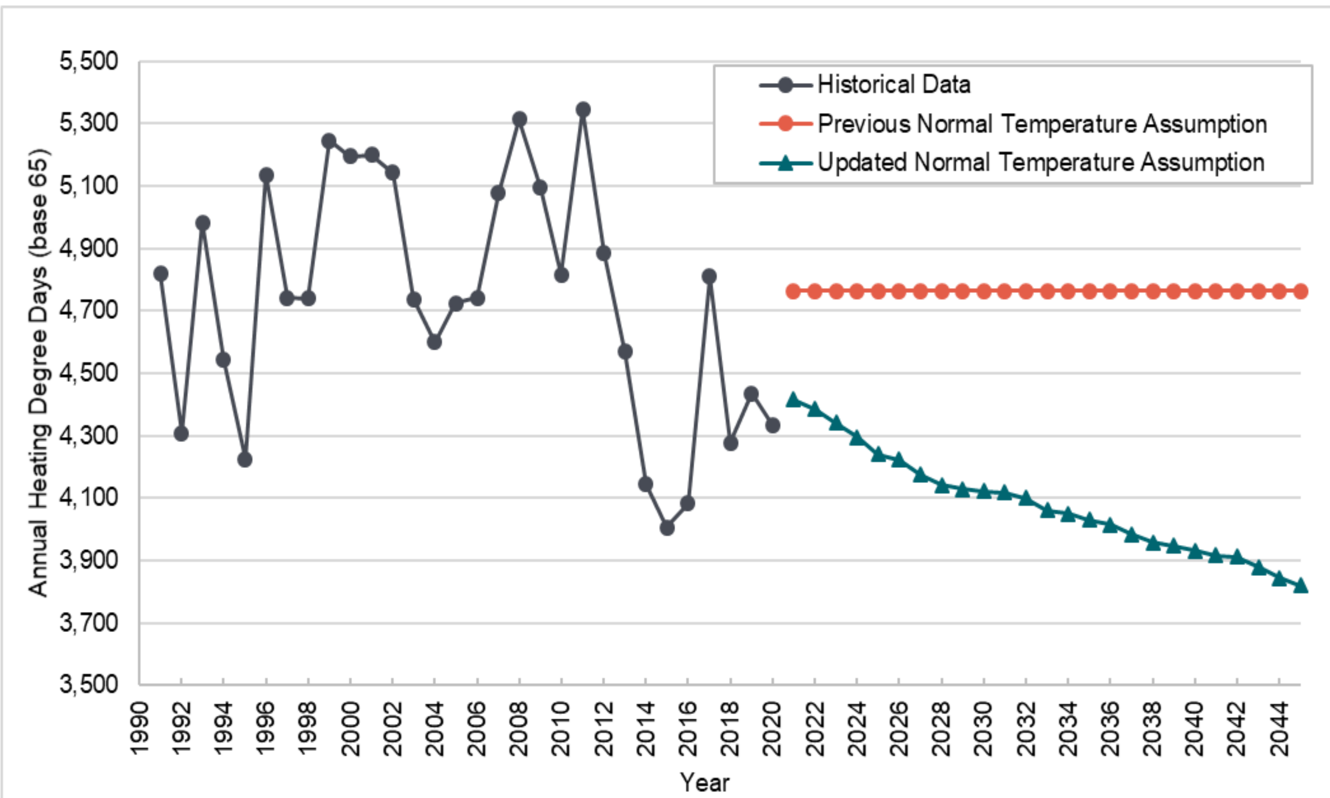
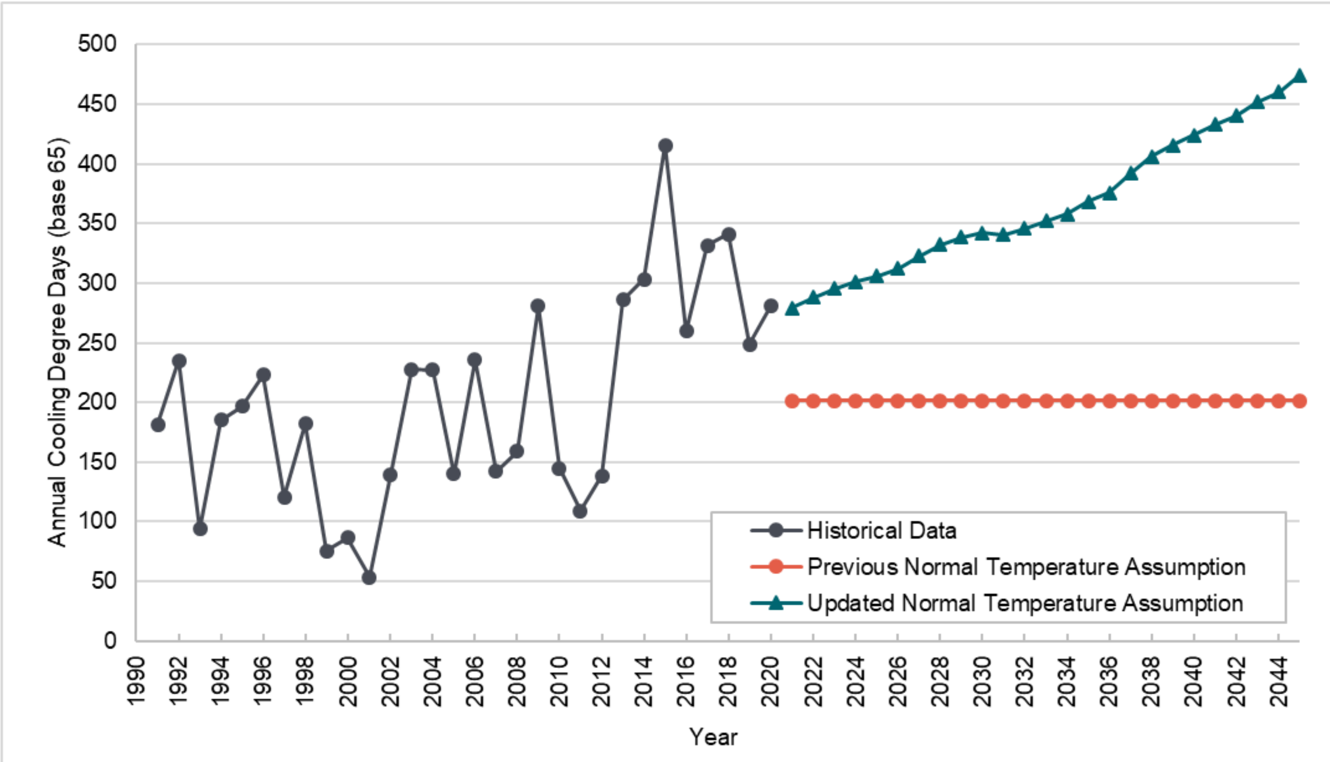


Figure 6.2: Cooling Degree Days, Previous Normal Temperature, and Current Normal Temperature Assumptions (CDD base temperature 65)



➔ See Appendix F: Demand Forecasting Models for more information about calculating the HDDs and CDDs that went into the demand forecast.

2.4. Normal Temperature for Peak Demand Forecast

The peak demand forecast uses a 1-in-2 seasonal peak minimum or maximum temperature during all peak hours. For the electric normal peak, we used a similar methodology as the normal energy demand forecast; we used data from 15 prior and 15 future years, including the year of interest, for the calculation. However, instead of averaging the 30 years of data for the peak, we calculated the 1-in-2 occurrence of a peak hour or median peak temperature.

We performed this calculation for each year in the forecast period: winter morning peaks, winter evening peaks, and summer peaks. The result was a 1-in-2 peak temperature of 25 in 2024, which increases to 26 degrees for winter morning peaks. For winter evening peaks, the 1-in-2 peak temperature is 27 for 2024 –2028 and rises to 28 for the rest of the forecast period. In the summer, the 1-in-2 peak is 94 for 2024–2028, 95 for 2029–2032, and 96 starting in 2033. We smoothed the peak normal temperatures to create a normal peak that increases temperature over time. We show the winter evening, winter morning, and summer peaks in Figures 6.3 and 6.4.

Figure 6.3: Normal Winter Peak Temperatures
Previous Normal and Updated Normals for Morning and Evening (ºF)

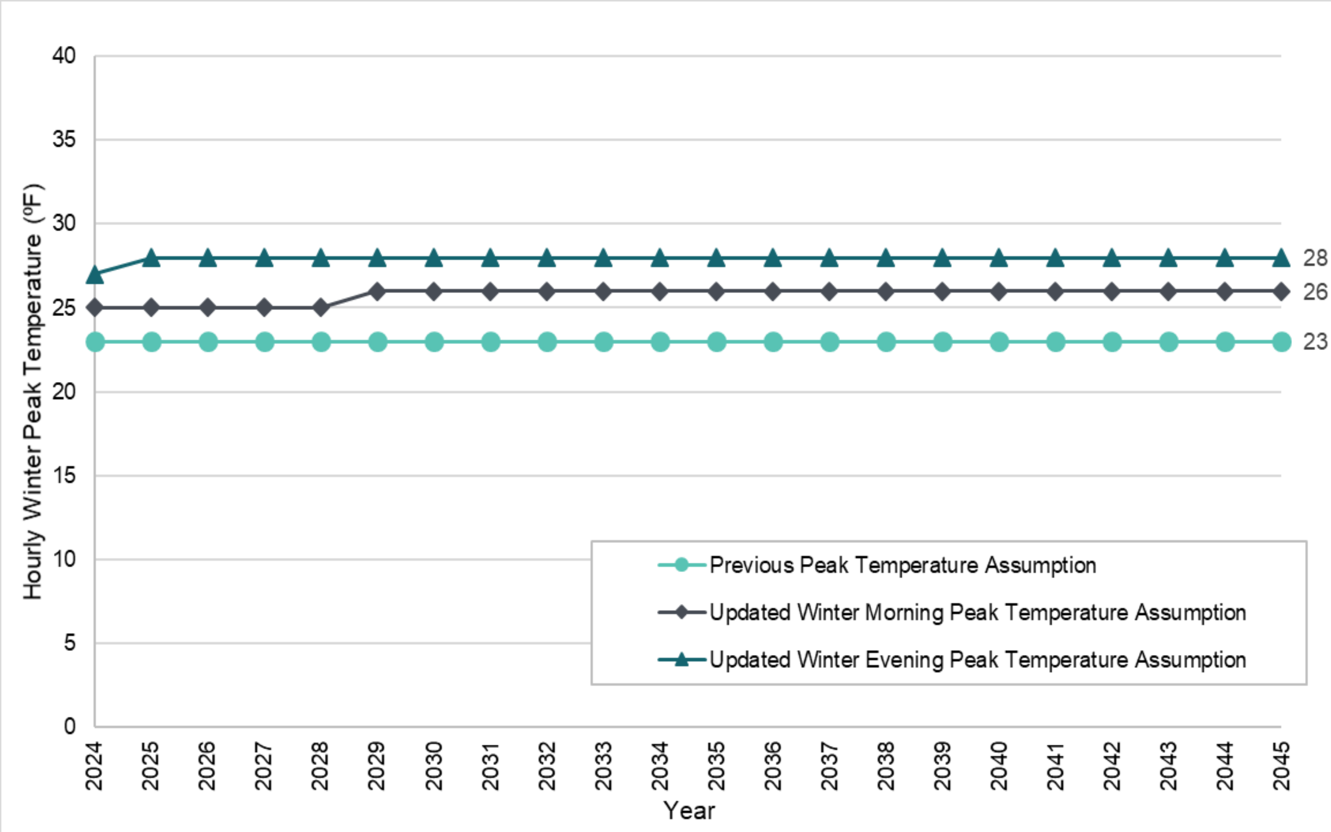
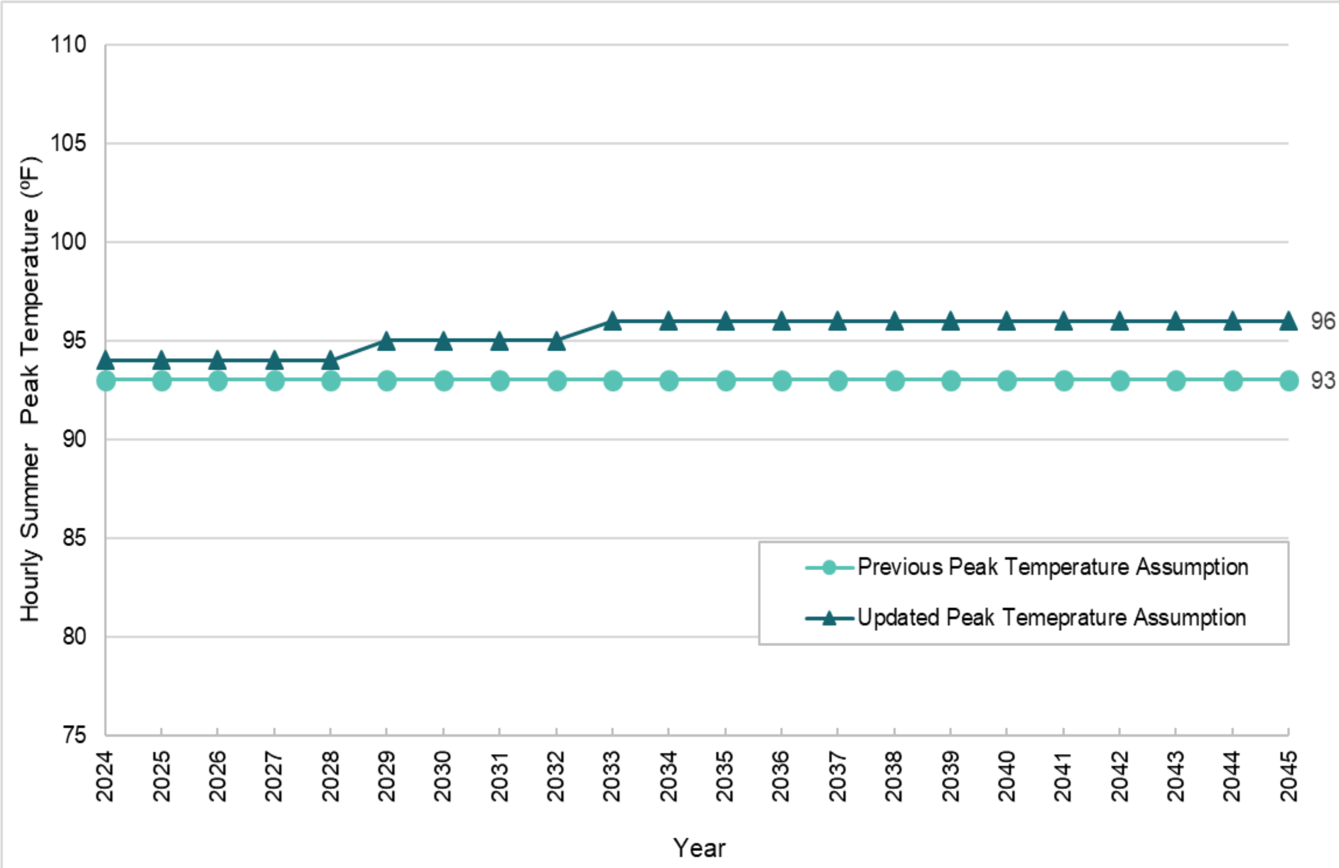


Figure 6.4: Normal Summer Peak Temperatures
Previous Normal and Updated Normal (ºF)



➔ See Appendix F: Demand Forecasting Models for a detailed discussion of the peak climate change temperature calculations.

3. Electric Demand Forecast

We present highlights of the 2023 Electric Report base demand forecast developed for the electric service area in Figures 6.5 through 6.7 and Tables 6.3 and 6.4. We summarize the population and employment assumptions for the forecast in this document's Details of Electric Forecast section and explained in detail in Appendix F: Demand Forecasting Models.

The demand forecast included only DSR measures implemented through December 2023 since the demand forecast helps determine the most cost-effective amount of DSR to include in the portfolio for subsequent periods.

3.1. Electric Energy Demand

In the 2023 Electric Report base demand forecast, we expect energy demand before additional DSR to grow at an average rate of 1.8 percent annually from 2024–2045, increasing energy demand from 2,551 aMW in 2024 to 3,699 aMW in 2045.

Puget Sound Energy serves primarily residential and commercial customers, with a minority share of energy demand associated with industrial, resale, and streetlight customer classes. Excluding losses, we projected residential and commercial customer classes to represent 49 percent and 39 percent of energy demand in 2024. During the forecast period, residential demand grows as we add new customers to the system and customers adopt electric vehicles (EVs). This demand growth is partially, but not entirely, offset by decreasing residential heating energy demand — a consequence of adopting trended normal temperatures consistent with climate change impacts.

Commercial energy demand grows similarly: we added new commercial customers to the system, and customers adopt EVs for fleet and other business purposes. The share of commercial demand associated with heating energy demand is less than residential customers; thus, climate change impacts are less severe for the commercial class.

Therefore, rising customer and EV counts drive most of the growth in energy demand and offset climate change impacts before DSR is applied.

Figure 6.5: Electric Energy Demand Forecast before Additional DSR
2023 Electric Report Base Demand Forecast versus 2021 IRP Base Demand Forecast (aMW)

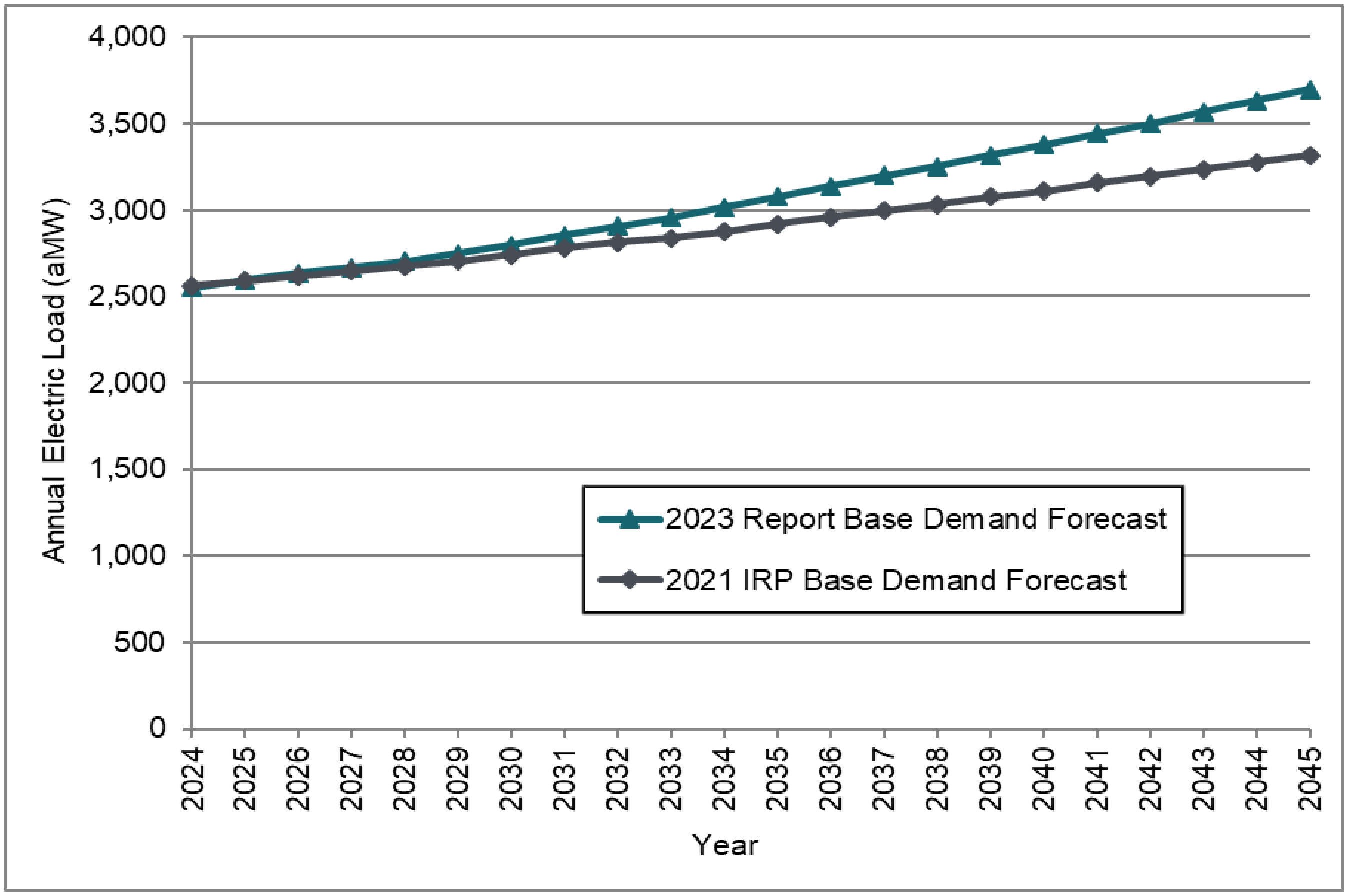


Table 6.3: Electric Energy Base Demand Forecast before Additional DSR (aMW)

Year	2024	2030	2035	2040	2045	AARG 2024-2045 (%)
Base Demand Forecast	2,551	2,799	3,076	3,378	3,699	1.8

3.2. Electric Peak Demand

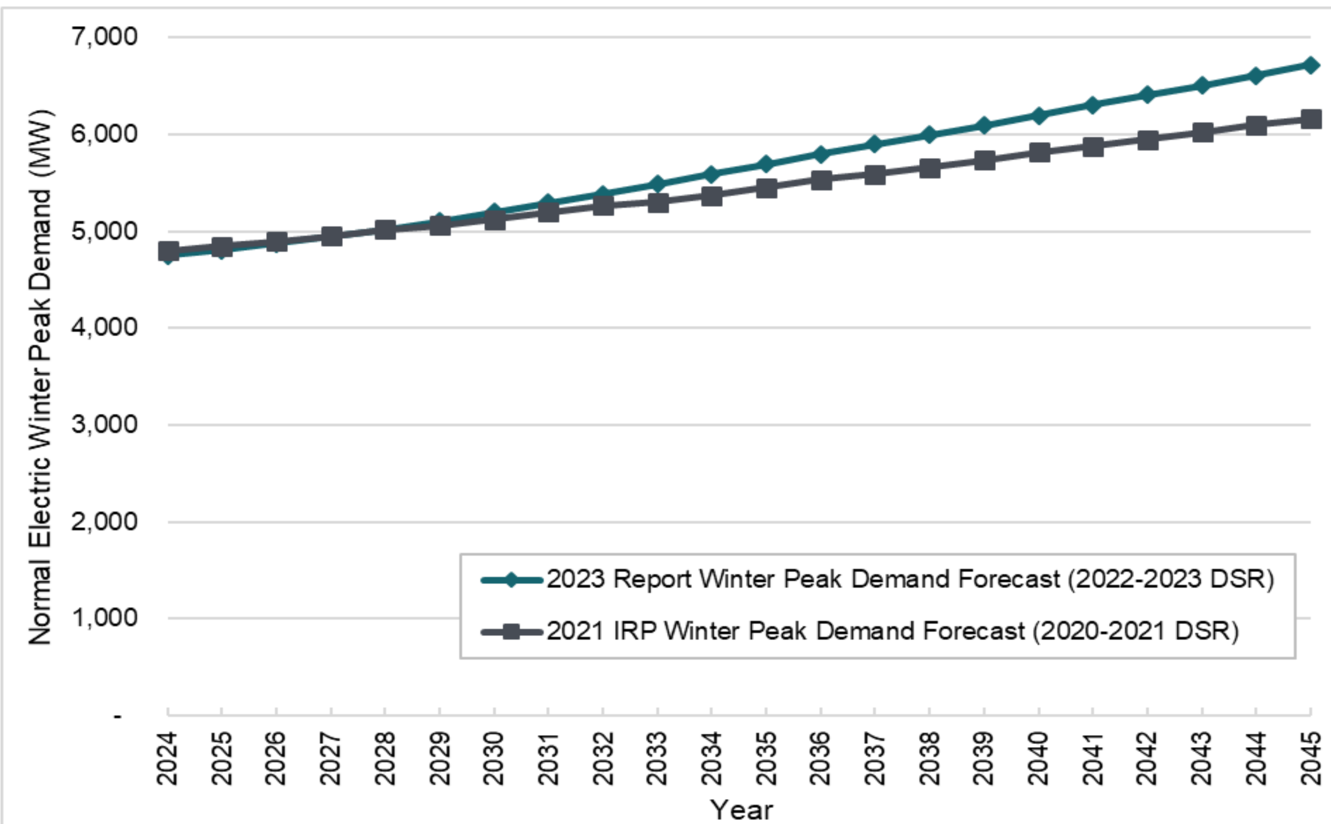
Puget Sound Energy is a winter peaking utility, which means the one hour with the highest demand of the year occurs in the winter. However, summer peaks are growing with warming summer temperatures and increased use of air conditioning and heat pumps for cooling. With the addition of data to reflect climate change modeling and the growing summer peaks, the team updated the capacity expansion model to analyze both winter and summer peaks. We provide a detailed discussion of the capacity expansion model in Appendix G, Electric Analysis Models. Different supply-side or demand-side resources may better meet a summer or a winter peak. Therefore, we consider demand during all hours of the year in resource adequacy modeling to help determine the best resources to meet the customer load. This section describes winter and summer electric peaks.

3.2.1. Winter Electric Peak Demand

We forecasted the normal electric winter peak hour demand with specific assumptions for normal peak conditions. We modeled the winter peak demand forecast with assumptions consistent with a one-in-two probability of occurrence. We define a winter peak event as a mid-week, non-holiday, and evening occurrence in December, with a temperature that reflects the climate change analysis (27- and 28-degrees Fahrenheit). We assumed these conditions because they are the expected conditions (50 percent or 1-in-2 probability) in which a peak event will occur based on historical system characteristics, forward-looking EV demand shapes, and climate change temperature projections.

It is important to note that actual winter peak demand may occur under different conditions, such as in the morning, at different temperatures, or in another month. For the base demand forecast, however, expected conditions are assumed. Please see the discussion on stochastic peak demand and hourly demand scenarios for variation in peak event conditions. Before demand-side resources, the 2023 Electric Report's base peak demand forecast grows at an average annual growth rate of 1.7 percent. This rate would increase peak demand from 4,753 MW in 2024 to 6,717 MW in 2045.

Figure 6.6: Winter Electric Peak Demand Forecast before Additional DSR
2023 Electric Report versus 2021 IRP Base Demand Forecast Hourly Annual Peak (MW)



Winter peak demand in the 2023 Electric Report base demand forecast is higher at the end of the study period (6,717 MW in 2045) than in the 2021 IRP (6,159 MW in 2045). Additionally, the 2023 Electric Report peak demand forecast has a faster average annual growth rate (1.7 percent) than the 2021 IRP (1.2 percent).

The 2023 Electric Report peak demand forecast projects faster growth than the 2021 IRP peak demand forecast because it includes a revised EV forecast that reflects more adoption and additional vehicle classes (medium and heavy duty). Observed actual customer and sales growth in 2020 and 2021 exceeded the 2021 IRP forecast, mainly due to less severe customer growth and demand declines due to economic turmoil. These positive impacts offset the step down in the forecast due to climate change and result in a forecast that starts at a point like the 2021 IRP base peak demand forecast.

3.2.2. Summer Electric Peak Demand

The team modeled the normal electric summer peak hour demand using 94 degrees Fahrenheit (2024–2029), 95 degrees Fahrenheit (2030–2033), and 96 degrees Fahrenheit (2034–2045) as the design temperatures. Summer peaks typically occur in July or August. Figure 6.7 shows the 2023 Electric Report's base peak demand forecast for the winter and summer.

The 2023 Electric Report's base summer peak demand forecast has an average annual growth rate of 2.2 percent, increasing the summer peak demand from 3,820 MW in 2024 to 6,005 MW in 2045. Because the summer peak forecast does not exceed the winter peak forecast in the timeframe shown, we assumed PSE will continue to be a winter peaking utility for the planning period of this 2023 Electric Report.

Figure 6.7: Winter and Summer Electric Peak Demand Forecasts before Additional DSR
Hourly Annual Peak (MW)

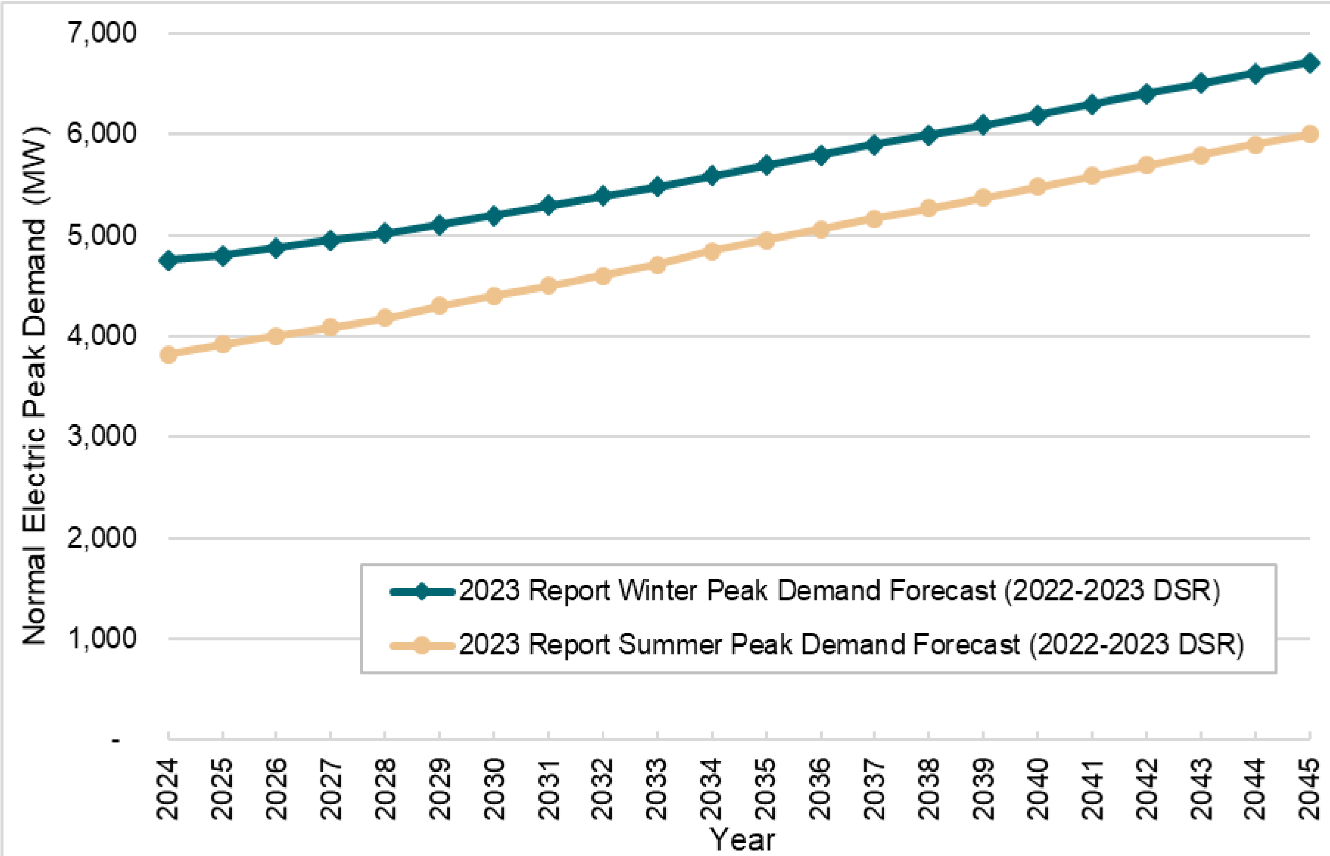


Table 6.4: Electric Peak Demand Forecast before Additional DSR
Winter and Summer Peaks, Hourly Annual Peak (MW)

Year	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Winter Demand Forecast	4,753	5,197	5,693	6,198	6,717	1.7
Summer Demand Forecast	3,820	4,401	4,953	5,481	6,005	2.2

The 2023 Electric Report's winter peak demand forecast consistently stays higher than the summer peak demand forecast for the entire planning horizon. Even with the projected higher growth rate using the climate change data for summer peak demand, the summer peak still does not come close to the winter peak. The spread between the two peaks goes from more than 900 MW in 2024 to more than 700 MW in 2045.

3.3. Impacts of Demand-side Resources

As we explained at the beginning of this chapter, the electric demand forecasts include only demand-side resources implemented through December 2023 since the demand forecast helps determine the most cost-effective level of DSR to include in the portfolio. To examine the effects of DSR on the energy and peak forecasts, we applied the cost-effective amount of DSR determined in this 2023 Electric Report[3] to the base energy and peak demand forecasts for 2024–2045. To account for the 2013 general rate case Global Settlement,[4] we also applied an additional 5 percent of DSR for that period. Teams at PSE use forecasts with DSR for financial and system planning decisions. We illustrate the results in Figures 6.8 thru 6.10.

3.3.1. DSR Impact on Energy Demand

When we applied the DSR bundles chosen in the 2023 Electric Report portfolio analysis to the energy demand forecast:

- Electric energy demand after additional DSR grows at an average annual rate of 0.72 percent from 2024 to 2045
- Electric energy demand in 2045 will be reduced by 21 percent to 2,949 aMW

3.3.2. DSR Impact on Peak Demand

When we applied the DSR bundles chosen in the 2023 portfolio analysis to the winter evening and summer peak demand forecast:

- Electric system winter peak demand in 2045 is reduced 13 percent to 5,867 MW
- Electric system winter peak demand after additional DSR grows at an average annual rate of 1.0 percent from 2024 to 2045
- Electric system summer peak demand in 2045 is reduced 17 percent to 5,003 MW
- Electric system summer peak demand after additional DSR grows at an average annual rate of 1.3 percent from 2024 to 2045

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3 For demand-side resource analysis, see Chapter 8: Electric Analysis and Appendix E: Conservation Potential Assessment and Demand Response Assessment.

4 For an Order Authorizing PSE to Implement Electric and Natural Gas Decoupling Mechanisms and To Record Accounting Entries Associated With the Mechanism, Docket UE-121697 and UG-121705, Washington Utilities and Transportation Commission. Page 73 Line 162.

Figure 6.8: Electric Energy Demand Forecast (aMW), before Additional DSR and after Additional DSR

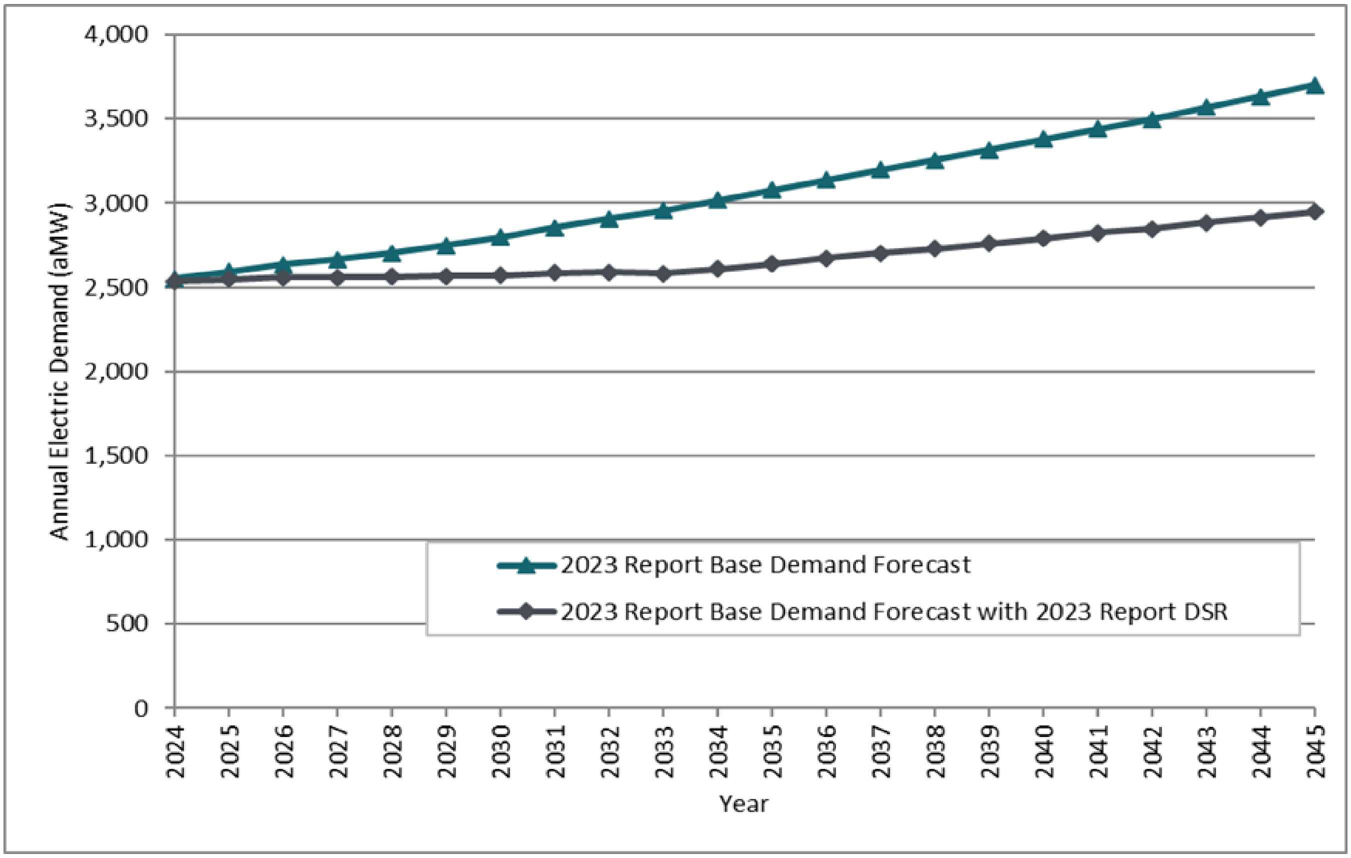


Figure 6.9: Electric Winter Peak Demand Forecast (MW), before Additional DSR and after Additional DSR

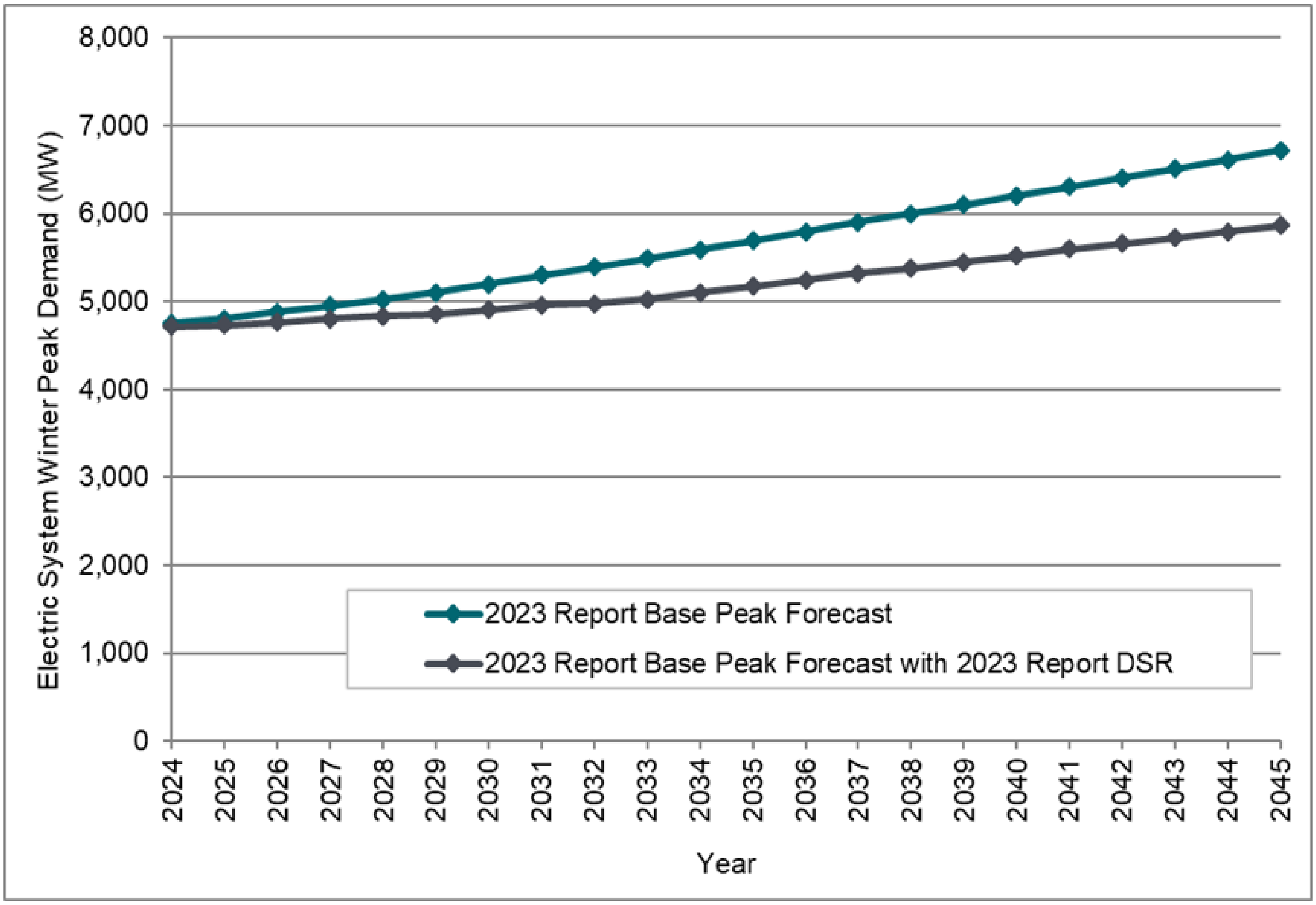
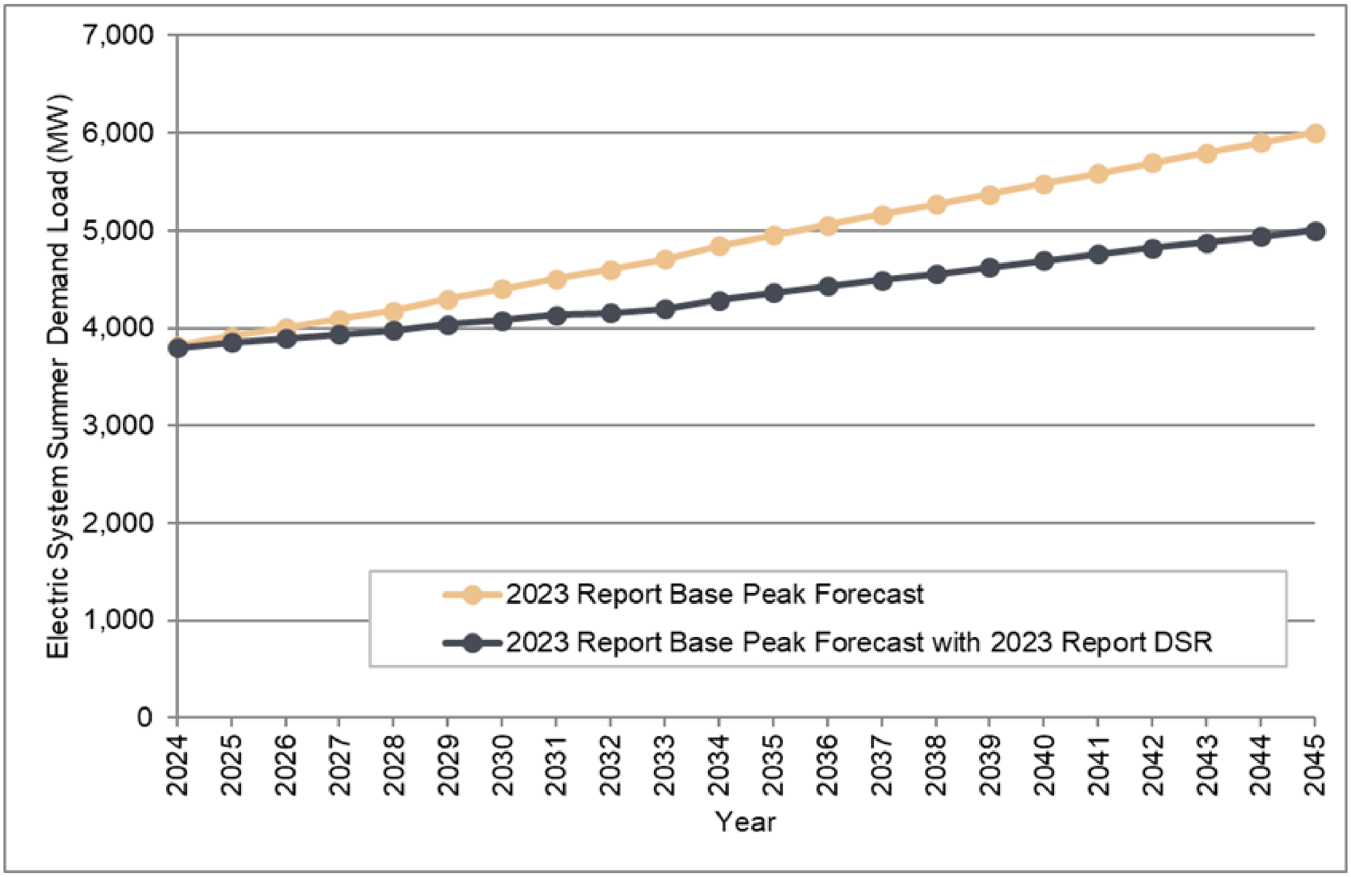


Figure 6.10: Electric Summer Peak Demand Forecast (MW), before Additional DSR and after Additional DSR



3.4. Details of the Electric Forecast

The electric forecast is comprised of demand from several different classes. These classes are residential, commercial, industrial, streetlight, and resale. We show details of each class in the following section.

3.4.1. Electric Customer Counts

We expect system-level customer counts to grow by 1.1 percent per year, from 1.25 million customers in 2024 to 1.57 million in 2045. This rate is faster than the average annual growth rate of 1.0 percent projected in the 2021 IRP base demand forecast.

Residential customers are PSE's largest customer class, with an approximately 88 percent share of electric customers by 2024. During the forecast period from 2024 to 2045, we expect residential customer counts to grow at an average annual rate of 1.1 percent per year. Commercial customers are PSE's second largest customer class, around 11 percent of total customers, and are expected to grow at an average annual rate of 1.3 percent per year over the forecast period. Industrial customer counts, around 0.3 percent of total customers, are expected to decline, following the historical trend of declining industrial activities in the service area. We expect these trends to continue as the economy in PSE's service area shifts toward more commercial and less industrial business sectors.

Table 6.5: December Electric Customer Counts by Class,
2023 Report Base Demand Forecast

Class	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Total	1,251,677	1,344,744	1,421,065	1,495,183	1,571,637	1.1
Residential	1,101,482	1,182,249	1,247,366	1,309,627	1,373,711	1.1
Commercial	138,449	149,815	160,282	171,484	183,126	1.3
Industrial	3,195	3,093	3,016	2,945	2,869	-0.5
Other	8,543	9,579	10,393	11,119	11,923	1.6

3.4.2. Electric Demand by Class

Over the next 20 years, we expect the residential and commercial classes to have positive demand growth, with the commercial class growing faster than the residential class before additional DSR. New customers and our projected rate of EV adoption create residential and commercial class demand growth.

Table 6.6: Electric Energy Demand by Class,
2023 Report Base Demand Forecast Before Additional DSR

Class	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Total	2,551	2,799	3,076	3,378	3,699	1.8
Residential	1,245	1,379	1,517	1,652	1,763	1.7
Commercial	986	1,085	1,204	1,349	1,534	2.1
Industrial	113	108	106	104	103	-0.5
Other	8	8	9	9	10	1.3
Losses	199	218	240	263	289	-

3.4.3. Electric Use per Customer

We expect residential use per customer, before additional DSR, to increase over the forecast period. Before EV adoption and climate change assumptions, residential use per customer is flat, but new demand from EVs outpaces usage losses due to lower normal HDDs due to the climate change update, resulting in positive net average use per customer demand growth. We expect commercial use per customer to increase over the forecast period due to EV adoption and higher normal CDDs. The non-residential classes have a lower share of energy demand devoted to heating, thus, are less impacted in the winter by lower normal HDDs.

Table 6.7: Electric Use per Customer,
2023 Report Base Demand Forecast Before Additional DSR

Type	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Residential	10.0	10.3	10.7	11.1	11.3	0.5
Commercial	62.8	63.7	66.1	69.4	73.7	0.7
Industrial	310.6	306.6	308.6	311.1	312.2	-0.1

3.4.4. Electric Customer Count and Energy Demand Share by Class

Table 6.8 shows customer counts as a percent of PSE's total electric customers. We show demand share by class in Table 6.9. We expect the share of residential customers and demand to remain stable over the forecast period before adjustment by the final DSR in the report analysis.

Table 6.8: December Customer Count Share by Class

Class	Share in 2024 (%)	Share in 2045 (%)
Residential	88.00	87.41
Commercial	11.06	11.65
Industrial	0.26	0.18
Other	0.68	0.76

Table 6.9: Energy Demand Share by Class, Before Additional DSR

Class	Share in 2024 (%)	Share in 2045 (%)
Residential	48.79	47.67
Commercial	38.67	41.49
Industrial	4.44	2.77
Other	0.30	0.27
Losses	7.80	7.80

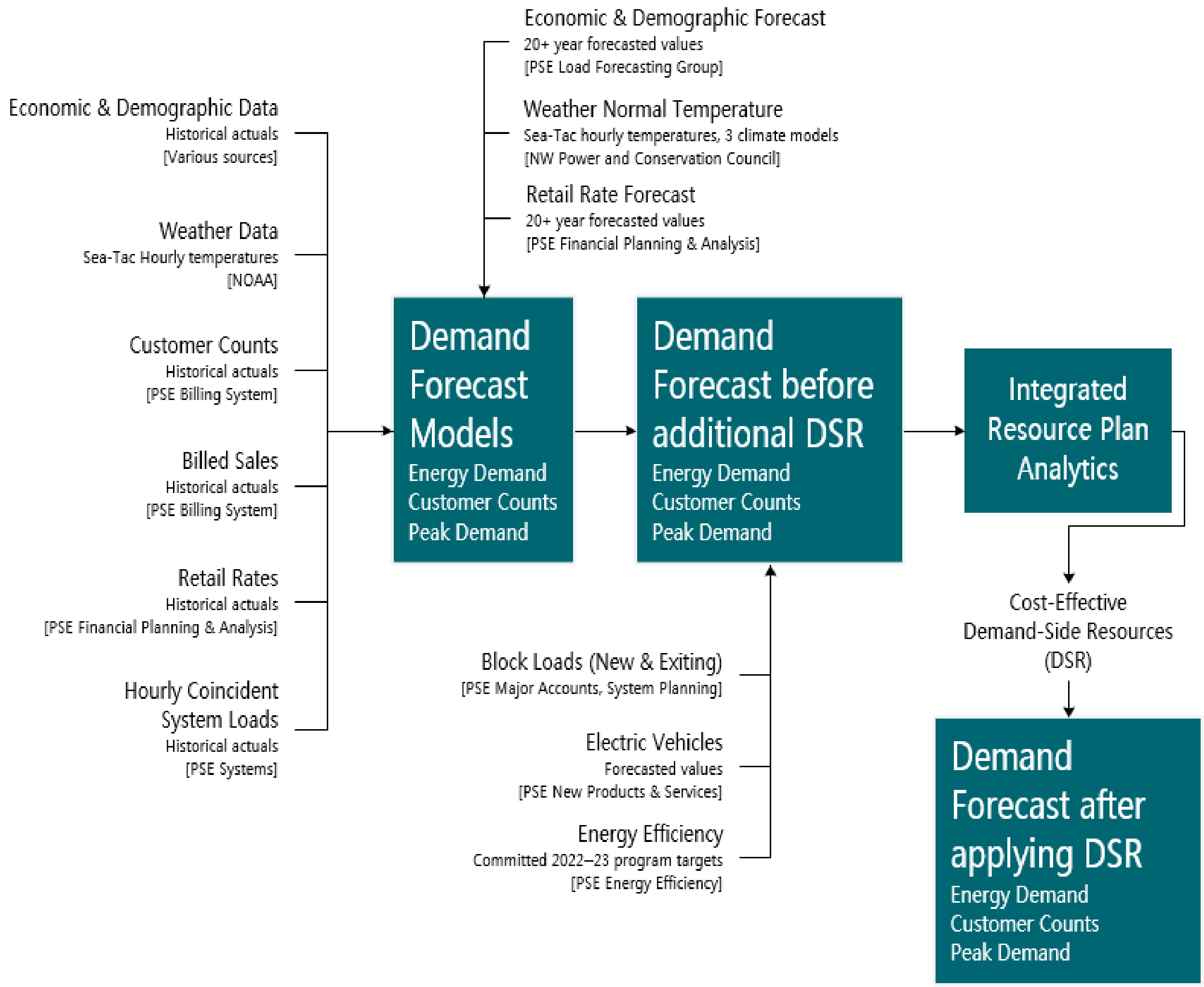
4. Methodology

We create relationships between historical growth and historical conditions to forecast customer demand. Therefore, we can use forecasted future conditions to forecast future growth. In the following section, we discuss how we forecasted demand.

4.1. Forecasting Process

Our regional economic and demographic model uses national and regional data to forecast total employment, employment types, unemployment, personal income, households, and consumer price index (CPI) for the PSE electric service area. We built the regional economic and demographic data used in the model from county-level information acquired from various sources. This economic and demographic information is combined with other PSE internal information to produce the base energy and peak demand forecasts for the service area. We illustrate the demand forecasting process in Figure 6.11 and list the economic and demographic input data sources in Table 6.10.

Figure 6.11: PSE Demand Forecasting Process



We divided customers into classes and service levels that use energy for similar purposes and at comparable retail rates to forecast energy sales and customer counts. We modeled the different classes and service levels using variables specific to their usage patterns. Electric customer classes include residential, commercial, industrial, streetlights, and resale. Although PSE provides electric transmission services to customers who purchase power from third-party suppliers, we did not include demand from these customers in the 2023 Electric Report's demand forecast.

We used multivariate time series econometric regression equations to derive historical relationships between trends and drivers and then employed them to forecast the number of customers and use per customer by class or service level. We multiplied these factors to arrive at the billed sales forecast. The main drivers of these equations include population, unemployment rates, retail rates, personal income, HDDs, CDDs, total employment, manufacturing employment, CPI, and U.S. Gross Domestic Product (GDP). We calculated demand from sales and included transmission and distribution losses in addition to sales. We based weather inputs on NOAA temperature readings at Sea-Tac Airport and incorporated historical and forecasted temperatures, including the effects of climate change. We also projected peak system demand by evaluating the historical relationship between actual peaks, the temperature at peaks, average system demand, day of the week, time of day, holidays, and estimated air conditioning trends. We forecasted peak demand with the future temperature at peak plus expected EV peak demand growth.

➔ See Appendix F: Demand Forecasting Models for detailed descriptions of the econometric methodologies used to forecast billed energy sales, customer counts, peak demand, hourly distribution of electric demand, and forecast uncertainty.

Table 6.10: Sources for County Economic and Demographic Data in Economic and Demographic Model

County-level Data	Source
Labor force, employment, unemployment rate	U.S. Bureau of Labor Statistics (BLS) www.bls.gov
Total non-farm employment, and breakdowns by type of employment	WA State Employment Security Department (WA ESD), using data from the Quarterly Census of Employment and Wages esd.wa.gov/labormarketinfo
Personal income	U.S. Bureau of Economic Analysis (BEA) www.bea.gov
Wages and salaries	U.S. Bureau of Economic Analysis (BEA) www.bea.gov
Population	WA State Employment Security Department (WA ESD) esd.wa.gov/labormarketinfo/report-library
Households, single- and multi-family	U.S. Census www.census.gov
Household size, single- and multi-family	U.S. Census www.census.gov
Aerospace employment, Regional Consumer Price Index (CPI)	Puget Sound Economic Forecaster www.economicforecaster.com

We obtained country-level economic and demographic data from Moody's Analytics.[5] The inputs into PSE's economic and demographic model from Moody's Analytics are gross domestic product (GDP), industrial production index, employment, unemployment rate, personal income, wages and salary disbursements, consumer price index (CPI), housing starts, population, conventional mortgage rate, and the three-month T-bill rate.

4.2. Stochastic Scenarios

We used stochastic analysis[6] to look at variability in our assumptions. We developed 310 stochastic scenarios to examine changes in the economic, demographic, electric vehicle, and temperature assumptions. We also examined model uncertainty in the stochastics. These 310 alternate future pathways for customer growth, energy demand per customer, and peak demand let us test the portfolio to see how it responds to conditions other than the base demand.

5 economy.com
6 Stochastic scenarios are created with a randomly determined set of inputs, which creates a probability distribution.

We created and ran 310 electric stochastic scenarios in the AURORA portfolio model to test the portfolio's robustness under various conditions. We show the range of the stochastics in Figures 6.12 through 6.14. Energy demand in 2045 ranges from 2,724 aMW to 4,743 aMW in the energy stochastic scenarios. Winter peak demand in 2045 ranges from 5,160 MW to 8,551 MW, and summer peak demand in 2045 ranges from 4,438 MW to 7,171 MW in the peak stochastic scenarios.

We develop stochastic simulations with outputs from PSE's economic and demographic model, variation in underlying econometric model uncertainty, electric vehicle adoption, and future temperatures from three climate models. We modeled electric energy and peak demand stochastic scenarios using 310 stochastic simulations. The stochastic simulations reflect variations in key regional economic and demographic variables such as population, employment, and income. The simulations also capture model uncertainty through stochastic variation of model statistics associated with underlying econometric models of average energy demand per customer, customer growth, and peak demand. We held electric vehicle assumptions constant in 250 scenarios, applied a high EV forecast to 30 scenarios with high economic outlooks relating to total employment, and applied a low EV forecast to another 30 scenarios with low economic scenarios with respect to total employment.

The stochastic scenarios use future temperatures from the CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA models, reflecting higher or lower temperature conditions. We sampled forecasted temperature years 2020–2049 from the three models for the 310 draws.

We ran the 310 electric stochastic scenarios in the AURORA portfolio model to test the portfolio's robustness under various conditions.

➔ Detailed descriptions of the stochastics are available in Chapter Eight: Electric Analysis.

Figure 6.12: Range of Energy Demand in Stochastic Scenarios Around Base Energy Demand Forecast (aMW) Before Additional DSR

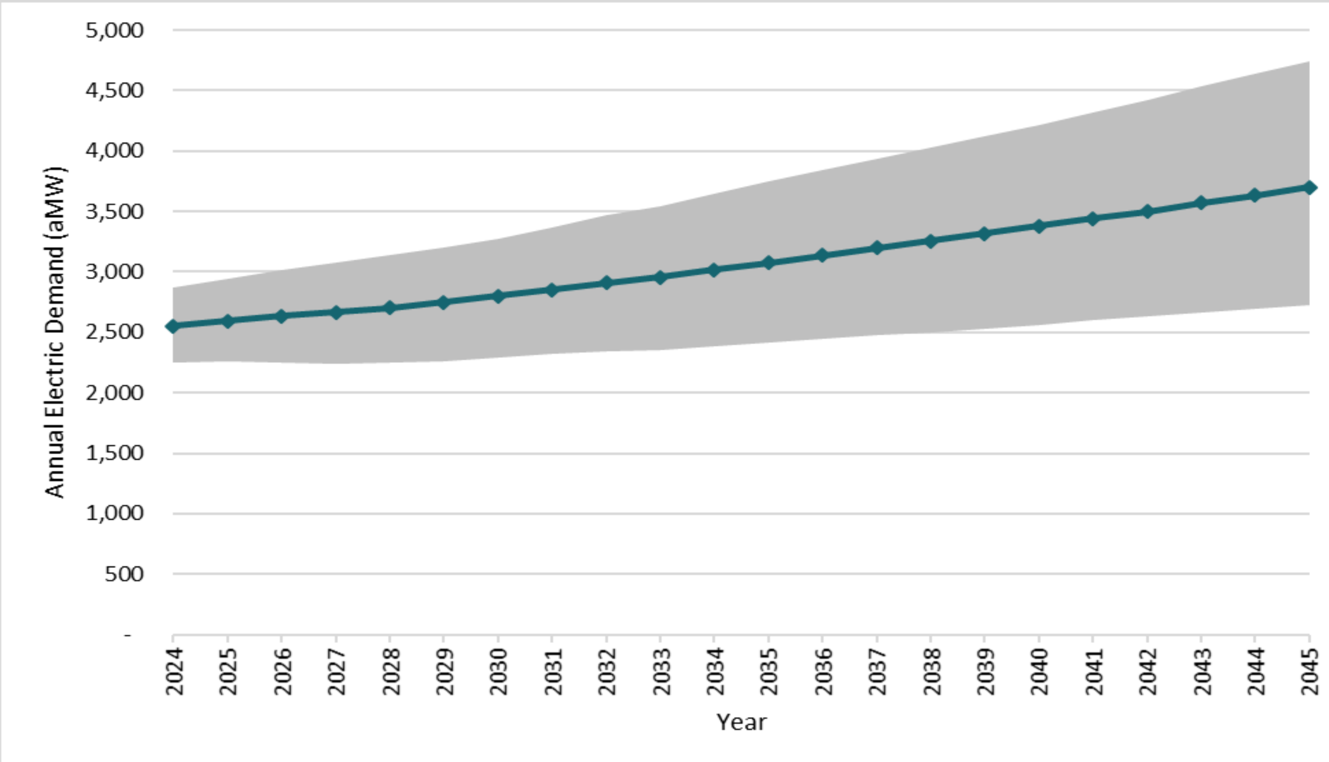


Figure 6.13: Range of Winter Peak Demand in Stochastic Scenarios around Base Peak Demand Forecast (MW) Before Additional DSR

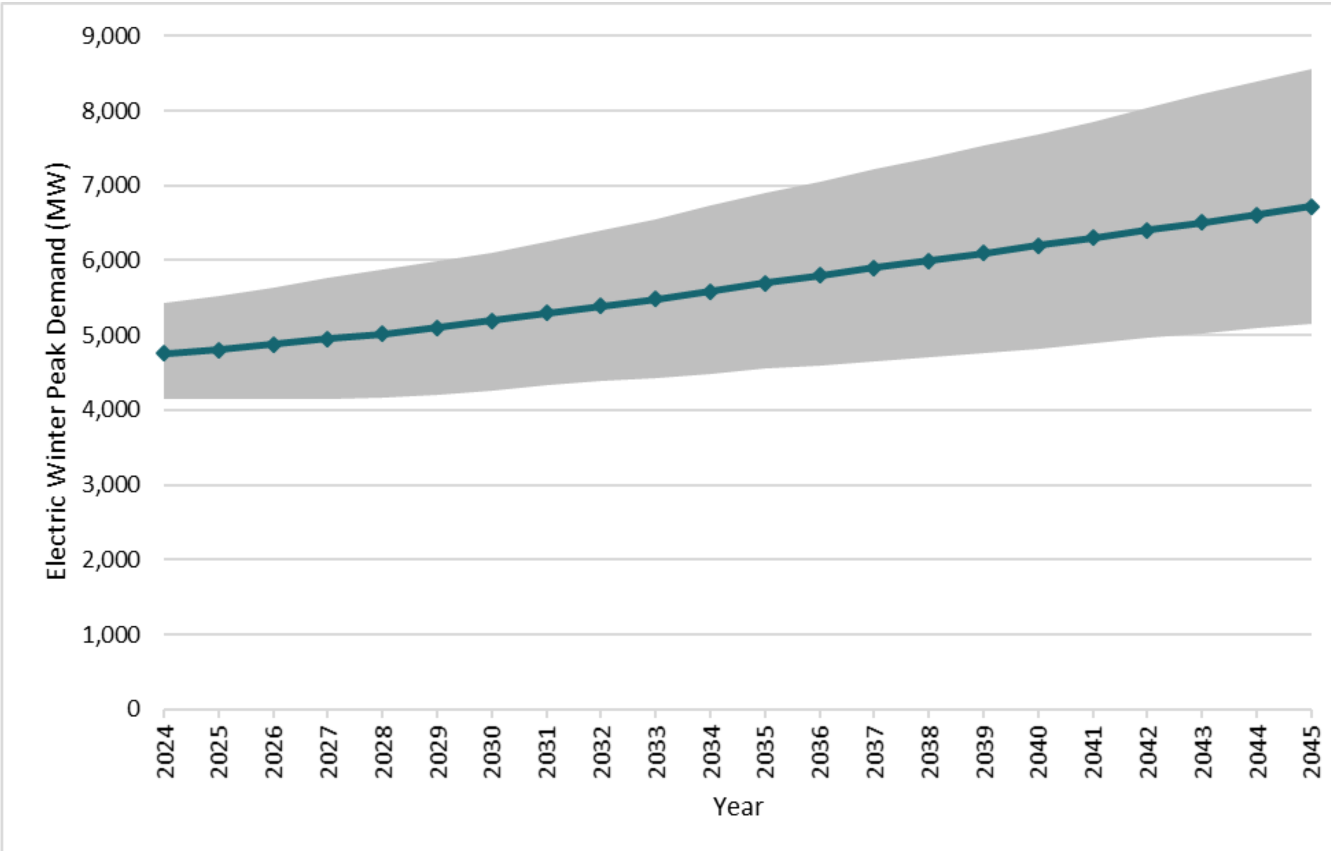
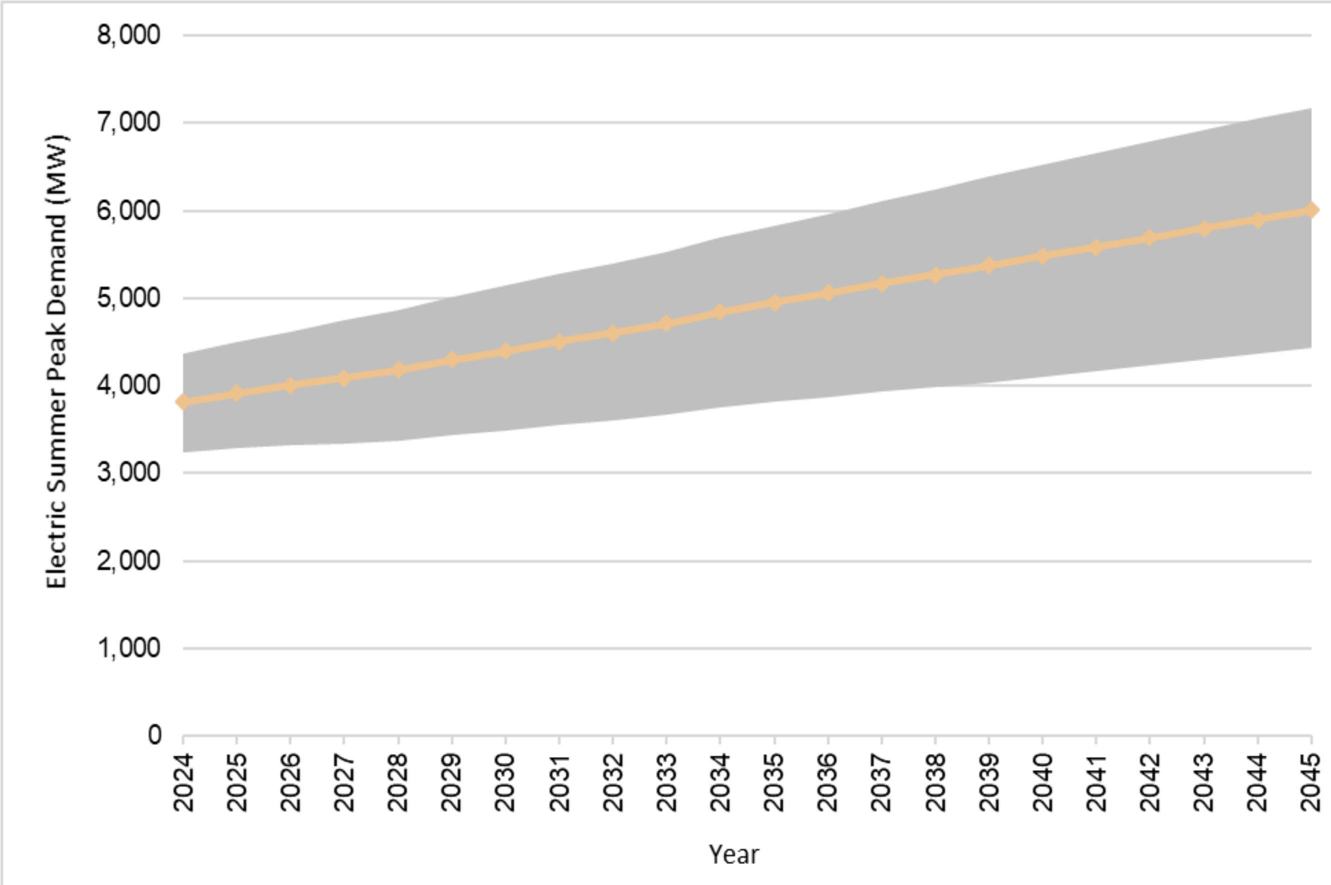


Figure 6.14: Range of Summer Peak Demand in Stochastic Scenarios around Base Peak Demand Forecast (MW) Before Additional DSR



➔ See Appendix F: Demand Forecasting Models for a detailed discussion of the stochastic simulations.

4.3. Resource Adequacy Model Inputs

In addition to the stochastic scenarios mentioned in the previous section, we also developed 90 electric demand draws for the resource adequacy (RA) model. We created these demand draws with stochastic outputs from PSE's economic and demographic model and two consecutive future weather years using the future temperatures from the climate change models. Since the RA model examines a hydro year from October through September, drawing two consecutive years preserves the characteristics of each future heating season. We created RA demand draws for the hydro years 2028–2029 and 2033–2034.

The RA model also examines adequacy in each hour of a given year; therefore, we scaled the 90 demand draws we used for RA model inputs to hourly demand using the hourly demand model. We created each of the 90 hourly demand forecasts without electric vehicle demand to account for growth in electric vehicles, then added the hourly forecast of electric vehicle demand to each demand forecast to create the final 90 hourly demand forecasts.

We highlight the differences between the RA model inputs and the stochastic scenarios in Table 6.11.

Table 6.11: Differences between the Resource Adequacy Model Inputs and the Stochastic Scenarios

Analysis Attribute	Stochastic Scenarios	Resource Adequacy Model
Number of draws	310	90
Forecasted years	2024–2045	October 2028–September 2029 and October 2033–September 2034
Model detail level	Monthly demand and peak demand	Hourly demand
Economic and demographic variation	Included	Included
Climate change impacts	Yes	Yes
Temperature assumptions	Forecasted temperatures from years 2020–2049 were sampled from the three climate change models — one year chosen for each draw	Forecasted temperatures from years 2020–2049 were used from the three climate change models — two consecutive weather years were chosen for each draw
Electric vehicles	Base forecast used in 250 draws, high used in 30 draws, low used in 30 draws	Base forecast used in each draw
Electrification and other conversion policies	No	No
Purpose	Used in the AURORA portfolio model to test the robustness of the portfolio under various conditions	Used in the resource adequacy modeling that determines the effective load-carrying capabilities (ELCCs)

➔ See Chapter Seven: Resource Adequacy Analysis, and Appendix F: Demand Forecasting Models for a detailed discussion of the hourly model.

4.4. Updates to Inputs and Equations

The following section summarizes updates to the demand forecast inputs and equations made since the 2021 IRP.

4.4.1. Climate Change Forecast

Previous IRPs used the most recent 30 years of historical temperatures to forecast what temperatures will be during the forecast. In this 2023 Electric Report, we used three climate change models by the NWPCC to establish an assumption of future normal temperatures. Section 2 Climate Change of this chapter details how we developed and used climate models in the forecast of this chapter details how we developed and used climate models in the forecast.

PSE PUGET SOUND ENERGY

4.4.2. Peak Modeling of Morning versus Evening

This 2023 Electric Report explicitly assumes an evening peak and its temperature impacts. Although a winter peak may occur in the morning or the evening, current characteristics of PSE's system demand indicate, on a weather and day-of-week normalized basis, higher levels of demand in the evening (around 200 MW) compared to the morning. This finding is consistent with historically observed December peaks (hour ending 18 on a weekday). Additionally, in the future forecast period, as the EV forecast grows, the difference between morning and evening peaks grows to be more than a few hundred MWs with larger EV peak demand in the evening, thus further decreasing the long-term likelihood of a morning peak occurrence. As part of our evaluation of the climate change temperature models, we recognized that the one-in-two minimum seasonal, hourly temperature for a winter evening is warmer than the morning. Hence, we calculated the typical effect of this assumption in the climate change datasets, which results in around two-degree warming to reflect evening conditions. This update reduced the winter peak demand forecast. This assumption does not impact summer peak temperature projections, as summer peaks always occur in the evening when the temperature is warmest.

4.4.3. 2018 Washington State Energy Code

The 2018 Washington State energy code change took effect in 2021. We considered the impact of this code change from 2021 through 2023 in the 2023 Electric Report forecast to understand the starting point for the forecast in 2024. The Conservation Potential Assessment (CPA) will determine the effects of this code change starting in 2024 and will also include the statutory requirement for the Washington State code cycle to make the code more stringent in terms of energy use. The law requires that the WA State code be improved in each code cycle update to achieve a 70 percent reduction in energy use by 2031 compared to the 2006 WA State code baseline. Therefore, a small amount of this code change is in the forecast, but we will account for most of this code change after the additional DSR forecast.

5. Key Assumptions

To develop PSE's demand forecasts, we must make assumptions about economic growth, energy prices, weather, and loss factors, including certain system-specific conditions. We describe these and other assumptions in the following section.

5.1. Economic Growth

Economic activity has a significant effect on long-term energy demand. Although the energy component of the national GDP has been declining over time, energy is still an essential input into various residential end uses such as space heating and cooling, water heating, lighting, cooking, dishwashing, clothes washing, electric vehicles, and other electric plug loads. The growth in the residential building stock, therefore, directly impacts the demand for energy over time. Commercial and industrial sectors also use energy for space heating and cooling, water heating, lighting, and other plug loads. Energy is also a critical input into many industrial production processes. Economic activities in the commercial and industrial sectors are, therefore, essential indicators for the overall trends in energy consumption.

5.1.1. National Economic Outlook

Because the Puget Sound region is a major commercial and manufacturing center with strong links to the national economy, the 2023 Electric Report forecast begins with assumptions about what is happening in the broader U.S. economy. PSE relies on Moody's Analytics U.S. Macroeconomic Forecast, a long-term forecast of the U.S. economy for economic growth rates. We used the November 2021 Moody's forecast for this 2023 Electric Report.

The Moody's forecast predicts:

- The economy will continue to recover from the COVID-19 pandemic with a return to full employment in 2023, and labor force participation will continue to increase as workers get healthy and children get vaccines.
- The recovery will continue through 2025. After 2025, Moody's predicts the economy will grow modestly in the long term.
- U.S. GDP will continue to grow over the forecast period with a 2.0 percent average annual growth from 2024–2045. This growth rate is lower than the Moody's forecast used in the 2021 IRP, which projected 2.2 percent average annual growth, but some of the 2021 IRP growth was from the projected recovery from COVID-19.

Moody's identified possible risks that could affect the accuracy of this forecast:[7]

- In the near term, supply constraints could cause the economy to grow less quickly.
- Rising long-term interest rates could cause a slump in the economic recovery.
- The congressional stimulus for COVID-19 could be smaller than predicted or not provide the boost to the economy that is predicted.
- The economic effects of COVID-19 are still unpredictable; additional waves that elude the vaccine could halt recovery.

5.1.2. Population Outlook

The Washington State Employment Security Department (WA ESD) average annual growth rate for the counties that make up the electric service area is 0.88 percent for 2024–2045. This rate is down from the 1.0 percent growth rate forecast in the 2021 IRP 2022–2045.

5.1.3. Regional Economic Outlook

We prepare regional economic and demographic forecasts using econometric models based on historical economic data for our service area counties and the United States macroeconomic forecasts.

Puget Sound Energy's electric service area stretches from south Puget Sound to the Canadian border and from central Washington's Kittitas Valley west to the Kitsap Peninsula. Puget Sound Energy serves more than 1.2 million electric customers in eight counties.

[7] Moody's Analytics (2021, November) Forecast Risks. Precis U.S. Macro. Volume 26 Number 8.

Within PSE's service area, demand growth is uneven. Most economic growth is driven by high-tech, information technology, or retail (including online retail). Supporting industries like leisure and hospitality employment are also growing. Job growth is concentrated in King County, which accounts for the largest share of the system electric sales demand today. Other counties are growing, but typically at lower magnitudes, and have added fewer jobs.

We used the following forecast assumptions in the 2023 Electric Report base electric demand forecast:

- We expect an inflow of 898,000 new residents (by birth or migration) to increase the local area population to 5.33 million by 2045, for an average annual growth rate of 0.88 percent. This growth rate is slightly lower than the 2021 IRP forecast, which projected an average annual population growth of 0.9 percent that would have resulted in 5.13 million electric service area residents by 2045.
- We expect employment to grow at an average annual rate of 0.46 percent between 2024 and 2045, smaller than the 0.6 percent annual growth rate forecasted in the 2021 IRP.
- We expect local employers to create about 205,681 total jobs between 2024 and 2045, mainly driven by growth in the commercial sector, compared to about 310,000 jobs forecasted in the 2021 IRP.
- We expect manufacturing employment to decline by 0.32 percent annually between 2024–2050 due to outsourcing manufacturing processes to lower wages or less expensive states or countries and the continuing trend of capital investments that increase productivity.

Table 6.12 shows the population and employment forecasts for PSE's electric service area.

Table 6.12: Population and Employment Growth, Electric Service Counties (1,000s)

Model Driver	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Population	4,436	4,716	4,938	5,136	5,334	0.88
Employment	2,215	2,291	2,340	2,380	2,421	0.46

5.2. Weather

In this 2023 Electric Report, PSE incorporated Climate Change temperatures from three climate models to calculate the normal temperatures for the base energy demand forecast and the design peak temperature for the base peak demand forecast. Section 2 Climate Change of this chapter and Appendix F: Demand Forecasting Models discuss more details of how we created this forecast.

➔ Appendix F: Demand Forecasting Models discusses more details of how we created this forecast.

5.3. Electric Vehicles

The energy consulting firm Guidehouse created an EV forecast for PSE in late 2021. This EV forecast includes two recent pieces of legislation: the Zero Emission Vehicles law of 2020 and the Clean Fuel Standard law of 2021. The forecast assumes 95,000 EVs on the road in PSE's service area in 2024, including light-, medium-, and heavy-duty vehicles. This forecast will increase to 1,147,000 EVs in 2045. Annual energy sales from new electric vehicles total 183,000 MWh in 2024 and 4,815,000 MWh in 2045.

We assumed that 74 percent of the charging from new EVs would be at residential locations, while the remaining 26 percent would be at commercial sites. This percentage changes during the forecast period as charging at commercial locations becomes more widely available. This percentage also changes as more medium- and heavy-duty electric vehicles become available and cost-effective, resulting in 35 percent of EVs charging on residential accounts and 65 percent charging on commercial accounts in 2045. Electric vehicles, especially medium- and heavy-duty models, are an emerging technology; thus, we anticipate we will revise this forecast on an ongoing basis.

The additional demand from electric vehicles grows to a 19 percent share of total peak demand by 2045 before including the cost-effective DSR identified in the 2023 Electric Report. Figure 6.15 shows the December evening peak demand, and Figure 6.16 shows the annual average energy demand from new electric vehicles. Figure 6.17 shows the forecast of electric vehicles as a percent of all vehicles purchased in the PSE service territory.

Guidehouse also created high and low EV forecasts for PSE in late 2021. The consulting firm created the high and low EV scenarios representing the 90^{th} and 10^{th} percentile. Figures 6.15 and 6.16 show the high and low electric vehicle energy and peak forecasts used in the stochastic scenarios.

Figure 6.15: Electric Vehicle Average Energy Demand from New Vehicles (aMW)
Base, High, and Low

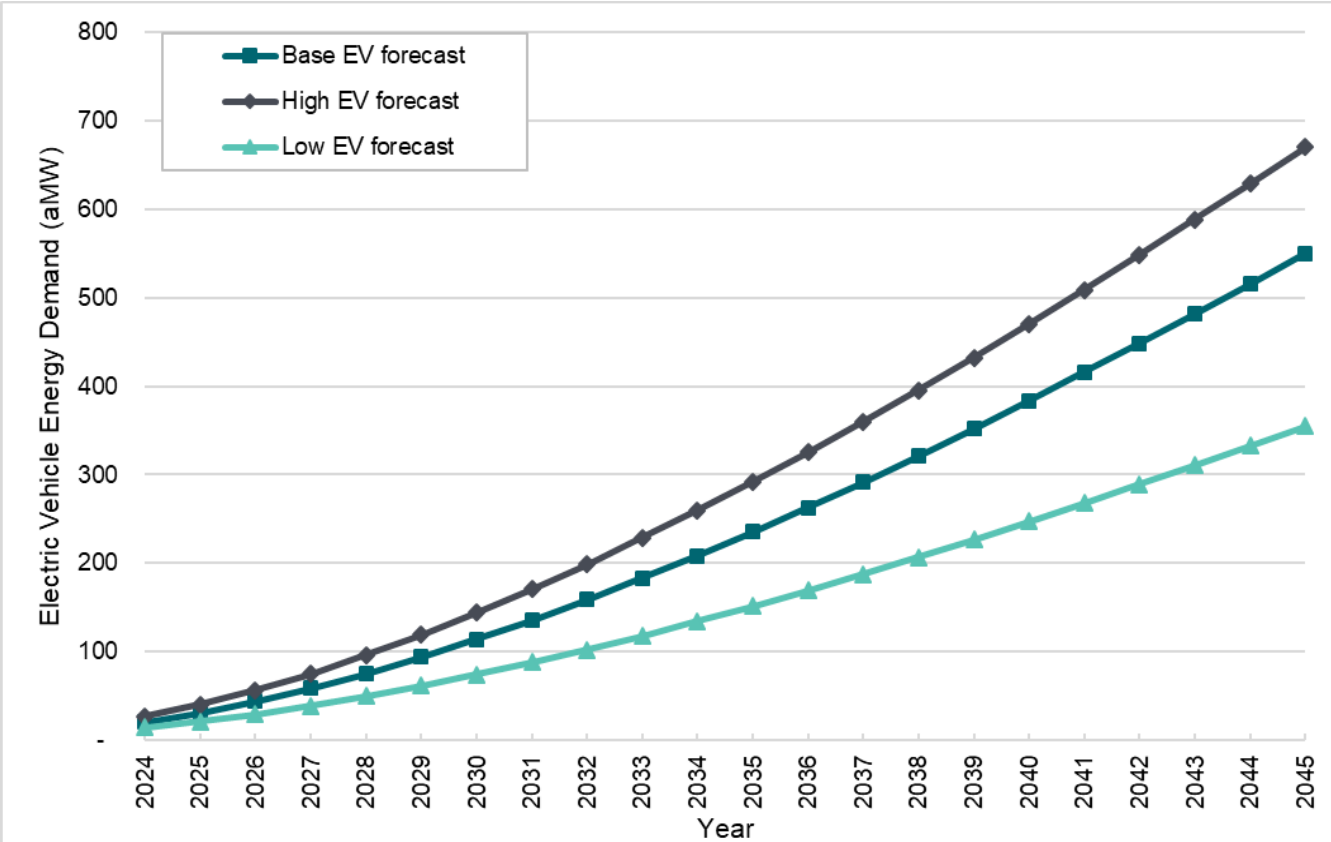


Figure 6.16: Electric Vehicle Peak Demand from New Vehicles (MW)
Base, High, and Low

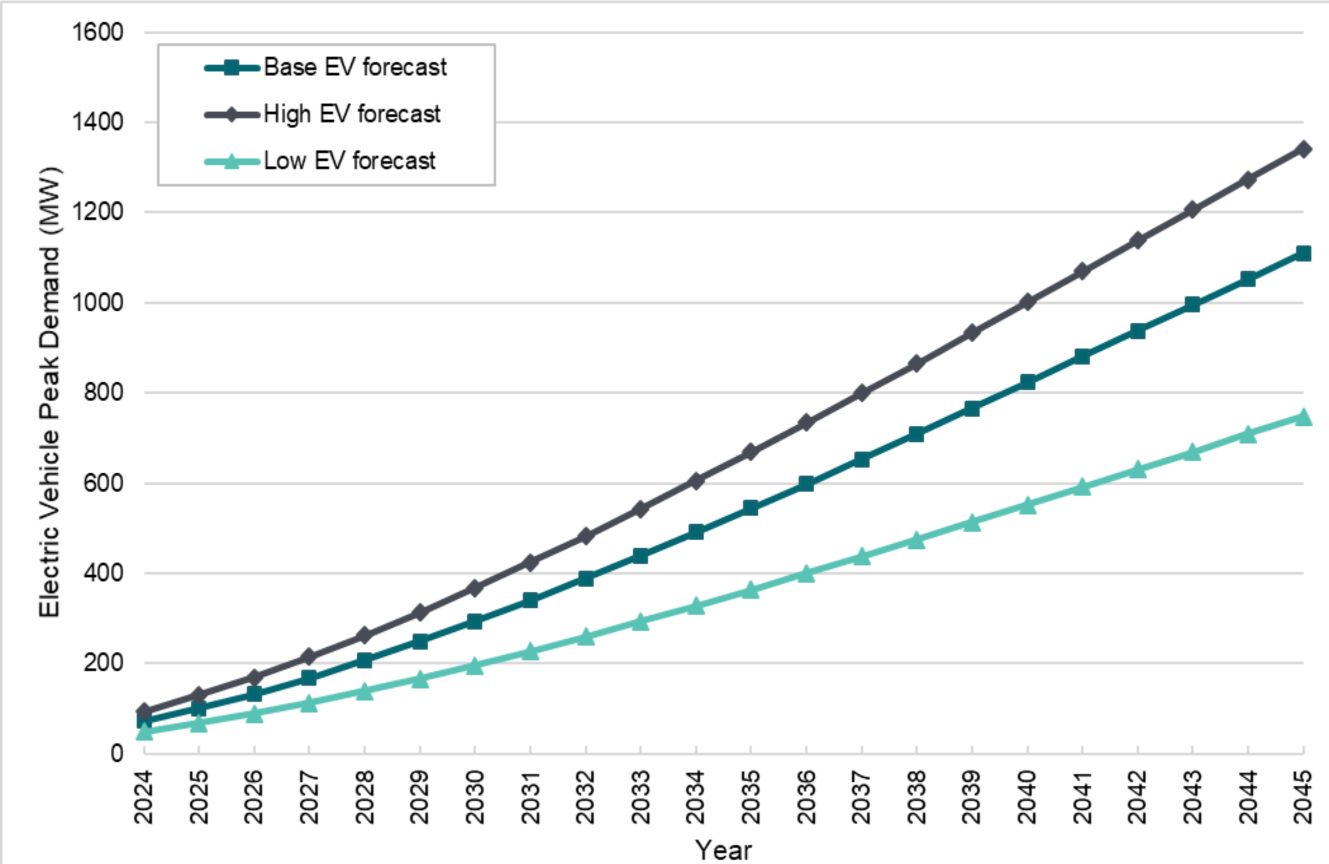
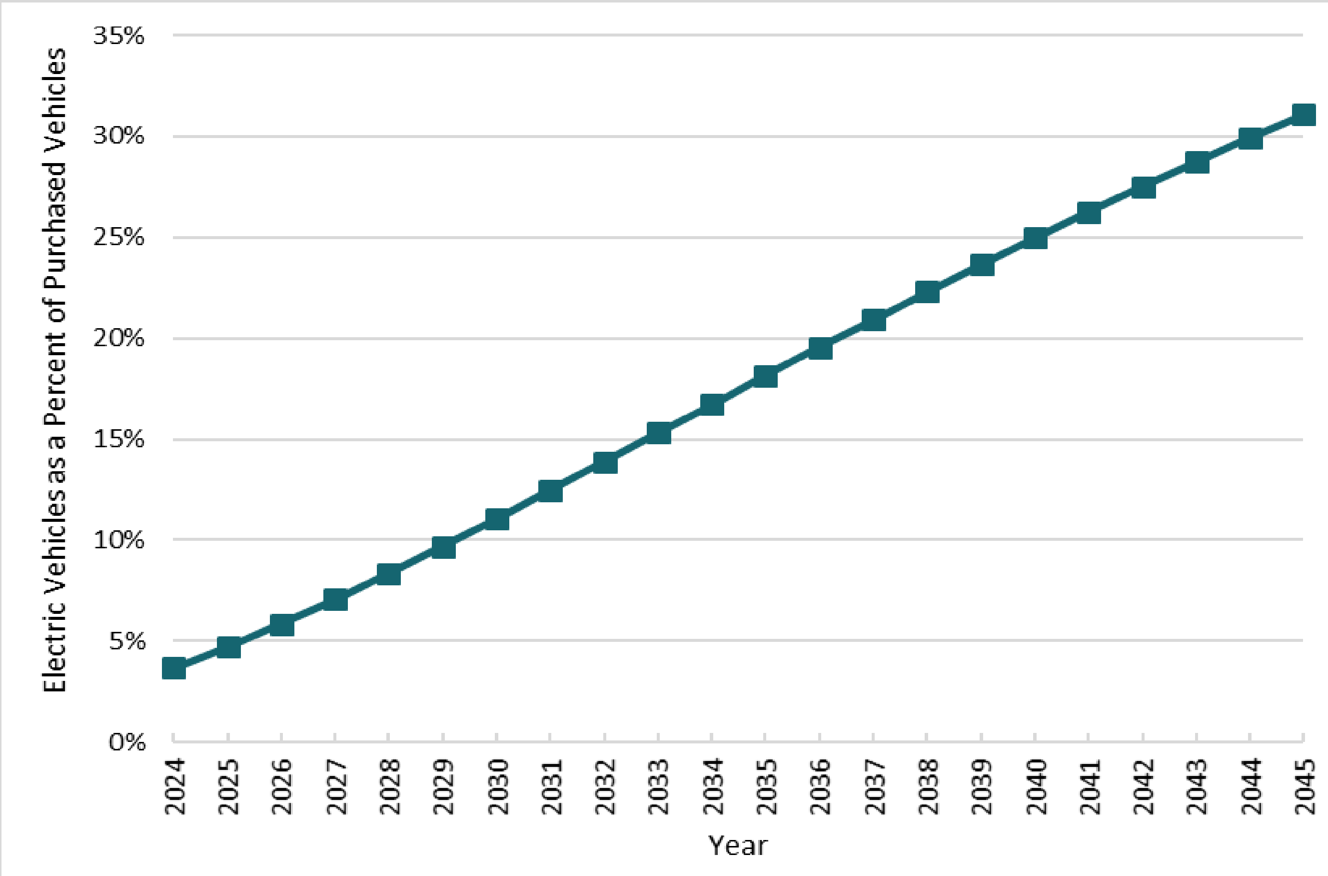


Figure 6.17: Electric Vehicles as a Percent of Purchased Vehicles



5.4. COVID-19 Impacts

After 2022, we made no explicit COVID-19 or remote work adjustments above and beyond the effects of the economic forecast incorporated into the demand forecast using the macroeconomic variables. The result is a slow recovery over the following few years and a recovered economy by 2024, with lingering effects from the recession persisting thorough out the remainder of the forecast. There exists a great deal of uncertainty around the steady state level of residential and commercial usage once behaviors developed during the pandemic settle.

We performed stochastic simulations that varied the economic forecast around this base forecast. These included simulations with better and worse economic outcomes. Since the 2023 Electric Report determines the resource need starting in 2024, the stochastic simulations show alternative ways the pandemic could resolve in the future.

5.5. Loss Factors

The electric loss factor is 7.8 percent. The loss factors we assumed in the demand forecast are system-wide average losses during normal operations for the past two to three years.

5.6. Block Load Additions

Beyond typical economic change, the demand forecast also considers known major demand additions and deletions that we would not account for through typical demand growth in the forecast. Most of these additions are from major infrastructure projects. These additions to the forecast are called block loads, and they use the information provided by PSE's system planners or major accounts. The adjustments to non-transport customers will add 85.6 MW of connected demand by 2025 for the electric system. We included these block loads in the commercial class, and King County has most of the additions.

5.7. Schedule Switching

In addition to block loads, PSE accounts for customers switching rate schedules. Customers who purchase their own electricity are called transport customers, and they rely on PSE for distribution services. In this 2023 Electric Report, we removed transport customers from the forecast before determining supply-side resource needs because PSE is not responsible for acquiring supply resources for electric transport customers.

5.8. Interruptible Demand

Puget Sound Energy has 151 electric interruptible customers; six are commercial and industrial customers, and 145 are schools. The school contracts limit the time of day when energy can be curtailed. The other customers represent 12 MW of coincident peak demand. In this 2023 Electric Report, we accounted for the 12 MW of demand that is interruptible from these customers

5.9. Retail Rates

We included retail energy prices — what customers pay for energy — as explanatory variables in the demand forecast models because they affect customer choices about the efficiency level of newly acquired appliances and how they are used — the energy source used to power them. The retail rate forecasts draw on information obtained from internal and external sources.

5.10. Distributed Generation

We did not include distributed generation, including customer-level generation via solar panels, in the demand forecast after 2023; we captured this energy production in the 2023 Electric Report modeling process as a demand-side resource. We include a description in Appendix E: Conservation Potential Assessment and Demand Response Assessment. .

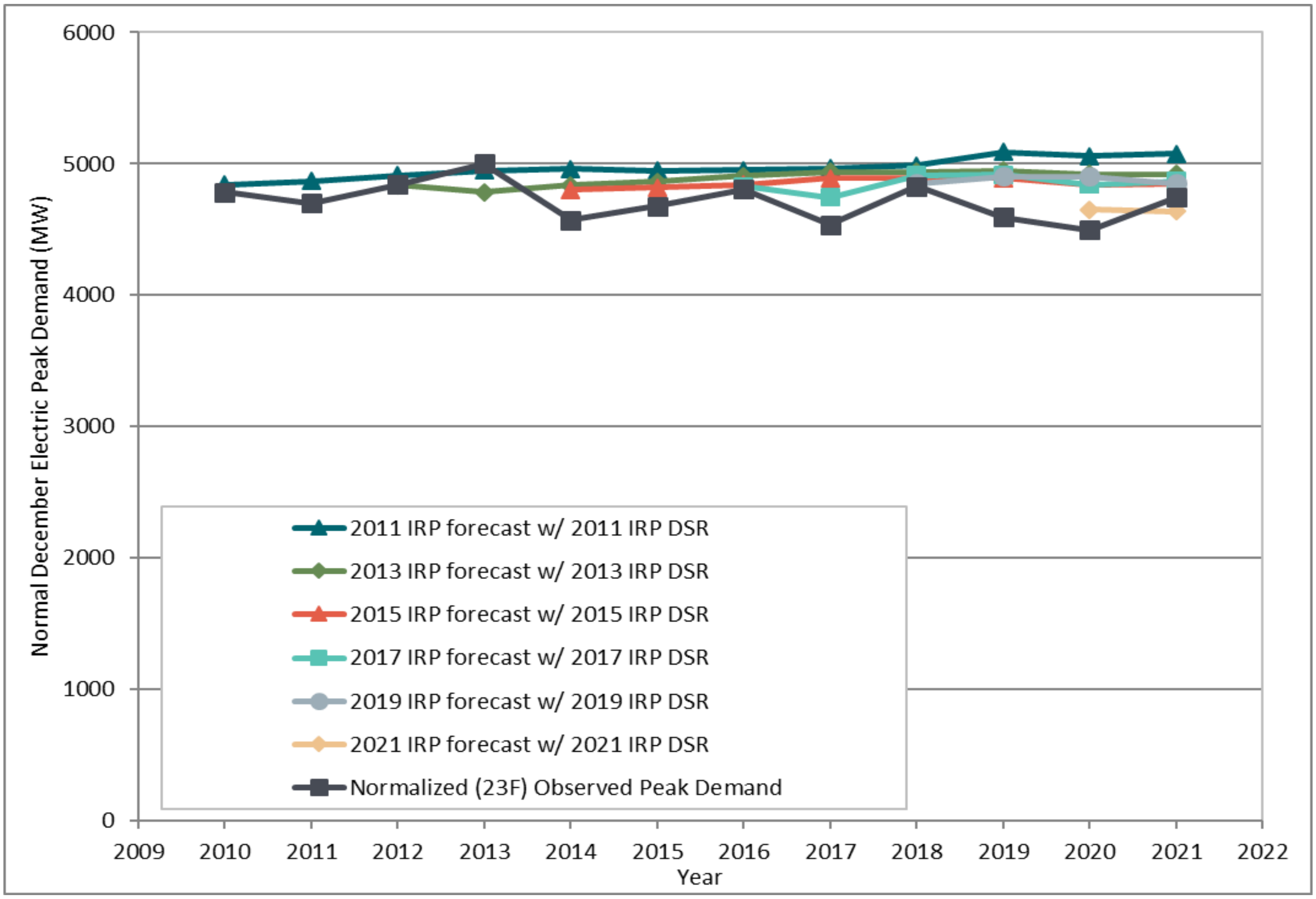
6. Previous Demand Forecasts

The following section compares actual peak demand to previous IRP forecasts. This section also identifies reasons prior forecasts may be off from current weather-normalized actual peaks.

6.1. IRP Peak Demand Forecasts Compared to Actual Peaks

Figure 6.18 compares 2011, 2013, 2015, 2017, 2019,[8] and 2021 IRPs' base peak demand forecasts after additional DSR with normalized[9] actual observations. We noted that the normalized actual observations account for peak hourly temperature, monthly HDDs, and the day of the week and time of day of the actual peak. We present the percent difference of normalized actual values compared to each IRP forecast for each year in Table 6.12.

Figure 6.18: Observed Normalized Electric December Peak Demand Compared to Previous IRP forecasts



8 A formal IRP was not filed by PSE in 2019. On October 28, 2019, the Washington Utilities and Transportation Commission Staff filed a Petition for Exemption from WAC 480-100-238 pursuant to WAC 480-07-100 until December 31, 2020. On November 7, 2019 the WUTC held an Open Meeting concerning this matter and subsequently issued Order 2, exempting PSE (and other investor owned utilities in Washington) from WAC 480-100-238. Pursuant to Order 2, PSE filed an IRP Progress Report in 2019.

9 Given that the forecasts are for peaks at a design temperature, observed actual peaks are adjusted to reflect what would have been the peak if the design peak temperatures had been achieved.

Table 6.12: Weather Normalized December Electric Peak Demand and Difference from Previous IRP Forecasts

Year	2011 (%)	2013 (%)	2015 (%)	2017 (%)	2019[8] (%)	2021 (%)
2010	1.2	-	-	-	-	-
2011	3.6	-	-	-	-	-
2012	1.5	-0.1	-	-	-	-
2013	-1.0	-4.3	-	-	-	-
2014	8.5	5.8	5.1	-	-	-
2015	5.7	4.0	3.0	-	-	-
2016	3.1	2.1	0.8	0.5	-	-
2017	9.5	8.8	7.8	4.6	-	-
2018	3.3	2.3	1.2	1.7	0.5	-
2019	10.8	7.7	6.5	7.1	6.8	-
2020	12.6	9.5	7.7	7.7	9.1	3.5
2021	7.1	3.8	2.2	2.6	2.8	-2.2

6.1.1. Reasons for Forecast Variance

As explained throughout this chapter, we based the IRP peak demand forecasts on forecasts of key demand drivers, including expected economic and demographic behavior, DSR, customer usage, and weather. When these forecasts diverge from observed actual behavior, so does the IRP forecast. As forecasts age, assumptions and conditions may change. Because of these changes, we expect older predictions to be farther off from observed actuals than more recent forecasts. We explain these differences in the next section.

Economic and Demographic Forecasts

Economic and demographic factors are key drivers for the IRP peak demand forecast. After the 2008 recession hit the U.S. economy, many economists, including Moody's Analytics, assumed that the economy would recover sooner than it did. We pushed out a complete recovery with each successive forecast as the U.S. economy failed to bounce back to its previous state year after year. The charts below compare Moody's forecasts of U.S. housing starts and population growth that we incorporated in the 2011 IRP through the 2019 IRP with actual U.S. housing starts and population growth. Moody's too-optimistic forecasts of housing starts and population growth during the recession led to over-estimated forecasts of customer counts. Puget Sound Energy now uses county population forecasts sourced from Washington's ESD to forecast the population in PSE's service area. We included Moody's forecast of housing starts and population from May 2020 and Nov 2021 in Figures 6.19 and 6.20 for comparison.

Additionally, while the Moody's forecast used in the 2019 IRP did predict a softening of the economy in 2020, it did not forecast the magnitude of the effects of the COVID-19 pandemic. Therefore, Moody's forecasts used before the 2021 IRP have likely overestimated economic growth in 2020, 2021, and 2022. The pandemic's repercussions on the economy and energy demand will likely be unknown during this reporting cycle.

Figure 6.19: Moody's Forecasts of U.S. Housing Starts Compared to Actual U.S. Housing Starts

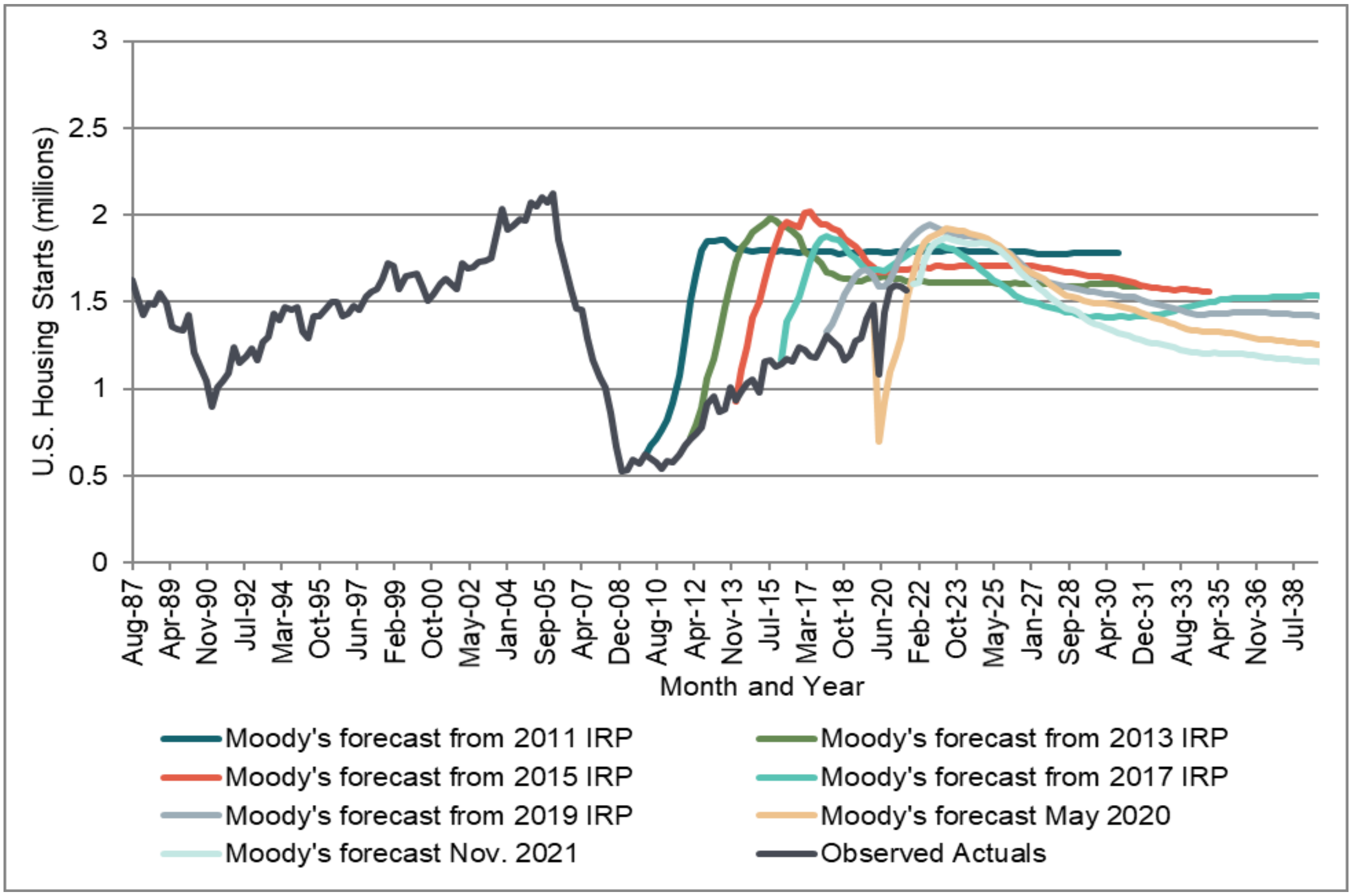
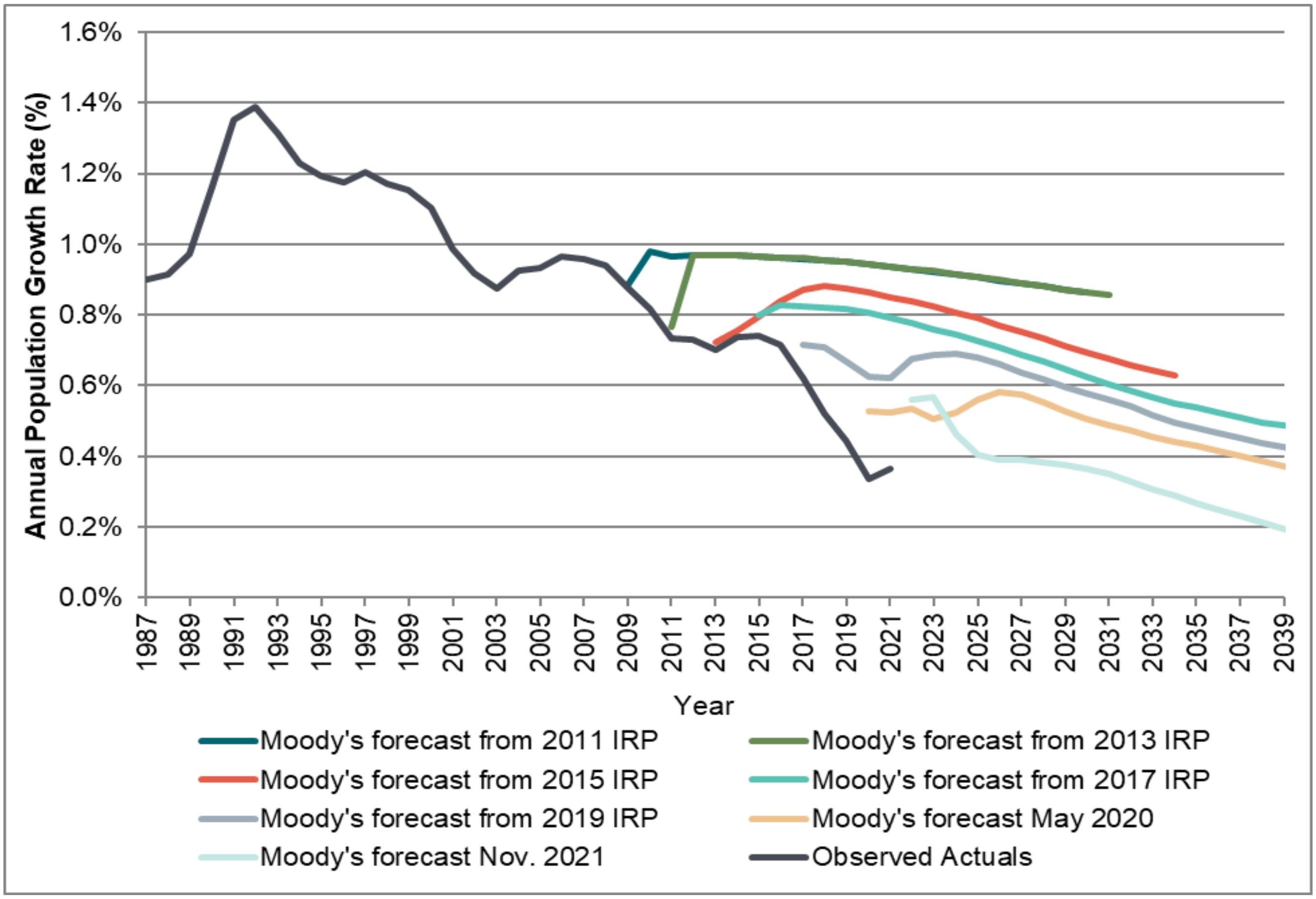


Figure 6.20: Moody's Forecasts of U.S. Population Growth Compared to Actual U.S. Population Growth



Demand-side Resources and Customer Usage

For the comparison in Figure 6.18 of weather-normalized peak observations to the IRP peak demand forecasts after additional DSR, we assumed the forecasted DSR was implemented. However, consumers can adopt energy-efficient technologies above and beyond what utility-sponsored DSR programs and building codes and standards incentivize. This consumer behavior leads to more actual DSR than we forecasted. The DSR programs can also change over time. In later IRPs, we can choose programs that were not cost-effective in the past but we now deem cost-effective. This situation can make an older forecast outdated, the DSR forecast too low, and the load forecast after additional DSR too high.

Also, the Global Settlement from the 2013 General Rate Case (GRC) PSE accelerates electric DSR by 5 percent yearly. We did not consider this additional DSR in comparing IRP forecasts with normalized actuals.

Normal Weather Changes

Normal weather assumptions change from forecast to forecast. We updated the normal weather assumption for the 2011 IRP to the 2021 IRP by rolling off two older years of temperature data and incorporating two new years of temperature data into the 30-year average. Over time, normal heating degree days have been declining, and the forecast of energy demand with normal weather has changed. In this 2023 Electric Report, we incorporated climate change into the normal definition, which altered the 2023 Electric Report base demand forecasts.

Additionally, over time our customers' weather sensitivity has been changing. As consumers implement energy efficiency measures, customers use less energy at a given temperature, including peak temperatures. More recent forecasts reflect this change in weather sensitivity better than older forecasts.

Non-design Conditions during Observed Peaks

Peak values are weather normalized using the peak forecasting model. This model uses peak values from each month to create a relationship between peak demand, monthly demand, and peak temperature. However, some of the observed December peaks shown above occurred on atypical days rather than typical days. For example, in 2014, the electric peak fell on the Monday morning after Thanksgiving weekend; in 2015, it fell on New Year's Eve; and in 2019, it fell on the day after Christmas. Usage on these days will likely differ from use on a typical non-holiday weekday peak. Therefore, when these dates are weather normalized, they may not line up with the forecasted values since the usage patterns are atypical.

Service Area Changes

In March 2013, Jefferson County left the PSE service area. We included Jefferson County usage in the electric peak demand forecast in the 2011 IRP. Therefore, when comparing that forecast to today's actuals, we expect that forecast to be higher than the actual peak demand.

RESOURCE ADEQUACY ANALYSIS

CHAPTER SEVEN

PUGET SOUND ENERGY

2023 Electric Progress Report

Contents

1. Introduction

The electricity industry in the Pacific Northwest (PNW) is transitioning as governments and system planners implement major decarbonization policies. The sector is retiring significant quantities of coal-fired capacity while adding new renewable generation resources. As a result, Puget Sound Energy (PSE) and other utilities are rethinking how we plan our systems, especially in resource adequacy (RA). As we transition to 100 percent clean energy by 2045, always having enough energy — maintaining resource adequacy — is paramount to ensure customers continue receiving reliable electricity and a smooth transition to a decarbonized system.

Puget Sound Energy contracted with the consulting firm Energy and Environmental Economics (E3) to produce the resource adequacy analysis for this 2023 Electric Progress Report (2023 Electric Report). E3 worked with our data and used their RECAP model to produce the study results. We based the work described in this chapter on the findings of E3's 2021 report, which recommended the following improvements to our resource adequacy modeling:

- Align the treatment of the first hour of loss-of-load events across the scenarios with and without battery storage
- Consider changing climate in evaluating energy demand, hydroelectric generation, and market purchases
- Consider load and renewable correlations. Puget Sound Energy did not have sufficient time to incorporate load and renewable correlations in the resource adequacy analysis. These correlations warrant study for future studies, as they could impact resource adequacy for PSE's system.
- Discharge storage at its rated capacity, for its rated duration; does not apply a minimum state of charge to the modeled energy capacity
- Incorporate hydroelectric dispatch capabilities and hydroelectric energy limitations
- Perform GENESYS sensitivity to determine if it would result in an increase in the storage ELCC; PSE did not run this sensitivity. The ELCC of energy storage is very high and there is sufficient energy to charge the energy storage. The GENESYS sensitivity would not add significant value on storage ELCC

Please see the entire docket and public comments on the UTC website.[1] We worked with E3 to meet all the modeling improvements described in the filing.

➔ See Appendix L: Resource Adequacy for more details regarding the filing and PSEs commitments.

Beyond implementing E3's recommendations, the other major change impacting the resource adequacy analysis is PSE's decision to reduce market reliance. In the past, PSE relied on purchases from the short-term wholesale energy markets as a cost-effective strategy to supplement resources to meet demand. This strategy also allowed us to avoid building significant amounts of generation capacity. Although wholesale electricity prices have remained low in recent

[1] utc.wa.gov/casedocket/2021/210220/docsets

years on average, the PNW has experienced periods of high wholesale electricity prices and low short-term market liquidity.

We expect this wholesale market volatility to limit our ability to rely on the market over time. Based on utilities' current plans, several studies discussed in this chapter's market reliance section have projected that the PNW will face a growing capacity shortage over the next decade.[2] Given the tightening of energy markets and to prepare for possible participation in the Western Resource Adequacy Program (WRAP), we plan to reduce our reliance on short-term wholesale market purchases to zero by 2029.

Peak capacity is the maximum capacity need of a system to meet loads.

Perfect capacity is the firm and reliable capacity required to maintain a chosen reliability metric.

The **planning reserve margin** is the generation resource capacity required to provide a minimum acceptable level of reliable service to customers under peak load conditions.

The **peak capacity credit** assigned to a resource is the effective load-carrying capability (ELCC). This value depends highly on the load characteristics and portfolio resource mix, which makes it unique to each utility; it is expressed as a percent of the equivalent nameplate capacity.

➔ For more information on market reliance, please refer to section four of this chapter.

Considering the projected capacity shortages for the NW region, the Western Power Pool (WPP) created the WRAP to provide a programmatic approach for utilities to work together to ensure resource adequacy throughout the region. The WRAP is the first regional reliability planning and compliance program in PNW history.[3] The Western Resource Adequacy Program is discussed in more detail later in this chapter in section six.

➔ The results of how the WRAP program will impact peak needs are in Chapter Eight: Electric Analysis.

1.1. Incorporating Climate Change

Puget Sound Energy's 2023 Electric Report incorporates climate change in the base energy and peak demand forecast for the first time. Before this report, we used historical temperatures from the range of temperature variability to create the resource adequacy model. We then iterated through the different temperature years to create hourly load draws that we used in the modeling simulations, but the underlying data did not recognize predicted effects from climate change.

The methodology we used to incorporate climate change in this report is the first step in an evolving process. We heard from interested parties that incorporating climate change into demand forecasting is a high priority. It is essential to consider climate change in resource planning because our customers rely on PSE energy to heat in the winter and stay cool in the summer. With an overall average warming trend, we would expect, on average, less overall heating demand and more cooling demand. We used recently developed regional climate model projections to create

[2] https://www.ethree.com/wp-content/uploads/2019/12/E3-PNW-Capacity-Need-FINAL-Dec-2019.pdf

[3] https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

demand draws for the resource adequacy simulation that reflect climate change. We also updated the peak demand forecast, which resulted in normal peak temperatures for summer and winter that increased over time.

➔ Please refer to Chapter Six: Demand Forecast for more details regarding how we incorporated climate change into our demand forecast.

Along with incorporating climate change in the demand forecast, we also updated hydroelectric generation draws. Previously, we used the historical 80-year hydroelectric stream flow data to create a generation forecast based on current operating conditions. The same climate change data we used for the demand forecast also provided stream flow data that we turned into predicted generation for the hydroelectric facilities.

➔ For details regarding the hydroelectric forecast, refer to Chapter Five: Key Analytical Assumptions.

2. Overview of Results

Resource Adequacy measures the ability of generating resources to meet load across a wide range of system conditions, accounting for supply and demand variability. No one can plan a perfectly reliable electrical system; however, we use several reliability metrics in the industry to ensure the system has adequate generation capacity during extreme events. We apply a five percent loss of load probability metric in the resource adequacy study, which means we plan our system to have an expected loss of load event occur once in 20 years. We reflected this in our planning reserve margin in Table 7.1, which shows the 2021 Integrated Resource Plan (IRP) results and the new seasonal analysis we used in this report. Overall, the peak capacity need increased from the 2021 IRP.

Table 7.1: Planning Reserve Margin and Peak Capacity Need — Percent Above Normal and MW Need Above Normal Peak

Study Years and Seasons	2027 Winter (2021 IRP)	2031 Winter (2021 IRP)	2029 Winter (2023)	2029 Summer (2023)	2034 Winter (2023)	2034 Summer (2023)
Planning Reserve Margin (%)	20.7	24.2	23.8	21.2	23.9	26.1
Additional Perfect Capacity Need (MW)	907	1,381	1,272	1,875	1,746	2,856

Table 7.1 shows the additional perfect capacity need comparing the results from the 2021 IRP to the 2023 Electric Report study years. The 2023 Electric Report is the first time we modeled the planning reserve margin for winter and summer. When comparing the results from these two reports, it is important to compare the 2021 IRP study years to the 2023 Electric Report winter results only, as prior IRPs have only evaluated the winter months. When you compare winter results, you see a slight increase in the perfect capacity need from 2027 to the 2029 winter. From this analysis, we found that although PSE is a winter-peaking utility, the additional perfect capacity need is higher in summer. This

high summer need means there are fewer resources available in the summer than in the winter, not that the summer peak is higher than the winter peak.

Table 7.2 compares the 2023 Electric Report and 2021 IRP effective load carrying capability (ELCC) results. The ELCC measures how many megawatts of a resource PSE can plan on to meet the planning reserve margin. We modeled most of the resources with saturation effects; the more resources added of the same location or type, the less effective they are at meeting peak capacity. The results in the table are for the first tranche[4] (the first amount of MW of installed capacity) of each resource — 100 MW for renewable resources and demand response and 250 MW for storage. The ELCC for additional resources declines based on the ELCC saturation results, which we described further in the Key Takeaways section and Appendix L: Resource Adequacy. There is an increase across all renewable resource ELCCs from the 2021 IRP to the 2023 Electric Report. Most significantly, solar and batteries increased due to the seasonal analysis and other modeling changes discussed throughout this chapter in greater detail.

Table 7.2: Effective Load Carrying Capability Results for First 100 MW for Wind and Solar or First 250 MW for Storage

Resource	Resource Type	2027[1] (%)	2031[1] (%)	2029[2] Winter (%)	2029[2] Summer (%)
British Columbia	Wind	-	-	34	13
Idaho	Wind	24	27	12	17
Montana Central	Wind	30	31	39	27
Montana East	Wind	22	24	32	19
Offshore	Wind	48	47	32	41
Washington	Wind	18	15	13	5
Wyoming East	Wind	40	41	52	34
Wyoming West	Wind	28	29	39	34
Distributed Energy Resources (DER) Ground Mount	Distributed Solar	1	2	4	28
DER Rooftop	Distributed Solar	2	2	4	28
Idaho	Utility-scale Solar	3	4	8	38
Washington East	Utility-scale Solar	4	4	4	55
Washington West	Utility-scale Solar	1	2	4	53
Wyoming East	Utility-scale Solar	6	5	11	29
Wyoming West	Utility-scale Solar	6	6	10	28
Lithium-ion Battery (2-hour)	Storage	12	16	89	97
Lithium-ion Battery (4-hour)	Storage	25	30	96	97
Lithium-ion Battery (6-hour)	Storage	N/A	N/A	98	98
Pumped Storage (8-hour)	Storage	37	44	99	99
Demand Response (3-hour)	Demand Response	26	32	69	95

4 Tranche is the capacity segment of a resource on the ELCC saturation curve.

Resource	Resource Type	2027[1] (%)	2031[1] (%)	2029[2] Winter (%)	2029[2] Summer (%)
Demand Response (4-hour)	Demand Response	32	37	73	99

Notes:

1. 2021 IRP (2021 IRP modeled ELCC saturation curves for Washington wind and Washington solar only)
2. 2023 Electric Progress Report

2.1. Key Takeaways

Several elements contributed to the increase in the planning reserve margin:

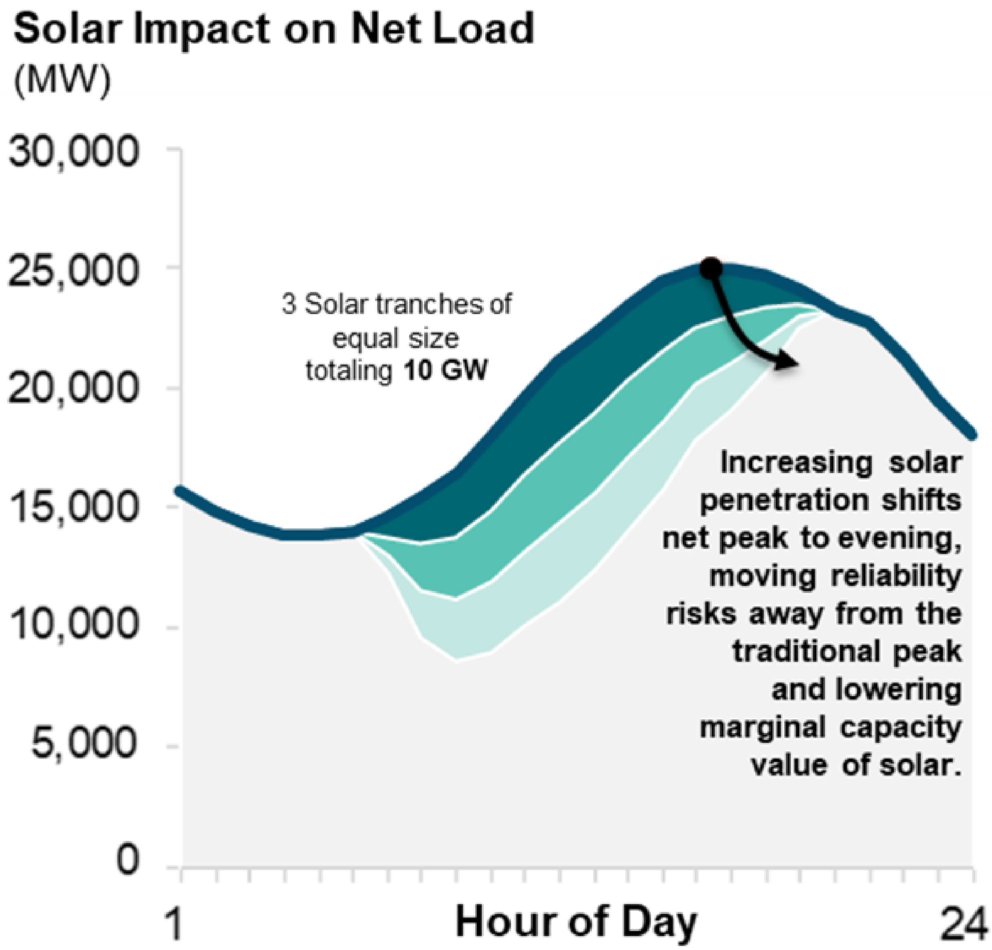
- Including climate change data in the load forecast and peak temperatures slightly lowered the normal winter peak and increased the normal summer peak. Even with the increase in normal summer peak temperatures, the summer peak does not come close to the level of the winter peak through the report's planning horizon.
- Increase in peak demand. Although climate change decreased normal winter loads, the updated electric vehicle (EV) forecast increased the demand. The increase in peak from the EV forecast was more significant than the decrease from the climate change data, resulting in an overall increase in peak demand.
- The analysis looked at winter and summer capacity needs.
- The climate change data also showed changes in the duration and frequency of outage events which impacted the results. The data shows a decrease in event duration, less frequent events in the winter, and more frequent events in the summer, increasing the ELCCs for shorter duration storage resources and solar.
- The hydro generation profile changed when we incorporated climate change into the modeling because the historical spring runoff now happens earlier in the year. The earlier spring runoff changes hydropower availability and leaves less water for the summer.

The saturation effect can have a significant impact on resource ELCCs. In the next section, we explain why it was vital to consider saturation when we evaluated the ELCC of a resource.

2.1.1. Effective Load Carrying Capability Saturation Effect

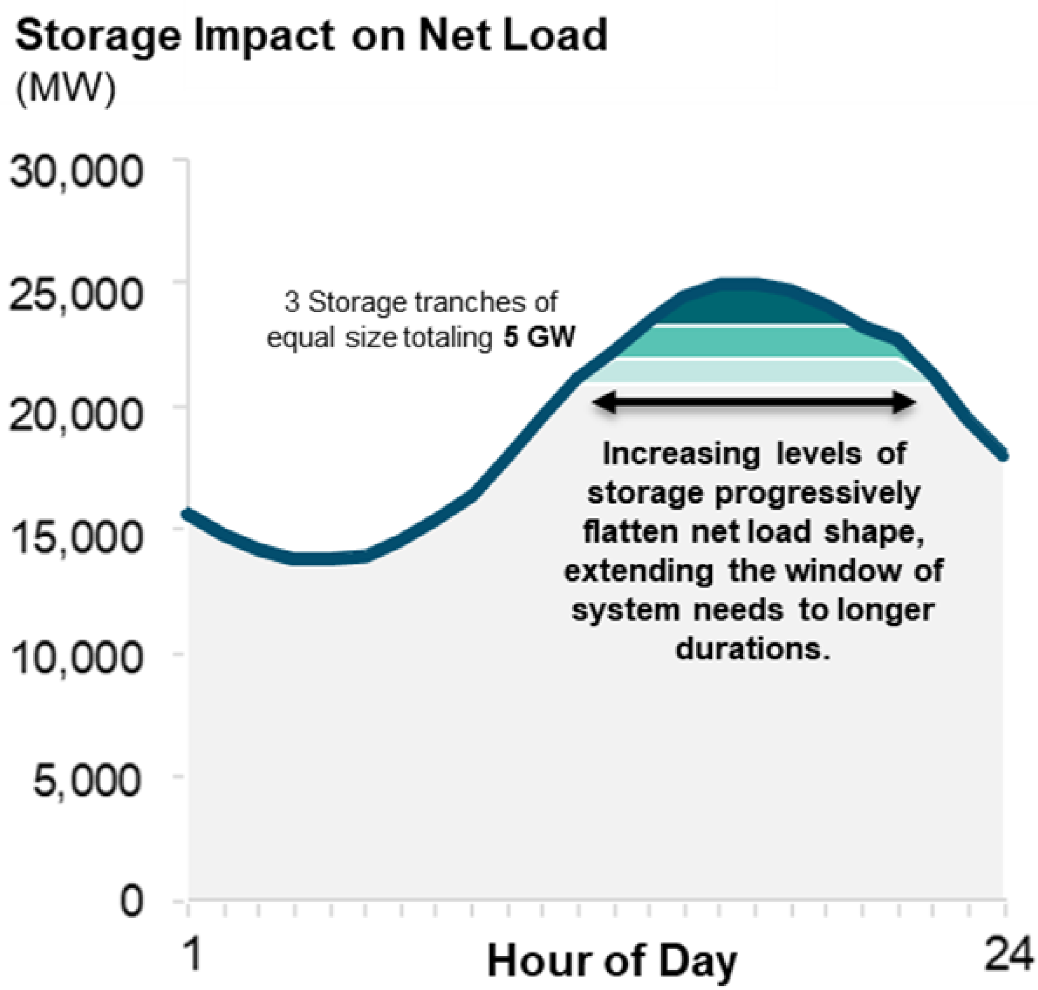
The ELCC of a dispatch-limited resource decreases as the penetration of that resource increases, known as the ELCC saturation effect. Figure 7.1 shows an example of ELCC saturation — the dynamics for solar on a peak summer day. Note that this is an illustrative example and does not represent PSE's system. The first grouping or tranche of solar produces a lot of energy during peak demand hours, showing a relatively high ELCC. However, when one adds more solar, the net peak demand (load minus renewable generation) shifts into the evening when solar generation is low. As a result, the ELCC for these later tranches is lower because the solar has mitigated most reliability concerns during the daytime but cannot contribute to the reliability needs at night. Wind resources experience this same saturation effect, except rather than shifting the net load from daytime hours to nighttime hours, wind resources shift the net load from times when wind generation is high to times when wind generation is low.

Figure 7.1: Example of ELCC Saturation Effect for Solar (Does Not Represent PSE's System)



The ELCC saturation effect applies to other dispatch-limited resources, such as energy storage and demand response. See Figure 7.2 for an example showing storage dynamics on the same peak day. Note that this is an example and does not represent PSE's system.

Figure 7.2: Example of ELCC Saturation Effect for Energy Storage (Does Not Represent PSE's System)



The first tranche of energy storage produces a lot of energy during peak demand hours, corresponding to having a relatively high ELCC. However, as one adds more energy storage, the net peak demand (load minus energy storage generation) flattens and spans a longer period, see Table 7.3. As a result, the ELCC for these later tranches is lower because the storage has already mitigated during the highest peak demand hours but can't contribute the same reliability value longer due to the limited stored energy available to discharge. Demand response resources experience this same saturation effect. The critical difference for demand response is that demand response resources generally have more restrictions on operations, including the number of calls and time between calls, in addition to the length of calls but without a need to charge.

Table 7.3: Storage ELCC Tranches in 2029

Resource	Season	ELCC 1 100 - 1,000 MW (%)	ELCC 2 1,000 – 1,500 MW (%)	ELCC 3 1,500 MW + (%)
Li-ion Battery (2-hour)	Winter	61	18	9
Li-ion Battery (4-hour)	Winter	78	21	10

Resource	Season	ELCC 1 100 - 1,000 MW (%)	ELCC 2 1,000 – 1,500 MW (%)	ELCC 3 1,500 MW + (%)
Li-ion Battery (6-hour)	Winter	86	26	11
Pumped Storage (8-hour)	Winter	92	33	12
Li-ion Battery (2-hour)	Summer	69	31	17
Li-ion Battery (4-hour)	Summer	94	52	15
Li-ion Battery (6-hour)	Summer	98	86	14
Pumped Storage (8-hour)	Summer	99	95	15

2.2. Planning Reserve Margin

The standard practice in the electricity industry is to express the total resource need as a planning reserve margin (PRM). The PRM is the difference between the total resource need and the utility's normal peak load, divided by the utility's normal peak load:

$$Planning\ Reserve\ Margin = \frac{(Total\ Resource\ Need - Normal\ Peak\ Load)}{Normal\ Peak\ Load}$$

The normal peak load is PSE's peak load forecast in MW. This normal peak load forecast is sometimes referred to as a median peak load or a one-in-two peak load because it is estimated such that there is a 50 percent probability of the true peak load being higher than this forecast and a 50 percent probability of it being lower.

The PRM represents the resource need amount beyond the normal peak load that PSE must maintain one-in-two to satisfy the total resource need and the reliability target of 5 percent loss of load probability (LOLP).

3. Resource Adequacy Analysis Results

This section describes the results of the resource adequacy analysis we prepared for this report. First, we present the capacity credit results for existing and contracted resources, representing how much existing and contracted resources contribute toward satisfying the PRM. Next, we present the total resource need and the PRM. The total resource need represents the capacity needed to satisfy PSE's reliability standard, and the PRM represents this amount relative to the median peak load. Lastly, we present the capacity contribution results for new generic resources.

3.1. Capacity Credit of Existing Portfolio

This section provides the capacity credit for all resources in PSE's portfolio, including hydroelectric, thermal, wind, and solar. This section also shows the capacity credit for other contracts and wholesale market purchases. E3 calculated the ELCC resource values for the three climate models and then averaged the results to get the final ELCC values.

3.1.1. Hydroelectric Resources

Puget Sound Energy owns three hydroelectric plants: Upper Baker, Lower Baker, and Snoqualmie Falls. E3 calculated the ELCC for each resource (see Table 7.4). The summer and winter ELCCs are similar for Upper Baker and Lower Baker. However, Snoqualmie Falls is a run-of-river hydroelectric facility; as a result, the ELCC is lower in summer due to lower summer river flows. The ELCC values in 2034 are like those in 2029.

Table 7.4: Effective Load Carrying Capability for PSE-owned Hydroelectric Resources (MW)

Hydroelectric Resources	Nameplate	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Upper Baker Units 1 and 2	107	70	69	77	79
Lower Baker Units 3 and 4	111	67	66	58	60
Snoqualmie Falls	53	39	39	11	12

We also contract with five Mid-C hydroelectric plants on the Columbia River for power. We calculate the capacity contributions based on the Pacific Northwest Coordination Agreement (PNCA) final regulation (see Table 7.5) for these plants. The capacity contributions are PSE's contractual capacity, less losses, encroachment, and Canadian Entitlement. These capacity contributions are the same for winter and summer.

Table 7.5: Capacity Credit for Mid-C Hydroelectric Resources (MW)

Hydroelectric Resources	2029	2034
Mid-C Rocky Reach	313	313
Mid-C Rock Island	121.2	121.2
Mid-C Wells	115	115
Mid-C Wanapum	6.1	6.1
Mid-C Priest Rapids	5	5

The capacity credit for the Mid-C hydroelectric resources is the same for winter and summer.

3.1.2. Thermal Resources

Puget Sound Energy owns several thermal plants. We calculate the capacity credit based on the plant's rating at different temperature levels (see Table 7.6). In winter, the capacity reflects the capacity rating when operating at an ambient temperature of 23 degrees Fahrenheit. In summer, the capacity reflects the capacity rating when operating at an ambient temperature of 96 degrees Fahrenheit. The efficiency of these thermal plants is lower at higher temperatures. As a result, the summer ratings are lower than the winter ratings.

Table 7.6: Capacity Credit for Thermal Resources (MW)

Thermal Plant	Winter	Summer
Encogen	182	149
Ferndale	266	246
Goldendale	315	268

Thermal Plant	Winter	Summer
Mint Farm	320	270
Sumas	137	117
Frederickson CC	134	104
Fredonia 1	117	91
Fredonia 2	117	91
Fredonia 3	63	46
Fredonia 4	63	46
Whitehorn 2	84	65
Whitehorn 3	84	65
Frederickson 1	84	65
Frederickson 2	84	65

Thermal plants can also have forced outages. Although forced outages do not impact the capacity credit assigned to thermal plants, E3 considered forced outages at these plants to determine the system overall resource need and PRM value The forced outage rates vary for each plant and range from 2.31 percent to 11.3 percent.

3.1.3. Wind and Solar

Puget Sound Energy owns and has contracts for power from several wind and solar projects. These projects include Hopkins Ridge Wind, Wild Horse Wind (including an expansion), Klondike Wind, Lower Snake River Wind, Skookumchuck Wind, Golden Hills Wind, Clearwater Wind, Lund Hill Solar, and Wild Horse Solar. E3 calculated the ELCC for wind and solar resources (see Table 7.7). The ELCC for wind resources is higher in winter (28 percent in 2029) than in summer (14 percent in 2029) because PSE's wind projects, in aggregate, output more energy in the winter. Conversely, the ELCC for solar resources in summer (45 percent in 2029) is higher than in winter (7 percent in 2029) because solar projects output more energy in the summer, and better align with peak demand. The ELCC values in 2034 are like those in 2029.

Table 7.7: Effective Load Carrying Capability for Wind and Solar Resources (MW)

Resources	Nameplate MW	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Wind	1,504	428	421	210	217
Solar	150	10	10	67	69

3.1.4. Other Contracts

In addition to the wind and solar contracts discussed in the proceeding section, PSE has several other contracts. We have a 300 MW power exchange contract with Pacific Gas and Electric Company (PG&E). Under this contract, PG&E must provide PSE with 300 MW of power in winter when needed, and PSE must provide PG&E with 300 MW of power in summer when needed. In addition to this contract, we have a few other small contracts.

➔ A full discussion of the contracts is in Appendix C: Existing Resource Inventory.

See E3's ELCC calculation for these contracts in Table 7.8. The ELCC in summer is negative, which means contracts result in a net increase in the overall resource need when included in the portfolio. The PG&E exchange has the most significant influence because PSE is obligated to send PG&E 300 MW of power in summer when needed, which increases PSE's overall summer resource need. Other contracts partially offset this increase. The ELCC in winter is above 350 MW. The ELCC values in 2034 are like those in 2029.

Table 7.8: Effective Load Carrying Capability for Other Contracts (MW)

Resources	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Other Contracts	382	376	-179	-185

3.1.5. Market Purchases

In addition to determining the capacity contribution of PSE's resources, E3 also estimated the ELCC of market purchases (see Table 7.9). These market purchases are how much power is available to purchase from the regional market on a short-term basis. We used the Classic GENESYS and the Wholesale Purchase Curtailment Model (WPCM) to determine the availability of market purchases. We have 2,031 MW of transmission from Mid-C to import power via market purchases, but we also use this transmission to deliver power from the Mid-C hydroelectric plants and Wild Horse Wind project.

The ELCCs show that the ELCC for market purchases is lower in summer than in winter. As discussed in Appendix L: Resource Adequacy, GENESYS and the WPCM model show that the PNW has less generation for us to call on in summer than in winter. Moreover, we project that the PNW will have less generation available in summer 2034 than in summer 2029. As a result, the ELCC for summer declines between 2029 and 2034. The ELCC for winter remains similar in 2034.[5]

Table 7.9: Effective Load Carrying Capability for Market Purchases (MW)

Resources	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Market Purchases	1,440	1,434	961	751

3.2. Total Resource Need and Planning Reserve Margin

E3 quantified the total resource need and PRM necessary to satisfy our five percent of LOLP reliability target (see Table 7.10). E3 first quantified the system's capacity shortfall, representing the additional perfect capacity needed to satisfy the reliability target. The capacity shortfall is higher in summer (1,875 MW in 2029) than in winter (1,272 MW in 2029). Although peak demand is lower in summer, the capacity contribution of resources is much lower in summer. Thermal ratings are lower due to higher ambient temperatures, the ELCC of wind and hydroelectric is lower in summer, the PG&E exchange reduces available capacity, and there are fewer market purchases available in summer.

5 https://www.pse.com/-/media/PDFs/IRP/2023/electric/appendix/21_EPR23_AppL_Final.pdf

These factors result in a more significant capacity shortfall in summer than in winter. The capacity shortfalls grow in both seasons as the load increases, but there are more in summer due to greater load growth.

E3 then calculated the total resource need. The total resource need is the sum of capacity contributions across all resources plus the additional perfect capacity needed. The total resource need is higher in winter (6,319 MW in 2029) than in summer (5,329 MW in 2029).

Lastly, E3 calculated the PRM. The PRM percentage is similar across seasons and years, ranging from 26 percent to 28 percent. The key factors influencing the PRM are load variability (beyond the median peak load), operating reserve requirements, thermal forced outages, and Mid-C hydroelectric performance (relative to its capacity contribution).

Table 7.10: Total Resource Need and Planning Reserve Margin (MW)

Resource(s)	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Thermal Plants	2,050	2,050	1,688	1,688
Mid-C Hydro	560	560	560	560
Wind, Solar, Baker, Other Contracts	997	981	244	252
Market Purchases	1,440	1,434	961	751
Additional Perfect Capacity Need	1,272	1,746	1,875	2,856
Total Resource Need	6,319	6,771	5,329	6,107
Median Peak Load	5,004	5,382	4,171	4,831
Planning Reserve Margin	26%	26%	28%	26%

In this analysis, we used one-in-two (P50) peak load forecast to calculate the planning reserve margin.

➔ See Appendix L: Resource Adequacy for more details on peak-load forecast.

3.3. Effective Load Carrying Capability for Incremental Resources

E3 evaluated the capacity contribution of incremental resources to PSE's current resource portfolio. These resources reflect a wide range of resource options, including in-state and out-of-state renewable resources, distributed solar resources, energy storage, demand response, hybrid, and thermal resources.

These resources do not represent specific wind or solar projects bid to PSE through a resource procurement. Instead, they are generic resource options that PSE would expect to receive in future procurements. We considered these generic options in our long-term portfolio analysis, and these capacity contribution values serve as inputs to the portfolio selection.

3.3.1. Generic Wind and Solar Resources

E3 calculated the ELCC for eight wind, two distributed solar, and five utility-scale solar resources (see Table 7.11). These ELCC values are the capacity contribution for the first 100 MW of incremental capacity added to PSE's system; the ELCC would be different if we added more than 100 MW to the system, as discussed in Appendix L.

In general, the ELCC for wind is higher in winter than in summer, and the ELCC for solar is higher in summer — seasonal generation patterns for these resources. The ELCC differs by location, reflecting differences in average generation and the timing of that generation. The ELCC is higher for resources with higher generation levels when PSE's system has a greater capacity need.

➔ See Appendix L: Resource Adequacy for details about the resource groups and saturation curve for the generic resource.

Table 7.11: Effective Load Carrying Capability for Generic Wind and Solar Resources (First 100 MW)

Resource	Resource Type	Winter (%)	Summer (%)
British Columbia	Wind	34	13
Idaho	Wind	1	1
Montana Central	Wind	39	27
Montana East	Wind	32	19
Offshore	Wind	32	41
Washington	Wind	13	5
Wyoming East	Wind	52	34
Wyoming West	Wind	39	34
Distributed Ground Mount	Distributed Solar	4	28
Distributed Rooftop	Distributed Solar	4	28
Idaho	Utility-scale Solar	8	38
Washington East	Utility-scale Solar	4	55
Washington West	Utility-scale Solar	4	53
Wyoming East	Utility-scale Solar	11	29
Wyoming West	Utility-scale Solar	10	28

3.3.2. Generic Energy Storage ELCC Saturation Curves

We asked E3 to model the ELCC of four types of energy storage resources (see Table 7.12). There are three lithium-ion battery storage resources, with two-hour, four-hour, and six-hour durations, and one eight-hour pumped hydroelectric storage resource. The duration metric specifies the amount of time a storage resource can continuously discharge at its rated capacity when fully charged. For example, a fully charged 100 MW Lithium-ion Battery (four-hour) can discharge at 100 MW for four consecutive hours. The roundtrip efficiency metric specifies the amount of energy conserved when charging and discharging a battery. The forced outage rate, like thermal resources, specifies the probability that a storage resource goes on a forced outage.

Table 7.12: Generic Energy Storage Resources

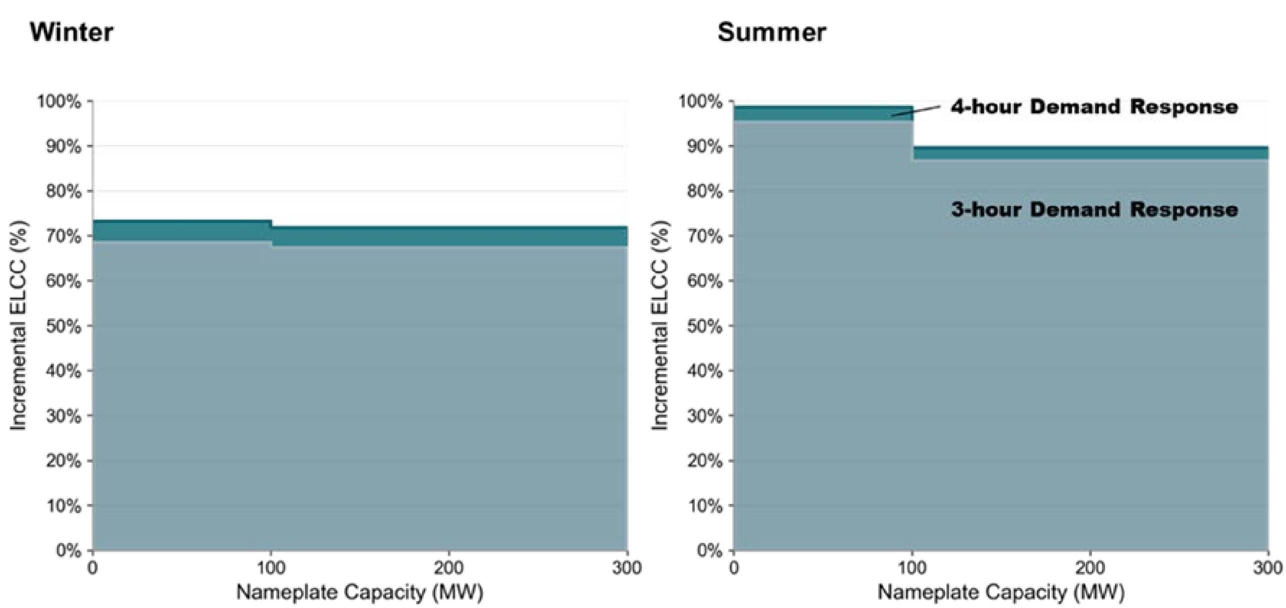
Resources	Technology	Duration	Roundtrip Efficiency (%)	Forced Outage Rate (%)
Lithium-ion Battery (2-hour)	Lithium-ion	2 hours	86	2
Lithium-ion Battery (4-hour)	Lithium-ion	4 hours	87	2
Lithium-ion Battery (6-hour)	Lithium-ion	6 hours	88	2
Pumped Storage (8-hour)	Pumped hydroelectric storage	8 hours	80	1

3.3.3. Generic Demand Response ELCC Saturation Curves

E3 calculated the ELCC saturation curves for two types of generic demand response programs: one with maximum three-hour call durations and another with maximum four-hour call durations (see Figure 7.3). E3 calculated two tranches for demand response: 0–100 MW and 100–300 MW. For both programs, we limited the number of calls to 10 in winter and 10 in summer. Also, PSE cannot call the same demand response program more than once in six hours.

As for storage, the ELCC of demand response diminishes with increasing penetration as the limited duration becomes less effective at addressing PSE's reliability needs at higher penetration levels. The ELCC for demand response is lower in winter than in summer because the duration of loss of load events is longer.

Figure 7.3: Effective Load Carrying Capability Saturation Curves for Demand Response Resources



3.3.4. Generic Hybrid Resources

PSE directed E3 to model the ELCC of four types of hybrid resources (see Table 7.13). We assumed that these hybrid resources would be in Washington State. The solar resource is Washington East Solar, the wind resource is Washington Wind, and the storage resource is Lithium-ion Battery Storage (four-hour). For each hybrid resource, we assumed that the renewable and storage resources would share the same interconnection. If the interconnection capacity is less than the capacity of the renewables plus the capacity of the storage, then this could limit how much power a hybrid resource can provide to PSE's system during some hours. Project developers often locate hybrid resources behind the same interconnection to reduce overall costs. For the Solar + Storage (Restricted Charging) resource, the battery storage resource can only charge from onsite renewable energy. The battery storage resource can charge from onsite renewable energy or the grid for other hybrid resources.

Table 7.13: Generic Hybrid Resources

Resources	Interconnection MW	Solar MW	Wind MW	Storage MW
Solar + Storage	100	100	-	50
Solar + Storage (Restricted Charging)	100	100	-	50
Wind + Storage	100	-	100	50
Solar + Wind + Storage	200	100	100	50

3.3.5. Generic Thermal Resources

In addition to calculating the ELCC of dispatch-limited resources, E3 also calculated the ELCC of three types of generic thermal resources (see Table 7.14). Three factors influence the capacity contribution of these resources: ambient temperature efficiency ratings, forced outage rates, and unit size.

PSE determined the capacity ratings of these units by season using the same ambient temperatures used for existing thermal plants. The summer rating is lower than the winter rating for combined cycle combustion turbine and frame combustion turbine units. The reciprocating internal combustion engines have the same efficiency ratings in the summer and winter.

Table 7.14: Effective Load Carrying Capability for Generic Natural Gas Resources

Resource	Nameplate Winter (MW)	ELCC Winter (%)	Nameplate Summer (MW)	ELCC Summer (%)
Combined Cycle	367	84	310	92
Frame Turbine	237	96	184	98
Reciprocating Engine	18	96	18	96

4. Market Risk Assessment

Puget Sound Energy has relied on short-term market resources to fill less than 1,500 MW of transmission capacity for more than 15 years. The total firm transmission contracts are 2,030 MW to Mid-C; we then subtract the transmission needed for resources at the Mid-C, which comes to less than 1,500 MW of available transmission left for short-term market purchases. See Appendix C: Existing Resource Inventory for the breakdown of transmission contracts. Relying on the surplus capacity of others in the region was a reasonable strategy when the region had significant surplus peak capacity. Experts predict the region soon will have no significant surplus peak capacity. They expect the region will be short of physical capacity, even under very conservative assumptions. Continuing to rely on short-term market purchases creates physical and financial risks for PSE's customers and shareholders. We need to adapt to changing market conditions.

4.1. Reduce Market Reliance

Due to the growing regional concerns about capacity in the short-term market and our interest in joining the WRAP, we will phase out reliance on short-term market purchases as we make plans to ramp into the WRAP. We reduced market reliance by more than 200 MW per year starting in 2024 and reached zero reliance by 2029 in this report.

Table 7.15 shows the ELCC adjustment to market reliance from E3's models but is not the final market reliance we used in the capacity expansion modeling described in Chapter Eight: Electric Analysis. We phased the market reliance for peak capacity down over time reaching zero by 2029.

Table 7.15: Effective Load Carrying Capability Adjusted MW of Market Reliance from E3 Model

Adjustment	Nameplate	Winter 2029	Summer 2029	Winter 2034	Summer 2034
Transmission Capacity	2,030	2,030	2,030	2,030	2,030
Resources at Mid-C	(512)	(512)	(512)	(512)	(512)
ELCC Adjustments	0	(78)	(557)	(84)	(767)
Total Available Transmission	1,518	1,440	961	1,434	751

4.2. Changing Regional Resource Adequacy

Numerous studies and articles highlight regional resource adequacy concerns. Three respected industry-based organizations periodically issue studies about resource adequacy in the Northwest and have recently raised critical concerns. The North American Electric Reliability Corporation (NERC)[6] studies regional entities and assessment areas, including WECC-NWPP-US & RMRG (Western Interconnection, Northwest Power Pool, and Rocky Mountain Reserve Sharing Group). The Western Electricity Coordinating Council (WECC)[7] evaluates resource adequacy across the entire western interconnection (WECC) and within five subregions, including NWPP-Northwest. The Pacific Northwest Utilities Conference Committee (PNUCC)[8] covers the Northwest regional planning area. All three organization's reports cover a ten-year horizon. Across the West, utilities plan to retire nearly 26 GW coal and natural gas resources over the next decade. Each of their most recent reports concluded that demand and resource variability is increasing rapidly, creating challenges for the bulk power system to provide reliable supply in the near

[6] 2021 Long-term Reliability Assessment, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf

[7] 2021 Western Assessment of Resource Adequacy" ("WARA"), https://www.wecc.org/Administrative/WARA%202021.pdf

[8] 2022 Northwest Regional Forecast, https://www.pnucc.org/wp-content/uploads/2022-PNUCC-Northwest-Regional-Forecast-final.pdf

term. The WECC put it most directly, stating, "As early as 2025, all subregions (of the WECC) will be unable to maintain 99.98 percent reliability because they will not be able to reduce the hours at risk for loss of load enough, even if they build all planned resource additions and import power."[7] The PNUCC concluded, "The annual energy picture reveals a regional resource deficit by next year (2023), which is three years earlier than last year's estimate."[8] And NERC determined, "The two largest U.S. assessment areas in the Western Interconnection — California/Mexico and the Northwest-Rocky Mountain — have the potential for high load-loss hours and energy shortfalls for 2022 and beyond."[6]

While each organization approached the analysis using its own assumptions and methodologies, some common themes emerge on what is driving the increase in variability:

- Government policies and consumer sentiment are accelerating the move to clean energy
- More frequent and extreme weather events due to climate change
- Retirement of baseload resources and the addition of variable energy resources

Traditional resource adequacy approaches have been based solely on capacity, which worked well when most generation assets were dispatchable and demand was more predictable. The peak capacity shortfall typically occurred during the annual peak capacity hour. In today's climate, however, the drivers affecting the generation and load variability can lead to critical capacity shortfalls that do not coincide with peak demand. Focusing only on capacity fails to account for this variability fully. The PNUCC Northwest Regional Forecast (NRF) is the best source for detailed information on this topic.

$$
\begin{aligned}
&NRF \\
&= \sum (Utility\ loads\ with\ planning\ reserve\ margin) \\
&- (resource\ forecasts\ for\ those\ owned\ \&\ contracted\ by\ utilities) \\
&+ (resource, conservation, demand\ response\ additions\ based\ on\ their\ IRPs)
\end{aligned}
$$

Table 7.16 shows that even with very conservative adjustments to the NRF, we expect the region to be significantly short in the winter of 2029 and extremely short of capacity in the summer of 2029. We made two adjustments to the winter for the following factors:

- Independent Power Purchaser (IPP) Generation: PSE's market survey shows 1,697 MW of IPP resources available today. It may not be reasonable to assume those resources will be uncontracted as the region considers entering the WRAP, but we included those here to be conservative.
- Southwest Imports: The Northwest Power and Conservation Council's Classic GENESYS model assumed 3,400 MW of imports from California would be available to the Pacific Northwest. As California electrifies transportation and buildings, those imports may not be available. We included them in this table to ensure a conservative perspective.

Table 7.16: Adjusted NRF Table Regional Capacity Short Position (MW)

PNUCC - Northwest Regional Forecast	Winter 2029	Summer 2029	Winter 2034	Summer 2034
PNUCC — Regional NRF Short	4,830	5,240	6,060	5,950

PNUCC - Northwest Regional Forecast	Winter 2029	Summer 2029	Winter 2034	Summer 2034
Identified Available Firm Resources in the Region (Operational)	1,700	-	1,700	-
California Imports	3,400	-	3,400	-
Net Regional Shortage	(270)	5,240	960	5,950

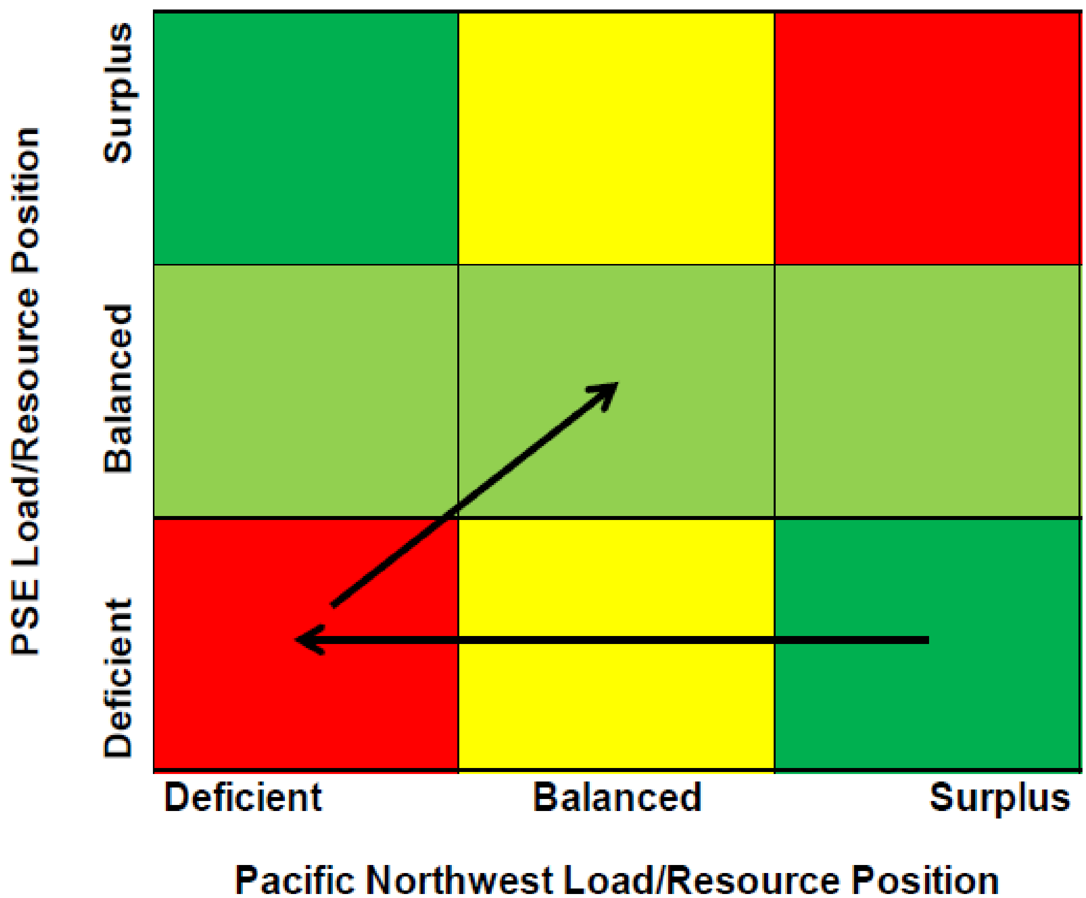
Note: PNUCC data not provided past 2031. PNUCC numbers for 2033 provided from the latest year available.

Table 7.16 highlights that the region will be short on peak capacity even with questionable assumptions on IPP resources and California imports.

4.3. Change Strategic Position

The risk matrix shown in Figure 7.4.provides an illustration of capacity position risk. When the region is surplus, it is prudent for PSE to be physically short — as illustrated by the box in Figure 7.4 with an 'X' below. In that scenario, we manage the financial risk, but we did not have to build unnecessary physical generation capacity. However, as the region grows short of capacity, PSE would shift to the 'Y' box, creating a physical and financial risk. Even if we can hedge the financial risk of relying on short-term market capacity resources, the physical reliability risk may not be manageable. We may not need to build resources to fill that entire market position, though. Puget Sound Energy could sign longer-term contracts to fill this position, if these options are available and do not leave the position to the short-term market. We must move to at least the balanced position in Figure 7.4 for our resource adequacy position going forward.

Figure 7.4: Capacity Position Risk Matrix



4.4. Market Reliance

The 2023 Electric Report reduces our reliance on the short-term market, eventually bringing market reliance to zero by 2029, as reflected in Table 7.17.

Table 7.17: Perfect Capacity Adjusted to Eliminate Short-Term Market Reliance (MW)

Resource	Winter 2029	Summer 2029	Winter 2034	Summer 2034
Mid-C Hydro	560	560	560	560
Thermal	2,050	1,688	2,050	1,688
All other resources	997	244	981	252
Short-term Market Purchases	-	-	-	-
Additional perfect capacity for 5% LOLP	2,712	2,836	3,180	3,607
Total Resources	6,319	5,329	6,771	6,107

5. Adjustments for Portfolio Analysis

Resource adequacy is an upstream study for the 2023 Electric Report. The resource adequacy analysis calculated planning reserve margin and resource ELCCs modeled in the AURORA database to perform long-term expansion planning and hourly dispatch. The long-term capacity expansion (LTCE) and hourly dispatch optimize new builds and mimic the hourly operation of the existing resources and new builds. New to the 2023 Electric Report is the winter and summer planning reserve margin. We included only the winter planning reserve in the AURORA model in previous IRPs. Starting with the additional perfect capacity for 5 percent LOLP provided by E3, we made minor adjustments to consider more current assumptions for existing resources' ELCC contribution and to eliminate short-term market reliance. We used the resulting seasonal PRM as an input to the AURORA model to serve as a target in the long-term capacity expansion when determining new resource alternatives.

Seasonal resource ELCCs are also new in the 2023 Electric Report and reflect existing and new resources in the AURORA model. In addition, the renewable resource and storage ELCC saturation effect represented by multiple tranches added model complexity and increased run-time significantly. AURORA evaluates new resources for each of the available builds for the year, so the model ends up with a large matrix of all the resource options and costs, contributing to the long run time. A review of the AURORA model study log shows that storage scheduling also contributes to the extended run time. To manage the large-scale optimization problem run-time and meet the IRP study needs, we adjusted new resource ELCCs, consolidating from six tranches to three.

➔ See Appendix L: Resource Adequacy for additional information on new resource ELCC aggregation.

6. Western Resource Adequacy Program

The Western Resource Adequacy Program (WRAP)[9] is a compliance-based framework designed to increase regional reliability at a reduced cost for participants. The Western Power Pool (WPP) and a steering committee comprised of western region market participants have proposed a design for a capacity-based RA program. This voluntary program

[9] https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

establishes a standardized way to approach the resource adequacy problem across twenty-six regional entities (participants) in the west, with an estimated combined peak load of 65,000 MW.

The WPP conducted an extensive public outreach process over the past few years to create a governance structure to give interested parties a voice in decision-making. Each entity conducts its regional planning and procurement to meet capacity RA. Each Load Responsible Entity (LRE) has its methods for calculating peak load, generation and transmission requirements, and capacity contribution. The LRE management approves new resources, which regulators regulate relative only to that LRE's need. Without transparency and coordination, LREs collectively may rely on market purchases relative to available capacity. Additionally, in the absence of regional coordination, the footprint's capacity could be contracted to other regions experiencing ever-growing capacity shortfalls or may not be scheduled in such a way as to meet the needs of participants within the footprint during capacity critical hours (CCH).

The individualized nature of the current planning framework can make it difficult for regulators, board members, interested parties, and utilities to understand whether, where, and when the region needs new capacity. The WRAP will increase visibility in the region's resources and transmission and help participants coordinate to fill these gaps collectively as they plan for the future.

The main components of the WRAP compliance framework are the forward showing program (FS) and the operational program (Ops Program) for both winter and summer seasons. These programs seek to balance reasonably conservative planning and the flexibility to protect customers from unreasonable costs.

The FS program establishes regional metrics for various resources' footprint and qualifying capacity contribution (QCC) values, sets deliverability expectations, and determines planning windows for demonstrating adequacy. Participants are required to show that they have contracted for the necessary amount of capacity resources to meet a P50 event plus a PRM. Participants must also demonstrate they have firm transmission rights to deliver at least 75 percent of their FS resources. The FS deadline for demonstrating adequate capacity and transmission is seven months before the beginning of each summer or winter season. The first binding season that a participant may elect is summer 2025. Participants must commit to go binding by summer 2028 to continue in the program.

The Ops program creates a framework to provide participants with pre-arranged access to capacity resources in the program footprint when a Participant is experiencing an extreme event, such as excess load or forced outages.

A key benefit of the WRAP is the ability to leverage the region's load and resource diversity so LREs can carry less PRM during the FS planning window than they would on a stand-alone basis. The Ops program allows participants to collectively manage the risk of capacity shortfall by prescriptively sharing available capacity and deliverability plans.

6.1. Planning Reserve Margin and Effective Load Carrying Capability

We ran a WRAP sensitivity analysis to see how the portfolio for this report would change if we used the WRAP metrics instead of the resource adequacy metrics we developed with E3.

➔ See Appendix L: Resource Adequacy for details regarding the methodology and approach the WPP used.

Table 7.18 WRAP Provided PSE Capacity Need (MW) 2029

Sensitivity	Winter 2029	Summer 2029
One-in-two Peak	4,570	3,447
PSE Planning Reserve Margin	21%[a]	14%[a]
Balancing Reserves	132	122
Less Existing Resources	(3,120)	(2,343)

Note:

a. WRAP PRM percent is an estimate.

Table 7.18 shows the estimated seasonal planning reserve margin and peak capacity shortfall in 2029. Additional resources will fill the peak capacity needs. Table 7.19 shows the resources seasonal peak capacity contribution, by ELCC. The WRAP footprint is split into two solar ELCC zones and 5 wind ELCC zones. The generic solar resources are in Zone Solar VER 1, which contains Northern states in the West, including Washington, Oregon, Idaho, Montana, and Wyoming. Generic wind resources are distributed in 5 wind zones as shown in Table 7.19.

Table 7.19 WRAP Provided ELCCs for 2029

Resource	Winter 2029	Summer 2029	WRAP Wind/Solar Zone
British Columbia Wind	25%	20%	Wind VER 5
Idaho Wind	31%	17%	Wind VER 2
Montana Central Wind	27%	13%	Wind VER 3
Montana East Wind	27%	13%	Wind VER 3
Offshore Wind* (E3's number)	31%	17%	Wind VER 2
Washington Wind	10%	18%	Wind VER 1
Wyoming East Wind	31%	15%	Wind VER 4
Wyoming West Wind	31%	15%	Wind VER 4
DER Ground Mount Solar	3%	23%	Solar VER 1
DER Rooftop Solar	3%	23%	Solar VER 1
Idaho Solar	3%	23%	Solar VER 1
Washington East Solar	3%	23%	Solar VER 1
Washington West Solar	3%	23%	Solar VER 1
Wyoming East Solar	3%	23%	Solar VER 1
Wyoming West Solar	3%	23%	Solar VER 1
Pump Storage	100%	100%	N/A
Nuclear	99%	99%	N/A
Li-ion Battery (2-hour)	40%	40%	N/A
Li-ion Battery (4-hour)	80%	80%	N/A
Li-ion Battery (6-hour)	100%	100%	N/A

Resource	Winter 2029	Summer 2029	WRAP Wind/Solar Zone
100 MW Washington Solar East Solar + 50 MW 4-hour Li-ion Battery	43 MW	63 MW	N/A
100 MW Washington Wind + 50 MW 4-hour Li-ion Battery	50 MW	58 MW	N/A
100 MW Washington Solar East + 100 MW Washington Wind + 50 MW 4-hour Li-ion Battery	5 54MW	81 MW	N/A
200 MW Montana Wind Central + 100 MW 8-hour PHES	154 MW	126 MW	N/A
Frame Turbine	100%	91%	N/A
Reciprocating Engine	N/A	N/A	N/A
Combined Cycle	86%	80%	N/A

ELECTRIC ANALYSIS
CHAPTER EIGHT

PUGET SOUND ENERGY

Contents

1. Introduction

Results of the electric analysis in Puget Sound Energy's (PSE's) 2023 Electric Progress Report (2023 Electric Report) from the following four-step process are illustrated in Figure 8.1. We described steps one, two, and three in detail in this chapter. We discussed step four in detail in Chapter Three: Resource Plan of the 2023 Electric Report.

Step 1. Establish Resource Needs

We identified three types of resource needs: peak capacity, energy, and CETA-renewable and non-emitting resource needs. Chapter Seven: Resource Adequacy Analysis presents our resource adequacy analysis for the peak need. Appendix C: Existing Resource Inventory describes the existing electric and CETA-eligible resources. Chapter Six: Demand Forecast shows the demand forecast we used to establish the resource needs.

Step 2. Determine Planning Assumptions and Identify Resource Alternatives

In this chapter, we discussed the reference portfolio and sensitivities developed for the 2023 Electric Report. Chapter Five: Key Analytical Assumptions presents the key analytical assumptions and a description of the sensitivities. Appendix D: Generic Resource Alternatives describes electric resource alternatives in detail.

Step 3. Analyze Alternatives Using Deterministic Portfolio, Portfolio Benefit Analysis Tool, and Stochastic Risk Analyses

The deterministic analysis identifies the least-cost mix of demand-side and supply-side resources that will meet needs, given the static assumptions defined in the scenario or sensitivity. We analyzed all scenarios and sensitivities using deterministic optimization analysis.

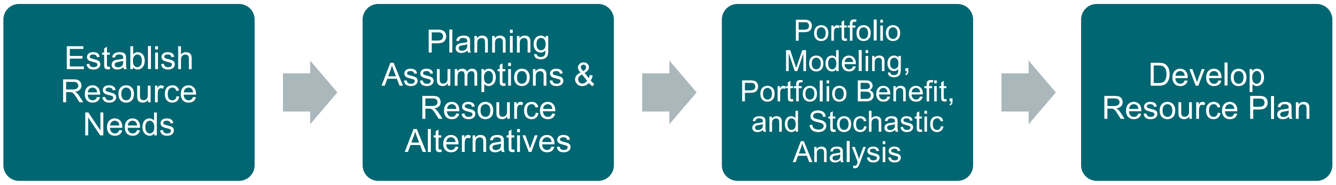
The portfolio benefit analysis tool helps support our understanding of equity-related benefits and the associated costs within each portfolio and informs our work as we strive to select a portfolio best suited to equitable outcomes for customers while also considering cost.

Stochastic risk analysis deliberately varies the static inputs to the deterministic analysis to test how the different portfolios developed in the deterministic analysis perform concerning cost and risk across a wide range of possible future power prices, gas prices, hydroelectric generation, wind generation, loads, and plant forced outages. We analyzed the reference and preferred (sensitivity 11 B2) portfolios using stochastic risk analysis.

Step 4. Develop Resource Plan

We studied the deterministic analysis, the portfolio benefits tool analysis, and the stochastic quantitative analysis results to understand the key findings that led to decisions for the preferred portfolio. We presented the analysis results in this chapter and Appendix H: Electric Analysis and Portfolio Model. Chapter Three: Resource Plan presents the resource plan decisions.

Figure 8.1: 2023 Electric Progress Report Process



2. Clean Energy Transformation Act

The 2021 Integrated Resource Plan (IRP) marked a significant departure from past IRPs due mainly to the passage of the Clean Energy Transformation Act (CETA). The new electric progress report rules, WAC 480-100-625,[1] outline the requirements for this report. Utilities must file a progress report at least every two years after the utility files its IRP, beginning January 1, 2023.

In this mandated report, the utility must update the following:

- Demand forecast
- Demand-side resource assessment, including a new conservation potential assessment
- Resource costs
- The portfolio analysis and preferred portfolio

The progress report must also update for any elements found in the utility's current clean energy implementation plan, as described in WAC 480-100-640.[2] The progress report must also include other updates necessary due to changing state or federal requirements or significant economic or market forces changes.

2.1. Demand Forecast

Puget Sound Energy's 2023 Electric Progress Report incorporates climate change in the base energy and peak demand forecast for the first time. Before this report, we used temperatures from the previous 30 years to model the expected normal temperature for the future. We then held this normal temperature constant for each future model year. This old approach was a common utility practice but did not recognize predicted climate change, which experts expect will increase temperatures, on average, over time.

> Puget Sound Energy incorporated climate change into the demand forecast for the first time in this report. We heard from interested parties that climate change is important to incorporate because it affects future demand and needs, and PSE agrees. We included climate change in the base demand forecast and the stochastic scenarios.

We know the methodology for incorporating climate change in this report is the first step, and we expect it will evolve. We heard from interested parties that incorporating climate change into demand forecasting is a high priority. Puget Sound Energy provides energy for heating in the winter and cooling in the summer. It is essential to consider climate change in resource planning because of the warming trends that we expect will likely lead to, on average, less heating demand in winter and more cooling demand in summer.

1 WAC 480-100-625
2 WAC 480-100-640

Climate scientists recently developed climate model projections for the region, which we will use to calculate a normal temperature assumption that reflects climate change. We also updated the peak demand forecast, which results in normal peak temperatures for summer and winter that increase over time.

We expect electric energy demand to grow at an average annual growth rate (AARG) of 1.8 percent from 2024 to 2045 before the additional demand-side resources (DSR) we identified in the 2023 Electric Report's base demand forecast. This growth rate increased our forecast from 2,551 average megawatts (aMW) in 2024 to 3,699 aMW in 2045, faster than the 1.2 average annual energy growth rate forecasted in the 2021 IRP.

➔ See Chapter Six: Demand Forecast and Appendix F: Demand Forecast Models for details regarding how PSE incorporated climate change into our demand forecast.

2.2. Demand-side Resources

We analyzed DSR alternatives in a conservation potential assessment (CPA) and demand response assessment to develop the supply curve we used as input to the portfolio analysis. The portfolio analysis then determined the potential maximum energy savings captured without raising the overall electric or natural gas portfolio cost. This analysis identified the DSR's cost-effectiveness level to include in the portfolio.

➔ The CPA updated for the 2023 Electric Report is in Appendix E: Conservation Potential and Demand Response Assessments.

Overall, the 2023 Electric Report CPA potential is down from the 2021 IRP by about 13 percent by 2045. Several updates and new data elements contributed to the reduced potential:

- The CPA incorporated a statutory provision requiring the state to adopt more efficient building energy codes to achieve a 70 percent reduction by 2031. This change in the CPA moved some of the potential from energy efficiency into codes and standards.
- The newly incorporated impact of climate change reduced savings in the later years of the study
- Updated building stock assessments, which have more efficiency penetration compared to the last stock assessment
- Updated savings from the most recent biennium program cycle

The CPA potential is also down in the 2023 Electric Report because of the following factors:

- Climate change reduced the normal winter peaks, thereby reducing the contribution of savings at the peak
- Updated conservation measure load shapes to align with the Northwest Power and Conservation Council's 2021 Power Plan[3]

3 https://www.nwcouncil.org/2021-northwest-power-plan/

- Updated PSE's system peak definition to reduce the morning and evening windows for very heavy load hours[4]

Demand response peak savings increased due to updates we made to the potential to align with the 2021 Power Plan and an increase in the transmission and distribution deferrals costs.

2.3. Resource Costs

Like the 2021 IRP, we aggregated publicly available generic resource costs from several sources, predominantly from the National Renewable Energy Laboratory's (NREL) 2022 Annual Technology Baseline.[5] We expect generic resource capital costs to decline as technological advances push costs down. The declining cost curves we applied to different resource alternatives came from the National Renewable Energy Laboratory (NREL) 2022 Annual Technology Baseline (ATB).

➔ A breakdown of the updated generic resource costs is in Chapter Five: Key Analytical Assumptions, with details in Appendix D: Generic Resource Alternatives.

2.4. Portfolio Analysis and Preferred Portfolio

We updated the portfolio analysis for the 2023 Electric Report. The assumptions and documentation of the model are in Chapter Five: Key Analytical Assumptions and Appendix H: Electric Analysis and Portfolio Model. The analysis results are later in this chapter, and we discussed the preferred portfolio in Chapter Three: Resource Plan.

2.5. State and Federal Requirements

Policy changes in the energy industry in Washington State and the United States have rapidly increased in the last decade. The following are the key policy changes impacting this report.

2.5.1. State Laws and Regulations

At the state level, PSE incorporated rules from the Climate Commitment Act (CCA), the Clean Energy Transformation Act (CETA), the Clean Energy Implementation Plan (CEIP), and new building codes.

2.5.2. Federal Laws

The Inflation Reduction Act (IRA) became law in August 2022. The two main incentives in the act applicable to PSE'S resource costs are the Production Tax Credits (PTCs) and Investment Tax Credits (ITCs). The IRA provides more long-term certainty in investment decisions by providing 10 years of energy tax incentive eligibility and

[4] In the 2021 IRP, we estimated the peak contribution from energy efficiency savings between peak hours, defined as: weekdays from hour ending (HE) 7–11 a.m. (6–11 a.m.) and HE 6–10 p.m. (5–10 p.m.); in the 2023 IRP this was updated to HE 8–10 a.m. and HE 6–7 p.m.

[5] https://atb.nrel.gov/

enhanced tools to accelerate or support credit monetization. Where previous tax rules for PTC (wind) and ITC (solar) were technology-specific, the new tech-neutral credit may allow the entity receiving the credit to choose the most efficient incentive type. The rules also provide bonuses for where and how operators build projects. The rules incentivize project developers to utilize domestically sourced materials, drive economic opportunity by placing projects in service in low-income communities, and leverage an existing workforce in census tracts deemed energy communities where new clean energy developments may impact fossil-fuel extraction and generation activities. The full effects of the legislation, once implemented, are not known at this time, but we were able to include some of the known effects of the federal IRA in this report.

Production Tax Credits provide an energy tax credit ($/MWh) for the first 10 years of energy output after a utility places a project in service. Before Congress enacted the IRA, PTCs expired for any new projects placed in service in 2022 and beyond. The IRA bill now extends PTCs to 100 percent for eligible projects in service before the end of 2032. The PTCs are now technology-neutral, so solar projects now qualify for PTC. We assumed PTC for wind and solar resources as the most economical use of the tax incentives.

Investment Tax Credits provide an energy tax credit based on the project's percentage of investment. Before Congress enacted the IRA, the ITC rate for projects placed in service in 2022 had phased down to 10 percent. The IRA increased the ITC rate to 30 percent. Previously, the regulations restricted ITC for battery storage projects to hybrid battery storage projects paired with solar or other renewable energy generation assets. The IRA now extends the ITC to cover all stand-alone energy storage applications. This change makes the system more flexible because the battery can charge from the grid and its paired solar project. We assumed ITC for energy storage resources.

The IRA includes subsidies for utility-scale resources and end-use customer appliances. We do not know how the federal government will implement the subsidies yet, so we cannot incorporate their impact on our customers' behavior. As we learn more about the policies to implement these subsidies, we will reflect the effects in future IRPs.

2.6. Economic or Market Forces

We incorporated the economic and market forces that affect the electric resource plan into the electric and natural gas price forecasts.

2.6.1. Electric Price Forecast

We developed this electric price forecast as part of our 2023 Electric Report. In this context, the electric price is not the rate charged to customers but PSE's price to purchase or sell one MWh of power on the wholesale market, given the prevailing economic conditions. Electric price is an essential input to this analysis since market purchases comprise a substantial portion of PSE's existing resource portfolio. The updated electric price forecast reflects higher avoided energy costs due to updated modeling methodologies and assumptions to the electric price forecast model. The levelized nominal power price for the 2023 Electric Report is $42.90/MWh compared to the 2021 IRP, which was $23.37/MWh.

➔ A detailed account of all updates to the electric price model is in Chapter Five: Key Analytical Assumptions and Appendix G: Electric Price Models.

2.6.2. Natural Gas Price Forecast

The projection for natural gas prices increased between the 2021 IRP and the 2023 Electric Report, particularly in the near term, increasing electric prices. Recent gas prices are elevated due to energy security concerns in Europe and accelerating coal retirements domestically, which leads to additional gas demand for the power sector and demand driven by liquefied natural gas (LNG) export expansion.

➔ We discuss natural gas in further detail throughout Chapter Five: Key Analytical Assumptions.

2.6.3. Alternative Fuels

For this report, we modeled two types of alternative fuels, hydrogen and biodiesel.

Hydrogen

Hydrogen is a highly flexible commodity chemical currently used in a wide range of industrial applications and poised to become a key energy carrier in the power sector. Production tax credits in the IRA reduce the market price of green hydrogen by up to $3 per kilogram, making it a cost-competitive energy carrier. We modeled green hydrogen as a fuel source for existing and new combustion turbines starting in 2030.

Biodiesel

Biodiesel is a renewable resource under RCW 19.405.020(34)[6] of CETA. Biodiesel must not be derived from crops raised on land cleared from old-growth or first-growth forests to be considered renewable. Biodiesel is chemically similar to petroleum diesel but is derived from waste cooking oil or dedicated crops. We modeled biodiesel as a fuel source for new combustion turbines starting in the model year 2024.

➔ Further discussion of hydrogen and biodiesel as fuel sources is in Appendix D: Generic Resource Alternatives.

[6] RCW 19.405.020

2.7. Elements Found in Clean Energy Implementation Plan

In December 2021, we filed our first CEIP. The plan illustrates PSE's four-year roadmap to meet the requirements of CETA and the specific actions PSE will take from 2022–2025 to meet those goals. The CEIP proposes an interim target of serving customers with 63 percent clean, CETA-eligible renewable resources by the end of 2025. We used the 63 percent target from the CEIP as the minimum for this 2023 Electric Report. The resource specific targets included in the CEIP and proposed in this report are:

- 25 MW of Distributed Energy Resources (DER) storage
- 80 MW of DER solar

We also applied certain customer benefit indicators (CBIs) identified in the CEIP that apply to resource planning.

3. Resource Need

Reliably meeting our customers' needs is the cornerstone of PSE's energy supply portfolio. For resource planning, the physical electricity needs of our customers are simplified and expressed as three resource needs: peak hour capacity need, energy need, and renewable and non-emitting energy need.

3.1. Peak Hour Capacity Need

We determined peak hour capacity need with a resource adequacy analysis that evaluated existing PSE resources compared to the projected peak need over the planning horizon. The capacity shown is the amount of effective capacity needed to maintain the resource adequacy target — the need after applying different resources' effective load carrying capacity (ELCC). Due to market reliance assumptions used in this 2023 Electric Report, the modeling indicates PSE could begin to experience a peak capacity shortfall starting in 2024. Before any conservation, the peak capacity need plus the planning margin required to maintain reliability is 2,629 MW by 2029. The 2,629 MW is the difference between the load forecast (the demand forecast plus the required planning margin) and the total peak capacity credit of existing resources. Figures 8.2 and 8.3 show the winter and summer peak capacity needs through 2045.

Figure 8.2: Effective Peak Capacity Need — Winter

(Physical Reliability Need, Peak Hour Need Compared to Existing Resources)

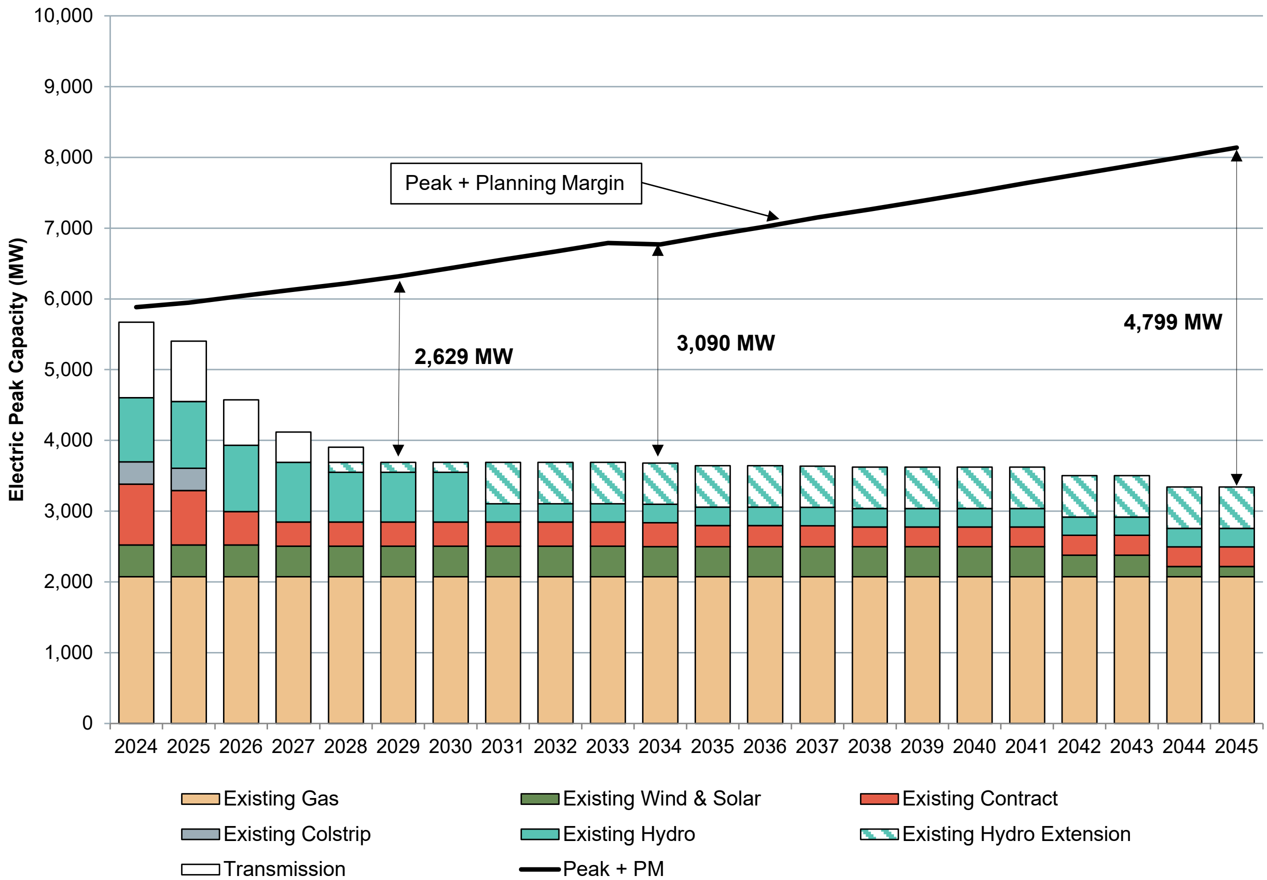
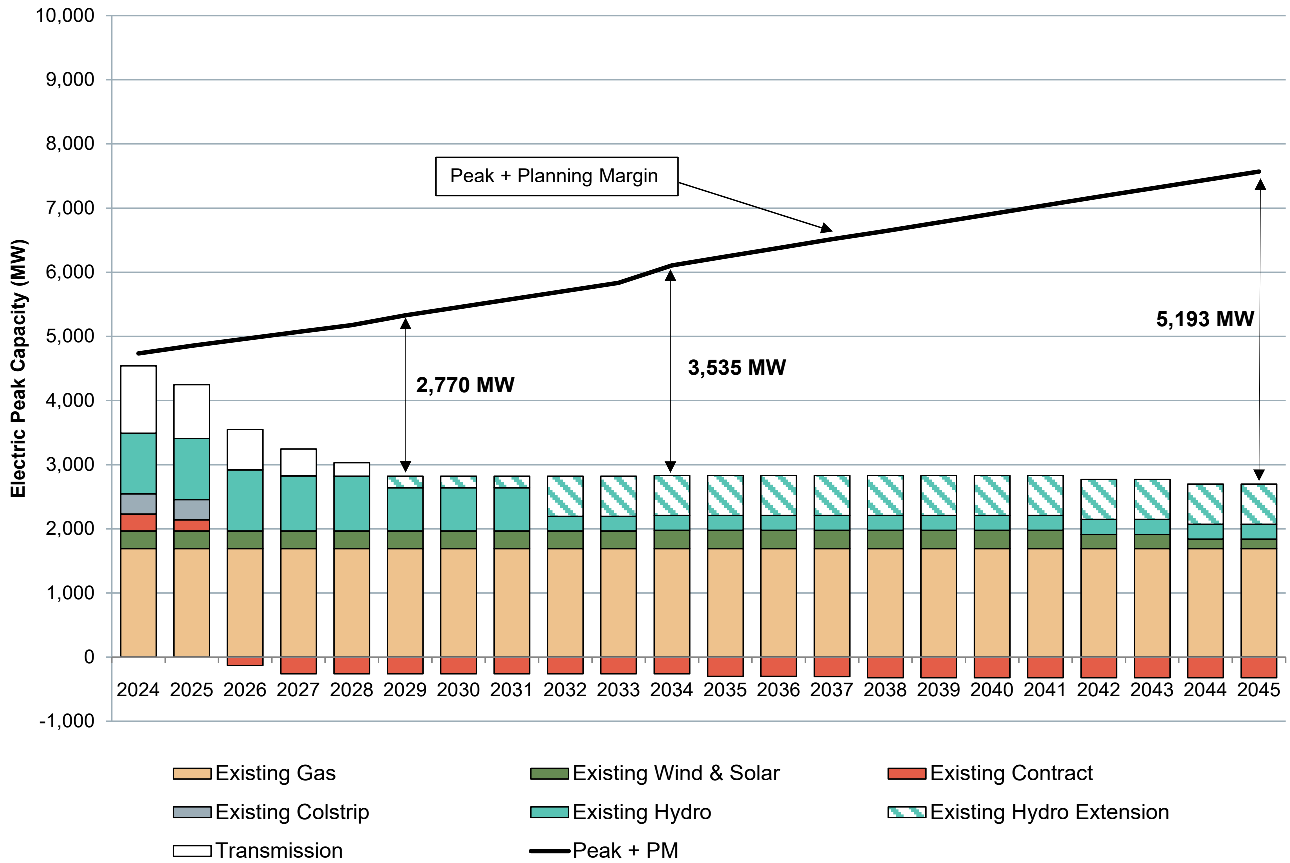


Figure 8.3: Effective Peak Capacity Need — Summer

(Physical Reliability Need, Peak Hour Need Compared to Existing Resources)



➔ See Chapter Seven: Resource Adequacy Analysis for a complete discussion of the resource adequacy analysis.

3.2. Energy Need

We must meet our customers' energy needs 24 hours a day, 365 days a year. Our models require the portfolios to supply the energy necessary to meet physical loads and examine how to do this most economically through existing resources, new resources, and purchasing and selling electricity on the energy market. Puget Sound Energy's annual energy need starts at 2,551 aMW for 2024, increases to 2,799 aMW in 2030, and reaches 3,699 aMW in 2045.

➔ See Chapter Six: Demand Forecast for a detailed discussion on energy demand.

3.3. Renewable and Non-emitting Energy Need

In addition to reliably meeting the physical needs of our customers, CETA requires that utilities meet at least 80 percent of electric sales (delivered load) in Washington State by non-emitting or renewable resources by 2030 and 100 percent by 2045.

Figure 8.4 illustrates PSE's renewable and non-emitting energy need. For the long-term IRP analysis, we assumed a linear ramp to achieve the Clean Energy Transformation Standards Act standards in 2030 and 2045 described in RCW 19.405.040;[7] however, actual resource acquisitions through implementation of the CEIP will likely produce a less linear pathway than we show. Before any conservation, the renewable energy need is over 7 million MWh in 2030 to meet the 80 percent clean energy standard. The renewable need is the difference between the green line and the teal bars in Figure 8.4.

[7] RCW 19.405.040

Figure 8.4: Qualifying Energy Need to Meet CETA Requirements

(Before Demand-side Resources)

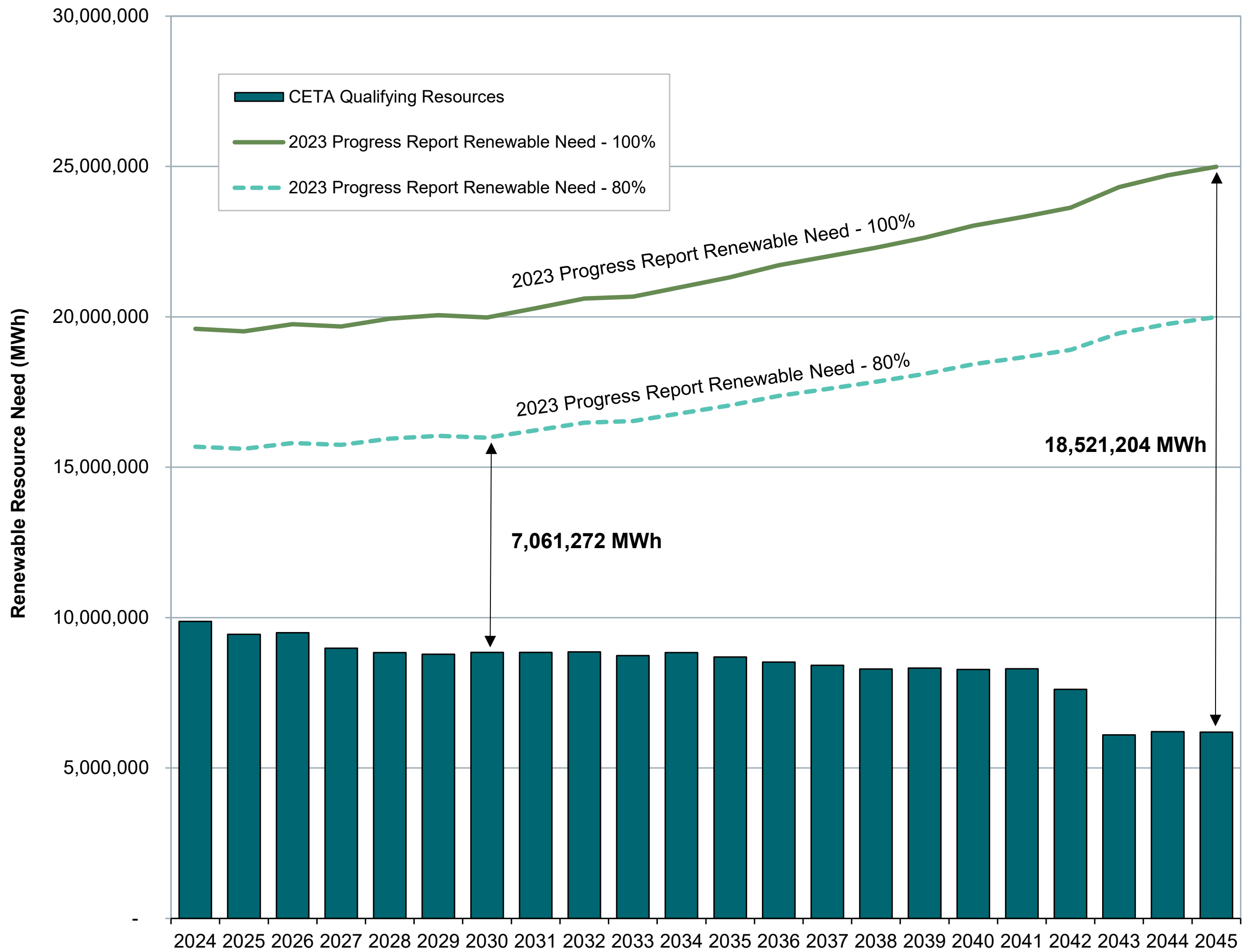
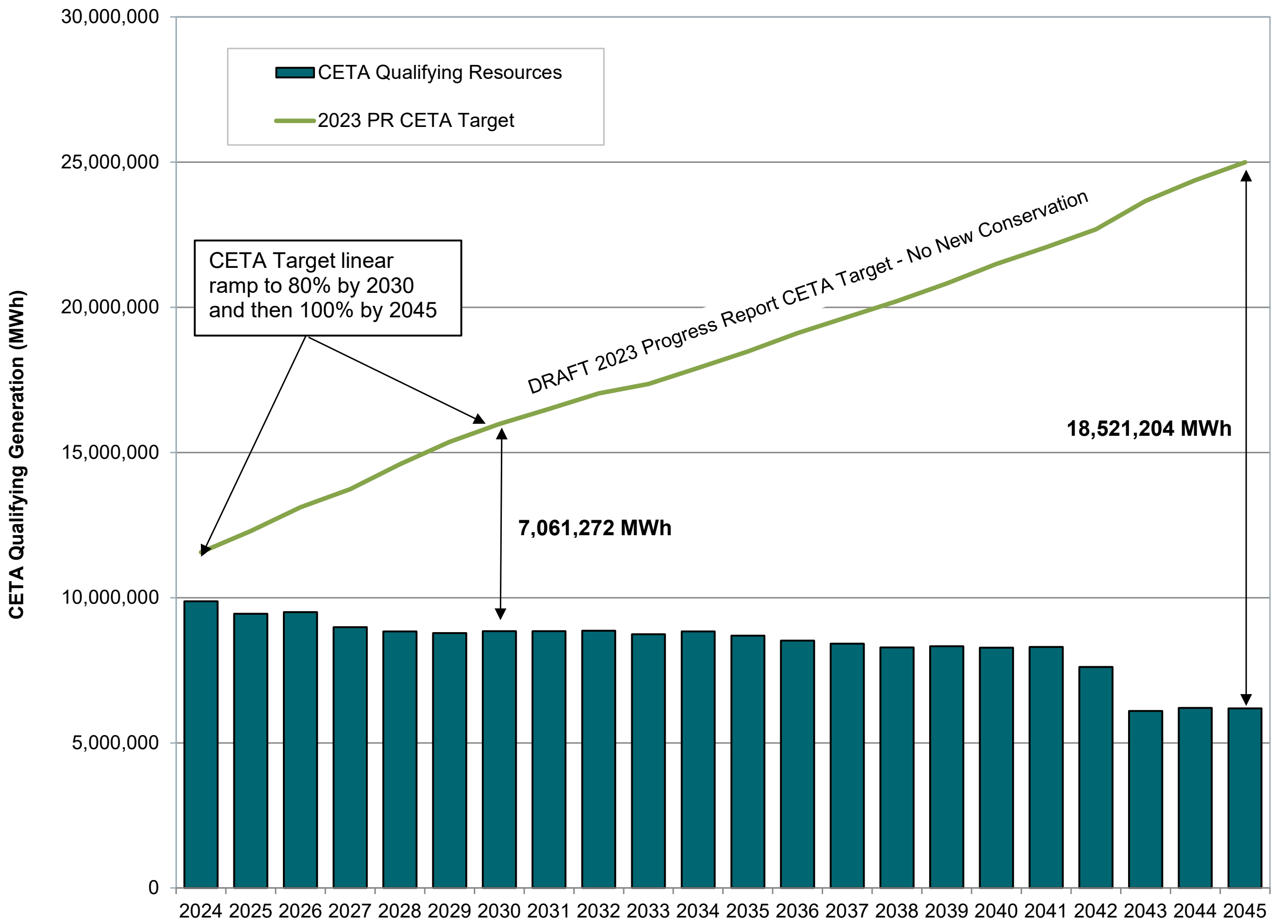


Figure 8.5 assumes a linear ramp to reach the 80 percent clean energy standard in 2030 and the 100 percent clean energy standard in 2045. We used the linear ramp to ensure the portfolio model gradually adds resources to meet clean energy standards rather than waiting until the goal's final target year to add them. The linear ramp starts in 2024, as the model assumes all new resources are self-builds, with most available to begin in 2024.

Figure 8.5: Renewable Need and Linear Ramp for CETA (Before Demand-side Resources)



4. Types of Analysis

We used deterministic optimization analysis to identify each portfolio's lowest reasonable cost. We then ran a stochastic risk analysis to test different resource strategies.[8] We used the portfolio benefit analysis to inform the equitable distribution of burdens and benefits in the resource planning process to ensure all customers benefit from the transition to clean energy.

4.1. Deterministic Portfolio Optimization Analysis

We subjected all the portfolios to deterministic analysis in the first stage of the resource plan analysis. This identifies the least-cost integrated portfolio — the lowest-cost mix of demand-side and supply-side resources that will meet the need under the given static assumptions defined in the scenario or sensitivity. This stage helped us learn how specific input assumptions, or combinations of assumptions, can impact the least-cost mix of resources.

[8] To screen some resources, we also used simpler, levelized cost analysis to determine if the resource is close enough in cost to justify spending the additional time and computing resources to include it in the two-step portfolio analysis.

4.2. Portfolio Benefit Analysis

The Clean Energy Transformation Act requires utilities to consider equity and ensure all customers benefit from the transition to clean energy. However, AURORA, a traditional production cost model used for portfolio modeling, only solves for the least-cost solution. Therefore, we developed and used a portfolio benefit analysis tool to support our understanding of equity-related benefits and the associated costs within each portfolio and inform our work as we strive to select a portfolio best suited to enable equitable outcomes for customers while also considering cost.

The portfolio benefit analysis measures potential equity-related benefits to customers within a given portfolio and the tradeoff between those benefits and overall cost. We evaluated these benefits using quantitative CBIs and their metrics. Customer benefit indicators are quantitative and qualitative attributes we developed for the 2021 CEIP in collaboration with our Equity Advisory Group (EAG) and interested parties. These CBIs represent the focus areas in CETA related to equity, including energy and non-energy benefits, resiliency, environment, and public health.

For this report, we evaluated each portfolio using a subset of the CBIs proposed in the 2021 Clean Energy Implementation Plan, which as of this date, is still pending Washington Utilities and Transportation Commission (Commission) approval. We selected the subset of CBIs based on whether the AURORA modeling tool could quantitatively evaluate them, i.e., AURORA already had a comparable metric. The CBIs we included in the portfolio benefit analysis are:

- **Improved access to reliable, clean energy** — measured by customers with access to distributed storage resources
- **Improved affordability of clean energy** — measured by the total portfolio cost
- **Improved outdoor air quality** — measured by sulfur oxides, nitrogen oxides, and particulate matter generated per portfolio
- **Increased number of jobs** — measured by the number of estimated jobs generated for each portfolio
- **Increased participation in Energy Efficiency, Distributed Energy Resource, and Demand Response Programs** — measured by energy efficiency capacity added and the number of customers projected to participate in distributed energy resources and demand response programs
- **Reduced greenhouse gas emissions** — measured by the total amount of CO_2-eq[9] generated per portfolio
- **Reduced peak demand** — measured by the decrease in peak demand achieved via demand response programs

The portfolio benefit analysis generates a CBI index for each portfolio, an aggregate measure of these CBIs (excluding the portfolio cost) normalized to the reference portfolio, also known as the least-cost portfolio. A higher CBI index indicates that a portfolio enables more equity-related benefits than the reference portfolio. The CBI index is then compared to its total cost (direct and externality costs).

[9] CO_2-eq or CO_2-equivelant is a measure used to compare the emissions from various greenhouse gases on the basis of their global-warming potential (GWP). Using the GWP, other greenhouse gases are converted to the equivalent amount of carbon dioxide.

➔ Appendix H: Electric Analysis and Portfolio Model includes a more detailed description of the methods used to conduct the portfolio benefits analysis.

4.3. Stochastic Risk Analysis

In this stage of the resource plan analysis, we examined how different resource strategies respond to the types of risk that reflect future uncertainty. We deliberately varied static inputs in the deterministic analysis to create simulations called draws, which we used to analyze the different portfolios.

With stochastic risk analysis, we tested the robustness of different portfolios to determine how well the portfolio might perform under various conditions. The goal is to understand the risks of varying candidate portfolios regarding costs. To assess those risks, we identified and characterized the likelihood of bad events and the likely adverse impacts they may have on a given portfolio.

To gain this understanding, we took some of the portfolios (drawn from the deterministic analysis of portfolios) and ran them through 310 draws[10] that modeled varying power prices, gas prices, hydroelectric generation, wind, and solar generation, load forecasts (energy and peak), and plant forced outages.

5. Reference Portfolio Analysis Results

The reference portfolio is the least-cost portfolio that meets CETA, energy, and reliability requirements. The reference portfolio sets the stage as the starting point that leads to an informed preferred portfolio. The reference case portfolio cost is $17.6 billion, and the social cost of greenhouse gases (SCGHG) is $3.2 billion, totaling $20.8 billion in total portfolio costs.

5.1. Reference Case Portfolio Builds

This section describes the resource additions needed for the reference portfolio to meet CETA requirements, reliability needs, and future energy growth.

5.1.1. Clean Energy Transformation Act

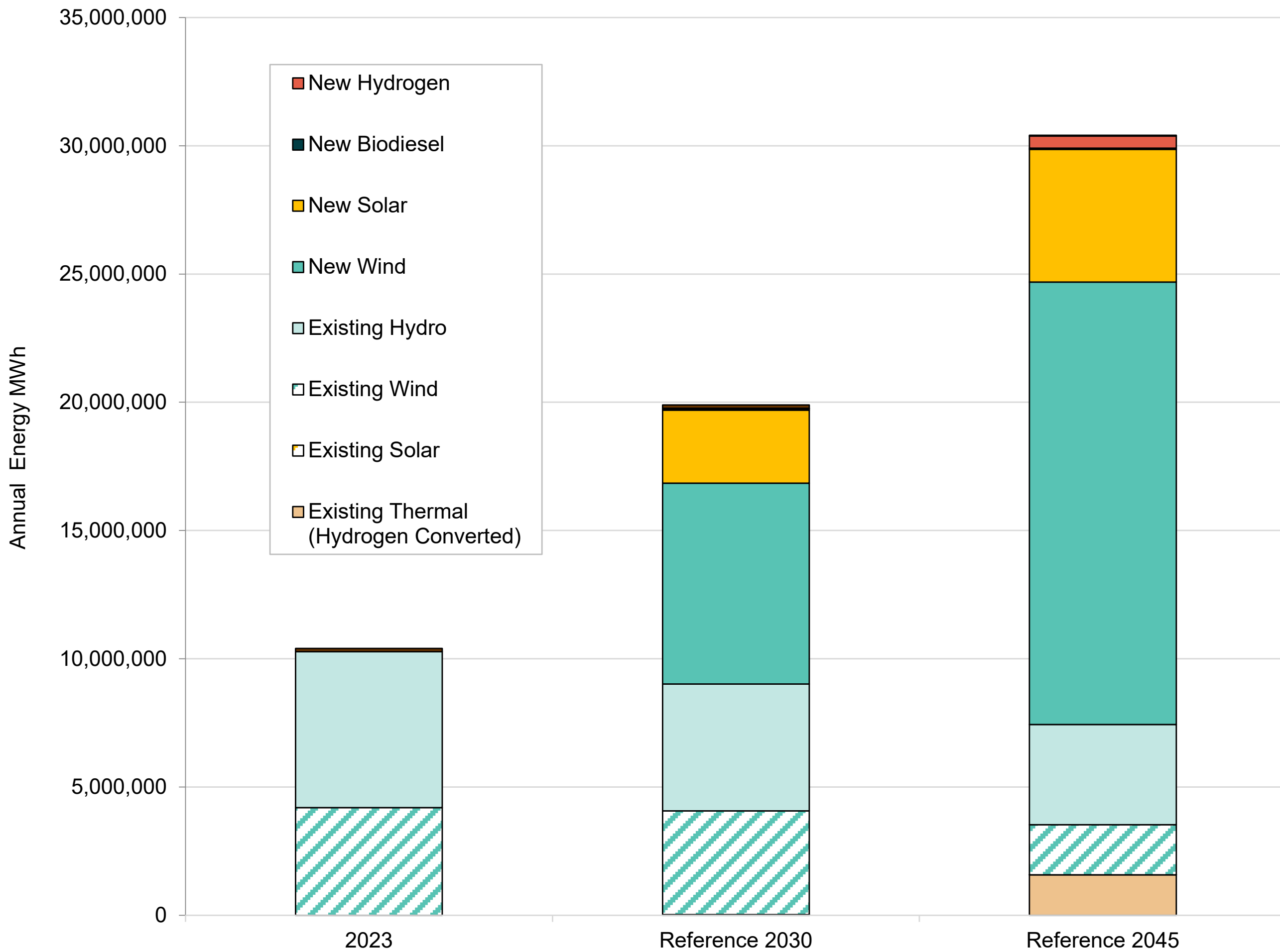
Figure 8.6 shows the energy breakdown from CETA-qualifying resources[11] for select years through 2045. Energy contribution from CETA-qualifying resources grows from over 10 million MWhs in 2023 to 20 million MWhs in 2030 and 30 million MWhs in 2045. New resources will be added to the portfolio starting in 2024, and by 2030 we will see a mix of hydroelectric, wind, solar, and hybrid resources (the renewable portion) eligible to meet CETA added to the portfolio. By 2045, energy from wind resources will make up most of the energy produced from CETA-qualifying

[10] Each of the 310 simulations is for the 22-year IRP forecasting period, 2024–2045.

[11] CETA-qualifying resources include all resources that qualify as renewable or non-emitting under CETA , which include renewables, hydrogen, biodiesel, and advanced nuclear as defined in RCW 19.405.020 (28) and (34)

resources. We also count energy from hydrogen and biodiesel peakers toward CETA achievement; however, those resources have a limited capacity factor and are mostly available to meet peak in high demand hours.

Figure 8.6: Energy for CETA-qualifying Resources — Reference Portfolio



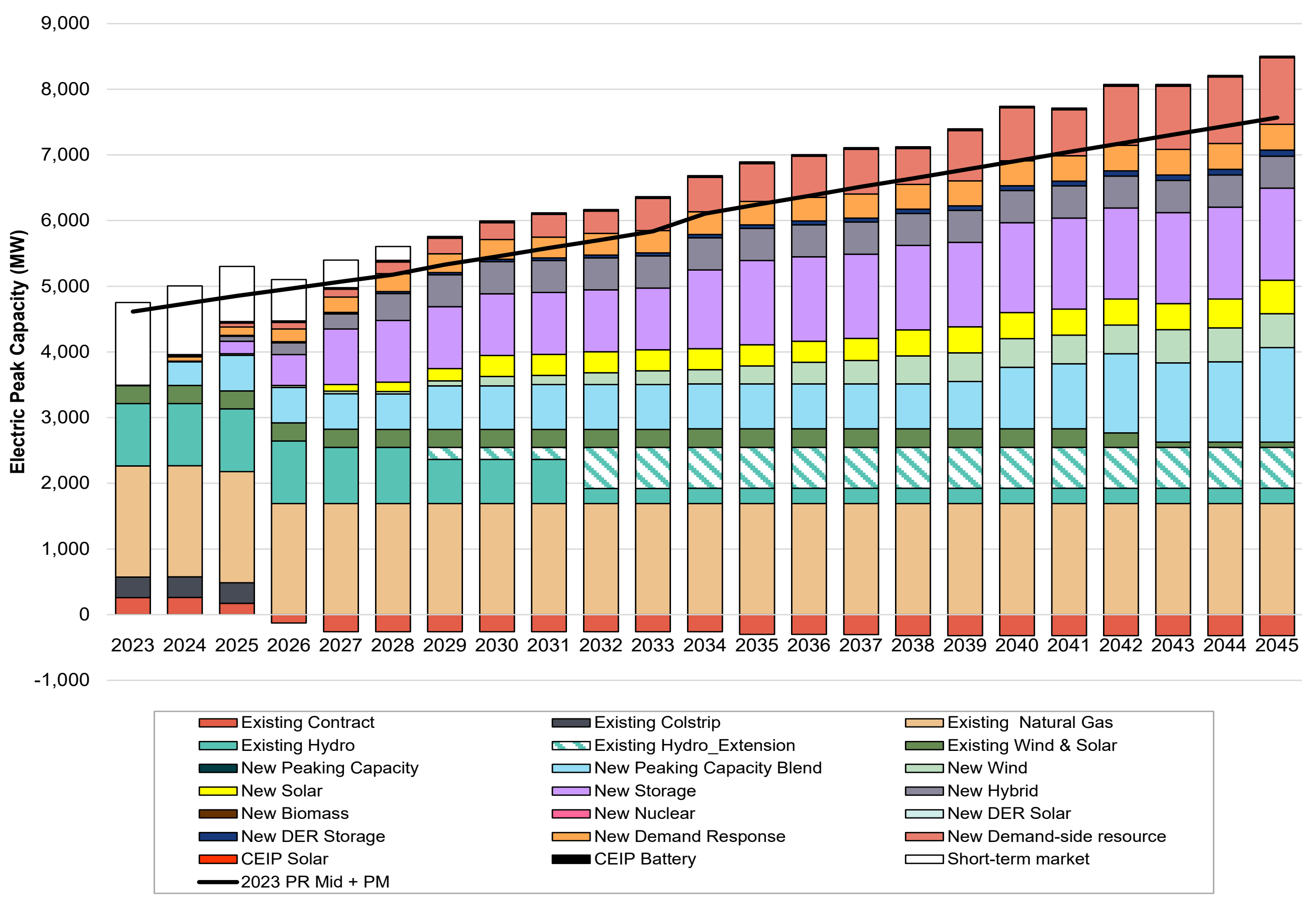
5.1.2. Meeting Reliability Needs

Many factors affect PSE's resource adequacy analysis, including climate change, electric vehicle forecast, and market reliance. Incorporating climate change data resulted in slightly lower normal winter peaks due to higher average temperatures in the winter, while the temperatures were higher on average for the summer leading to higher summer peaks. We also updated the electric vehicle forecast, which increased the winter peak demand. The increase from the electric vehicle forecast offset the decrease in normal winter peak from the climate change data.

Regarding market reliance, there is a concern about the availability of firm capacity in the short-term market. Puget Sound Energy currently has over 2,000 MW of available capacity to the Mid-Columbia (Mid-C) market, with a portion allocated to existing PSE-owned or contracted Mid-C resources, leaving PSE net about 1,400 MW to 1,500 MW of available Mid-C capacity for short term market purchases. This 1,500 MW of available Mid-C capacity was a firm resource in portfolio modeling for previous IRPs. For the 2023 Electric Report, we assumed that access to the short-term market would continue to be available but in decreasing amounts into the future. By 2029, we assumed that none of the transactions in the short-term market would be firm. The assumed reduction in market reliance increased PSE's peak needs. The winter peak need remains greater than the summer peak need through 2045.

Figure 8.7 provides a breakdown of peak capacity contribution by resource type for the summer. The solid black line in the chart represents the summer peak capacity. The combination of existing and new resource peak capacity for the reference portfolio in the summer is surplus of the summer target. Many of the resources we added to help meet CETA requirements, particularly solar resources, have a larger peak capacity contribution in the summer than in the winter. The peak contribution from energy storage resources is also larger in the summer than in the winter — PSE's system is built to meet winter peaking needs and is consequently surplus in the summer months.

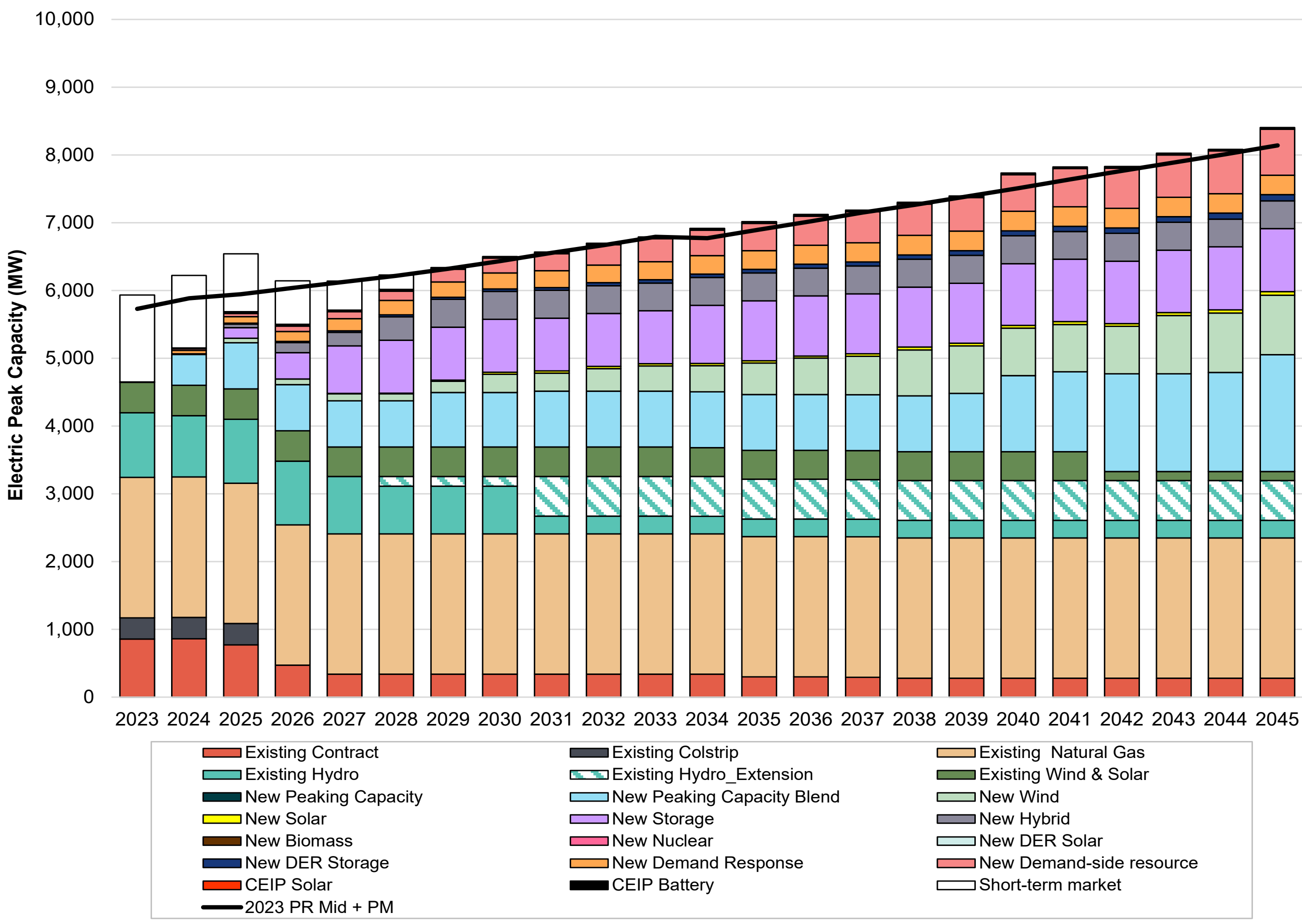
Figure 8.7: Effective Summer Peak Capacity by Resource Type – Reference Portfolio



➔ See Chapter Seven: Resource Adequacy Analysis for more details on resource adequacy.

However, new renewable resources' peak capacity is insufficient to meet winter peaks. We still need additional new peaking capacity to add to the reference portfolio. Looking at the same chart for the winter, we see the reference portfolio is no longer surplus but on target to meet the winter peak capacity. Figure 8.8 provides a breakdown of peak capacity by resource type for the winter. The solid black line in the chart represents the winter peak capacity plus the planning margin. Winter peak need drives new capacity resource builds for the reference portfolio.

Figure 8.8: Effective Winter Peak Capacity by Resource Type – Reference Portfolio



5.1.3. Meeting Future Growth

Puget Sound Energy meets our CETA, energy, and reliability requirements through a combination of conservation, demand response, distributed energy and clean energy resources, energy storage, and CETA-qualifying peaking new capacity resources. Overall cumulative capacity builds through 2045 is 14,287 MW. Table 8.1 summarizes the reference portfolio's incremental nameplate capacity for select years and the cumulative nameplate capacity.

Table 8.1: Incremental Resource Additions — Reference Portfolio (MW)

Resource Type	2024–2025 Incremental	2026–2030 Incremental	2030 Cumulative	2031–2045 Incremental	2045 Cumulative
Demand-side Resources	**184**	**369**	**553**	**547**	**1,100**
Conservation	51	175	226	469	695
Demand Response	133	194	327	78	405
Distributed Energy Resources	**182**	**252**	**434**	**1,177**	**1,612**
DER Solar	142	230	372	1,122	1,494
Net Metered Solar	59	225	284	1,109	1,393
CEIP Solar	79	-	79	0	79
New DER Solar	4	5	9	13	22
DER Storage	40	22	62	55	117
Supply-side Resources	**1,761**	**4,227**	**5988**	**5,587**	**11,575**
CETA Qualifying Peaking Capacity	711	128	839	949	1,788
Wind	600	800	1400	2,650	4,050
Solar	0	1,100	1100	1,290	2,390
Green Direct	0	100	100	0	100
Hybrid (Total Nameplate)	250	1,300	1550	0	1,550
Hybrid Wind	*100*	*800*	*900*	*0*	*900*
Hybrid Solar	*100*	*100*	*200*	*0*	*200*
Hybrid Storage	*50*	*400*	*450*	*0*	*450*
Biomass	0	0	0	0	0
Advanced Nuclear SMR	0	0	0	0	0
Standalone Storage	200	800	1000	700	1,700
Total	**2,127**	**4,849**	**6976**	**7,311**	**14,287**

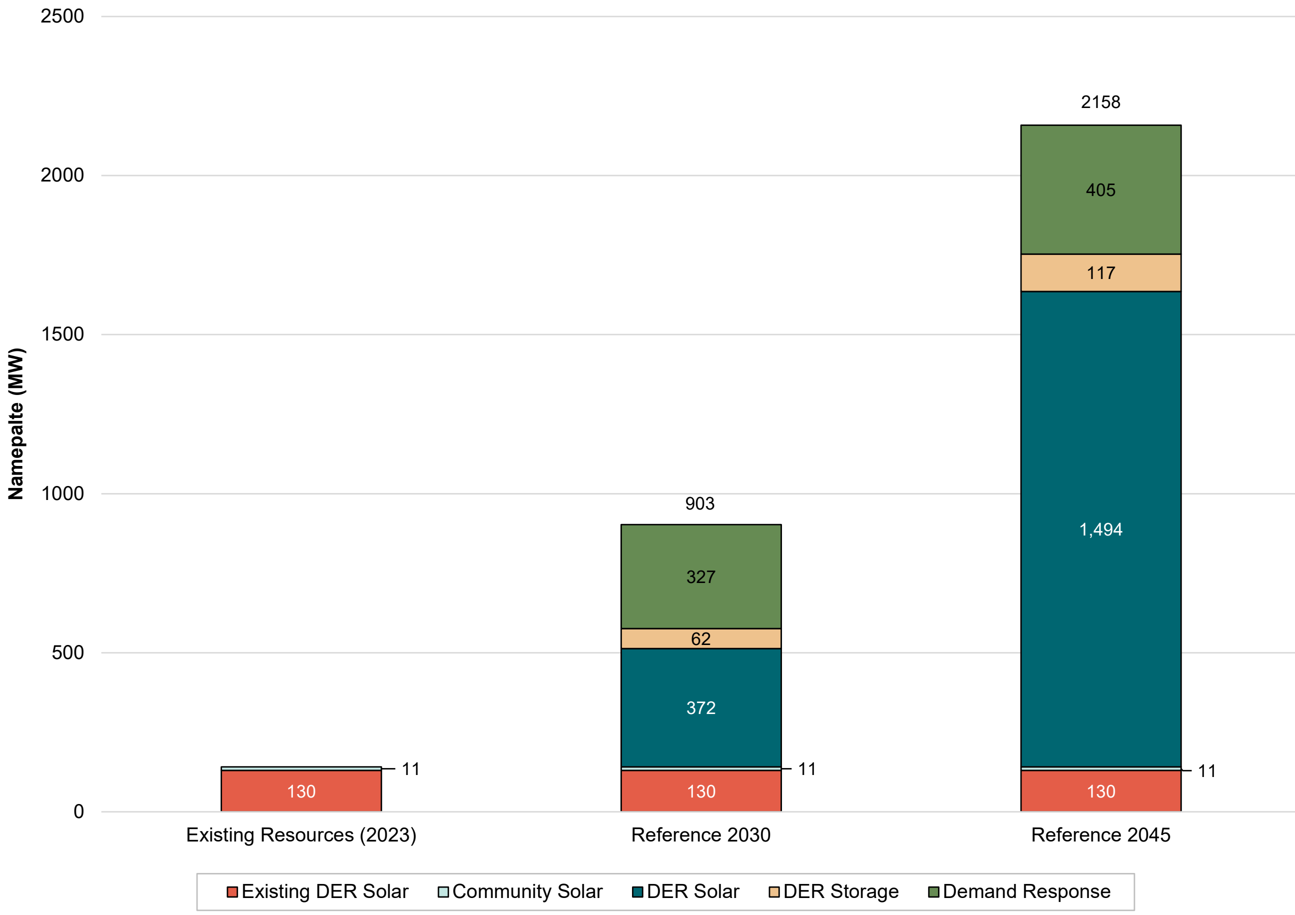
Demand-side Resources

In the AURORA model, conservation is consider a supply-side resource eligible to meet CETA requirements and competes with lower cost renewable resources during the resource selection. Conservation selected in the reference portfolio includes future effects of current Codes & Standards, Distribution Efficiency, and energy efficiency programs, with a total 695 MW added by 2045. A significant amount of demand response programs will be added to the reference portfolio for 405 MW by 2045, including a 12 MW demand response potential for interruptible customers. The high peak contribution and low program costs lead to increased amounts of demand response selected in the reference portfolio.

Distributed Energy Resources

Distributed energy resources for the reference portfolio combine net metering solar forecasts from Cadmus, PSE's forecast of DER solar additions, and DER solar targeted in the 2021 CEIP, totaling 1,494 MW by 2045. The total DER storage added to the portfolio by 2045 is 117 MW, a combination of PSE's forecast of DER storage projects and the DER storage targeted in the 2021 CEIP. Figure 8.9 shows the significant growth in distributed energy resources through 2045

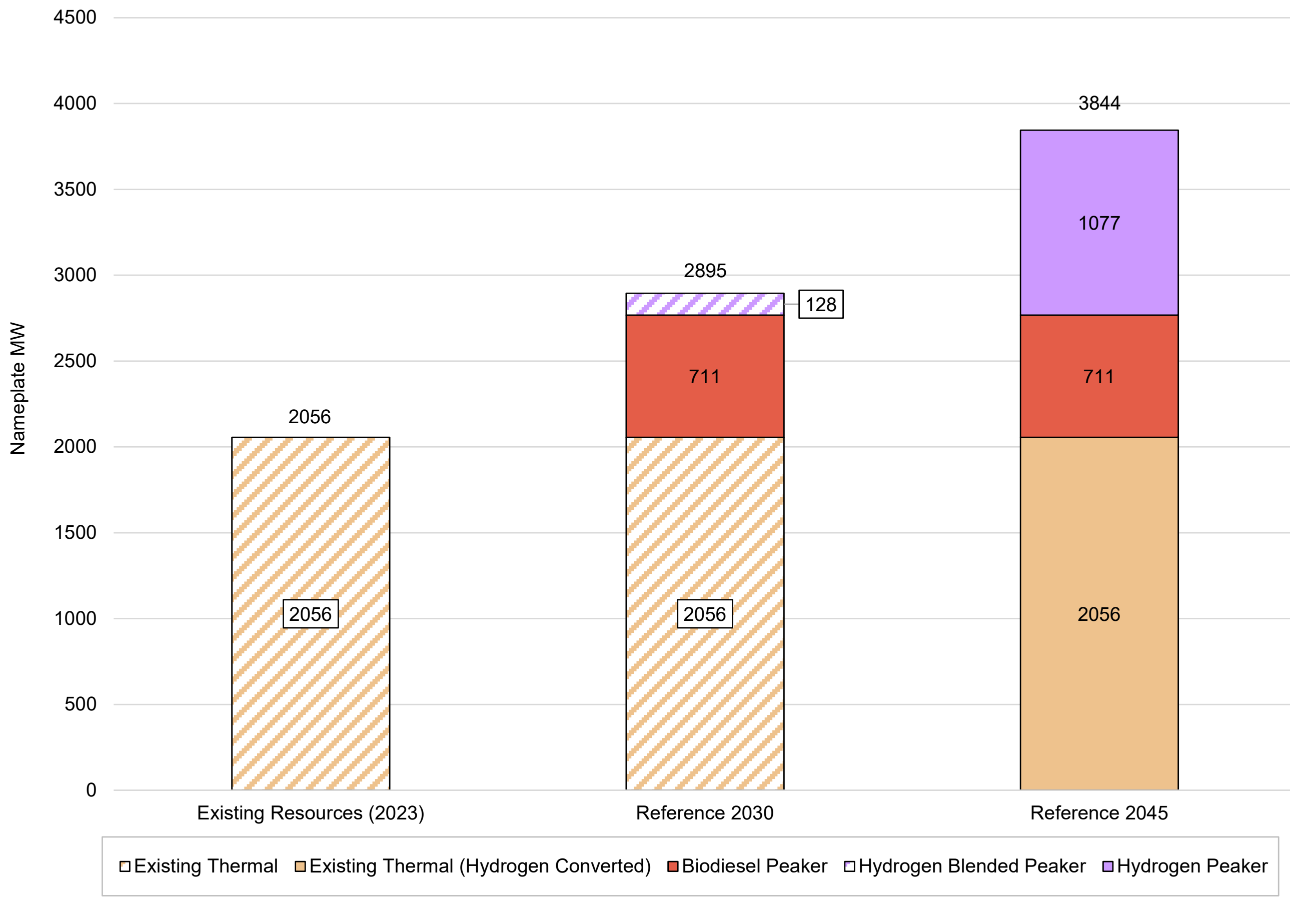
Figure 8.9: Cumulative Nameplate Capacity in MW for Distributed Energy Resources – Reference Portfolio Clean Energy Transformation Act Qualifying Peaking Capacity



CETA Qualifying Peaking Capacity Resources

By 2025, we will add 711 MW of frame peaker biodiesel plants in the reference portfolio to fill the peak need as we phase out our reliance on firm, short-term market purchases. These biodiesel peakers also help to counteract the anticipated retirement of Colstrip and Centralia power purchase agreements (PPA) by the end of 2025. By 2030, we see the addition of 128 MW of peakers using blended natural gas and hydrogen resources as firm short-term market purchases decline to zero MW. In 2031–2045, we see the addition of 711 MW of frame peaker blended natural gas and hydrogen resources and 238 MW of reciprocating peaker blended natural gas and hydrogen resources to help fill the peak needs for the portfolio in the later years. These natural gas/hydrogen blend peaking units can also have biodiesel backup capability if hydrogen is unavailable physically or economically. A discussion of the natural gas and hydrogen blending is in Appendix D: Generic Resource Alternatives. Figure 8.10 shows the cumulative additions of CETA-qualifying peaking capacity resources through 2045.

Figure 8.10: Cumulative Nameplate Capacity in MW for CETA-qualifying Peaking Capacity Resources — Reference Portfolio



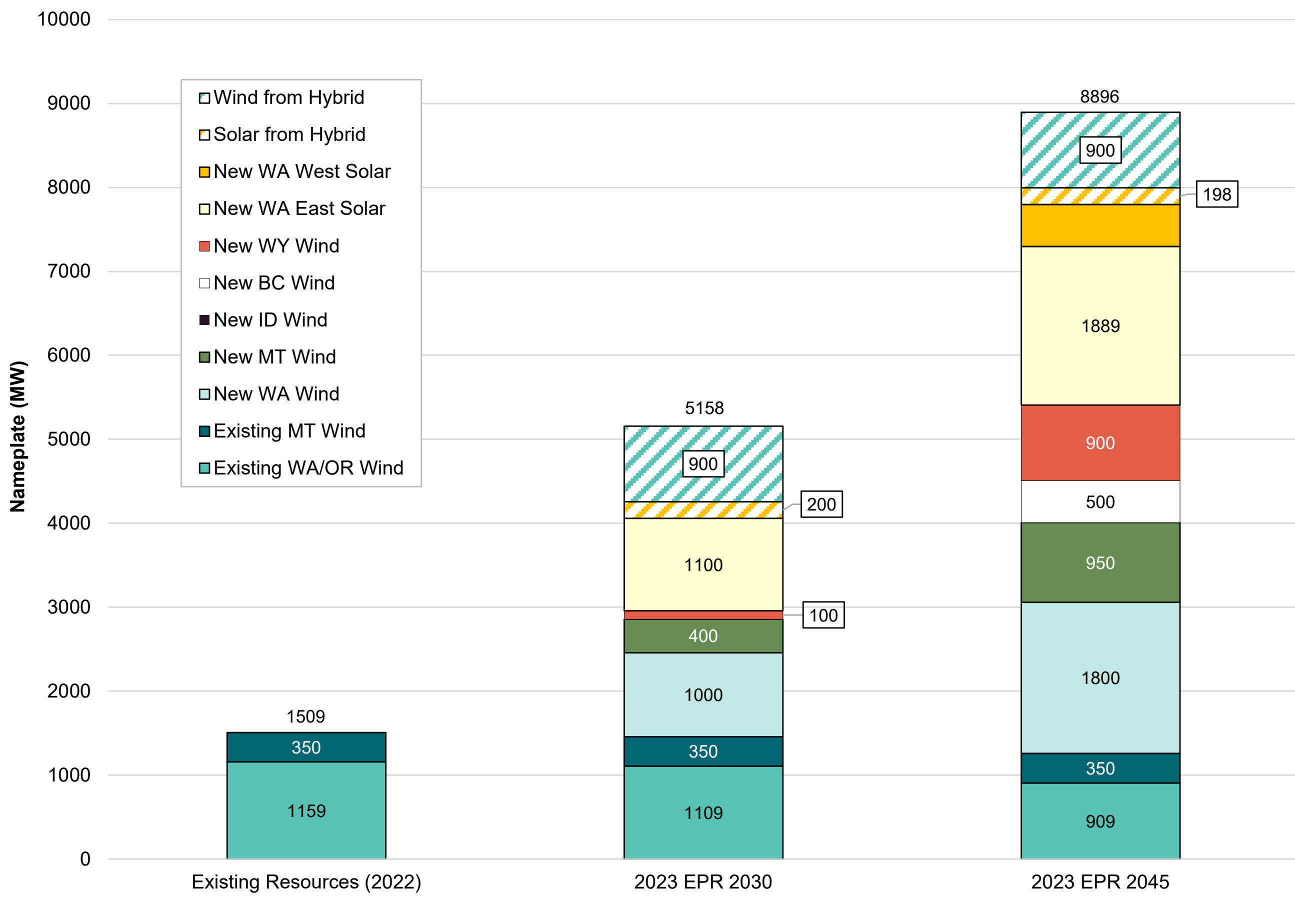
Wind and Solar Resources

We modeled multiple wind regions for this report, and we see this diversity reflected in the Reference portfolio, including Washington wind (WA), British Columbia wind (BC), Montana wind (MT), and Wyoming wind (WY) resources. Although we limited transmission for the wind resources in the near term, we assume unlimited transmission starting in 2035 for the various regions.

➔ A discussion of the transmission constraints is in Chapter Five: Key Analytical Assumptions.

By 2045, we added 5,050 MW of wind to the portfolio. This total includes a 100 MW Green Direct wind we added to the portfolio in 2026. Almost 2,100 MW of solar added to the reference portfolio comes from the WA East region and an additional 500 MW from the WA West region. We will add nearly 8,900 MW of wind and solar to the portfolio by 2045 to meet CETA requirements. Figure 8.11 shows wind and solar resources' significant growth and diversification through 2045.

Figure 8.11: Wind and Solar Resources Cumulative Nameplate Capacity – Reference Portfolio (MW)

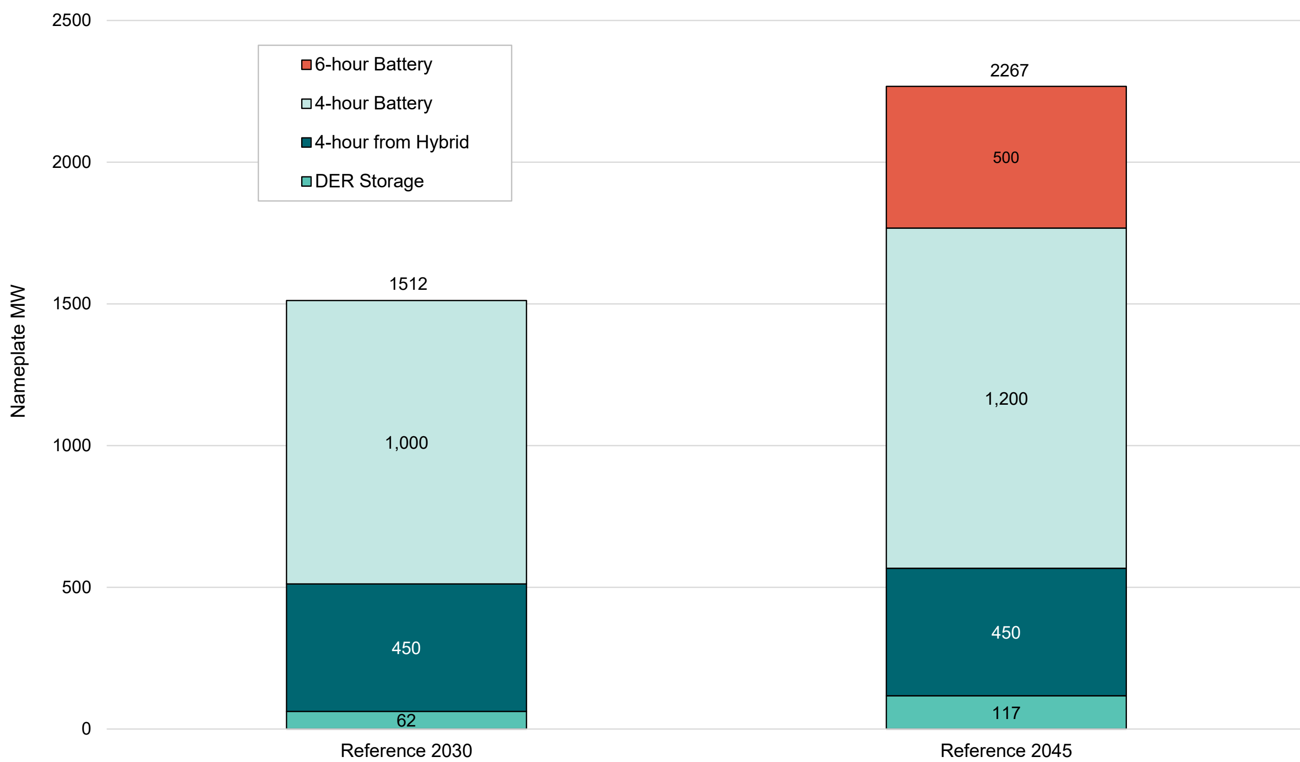


Energy Storage

Energy storage added to the portfolio comes from 1,200 MW of 4-hour batteries and 500 MW of 6-hour batteries. An additional 450 MW of 4-hour batteries are also added from the hybrid resources. Storage resources have a high effective load carrying capability (ELCC) for the first tranche of 1,000 MW, which is beneficial in meeting peak needs; however, the saturation effect can significantly impact the ELCCs. Figure 8.12 shows the storage additions through 2045.

➔ See Chapter Five: Key Analytical Assumptions for a detailed discussion of hybrid resources, and Chapter Seven: Resource Adequacy for ELCC energy storage and saturation effects.

Figure 8.12: Cumulative Nameplate Capacity in MW for Storage Resources — Reference Portfolio



Nuclear Small Modular Reactors and Biomass

Advanced nuclear small modular reactors (SMRs) and Biomass resources are CETA-qualifying resources; however, we did not add them to the reference portfolio due to higher costs than the resources.

➔ See Appendix I: Electric Analysis Inputs and Results for more detailed information on portfolio build results.

6. Sensitivity Analysis Results

Portfolio sensitivity analysis is an essential form of risk analysis that helps us understand how specific assumptions change the mix of resources in the portfolio and affect portfolio costs. Examples of a sensitivity include requiring the model to have 400 megawatts of energy storage in 2025 and 2026, relaxing transmission constraints between 2040 and 2045, or restricting any thermal resource additions during the entire planning period. This section provides the results and detailed analysis for each sensitivity.

More results, including year-by-year resource timelines, cost breakdowns, and emissions data, are in Appendix I: Electric Analysis Inputs and Results. Chapter Five: Key Analytical Assumptions includes a detailed description of the scenarios and sensitivities and the key assumptions used to create them: customer demand, natural gas prices, possible

CO_2 prices, resource costs (demand-side and supply-side), and power prices. Appendix D: Generic Resource Alternatives discusses existing electric resources and resource alternatives. Appendix J: Economic, Health, and Environmental Benefits Assessment of Current Conditions details the CBIs we used in the customer benefits analysis.

6.1. Summary of Resource Modeling Assumptions

The resource alternative sensitivities schedule targeted and isolated resource additions to explore the effects on builds, cost, and emissions. Sensitivities 2–9 explore adding additional conservation, distributed resources, pumped heat electrical storage (PHES) resources, maximizing existing Montana transmission, and pursuing advanced nuclear SMR resources.

The diversified portfolio sensitivities 11 A1 and 11 B2 take what we learned from sensitivities 2–9 and combine them in a portfolio to identify an achievable portfolio of diverse resources that maximize equity-related benefits while maintaining reliability and affordability.

We modeled sensitivities 10 and 12 through 16 following requests from interested parties.

Table 8.2 describes the sensitivities we evaluated in this 2023 Electric Report.

➔ Additional details, including assumptions, are available in Chapter Five: Key Analytical Assumptions.

Table 8.2: 2023 Electric Progress Report Portfolios and Sensitivities

ID	Name	Type	Description
1	Reference	Portfolio	Least-cost and CETA-compliant
2	Conservation Bundle 10	Resource Alternative	Reference + Increase conservation to 486 aMW by 2045
3	Conservation Bundle 7	Resource Alternative	Reference + Increase conservation to 381 aMW by 2045
4	DER Solar	Resource Alternative	Reference Portfolio + 30 MW/year of DER rooftop solar from 2026–2045
5	DER Batteries	Resource Alternative	Reference + 25 MW/year of DER batteries (3-hour Li-ion) from 2026–2031
6	MT Wind PHES, All East Wind	Resource Alternative	Reference + 400 MW MT East Wind + 200 MW MT PHES in 2026
7	MT Wind PHES, Central & East Wind	Resource Alternative	Reference + 200 MW MT East Wind + 200 MW MT Central Wind + 200 MW MT PHES in 2026
8	PNW PHES	Resource Alternative	Reference + 200 MW of PNW PHES in 2026
9	Advanced Nuclear SMRs	Resource Alternative	Reference + 250 MW of advanced nuclear SMRs in 2032
11 A1	Least Diversified Sensitivity w/ Advanced Nuclear SMRs	Diversified portfolio	Reference + more conservation (Bundle 7) + 400 MW MT East Wind + 200 MW MT

ID	Name	Type	Description
			PHES in 2026 + 250 MW advanced nuclear SMRs in 2032
11 A2	Diversified + PNW PHES	Diversified portfolio	Diversified Portfolio 11 A1 + 200 MW PNW PHES in 2026
11 A3	Diversified + DER Solar	Diversified portfolio	Diversified Portfolio 11 A2 + 30 MW per year of DER rooftop solar from 2026–2045
11 A4	Diversified + DER Batteries	Diversified portfolio	Diversified Portfolio 11 A3 + 25 MW per year of DER batteries (3hr Li-ion) from 2026–2031
11 A5	Diversified + All DR Programs	Diversified portfolio	Diversified Portfolio 11 A4 + All DR Programs
11 B1	Least Diversified w/o Advanced Nuclear SMRs (11 A1 – Adv. Nuclear SMRs)	Diversified portfolio	Reference portfolio + more conservation (Bundle 7) + 400 MW MT East Wind + 200 MW MT PHES in 2026 Similar to Diversified Portfolio A1, without Adv. Nuclear SMRs
11 B2	Most Diversified w/o Advanced Nuclear SMRs (11 A5 – Adv. Nuclear SMRs)	Diversified portfolio	Diversified Portfolio 11 A5 less 250 MW Advanced Nuclear SMRs in 2032
10	Thermal builds prohibited before 2030	Requested Sensitivity	Reference + Peaker plants use biodiesel as an alternative fuel.
12	100% Renewable/Non-Emitting by 2030	Requested Sensitivity	Reference + Existing thermal retired by 2030; no new thermal allowed
13	High Carbon Price	Requested Sensitivity	Reference + CCA ceiling price used for all carbon allowances
14	No Hydrogen Fuel Available	Requested Sensitivity	Reference + Natural gas and biodiesel fuel are available, but not hydrogen fuel
15	SGHG in Dispatch	Requested Sensitivity	Reference + Model SCGHG costs as dispatch cost in the long-term capacity (LTCE) expansion model
16	WRAP Adjustment	Requested Sensitivity	Reference + Adjust PRM and ELCCs using information from WRAP

6.2. Key Findings

This section briefly summarizes the results of each sensitivity analyzed in this report.

6.2.1. Resource Alternative Sensitivities

Sensitivity 2 — Conservation Bundle 10 and Sensitivity 3 — Conservation Bundle 7

More expensive conservation measures led to a slightly lower selection of renewable resources and increased the overall portfolio costs. Increased additions of conservation measures provided near-term benefits in greenhouse gas emission reductions. However, the impact of emission reduction in the long-term, particularly in 2045, when almost all the resources in the portfolio are considered CETA-qualifying, is less significant. A further discussion of energy efficiency measures modeled can be found in Appendix E: Conservation Potential Assessment.

Sensitivity 4 DER Solar: Scheduling in additions of DER Solar at a rate of 30MW per year did not produce a substantially different portfolio but accounted for a notable increase in solar capacity and moderate change in total portfolio cost.

Sensitivity 5 DER Storage: Significant resource movement occurred due to a relatively small incremental increase in DER storage, such as 500 MW less utility-scale solar, added to the portfolio compared to the reference portfolio. This sensitivity decreased portfolio cost by $0.14 billion and decreased the total portfolio cost with SCGHG by $0.08 billion.

Sensitivity 6 MT Wind and Pumped Hydroelectric Energy Storage (PHES), All MT East Wind: Scheduled additions of eastern Montana wind and Montana pumped hydroelectric storage delay the addition of CETA qualifying peak resources, resulting in an accelerated reduction of GHG emissions but at an overall higher portfolio cost. Compared to sensitivity 7, which adds both eastern and central Montana wind and Montana PHES, sensitivity 6 provides fewer greenhouse gas reductions but significantly lower total portfolio cost. Therefore, sensitivity 6 is a more cost-effective strategy to lower greenhouse gas emissions and diversify energy storage resources.

Sensitivity 7 MT Wind and PHES, Central and East Wind: Scheduled additions of Montana east and central wind and Montana PHES slightly accelerate the reduction of greenhouse gases compared to the reference portfolio but at a higher overall portfolio cost. Compared to sensitivity 6, which adds only eastern Montana wind and Montana PHES (no central Montana wind), the greenhouse gas emission reductions for sensitivity 7 are greater, but the overall portfolio cost is also higher. Therefore, it is not a cost-effective strategy to overbuild the capacity of Montana transmission to reduce greenhouse gas emissions and diversify the energy storage resources.

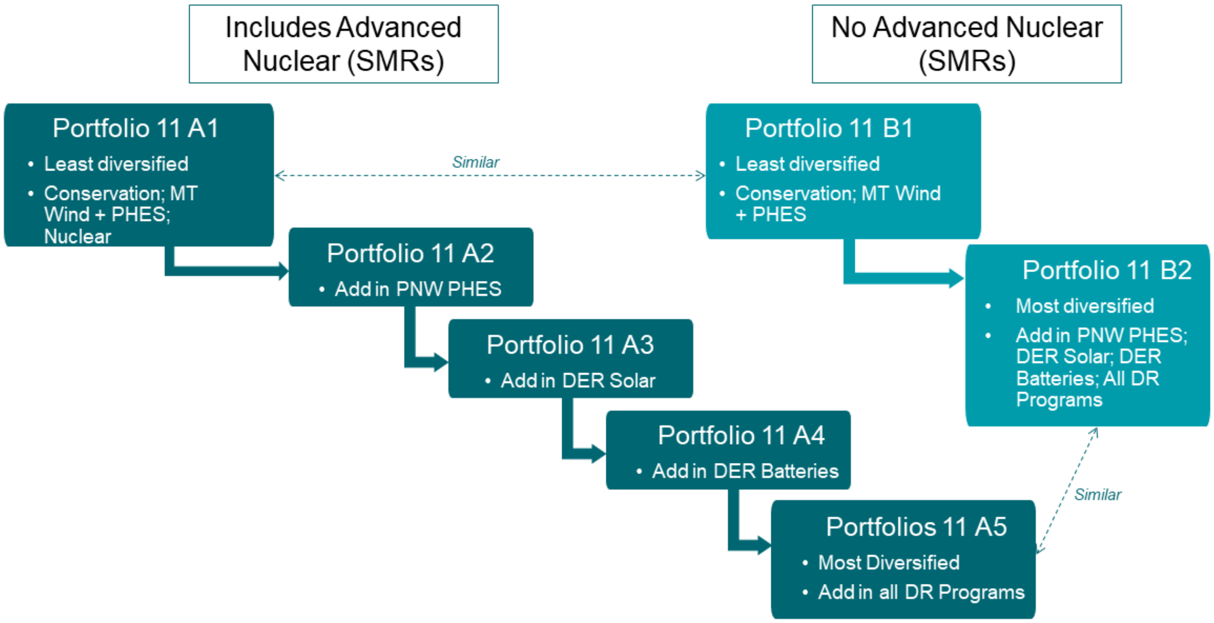
Sensitivity 8 PNW PHES: There is little difference between sensitivity 8 and the reference portfolio. Adding PNW PHES increases portfolio cost but results in little change to the overall outcome of the portfolio in terms of resource additions and greenhouse gas emissions, suggesting there is little benefit in adding PNW PHES as a means to diversify away from battery energy storage systems in the preferred portfolio.

Sensitivity 9 Advanced Nuclear Small Modular Reactors (SMRs): The ability of advanced nuclear SMRs to provide reliability and flexibility benefits for peak events while also providing the added benefit of emission-free production for meeting the CETA clean energy standards lead to the displacement of some renewable and peaking capacity resources. Overall, we see slightly lower portfolio additions by 2045 due to the addition of 250 MW of SMR; however, these advanced nuclear SMRs are more expensive and raise the portfolio costs by $1.47 billion.

6.2.2. Diversified Portfolio Sensitivities

The diversified portfolio sensitivities broaden the resource additions, lower the technology and feasibility risks, and seek to maximize equity-related benefits. Figure 8.13 illustrates the relationships between the diversified portfolios we explored in this report.

Figure 8.13 Diversified Portfolio Sensitives Map



Sensitivity 11 A1–A5 Diversified: All diversified 11 A sensitivities have higher costs than the reference portfolio. As expected, each sequential resource addition correspondingly increases the sensitivity cost: of the diversified 11 A sensitivities, 11 A1 has the least cost and 11 A5 the highest. Adding advanced nuclear SMR resources will cause an additional cost spike in 2032.

Resource additions are relatively similar across the 11 A sensitivities by 2030, with expected variation in DER resources as these are added in 11 A3 and beyond. Notably, CETA qualifying peaking capacity in 2030 is equivalent across all sensitivities, including the reference, indicating a need for dispatchable energy soon. In the longer term, the wind, solar, and hybrid resource mix becomes slightly more pronounced across the diversified 11 A sensitivities, while CETA-qualifying peaking capacity, demand-side resources, and stand-alone storage resources are relatively similar. All diversified 11 A sensitivities reduce GHG emissions compared to the reference portfolio. This reduction is greatest in sensitivity 11 A5, which produces 7 million short tons fewer emissions than the reference portfolio.

Sensitivity 11 B1 Least Diversified without Advanced Nuclear SMR: Sensitivity 11 B1 provides a little diversification relative to the reference portfolio by adding PHES and increasing energy efficiency measures. These scheduled additions result in a markedly different overall portfolio with fewer nameplate additions, made possible by selecting resources with higher peak capacities contributions, such as hybrid resources instead of stand-alone wind and solar resources. Despite adding fewer resources overall, the early addition of hybrid and storage resources inflated the portfolio cost above the reference portfolio. Greenhouse gas emission reductions are accelerated before 2030 but align with the reference portfolio 2030–2045.

Sensitivity 11 B2 Most Diversified without Advanced Nuclear SMRs: Sensitivity 11 B2 provides diversification relative to the reference portfolio by adding distributed energy resources, PHES, and additional DSR. This diversification shifts the resource mix away from utility-scale resources toward distributed energy resources and DSR. Early additions of Montana wind and distributed solar reduce existing thermal resources dispatch and accelerate the reduction of greenhouse gases before 2030. Fewer new thermal peaking capacity resources are required in sensitivity 11 B2 due to increased additions of stand-alone storage and hybrid resources. We selected this portfolio as the preferred portfolio and explained its benefits in Chapter Three: Resource Plan of the 2023 Electric Report.

6.2.3. Requested Sensitivities

Sensitivity 10 No New Thermal before 2030 and Biodiesel as the Alternative Fuel: Delaying the availability of thermal peaking capacity resources until 2030 results in an additional 3,700 MW of battery storage and 900 MW of hybrid resources before 2030, displacing 839 MW of thermal plants built during that time. Adding over 5.0 GW of batteries in six years would be challenging to accomplish, given the magnitude. As of October 2022, only 7.8 GW of utility-scale batteries are operating nationwide.[12] After we lifted the thermal restriction in the model, it added minimal batteries due to the over-saturation of batteries in meeting peak. This sensitivity is $0.91 billion more expensive than the reference portfolio.

Sensitivity 12 100 Percent Renewable/Non-Emitting by 2030: Implementing the necessary changes for this sensitivity created substantial issues for the model. The short-term resource need became too large due to mass retirements of firm capacity, and the model could not make up for this with available new resources and transmission constraints as defined in the reference case. This sensitivity did not produce a solution, which speaks to the challenges of quickly retiring large amounts of thermal capacity.

Sensitivity 13 High Carbon Price Based on the Ceiling Price Assumption: The resource mix between the reference portfolio and sensitivity 13 is very similar, indicating that increased carbon costs do not significantly impact build decisions. This sensitivity costs less than the reference, driven primarily by a lower SCGHG. These results indicate a decrease in emitting resource dispatch, as we may expect with higher market prices for carbon allowances.

Sensitivity 14 No Hydrogen Fuel Available: There is a significant difference between sensitivity 14 and the reference portfolio. Without access to hydrogen fuel, we no longer see an accelerated reduction in GHG emissions, and portfolio costs are significantly higher, suggesting a notable benefit to hydrogen fuel as an alternative fuel option. Therefore, we should continue exploring blending hydrogen with natural gas fuel.

Sensitivity 15 SCGHG in Dispatch: Including the SCGHG in the dispatch cost for the long-term capacity expansion model adversely decreases the capacity factor of PSE's thermal plants, resulting in 2,000 MW of renewable resource additions by 2025, more than the energy needed for the year. This scenario also doubles PSE's existing renewable resources of 1,700 MW in three years. The CETA requirement is the driving factor for the resource build decisions by 2045.

Sensitivity 16 WRAP Adjustment: We cannot run the long-term capacity expansion model to evaluate sensitivity 16 due to incomplete information regarding ELCC saturation curves for renewable and storage resources from the Western Resource Adequacy Program (WRAP). We also understand that the WRAP data is not intended for long-term resource planning. Our best estimate using the WRAP PRM shows a decrease in the winter peak capacity need

[12] https://www.eia.gov/todayinenergy/detail.php?id=54939

by 300 MW and a reduction in the summer peak need by 1,200 MW in 2029. We need further study to incorporate WRAP in long-term resource planning. The WRAP estimated seasonal PRMs are in Table 8.3.

Table 8.3 PRM and Peak Capacity Needs

Sensitivity Year/Season	1 Reference 2029 Winter	1 Reference 2029 Summer	16 WRAP Adjustment 2029 Winter	16 WRAP Adjustment 2029 Summer
Peak Load (MW)	5,104	4,300	4,570	3,447
PRM (MW)	1,215	1,029	956	470
PRM%	24%	24%	21%	14%
Existing Resources Peak Capacity (MW)	3,607	2,493	3,120	2,343
Additional perfect capacity for 5% LOLP (MW)	2,712	2,837	2,406	1,574

6.3. Portfolio Costs

This section describes the changes in portfolio costs for the sensitivities evaluated in the 2023 Electric Progress Report. The portfolio cost in dollars is the levelized, net present value of the annual cost impacts for 22 years excluding SCGHG costs. This includes:

- Alternative compliance costs
- CCA costs
- Decommissioning costs as part of the economic decision of plant retirements
- Fixed and variable costs of existing resources and new resources
- Fuel costs
- Net market purchases and sales

We report the SCGHG as an externality cost separately. The sum of the portfolio costs and the SCGHG costs is what we refer to as total portfolio costs in this chapter.

6.3.1. Resource Alternative Sensitivities

Table 8.4 and Figure 8.14 show the costs associated with the Resource Alternative sensitivities 2–9 described in this section.

Sensitivity 2 — Conservation Bundle 10 and Sensitivity 3 — Conservation Bundle 7: As expected, increased distribution and energy efficiency additions led to higher portfolio costs. The portfolio cost of sensitivity 2 is $0.97 billion higher than the reference portfolio. However, the SCGHG of sensitivity 2 is $0.17 billion lower than the reference portfolio. This results in a net increase in total portfolio cost of $0.81 billion for sensitivity 2 compared to the reference portfolio. For sensitivity 3, the portfolio cost is $0.35 billion higher than the reference portfolio. Similar to sensitivity 2, the SCGHG of sensitivity 3 is also lower than the reference portfolio by $0.34 billion. This results in a net increase in total portfolio cost of $0.01 billion for sensitivity 3 compared to the reference portfolio.

Sensitivity 4 DER Solar: The total portfolio cost of sensitivity 4 is higher than the reference as expected by the substantial increase in DER solar resources shown to be relatively high cost by the reference case. The difference in portfolio cost between the two is significant at $0.45 billion, but with the inclusion of the social cost of greenhouse gases (SCGHG), the total portfolio cost difference is more moderate at $0.23 billion.

Sensitivity 5 DER Storage: The total portfolio costs between sensitivity 5 and the reference case were reasonably consistent. The total portfolio cost changes slightly, making sensitivity 5 $0.08 billion less over its lifetime. There is a bigger difference between the two in portfolio cost, but some of this is offset by small changes in SCGHG costs. Emissions are similar enough in both cases that the portfolio cost comparison with and without SCGHG does not vary dramatically, and the two portfolios follow similar cost trends in both instances.

Sensitivity 6 MT Wind and PHES, All MT East Wind: The portfolio cost of sensitivity 6 is $0.2 billion higher than the reference portfolio. However, the SCGHG of sensitivity 6 is $0.18 billion lower than the reference portfolio. These two components of the total cost of the sensitivity are offsetting, resulting in the total portfolio cost for sensitivity 6, which is just $0.02 billion higher than the reference portfolio. Compared to the reference portfolio, the scheduled addition of Montana east wind and Montana PHES delay the addition of 474 MW of CETA-qualifying peaking resources from 2025–2029 and offsets dispatch of existing thermal resources resulting in an accelerated reduction in GHG emissions but at a higher overall cost.

Sensitivity 7 MT Wind and PHES, Central and East Wind: The portfolio cost of sensitivity 7 is $0.7 billion higher than the reference portfolio. However, the SCGHG of sensitivity 7 is $0.37 billion lower than the reference portfolio. This results in a net increase in total portfolio cost of $0.33 billion for sensitivity 7 compared to the reference portfolio. Compared to the reference portfolio, the scheduled addition of Montana wind and Montana PHES delays the addition of 474 MW of CETA-qualifying peaking resources from 2025 to 2027 and offsets the dispatch of existing thermal resources resulting in an accelerated reduction in GHG emissions but at a higher overall cost.

Sensitivity 8 PNW PHES: The portfolio cost of sensitivity 8 is $0.55 billion higher than the reference portfolio. However, the SCGHG of sensitivity 8 is $0.12 billion lower than the reference portfolio. This results in a net increase in total portfolio cost of $0.43 billion for sensitivity 8 compared to the reference portfolio.

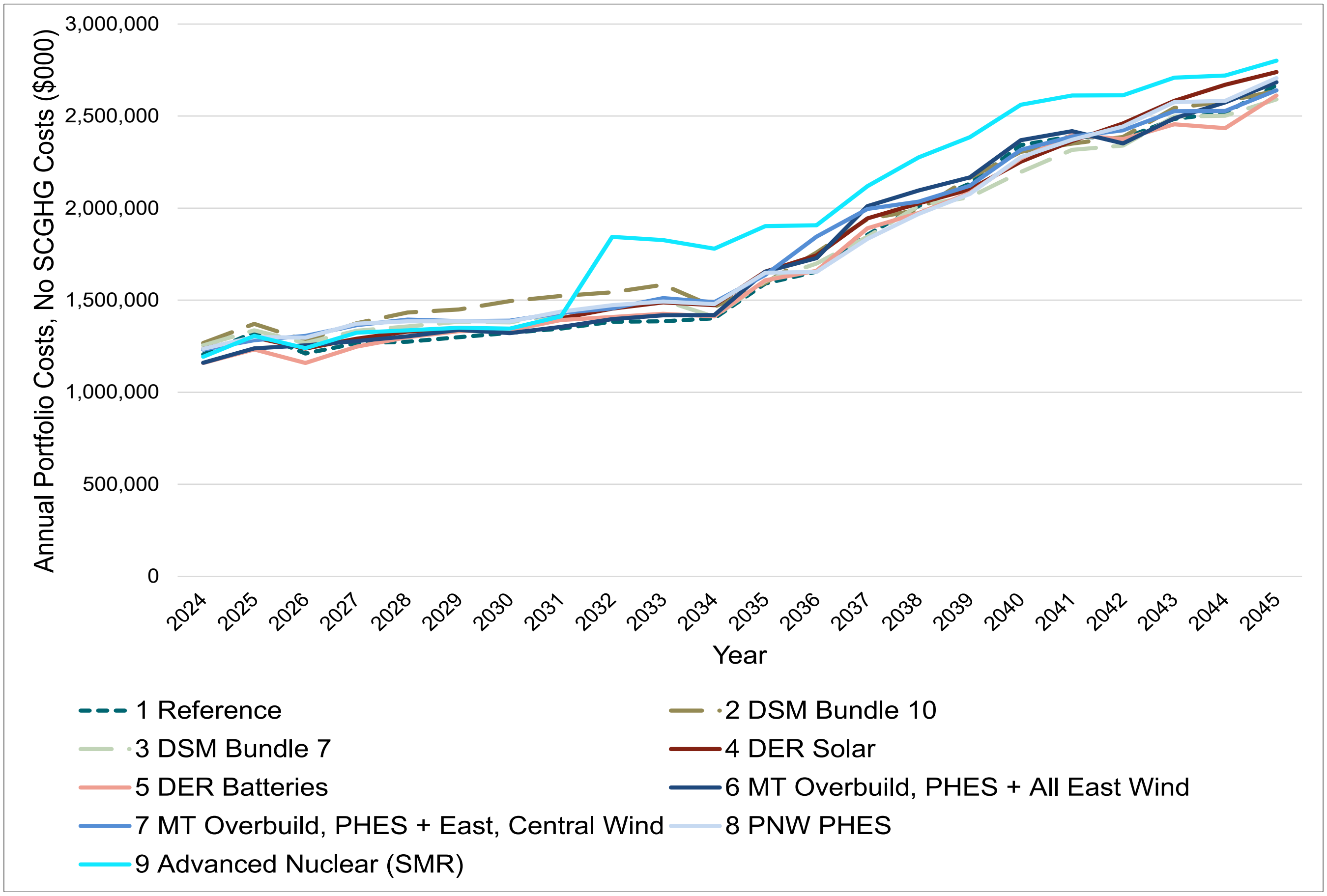
Sensitivity 9 Advanced Nuclear SMRs: Sensitivity 9 is a higher cost overall than the reference portfolio, and costs begin to diverge at a greater pace as the model added advanced nuclear SMR resources to the portfolio in 2032. This results in a net increase in total portfolio cost of $1.47 billion for sensitivity 9 compared to the reference portfolio.

Table 8.4 Resource Alternatives Portfolio Costs, 2024–2045 NPV ($ Billions)

Portfolio	Portfolio Cost ($)	SCGHG Costs ($)	Total ($)	Change from Reference ($)	Change from Reference (%)
1 Reference	17.61	3.24	20.85	0.00	-
2 DSM Bundle 10	18.58	3.07	21.65	0.81	4
3 DSM Bundle 7	17.96	2.90	20.86	0.01	0
4 DER Solar	18.06	3.02	21.08	0.23	1
5 DER Batteries	17.47	3.30	20.77	-0.08	0

Portfolio	Portfolio Cost ($)	SCGHG Costs ($)	Total ($)	Change from Reference ($)	Change from Reference (%)
6 MT Overbuild, PHES + All East Wind	17.81	3.06	20.87	0.03	0
7 MT Overbuild, PHES + East, Central Wind	18.31	2.87	21.18	0.34	2
8 PNW PHES	18.16	3.12	21.28	0.44	2
9 Advanced Nuclear SMRs	19.34	2.98	22.32	1.47	7

Figure 8.14: Annual Portfolio Costs — Resource Alternatives



6.3.2. Diversified Portfolio Sensitivities

The costs associated with the diversified portfolio sensitivities 11 A1-A5 and 11 B1-B2 are described in this section and summarized in Table 8.5 and Figure 8.15.

Sensitivity 11 A1 – A5 Diversified: All diversified 11 A sensitivities cost substantially more than the least-cost reference portfolio (Table 8.5). The least-diversified sensitivity, 11 A1, adds conservation, an advanced nuclear SMR power plant, and maximizes existing Montana transmission. These resource additions cost $2 billion (10 percent) more than the reference portfolio. Each subsequent resource addition, as observed in sensitivities 11 A2 through 11 A5, increases the total cost compared to the sensitivity proceeding it. However, adding DER solar and demand response programs cost approximately $0.02 billion each, whereas adding the Pacific Northwest PHES and DER batteries cost nearly twenty times this amount, approximately $0.4 billion each.

Generally, the diversified 11 A sensitivity costs are similar year to year through the 22-year planning period. Though costlier, they follow the reference portfolio trend through 2045 (Figure 8.15). Adding 250 MW of advanced nuclear SMRs is the notable exception: the spike above the reference portfolio in 2032 reflected the costs of this technology when we added this resource to the 11 A sensitivities.

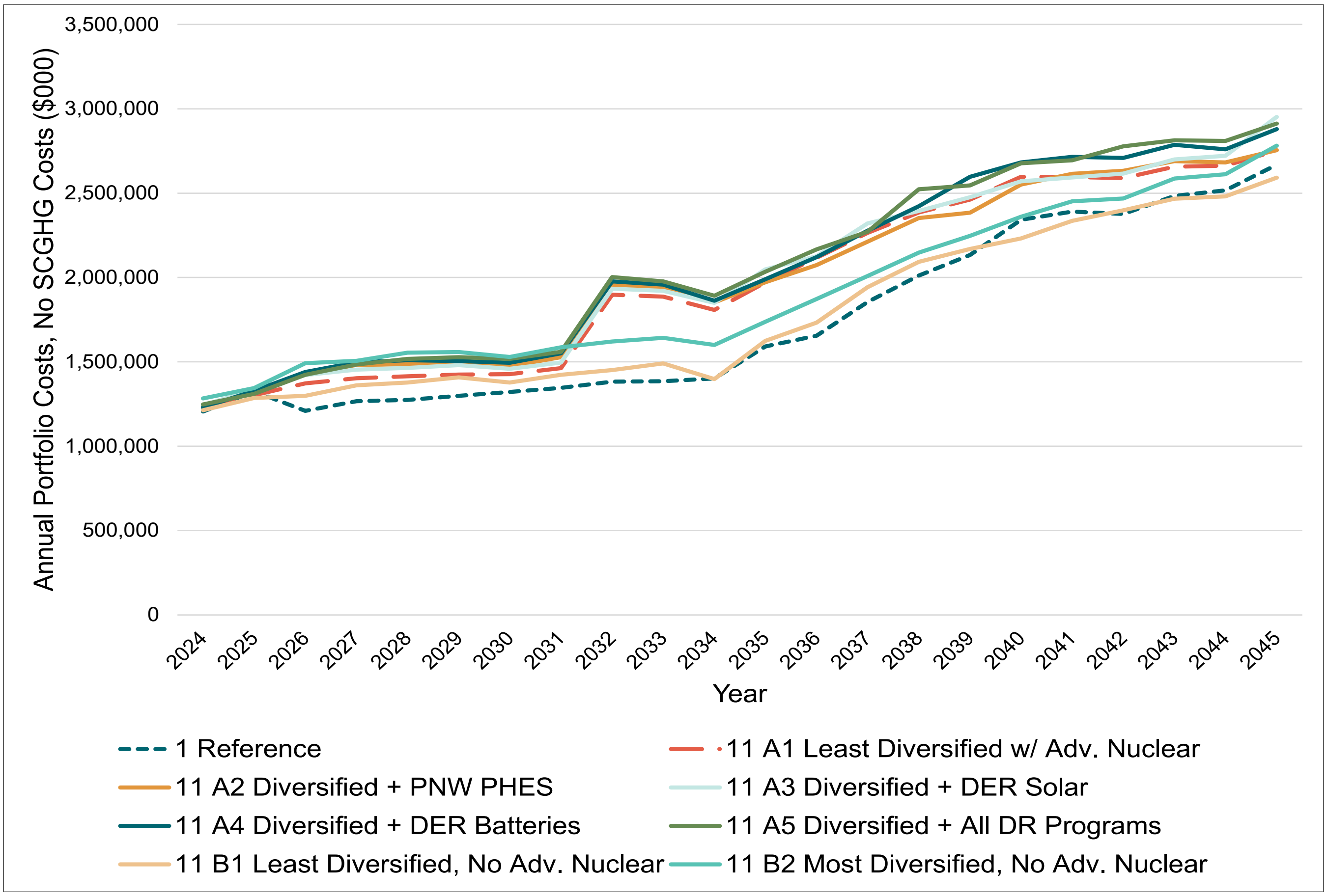
Sensitivity 11 B1 Least Diversified without Advanced Nuclear SMRs: The cost of sensitivity 11 B1 is $0.48 billion higher than the reference portfolio. However, the SCGHG of sensitivity 11 B1 is $0.24 billion lower than the reference portfolio. This results in a net increase in the total cost of $0.24 billion for sensitivity 11 B1 compared to the reference portfolio. Early additions of hybrid and storage resources resulted in increased capital spending on resources in the years before 2030. Despite fewer nameplate additions overall, sensitivity 11 B1 results in a higher cost due to generally higher cost resources added earlier in the modeling horizon.

Sensitivity 11 B2 Most Diversified without Advanced Nuclear SMRs: The portfolio cost of sensitivity 11 B2 is $1.95 billion higher than the reference portfolio. However, the SCGHG of sensitivity 11 B2 is $0.29 billion lower than the reference portfolio. This results in a net increase in the total cost of $1.66 billion for sensitivity 11 B2 compared to the reference portfolio.

Table 8.5: 11 A Diversified Portfolio Costs, 2024–2045 NPV ($ Billions)

Portfolio	Portfolio Cost ($)	SCGHG Costs ($)	Total ($)	Change from Reference ($)	Change from Reference (%)
1 Reference	17.61	3.24	20.85	0.00	0
11 A1 Least Diversified w/ Adv. Nuclear SMRs	20.01	2.82	22.83	1.99	10
11 A2 Diversified + PNW PHES	20.32	2.93	23.25	2.40	12
11 A3 Diversified + DER Solar	20.44	2.83	23.27	2.42	12
11 A4 Diversified + DER Batteries	20.74	2.90	23.64	2.80	13
11 A5 Diversified + All DR Programs	20.89	2.78	23.67	2.82	14
11 B1 Least Diversified w/o Advanced Nuclear SMRs	18.09	3.00	21.09	0.24	1
11 B2 Most Diversified w/o Advanced Nuclear SMRs	19.56	2.95	22.51	1.66	8

Figure 8.15: Annual Portfolio Costs — Diversified Portfolios



6.3.3. Requested Sensitivities

The costs associated with sensitivities 10 and 12-16 are described in this section and summarized in Table 8.6 and Figure 8.16.

Sensitivity 10 No New Thermal before 2030 and Biodiesel is the Alternative Fuel: The portfolio cost of sensitivity 10 is $1.67 billion higher than the reference portfolio. However, the SCGHG of sensitivity 10 is $0.77 billion lower than the reference portfolio. These two components of the total cost of the sensitivity are offsetting, resulting in the total portfolio cost for sensitivity 10, which is just $0.91 billion higher than the reference portfolio. The restriction on thermal additions before 2030 results in the addition of more expensive stand-alone storage and hybrid resources in the near term and offsets dispatch of existing thermal resources resulting in reduced GHG emissions but at a higher overall cost.

Sensitivity 12 100 percent Renewable/Non-Emitting: This sensitivity did not solve due to the issues we discussed in the Key Findings section and consequently did not produce any portfolio cost metrics.

Sensitivity 13 High Carbon Price Based on the Ceiling Price Assumption: The portfolio cost without the SCGHG adder for this sensitivity is $0.50 billion higher than the reference case, likely driven by higher market prices. However, the SCGHG adder is $0.52 billion less than the reference case, resulting in an overall portfolio cost of $0.02

billion less than the reference case. This sensitivity illustrates that the higher market prices for carbon allowances result in decreased emitting resource dispatch, as shown by the lower SCGHG.

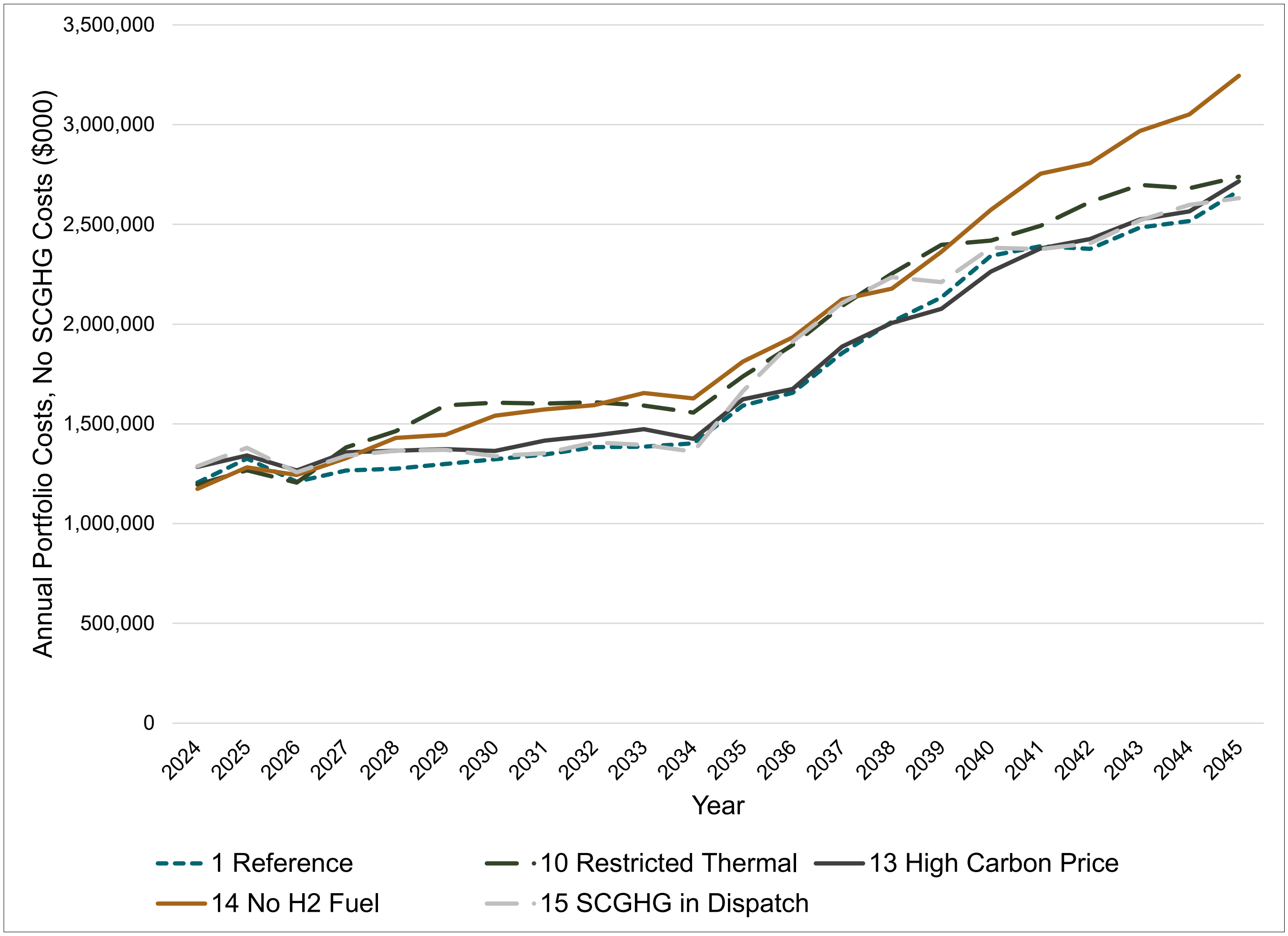
Sensitivity 14 No Hydrogen Fuel Available: The portfolio cost of sensitivity 14 is $2.03 billion higher than the reference portfolio. We also see an increase in SCGHG costs for sensitivity 14, which is $2.19 billion higher than the reference portfolio. This results in a net increase in total portfolio cost of $4.23 billion for sensitivity 14 compared to the reference portfolio.

Sensitivity 15 SCGHG in Dispatch: The portfolio costs are higher for sensitivity 15, with a portfolio cost of $18.34 billion. Though the sensitivity 15 portfolio cost is $0.73 billion higher than the reference portfolio, it greatly decreases the emission costs to $2.47 billion. The total cost of sensitivity 15 ($20.81 billion) is 0.04 billion lower than the reference portfolio total cost ($20.85 billion).

Table 8.6: Other Requested Sensitivities Portfolio Costs, 2024–2045 NPV (Billions)

Sensitivity	Portfolio Cost ($)	SCGHG Costs ($)	Total ($)	Change from Reference ($)	Change from Reference (%)
1 Reference	17.61	3.24	20.85	0.00	-
10 Restricted Thermal	19.28	2.47	21.75	0.91	4
13 High Carbon Price	18.11	2.72	20.83	-0.01	-0.1
14 No H2 Fuel	19.64	5.43	25.07	4.23	20
15 SCGHG in Dispatch	18.34	2.47	20.81	-0.04	0.2

Figure 8.26: Annual Portfolio Costs — Other Requested Sensitivities



6.4. Modeling Builds

This section describes the changes in resource builds for the sensitivities evaluated in this 2023 Electric Report.

6.4.1. Resource Alternative Sensitivities

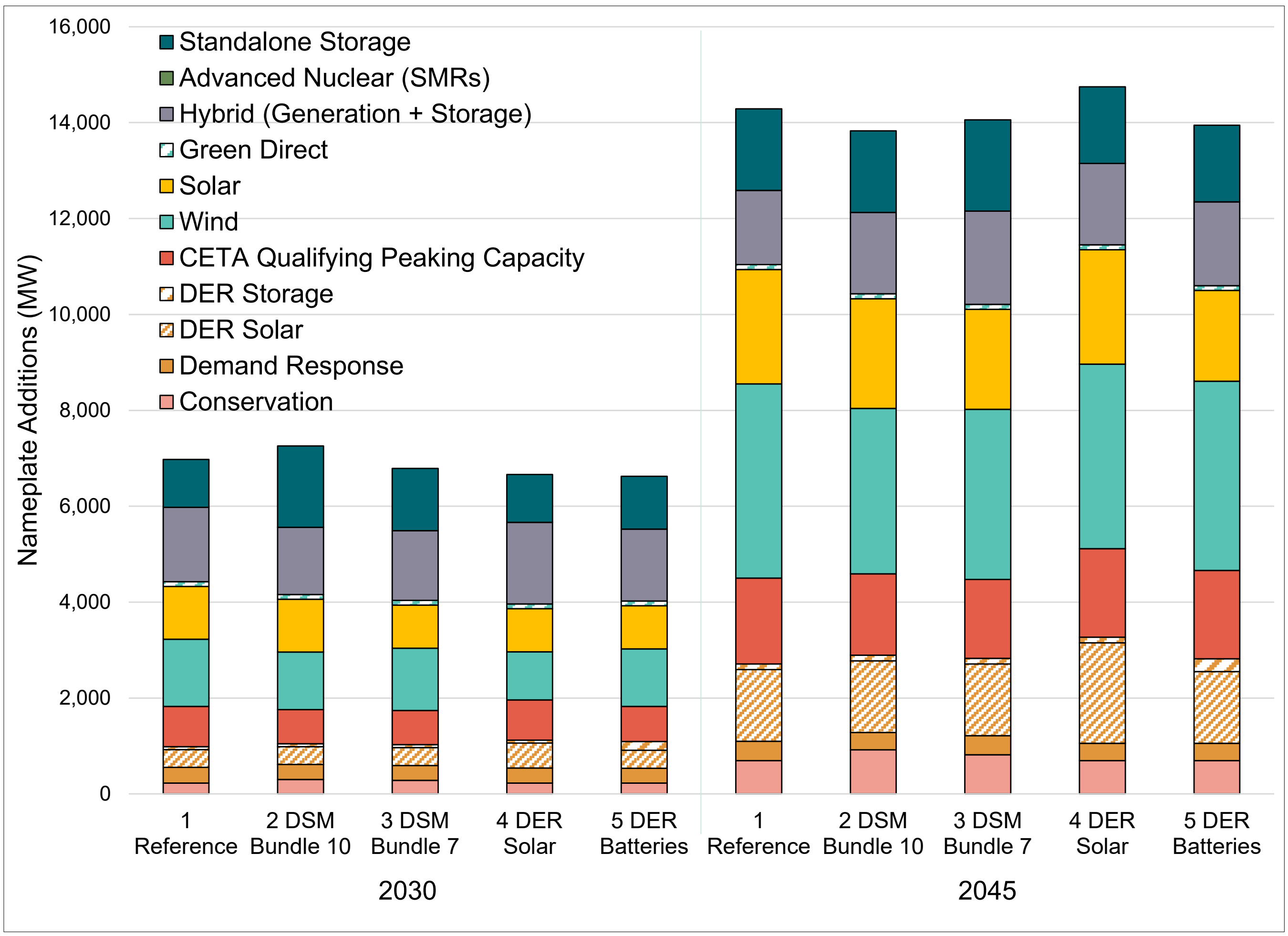
In this section, we described the resources added in the Resource Alternative sensitivities 2–9 and summarized them in Figures 8.17 and 8.18.

Sensitivity 2 — Conservation Bundle 10 and Sensitivity 3 — Conservation Bundle 7: Overall builds are similar, except for the increased addition of distributed and energy efficiency measures and slightly fewer renewable resources needed to meet CETA requirements in sensitivity 2 and sensitivity 3.

Sensitivity 4 DER Solar: Aside from the increase in DER solar capacity for sensitivity 4, it adds a similar mix of capacity by 2045 compared to the reference portfolio, although the timing of resource additions is quite different. Notable differences include a 450MW reduction in CETA-qualifying peaking capacity and a 400MW increase in utility-scale solar before 2025 for sensitivity 4. However, these resource groups end up in almost identical places at the end of the planning horizon. One consistent difference is that sensitivity 4 picks up less demand response than the reference portfolio, totaling a 41MW winter peak difference by 2045. At a coarser level, all capacity addition resource groups in sensitivity 4 are within 200 MW of their analogous group in the reference case.

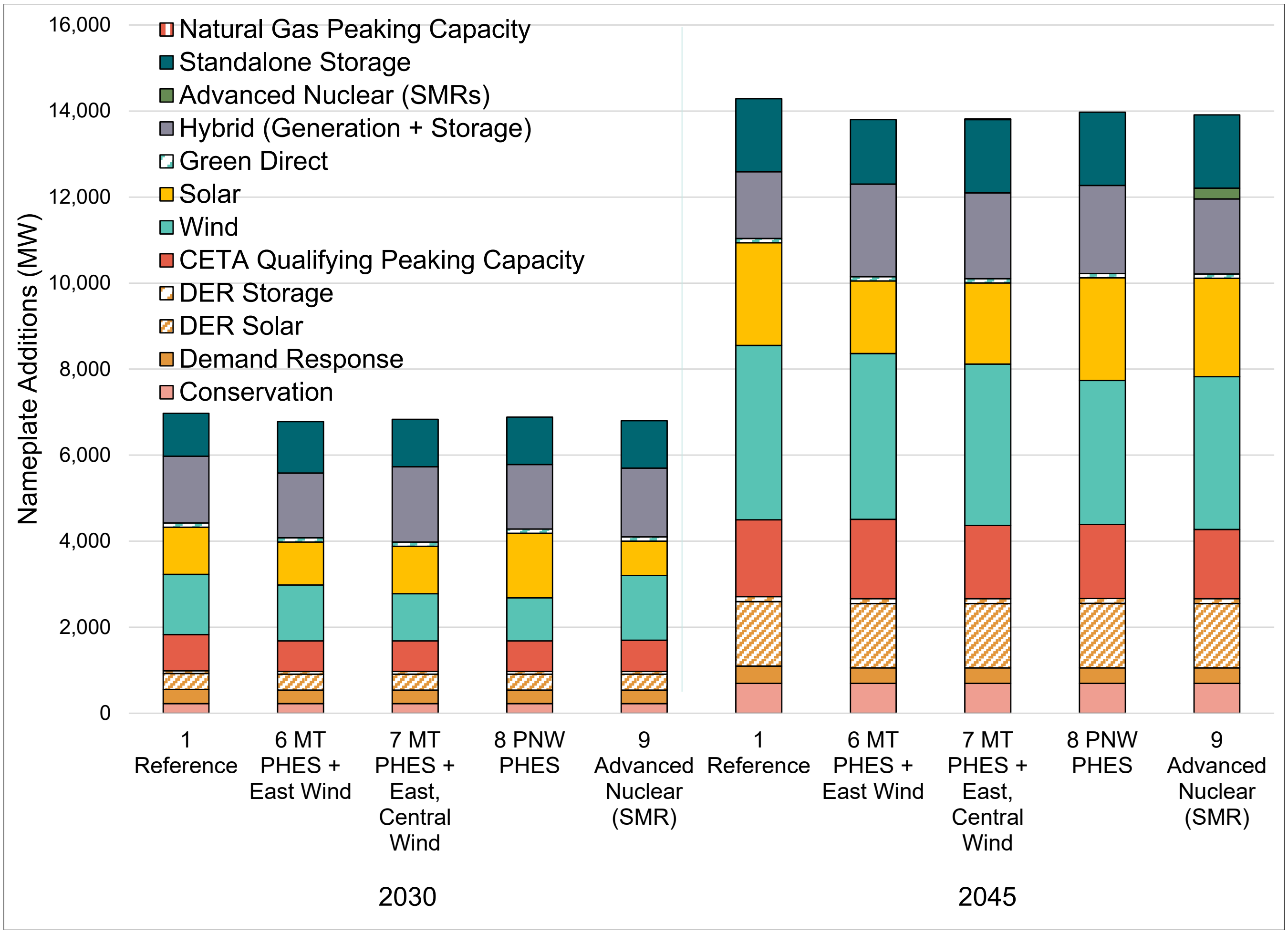
Sensitivity 5 DER Storage: A comparison between sensitivity 5 and the reference portfolio in terms of resource additions shows significant movement in certain resource groups. Most notably, by 2045, it will pick up 500 MW less solar than the reference portfolio. Other observed changes besides the prescribed DER storage increase (150 MW) include roughly 200 MW more hybrid capacity, 45 MW less demand response, a 55 MW increase in CETA-qualifying peaking capacity, and 100 MW less stand-alone storage — all by 2045. The reference portfolio builds resources earlier than sensitivity 5, building 500 MW more capacity by 2025, which lessens to a 341 MW capacity difference in 2045 at the end of the planning period.

Figure 8.37: Resource Additions — Resource Alternatives Part 1



Sensitivity 6–9: Overall builds are similar for each sensitivity and the reference portfolio, except for the scheduled addition of the resource we tested for the sensitivity.

Figure 8.48: Resource Additions — Resource Alternatives Part 2



6.4.2. Diversified Portfolio Sensitivities

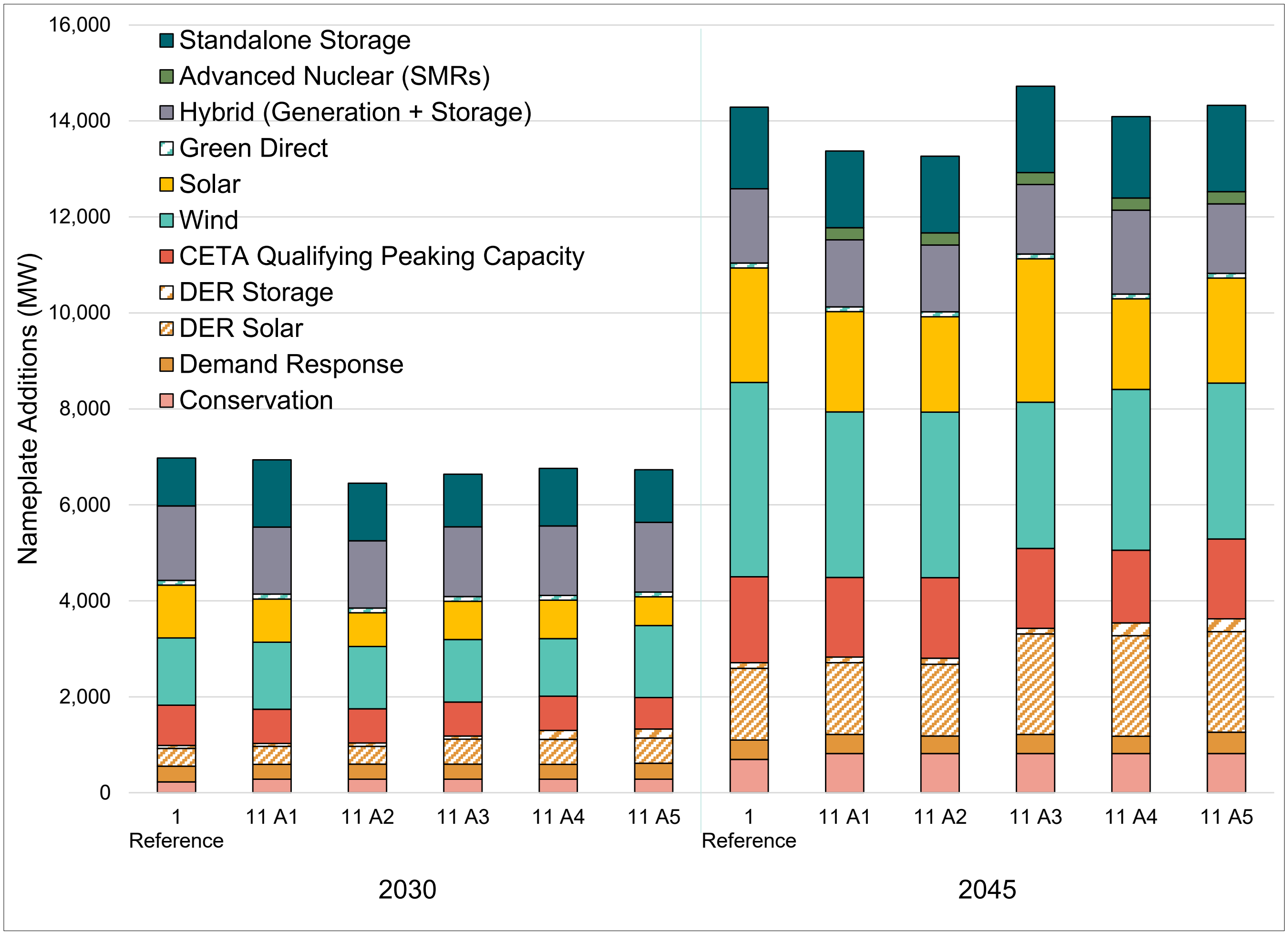
The resources added in the diversified portfolio sensitivities 11 A1–11 A5, and 11 B1–11 B2 are described in this section and summarized in Figures 8.19 and 8.20.

Sensitivity 11 A1– A5 Diversified: In the first two years of the planning period, between 2024 and 2025, the demand-side and distributed resource additions in the diversified 11 A sensitivities mirror the reference portfolio. However, this very near-term look highlights several strategies for meeting energy needs. Sensitivities 11 A1 and 11 A2 displace all three early CETA-qualifying peaking plants built in the reference portfolio with various combinations of renewable and storage resources (wind, solar, stand-alone storage, and hybrid). Peaking capacity is reduced but not replaced entirely in sensitivities 11 A3, 11 A4, and 11 A5, to 237, 474, and 18 MW, respectively. However, by 2030, CETA-qualifying peaking capacity will be equivalent across all diversified 11 A sensitivities at 711 MW, except for 11 A5, which builds slightly less at 657 MW. This indicates a constant need for dispatchable energy in the near-term planning horizon.

In the longer term, between 2031 and 2045, the resource mix becomes slightly more pronounced between the diversified sensitivities. Distributed solar and battery additions increase as expected in sensitivities 11 A3, 11 A4, and

11 A5, where we required the model to select these resource additions. Wind, solar, and hybrid resources are added in varying amounts across the 11 A sensitivities but generally sum to similar quantities by 2045. CETA-qualifying peaking capacity is a stable addition across all sensitivities, even with 250 MW of advanced nuclear SMRs, which diversifies dispatchable resources but does not displace the equivalent peaking capacity from the 11 A sensitivities. Battery storage and DSR are relatively constant across sensitivities by 2045, but both peak in 11 A5.

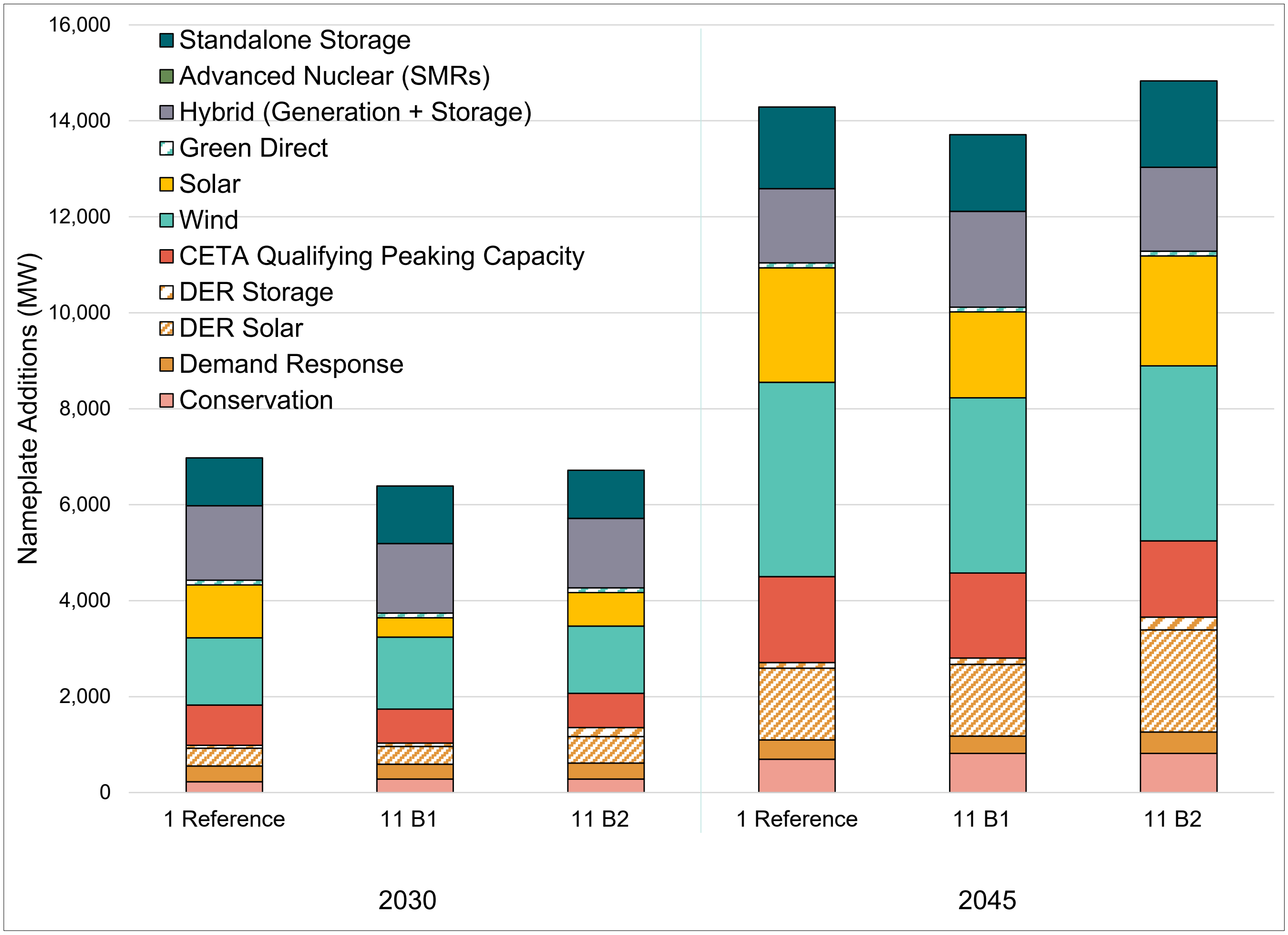
Figure 8.19: Resource Additions — Diversified Portfolio Sensitives Part 1



Sensitivity 11 B1 Least Diversified without Advanced Nuclear SMRs: Overall resource builds are similar between the reference and sensitivity 11 B1 but with a few notable differences. Sensitivity 11 B1 results in nearly 600 MW fewer nameplate capacity additions by favoring resources with a greater peak capacity contribution, such as energy efficiency measures and shifting from stand-alone wind and solar to hybrid resources. Sensitivity 11 B1 defers the addition of thermal peaking capacity resources through the earlier addition of hybrid and storage resources compared to the reference portfolio.

Sensitivity 11 B2 Most Diversified without Advanced Nuclear SMRs: Overall resource builds are similar between the reference and 11 B2 sensitivities. Sensitivity 11 B2 incorporates 780 MW more distributed solar and storage resources through scheduled resource additions than the reference case. The distributed energy resource additions in sensitivity 11 B2 reduce the capacity of stand-alone, utility-scale wind and solar resources added to the sensitivity. The percentage of demand-side and distributed resources in the sensitivity portfolio resource mix increases from 19 percent in the reference portfolio to 25 percent in sensitivity 11 B2. Increased addition of resources with high peak capacity contributions, including stand-alone storage, hybrid resources, and energy efficiency measures, reduce the total thermal peaking capacity added to sensitivity 11 B2 by 200 MW compared to the reference portfolio.

Figure 8.20: Resource Additions — Diversified Portfolio Sensitivities Part 2



6.4.3. Requested Sensitivities

We described the resources added in sensitivities 10 and 13–16 in this section and summarized in Figure 8.21.

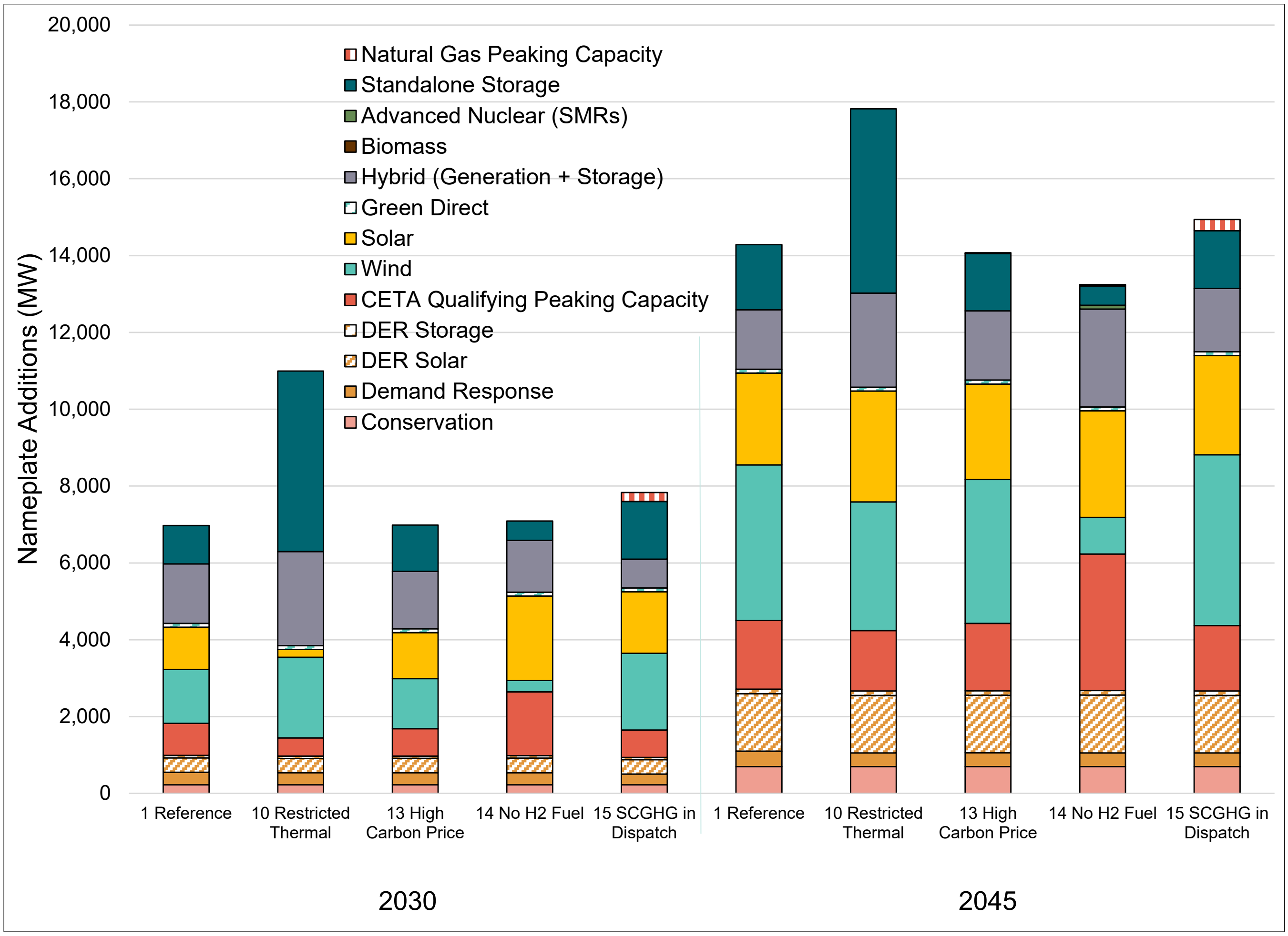
Sensitivity 10 No New Thermal before 2030, and Biodiesel as the Alternative Fuel: Sensitivity 10 adds 4,700 MW of storage to the portfolio through 2030. Once we removed the thermal restriction, an additional 1,569 MW of CETA-qualifying peaking resources were added to the portfolio, while only 100 MW of storage was added to the portfolio. The major difference between sensitivity 10 and the reference portfolio is an additional 4,000 MW of storage and hybrid resources and 200 MW less of CETA-qualifying peaking resources. We can explain this difference because as the portfolio becomes saturated with storage, the ELCC decreases.

Sensitivity 13 High Carbon Price based on the Ceiling Price Assumption: Overall builds are similar for sensitivity 13 and the reference portfolio. By 2045, sensitivity 13 has 100 MW less wind and solar resources, 50 MW less storage resources, 41 MW less of demand response, and nearly identical CETA-qualifying resources.

Sensitivity 14 No Hydrogen Fuel available: Without access to hydrogen fuel, sensitivity 14 incorporates 3,555 MW of frame peaker biodiesel resources. Interestingly, the increase in frame peaker biodiesel resources reduces the total capacity of stand-alone storage and utility-scale wind resources added to the portfolio. To meet the CETA requirement, we see a shift to increased utility-scale solar resources added in sensitivity 14. We also see the addition of 100 MW of advanced nuclear SMR resources in 2045.

Sensitivity 15 SCGHG in dispatch: Overall, we see more renewable resources added to the portfolio in the near term and a total of 8,400 MW of renewable resources added by 2045. Though surprising, we see one natural gas frame peaker and two hydrogen blend peakers added in 2024 in sensitivity 15 compared to one biodiesel peaker in the reference portfolio for the same year. These peakers are added to meet the peak capacity needs and resource adequacy requirements. The levelized cost of the capacity of the natural gas frame peaker plant with the SCGHG as an externality cost is $114/kw-yr, whereas the levelized cost of capacity with the SCGHG in dispatch is $104/kw-yr. When modeling SCGHG in dispatch, there are adverse effects on the cost of capacity of peaking resources which, in this case, led to increased resource additions earlier in the time horizon.

Figure 8.21: Resource Additions — Requested Sensitivities



7. Portfolio Benefit Analysis Results

This section describes the results of the portfolio benefit analysis.

➔ Appendix I: Electric Analysis Inputs and Results provides all underlying data, calculations, and a summary of the results in an Excel spreadsheet and may be a useful reference while reading this section.

7.1. Reference Portfolio

All results from the portfolio benefit analysis are relative to the reference portfolio. We used relative measures in this analysis because prescriptive guidelines on creating an equitable energy portfolio are currently unavailable. Relative measures provide us with an understanding of how one portfolio may enable more equitable outcomes than another.

The reference portfolio includes many aspects of an equity-enabling portfolio. The reference portfolio is the least-cost solution[13] identified by the AURORA long-term capacity expansion model: because electricity affordability is essential in enabling equitable outcomes, a low-cost portfolio is desirable. The reference portfolio produces more greenhouse gas emissions than most other portfolios analyzed but reaches zero greenhouse emissions by 2045. Similarly, the reference portfolio has higher outdoor air quality emissions (SO_2, NO_x, and PM) than most other portfolios but sees significant reductions by the end of the planning horizon.

The reference portfolio adds an estimated 45,736 jobs from new resource additions, more than many other portfolios analyzed. The reference portfolio is in the top third of portfolios for demand response peak capacity and demand response customer participation metrics. However, the reference portfolio lacks customer participation in distributed energy resources for both solar and storage. While the reference portfolio may have a CBI index of zero, it provides various customer benefits and represents a strong starting point for other portfolios.

Table 8.7 presents the reference portfolio CBI metrics against which we compared all other portfolios.

Table 8.7: Reference Portfolio CBI Metrics

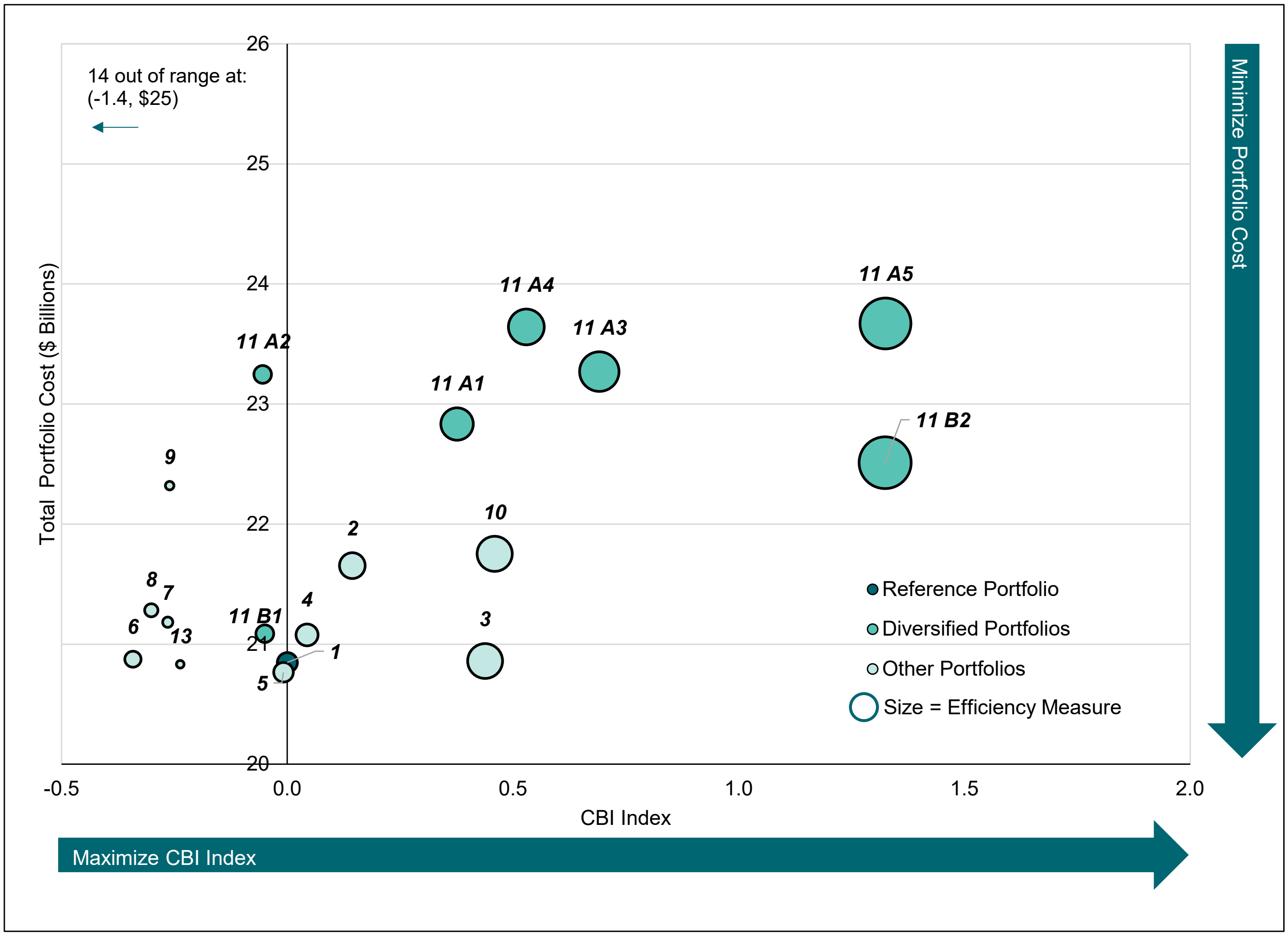
CBI Metric	Reference Portfolio
Cost (, Billions)	20.85
GHG Emissions (Short Tons)	48,824,734
SO_2 Emissions (Short Tons)	28,841
NO_x Emissions (Short Tons)	11,426
PM Emissions (Short Tons)	9,036
Jobs (Total)	45,736
Energy Efficiency Added (MW)	695
DR Peak Capacity (MW)	291
DER Solar Participation (Total New Participants)	12,115
DR Participation (Total New Participants)	513,238
DER Storage Participation (Total New Participants)	8,125

Figure 8.22 shows the results of the portfolio benefit analysis for all portfolios. Each portfolio is plotted with its CBI index value on the x-axis and total portfolio cost on the y-axis to show the tradeoff between equity enabling value and cost. The most desirable portfolios appear in the lower right corner of the plot, where cost is minimized and the CBI index is maximized. The point size estimates the CBI index per dollar spent on the portfolio, where larger points represent greater value per cost.

We plotted the reference portfolio at the CBI index equals zero line. We plotted portfolios containing elements that improve upon the reference portfolio's ability to enable equitable outcomes to the right of this line and those which may detract from equitable outcomes to the left of this line.

[13] Portfolios 5 and 13 are slightly lower cost than the reference portfolio by $80 million and $10 million, respectively. These small decreases in cost are within the 1 percent study precision tolerance of the AURORA long-term capacity expansion model.

Figure 8.22: Portfolio Benefit Analysis Results



7.1.1. Energy Efficiency

Our analysis shows portfolios that include increased energy efficiency measures tend to enable more equitable outcomes than the reference portfolio, as observed by the relationship between portfolios 2, 3, the diversified portfolios, and the reference portfolio. Portfolios 2, 3, and the diversified portfolios include increased energy efficiency measures. The reference case economically selected up to 695 aMW of conservation by 2045. We tested a large increase in energy efficiency by adding 923 aMW of conservation by 2045 in portfolio 2. This resulted in a relatively small increase in the CBI index, +0.14, but a much higher cost, +810 million. Understanding that increasing conservation results in diminishing returns, we tested slightly less conservation in portfolio 3 by adding 818 aMW and observed a larger increase in CBI index, +0.44, and a smaller increase in cost, +10 million.

The relationship between portfolios 2 and 3 illustrate the complexity of interaction between individual CBI metrics, the overall CBI index, and cost. Energy efficiency is one of the metrics used in this CBI index calculation, so intuitively, increasing its value should increase the overall CBI index. However, by reducing the amount of energy efficiency from 923 aMW to 818 aMW, portfolio 3 added other resources, which improved the CBI index for other metrics resulting in a higher overall CBI index at a lower cost.

As we developed the diversified portfolios, we incorporated 818 aMW of conservation, given the large increase in the CBI index for the relatively small increase in total portfolio cost.

7.1.2. Pumped Hydroelectric Storage

Portfolios that include PHES tend to have a lower CBI index than the reference portfolio. Portfolios 6, 7, 8, and the diversified portfolio include PHES. PHES is a costly resource and was not selected economically by any portfolios, so we tested scheduled additions of PHES to understand any benefit in diversifying energy storage away from solely battery energy storage.

We found that PHES delays the need to add thermal peaking capacity and reduces the dispatch of existing thermal resources when added to a portfolio resulting in fewer greenhouse gas emissions. Unfortunately, adding PHES tends to reduce the number of jobs expected from portfolios and reduces the amount of demand response selected by the portfolio resulting in an overall CBI index of less than zero or worse than the reference portfolio and portfolios 6, 7, and 8. Given the reduction of greenhouse gas emissions and diversification benefits of PHES, we decided to add PHES to the diversified portfolios. In portfolios 11 A5 and 11 B2, we controlled for the negative CBI index impacts of PHES by scheduling distributed solar and battery resources, discussed in Section 7.1.3, and maximizing demand response programs, resulting in portfolios with the highest overall CBI indices.

7.1.3. Distributed Energy Resources

We tested portfolios 4 and 5, which scheduled additions of distributed energy resources, solar, and storage, respectively, to understand how adding these resources would impact the cost. Distributed energy resources tend to cost more than their utility-scale counterparts and, therefore not selected in the reference portfolio. However, we created customer benefit indicators precisely to monitor customer participation in distributed solar and distributed storage technologies. We thought adding these resources to the portfolio would significantly increase the overall CBI index. However, portfolio 4, which adds distributed solar, only scores marginally better than the reference portfolio, and portfolio 5 scores worse. Adding distributed energy resources tends to reduce the number of jobs associated with the portfolio, and the amount of demand response added. These changes result in little net benefit for the increased DER participation metrics.

However, when we added DERs in coordination with other resources, the benefit became much stronger, as demonstrated in diversified portfolios 11 A3, 11 A4, 11 A5, and 11 B2, which have overall CBI indices much greater than the reference portfolio.

7.1.4. Diversified Portfolios

Diversified portfolios include several scheduled resource additions to create a diverse mix of resources within the portfolio. Increased diversification enables more equitable outcomes through greater participation in DER, more demand response programs, and lower greenhouse gas and outdoor air quality emissions. Portfolios 11 A5 and 11 B2, the most diversified portfolios, tie for the highest overall CBI index at +1.32 from the reference portfolio. Considering the tradeoff between the CBI index and cost, 11 B2 provides the better value, given that it is 1.16 billion less expensive than 11 A5.

8. Stochastic Portfolio Analysis Summary

We test the robustness of different portfolios with stochastic risk analysis to learn how well the portfolio might perform under various conditions. In this analysis, we run select portfolios through 310 simulations or draws[14] that vary power prices, gas prices, hydroelectric generation, wind generation, solar generation, load forecasts (energy and peak), and plant forced outages. From this analysis, we can quantify the risk of each portfolio. We tested two different portfolios in the stochastic portfolio analysis, as and described in Table 8.8.

Table 8.8: Portfolios Tested for Stochastic Analysis

ID	Name	Description
1	Reference Portfolio	The reference portfolio is a least-cost, CETA-compliant portfolio that allows the AURORA long-term capacity expansion model to optimize resource selection with as few constraints as possible. The reference portfolio is a basis against which to compare other portfolios.
11 B2	Preferred Portfolio	This sensitivity is the most diversified portfolio we developed in this report, but without adding advanced nuclear SMR technology to the portfolio. We built this portfolio on the least-cost reference portfolio; it increases conservation and adds pumped hydroelectric storage, distributed energy, and demand response.

8.1. Risk Measures

The results of the risk simulation allow us to calculate portfolio risk. We calculated risk as the average value of the worst 10 percent of outcomes (TailVar90). This risk measure is the same one the Northwest Power and Conservation Council (NPCC) uses in its power plans.

8.2. Stochastic Results

Our electric stochastic analysis holds portfolio resource builds constant across the 310 simulations. These resource forecasts are a guide. We will make resource acquisition decisions based on the latest information from the 2021 All-Source RFP[15] and other acquisition processes. The risk simulation results, however, indicate the portfolio costs risk range under varying input assumptions. Table 8.9 compares the portfolio costs for the deterministic run; the mean portfolio cost across 310 simulations, and the TailVar90 of portfolio cost for the two portfolios examined for the stochastic analysis. The mean portfolio cost of the 310 simulations is lower than the deterministic model runs for the reference and preferred portfolios.

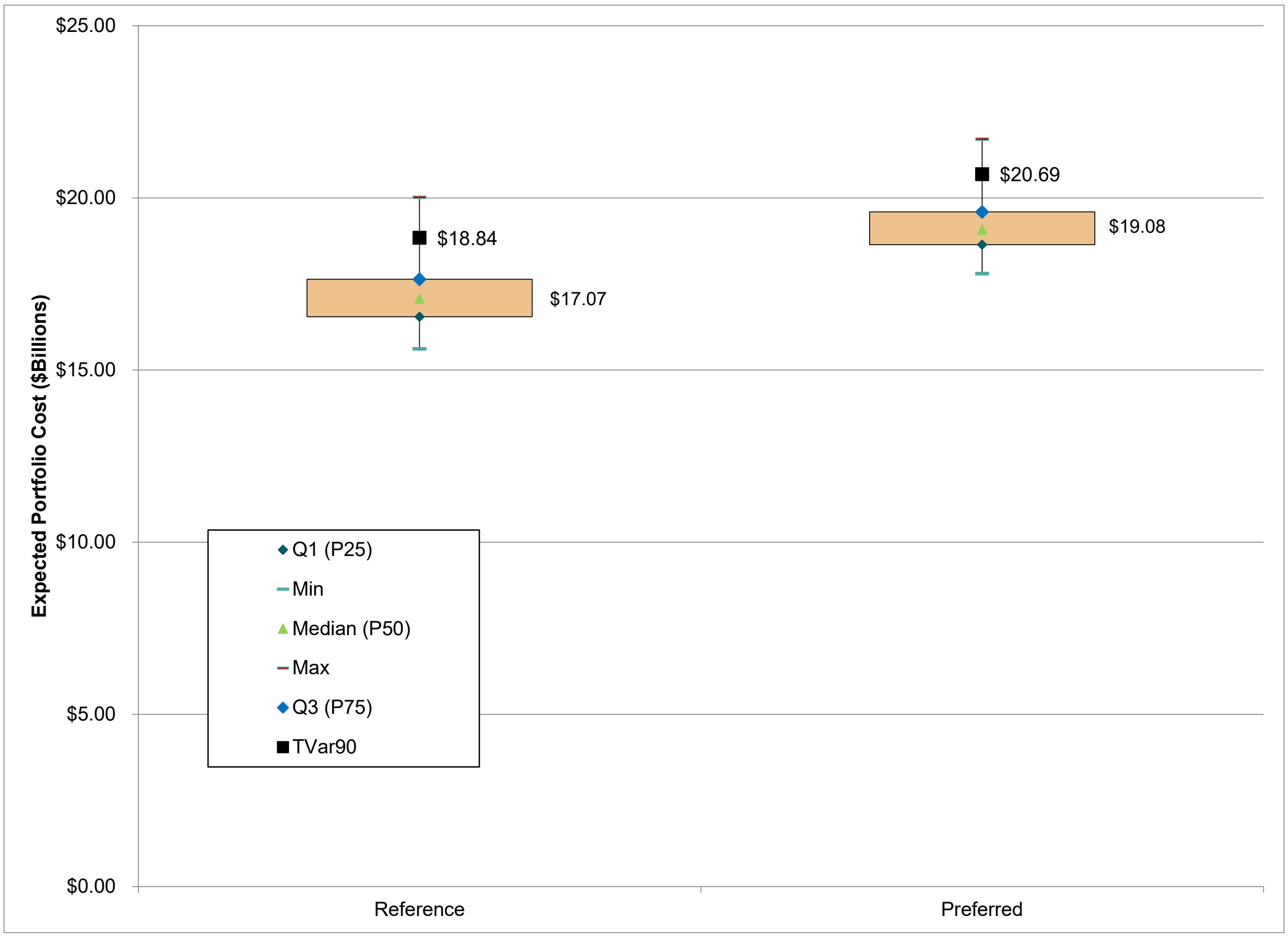
[14] Each of the 310 simulations is for the 24-year IRP forecasting period, 2022-2045.
[15] https://www.pse.com/en/pages/energy-supply/acquiring-energy

Table 8.9: Portfolio Costs Across 310 Simulations (Billion$)

Revenue Requirement	Portfolio	Deterministic ($)	Difference from Reference ($)	Mean ($)	Difference from Reference ($)	TVar90 ($)	Difference from Reference ($)
1	Reference	17.60	--	17.20	--	18.80	--
11 B2	Preferred	19.60	2.00	19.20	2.00	20.70	1.90

Figure 8.23 compares the expected portfolio costs for each portfolio. The vertical axis represents the costs, and the horizontal axis represents the portfolio. The green triangle on each box represents the median for that portfolio. The interquartile range box represents the middle 50 percent of the data. The whiskers extending from either side of the box represent the portfolio's minimum and maximum data values. The black square represents the TailVar90, the average value for the highest 10 percent outcomes.

Figure 8.23: Range of Portfolio Costs across 310 Simulations



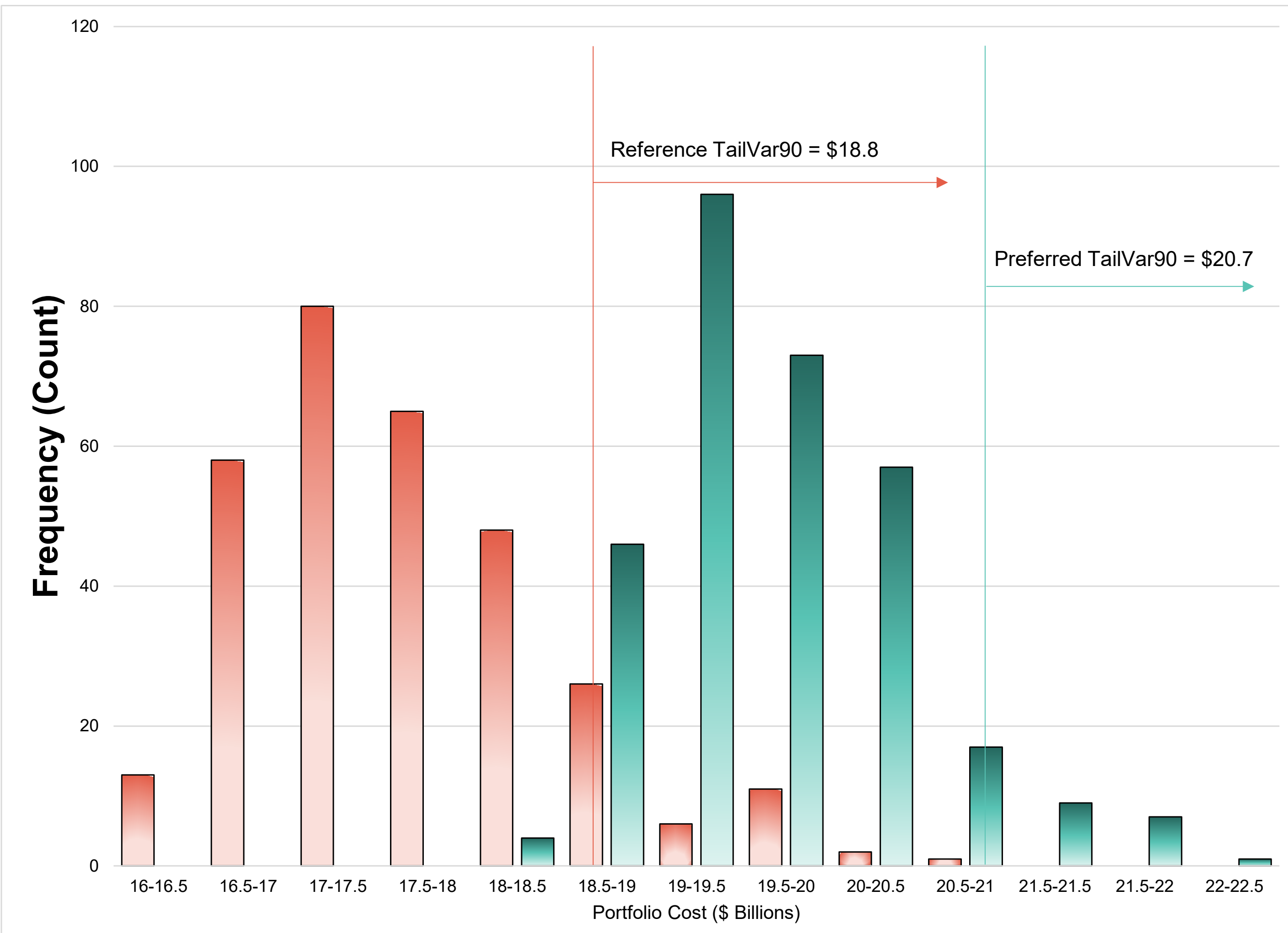
Key results of the analysis include:

- The mean value for the sensitivity 11 B2 portfolio is higher than the reference portfolio, suggesting that diversifying the resource mix results in higher portfolio costs.

- The range for sensitivity 11 B2 is narrower than the reference portfolio, indicating that the varied inputs have less of an impact on the overall portfolio costs.
- While the interquartile range for sensitivity 11 B2 portfolio is comparatively narrower than the reference portfolio, suggesting that the expected portfolio costs are less variable and higher, TailVar90, at 20.7 billion, indicates a risk of higher costs for this portfolio.

Figure 8.24 compares the reference to sensitivity 11 B2. We sorted each simulation's portfolio cost results into bins containing a narrow range of expected portfolio costs. The shorter right-hand tail and lower TailVar90 value of sensitivity 11 B2 indicate less risk associated with sensitivity 11 B2 than the reference portfolio, despite the higher average portfolio cost.

Figure 8.24: Frequency Histogram of Expected Portfolio Cost ($ Billions) — Reference vs. Sensitivity 11 B2



In addition to the expected portfolio costs, we evaluated the expected SCGHG. Table 8.10 and Figure 8.25 compare the SCGHG costs for the deterministic run, the mean across 310 simulations, and the TailVar90 of the two portfolios.

Key results of the analysis include:

- In contrast, the mean value for the sensitivity 11 B2 portfolio is higher than the reference portfolio, suggesting that diversifying the resource mix to include more conservation and distributed energy resources results in lower average emissions.
- The range for sensitivity 11 B2 is more comprehensive than the reference portfolio, indicating the inputs were varied have a bigger impact on the overall SCGHG costs.

Table 8.10: SCGHG across 310 Simulations ($ Billions)

SCGHG	Portfolio	Emissions ($)	Difference from Mid ($)	Mean ($)	Difference from Mid ($)	TVar90 ($)	Difference from Mid ($)
1	Reference	3.24	--	3.59	--	5.02	--
11 B2	Preferred	3.33	0.09	3.33	(0.26)	4.79	(0.23)

Figure 8.25: Range of SCGHG Costs across 310 Simulations

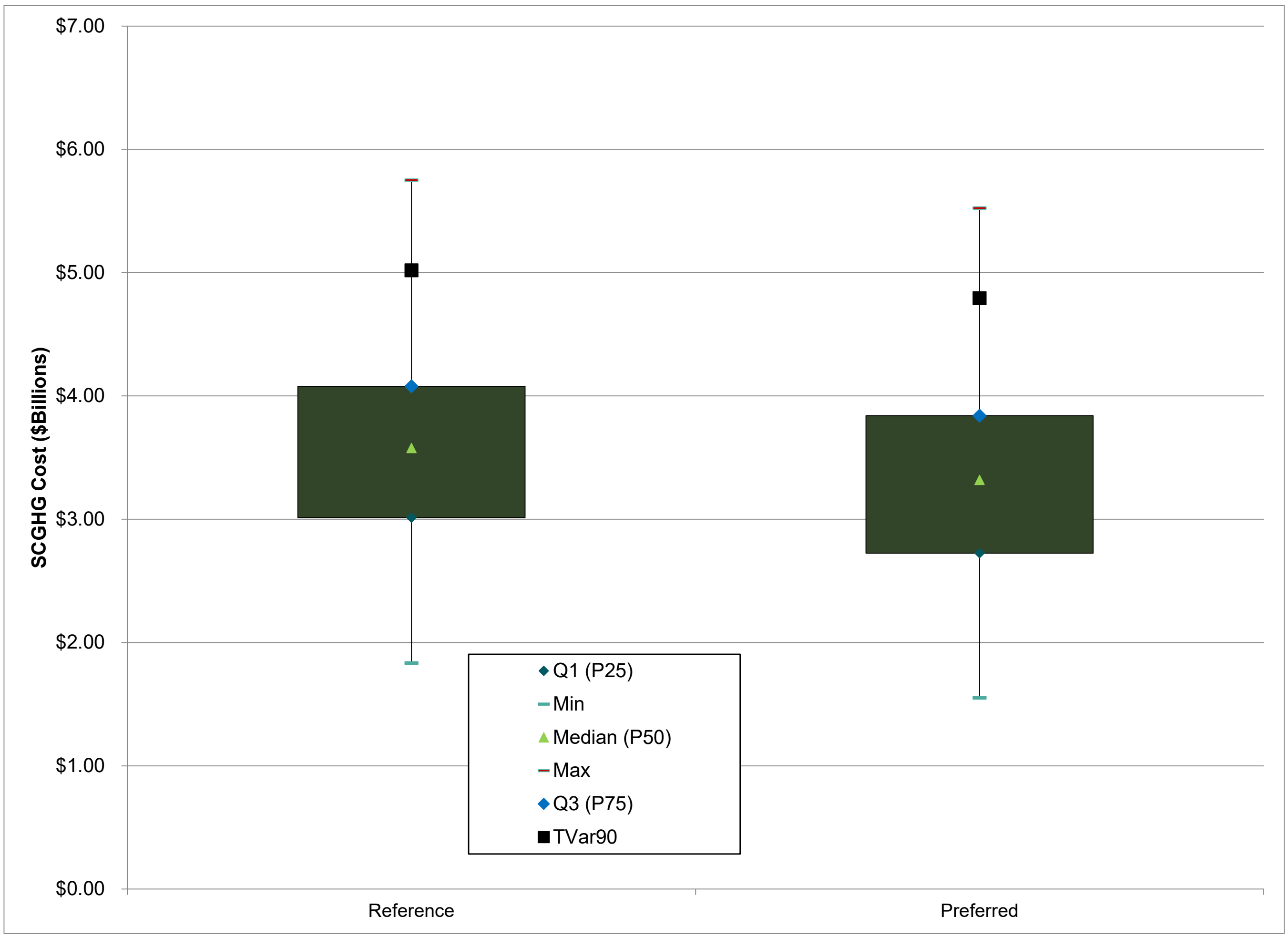


EXHIBIT 50-2

2025

Electric Integrated Resource Plan

AVISTA

Safe Harbor Statement

This document contains forward-looking statements. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond the Company's control, and many of which could have a significant impact on the Company's operations, results of operations and financial condition, and could cause actual results to differ materially from those anticipated.

For a further discussion of these factors and other important factors, please refer to the Company's reports filed with the Securities and Exchange Commission. The forward-looking statements contained in this document speak only as of the date hereof. The Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New risks, uncertainties and other factors emerge from time to time, and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the Company's business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

Production Credits

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2025 Electric IRP
Executive Summary

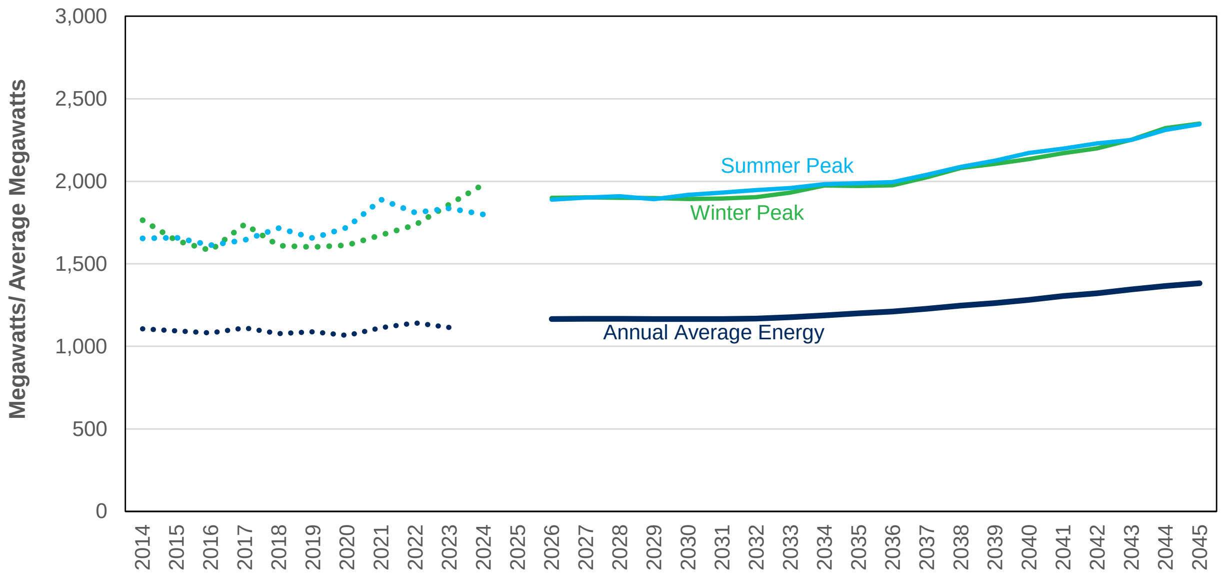
The Integrated Resource Plan (IRP) is a comprehensive planning document outlining Avista's strategy to meet the future energy needs of its customers in a cost-effective and sustainable manner. It involves analyzing different energy resources, such as wind, solar, plant upgrades, energy storage, natural gas, and energy efficiency to find the best mix of resources to ensure a reliable and affordable energy supply. The IRP process includes public input, regulatory, and peer review to ensure the plan aligns with IRP requirements and expectations. Essentially, the IRP serves as a roadmap for the utility's long-term energy planning and decision-making as it begins its resource acquisition process.

Since 2014, Avista's annual energy demand has remained flat with an annual growth rate of 0.09% per year. Between recent economic growth in the community and a new large load beginning in August 2024, the 2026 loads are forecasted to be 4.5% higher than 2023 levels, an increase of 50 aMW. Absent any additional new large loads, annual energy growth is projected to continue to be slow over the next seven years. Load levels are relatively flat due to energy efficiency and a reduction of line losses from exiting Colstrip at the end of 2025. Over the next 20 years, annual growth is expected to be 0.91% on average with the last 10 years of the plan growing at 1.4% annually with more electrification of buildings and transportation.

While annual average energy growth is historically flat, both winter and summer peak loads recently hit all-time highs. By 2024, summer peak load was 8.8% higher and winter peak loads were 12.2% higher[1] than 2014 actual peak load. Avista anticipates peak growth to continue to grow faster than energy. The summer peak load is forecast to grow by 1.14% annually and winter peak by 1.12% over the next 20 years. The last 10 years of the plan show significantly higher load growth with 1.7% annual peak load growth due to expectations of building and transportation electrification. Figure 1 summarizes Avista's historical and forecasted demand.

[1] Peak loads are adjusted for demand curtailment.

Figure 1: Customer Load Forecast



Energy efficiency continues to be a cost-effective method to reduce customer demand and avoid new generating resources. Customer load today would be 156 aMW higher absent these efforts. In 2045, energy efficiency is expected to reduce load by an additional 105 aMW, thus meeting 32% of future demand. The top energy efficiency methods to reduce future load include offering incentives for more efficient lighting, space heating and cooling, and water heating. The 2026-2027 biannual energy efficiency target in Washington is 73,672 MWh and for Idaho is 19,595 MWh.

In 2026, Avista's generating capability is approximately 52% from clean energy sources and 48% from natural gas resources as shown in Figure 2. Absent the economic dispatch of natural gas generators, Avista could generate 1,569 aMW in normal weather conditions. Given the 2026 load forecast is 1,165 aMW, Avista is long on energy resources and intends to be long on generating capability to prepare for the risk of low hydro conditions and to meet peak load creating energy length. The excess energy is sold to reduce Avista's customer rates when beneficial for our customers.

Due to Avista's energy position length compared to demand; capacity planning for sustained peak hours is Avista's most significant constraint on the system. Due to recent peak load growth, the Company is in a short to even position over the next three years during both summer and winter peaks. Avista uses a 24% planning reserve margin above its expected monthly peak load in the winter and 16% in summer months to identify when it should acquire new capacity. With these planning metrics, Avista's first long-term short position begins in 2030 as shown in Figure 3. Most of the 2030 shortfall is due to an assumed retirement of the 66 MW Northeast Combustion Turbines (CTs) in Spokane, Washington.

Figure 2: 2026 Generating Capability by Fuel Source

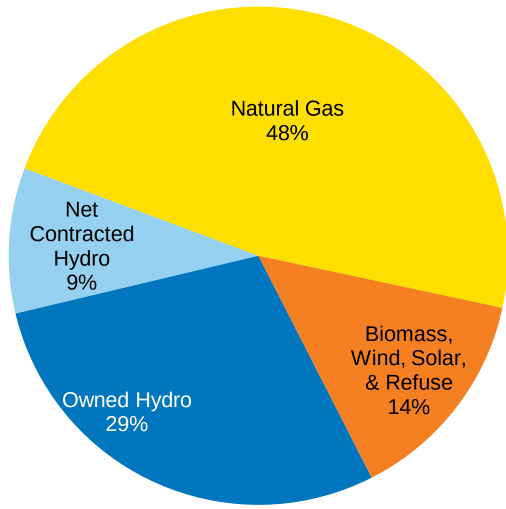
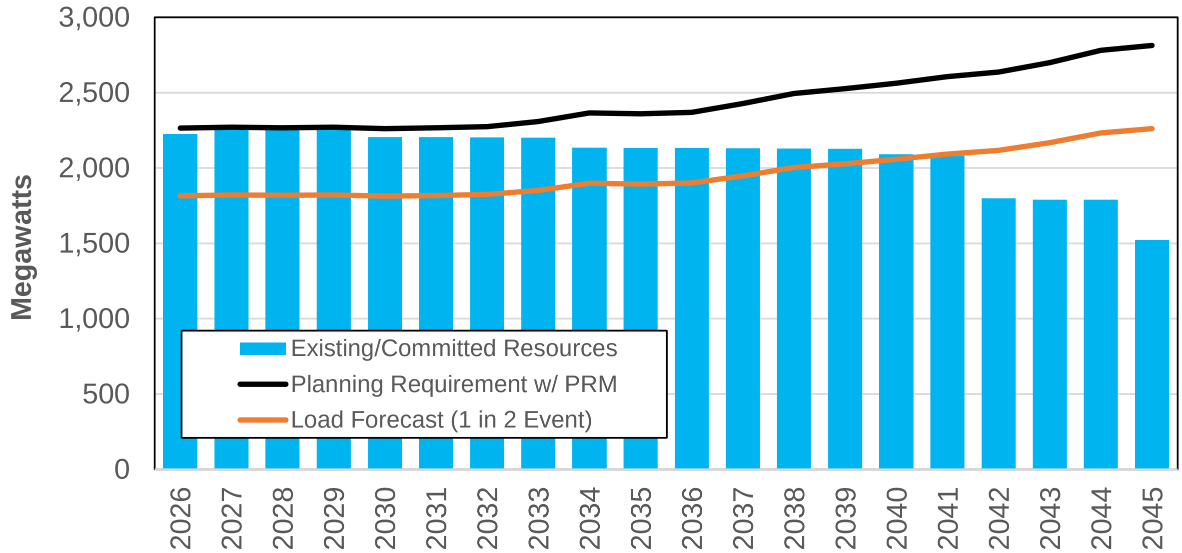


Figure 3: January Peak Load and Resource Position



To address capacity deficits Avista anticipates issuing an all-source request for proposals (RFP) in May 2025 to cover future resource shortfalls. The RFP may also bring cost effective resource options to meet future Washington Clean Energy Transformation Act (CETA) requirements or take advantage of low-cost energy resource opportunities. Avista's Preferred Resource Strategy (PRS) attempts to forecast the most cost-effective resource opportunities to meet Avista's customer needs. Given capacity needs are small until the mid-2030s, the resource strategy does not anticipate large resource acquisitions immediately unless the energy market is insufficient, loads grow, or early acquisition benefits from tax credits.

Avista serves both Washington and Idaho customers, but resource policies differ between the two jurisdictions. Avista balances this difference by selecting resources in the IRP based on the state driving the resource need. Short run capacity deficits are driven by Idaho's capacity needs, but in the long run, Washington's CETA policy drives most of the resource selection. Avista currently allocates resources and costs based on each state's load allocation, where approximately 2/3 of the generation is assigned to Washington and 1/3 is assigned to Idaho. The divergence where Idaho's resource selection prefers natural gas CTs and wind, while Washington's strategy selects only clean energy resources, challenges actual resource acquisition to ensure cost recovery without separating the system into two. Due to this resource divergence, and the plan being based on generic resources, actual resource acquisitions may differ from this plan.

As reflected in Table 1 below, in the first 10 years of the plan, market reliance is anticipated for smaller capacity needs in 2026 to 2028. Avista proposes using the energy market in this period due to the small shortfall. In the meantime, Avista intends to begin both direct load control and rate-based demand response (DR) programs.[2] The next resource is distributed solar using Washington State's community solar grants, the selection include a project each year throughout this IRP as a method to ensure an equitable transition to clean energy for Washington's Highly Impacted Communities and Vulnerable Populations, jointly referred to as Named Communities. The first utility scale resource acquisition begins in 2029 with wind followed by a natural gas CT in 2030. Avista anticipates a majority of the early resource additions throughout the first 10 years to be 857 MW of wind to take advantage of the Inflation Reduction Act (IRA) incentives to cover minor resource adequacy needs and set up the utility to have enough clean energy resources further out in the plan.

[2] Demand response capacity amounts are for the 2045 potential. These programs are expected to ramp over time as customers sign up to participate.

Table 1: Preferred Resource Strategy in MW of Capability (2026 to 2035)

Resource	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2026-2035
Market	39	4	10	-	-	-	-	-	-	-	n/a
Regional Transmission Expansion	-	-	-	-	-	-	-	300	-	-	300
Natural Gas CT	-	-	-	-	90	-	-	-	-	-	90
NW Wind	-	-	-	200	200	100	-	157	-	-	657
Montana Wind	-	-	-	-	-	100	100	-	-	-	200
Distributed Solar	-	0.5	0.6	0.6	0.7	0.8	0.8	1.0	0.5	0.5	6
Demand Response (Pricing)	14	-	-	3	-	-	-	-	-	6	23
Demand Response (DLC)	10	-	-	-	-	-	-	-	-	3	13
Annual Total (Excludes Market)	**25**	**1**	**1**	**203**	**291**	**201**	**101**	**458**	**1**	**9**	**1,290**

Later in the plan (Table 2 showing the 2036 to 2045 PRS), Avista's resource needs grow due to rapid load growth and resource retirements. In this period, Avista will continue to invest in DR and distributed solar but will also need to rely on new technologies to meet capacity requirements using non-greenhouse gas emitting resources, including ammonia and hydrogen-based fuels via power to gas processes, long duration energy storage, and nuclear energy. Avista also sees a future in supplementing its 2045 clean energy targets with solar paired with energy storage, biomass, and geothermal. The 568 MW of wind in the last 10 years includes replacing expiring wind power purchase agreements (PPA) at the Palouse and Rattlesnake Flat Wind facilities. The 185 MW of natural gas CTs are the lowest cost resource to meet Idaho's capacity deficits. In 2045, changes to current facilities will be integral in meeting Washington's clean energy objectives. The first is co-firing hydrogen produced using clean energy blended with natural gas at Coyote Springs 2, a 320 MW natural gas facility capable of co-firing 30% hydrogen. The second change is upgrading the existing Kettle Falls biomass generator and adding a second unit.

New transmission is integral to meeting Avista's future needs. Between Avista's 10-year system assessment and this IRP, new transmission is needed to access markets and to integrate new load and generation. The IRP identifies a regional effort to develop a transmission path between Colstrip, Montana and North Dakota via a DC intertie. Currently being developed by Grid United, the North Plains Connector would be an economically viable option to assist in meeting long-term capacity requirements. This plan includes 300 MW of this new transmission capacity beginning in 2032. New transmission upgrades will also be needed to integrate proposed resources selected in PRS, including upgrades between Spokane and North Idaho, and access to energy markets. Other major transmission projects proposed include the addition of the Blue Bird – Garden Springs 230 kV substation in west Spokane, upgrading the Colstrip transmission system in Montana, and upgrading the Lolo-Oxbow line between Avista and Idaho Power.

Table 2: Preferred Resource Strategy in MW of Capability (2036 to 2045)

Resource	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2036-2045
Natural Gas CT	-	-	-	-	90	-	95	-	-	-	185
NW Wind	-	-	-	-	-	140	-	120	108	200	568
Distributed Solar	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	5
Utility-Scale Solar	-	-	-	-	-	-	-	180	120	-	300
4-hr Batteries	-	-	-	-	-	-	-	90	60	-	150
Long Duration Energy Storage	-	-	-	-	-	-	-	-	26	85	111
Power to Gas CT (Ammonia)	-	-	-	-	90	-	210	-	-	-	300
Hydrogen co-fire at Coyote Springs 2	-	-	-	-	-	-	-	-	-	94	94
Biomass	-	-	-	-	-	-	-	-	-	68	68
Geothermal	-	-	-	-	-	-	-	-	-	20	20
Nuclear	-	-	-	-	-	-	-	-	-	100	100
Demand Response (Pricing)	-	-	3	-	4	-	-	-	-	-	7
Demand Response (DLC)	-	-	2	20	-	6	-	11	7	-	45
Annual Total	**1**	**1**	**5**	**21**	**185**	**146**	**305**	**402**	**322**	**568**	**1,954**

Avista evaluated 25 potential resource scenarios to understand how the resource portfolio may change under differing future assumptions. Highlights from the scenario analysis include:

- 4-hour battery energy storage is the least cost resource to meet immediate capacity needs absent market acquisitions due to short resource development timelines.
- Significant nuclear energy, energy storage, and solar will be required in the high load scenarios due to the limited ability to add other resources due to limited existing transmission and the high cost to build new transmission.
- Avista's wind acquisition strategy depends on the availability of low-cost sites without significant transmission interconnect costs, but these sites could be obtained by other utilities and may lessen Avista ability to acquire lower cost resources.
- Avista does not need additional clean energy resources to comply with CETA until the mid-2030s. Due to IRA incentives and expectations of high wholesale electric prices, acquiring wind generation prior to physical need is economically beneficial to customers due to the ability to sell the power on the wholesale market, however wind acquisition could be delayed if pricing of future projects is higher than the energy market forecast.
- Natural gas resources are the lowest cost capacity resource for Idaho customers so long as transmission and fuel transportation (or fuel storage) can be available (or constructed).
- Solar is less favored compared to wind due to the low wholesale market price forecast in the middle of the day driven by the abundance of other utilities pursuing solar.
- The resource adequacy targets utilities should plan for in IRPs remains uncertain, but regional solutions such as the Western Resource Adequacy Program (WRAP) could reduce Avista's cost to meet resource adequacy on its own. Even if higher

resource targets are preferred, the cost impact of additional capacity is manageable.

From this IRP, Avista has identified several Actions Items to undertake as it moves to the next plan. First, Avista will be working with interested parties in Washington State to develop its Clean Energy Implementation Plan (CEIP) for 2026 to 2029. This plan will be filed October 1, 2025. Beyond the CEIP, Avista has the following goals:

- Determine the Northeast CTs retirement date and develop a plan for replacing the lost capacity.
- Pursue transmission expansion opportunities within Avista’s service territory and those connecting with Avista’s transmission system.
- Develop an all-source Request for Proposal (RFP) in 2025 for the new resources needed to meet future capacity deficiencies and determine if the renewable energy identified in the PRS is cost effective. The RFP will request proposals for demand response opportunities.
- Investigate options to increase natural gas availability for existing and potential natural gas generation.

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Acronym List

ADSS: Avista's Decision Support System

AEG: Applied Energy Group

aMW: Average Megawatt(s)

ARAM: Avista Reliability Assessment Model

BCP: Biennial Conservation Plan

CAIDI: Customer Average Interruption Duration Index

CCA: Climate Commitment Act

CEMI: Customer Experiencing Multiple Interruptions

CBO: Community Based Organizations

CCA: Climate Commitment Act

CC&B: Customer Care and Billing

CDD: Colling Degree Day

CEAP: Clean Energy Action Plan

CEIP: Clean Energy Implementation Plan

CETA: Clean Energy Transformation Act

CBI: Customer Benefit Indicator

CPA: Conservation Potential Assessment

CPI: Consumer Price Index

CT: Combustion Turbine

CCCT: Combined Cycle Combustion Turbine

CTA: Consumer Technology Association

DER: Distributed Energy Resource

DOE: Department of Energy

DOH: Department of Health

DPAG: Distribution Planning Advisory Group

DR: Demand Response

EAG: Equity Advisory Group

EAAG: Energy Assistance Advisory Group

EEAG: Energy Efficiency Advisory Group

EIA: Energy Independence Act

ELCC: Equivalent Load Carrying Capability

ERWH: Electric Resistance Water Heater

EUE: Expected Unserved Energy

EUI: Energy Use Index

EV: Electric Vehicle

FERC: Federal Energy Regulatory Commission

FSP: Forward Showing Program

H2: Hydrogen

HDD: Heating Degree Day

HG: Mercury

IAQ: Indoor Air Quality

IOU: Investor-Owned Utility

IP: Industrial Production Index of the U.S. Federal Reserve

IPCC: Intergovernmental Panel on Climate Change

IRP: Integrated Resource Plan

GHG: Greenhouse Gas

GISS: Goddard Institute for Space Studies

GWh: Gigawatt-hour(s)

HRSG: Heat Recovery Steam Generator

LDC: Local Distribution Center

LGIR: Large Generation Interconnection Request

LOLE: Loss of Load Expectation

LOLEV: Loss of Load Expected Events

LOLH: Loss of Load Hours

LOLP: Loss of Load Probability

MIP: Mixed Integer Program

MISO: Mid-Continent Independent System Operator

MSA: Metropolitan Statistical Area

MW: Megawatt(s)

MWh: Megawatt-hour(s)

NC: Named Community

NCIF: Named Community Investment Fund

NEEA: Northwest Energy Efficiency Alliance

NEI: Non-Energy Impact

NOx: Nitrous Oxide

NREL: National Renewable Energy Laboratory

OASIS: Open Access Same-time Information System

O&M: Operations and Maintenance

P2G: Power to Gas

PPA: Power Purchase Agreement

PRiSM: Preferred Resource Strategy Model

PRM: Planning Reserve Margin

PRS: Preferred Resource Strategy

PT: Production Tax (ratio)

PUD: Public Utility District

PURPA: Public Utility Regulatory Policies Act

QCC: Qualifying Capacity Credit

QF: Qualifying Facility

RA: Resource Adequacy

RAP: Real Average Energy Price

RCP: Representative Concentration Pathway

RCW: Revised Code of Washington

RFP: Request for Proposal

RMJOC: River Management Joint Operating Committee

SBCC: State Building Code Council

SCR: Selective Catalytic Reduction

SMR: Small Modular Reactor

SO2: Sulfur Dioxide

SPP: Southwest Power Pool

T&D: Transmission and Distribution

TAC: Technical Advisory Committee

TE: Transportation Electrification

TEP: Transportation Electrification Plan

TOU: Time of Use (Rates)

TRC: Total Resource Cost

UCT: Utility Cost Test

UEC: Unit Energy Consumption

UPC: Use Per Customer

UTC: Washington Utilities and Transportation Commission

VOC: Volatile Organic Compounds

VER: Variable Energy Resource

WAC: Washington Administrative Code

WECC: Western Electricity Coordinating Council

WPP: Western Power Pool

WRAP: Western Resource Adequacy Program

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1. Introduction

Avista is a multijurisdictional utility serving electric in Washington and Idaho and natural gas customers in Washington, Idaho, and Oregon. Each state has its own rules and regulations regarding filing dates, content, and methods used to develop electric integrated resource plans. Avista works diligently to consolidate the different state requirements into one plan filed every other year.

The energy planning requirements between Avista's two electric jurisdictions take different approaches to planning. Idaho focuses on reliability and serving customers with the lowest cost resources. Washington's energy policy focuses on the lowest reasonable cost while transitioning the economy to cleaner energy resources through the Clean Energy Transformation Act (CETA), Climate Commitment Act (CCA) and other related policies. These requirements change how resource planning is approached, the modeling techniques and assumptions being used, and requires careful consideration and implementation of many new issues going well beyond the traditional utility planning requirements of safety, reliability, and lowest cost. These three pillars of resource planning have not gone away and still need to be met along with the new requirements and aspirations. Some of these new requirements will take several iterations to determine how to plan for and implement them while still meeting the traditional planning requirements.

Washington requires clean energy use and development to meet CETA's 100% clean energy goals, additional emphasis on health and equity issues, promoting more diverse participation in the planning process, and disincentives for greenhouse gas emitting resources. These disincentives include the end of coal-fired plants serving Washington customers by 2026 and the tapering down of the use of natural gas-fired plants as CETA gets closer to its 100% clean energy goal in 2045.

This chapter discusses the IRP requirements for Idaho and Washington, the process used to develop the IRP, where each of the requirements can be found, changes from the 2023 IRP, and concludes with an overview of the chapters and appendices included.

IRP Process

This IRP includes a series of public meetings with a mix of technical experts, such as commission staff, regional utility professionals, project developers, advocacy groups, environmental groups, interested state agencies, and both commercial and residential customers. Table 1.1 lists the dates and topics covered in each of the public meetings with assumptions and concepts used in the creation of this IRP. The meetings included discussions about:

- how loads are expected to be served between 2026 and 2045 and the resources already in place to serve current and future needs,
- the operating and environmental costs and benefits of new resources,
- the costs and benefits of energy efficiency measures and demand response,
- different types of energy storage,
- the expected future and alternate futures, and
- the estimated non-energy impacts of resource decisions.

All these issues combined with the assumptions made and how each are included in the analysis are discussed. The subsequent results of the modeling provide an expectation of future prices for different resources, energy efficiency, demand response, and energy storage options can be evaluated against. Avista develops a preferred portfolio of resources as a roadmap to serving future needs. There are also less technical public meetings for customers and others who are interested in hearing about the plan and providing comments.

Table 1.1: TAC and Public Meeting Dates and Agenda Items

Meeting Date	Agenda Items
TAC 1 – September 26, 2023	• CEIP Update • TAC Process and Methods Proposals • PLEXOS Overview and Back Cast Analysis • Available Resource Options Discussion • Work Plan
TAC 2 Equity Focus – January 30, 2024	• How Avista Includes Equity Principles • Customer Benefit Indicators • How Avista Practices Equity Outcomes • Equity Planning in the IRP
TAC 3 – March 21, 2024	• Review of January Cold Weather Event • Wholesale Price Forecasts – Natural Gas and Electric • Portfolio and Market Scenario Options
TAC 4 – April 9, 2024	• Future Climate Analysis • Economic Forecast & Five-Year Load Forecast
TAC 5 – April 23, 2024	• Long Run Load Forecast • Load Forecast Comparison • Review Planned Scenario Analysis
TAC 6 – May 7, 2024	• Conservation Potential Assessment • Demand Response Potential Assessment
TAC 7 – May 21, 2024	• Variable Energy Resources Study • Portfolio/Market Scenarios
TAC 8 – June 4, 2024	• Electrification Scenarios • New Resource Options Costs and Assumptions • 2030 Loss of Load Probability Study
TAC 9 – June 18, 2024	• Load & Resources Discussion • IRP Generation Option Transmission Planning Studies • Distribution Planning and Microgrids

Technical Modeling Workshop – June 25, 2024	• PRiSM Model Tour • New Resource Cost Model • ARAM Model Tour
TAC 10 – July 16, 2024	• Preferred Resource Strategy Results • Resource Adequacy • Washington Customer Benefit Indicator Impacts • Resiliency Metrics
TAC 11 – July 30, 2024	• Connected Communities Program Update • Avista – Spokane Tribe Energy Resiliency Partnership Update • Preferred Resource Strategy Results • Avoided Costs • Remaining TAC Schedule & Scenario Planning
TAC 12 – August 13, 2024	• Preferred Resource Strategy Results • Avoided Costs
TAC 13 – September 17, 2024	• Energy Efficiency Update • Scenario Analysis
Virtual Public Meetings – Natural Gas and Electric IRPs – November 13, 2024	• Recorded Presentation • Morning Comment and Question Session • Daytime Comment and Question Session

Avista greatly appreciates the valuable contributions and time commitments made by each of its TAC members and wishes to acknowledge and thank the organizations and members who participated in the development of this IRP. Table 1.2 lists organizations participating in the 2025 IRP TAC process.

Table 1.2: External Technical Advisory Committee Participating Organizations

Organization	
Avangrid	National Grid
Applied Energy Group	Northwest LECET
Biomethane, LLC	NW Energy Coalition
Bonneville Power Administration	Northwest Laborers
Building Industry Association of Washington	Northwest Power and Conservation Council
California Hydronics Corporation	Pacific NW Utilities Conference Committee
City of Spokane	Phil Jones Consulting
Clearwater Paper	Puget Sound Energy
Clearway Energy	Pullman City Council
Creative Renewable Solutions	Renewable Northwest
DNV	Residential and Small Commercial Customers
Energy Keepers Inc.	Sapere Consulting
Form Energy	Sun2o Partners
Fortis BC	Tollhouse Energy
Gail Head Development	Utilicom Consulting Group
Grant County PUD	Wartsila Energy
Grid United	Washington SEIA
Idaho Power	Washington State Office of the Attorney General
Idaho Public Utilities Commission	Washington State Department of Enterprise Services
Invenergy	Washington State University
LIUNA	Washington Utilities and Transportation Commission
Mitsubishi Power Americas	White Gull Analytics
Myno Carbon	Whitman County Commission
Sun2o Partners	

Washington IRP Report Requirements

This IRP satisfies the requirements for the content of an IRP defined in WAC 480-100-620 and the minimum requirements under WAC 480-100-620(2-17) include the following shown in Tables 1.3 through 1.18:

Table 1.3: Timing and Plan Horizon

WAC Rule	Requirement	IRP Discussion
WAC 480-100-620(2)	Load Forecast	Chapter 3 – Economic and Load Forecast

Table 1.4: Load Forecast Requirements

WAC Rule	Requirement	IRP Discussion
WAC 480-100-620(2)	The IRP must include a range of forecasts of projected customer demand that reflect the effect of economic forces on the consumption of electricity and address changes in the number, type, and efficiency of end uses of electricity.	Chapter 3 – Economic and Load Forecast

Table 1.5: Distributed Energy Resource Requirements

WAC Rule	Requirement	IRP Discussion
WAC 480-100-620(3)(a)	The IRP must include assessments of a variety of distributed energy resources. These assessments must incorporate nonenergy costs and benefits not fully valued elsewhere within any integrated resource plan model. Utilities must assess the effect of distributed energy resources on the utility's load and operations under RCW 19.280.030 (1)(h). The commission strongly encourages utilities to engage in a distributed energy resource planning process as described in RCW 19.280.100. If the utility elects to use a distributed energy resource planning process, the IRP should include a summary of the results.	Chapter 3- Economic and Load Forecast Chapter 6 – Distributed Energy Resources
WAC 480-100-620(3)(b)(i-iv)	(i) Energy efficiency and conservation potential assessment – The IRP must assess currently employed and potential policies and programs needed to obtain all cost-effective conservation, efficiency, and load management improvements, including the ten-year conservation potential used in calculating a biennial conservation target under chapter 480-109 WAC; (ii) Demand response potential assessment – The IRP must assess currently employed and new policies and programs needed to obtain all cost-effective demand response; (iii) Energy assistance potential assessment – The IRP must include distributed energy programs and mechanisms identified pursuant to RCW 19.405.120, which pertains to energy assistance and progress toward meeting energy assistance need; and (iv) Other distributed energy resource potential assessments – The IRP must assess other distributed energy resources that may be installed by the utility or the utility's customers including, but not limited to, energy storage, electric vehicles, and photovoltaics. Any such assessment must include the effect of distributed energy resources on the utility's load and operations.	Chapter 2- PRS Chapter 6 – Distributed Energy Resources Appendix N- Energy Burden Assessment

Table 1.6: Supply-Side Resource Requirements

WAC Rule	Requirement	IRP Discussion
WAC 480-100-620(4)	The IRP must include an assessment of a wide range of commercially available generating and nonconventional resources, including ancillary service technologies.	Chapter 7 – Supply-Side Resource Options Appendix G – Public Input and Results Data

Table 1.7: Renewable Resource Integration Requirements

WAC Rule	Requirement	IRP Discussion
WAC 480-100-620(5)	An assessment of methods, commercially available technologies, or facilities for integrating renewable resources including, but not limited to, battery storage and pumped storage, and addressing overgeneration events, if applicable to the utility's resource portfolio. The assessment may address ancillary services.	Chapter 7 – Supply-Side Resource Options

Table 1.8: Regional Generation and Transmission Requirements

WAC Rule	Requirement	IRP Discussion
WAC 480-100-620(6)(a)	The IRP must include an assessment of the availability of regional generation and transmission capacity on which the utility may rely to provide and deliver electricity to its customers. (a) The assessment must include the utility's existing transmission capabilities, and future resource needs during the planning horizon, including identification of facilities necessary to meet future transmission needs.	Chapter 8 – Transmission Planning & Distribution
WAC 480-100-620-(6)(b)	(b) The assessment must also identify the general location and extent of transfer capability limitations on its transmission network that may affect the future siting of resources.	Chapter 8 – Transmission & Distribution Planning Appendix D – Transmission & Distribution Assessments Appendix J – New Resource Transmission Table

Table 1.9: Resource Evaluation Requirements

WAC Rule	Requirement	IRP Discussion
WAC 480-100-620(7)	The IRP must include a comparative evaluation of all identified resources and potential changes to existing resources for achieving the clean energy transformation standards in WAC 480-100-610 at the lowest reasonable cost.	Chapter 2 – Preferred Resource Strategy Chapter 10- Scenario Analysis

Table 1.10: Resource Adequacy Requirements

WAC Rule	Requirement	IRP Discussion
WAC 480-100-620(8)	The IRP must include an assessment and determination of resource adequacy metrics. It must also identify an appropriate resource adequacy requirement and measurement metrics consistent with RCW 19.405.030 through 19.405.050.	Chapter 2 – Preferred Resource Strategy

Table 1.11: Economic, Health, & Environmental Burdens & Benefits Requirements

WAC Rule	Requirement	IRP Discussion
WAC 480-100-620(9)	The IRP must include an assessment of energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks; and energy security risk. The assessment should be informed by the cumulative impact analysis conducted by the department of health.	Clean Energy Action Plan

Table 1.12: Load Forecast

WAC Rule	Requirement	IRP Discussion
WAC 480-100-620(10)(a)	The IRP must include a range of possible future scenarios and input sensitivities for the purpose of testing the robustness of the utility's resource portfolio under various parameters. The IRP must also provide a narrative description of scenarios and sensitivities the utility used, including those informed by the advisory group process. (a) At least one scenario must describe the alternative lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply with RCW 19.405.040 and 19.405.050, as described in WAC 480-100-660(1). This scenario's conditions and inputs should be the same as the preferred portfolio except for those conditions and inputs that must change to account for the impact of RCW 19.405.040 and 19.405.050.	Chapter 10 – Portfolio Scenarios Chapter 3- Load Forecast

WAC 480-100-620(10)(b)	At least one scenario must be a future climate change scenario. This scenario should incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change.	Chapter 3- Economic and Load Forecast Chapter 5- Resource Needs Assessment Chapter 10 – Portfolio Scenarios
WAC 480-100-620(10)(c)	At least one sensitivity must be a maximum customer benefit scenario. This sensitivity should model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals.	Chapter 10 – Portfolio Scenarios

Table 1.13: Portfolio Analysis and Preferred Portfolio Requirements

WAC Rule	Requirement	IRP Discussion
WAC 480-100-620(11)(a)	The utility must integrate the demand forecasts and resource evaluations into a long-range integrated resource plan solution describing the mix of resources that meet current and projected resource needs. Each utility must provide a narrative explanation of the decisions it has made, including how the utility's long-range integrated resource plan expects to: (a) Achieve the clean energy transformation standards in WAC 480-100-610 (1) through (3) at the lowest reasonable cost;	Chapter 2 – Preferred Resource Strategy
WAC 480-100-620(11)(b)	Serve utility load, based on hourly data, with the output of the utility's owned resources, market purchases, and power purchase agreements, net of any off-system sales of such resource;	Chapter 2 – Preferred Resource Strategy
WAC 480-100-620(11)(c)	Include all cost-effective, reliable, and feasible conservation and efficiency resources, using the methodology established in RCW 19.285.040, and demand response;	Chapter 6 – Distributed Energy Resources
WAC 480-100-620(11)(d)	Consider acquisition of existing renewable resources;	Included as part of future RFP analysis
WAC 480-100-620(11)(e)	In the acquisition of new resources constructed after May 7, 2019, rely on renewable resources and energy storage, insofar as doing so is at the lowest reasonable cost;	Included as part of future RFP analysis
WAC 480-100-620(11)(f)	Maintain and protect the safety, reliable operation, and balancing of the utility's electric system, including mitigating over-generation events and achieving the identified resource adequacy requirement;	Chapter 5- Resource Needs Assessment

WAC 480-100-620(11)(g)(i and ii)	Achieve the requirements in WAC 480-100-610 (4)(c); the description should include, but is not limited to: (i) The long-term strategy and interim steps the utility will take to equitably distribute benefits and reduce burdens for highly impacted communities and vulnerable populations; and (ii) The estimated degree to which benefits will be equitably distributed and burdens reduced over the planning horizon.	Clean Energy Action Plan
620(11)(h)	Assess the environmental health impacts to highly impacted communities;	Clean Energy Action Plan
620(11)(i)	Analyze and consider combinations of distributed energy resource costs, benefits, and operational characteristics including ancillary services, to meet system needs; and	Chapter 6- Distributed Energy Resources
620(11)(j)	Incorporate the social cost of greenhouse gas emissions as a cost adder as specified in RCW 19.280.030(3).	Chapter 2- Preferred Resource Strategy Clean Energy Action Plan

Table 1.14: Clean Energy Action Plan

WAC Rule	Requirement	IRP Discussion
WAC 480-100-620(12)(a)	The utility must develop a ten-year clean energy action plan for implementing RCW 19.405.030 through 19.405.050. The CEAP must: (a) Be at the lowest reasonable cost;	Clean Energy Action Plan
WAC 480-100-620(12)(b)	Identify and be informed by the utility's ten-year cost-effective conservation potential assessment as determined under RCW 19.285.040;	Chapter 6 – Distributed Energy Resources Appendix C – AEG Conservation and DR Assessments
WAC 480-100-620(12)(c)(i – iii)	Identify how the utility will meet the requirements in WAC 480-100-610 (4)(c) including, but not limited to: (i) Describing the specific actions the utility will take to equitably distribute benefits and reduce burdens for highly impacted communities and vulnerable populations; (ii) Estimating the degree to which such benefits will be equitably distributed and burdens reduced over the CEAP's ten-year horizon; and	Clean Energy Action Plan

	(iii) Describing how the specific actions are consistent with the long-term strategy described in WAC 480-100-620 (11)(g).	
WAC 480-100-620(12)(d)	Establish a resource adequacy requirement;	Clean Energy Action Plan Chapter 5 Resource Needs Assessment
WAC 480-100-620(12)(e)	Identify the potential cost-effective demand response and load management programs that may be acquired;	Chapter 6 – Distributed Energy Resources
WAC 480-100-620(12)(f)	Identify renewable resources, nonemitting electric generation, and distributed energy resources that may be acquired and evaluate how each identified resource may reasonably be expected to contribute to meeting the utility's resource adequacy requirement;	Clean Energy Action Plan
WAC 480-100-620(12)(g)	Identify any need to develop new, or to expand or upgrade existing, bulk transmission and distribution facilities;	Clean Energy Action Plan
WAC 480-100-620(12)(h)	Identify the nature and possible extent to which the utility may need to rely on an alternative compliance option identified under RCW 19.405.040 (1)(b), if appropriate; and	Clean Energy Action Plan
WAC 480-100-620(12)(i)	Incorporate the social cost of greenhouse gas emissions as a cost adder as specified in RCW 19.280.030(3).	Clean Energy Action Plan

Table 1.15: Avoided Cost and Nonenergy Impact Requirements

WAC Rule	Requirement	IRP Discussion
WAC 480-100-620(13)	The IRP must include an analysis and summary of the avoided cost estimate for energy, capacity, transmission, distribution, and greenhouse gas emissions costs. The utility must list nonenergy costs and benefits addressed in the IRP and should specify if they accrue to the utility, customers, participants, vulnerable populations, highly impacted communities, or the general public. The utility may provide this content as an appendix.	Chapter 2 – Preferred Resource Strategy Appendix K-Schedule 62

Table 1.16: Data Disclosure Requirements

WAC Rule	Requirement	IRP Discussion
WAC 480-100-620(14)	The utility must include the data input files made available to the commission in native format per RCW 19.280.030 (10)(a) and (b) and in an easily accessible format as an appendix to the IRP. For filing confidential information, the utility may designate information within the data input files as confidential, provided that the information and designation meet the requirements of WAC 480-07-160.	Appendix G – Public Input and Results Data Appendix H – Confidential Inputs and Models

Table 1.17: Information from Qualifying Facilities Requirements

WAC Rule	Requirement	IRP Discussion
WAC 480-100-620(15)(a)	Each utility must provide information and analysis that it will use to inform its annual filings required under chapter 480-106 WAC. The detailed analysis must include, but is not limited to, the following components: (a) A description of the methodology used to calculate estimates of the avoided cost of energy, capacity, transmission, distribution and emissions averaged across the utility; and	Chapter 2 – Preferred Resource Strategy Appendix K-Schedule 62
WAC 480-100-620(15)(b)	Resource assumptions and market forecasts used in the utility's schedule of estimated avoided cost required in WAC 480-106-040 including, but not limited to, cost assumptions, production estimates, peak capacity contribution estimates and annual capacity factor estimates.	Chapter 9-Market Analysis Appendix G-Public Input and Results Data

Table 1.18: Report of Substantive Changes Requirements

WAC Rule	Requirement	IRP Discussion
WAC 480-100-620(16)	The IRP must include a summary of substantive changes to modeling methodologies or inputs that result in changes to the utility's resource need, as compared to the utility's previous IRP.	Chapter 1 – Introduction, Involvement and Process Changes

Table 1.19: Summary of Public Comments Requirements

WAC Rule	Requirement	IRP Discussion
WAC 480-100-620(2)	The utility must provide a summary of public comments received during the development of its IRP and the utility's responses, including whether issues raised in the comments were addressed and incorporated into the final IRP as well as documentation of the reasons for rejecting any public input. The utility may include the summary as an appendix to the final IRP. Comments with similar content or input may be consolidated with a single utility response	Appendix M – Public Comments

Policy Statement for IRA and IIJA Funding in IRPs

Table 1.20 shows how this IRP conforms with the UTC's expectations and preferences regarding the incorporation of the Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act of 2021 (IIJA) in the IRP in Docket U-240013.

Table 1.20: Policy Statement Concerning IRA and IIJA in the IRP

Expectation	IRP Discussion
Utilities are expected to update IRP cost assumptions to include the extended ITC and PTC tax credits through the current expiration date, incorporate the "bonus" credits15 where appropriate, and include sensitivity analysis for varying level of program uptake (*e.g.,* electric vehicle adoption, distributed energy resources, building electrification, energy efficiency, etc.). This includes natural gas utilities reflecting the impact of these federal funding dollars that may promote electrification into their load forecasts.	Chapter 7 – Supply Side Resource Options Appendix G: Supply Side Resource Options.xlsm Chapter 3: Economic and Load Forecast
While we recognize the rebate programs for electric utilities are more difficult to forecast, scenarios should be included to evaluate a high, medium, and low uptake to better inform project selection downstream during development of the utilities' CEIPs, and the following procurement and acquisition processes when data from rebate programs becomes available.	This will be addressed in the CIEP
Additionally, we expect electric utilities to identify and evaluate transmission needs that may qualify for IRA transmission-related programs. We also encourage utilities to evaluate alternative options such as clean repowering and reconductoring.	Chapter 8 Transmission Planning & Distribution Clean Energy Action Plan
Further, utilities should include an index within the IRP to notate where IRA and IIJA opportunities are included within its analysis. We believe the public benefit of documenting this information to facilitate review by the Commission, advisory groups, and other interested persons outweighs the burden the requirement may impose on utilities.	Table 1.20 Policy Statement Concerning IRA and IIJA in the IRP
Finally, utilities are encouraged to review the RMI publication, *"Planning to Harness the Inflation Reduction Act: A Toolkit for Regulators to Ensure Resource Plans Optimize Federal Funding,"* as 2025 IRPs are under development.	Noted

Washington Clean Energy Implementation Plan (CEIP) Coordination

The IRP, in accordance with WAC 480-100-625 (4)(c), updates any elements in the utility's current CEIP as described in WAC 480-100-640. Avista's 2021 CEIP was approved with Conditions in June 2022. Avista has included the inputs used and approved in the development of the 2021 Clean Energy Action Plan (CEAP) filed with the 2021 IRP. In addition, Conditions agreed to as part of the approval of the 2021 CEIP in Docket UE-210628 are included in the modeling informing this IRP. The following assumptions were used to develop the clean energy requirements for 2030 and 2045 CETA requirements.

- Qualifying clean energy is determined by procurement and delivery of clean energy to Avista's system for all years.
- The clean energy goal is applied to retail sales *less* in-state Public Utility Regulatory Policies Act (PURPA) generation constructed prior to 2019 *plus* voluntary renewable energy programs.
- Customer voluntary Renewable Energy Credits (REC) programs do not qualify toward the CETA standard.
- Primary compliance generation includes:
- Washington's share of legacy hydro generation (defined the facility is operating or contracted with deliveries before 2022).
- All wind, solar, and biomass generation. Nonpower attributes associated with Idaho's share may be purchased by Washington,
- Newly acquired or contracted non-emitting generation including hydro, wind, solar, or biomass.
- Avista may transfer qualifying clean energy allocated to the Idaho jurisdiction to Washington by compensating Idaho at market REC prices.
- Avista is not planning to use Idaho's share of legacy hydro prior to 2030 for compliance. After 2030, these resources are planned to be available for Alternative Compliance.

Conditions For IRP Progress Report from the CEIP

Several of the Washington Utilities and Transportation Commission's (WUTC) approved conditions for the Company's CEIP were required to be included in the 2023 Progress Report. The following six conditions, listed by their original number issued in Order 01 from the WUTC, are covered in the 2023 Progress Report and if applicable updated in this 2025 IRP.

(2) Avista will apply Non-Energy Impacts (NEIs) and Customer Benefit Indicators (CBIs) to all resource and program selections in determining its Washington resource strategy, in its 2023 IRP/Progress Report and will incorporate any guidance given by the Commission on how to best utilize CBIs in CEIP planning and evaluation. Avista agrees to engage and consult with its applicable advisory groups (IRP Technical Advisory Committee (TAC) and Energy Efficiency Advisory Group (EEAG)) regarding an appropriate methodology for including NEIs and CBIs in its resource selection. (Per Order 01: Avista will consult with its Equity Advisory Group (EAG) after the development of this methodology to ensure the methodology does not result in inequitable results.)

> *Avista discussed with the TAC and EEAG on Oct 11, 2022, its approach to using both NEI and CBIs with the progress report, The EAG was also consulted during its meetings held on November 16th and 18th, 2022. Members did not voice concerns pertaining to inequities in the Company's approach.*

(8) Avista in its IRP resource selection model for the 2023 IRP Progress Report will give the model the option to meet Clean Energy Transformation Act (CETA) goals with a choice between an Idaho allocated existing renewable resource at market price (limited to Kettle Falls, Palouse Wind, Rattlesnake Flat, Chelan PUD purchase contracts 2 & 3 or acquiring a new 100% allocated Washington renewable resource for primary compliance. Further, the model will have the option to acquire new 100% allocated resource, market REC, or Idaho allocated REC (at market prices) to meet alternative compliance.

> *Avista included logic in the PRiSM model to choose how it solves to meet primary and alternative compliance requirements either by using existing resources or by acquiring new resources.*

(14) Avista will include a Distributed Energy Resources (DERs) potential assessment for each distribution feeder no later than its 2025 electric IRP. Avista will develop a scope of work for this project no later than the end of 2022, including input from the IRP TAC, EEAG, and Distribution Planning Advisory Group (DPAG). The assessment will include a low-income DER potential assessment. Avista will document its DER potential assessment work in the Company's 2023 IRP Progress Report in the form of a project plan, including project schedule, interim milestones, and explanations of how these efforts address WAC 480-100-620(3)(b)(iii) and (iv).

> *The potential assessment for this study was discussed at both the TAC and EEAG meetings in October 2022 during the 2023 Progress Report/IRP process, the project plan and schedule are described in Chapter 5 and the proposed scope of work is in Appendix G of the 2023 IRP. The project was completed in 2024, and the associated report is available in Appendix F of this plan.*

(34) For its 2023 IRP Progress Report, Avista commits to reevaluate its resource need given acquisitions the Company has made since its 2021 IRP (e.g., Chelan PUD hydro slice contracts) and include those proposed changes in its 2023 Biennial Clean Energy Implementation Plan (CEIP) Update.

> *Avista has included within its resource energy need all long-term resources currently under contract including the Chelan PUD slice agreements and the Columbia Basin Hydro agreement in the 2023 Progress Report/IRP. Further, it includes planned upgrades to both Kettle Falls and Post Falls as well as the extension of the existing Lancaster Purchase Power Agreement (PPA).*

> *After the 2023 Progress Report/IRP was completed, Avista chose to no longer pursue an upgrade to Kettle Falls upon completion of the 2023 RFP. The Post Falls project is underway, but upon further evaluation, no additional capacity at the project is planned under the new project configuration.*

(35) Avista recognizes that not all CBIs will be relevant to resource selection (for example, some CBIs pertain to program implementation). For its 2023 IRP Progress Report, and future IRPs and progress reports, Avista should discuss each CBI and where the CBI is not relevant to resource selection, explain why.

Chapter 11 of the 2023 IRP outlines how each CBI is relevant or not to resource selection or studied within the resource planning process. For those CBIs with a relation to resource selection, a forecast of their impact on the plan is included. The 2025 Clean Energy Action Plan also includes this relevant information.

(36) For its 2023 IRP Progress Report, Avista will:

A. At the September 28, 2022, Electric IRP TAC meeting, present draft supply side resource cost assumptions, including DERs. The Company commits to revising said cost assumptions if TAC stakeholder feedback warrants changes. Avista will update its 2023 Electric IRP Work Plan (UE-200301) to reflect the date of this TAC meeting.
B. Use the Qualifying Capacity Credit (QCC) for renewable and storage resources from the Western Power Pool's Western (WPP) Regional Adequacy Program (WRAP), if available, or explain why the WRAP's QCCs are inappropriate for use.
C. Update its load forecast to include the baseline zero emission vehicles (ZEV) scenario from its Transportation Electrification Plan.

Avista presented and provided TAC members with a complete supply resource assumptions at the September 2022 meeting during the 2023 Progress Report/IRP process. The resource assumptions are discussed in Chapter 6 of 2023 Progress Report/IRP, along with associated technical documentation in Appendix F of the 2023 IRP. Avista also uses QCC values where applicable from the WRAP, these are discussed in Chapter 3 for existing resources, Chapter 5 for DERs, and Chapter 6 for utility scale resources. Within Chapter 2 is a discussion of the associated loads included using the Transportation Electrification Plan from the 2023 IRP. The 2025 IRP continues to use the same methodology as the 2023 IRP with updated assumptions.

Idaho Regulatory Requirements

The IRP process for Idaho has several requirements documented in IPUC Orders Nos. 22299 and 25260. Order 22299 dates back to 1989; this order outlines the requirement for the utility to file a *"Resource Management Report [(RMR)]". This report recognize[s] the managerial aspects of owning and maintaining existing resources as well as procuring new resources and avoiding/reducing load. [The Commission's] desire is the report on the utility's planning status, not a requirement to implement new planning efforts according to some bureaucratic dictum. We realize that integrated resource planning is an ongoing, changing process. Thus, we consider the RMR required herein* *to be similar to an accounting balance sheet, i.e., a "freeze-frame" look at a utility's fluid process.*

The report should discuss any flexibilities and analyses considered during comprehensive resource planning such as:

1. Examination of load forecast uncertainties
2. Effects of known or potential changes to existing resources
3. Consideration of demand- and supply-side resource options
4. Contingencies for upgrading, optioning and acquiring resources at optimum times (considering cost, availability, lead-time, reliability, risk, etc.) as future events unfold.

Avista outlines the order's requirements below for ease of readability for each of the Commission's requirements.

Existing Resource Stack

Identification of all resources by category below;[3] including the utility shall provide a copy of the utility's most recent U.S. Department of Energy Form EIA-714 submittal and the following specific data, as defined by the NERC, ought to be included as an appendix:[4]

a) Hydroelectric;
    i. Rated capacity by unit;
    ii. Equivalent Availability Factor by month for most recent 5 years;
    iii. Equivalent Forced Outage Rate by month for most recent 5 years; and
    iv. FERC license expiration date.
b) Coal-fired;
    i. Rated Capacity by unit;
    ii. Date first put into service;
    iii. Design plant life (including life extending upgrades, if any);
    iv. Equivalent Availability Factor by month for most recent 5 years; and
    v. Equivalent Forced Outage Rate by month for most recent 5 years.
c) Oil or Gas fired;
    i. Rated Capacity by unit;
    ii. Date first put into service;
    iii. Design plant life (including life extending upgrades, if any);
    iv. Equivalent Availability Factor by month for most recent 5 years; and
    v. Equivalent Forced Outage Rate by month for most recent 5 years.
d) PURPA Hydroelectric;
    i. Contractual rated capacity;

[3] Resources less than three megawatts should be grouped as a single resource in the appropriate category.

[4] FERC Form 714 can be on-line at https://www.ferc.gov/docs-filing/forms/form-714/data.asp

   ii. Five-year historic hours connected to system, by month (if known);
   iii. Five-year historic generation (kWh), by month;
   iv. Level of dispatchability, if any; and
   v. Contract expiration date.
e) PURPA Thermal;
   i. Contractual rated capacity;
   ii. Five-year historic hours connected to system, by month (if known);
   iii. Five-year historic generation (kWh), by month;
   iv. Level of dispatchability, if any; and
   v. Contract expiration date.
f) Economy Exchanges;
   I. For contract purchases & exchanges, key contract terms and conditions relating to capacity, energy, availability, price, and longevity.
   II. For economy purchases and exchanges, 5-year historical monthly average capacity, energy, and prices.
g) Economy Purchases;
   I. For contract purchases & exchanges, key contract terms and conditions relating to capacity, energy, availability, price, and longevity.
   II. For economy purchases and exchanges, 5-year historical monthly average capacity, energy, and prices.
h) Contract Purchases;
   I. For contract purchases & exchanges, key contract terms and conditions relating to capacity, energy, availability, price, and longevity.
   II. For economy purchases and exchanges, 5-year historical monthly average capacity, energy, and prices.
i) Transmission Resources; and
   I. Information useful for estimating the power supply benefits and limitations appurtenant to the resources in question.
j) Other.
   I. Information useful for estimating the power supply benefits and limitations appurtenant to the resources in question.

Load Forecast

Each RMR should discuss expected 20-year load growth scenarios for retail markets and for the federal wholesale market including "requirements" customers, firm sales, and economy (spot) sales. For each appropriate market, the discussion should:

a) identify the most recent monthly peak demand and average energy consumption (where appropriate by customer class), both firm and interruptible;
b) identify the most probable average annual demand and energy growth rates by month and, where appropriate, by customer class over at least the next three years and discuss the years following in more general terms;

c) discuss the level of uncertainty in the forecast, including identification of the maximum credible deviations from the expected average growth rates; and
d) identify assumptions, methodologies, databases, models, reports, etc. used to reach load forecast conclusions.

This section of the report is to be a short synopsis of the utility's present load condition, expectations, and level of confidence. Supporting information does not need to be included but should be cited and made available upon request.

Additional Resource Menu

This section should consist of the utility's plan for meeting all potential jurisdictional load over the 20-year planning period. The discussion should include references to expected costs, reliability and risks inherent in the range of credible future scenarios.

- An ideal way to handle this section could be to describe the most probable 20-year scenario followed by comparative descriptions of scenarios showing potential variations in expected load and supply conditions and the utility's expected responses thereto. Enough scenarios should be presented to give a clear understanding of the utility's expected responses over the full range of possible future conditions.
- The guidance provided above is intended to ensure maximum flexibility to utilities in presenting their resource plans. Ideally, each utility will use several scenarios to demonstrate potential maximum, minimum and intermediate levels of new resource requirements and the expected means of fulfilling those requirements. For example,
- A credible scenario requiring maximum new resources might be regional load growth exceeding 3% per year combined with catastrophic destruction (earthquake, fire, flood, etc.) of a utility's largest resource (i.e., Bridger coal plant for IPCo and PP&L, Hunter coal plant for UP&L and Noxon hydro plant for WWP).
- A credible scenario causing reduced utilization of existing resources might be regional stagflation combined with loss of a major industry within a utility's service territory. Analyses of intermediate scenarios would also be useful.
- To demonstrate the risks associated with various proposed responses, certain types of information should be supplied to describe each method of meeting load. For example,
- If new hydroelectric generating plants are proposed, the lead time required to receive FERC licensing and the risk of license denial should be discussed.
- If new thermal generating plants are proposed, the size, potential for unused capacity, risks of cost escalation and fuel security should be discussed and compared to other types of plants.
- If off-system purchases are proposed, specific supply sources should be identified, regional resource reserve margin should be discussed

with supporting documentation identified, potential transmission constraints and/or additions should be discussed, and all associated costs should be estimated.

- If conservation or demand side resources are proposed, they should be identified by customer class and measure, including documentation of availability, potential market penetration and cost.
- Because existing hydroelectric plants could be lost to competing companies if FERC relicensing requirements are not aggressively pursued, relicensing alternatives require special consideration. For example,
- If hydroelectric plant relicensing upgrades are proposed, their costs should be presented both as a function of increased plant output and of total plant output to recognize the potential of losing the entire site.
- Costs of upgrades not required for relicensing should be so identified and compared only to actual increased capacity/energy availability at the unit, line, substation, distribution system, or other affected plant. Increased maintenance costs, instrumentation, monitoring, diagnostics, and capital investments to improve or maintain availability should be quantified.
- Because PURPA projects are not under the utility's control, they also require special consideration. Each utility must choose its own way of estimating future PURPA supplies. The basis for estimates of PURPA generation should be clearly described.

Other provisions from Order 22299

- Because the RMR is expected to be a report of a utility's plans, and because utilities are being given broad discretion in choosing their reporting format, Least Cost Plans or Integrated Resource Plans submitted to other jurisdictions should be applicable in Idaho.
- Utilities should use discretion and judgement to determine if reports submitted to other jurisdictions provide such emphasis, if adding an appendix would supply such emphasis, or if a separate report should be prepared for Idaho.
- The project manager responsible for the content and quality of the RMR shall be clearly identified therein and a resume of her/his qualifications shall be included as an appendix to the RMR.
- Finally, the Resource Management Report is not designed to turn the IPUC into a planning agency nor shall the Report constitute pre-approval of a utility's proposed resource acquisitions.
- The reporting process is intended to be ongoing-revisions and adjustments are expected. The utilities should work with the Commission Staff when reviewing and updating the RMRs. When appropriate, regular public workshops could be helpful and should be a part of the reviewing and updating process.
- Most parties seem to agree that reducing and/or avoiding peak capacity load or annual energy load has at least the equivalent effect

on system reliability of adding generating resources of the same size and reliability. Furthermore, because conservation almost always reduces transmission and distribution system loads, most parties consider reliability effects of conservation superior to those of generating resources. Consequently, the Commission finds that electric utilities under its jurisdiction, when formulating resource plans, should give consideration to appropriate conservation and demand management measures equivalent to the consideration given generating resources.

- Therefore, we find that the parties should use the avoided cost methodology resulting from the No. U-1500-170 case for evaluating the cost effectiveness of conservation measures. The specific means for comparing No. U-1500-170 case avoided costs to conservation costs will initially be developed case-by-case as specific conservation programs are proposed by each utility. Prices to be paid for conservation resources procured by utilities are discussed later in this Order.
- Give balanced consideration to demand side and supply side resources when formulating resource plans and when procuring resources.
- Submit to the Commission, no later than March 15, 1989, and at least biennially thereafter, a Resource Management Report describing the status of its resource planning as of the most current practicable date.

Order 25260 Requirements

This order documents additional requirements for resource planning including:

- Give full consideration to renewables, among other resource options.
- Investigate and carefully weigh the site-specific potential for particular renewables in their service area.
- Deviations from the integrated resource plans must be explained. The appropriate place to determine the prudence of an electric utility's plan or the prudence of an electric utility's following or failing to follow a plan will be in general rate case or other proceeding in which the issue is noticed.

Summary of Changes from the 2023 IRP

Avista’s 2025 IRP methodology is similar to the 2023 IRP, but with updated assumptions. The major assumption changes include capacity and energy position results, updated energy efficiency and demand response potentials, updates to supply-side resource options and costs, refreshed wholesale market analysis and additional methods for the portfolio optimization analysis, each are described below.

Capacity and Energy Position, Including Load Forecasting

- Avista continues to use the WPP's WRAP methodology for capacity planning. But uses its own planning reserve margin of 24% in the winter and 16% in the summer. Avista also uses information from the WRAP and public reports to estimate resource QCC values.
- Load and hydro forecasts use the Representative Concentration Pathway (RCP) 4.5[5] temperature and hydro forecast for future years rather than historical averages for winter months, Avista uses RCP 8.5 temperatures for summer months.
- Avista did not consider upgrades to Kettle Falls or Post Falls in the baseline capacity/energy position.

Energy Efficiency and Demand Response

- Demand Response QCC values are credited with the planning reserve margin value for capacity analysis. This assumes DR is netted prior to calculating the PRM resulting in additional preference for these programs.
- Avista evaluated additional electric vehicle load control options.

Supply-Side Resource Options

- Avista refined the list of available resources based on potential technologies being acquired. This includes removing liquid-air storage and combined flow battery technologies as a generic resource type. Avista added hydrogen co-firing to Coyote Springs 2 and Rathdrum CTs.

Market Analysis

- A new regional resource forecast is updated to reflect the latest available information utilizing Energy Exemplar's latest Western Electricity Coordinating Council (WECC) database and Avista's National Consultant's electric forecast.
- The Climate Commitment Act (CCA) is reflected in the market forecast using Ecology's price estimate for imported power and power plants without free allowances. Avista assumed the CCA prices will be included in dispatch decisions for all in-state plants beginning in 2031.

Portfolio Optimization Analysis

- Added a natural gas LDC module with the ability to move natural gas customers to electric dynamically if cost effective or for a scenario analysis.

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[5] RCP 4.5 is defined in Chapter 4.

2025 IRP Chapter Outline

Chapter 1: Introduction, Involvement and Process Changes

This chapter introduces the IRP, covers requirements and details public participation and involvement in the process used to develop it, as well as highlighting significant assumption, modeling and process changes between the 2023 and 2025 IRPs.

Chapter 2: Preferred Resource Strategy

This chapter details the Preferred Resource Strategy (PRS) selection process used to develop the 2025 PRS and resulting avoided costs.

Chapter 3: Economic and Load Forecast

This chapter covers regional economic conditions, Avista's energy and the peak load forecasts, including scenarios with different load projections.

Chapter 4: Existing Supply Resources

This chapter provides an overview of Avista-owned generating resources and its contractual resources and obligations and environmental considerations.

Chapter 5: Resource Needs Assessment

This chapter reviews Avista reliability planning and reserve margins, risk planning, resource requirements and provides an assessment of its reserves and resource flexibility. This chapter also covers the RCP 4.5 and 8.0 temperature and hydrology forecasts.

Chapter 6: Distributed Energy Resource Options

This chapter discusses customer focused resources such as energy efficiency programs, demand response and distributed generation and energy storage. It provides an overview of the conservation and demand response potential assessments, and customer owned or other distributed generation resources.

Chapter 7: Supply-Side Resource Options

This chapter covers the cost and operating characteristics of utility scale supply-side resource options modeled for the 2025 IRP.

Chapter 8: Transmission Planning & Distribution

This chapter discusses Avista distribution and transmission systems, as well as regional transmission planning issues. It includes details on transmission cost studies used in IRP modeling and summarizes Avista's 10-year Transmission Plan. The chapter concludes with a discussion of distribution planning, including storage benefits to the distribution system.

Chapter 9: Market Analysis

This chapter details Avista IRP modeling and its analyses of the wholesale electric and natural gas markets.

Chapter 10: Scenario Analysis

This chapter presents alternative resource portfolios and shows how each scenario performs under different energy market conditions.

Chapter 11: Action Plan

This chapter discusses progress made on Action Items in the 2023 IRP. It details the areas Avista will focus on between publication of this plan and the 2027 IRP.

Clean Energy Action Plan

Avista's 10-year Clean Energy Action Plan (CEAP) is the lowest reasonable cost plan of resource acquisition given societal costs, clean energy, and reliability requirement targets over the IRP's 20-year time horizon, including known information and assumptions regarding the future. This plan describes how Avista will meet the key considerations required by the UTC. The CEAP is the basis for the 2025 Clean Energy Implementation Plan (CEIP).

2025 IRP Appendices

Appendix A: TAC and Public Presentations

This appendix includes the presentations for the 14 TAC meetings and meeting notes.

Appendix B: IRP Work Plan

This appendix includes 2025 IRP Work Plan outlining the process Avista's used to develop its 2025 Electric IRP for filing with the Washington and Idaho Commissions by January 2, 2025.

Appendix C: AEG Conservation and Demand Response Potential Assessments

This appendix includes the conservation (energy efficiency) and demand response potential assessment studies completed by AEG for Avista's service territory including the measure list of program options.

Appendix D: 10-Year Transmission/ Distribution Plan

This appendix includes Avista's 10-year System Plan and the transmission and distribution system assessment reports.

Appendix E: Transmission Generation Integration Study

This appendix includes the assessment of cost and system changes to integrate resource opportunities onto Avista's transmission system resource option study results.

Appendix F: Distributed Energy Resources Study
This appendix includes the study results for the feeder level potential of distributed energy resources for the Washington service territory and the forecasting methodology reports.

Appendix G: Public Input and Results Data
This appendix includes modeling input data including: CCA prices, load forecast, natural gas prices, social cost of carbon, and resource option costs. It includes the named community maps, the PRiSM models for resource selection, and the electric market price forecast. Energy Efficiency avoided cost calculations.

Appendix H: Confidential Inputs and Models
This appendix including the Aurora model, ARAM models for resource adequacy, and the Hourly CETA analysis.

Appendix I: Historical Generation Operation Data (Confidential)
This confidential appendix includes actual monthly data for PURPA generation and forced outage data for Avista resources.

Appendix J: New Resource Table for Transmission
This appendix approximates the potential location of new resources for transmission planning.

Appendix K: Washington State Schedule 62 (Partially Confidential)
This appendix includes the proposed rates and confidential supporting files and avoided cost calculations for small PURPA generators qualifying for Schedule 62.

Appendix M: Public Comments
This appendix includes written comments from the public and advisory group members.

Appendix N: Energy Burden Assessment
This appendix includes Avista's energy burden assessment performed by Empower Dataworks per WAC 480-100-620(3)(iii).

2. Preferred Resource Strategy

The IRP starts with Avista's current resource position and projected load growth. The Preferred Resource Strategy (PRS) is mix of new generation, storage, demand response, market purchases, and energy efficiency options to meet load growth in a safe, reliable, cost-effective, and equitable manner as reasonably possible. The PRS must also meet state and federal policy goals, such as Washington's clean energy and reduced greenhouse gas (GHG) emissions goals. The resource strategy is not a specific action plan, but it does guide what types of resources Avista may pursue to meet load growth while honoring regulatory and policy requirements. The actual acquisition of new resources will use a Request for Proposal (RFP) process or other market opportunities to obtain the needed resources.

Section Highlights

- Energy efficiency meets 32% of future load growth; the biennial energy efficiency target for 2026-2027 is 55% higher than the 2024-2025 target.
- Demand Response reduces system peak load 4% by 2045.
- Wind generation may be acquired as early as 2029 if it benefits customers to acquire the resource early.
- Avista's capacity position may drive the need for new resources earlier if loads increase faster than forecasted.
- Transmission interconnect and capacity limits could decrease future generation acquisition and may drive alternative resource choices rather than preferred options.
- Meeting Washington's 2045 clean energy targets will require a diversified clean capacity portfolio using emerging technologies such as small modular reactors, power-to-gas (ammonia/hydrogen) fueling combustion turbines, and long-duration energy storage technologies.

The procurement of supply-side resources will be through energy market transactions and a competitive bidding process with energy suppliers. This IRP shows resource owners and developers the timing, size, and types of resources most applicable for procurement. Avista expects this process may result in a different resource mix compared with the one presented in this chapter once real projects are known. Lastly, the IRP helps determine the avoided costs of serving future loads and shows how external forces and policies impact the utility's resource mix. Avista will use this strategy to inform its Washington Clean Energy Implementation Plan (CEIP) for 2026 through 2029; however, the ultimate action plan approved by the Commission for this period may differ from this plan.

The PRS uses the best available information at the time of the analyses, including Avista's interpretation of Washington's Clean Energy Transformation Act (CETA) requirements. CETA's "use rules" determine how renewable energy will qualify as either "primary" or "alternative" compliance to the 2030 greenhouse neutral standard. The IRP utilizes a least-cost planning methodology with specific social cost impacts specified by Washington's requirements such as the social cost of greenhouse gas (SCGHG) and Non-Energy Impacts (NEI). Due to divergent Idaho and Washington state energy policies, Avista separates the two jurisdictions for this plan by creating an individual resource plan as needed for each state while adding shared system resources where possible. Although, actual resource acquisitions are not separated by jurisdiction at this time.

Avista's PRS describes the lowest reasonable cost resource mix considering risk, given Avista's needs for new capacity, energy, and clean or non-carbon emitting resources for each state, while accounting for social and economic factors prescribed by Washington State policies. The PRS includes supply-side resources, distributed energy resource (DER) options, energy efficiency, and demand response (DR) to serve customer loads. The plan compares resource options to find the lowest-cost portfolio considering the non-power costs/benefits (such as NEIs) to meet seasonal capacity deficits, annual energy needs, and CETA requirements. The analysis considers a minimum spending threshold using the Named Communities Investment Fund (NCIF)[6] to enhance the equitable transition to clean energy in Washington's Named Communities. The Idaho portion of the plan utilizes a least cost methodology without societal cost estimates.

Distributed Energy Resource Selections

Energy Efficiency Selections

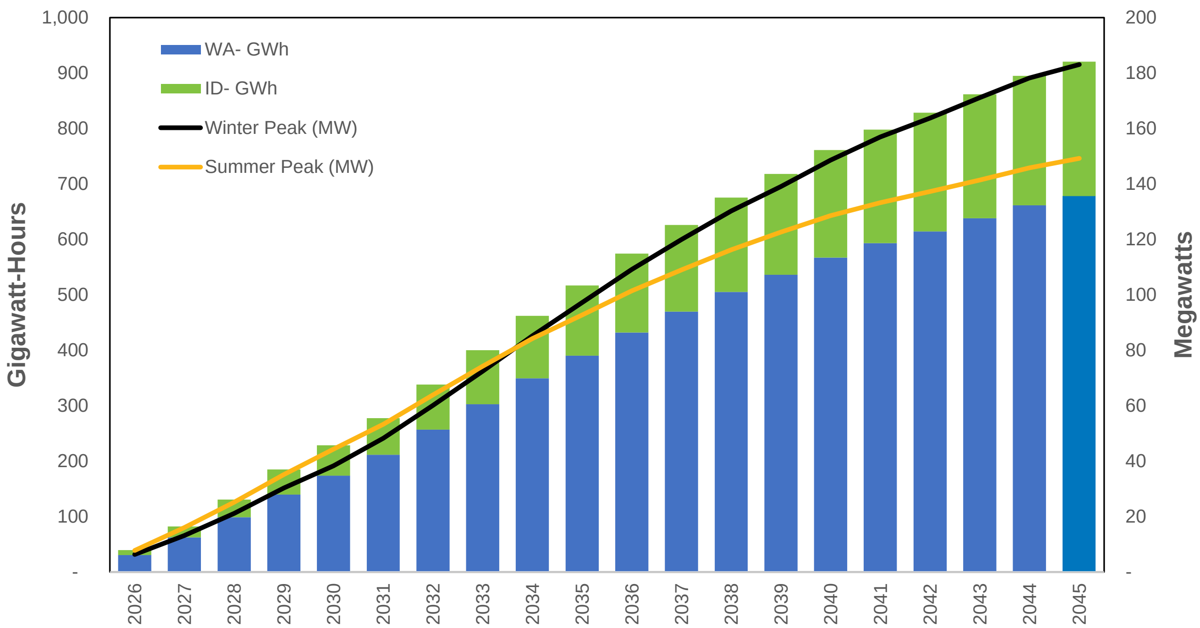
Energy efficiency savings meets 32% of future load growth in this plan. However, new loads, including electric transportation and building electrification, will outpace energy efficiency adoption limiting energy efficiency's ability to minimize load growth. Without electrification, energy efficiency could keep future load growth flat. Avista's load forecast (described in Chapter 3) is net of future energy efficiency savings. Avista adds back the selected quantity of efficiency savings to the load forecast through an iterative technique in the Preferred Resource Strategy Model (PRiSM) until the amount of energy efficiency selected netted from the load equals the load forecast. This evaluation considers over 3,000 energy efficiency measures and individually models each program's capacity and energy contributions to rigorously evaluate each program's benefit to the system. This method ensures an accurate accounting of peak savings.

Over the planning horizon, energy efficiency programs will reduce 870 cumulative gigawatt-hours of energy sales between 2026 and 2045. When considering the reductions of transmission and distribution losses by energy efficiency, loads are 105 aMW less with these programs. Figure 2.1 shows total energy and peak hour savings by state for both winter and summer. Winter peaks are reduced by nearly 183 MW and summer peaks are reduced by approximately 149 MW. Over the IRP planning horizon, 26% of energy

[6] The NCIF was proposed in Avista's 2021 CEIP and commits to spend up to $5 million annually on specific actions in Named Communities.

efficiency comes from Idaho customers and 74% from Washington customers. Washington has more energy efficiency savings relative to its 65% share of total load due to its higher avoided costs driven by CETA and other policies, such as including societal benefits in the economic evaluation.

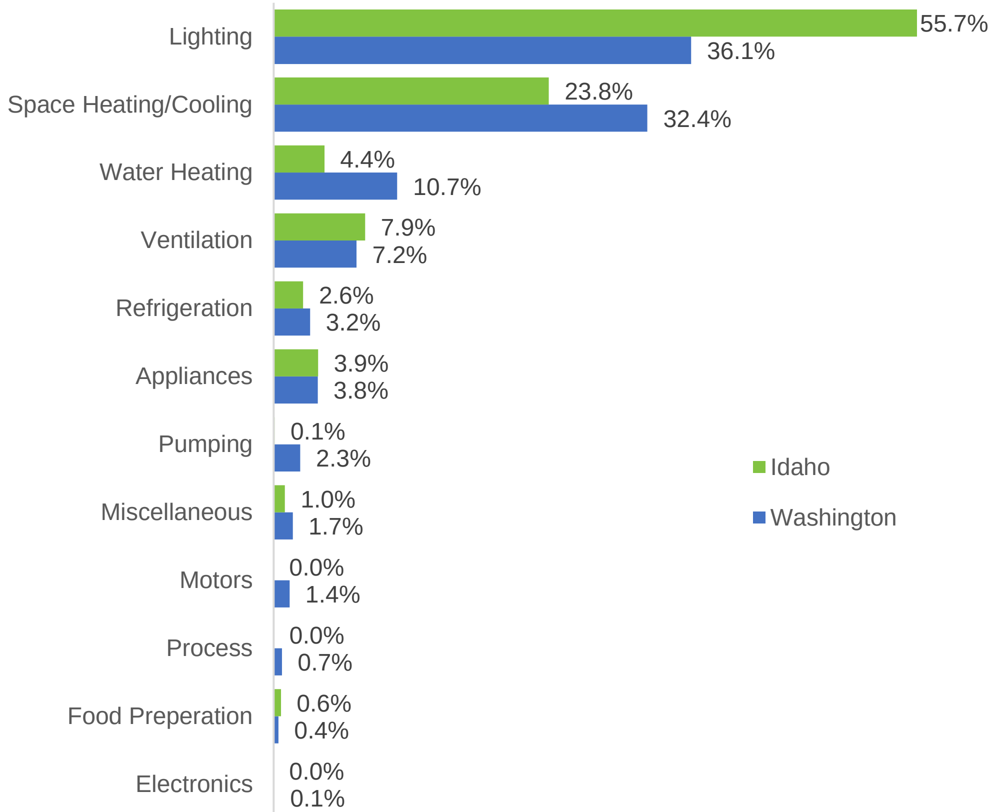
Figure 2.1: Energy Efficiency Annual Forecast



Commercial customers deliver 59% of the total energy efficiency savings, followed by residential customers (33%), with the remainder from industrial customers. Of the total savings, low-income households provide 16% of the energy efficiency savings and receive benefits at zero or minimal customer cost. The greatest sources of energy efficiency, at 68%, are from lighting and space heating/cooling measures. Figure 2.2 shows the program type by share of the total percentage of savings through 2045. Idaho has fewer program types due to lower avoided costs triggering fewer programs overall, while Washington's higher avoided costs identify more programs as cost effective.

Avista separately analyzes energy efficiency programs for low-income households compared to other households. This allows Avista to include non-energy impacts for Washington's lower income customers to increase savings potential. By 2045, 22% of Washington's energy savings is from low-income households or 15.7 aMW of energy savings.

Figure 2.2: Energy Efficiency Savings Programs by Share of Total



Washington Biennial Conservation Plan

The amount of energy efficiency the PRS identifies leads to specific programs in Washington and Idaho. To meet Washington's Energy Independence Act (EIA) requirements, the IRP determines cost-effective solutions and potential new programs for business planning, budgeting, and program development. Pursuant to Washington requirements, the biennial conservation target must be no lower than a pro rata share of the utility's ten-year conservation potential. In setting Avista's target, both the two-year achievable potential and the ten-year pro rata savings are determined with the higher value used to inform the EIA biennial target. Figure 2.3 shows the annual selection of new energy efficiency in Washington compared to the 10-year pro-rata share methodology.

The 2026-2027 achievable potential identified by the Conservation Potential Assessment (CPA) is 58,873 MWh for Washington although the pro-rata share of the ten-year potential is 73,672 MWh. The target exceeds the achievable potential by nearly 14,799 MWh over the two-year period. The pro-rata target is higher than the two-year potential as savings occurring later in the 10-year period as compared to the first two years of the plan increases the target. Avista will have a challenge to identify and acquire this additional energy efficiency. Table 2.1 outlines Avista's biennial target of 73,672 MWh and includes adjustments for NEEA and decoupling. This biennial target is 55% higher than the 2024-25 goal of 47,635 MWh.

Figure 2.3: Washington Annual Achievable Potential Energy Efficiency (GWh)

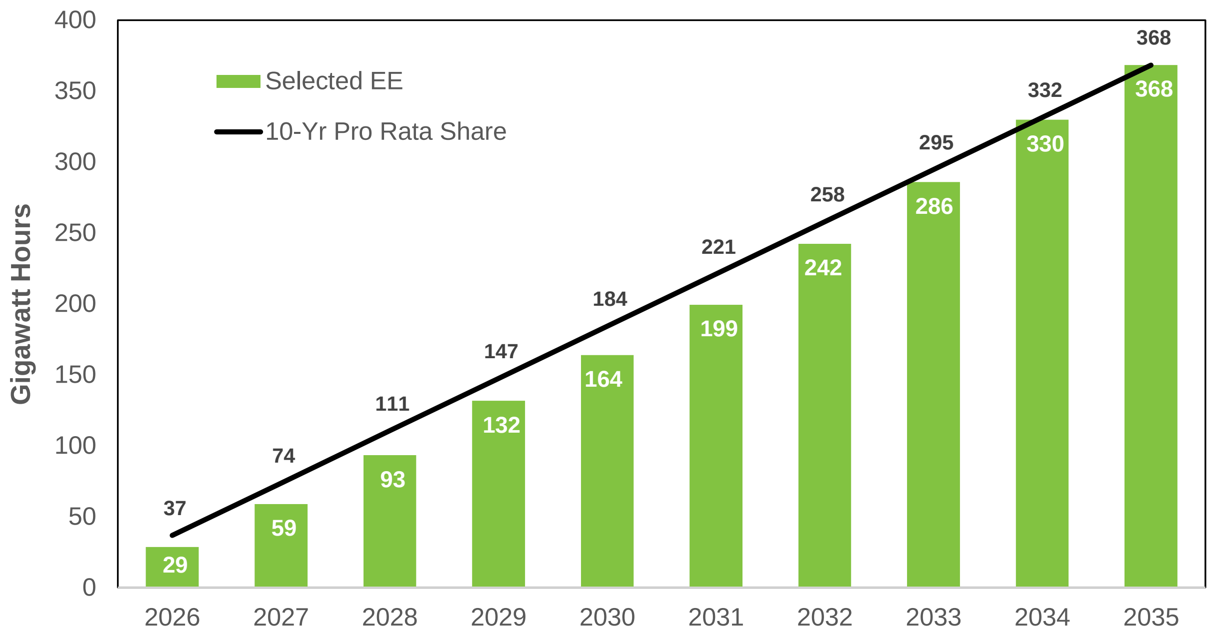


Table 2.1: Biennial Conservation Target for Washington Energy Efficiency

2026-2027 Biennial Target (MWh)	
CPA Pro-Rata Share	73,672
NEEA Programs	12,877
EIA Target	**86,549**
Decoupling Threshold	4,327
Total Utility Conservation Goal	**90,877**
Excluded Programs (NEEA)	-12,877
Utility Specific Conservation Goal	**77,999**
Decoupling Threshold	-4,327
EIA Penalty Threshold	**73,672**

Demand Response Selections

Demand response (DR), Virtual Power Plants (VPPs), and/or modified retail pricing programs will be integral to Avista's strategy to meet peak customer load requirements with non-emitting resources. Avista added 30 MW of industrial DR within the last three years and agreed to pilot three DR programs in the 2021 CEIP process. There is uncertainty in these programs' ability to meet planning reserve margin (PRM) due to the time duration limits and load snap back effects without traditional resources available to meet high demand days. Further, programs using retail rates, such as Time of Use (TOU) rates, are not dispatchable and are dependent on customers' willingness to participate at the time of a DR event. Given these concerns, DR's valuation within the IRP may change in the future based on learnings derived from the pilot efforts. Chapter 6 has more details about DR options considered in this plan.

Three major changes from the 2023 IRP when evaluating DR include:

(1) Use of a capacity adjustment by assuming the demand reduction lowers load and therefore lowers the total MWs estimated in the planning reserve margin (PRM).
(2) Programs assume a Transmission & Distribution (T&D) financial credit of $25.38 per kW-year[7] to account for potential savings in T&D investment.
(3) The Qualifying Capacity Credit (QCC) do not degrade over time as compared to the 2023 IRP.[8]

These changes significantly increase future DR programs compared to prior IRPs, and, along with updated costs and program assumptions, lead to the savings shown in Figure 2.4. DR selections total 51.6 MW of winter savings in Washington by 2045 (56.3 MW summer) and 10.6 MW winter (4.3 MW summer) in Idaho. The programs by year and state are shown in Table 2.2. Without advanced metering infrastructure in Idaho until 2029, Idaho DR programs are deployed later than Washington due to later automated meter infrastructure deployment. Overall, less DR is expected in Idaho due to lower-cost alternatives such as natural gas turbines, whereas Washington must use higher-cost methods to meet peaks due to CETA requirements. When combining existing DR programs with the PRS's DR selection, system peak load could be reduced 4% by 2045, with Washington programs decreasing peak load between 5% and 6%.

Avista is piloting TOU rates and Peak Time Rebate programs over the next two years (2025-2026) and partnering with Northwest Energy Efficiency Alliance (NEEA) to evaluate CTA-2045 grid-enabled water heaters (see Chapter 6 for further information). Lessons learned from these pilots will provide greater understanding of the program benefits, costs, and acceptance to determine whether DR will be selected earlier in the 2027 IRP as compared to this plan's selection. If the capacity need is greater, DR in Washington would likely be selected earlier. However, due to other resources being selected to meet the capacity need, DR is pushed to periods when greater resource deficits occur. Avista expects third-party aggregators will submit proposals in future RFPs where the DR resource could be more cost effective compared to other options.

[7] The credit was created by the revenue requirement of net value of current T&D plant assets on a historic basis and is compared against the peak load for the system to estimate a $/kW-year value.
[8] The 2023 IRP assumed the QCC value by 2045 is 20% of the 2024 value. This IRP assumes the 2045 value is 80% of the 2026 QCC value, significantly increasing the amount of capacity DR is assumed to deliver to the system.

Figure 2.4: Total Demand Response by State and Year in Winter

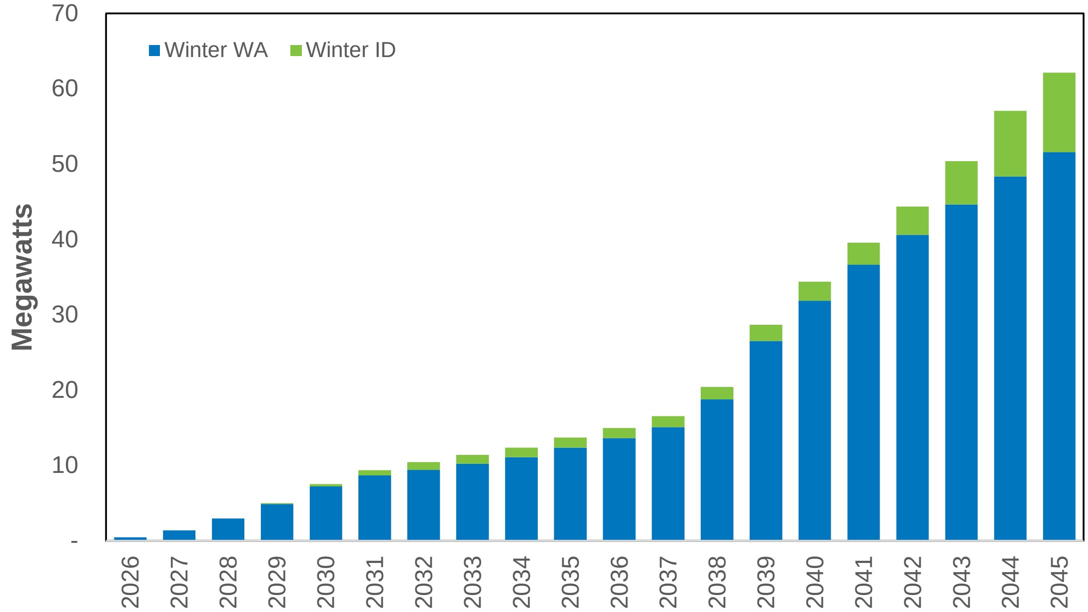


Table 2.2: Demand Response Selection

Program	Customer Segment	Washington Start Year	Idaho Start Year
Electric Vehicle TOU	Commercial	Available	2029
Battery Energy Storage	All	2026	2035
Variable Peak Pricing	Large Com./Ind.	2026	2029
Peak Time Rebate	Res./Com.	2035	2040
Behavioral	Res./Com.	2038	2043
Time of Use Rates	Res./Com.	2038	n/a
Third Party Contracts	Large Com.	2039	2044
CTA ERWH	Res./Com.	2041	n/a
Central A/C	Res./Com.	2043	n/a

Washington Named Community Investment Fund (NCIF)

The IRP focuses on ensuring enough energy or capacity is available to meet customer load for specific periods of time. The NCIF will fund future projects with unknown energy benefits and will be developed based on direction from the communities Avista serves. Even though the specific actions or projects are unknown, the IRP needs to account for these benefits by reducing resource acquisition targets. The actual funding decisions may or may not impact overall resource needs and rely on Avista's Equity Advisory Group's (EAG) recommendations. Given an IRP cannot forecast specific projects, this analysis is designed to estimate possible project impacts by selecting resources or energy efficiency programs meeting NCIF objectives. This is done by including $0.4 million of incremental supply-side DERs each year (after tax incentives) and providing an additional $2 million of energy efficiency upfront spending estimated by the present value of the Utility Cost Test (UCT) for resource selection.

The result of this effort is the selection of approximately 22.1 MW of community solar through 2045. The quantity of community solar is a direct result of Washington State (Commerce) and NCIF funding covering 100% of the community solar costs including administration. The IRP modeling suggests between 2026 and 2033, the period when Commerce funding is available, 9.9 MW (AC) could be developed (1.4 MW per year). After the state funding expires, the new solar estimate drops to 1 MW per year. The total final amount of solar added to benefit these communities may differ from this forecast and will be determined based on upon available funding and project limitations. Due to project funding priorities, it is also possible that no community solar is added if the funds are allocated to other projects.

In addition to assumed new community solar, Avista's energy efficiency targets are 3.4%, or 22.4 GWh higher to reflect additional investments in Named Communities through 2045.[9] For the 2026-27 biennial period, the energy efficiency target increases 3% to reflect this anticipated additional spending. Each of these activities along with the energy efficiency for low-income households outside of the NCIP contribute toward meeting the energy assistance needs of our communities with distributed energy resources as required by 480-100-620(3)(b)(iii).

Distribution Scale Energy Storage

Using energy storage on the distribution system may mitigate the need for upgrading certain portions of the delivery system when summer peak temperatures drive the need for enhancing distribution substations. This IRP did not identify any distribution level storage using generic system benefits combined with energy benefits. This does not mean future projects lack economic value or will not be the least cost solution for customers, but rather when analyzing future distribution system needs, the study will need to be performed using this IRP's avoided cost calculations to evaluate potential feeder upgrades against traditional methods of delivering energy. The 2027 IRP will incorporate any known potential for feeders where the distribution plan determines if energy storage is a solution to solve future needs of the delivery system.

Supply-Side Resource Selections

The PRS is designed to meet resource needs described in Chapter 5 with generic new resources as described in the DER (Chapter 6) and supply-side resources (Chapter 7) chapters. When Avista prepares to acquire new resources for its energy/capacity needs, an All-Source RFP will be issued to find the best resource options to meet the need rather than using specific IRP resource requirements. The resource strategy discussed here is based on the best available information for planning purposes and is a result of future load expectations and resource pricing. Due to uncertainty about these planning

[9] For energy efficiency, energy potential is estimated using low-income versus non-low income and does not include geographic areas.

assumptions, Avista continuously evaluates the alternative portfolios discussed in Chapter 10 and will continue to revise this plan every two years.

Avista separates resource selection between its two jurisdictions in this plan due to differing state-level policy objectives and financial evaluation methodologies. Each state is separated according to its load along with its planning risk adjustments (totaling the planning obligation). Existing resources are netted against the obligation for each state using the existing Production Transmission (PT) ratio to allocate resource costs, approximately 65.5% assigned to Washington and 34.5% to Idaho in 2026. The PT ratio is adjusted each year based on the expected state-level load changes within the load forecast. The amount of assigned existing resources shifts to the faster-growing state as it gets a higher percentage of the PT ratio. In addition the splitting resources by the PT ratio, PURPA resources are assigned to the jurisdiction of qualification. New resources are then selected based on the objective function described later in this chapter to fill any needs.

Existing Thermal Generation Forecast

The resource strategy includes the retirement or exit of several resources from the existing power supply portfolio. The first resource exit is the 222 MW of Colstrip Units 3 and 4 at the end of 2025 when ownership is transferred to NorthWestern Energy. There are also approximate retirement dates and PPA expirations for several of Avista's natural gas peaking and wind facilities. While these dates are subject to change, this plan uses current expected retirement dates to determine the need for additional resources. These retirements include Northeast by the end of 2029, Kettle Falls combustion turbine (CT) and Boulder Park CT by the end of 2039, and Rathdrum CT by the end of 2044. The Lancaster PPA concludes at the end of 2041, and Coyote Springs 2, the final natural gas facility, does not have a planned retirement year. Given CETA's 2045 100% clean energy requirement, this IRP determines Coyote Springs 2 in 2045 could co-firing 30% of its fuel with hydrogen for Washington customers and allocate the remaining 70% of the production to Idaho customers. Table 2.3 summarizes resource retirement assumptions. Avista's schedule for long-term power purchase contracts, including wind PPAs, are included in Chapter 4. Currently, Avista has no plans to retire any of its hydroelectric resources.

Table 2.3: Thermal Resource Portfolio Exit Assumptions

Resource	Fuel Type	Final Year	Capacity (MW in January)
Northeast	Natural Gas	2029	64.0
Boulder Park	Natural Gas	2039	24.6
Kettle Falls CT	Natural Gas	2039	10.9
Lancaster	Natural Gas	2041	281.7
Rathdrum CTs	Natural Gas	2044	174.5
Total			**555.7**

Supply-Side Resource Selections (2026 to 2035)

Avista recently completed a large resource acquisition process acquiring long-term contracts for hydroelectric power from Chelan PUD and Columbia Basin Hydro, extending the Lancaster PPA, and adding the Clearwater Wind PPA. Following the 2023 IRP, Avista expected these acquisitions would create a long position and new resources would not be required for a few years. However, the long resource position quickly dissipated with the addition of a large-load customer and overall customer load growth, especially in winter peaks. These changes now show a small energy and capacity deficit in January 2026, while most of the remaining months are long until 2030.

Avista plans to meet small capacity and energy deficits between 2026 and 2029 by using short term market purchases and the demand response programs mentioned earlier in this chapter. To meet the Idaho customer portion of the 2030 capacity deficit, a 90 MW natural gas combustion turbine (CT) is selected. This resource replaces the expected lost capacity of the Northeast CT and addresses future natural gas retirements while accommodating load growth in Idaho. This analysis models this capacity addition as a third unit at the Rathdrum CT site. Table 2.4 summarizes the capacity addition plan through 2035. Avista expects the RFP resource selection will be different from this IRP, as the IRP assumes non-specific project sites, interconnection, and locational budgets in its evaluation whereas the proposals received in the RFP will have specific projects and costs.

The 2023 IRP determined that the early acquisition of 400 MW of wind was cost-effective due to available production tax credits. This plan produces the same result but also shows the need for additional wind capacity due to the higher electric market price forecast and the potential for more wind availability than assumed in the prior plan. This plan selects 200 MW of northwest wind in 2029, followed by an additional 200 MW each year through 2032 and 157 MW in 2033 for a total of 857 MW of wind. This includes wind located in Montana and off Avista's transmission system but still within the northwest. This IRP finds customers benefit in both states by selecting 357 MW of wind as a system resource and 500 MW as a Washington-only resource. However, this selection of wind comes with several important caveats:

- These selections are a result of high electric market prices and low-priced wind PPAs. If actual PPA pricing is higher or market prices fall, the resource selection will change as a result of the RFP process.
- Avista's transmission system can accommodate up to 500 MW[10] of wind without substantial transmission expansion. If wind projects are exported off Avista's system, the resource selection will result in less wind for Avista customers at low pricing.

[10] The 2023 IRP assumed only 200 MW of additional wind would be available without major transmission expansion.

- The model assumes tax credits will expire in 2032[11] and not be extended, thus driving early acquisition. If tax credits expire early, or are extended, the wind acquisition strategy will change.

To account for this uncertainty, the plan will be revised in the 2027 IRP. However, a future all-source RFP will provide real options to evaluate whether early acquisition of this amount of wind is cost effective given Avista's resource needs.

Table 2.4: Resource Selections (2026-2035)

Resource	Year	Jurisdiction	Capability (MW)	Energy Capability (aMW)
Northwest Wind	2029	Washington	200	69
Northwest Wind	2030	Washington	200	69
Natural Gas CT	2030	Idaho	90	86
Northwest Wind	2031	Washington	100	34
Montana Wind	2031	System	100	44
Montana Wind	2032	System	100	44
Northwest Wind	2033	System	157	54
Total			**947**	**399**

Supply-Side Resource Selections (2036 to 2045)

The IRP did not select utility-scale supply-side resources between 2034 and 2040 due to the early acquisition of renewables, the utilization of new transmission, and the ability of DR and energy efficiency to meet load growth-related requirements. As Washington's 100% clean energy target approaches, the deadline to replace natural gas resources, while meeting higher load growth due to electrification, will require substantial new resources after 2040. Idaho resource needs follow load growth and natural gas resource retirements. Table 2.5 outlines the resource additions and the associated production from added resources between 2036 and 2045. New resources are selected using familiar technologies such as natural gas turbines, wind, solar, lithium-ion batteries, and biomass, but also technologies new to Avista, including power-to-gas combustion turbines (CTs), nuclear, iron-oxide energy storage, and geothermal. While 2045 is a long way off, Avista will need to follow technology development and potentially develop sites for these resources up to 10 years ahead of need. Therefore, the 2045 targets will be continually evaluated in future RFPs to ensure resources can be developed in time to meet state goals.

To meet Washington's 2045 clean energy requirements, a diversified mix of new resources will be required including wind, solar, 4-hour lithium-ion energy storage, biomass, geothermal, nuclear, and 100-hour iron-oxide energy storage. Power-to-gas technologies, where renewable energy is converted to hydrogen and either consumed directly as hydrogen or converted into ammonia, are also required. As mentioned earlier,

[11] The credit may be extended for projects meeting the safe harbor construction requirements.

the 2036-2045 strategy also includes co-firing a 30% hydrogen blend in the Coyote Springs 2 facility to enable the plant to continue to provide some capacity to Washington customers.

With the addition of natural gas resources to meet Idaho needs, adequate fuel supply is needed, but existing regional pipelines are contractually full. To address this concern in the plan, Avista includes the proportionate cost of a new LNG storage facility within the cost of new natural gas generation. If firm fuel supply is not ultimately available, Avista may need to pursue natural gas storage in the local vicinity of the generation to ensure the ability to generate in winter peak events.

Table 2.5: PRS Resource Selections (2036-2045)

Resource	Year	Jurisdiction	Capacity (MW)	Energy Capability (aMW)
Natural Gas CT	2040	Idaho	90	86
Power to Gas CT	2040	Washington	90	5
PPA Wind Renewal/Repower	2041	Washington	140	48
Natural Gas CT	2042	Idaho	95	90
Power to Gas CT	2042	Washington	210	11
PPA Wind Renewal/Repower	2043	Washington	120	41
Solar + 90 MW 4-hour Storage	2043	Washington	180/90	53
Solar + 60 MW 4-hour Storage	2044	Washington	120/60	36
Iron-Oxide 100-hour Storage	2044	Washington	26	n/a
Northwest Wind	2044	Washington	108	37
Iron-Oxide 100-hour Storage	2045	Washington	85	n/a
Nuclear	2045	Washington	100	98
Northwest Wind	2045	Washington	200	69
Geothermal	2045	Washington	20	18
Kettle Falls Upgrade	2045	System	10	9
Kettle Falls Unit 2	2045	Washington	58	29
Coyote Springs 2 Hydrogen Co-Fire	2045	Washington	n/a	n/a
Total			**1,652**	**629**

Transmission Requirements

Avista will require new transmission to integrate new generating resources and access new markets. Historically, the IRP only modeled interconnection costs for new resources and did not conduct detailed transmission studies. Avista does, however, develop a 10-year transmission plan with specific transmission projects (see Appendix D). The IRP considers limits on resources with low-cost interconnections and determines whether resource need triggers a major transmission build. As a result of this analysis, the IRP modeling identified upgrades to integrate new generation in the Rathdrum, Idaho area. This location will likely be the site of future generation, whether it be natural gas, hydrogen-based fuels, or energy storage. Increasing the intertie between north Idaho and Spokane is required to site any generation.

The second major project is a new DC transmission line between Colstrip, Montana, and North Dakota. This proposed line by Grid United would create a diversified market for Avista to participate in for energy purchases and sales. This market could provide reliable capacity to offset the need for building new generation resources due to diversity in time, weather, and other market conditions. Furthermore, this line could allow Avista and other utilities to arbitrage the price differences between the Northwest and the Midcontinent Independent System Operator (MISO) and/or Southwest Power Pool (SPP) markets to benefit customers.

In this IRP, Avista modeled this transmission resource as providing a capacity benefit in a limited manner when Montana wind generation is not available. The initial analysis did not consider any arbitrage value as this analysis will be evaluated outside of the IRP prior to making any investment decision. With these assumptions, the new line was selected by the model in 50 MW increments for the Washington service area. Avista then evaluated whether the arbitrage value would select the new transmission line earlier, all at once, or for both jurisdictions. Avista found adding a minimal arbitrage value results in the model selecting the line all at once for both jurisdictions. Therefore, this IRP assumes Avista will participate in the line at 300 MW with an expected on-line date of 2033. At the time of this IRP, Avista signed a Memorandum of Understanding to continue exploring this option with Grid United. Initial IRP analysis shows the new transmission line appears to be a favorable project in lieu of alternative generation resources and Avista will continue to evaluate the economics of this project between this IRP and the 2027 IRP.[12]

Avista has limited firm transmission rights to the Mid-Columbia market and other regions. This IRP identifies that Avista should invest in new transmission projects to increase connectivity to both markets and/or other balancing authorities to import resources and diversify market access. The challenge with this conclusion is identifying the specific locations and markets for these transmission enhancements when the location of new resources is uncertain.

The last new transmission asset Avista should consider developing is the Big Bend area in the western part of its system. This area has solar and wind potential but needs new transmission to deliver these resources to Avista’s load or to other utilities. This IRP did not specifically select resources in this area due to the approximate $260 million cost and 10 or more years of development time to expand the system. Given the risk of wind resources in low-cost connection areas of the transmission system being exported to another buyer, Avista may need to access wind resources for the 2045 100% clean energy compliance. Developing this transmission may give Avista optionality to meet future load needs if lower cost wind is not available when needed or loads grow faster than anticipated.

[12] The IRP analysis was conducted prior to the announcement by the DOE awarding a $605 million Grid Resilience and Innovation Partnership (GRIP) grant to the project.

Power-to-Gas Fuels

Toward the end of this plan, Avista identifies two types of power-to-gas (P2G) projects. The first is to co-fire hydrogen at Coyote Springs 2[13] for up to 30% of its fuel supply by 2045. To achieve this, additional hardware will be required at the facility along with new fuel-handling equipment. This includes a dual gas control module, manifold skid, hazardous gas and fire detection system upgrades, detection systems, adding welded fuel nozzles, metering and sensors, and an additional selective catalytic reduction (SCR) catalyst or ammonia injection component to reduce NO_X emissions. However, the biggest challenge will be sourcing the hydrogen fuel supply. The IRP analysis assumes a fuel delivery system will be in place, although the method of fuel delivery and/or storage is unknown. The Pacific Northwest Hydrogen Hub, funded in part by the U.S. Department of Energy, or separate hydrogen supply chain with on-site fuel storage are potential options.

The second P2G project identified in this plan is new combustion turbines using clean energy-based ammonia. Ammonia can be commercially derived from hydrogen produced by excess clean energy and efficiently stored and transported. Turbine manufacturers are developing turbines capable of using this fuel source. This IRP assumes ammonia is a cost-effective way to store energy in a relatively small footprint for long durations. This technology does not use natural gas as fuel but operates with similar characteristics. The advantage with ammonia, compared to hydrogen, is the ability to store large quantities without underground storage, and the ability to transport the energy via rail or truck. Significant infrastructure for ammonia production, handling and storage for industrial and agricultural use already exists. Due to hydrogen and ammonia being new generation fuels with no major supply chain in place in the Northwest for this use, Avista limited this technology to 300 MW. Absent a robust supply chain similar to the natural gas system, Avista would need four 30,000 metric ton tanks to store the fuel to meet the high fuel usage scenario studied in this plan. Due to storage requirements and safety concerns, Avista limits the locations for this technology to larger land requirements than a similar natural gas facility with access to pipelines.

The storage needs of these ammonia facilities will be determined by how much the facility is expected to operate and what energy is used to create the fuel. For example, if solar and water were to be used in the development of the ammonia through hydrolysis and the Haber-Bosch process in the 95th percentile use case (i.e., ammonia is called on to run at a 19% capacity factor), it would require an equivalent 1,600 MW of solar capacity using a 13.4% round trip efficiency rate from solar power to long-duration dispatchable ammonia power. However, if the ammonia creation were not dependent on solar energy and refilled faster during winter months, the storage requirements to operate at higher capacity factors would be less due to a just-in-time delivery system. Given ammonia is a world-wide commodity, it is possible Avista will be able to access supply without having

[13] GE has expressed this technology's maximum hydrogen co-fire ability is 32%, so 30% is used as a conservative planning estimate.

to internally develop its own supply chain, reducing the need for large amounts of storage and self-development of additional renewable resources dedicated to fuel production. Given this identified technology need is more than 10 years away, Avista can monitor the development of both the generation technology and supply chain for this option. If ammonia for power generation does mature at the generation or fuel level.

An alternative fuel is synthetic methane. The fuel is expected to be higher priced but uses the same principle of clean hydrogen but uses carbon dioxide rather than nitrogen for chemical bonding. An advantage of this fuel is it can use existing generation technology and fuel delivery systems, but the technology is still in its infancy.

Nuclear Energy

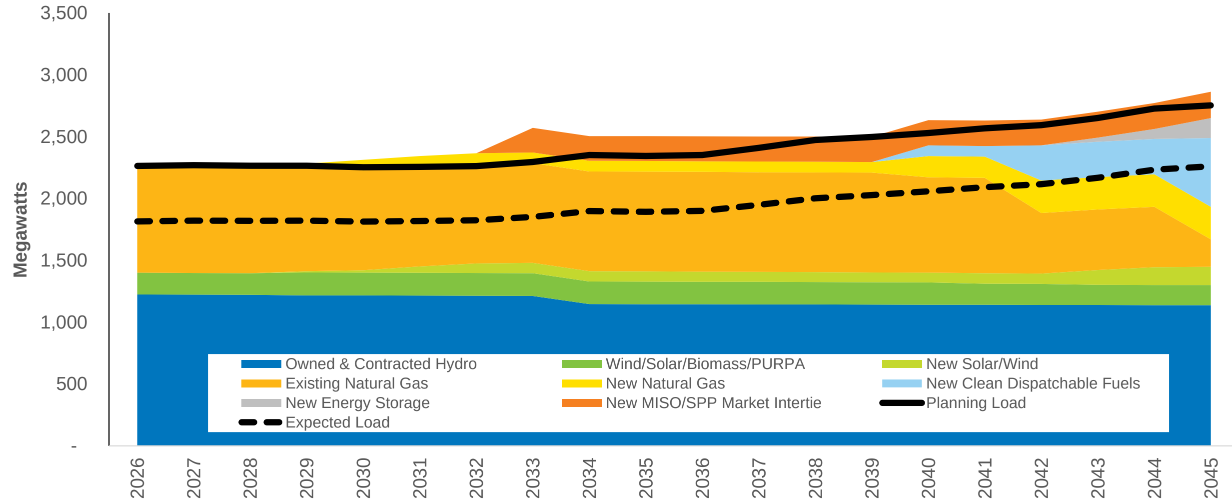
For the first time since the 1980s, nuclear power appears in the resource plan. While not appearing until 2045, small modular reactors (SMR) could play a key role in developing a reliable and clean resource portfolio replacing Avista's natural gas resources. Given the time horizon for the selection, Avista will continue to monitor this resource development as other utilities and developers are pursuing it. Avista will need to consider all resource options to meet the clean capacity acquisitions needed beginning in 2040. With potential long lead time and permitting, the development and procurement phase of this resource may need to begin as early as 2030 to ensure it can be completed in time.

System Overview

Figures 2.5 through 2.7 summarize the future resource additions by combining the existing portfolio of resources, with already-contracted additions and future resource selections from this plan. The black solid line represents the planning load resources expected to meet (including expected load and a planning margin or reserves to account for unexpected conditions) and the dotted line represents expected load given normal conditions.

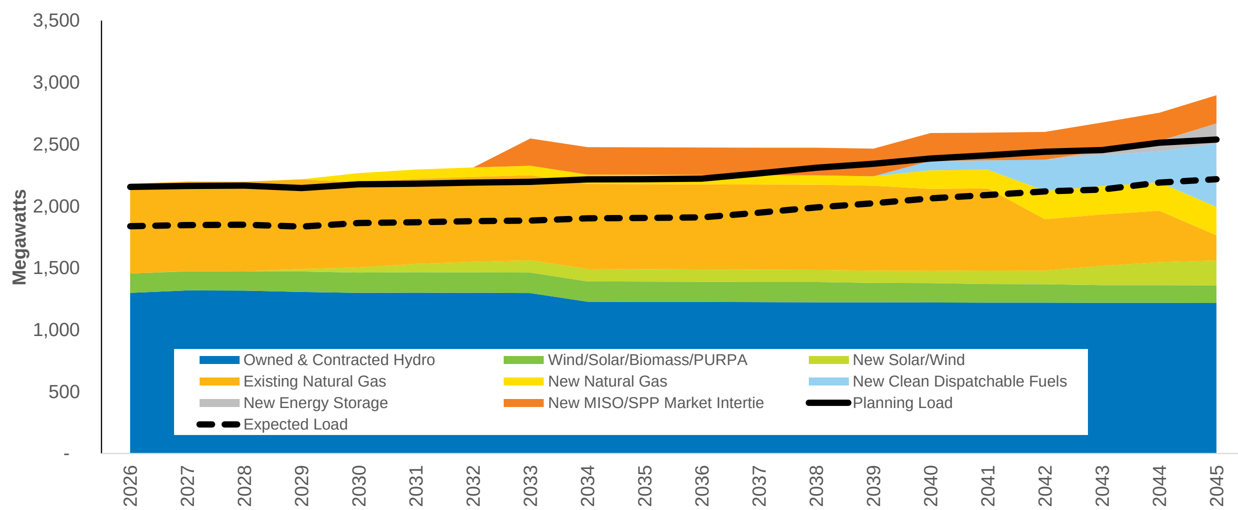
Historically, Avista operated in a long-capacity resource position – meaning resource capability exceeds expected load. But as shown in Figure 2.5, the resource portfolio is nearly balanced until 2033 with the forecasted completion of the North Plains intertie with MISO/SPP. While the planning margin target is met, the risk of meeting customer load is still a concern in the event of unplanned extreme weather conditions or the inability to buy power from the energy market. For example, during the January 2024 cold snap, Avista was near a resource-even position, but extreme cold temperatures and low hydroelectric conditions combined with a temporary loss of generation assets due to natural gas delivery system constraints required Avista to depend on the energy market.

Figure 2.5: System Winter Capacity Load & Resources



The summer capacity position in Figure 2.6 is similar to the winter position, except the portfolio has slightly more excess capacity because the winter capacity targets are the more difficult constraint to meet. Avista plans for a smaller planning margin in the summer compared to winter due to several factors. The system is less reliant on hydroelectric energy as the peak summer hour duration is shorter than winter. Another factor is summer peak loads do not vary year to year as much as winter peaks due to less peak day temperature variation.

Figure 2.6: System Summer Capacity Load & Resources



Avista's annual energy position (Figure 2.7) is long compared to the annual average needs because:

(1) Avista solves to meet monthly energy requirements, Avista is generally more constrained in winter and summer months and acquiring energy to meet these

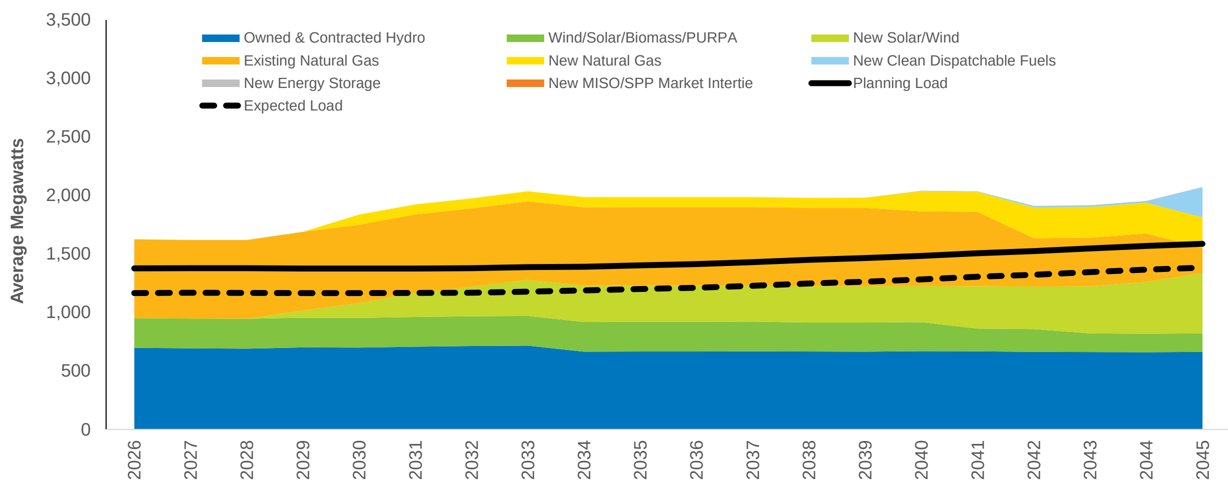
shortages creates length in other months since you typically cannot develop or obtain contracts for resources with operations limited to one period of time.

(2) Excess energy in the spring from hydroelectric and wind generation creates an extremely long position compared with load than other seasons.

(3) Avista plans its system to meet peak load requirements. The generation can create excess energy in other time periods when not needed for Avista customers and can be sold to benefit customers assuming the resource is economic to operate.

The solid black line in Figure 2.7 represents the planning load level including the risk of load exceeding expected average weather conditions and/or renewable energy volatility, such as hydroelectric or wind, producing less generation than anticipated in a normal year. The dotted line is the expected average load under normal weather conditions.

Figure 2.7: System Annual Energy Load & Resources



Resource Adequacy Analysis

One of the greatest modeling challenges for the IRP is developing a capacity expansion model to optimize resource selections to meet resource adequacy requirements in a lowest cost manner. The current industry standard for testing resource adequacy is to conduct Monte-Carlo or stochastic analysis of hourly operations to evaluate the probability of not meeting loads with any given resource portfolio. With today's technology, and the large number of simulations over multiple forecast years, it is not possible to add a capacity expansion optimization routine to this effort. To overcome this challenge, capacity expansion models such as PRiSM use a target for adding resources, such as expected load plus a planning margin and develop a system to quantify how resources can meet these load targets, known as Qualifying Capacity Credits (QCC). Avista assigns QCCs to each resource for each forward month to ensure the model selects enough capacity to meet the load target. To validate whether this resource selection passes a Monte Carlo style resource adequacy evaluation, a resource adequacy analysis is required after the PRS is determined.

Avista developed an hourly tool called Avista Resource Adequacy Model (ARAM) to assess resource portfolios for resource adequacy – see Chapter 5 for more information on this model and reliability metrics. This IRP tests two future years (2030 and 2045) using this tool to ensure the PRS complies with Avista resource adequacy tests. Avista's primary focus for reliability planning is to meet a 5% loss of load probability (LOLP). This target means Avista would meet all load requirements in 95% of all future conditions while not exceeding 330 MW of market purchases during capacity-constrained hours. For the 2030 and 2045 periods when adding future resources, the PRS meets this requirement with a 3.2% probability in 2030 and 3.3% probability in 2045 as shown in Table 2.6. The reason the LOLP is below the 5% threshold is the capacity expansion model suggests a higher resource buildout than required, whereas the minimum PRM is 24%, but in 2030 and 2045 the resource PRM is 29.6% and 28.6% respectively. This resource length pushes down the resulting LOLP. Also shown are other industry standard reliability metrics used to evaluate resource adequacy. Although the PRS results in a LOLP less than 5%, this does not guarantee Avista will be able to meet 100% of its load in all conditions. For example, in a high load and low water event, the utility still may have to rely on the market above the assumed 330 MW market limits (plus 300 MW for 2045 when the eastern interconnect transmission is considered) or risk failing to serve all load.

Table 2.6: Reliability Metrics

Metric	2030 w/o new resources	2030 w/ PRS	2045 w/ PRS
LOLP	6.9%	3.2%	3.3%
LOLE	0.227	0.07	0.09
LOLH	2.59	0.73	1.1
LOLEV	0.495	0.176	0.304
EUE	488	115	172

Washington Hourly Clean Energy Analysis

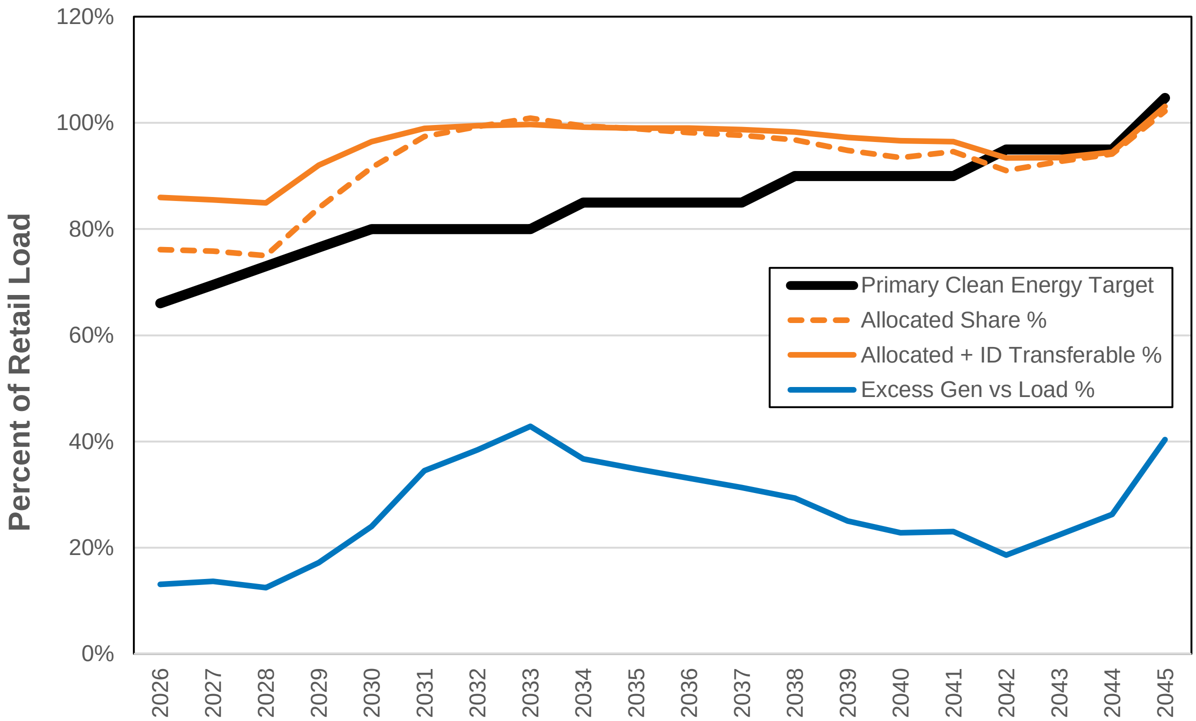
The "use" rules for compliance with CETA's clean energy standard are still being developed by the Washington UTC. The Washington Department of Commerce (governing consumer owned utilities) rules include an hourly analysis requirement in planning. Avista assumes the UTC rules will include a similar requirement for the development of this plan. Today's capacity expansion models (such as PRiSM) are not able to model at an hourly level of granularity when selecting new resources over 20 years. This limitation also exists in commercially available software, and while theoretically possible, the solution time is likely too long to be useful. In Avista's situation, PRiSM solves the system monthly using hourly data from the Aurora model.

For this first hourly analysis, the hourly data from the Aurora modeling is analyzed to determine how well the energy matches up to (retail) load on an hourly basis using market-based dispatch of resources. However, this methodology does not show how the utility could use its resources to meet only its load, but rather it dispatches resources to serve regional load (market) as to reflect actual future operations. This is because utilities do not dispatch resources to serve only their own load, but also regional demand based on market prices, allowing the utility to optimize its resource portfolio for the benefit of its customers by selling excess energy to others when prices are high and purchasing from the market when prices are lower. Avista is conducting a second analysis to determine whether it could meet the hourly 100% clean energy goal in 2045 if the utility were to dispatch its resources only to load without the market (discussed below).

For this first view of hourly compliance using market-based dispatch, Figure 2.8 provides an annual summary of the results, where the black line represents the annual goal of "primary" compliance or the total amount of energy as a percentage of retail load where clean energy must be generated in the same hour. In 2045, the clean energy goal is slightly above retail load due to the fact Avista must serve all Washington retail load and line losses with clean energy. The orange lines represent how well the Avista portfolio performs against this requirement. The solid orange line includes both the allocated clean energy to Washington based on the current PT ratio plus the transferrable portion from Idaho. As a reference, the dashed orange line shows only the Washington allocated portion. Avista meets the hourly requirement in all years until 2042. In 2042, 94% of the load in all hours is met with clean energy compared to the goal of 95% (assuming market-based dispatch).

The solid blue line represents how much additional clean energy is produced, but the energy produced is excess to the hourly load when the model dispatches to regional loads. The next step is to determine if the Company "could" serve the load targets between 2042 and 2045 by either moving clean energy generation to different hours using either future energy storage or existing hydroelectric storage, or increased amounts of dispatchable clean energy such as ammonia turbines to achieve these targets. This analysis will be performed for only the 2045 period in the final IRP, assuming 2045 could be solved with Avista flexible resources, meeting 2042-2044 could be assumed to be capable as well.

Figure 2.8: CETA Hourly Analysis



2045 100% Clean Energy Analysis

Avista's hourly modeling approach, as described in the previous section, dispatches resources to market. Avista anticipates market purchases will continue to be a method of meeting load in the future but may require a clean energy market to ensure compliance with CETA. However, Avista tested if Avista's 2045 portfolio could in fact serve 100% of its Washington load with clean energy if it were to redispatch resources to meet load demands. The concept requires resources with energy storage (batteries and hydro) and fuel (ammonia) to redispatch to generation to meet load each hour. Resources such as hydrogen, ammonia, and biomass are limited in annual dispatch to ensure fuel availability. For example, Kettle Falls Unit 2 is limited to 50% capacity factor due to limited wood fuel. The model then solves using the same monthly hydro levels and hourly wind and solar generation from Figure 2.6. Effectively, the model solves dispatchable resources to meet load. Figure 2.7 shows the results of this analysis by month. The results show Avista can meet 100% of Washington load with clean energy when average load and renewable generation is assumed; in fact, it has excess generation in many of the hours. The model also did not require any of the Idaho share of clean resources in this example. Although, in non-spring months, the model found many hours where clean generation equals load exactly. For example, in January 2045, 41% of the hour's clean generation equals load, but overall, in the month, 14% more clean generation was created versus actual load.

Table 2.7: 2045 Hourly Analysis

Month	Clean Energy %	Percent of Hours Clean Generation Equals Load
1	114%	41%
2	123%	4%
3	137%	0%
4	165%	0%
5	178%	0%
6	170%	0%
7	134%	3%
8	120%	31%
9	132%	15%
10	126%	32%
11	114%	39%
12	121%	35%

Air Emissions Forecast

Avista's recent resource portfolio changes will significantly improve its air emission profile. These portfolio changes include transferring ownership of Colstrip Units 3 and 4 to NorthWestern Energy at the end of 2025 and replacing this generation by signing hydroelectric power purchase agreements (PPAs) with Chelan PUD and Columbia Basin Hydro, as well as a 100 MW PPA from Clearwater Wind. Figure 2.8 illustrates the expected clean energy generation as a percentage of customer load by year and by jurisdiction. The chart compares total annual clean energy production for each state's allocated share of energy[14] compared to its estimated state load. In Washington, Avista will need to produce more clean energy than its load to meet the hourly 100% clean energy requirements. On a system basis, the resource portfolio by 2045 could generate 10% excess clean energy as compared to annual average load.

This over generation phenomenon is due to CETA requiring Washington's load to meet 100% of its generation needs using renewable or non-emitting generation in all hours and under all-weather scenarios. This includes meeting higher needs in summer or winter months with clean energy and accounting for renewable and load variability when there are low hydroelectric or wind years. This requirement will create substantial amounts of surplus generation in months with lower loads. This high level of surplus power will be compounded by all other Washington utilities also having surplus production beyond their needs, driving market prices to very low or negative levels. This oversupply could spur development of hydrogen to assist fueling future hydrogen/ammonia CTs. When Avista evaluates meeting CETA's 100% clean energy requirements, three resource strategies could take place in the future:

[14] This excludes potential transfers of clean energy between states to satisfy CETA requirements.

(1) building long duration energy storage to move renewable energy from lower to higher load periods,
(2) having enough variable energy resources (VER) in place to statistically be able to generate at least the amount of energy needed in higher load periods, or
(3) controlling or owning dispatchable clean generation such as nuclear or biomass.

The 2023 IRP results solve the 2045 challenge, this IRP includes more renewable/non-emitting generation and less energy storage by 2045. The 2025 PRS assumes a more diversified mix of resources including components of all three options to achieve the 100% goal. However, the maturity of some of these technologies, such as long-term storage or nuclear, may not be at a level of commercial availability for a decade or more. Clean resource choices will ultimately be based on the economics of each of the options compared to the cost increase caps set by CETA.

While Avista's resource plan includes significant renewable energy additions, greenhouse gas emissions will still not be zero. Figure 2.9 compares greenhouse gas emissions from 2023 (red line) and the 2019-2023 average (black line) from Avista controlled generation to the forecasted emissions from this plan. When looking at Avista controlled generation's 2026 forecast of emissions (blue bar), emissions are expected to be 59% less than 2023's or 49% less than the 5-year average.

This reduction is mainly due to the removal of Colstrip from the resource portfolio. Also, emissions were higher in 2023 due to a lower-than-normal water year in the Northwest, thus driving market prices higher and making both coal and natural gas cost effective to run at higher capacity factors. Avista expects 2024 may also show higher greenhouse gas emissions due to even lower water availability for hydroelectric generation in the region.

Figure 2.9: System and State Clean Energy Ratios Compared to Load

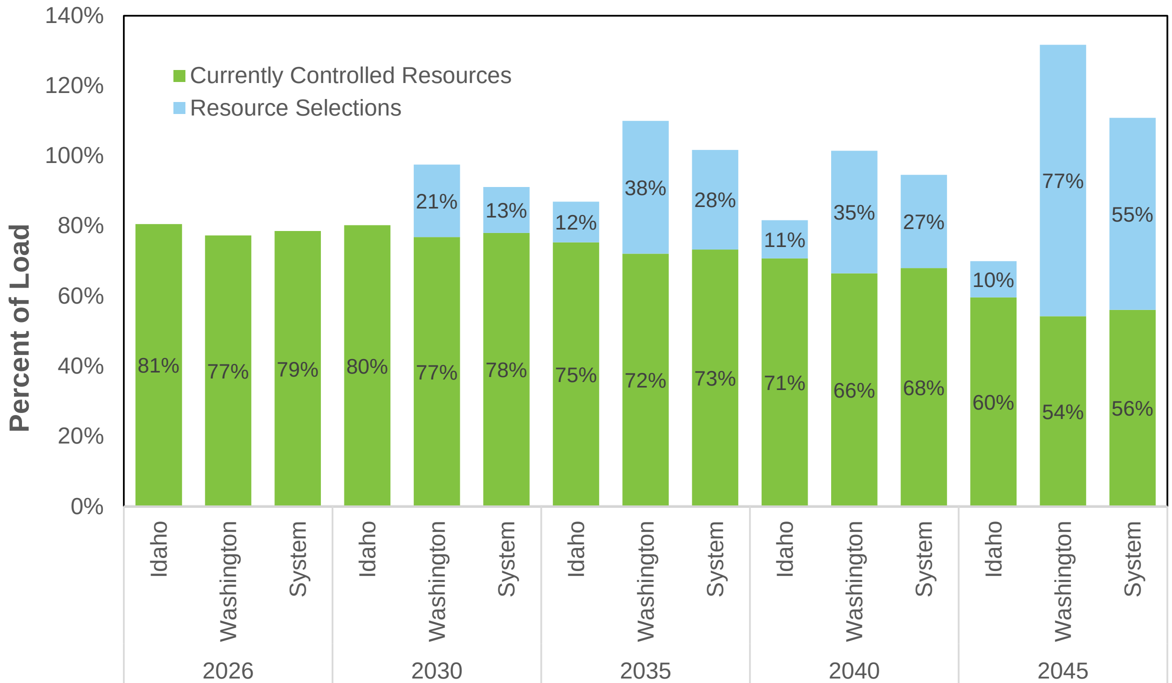
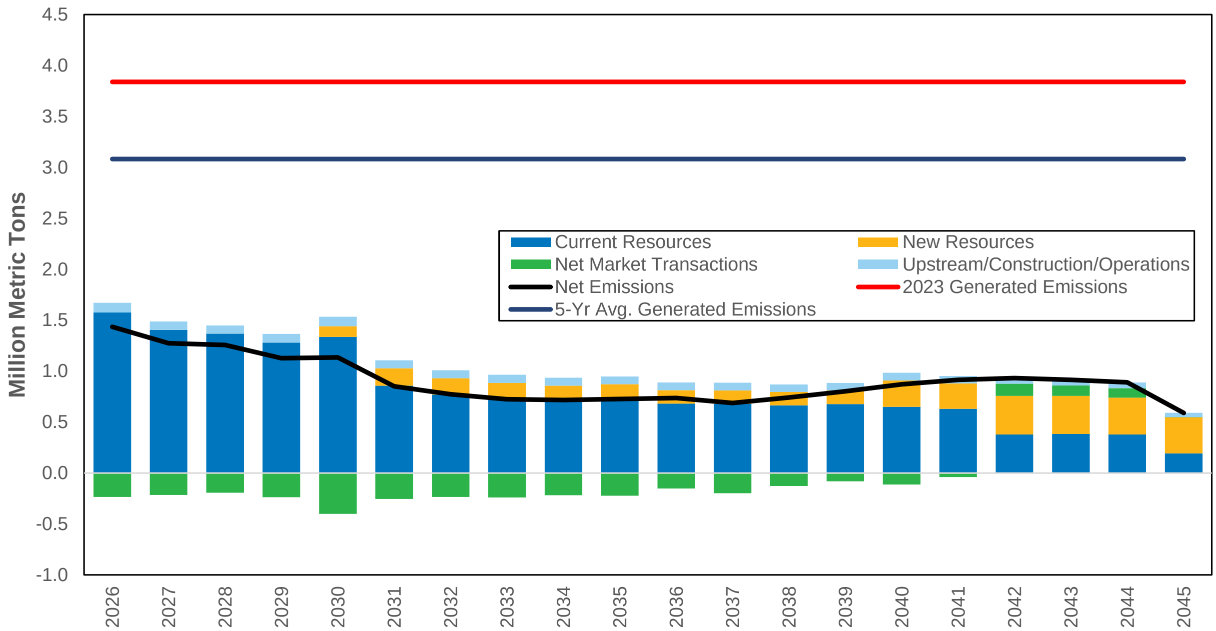


Figure 2.9 also includes estimates for upstream emissions related to natural gas deliveries, construction of new facilities, and plant operations. The chart also estimates the effect of market transaction emissions on the portfolio by either subtracting or adding emissions based on Avista's position – whether Avista is a net buyer or seller of energy (green bar). Emissions notably decline in 2031 due to assuming regional generators will not be given free allowances in the same manner as today under Washington's Climate Commitment Act (CCA), effectively requiring a greater number of facilities to account for the price of carbon when dispatching generating plants. The major drop in current resource emissions in 2042 is due to the expiration of the Lancaster PPA. This plan assumes it is replaced by additional natural gas CTs as shown in the orange bars operating at lower capacity factors. Even with the addition of new natural gas CTs replacing existing facilities, 2045 emissions are estimated to be 82% lower than the 5-year average from 2019 through 2023.

Figure 2.10: Avista System Greenhouse Gas Emissions



An alternative method to calculate total greenhouse gas emissions is to calculate the emission intensity of load. In this example, the total plant emissions (where Avista controls dispatch) are divided by the system load on a pounds per MWh basis. In this case, the 2023 emissions intensity was 867 lbs./MWh compared to the 2019-2023 average of 702 lbs./MWh. The future forecast shows a substantial decline at 340 lbs./MWh in 2026 to 100 lbs./MWh by 2045. The 2045 intensity of emissions is 86% lower than the 5-year average. With this method the annual emissions rate percentage is reduced more than the total emissions due to the reductions from serving more load with a cleaner mix of energy resources.

The last emissions profile for the resource portfolio includes other major air emissions from Avista's generation plants. These emissions are well below air quality standards set by the air regulatory agencies and are controlled and monitored at the plant level with the best available technologies at the time of construction or modification. Avista tracks the four major air emissions in the IRP shown in Figure 2.11: Nitrous Oxide (NO_X), Sulfur Dioxide (SO_2), Mercury (Hg),[15] and Volatile Organic Compounds (VOCs) at owned or controlled plants. After Colstrip leaves the portfolio in 2025, air emissions levels are minimal by using natural gas generation with run time limitations on generators or by emissions control systems. Kettle Falls is the only remaining facility with material air emission levels from wood waste burning. The reason for the 2045 emission increase is

[15] Avista does not track mercury emissions at natural gas facilities since it is not a permit requirement, the emissions beyond 2025 are for Kettle Falls based on historic emissions intensity rates, although the most recent study conducted after the IRP modeling was complete, indicated them as non-detectable. For Colstrip, a default emission factor is used for mercury emissions.

due to additional biomass generation at Kettle Falls for increased capacity from a second unit being added to the plant.

Beyond wood waste emissions, the plan includes burning both ammonia and hydrogen in combustion turbines. Both fuels have NO_X emission controls and adhere to air quality limits but will still have non GHG air emissions. For existing and potential plants selected to serve Washington customers, a non-energy impact of these emissions was considered in the economic evaluation.

Figure 2.11: System Greenhouse Gas Emissions Intensity

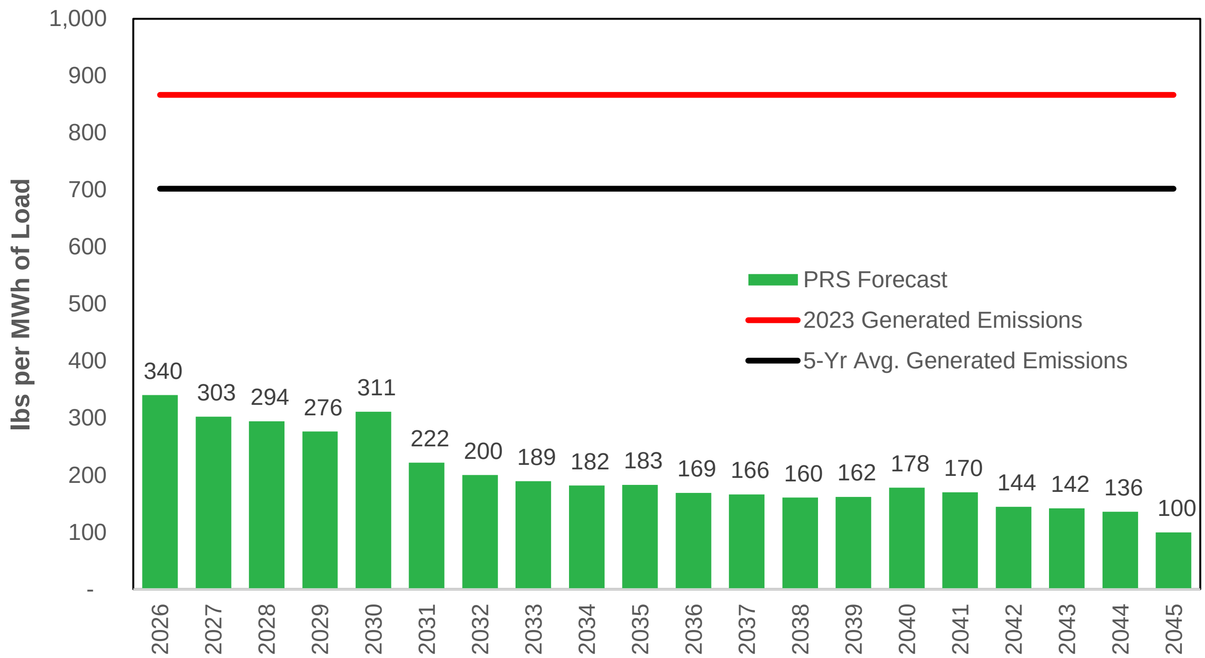
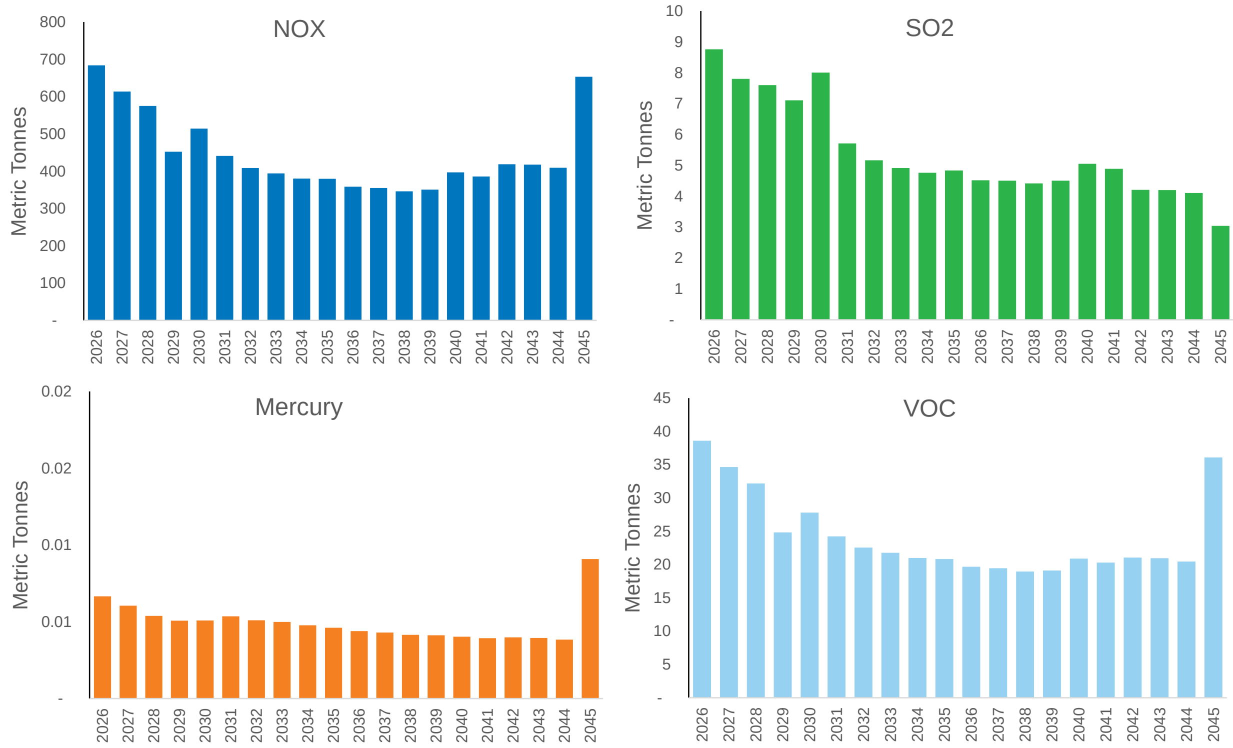


Figure 2.12: Avista Owned and Controlled Generating Plant Air Emissions



Risk Assessment

Future planning of resource adequacy requires consideration of many risks. Avista is utilizing the risks identified by the November 2020 paper "Implications of Regional Resource Adequacy Program on Utility Integrated Resource Planning"[16] as a framework to present how Avista manages these risks. While a current long-term resource deficit is projected for 2030, the risks outlined below will inform Avista's ultimate identification of resource needs.

Peak Demand Forecast

Avista's peak demand forecast is based on historical and forecasted future weather conditions. While weather is unknown for future loads, there are other load risks to be considered. Avista considers load changes from other risks in the scenario analysis Chapter 10 – specifically related to the impacts of electrification and customer growth, including the potential for energy intensive data centers to be located within Avista's service territory. Avista developed several load scenarios described Chapter 3 to understand the portfolio implications of load changes. If future loads are lower, there is a financial risk, as the outcome is a more reliable system at likely higher costs. However, if

[16] Implications of a regional resource adequacy program on utility integrated resource planning https://www.westernenergyboard.org/wp-content/uploads/11-2020-LBNL-WIEB-regional-resource-adequency-and-utility-integrated-resource-planning-final-paper.pdf.

future loads are higher, having an underbuilt system that cannot meet a higher load scenario creates a risk of resource adequacy and reliability challenges.

The underlying solution in the scenario analysis to protect against short-term, higher-than-expected loads, is to develop DR programs and a four-hour energy storage system as they have the shortest construction requirement. If data center loads are extremely high in the next 5 years, additional resources will be required, including solar with batteries and potentially natural gas turbines. However, if Avista acquires resources to manage this risk and loads do not materialize, then utility rates will be higher.

Demand-Side Resource Contribution

Avista includes demand-side resources as options when determining the amount and type of resources needed to meet future demand. Demand-side resources may also impact the net demand of the system prior to this inclusion; customer adoption is an example of this. Chapter 6 discusses each of the Distributed Energy Resource (DER) options included in this IRP, including energy efficiency, DR, include other DER generation and storage options.

The focus of DER modeling within the IRP is to ensure supply-side resources are not overbuilt. For example, rooftop solar may reduce Avista's summer energy needs, but have a limited impact on winter loads. To address this risk, Avista includes an estimate of incremental customer owned generation in its load forecast. The greatest uncertainty or risk regarding demand-side resources is whether they will impact winter peak load requirements. Given most DER additions today are solar, this risk is low. Avista does find customer storage DR solutions may assist with meeting peak loads. Regardless, a small portfolio risk remains in customer(s) willingness to develop storage solutions or willingness to allow their energy storage to be used to meet system needs.

Power Plant Retirement

Avista's Colstrip ownership will end December 31, 2025. Avista also plans for plant retirements for each of its existing natural gas peaking generators and has proposed end dates for its combined cycle combustion turbines (CCCTs) to serve Washington customers. In this IRP, the ability of these resources to operate until their proposed end date is a significant resource adequacy risk. Avista sees this potential risk for the projected 2029 retirement of the Northeast CTs in the short term. If Northeast is forced to retire earlier due to mechanical failure, given Avista's short-term projected capacity position is near even, scenario analysis indicates an immediate need to acquire nearly 80 MW of energy storage to replace the lost capacity. However, if the Northeast facility can continue operating beyond 2030[17], it would delay the need for replacement resources only for a short time. While it is unlikely, the forced unavailability of another resource will require an immediate replacement. To mitigate this risk, Avista could begin to invest in

[17] Northeast's air permit expires December 31, 2032.

the development of multiple technologies to be ready and available for construction if resources are retired early and to mitigate the high load risk discussed earlier.

Renewable Contribution

In 2035, 125 MW of wind is expected to be available to meet winter peak load. Of the 1,200 MW of wind capacity, this translates to a 10% QCC, with a majority of this benefit (76 MW) from the Montana portion of the wind portfolio. While wind in Montana has high-capacity factors in winter months, these facilities are known to be unavailable when temperatures are too cold. The region witnessed this phenomenon in January 2024. Given this risk, Avista could see a planning capacity deficit if the wind turbines cannot operate during cold weather events or if more reliable capacity is not built.

To help mitigate this risk, participating in the transmission line to North Dakota could provide another market to purchase power – gaining access to this region of the country with different load and weather conditions. One risk mitigation effort would be to reduce the QCC of wind resources in winter periods resulting in additional capacity resource selection. Avista expects the Western Resource Adequacy Program (WRAP) process, administered by the Western Power Pool, will continue to monitor the performance of wind in cold weather events and anticipates a future revision to winter QCCs. Additionally, another risk for the wind QCCs revolves around the summer contribution if temperatures are too high and there is a potential need for wind facilities to curtail generation. Given the climate of Avista's service territory, the last mitigation effort is to ensure any future wind technology Avista acquires must have suitable weather protection packages for year-round operations, but these weather packages may still not be enough to meet the most extreme temperatures seen in Montana winters.

Storage Efficiency

Given the PRS, storage efficiency is not a short-term risk to the utility. In the long-term and under different future scenarios, however, this risk could materialize. Avista sees two risks for storage efficiency. The first risk is similar to the renewable QCC contribution, described above, where short duration resources may help improve reliability in small increments. But the need to recharge the storage device after every use reduces its reliability benefit. In this IRP, if the region does not develop enough sustainable and dispatchable resources, the method to mitigate this risk is to reduce QCC values for short duration storage over time.

The second risk of energy storage is the efficiency to recharge the device. Not all storage technologies have the same recharging capability based on energy losses and time to recharge. Therefore, these considerations should be considered when determining each device's credit toward meeting peak demand. Avista's resource strategy includes new energy storage technologies using renewable fuels, such as green hydrogen and ammonia. These technologies protect against declining efficiencies found in today's battery technology and offer longer duration periods. These resources have other risks including technological risk (these are new and relatively unproven in large scale), and they require significant energy to produce the fuel whereas the round-trip efficiency is less than 25%.

Market Availability

In previous IRPs, Avista found market availability to be the greatest risk in resource adequacy absent a resource adequacy market or program. Avista's previously performed resource adequacy analysis assumed the utility was limited to 330 MW of market reliance during a peak event. With the development of the WRAP, and the pending binding requirements, Avista may be able to increase its market reliance threshold by adopting lower PRM values compared with those used today. However, in today's environment and reflected by the experience gained in the January 2024 winter peak event, it is clear the regional market is limited in cold weather and drought conditions for our hydroelectric resources. As witnessed in this recent event, the region was short of capacity and imported 4,745 MW[18] from outside the region during a time when transmission capability was also limited. Given Avista's controlled load is 5-7% of the Northwest system, Avista in theory could be allocated 240 MW to 300 MW of this import capability. Considering this range for an actual event gives Avista confidence in the 330 MW assumption for market access during a peak event.

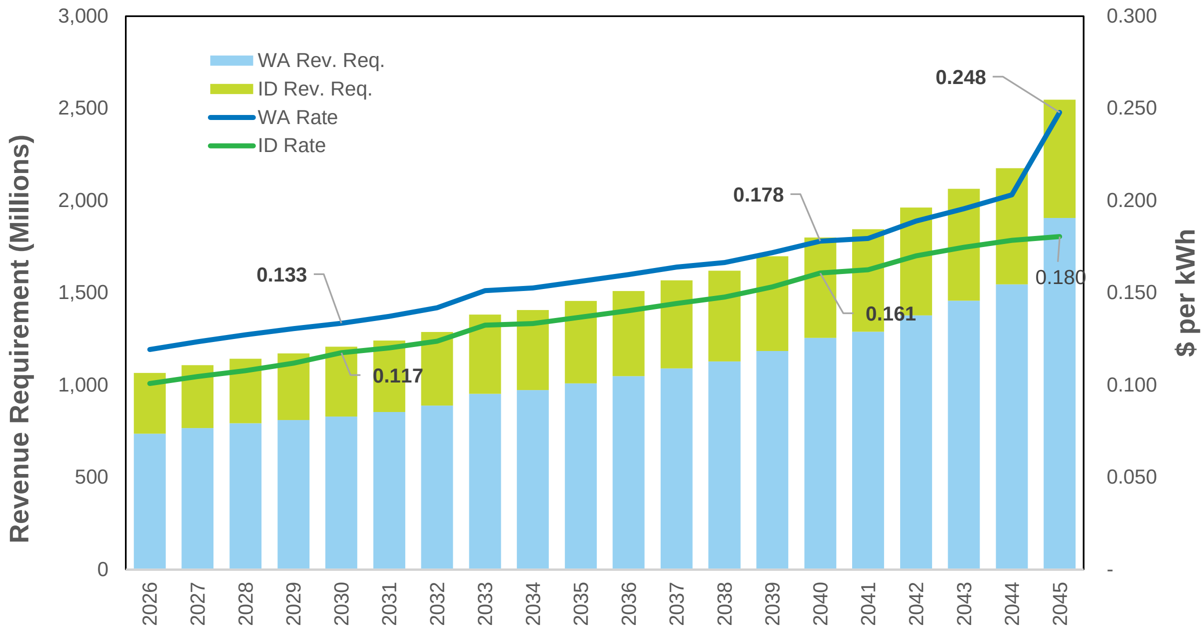
Cost and Rate Projections

The IRP cost and rate projection does not include detailed forecasts beyond specific generation acquisition, distribution, administrative, and Operations & Maintenance (O&M) recovery costs. Rather, the IRP focuses on energy supply costs. Avista assumes these non-generation costs increase by 3.8% per year to approximate an annual average customer rate estimate using historic non-power supply cost growth rates. Further resources are "priced" at levelized cost and may differ from actual revenue requirement needs. Annual projected rates and revenue requirements are shown in Figure 2.13. Rates are calculated by the total revenue requirement divided by retail sales and do not represent rate class forecasts. Also, as future rates will be determined by actual investments and evaluated by the Idaho and Washington commissions, this analysis should only be used for comparative and informational purposes.

The projected Washington revenue requirement grows at 5.1% a year and rates increase 3.9% a year. Between 2040 and 2045, the revenue requirement and rates are estimated to grow faster at 8.7% and 6.8% respectively. Future projected costs and rates for Idaho are generally lower where the average revenue requirement grows at 3.6% each year and rate increases are less at 3.1% annually.

[18] Analysis of the January 2024 Winter Weather Event.pdf (powerex.com).

Figure 2.13: Projected Revenue Requirement and Rate Forecast by State



CETA's Cost Cap Considerations

Avista's resource strategy does not consider CETA's cost cap due to uncertainty of how it will be applied. Given the PRS cost forecast, the only period when the cost cap could be applicable is 2045. The cost cap is designed to limit compliance costs where compliance is higher than a 2% cumulative investment each year as compared with a resource portfolio not complying with the clean energy standard known as the Alternative Lowest Reasonable Cost Portfolio. This portfolio is determined by placing a SCGHG on the resource choices and includes previous CETA resource additions but excludes CETA's clean energy targets. Lastly, the utility can only request to use the cost cap after the compliance period has ended.

The 2% cost cap is based upon rates in the year prior to the compliance period and does not account for the higher cost of compliance since the law began in 2019. Therefore, the 2% cost is a compounding higher rate and compares only the incremental societal costs of the system but not the actual costs of the system. Given these challenges, it is nearly impossible to estimate what the cost cap will be for the 2045 compliance period. It is also unknown if the cost cap in this period will be spread over multiple compliance years or a single year, or if it still applies. Lastly, CETA is mostly focused on meeting the requirements through 2044. The 2045 target is a goal without statutory penalty for non-compliance. Avista expects the legislature will address 2045 planning to meet this goal over the next 10 years. Given the concern of hitting the cost cap in 2045, a portfolio in Chapter 10 attempts to identify a future portfolio meeting a theoretical cost cap. The main difference in this scenario is the cost constrained portfolio would retain Coyote Springs 2 as a natural gas facility with its full associated pro-rata generation capacity allocated to

Washington customers (rather than limiting its share to the hydrogen co-fire), avoiding a second Kettle Falls unit.

Resiliency Metrics

As part of this plan, Avista measures other metrics rather than the emissions and costs, these include job creation, energy burden, generation location, and many others. For example, in Washington Customer Benefit Indicators (CBIs) are created to measure the equitable transition to clean energy. These CBI metrics are available in the 2025 Clean Energy Action Plan (CEAP). Avista added additional metrics for this plan to understand the resiliency of our generation fleet.

Resource Portfolio Diversity and Resiliency

In the TAC process resource diversity was discussed as a measure of resiliency. The goal with this metric is to ensure Avista is not over reliant on one resource type or location. Typically, resiliency is mentioned within the energy delivery system, but when it comes to utility scale power generation, resilience is typically focused on the plants' ability to either operate through or return to operation during an event. Another method to address this potential risk is to have a more diversified resource portfolio. Figures 2.14 and 2.15 show three metrics to measure diversity. Two of the measurements relate to locational diversity for increasing resiliency, and the third is associated with fuel diversity of resources. These metrics are split between winter and summer capacity, as both periods of time are key to Avista's resource adequacy.

The diversity measurement uses the Herfindahl-Hirschman Index. The index is traditionally used to determine market concentration or competitiveness, but in resource planning it has also been used as a measure of resource diversity. Higher scores indicate more concentration of resources, meaning less diversity as a share of the portfolio. Conversely, the lower the score the more diverse the resource mix. From a market concentration perspective, a score greater than 2,500 is highly concentrated and a score below 1,500 is competitive, with scores between these amounts indicating moderate levels of market concentration.

Fuel Sources

Fuel diversity is Avista's greatest resource risk. This measurement looks at the source of the fuel for each generator. For example, the fuel source of Avista's Noxon Rapids Hydroelectric project is the Clark Fork River, and the source of Palouse Wind is eastern Washington Wind. For each of Avista's resources, a fuel source is identified. The calculation is high due to the amount of Clark Fork Hydro reliance and Gas Transmission Northwest (GTN) fuel delivery reliance for the Company's natural gas CTs. The index falls (blue line, Figures 2.14 and 2.15) in 2041 due to the expiration of the Lancaster PPA as replacement resources do not use GTN fuel.

Facility (Interconnection Point)

Avista has many small and large generators, but due to the large number of resources, this index (orange line, Figures 2.14 and 2.15) is relatively diverse in total, and results in the lowest score of the three diversity and resiliency metrics evaluated. This measurement could also be related to shaft risk – or the risk of losing one unit causing a resource adequacy event due to its size in relation to total load. Even though this measurement is low, compared to the Company's peer utilities, Avista has one of the highest shaft risks as a percentage of load. Due to this risk, Avista uses its single largest shaft (Coyote Springs 2) as its minimum planning margin quantity for summer capacity planning (16% in the summer).

Transmission (Geographic)

The last metric (green line, Figures 2.14 and 2.15) considered in this analysis is facility location and this metric relates to the location of the resource. The result of this metric is near the limit of concentration. This is due to the concentration of resources limited to a few locations across Avista's small service area. Avista's largest location risk resource is the Noxon Rapids and Cabinet Gorge area. To mitigate risks of transmission outages, Avista developed multiple transmission pathways from this area to move energy to load. The measurement was first discussed to mitigate risk from wildfire, whereas a more diversified locational portfolio would be less impacted by wildfires. It's uncertain if this metric can help assess wildfire risk.

Figure 2.14: Resource Diversity (Winter Capacity)

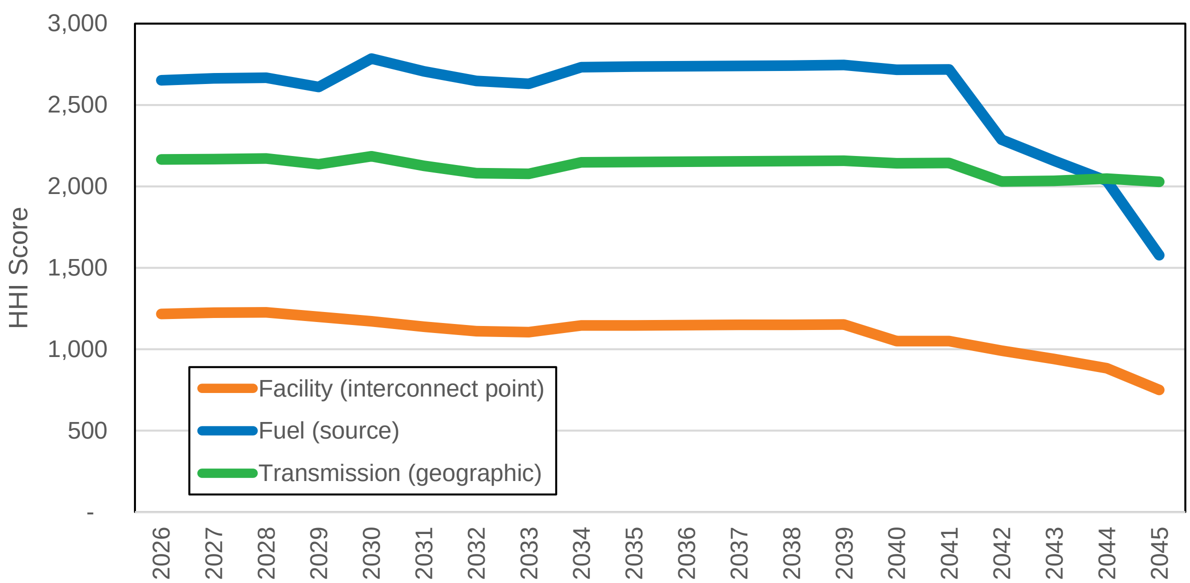
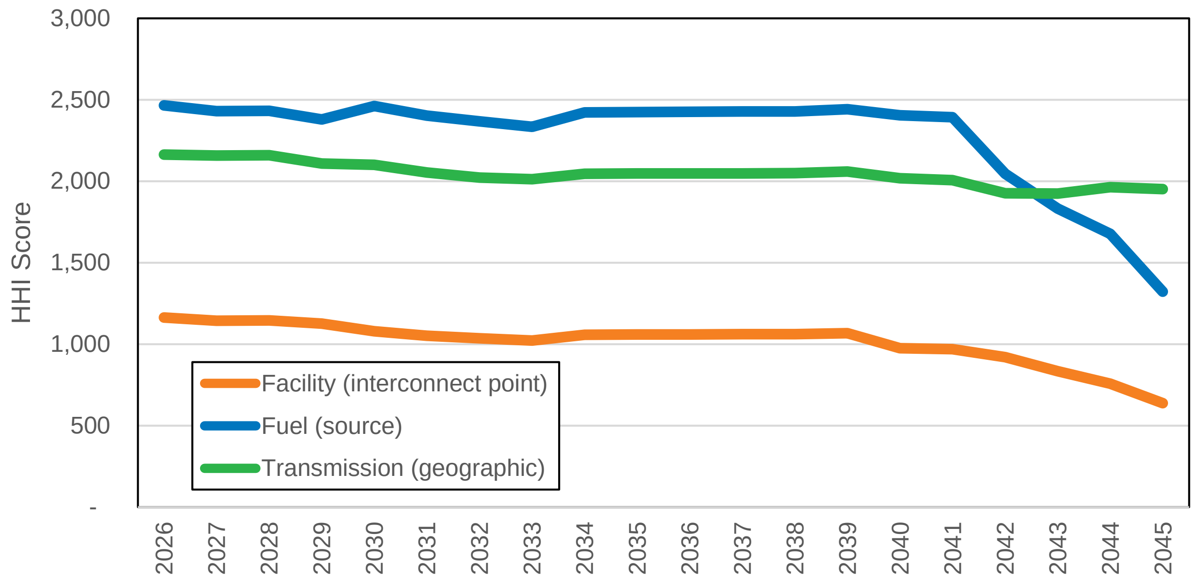


Figure 2.15: Resource Diversity (Summer Capacity)



Modeling Process

Avista utilizes a mixed integer optimization model to select supply-side and demand-side resources to meet customer energy and capacity needs. Avista developed PRiSM to aid in resource selection by using information from its hourly dispatch model, Aurora. PRiSM evaluates each resource option's capital recovery, fixed operation costs, and non-energy financial impacts relative to their operating margins from Aurora and the option's capability to serve energy, peak loads, and clean energy obligations. PRiSM then determines the lowest-cost mix of resource options meeting Avista's resource needs using monthly granularity. The model can also measure and optimize the risk of various portfolio additions when informed by Monte Carlo data. For this analysis, Avista includes its forecast of 300 Monte Carlo market futures rather than a single forecast for its evaluation. The PRS version of the PRiSM Excel workbook is publicly available in Appendix G.

PRiSM

Avista staff developed the first version of PRiSM in 2002 to support resource decision making in its 2003 IRP. The model continues to support the IRP as enhancements have improved the model over time. PRiSM uses a mixed integer programming routine to support complex decision making with multiple objectives. The results ensure optimal values for variables given system constraints. The model uses an add-in function to Excel from Lindo Systems named *What's Best* along with *Gurobi's* solver application. Excel then becomes PRiSM's user interface. PRiSM simultaneously solves to meet system reliability, energy obligations, and jurisdictional clean energy standards while minimizing costs.

The model analyzes resource needs by state for Avista's entire system to ensure each state will be assigned the appropriate amount of incremental costs (if any) of new resource choices. PRiSM must satisfy deficits for each state and the system load and resource balances for each month. For this IRP, the PRiSM model was enhanced to include a simplified monthly natural gas Local Distribution Customer (LDC) model. This model assists in determining the impacts of electrification of buildings. The model co-optimizes solving for natural gas and electric demand allowing for the model to choose to electrify load if the cost of natural gas service is too high. This enhancement was designed for studying building electrification scenarios. This enhancement can also determine what the total system cost impacts are if natural gas load is electrified.

The model solves using the net present value of utility costs given the following inputs:

1. Expected future deficiencies for each state and the system:
    - Summer Planning Margin (16%, May through September)
    - Winter Planning Margin (24%, October through April)
    - Monthly energy targets by state including additional contingency energy
    - Monthly clean energy requirements
1. Costs to serve future retail loads as if served by the wholesale marketplace (from Aurora)
    - Existing resource and energy efficiency contributions
    - Operating margins
    - Fixed operating costs
    - Capital costs
    - Greenhouse Gas (GHG) emission levels
    - Upstream GHG emission levels
    - Operating GHG emissions
2. Supply-side resource, energy efficiency and demand response options
    - Fixed operating costs
    - Return on capital
    - Interest expense
    - Taxes
    - Power/Gas Purchase Agreements
    - Peak contribution from Western Resource Adequacy Program (WRAP)/ E3 regional study
    - Generation levels
    - GHG emission levels for Climate Commitment Act (CCA)
    - Upstream GHG emission levels (WA only)
    - Construction and operating GHG emissions (WA only)
    - Transmission/transport costs
3. Constraints
    - Must meet energy, capacity, and Washington's clean energy shortfalls without market reliance for each state

- Named Community Investment Fund minimum spending (WA only)
- Resource quantities available to meet future deficits

The model's operation is characterized by the following objective function:

Minimize: (WA "Societal" $NPV_{2026\text{-}45}$) + (ID $NPV_{2026\text{-}45}$) + (LDC Natural Gas $NPV_{2026\text{-}45}$)

Where:

- WA $NPV_{2026\text{-}45}$ = Market Value of Load + Existing & Future Resource Cost/Operating Margin + Social Cost of Greenhouse Gas + Non-Energy Impacts + Energy Efficiency Total Resource Cost
- ID $NPV_{2026\text{-}45}$ = Market Value of Load + Existing & Future Resource Cost/Operating Margin + Energy Efficiency Utility Resource Cost

Subject to:

- Resource availability and timing
- Energy efficiency potential
- Demand response potential
- Winter peak monthly requirements
- Summer peak monthly requirements
- Annual energy monthly requirements
- Washington's clean energy monthly goals
- Named Community Investment Fund outlays (WA only).

Avoided Cost

Avista calculates the avoided or incremental cost to serve customers by comparing the PRS cost to alternative portfolios. Avista splits avoided costs between energy and capacity to ensure the financial benefits are correctly attributed to the need of the system. Avoided costs are useful to inform prices in new Public Utility Regulatory Policies Act (PURPA) agreements, small resource acquisitions, and energy efficiency. As Washington and Idaho have different energy policies, calculating costs requires an analysis of incremental costs based on each state's specific policies. This portion of the chapter estimates Avista's avoided cost of energy and capacity based on this IRP's portfolio analysis. The calculations here are not used for setting Washington PURPA rates provided in Schedule 62 but may inform its calculation. Specific Schedule 62 calculations are in Appendix L.

Energy Efficiency

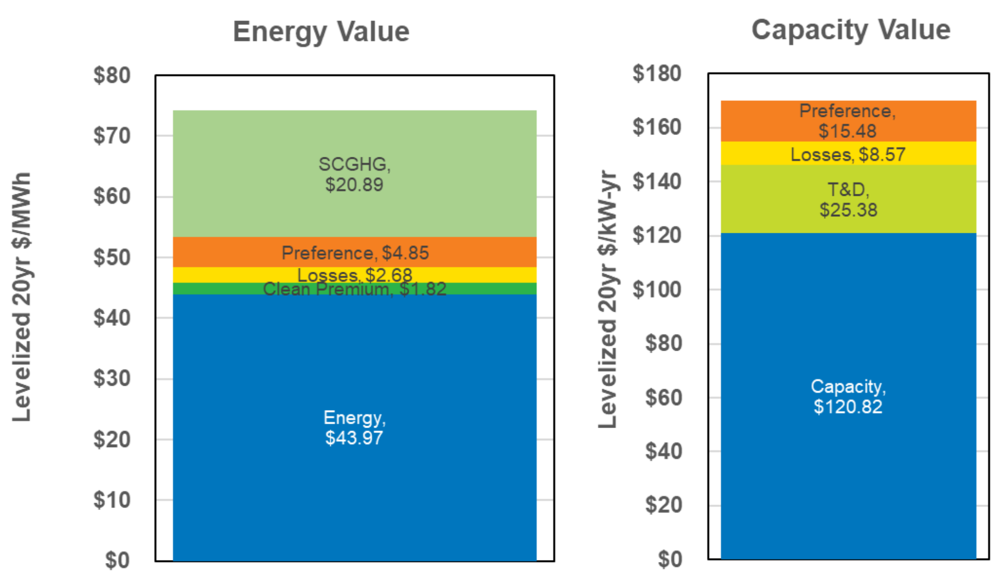
Washington's EIA requires utilities with more than 25,000 customers to acquire all cost-effective and achievable energy conservation.[19] These targets are also used for setting

[19] The EIA defines cost effective as 10% higher cost than a utility would otherwise spend on energy acquisition.

efficiency requirements in Washington's CEIP. For Washington, Avista uses the Total Resource Cost (TRC)[20] test plus non-energy impacts with a social cost of greenhouse gas (SCGHG) savings to estimate its cost-effective energy savings, while Idaho uses the Utility Cost Test (UCT). The estimated avoided cost of energy efficiency in Washington is shown in Figure 2.16 and Idaho's is shown in Figure 2.17. The total 20-year Washington energy avoided cost for energy efficiency is $74.21 per MWh and capacity is $170.24 per kW-yr. These estimates do not include non-energy benefits, as these benefits are program specific and will increase the avoided cost depending on whether the program has non-energy impacts.

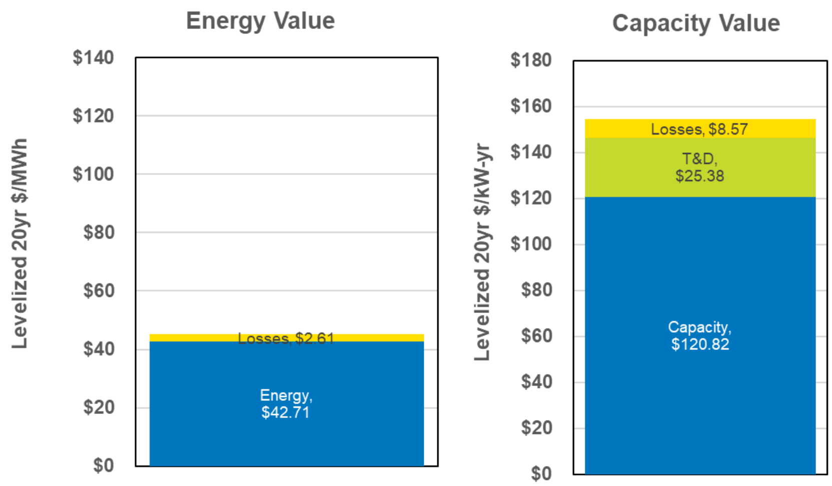
Idaho uses the UCT where the avoided cost is less due to the exclusion of clean energy premiums, the Power Act[21] preference, and avoidance of the social cost of GHG. Idaho 20-year energy avoided cost is $45.32 per MWh and capacity is $154.77 per kW-yr. Avista includes the savings of future transmission and distribution expenses and line loss savings in both states' avoided cost.

Figure 2.16: Washington Energy Efficiency Avoided Cost



[20] See Chapter 5 for further information on the TRC and UCT methodologies.
[21] Washington's EIA requires a 10% cost advantage adder for energy efficiency to give this resource preference as required in the Northwest Power Act.

Figure 2.17: Idaho Energy Efficiency Avoided Cost



Supply Avoided Costs

Avoided costs change as Avista's load and resource positions changes, as well as with changes in the wholesale power market and new resource costs. Avoided costs are a best-available estimate at the time of this analysis using the 2025 IRP assumptions. The prices in Tables 2.7 and 2.8 represent energy and capacity values for different periods and product types by state. For example, a new generation project with equal annual deliveries in all hours has an energy value equal to the flat energy price.[22] In addition to the energy prices, these theoretical resources would also receive capacity payments for production at the time of system peak. For this IRP, winter peak months are driving the 2030 resource deficit period.

Capacity value is the resulting average cost of capacity each year. Specifically, the calculation compares a portfolio where the objective is to build only capacity resources to meet only capacity requirements (excluding SCGHG) against a lower-cost portfolio with no resource additions. Avista uses the jurisdiction's annual revenue requirement[23] differences to create annualized costs of capacity beginning in the first year of a major resource deficit. Recognizing the fluctuation of cash flows, the variability in annual values is levelized and tilted using a 2% escalator. The next step divides the costs by added capacity amounts during the winter peak. This value is the cost of capacity per MW or cost per kW-year. The capacity payment applies to the capacity contribution of the resource at the time of the winter peak hour. For Washington, the capacity requirements calculation uses only clean resources to meet the capacity need.

[22] Projects with undetermined energy production are estimated based on the resource's hourly production forecast.
[23] Transmission costs associated with new resources are included within the capacity cost. These include the interconnection of the resource to the system and the cost to wheel power to Avista's customers.

Capacity pricing at the full capacity payment, shown in Tables 2.8 and 2.9, assumes a 100% QCC or Equivalent Load Carrying Capability (ELCC) in the winter. For example, if solar receives a 2% QCC credit based on ELCC analysis, then it would receive 2% of the capacity payment compared with its deliverable capacity. Avista will need to either conduct an ELCC analysis or utilize the QCC value from the WRAP for any specific projects it evaluates to determine its peak credit. The current forecast assumes Avista's capacity deficit is higher in the winter than summer for all future years of the planning horizon. While a mild winter and hotter than expected summer could result in an actual summer peak greater than winter, Avista must continue to plan for extreme winter events as experienced in January 2024.

VERs such as wind or solar, consume ancillary services because their output cannot be forecasted with great precision. Consequently, VERs seeking avoided cost pricing may receive reduced payments to compensate for ancillary service costs from Avista's VER integration study.

In addition to the capacity premium, Avista includes an energy premium calculation similar to the capacity credit but estimates the cost to comply with monthly energy targets of the system. This adder is included for the first year of new resource additions. For Washington, it corresponds to the first resource addition in 2029 and for Idaho in 2030. This value is calculated by taking the difference between the PRS and a portfolio meeting only state capacity deficits.

Table 2.8: Idaho New Resource Avoided Costs

Year	Flat Energy ($/MWh)	On-Peak Energy ($/MWh)	Off-Peak Energy ($/MWh)	Energy Premium ($/MWh)	Capacity Premium ($/kW-Yr)
2026	$41.61	$42.50	$40.42	$0.00	$0.00
2027	$37.88	$37.26	$38.70	$0.00	$0.00
2028	$35.13	$33.57	$37.19	$0.00	$0.00
2029	$34.57	$33.01	$36.64	$0.00	$0.00
2030	$38.56	$36.84	$40.85	$4.46	$100.30
2031	$43.00	$40.96	$45.74	$4.55	$102.30
2032	$42.74	$40.36	$45.92	$4.64	$104.30
2033	$43.82	$41.29	$47.20	$4.73	$106.40
2034	$43.92	$41.19	$47.54	$4.82	$108.50
2035	$44.93	$42.18	$48.59	$4.92	$110.70
2036	$44.50	$41.72	$48.21	$5.02	$112.90
2037	$45.69	$42.61	$49.82	$5.12	$115.20
2038	$45.66	$42.64	$49.68	$5.22	$117.50
2039	$46.29	$43.19	$50.42	$5.33	$119.80
2040	$47.28	$43.96	$51.69	$5.43	$122.20
2041	$47.66	$44.19	$52.29	$5.54	$124.70
2042	$49.92	$46.35	$54.68	$5.65	$127.20
2043	$50.52	$46.88	$55.38	$5.77	$129.70
2044	$51.24	$47.58	$56.12	$5.88	$132.30
2045	$52.39	$48.71	$57.26	$6.00	$134.90
Levelized	$42.77	$40.64	$45.60	$3.48	$78.20

Table 2.9: Washington New Resource Avoided Costs

Year	Flat Energy ($/MWh)	On-Peak Energy ($/MWh)	Off-Peak Energy ($/MWh)	Energy Premium ($/MWh)	Capacity Premium ($/kW-Yr)
2026	$41.98	$43.12	$40.46	$0.00	$0.00
2027	$38.14	$37.82	$38.58	$0.00	$0.00
2028	$35.40	$34.18	$37.03	$0.00	$0.00
2029	$35.04	$33.84	$36.64	$3.31	$0.00
2030	$39.18	$37.89	$40.90	$3.37	$132.30
2031	$44.10	$42.38	$46.40	$3.44	$135.00
2032	$44.33	$42.27	$47.09	$3.51	$137.70
2033	$45.40	$43.23	$48.29	$3.58	$140.40
2034	$45.55	$43.17	$48.72	$3.65	$143.20
2035	$46.71	$44.27	$49.96	$3.73	$146.10
2036	$46.40	$43.90	$49.74	$3.80	$149.00
2037	$47.66	$44.82	$51.45	$3.88	$152.00
2038	$47.77	$44.98	$51.51	$3.95	$155.00
2039	$48.48	$45.58	$52.35	$4.03	$158.10
2040	$49.59	$46.43	$53.79	$4.11	$161.30
2041	$50.01	$46.68	$54.44	$4.20	$164.50
2042	$52.31	$48.88	$56.90	$4.28	$167.80
2043	$52.97	$49.45	$57.66	$4.37	$171.20
2044	$53.84	$50.27	$58.61	$4.45	$174.60
2045	$55.07	$51.48	$59.83	$4.54	$178.10
Levelized	$44.13	$42.27	$46.60	$2.87	$103.50

3. Economic and Load Forecast

Avista's loads are an integral component of the Integrated Resource Plan (IRP). This chapter summarizes the analysis methods and results of customer and load projections between 2026 to 2045. The 2025 IRP utilizes a new load forecasting approach which includes 3 phases: 1) the initial phase covers the first five years of the forecast and uses econometric forecasting similar to prior plans, 2) the second phase calibrates with the first five years and uses an end-use forecast model for the remaining years to forecast specific customer uses of electricity, and 3) the final phase adjusts the long-term forecast for monthly weatherization, line loss adjustments, and large industrial loads. In addition to the expected case load forecast, multiple scenarios were also conducted to understand effects to load due to population, electric vehicles, and building electrification.

Section Highlights

- The energy forecast grows at 0.91% per year as compared to 0.85% in the 2023 IRP.
- Peak load growth is estimated at 1.32% in the winter and 1.09% in the summer.
- In contrast to previous years, Avista used end-use modeling techniques to develop the long-term load forecast.
- Avista expects a 214 aMW increase in load over the forecast period, a 400 MW increase in winter peak, and a 380 MW increase in summer peak over the next 20 years.
- Increased building and transportation electrification adoption rates in both Washington and Idaho could increase winter peak by 930 MW by 2045.

Medium-term Economic & Load Forecast

This section summarizes customer and load projections for the medium-term forecast. This forecast covers the first five years of the IRP forecast (2024-2028).

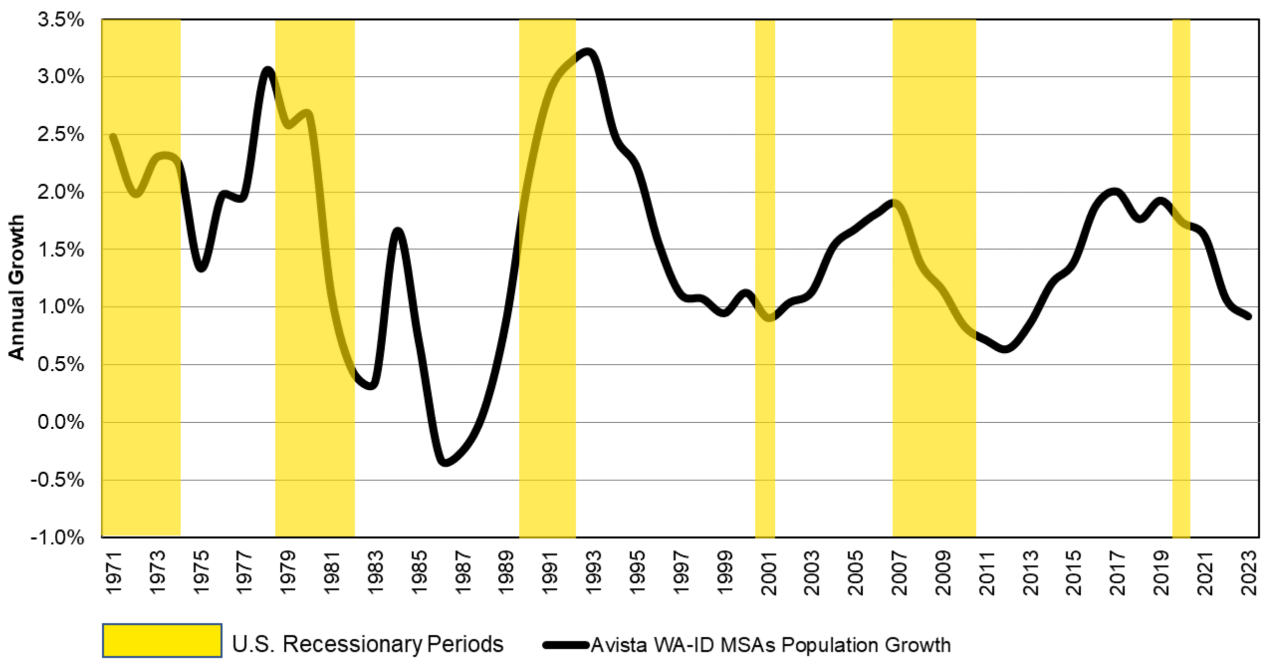
Economic Characteristics

Avista's core electric service area includes more than a half million people residing in Eastern Washington and Northern Idaho. Three Metropolitan Statistical Areas (MSAs) dominate its service area: the Spokane and Spokane Valley, Washington MSA (Spokane-Stevens counties); the Coeur d'Alene, Idaho MSA (Kootenai County); and the Lewiston-Clarkson Idaho-Washington, MSA (Nez Perce-Asotin counties). These MSAs account for more than 70% of both Avista's customers (i.e., meters) and load. The remaining 30% are in low-density rural areas in both states. Washington accounts for approximately two-thirds of electric customers and Idaho the remaining one-third.

Population

Population growth is increasingly a result of net migration to Avista's service area as more people move here. Net migration is strongly associated with both service area and national employment growth through the business cycle. The regional business cycle follows the U.S. business cycle, meaning regional economic expansions or contractions follow national economic trends.[24] Econometric analysis shows when regional employment growth is stronger than U.S. growth over the business cycle, it is associated with increased in-migration and the reverse holds true. Figure 3.1 shows annual population growth since 1971 and highlights the recessions in yellow. During all deep economic downturns since the mid-1970s, reduced population growth rates in Avista's service territory led to lower load growth.[25] The Great Recession reduced population growth from nearly 2% in 2007 to less than 1% from 2010 to 2013. Accelerating service area employment growth in 2013 helped push population growth above 1% after 2014.

Figure 3.1: MSA Population Growth and U.S. Recessions, 1971-2023



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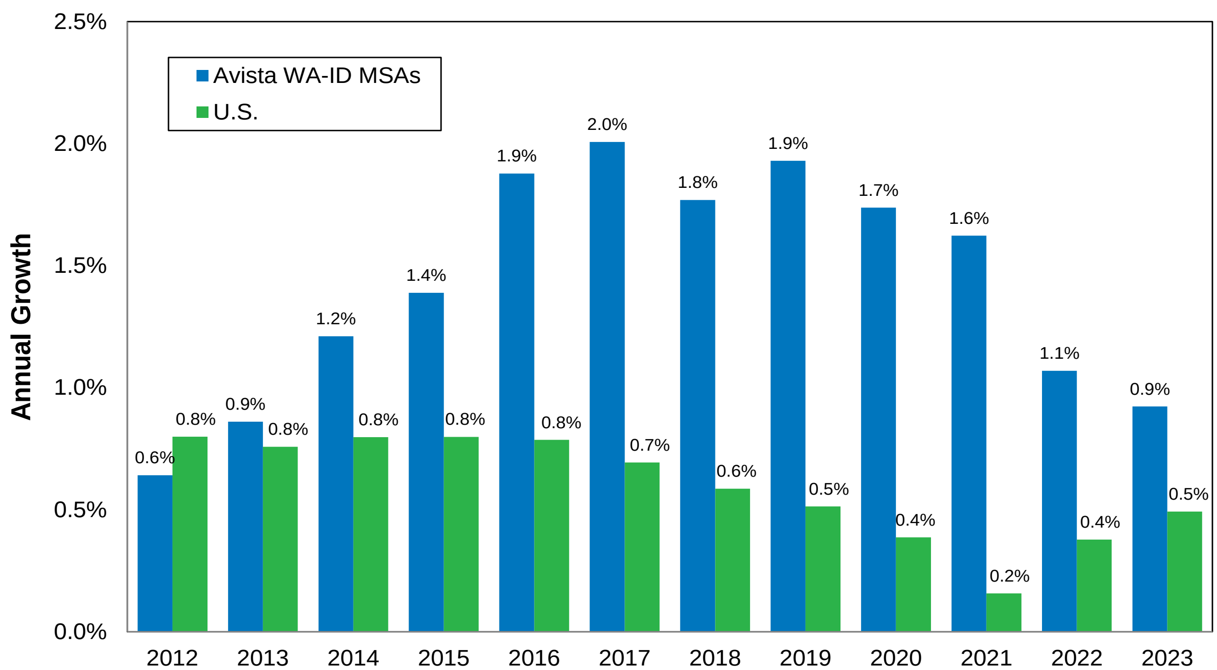
[24] *An Exploration of Similarities between National and Regional Economic Activity in the Inland Northwest*, Monograph No. 11, May 2006. http://www.ewu.edu/cbpa/centers-and-institutes/ippea/monograph-series.xml.

[25] Data Source: Bureau of Economic Development, U.S. Census, and National Bureau of Economic Research.

Figure 3.2 shows population growth since 2012.[26] Service area population growth between 2010 and 2012 was lower than the U.S.; however, it was closely associated with the strength of regional employment growth relative to the U.S. over the same period. The same can be said for the increase in service area population growth in 2014 relative to the U.S. population growth. The association of employment growth to population growth has a one-year lag. The relative strength of service area employment growth in year "y" is positively associated with service area population growth in year "y+1". Econometric estimates using historical data show when holding the U.S. employment-growth constant, every 1% increase in service area employment growth is associated with a 0.4% increase in population growth in the next year.

Figure 3.2: Avista and U.S. MSA Population Growth, 2012-2023

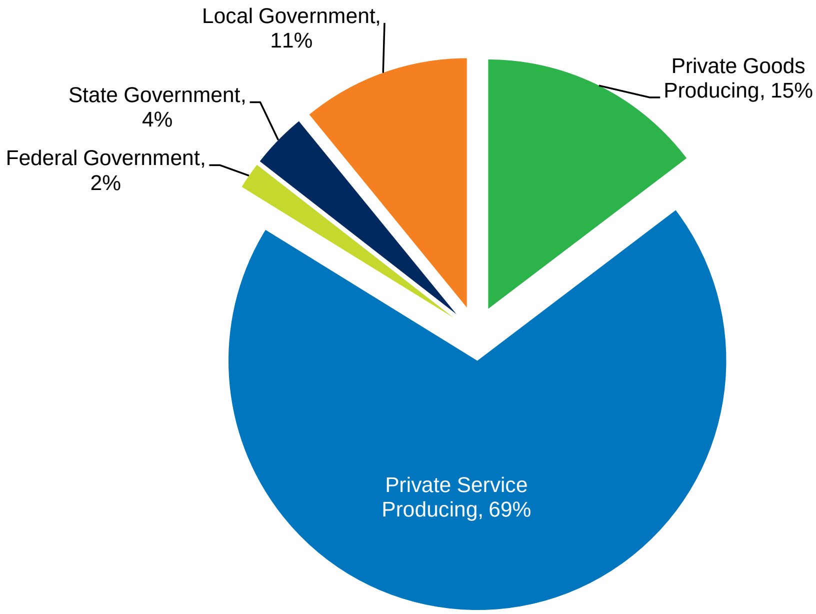


Employment

Given the correlation between population and employment growth, it is useful to examine the distribution of employment and employment performance since 2012. The Inland Northwest is a services-based economy rather than its former natural resources-based manufacturing economy. Figure 3.3 shows the breakdown of non-farm employment for all three-service area MSAs from the Bureau of Labor and Statistics. Almost 70% of employment in the three MSAs is in private services (69%), followed by government (17%) and private goods-producing sectors (15%). Farming accounts for 1% of total employment. Spokane and Coeur d'Alene MSAs are major providers of health and higher education services to the Inland Northwest.

[26] Data Source: Bureau of Economic Analysis, U.S. Census, and Washington State Office of Financial Management.

Figure 3.3: Avista's MSA Non-Farm Employment Breakdown by Major Sector, 2023



Following the Great Recession, regional employment recovery did not materialize until 2013, when services employment started to grow.[27] Service area employment growth began to match or exceed U.S. growth rates by the fourth quarter 2014. Since the COVID-19 induced recession in 2020, service area employment has more than recovered from the losses resulting from the nationwide shutdowns. Figure 3.4 compares Avista's Washington and Idaho MSAs and the U.S. non-farm employment growth for 2012 to 2023.

[27] Data Source: Bureau of Labor and Statistics.

Figure 3.4: Avista and U.S. Non-Farm Employment Growth, 2012-2023

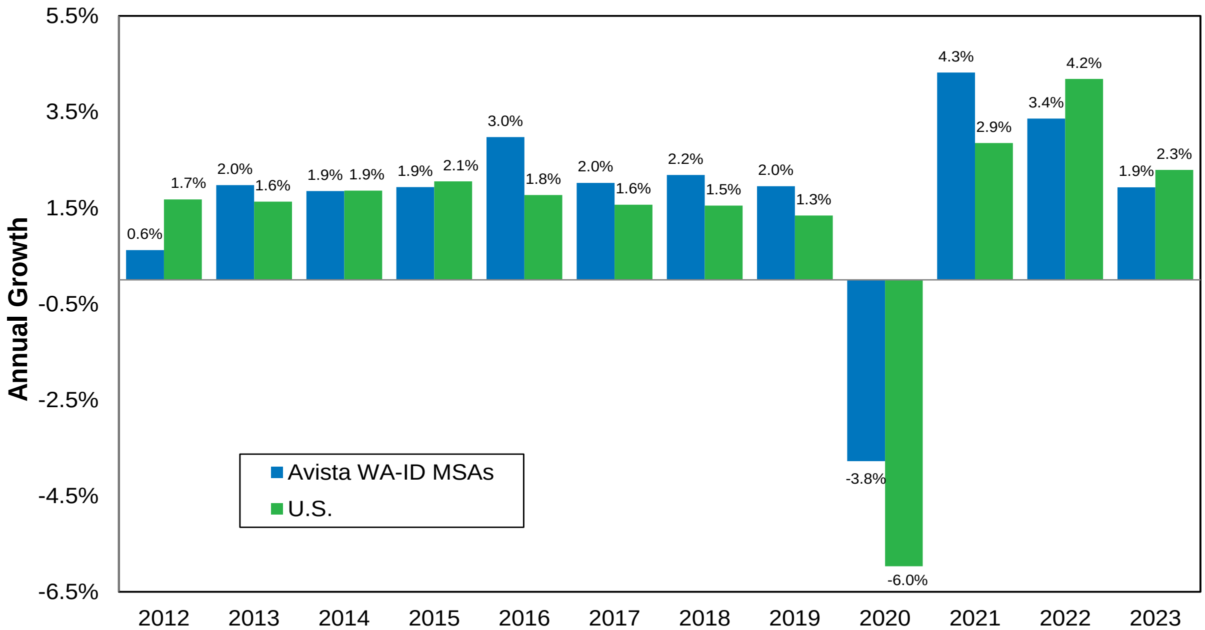


Figure 3.5 shows the distribution of personal income, a broad measure of both earned income and transfer payments, for Avista's Washington and Idaho MSAs.[28] Regular income includes net earnings from employment, and investment income in the form of dividends, interest, and rent. Personal current transfer payments include money income and in-kind transfers received through unemployment benefits, low-income food assistance, Social Security, Medicare, and Medicaid.

Transfer payments in Avista's service area in 1970 accounted for 12% of the local economy. The income share of transfer payments has nearly doubled over the last 40 years locally to 23%. Although 56% of personal income is from net earnings, transfer payments still account for more than one in every five dollars of personal income. Recent years have seen transfer payments become the fastest growing component of regional personal income. This growth in regional transfer payments reflects an aging regional population, a surge of military veterans, and the lingering impacts of the COVID-19 transfer payments to households, including enhanced unemployment benefits.

Figure 3.6 shows the real (inflation adjusted) average annual growth per capita income by MSA for Avista's service area and the U.S. overall. Although between 1980 and 1990, the service area experienced significantly lower income growth compared to the U.S. because of the back-to-back recessions of the early 1980s according to the Bureau of Economic Analysis. The impacts of these recessions were more negative in the service area compared to the U.S., so the ratio of service area per capita income to U.S. per

[28] Data Source: Bureau of Economic Analysis.

capita income fell from 93% in the 1970s to around 85% by the mid-1990s. The income ratio has not recovered.

Figure 3.5: MSA Personal Income Breakdown by Major Source, 2022

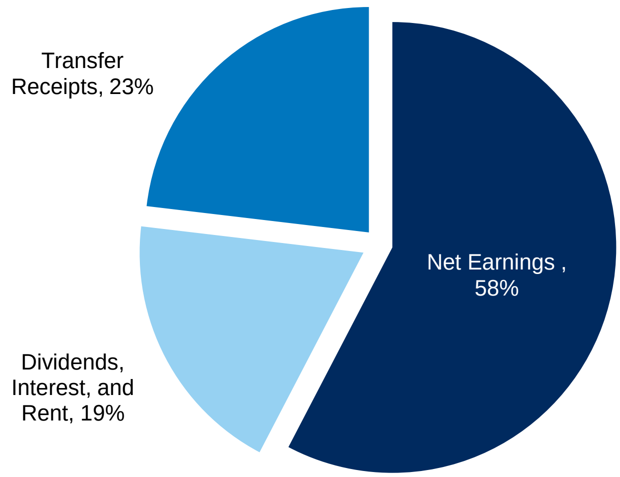
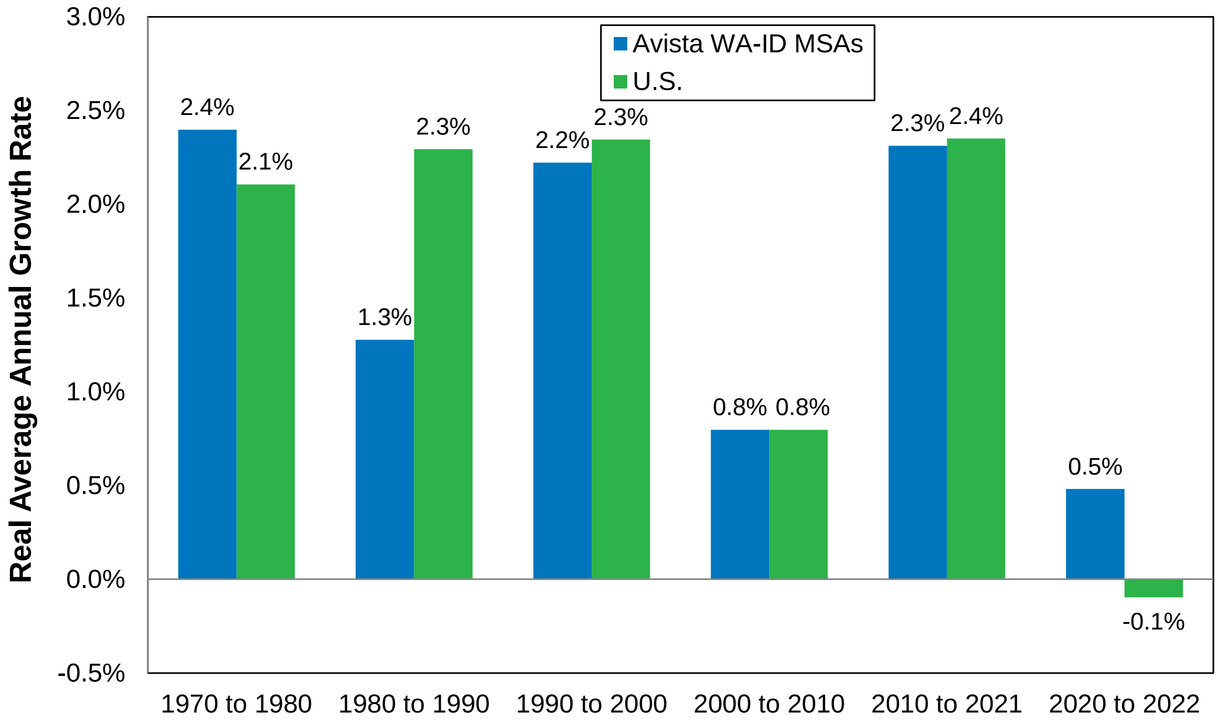


Figure 3.6: Avista and U.S. MSA Real Personal Income Growth



Overview of the Medium-Term Retail Load Forecast

As described above, the load forecast for the 2025 IRP was done in three phases. The following section describes the first phase – the development of a medium-term forecast for the period 2026-2029. The forecast serves as the basis for the second phase, an end-use forecast for the remaining period 2029 to 2045.

The medium-term forecast is based on a monthly use per customer (UPC) forecast and a monthly customer forecast for each customer class in most rate schedules.[29] The load forecast multiplies the customer and UPC forecasts. The UPC and customer forecasts are generated using time-series econometrics, as shown in Equation 3.1.

Equation 3.1: Generating Schedule Total Load

$$F(kWh_{t,y_c+j,s}) = F(kWh/C_{t,y_c+j,s}) \times F(C_{t,y_c+j,s})$$

Where:

- $\mathrm{F}(\mathrm{kWh}_{\mathrm{t,y_c+j,s}})$ = the forecast for month t, year j = 1,…,5 beyond the current year, y_c ,for schedule s.
- $\mathrm{F}(\mathrm{kWh}/\mathrm{C}_{\mathrm{t,y_c+j,s}})$ = the UPC forecast.
- $\mathrm{F}(\mathrm{C}_{\mathrm{t,y_c+j,s}})$ = the customer forecast.

UPC Forecast Methodology

The econometric modeling for UPC is a variation of the "fully integrated" approach expressed by Faruqui (2000) in the following equation:[30]

Equation 3.2: Use Per Customer Regression Equation

$$kWh/C_{t,y,s} = \alpha W_{t,y} + \beta Z_{t,y} + \epsilon_{t,y}$$

The model uses actual historical weather, UPC, and non-weather drivers to estimate the regression in Equation 3.2. To develop the forecast, normal weather replaces actual weather (W) along with the forecasted values for the Z variables (Faruqui, pp. 6-7). Here, W is a vector of heating degree day (HDD) and cooling degree day (CDD) variables; Z is a vector of non-weather variables; and $\varepsilon_{t,y}$ is an uncorrelated N(0,σ) error term. For non-weather sensitive schedules, W = 0.

The W variables are HDDs and CDDs. Depending on the rate schedule, the Z variables may include real average energy price (RAP); the U.S. Federal Reserve Industrial Production Index (IP); residential natural gas penetration (GAS); non-weather seasonal dummy variables (SD); trend functions (T); and dummy variables for outliers (OL) and

[29] For schedules representing a single customer, where there is no customer count and for street lighting, Avista forecasts total load directly without first forecasting UPC.

[30] Faruqui, Ahmad (2000). *Making Forecasts and Weather Normalization Work Together*, Electric Power Research Institute, Publication No. 1000546, Tech Review, March 2000.

periods of structural change (SC). RAP is measured as the average annual price (schedule total revenue divided by schedule total usage) divided by the Consumer Price Index (CPI), less energy. For most schedules, the only non-weather variables are SD, SC, and OL. See Table 3.1 for the occurrence RAP and IP.

If the error term appears to be non-white noise, then the forecasting performance of Equation 3.2 can be improved by converting it into an (ARIMA) “transfer function” model such that $\epsilon_{t,y} = ARIMA\epsilon_{t,y}(p,d,q)(p_k,d_k,q_k)_k$. The term p is the autoregressive (AR) order, d is the differencing order, and q is the (MA) order. The term p_k is the order of seasonal AR terms, d_k is the order of seasonal differencing, and q_k is the seasonal order of MA terms. The seasonal values relate to “k,” or the frequency of the data, with the current monthly data set, k = 12.

Certain rate schedules, such as lighting, use simpler regression and smoothing methods because they offer the best fit for irregular usage without seasonal or weather-related behavior, are in a long-run steady decline, or are seasonal and unrelated to weather. Over the 2024-2028 period, Avista defines normal weather for the load forecast as a 20-year moving average of degree-days taken from the National Oceanic and Atmospheric Administration’s Spokane International Airport data. Normal weather updates only occur when a full year of new data is available. For example, normal weather for 2018 is the 20-year average of degree-days for the 1998 to 2017 period; and 2019 is the average of the 1999 to 2018 period. This medium-term forecast uses the 20-year average from the 2004 to 2023 period to develop the 2024 to 2028 forecast.

The choice of a 20-year moving average for defining normal weather reflects several factors. First, climate research from the National Aeronautics and Space Administration’s (NASA) Goddard Institute for Space Studies (GISS) shows a shift in temperature starting almost 30 years ago. The GISS research finds summer temperatures in the Northern Hemisphere increased one degree Fahrenheit above the 1951-1980 reference period; the increase started roughly 30 years ago in the 1981-1991 period.[31] An in-house analysis of temperature in Avista’s Spokane/Kootenai service area, using the same 1951-1980 reference period, also reflects an upward shift in temperature starting about 30-years ago. As provided in Chapter 5, the longer-term temperature assumption in the IRP uses the Representative Concentration Pathways (RCP) 8.5 for June, July, August, and September, and the RCP 4.5 for the remainder of the year.

The second factor in using a 20-year moving average is the volatility of the moving average as a function of the years used to calculate the average. The 10 and 15-year moving averages show considerably more year-to-year volatility than the 20-year moving average. This volatility can obscure longer-term trends and leads to overly sharp changes in forecasted loads when applying the updated definition of normal weather each year.

[31] See Hansen, J.; M. Sato; and R. Ruedy (2013). *Global Temperature Update Through 2012*, http://www.nasa.gov/topics/earth/features/2012-temps.html.

These sharp changes would also cause excessive volatility in the revenue and earnings forecasts.

As noted earlier, if non-weather drivers appear in Equation 3.2, then they must also be in the five-year forecast used to generate the UPC forecast. The assumption in the five-year forecast is for RAP to be constant through 2028.

Table 3.1: UPC Models Using Non-Weather Driver Variables

Schedule	Variables	Comment
Washington:		
Residential Schedule 1	GAS	Ratio of natural gas residential schedule 101 customers in WA to electric residential schedule 1 customers in WA.
Industrial Schedules 11, 21, and 25	IP	
Idaho:		
Residential Schedule 1	GAS	Ratio of natural gas residential schedule 101 customers in ID to electric residential schedule 1 customers in ID.
Industrial Schedules 11 and 21	IP	

The forecasts for GDP reflect the average of forecasts from multiple sources including the Bloomberg survey of forecasts, the Philadelphia Federal Reserve survey of forecasters, the Wall Street Journal survey of forecasters and other sources. Averaging forecasts reduces the systematic errors of a single-source forecast and assumes macroeconomic factors flow through the UPC in the industrial rate schedules. Figure 3.7 shows the methodology for forecasting IP growth. Figure 3.8 shows the historical relationship between the IP and industrial load for electricity.[32,33] The load values used in Figure 3.8 have been seasonally adjusted using the Census X11 procedure. Over the long run, the historical relationship is positive between industrial load growth and IP growth. However, the sensitivity of industrial loads to IP expansions weakened after. It's unclear if this is a longer-term trend or something more temporary, like the 2002-2007 period of flat load growth with surging IP. In contrast, Avista's industrial load growth has consistently fallen in response to recessions.

[32] Data Source: U.S. Federal Reserve and Avista records.
[33] Figure 3.8 excludes one large industrial customer with significant load volatility.

Figure 3.7: Forecasting IP Growth

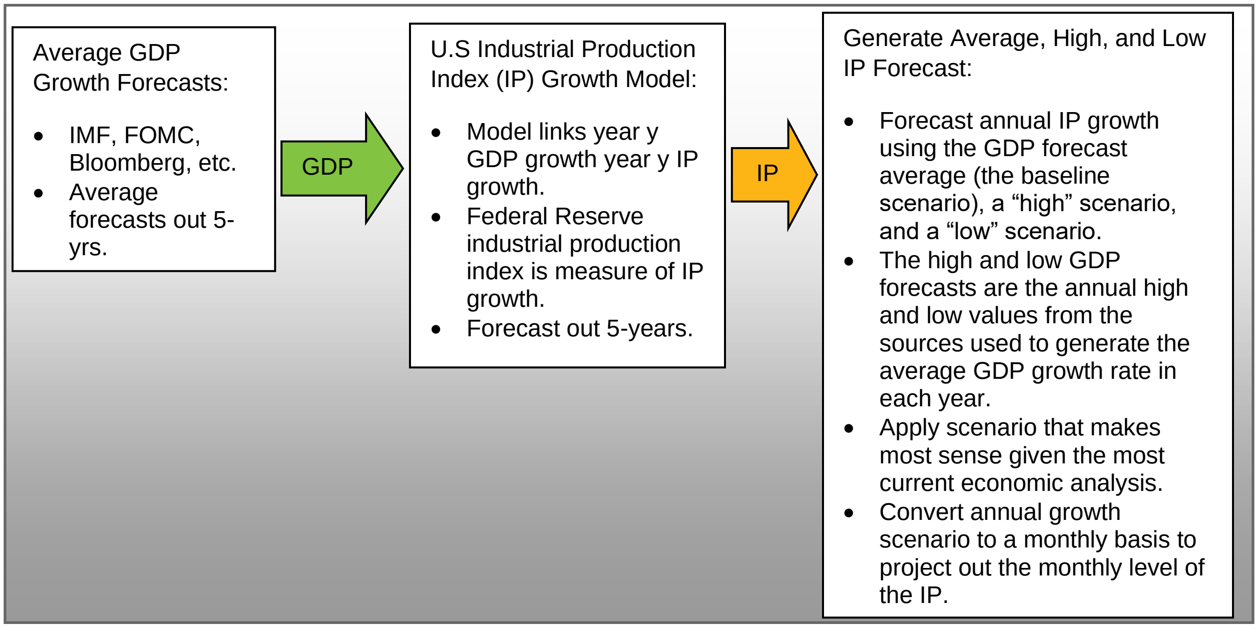
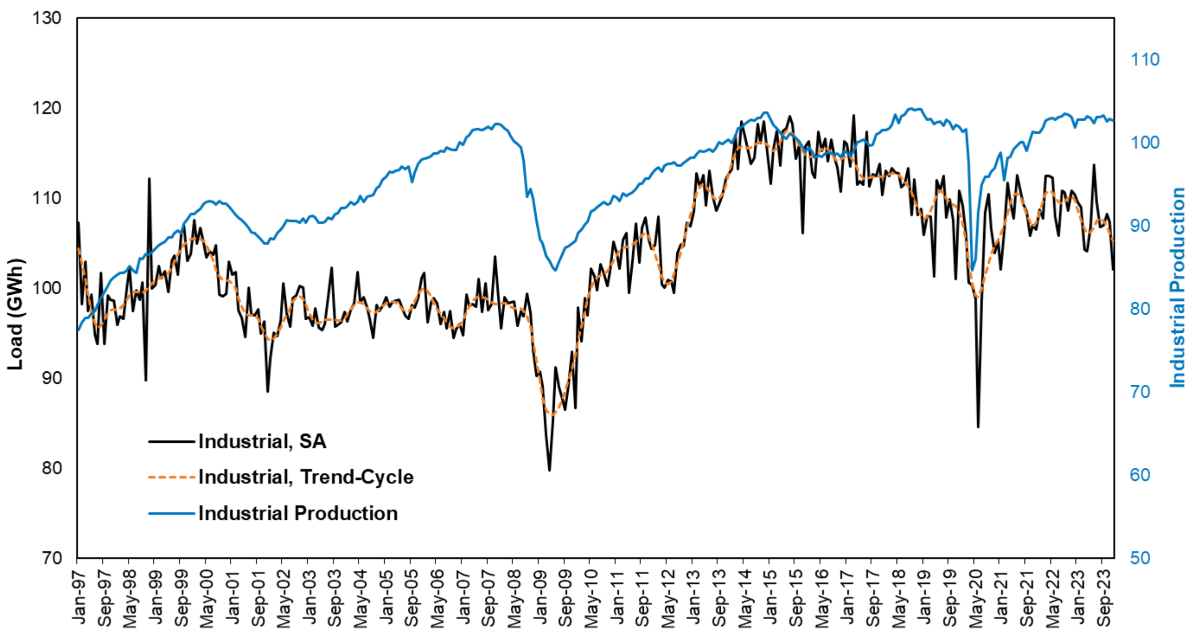


Figure 3.8: Industrial Load and Industrial (IP) Index



Customer Forecast Methodology

The econometric modeling for the customer models ranges from simple smoothing models to more complex autoregressive integrated moving average (ARIMA) models. In some cases, a pure ARIMA model without any structural independent variables is used. For example, the independent variables are only the past values of the rate schedule customer counts but are also the dependent variable. Because the customer counts in most rate schedules are either flat or growing in a stable fashion, complex econometric models are generally unnecessary for generating reliable forecasts. Only in the case of certain residential and commercial schedules is more complex modeling required.

For the main residential and commercial rate schedules, the modeling approach needs to account for customer growth between these schedules with a high positive correlation over a 12-month period. This high customer correlation translates into a high correlation between residential and commercial customer growth over the same 12-month period. Table 3.2 shows the correlation of customer growth between residential, commercial, and industrial consumers of Avista's electricity and natural gas. To assure this relationship in the customer and load forecasts, the models for the Washington and Idaho Commercial models use Schedules 11, while Washington and Idaho Residential models use Schedule 1 as a forecast driver. Historical and forecasted Residential Schedule 1 customers become drivers to generate customer forecasts for Commercial Schedule 11 customers.

Table 3.2: Customer Growth Correlations, 1998-2023

Customer Class (Annual growth)	Residential	Commercial	Industrial	Streetlights
Residential	1.00			
Commercial	0.72	1.00		
Industrial	-0.29	-0.02	1.00	
Streetlights	-0.19	-0.06	-0.03	1.00

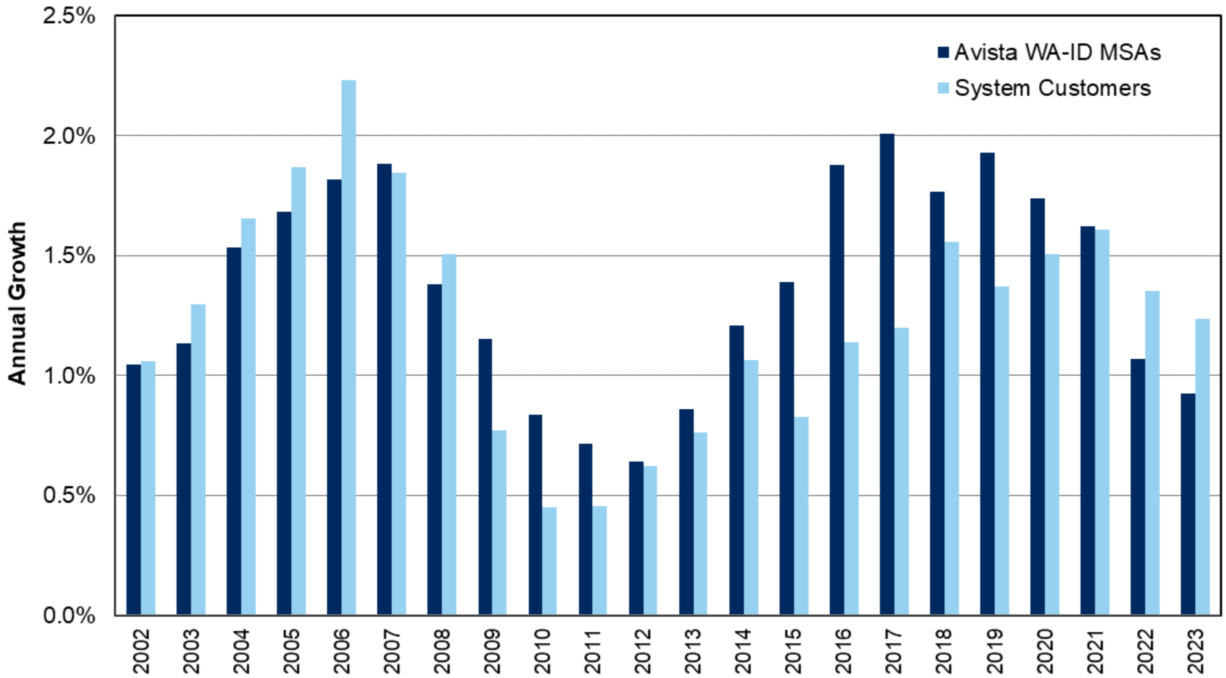
Figure 3.9 shows the relationship between annual population growth and year-over-year customer growth.[34] Customer growth has closely followed population growth in the combined Spokane/Kootenai MSAs over the last 20 years. Population growth averaged 1.3% over the 2000-2023 period and customer growth averaged 1.2% annually.

Figure 3.9 demonstrates how population growth is the primary driver of customer growth. As a result, forecasted population growth is the primary driver of Residential Schedule 1 customers in Washington and Idaho. The forecast is made using an ARIMA times-series model for Schedule 1 customers in Washington and Idaho.

[34] Data Source: Bureau of Economic Analysis, U.S. Census, Washington State OFM, and Avista records.

Forecasting population growth is a process that links U.S. Gross Domestic Product (GDP) growth to service area employment growth and then links regional and national employment growth to service area population growth.

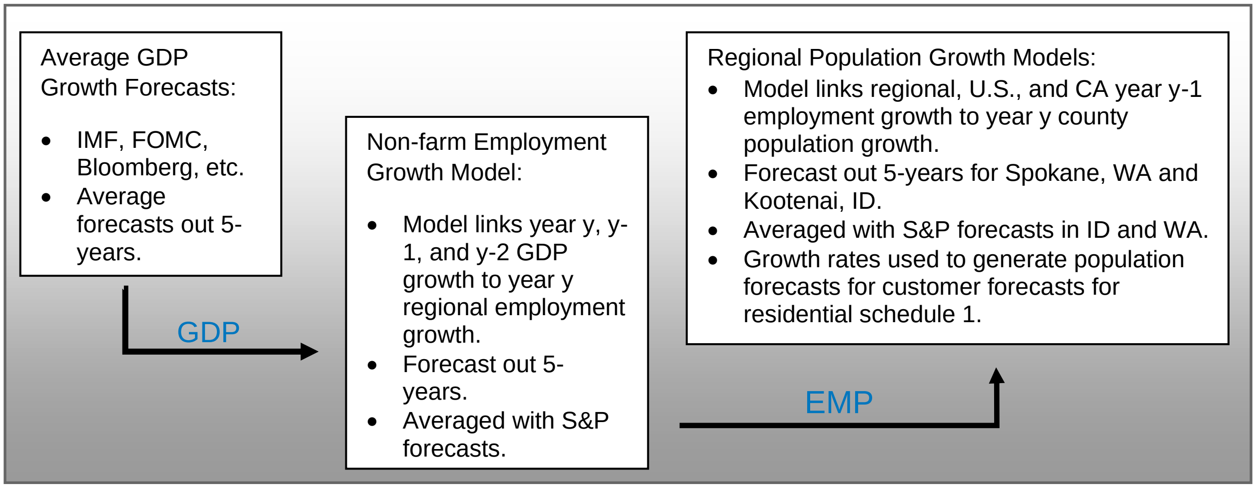
Figure 3.9: Population Growth vs. Customer Growth, 2002-2023



The same average GDP growth forecasts used for the IP growth forecasts are inputs to the five-year employment growth forecast. Avista averages employment forecasts with S&P Connect (formerly IHS Connect) forecasts for the same counties. Averaging reduces the systematic errors of a single-source forecast. The averaged employment forecasts become inputs to generate population growth forecasts. Figure 3.10 summarizes the forecasting process for population growth for use in estimating Residential Schedule 1 customers.

The employment growth forecasts (average of Avista and S&P Connect forecasts) become inputs used to generate the population growth forecasts. The Spokane and Kootenai forecast are averaged with S&P Connect's forecasts for the same MSA. These averages produce the final population forecast for each MSA. These forecasts are then converted to monthly growth rates to forecast population levels over the next five years.

Figure 3.10: Forecasting Population Growth



Monthly Peak Load Forecast Methodology

The IRP's main requirement is to ensure enough resources are available to meet resource adequacy needs, especially in the coldest and hottest days. Avista develops an estimated peak load for each month and a seasonal peak as part of the load forecast.

The estimated regression Equation 3.3 is used to generate the starting seasonal peak values for 2024. These starting peak values are extrapolated out over time by applying an average annual growth rate over the forecast horizon. The annual growth rates are provided by Applied Energy Group (AEG) as part of the end use forecast to be discussed below. The process of generating the starting peak values follows:

- Historical data going back to 2004 is used to estimate the regression coefficients shown in Equation 3.3. Diagnostic checks are done to ensure the estimated error term from the regression on historical data meets the assumptions that it should be uncorrelated over time and be approximately N(0, σ).
- Using actual weather data by month, the hottest average summer day in a given year and coldest average winter day in a given year is extracted from the average temperature time-series. These summer and winter series reflect two subset series reflecting extreme temperatures.
- Using the subset series of temperature extremes, the average extreme temperature for summer months is calculated using the 20-year period, 2004-2023 (i.e., an average based on n = 20). For winter months, the average extreme temperature is calculated using the 76-year period, 1949-2024. The differing sample size between summer and winter reflects warming summers, if included older summer temperatures the forecast would be biased down. In the winter, temperature anomalies are still heavily skewed to very low temperatures. Therefore, allowing a longer winter average reduces the risk of under allocating peak resources for winter peak.

- The 20-year summer average and 76-year winter average are converted into degree days (CDD for summer and HDD for winter) using a 65-degree Fahrenheit base. For the starting summer net peak, the CDD value is entered into Equation 3.3 with appropriate values for the remaining values. The same is done for HDD to arrive at the starting winter peak for net peak for 2024/2025.
- Using the full starting peak native load values, peak growth rates provided by AEG's end use forecast are used to escalate the starting values over the IRP's forecast horizon.

Equation 3.3: Peak Load Regression Model

$$hMW_{d,t,y}^{netpeak} = \lambda_0 + \lambda_1 HDD_{d,t,y} + \lambda_2 (HDD_{d,t,y})^2 + \lambda_3 HDD_{d-1,t,y} + \lambda_4 CDD_{d,t,y} + \lambda_5 CDD_{d,t,y}^{HIGH} + \lambda_6 CDD_{d-1,t,y} + \phi_1 GDP_{t.y-1} + \phi_2 (D_{SUM} \cdot GDP_{t.y-1}) + \phi_3 (D_{WIN} \cdot GDP_{t.y-1}) + \boldsymbol{\omega_{WD} D_{d,t,y}} + \boldsymbol{\omega_{HD} D_{d,t,y}} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{COVID} D_{Jan\ 2022\uparrow=1} + \omega_{OL} D_{Mar\ 2005=1} + \epsilon_{d,t,y}\ for\ t,y = June\ 2004 \uparrow$$

Where:

- $\mathrm{hMW}_{\mathrm{d,t,y}}^{\mathrm{netpeak}}$ = metered peak hourly usage on day of week d, in month t, in year y, and excludes two large industrial producers and special peak adders for future EVs, solar, and natural gas restrictions. The data series starts in June 2004.
- $\mathrm{HDD}_{\mathrm{d,t,y}}$ and $\mathrm{CDD}_{\mathrm{d,t,y}}$ = heating and cooling degree days the day before the peak.
- $(\mathrm{HDD}_{\mathrm{d,t,y}})^2$ = squared value of $HDD_{d,t,y}$,$\mathrm{HDD}_{\mathrm{d-1,t,y}}$ and $\mathrm{CDD}_{\mathrm{d-1,t,y}}$ = heating and cooling degree days the day before the peak.
- $\mathrm{CDD}_{\mathrm{d,t,y}}^{\mathrm{HIGH}}$ = maximum peak day temperature minus 65 degrees.[35]
- $\mathrm{GDP}_{\mathrm{t.y-1}}$ = extrapolated level of real GDP in month t in year y-1.
- $(D_{SUM} * GDP_{t.y-1})$ = a slope shift variable for GDP in the summer months, June, July, and August.
- $(D_{WIN} * GDP_{t.y-1})$ = a slope shift variable for GDP in the winter months, December, January, and February.
- $\boldsymbol{\omega_{WD} D_{d,t,y}}$ = dummy vector indicating the peak's day of week.
- $\boldsymbol{\omega_{HD} D_{d,t,y}}$ = dummy vector indicating the high peak hours 8 am, 9 am, 4 pm, 5 pm, 6 pm, and 7 pm.
- $\boldsymbol{\omega_{SD} D_{t,y}}$= seasonal dummy vector indicating the month.
- $\omega_{COVID} D_{Jan\ 2022\uparrow=1}$= dummy variable that controls for a step-up in peak following the COVID pandemic starting in January 2022.
- $\omega_{OL} D_{Mar\ 2005=1}$ = a dummy variable to control for an extreme outlier in March 2005.
- $\varepsilon_{d,t,y}$ = uncorrelated N(0, σ) error term.

[35] This term provides a better model fit than the square of CDD.

Long-Term Load Forecast

Previous IRPs used regression modeling techniques to forecast future load for the entire forecast period. These modeling techniques use load related data, such as temperature, population, and GDP to forecast the future using past data relationships. Avista is currently entering a period where past energy use patterns may not be a good prediction of the future. EV use, building electrification, changes in long-run temperatures, new energy efficiency efforts, and distributed energy resources are not present in the historical data used for regression models, but will likely be part of the future. End-use modeling addresses this issue by starting at the customer equipment level (EVs, heat pumps, etc.) rather than using historical data. The system load forecast is the aggregation of customers and their adoption rates of customer equipment. This approach allows modification of specific equipment adoption rates based on customer preference, economic considerations, and regulatory frameworks.

Avista contracted with AEG to assist with the end-use portion of the forecast utilizing the load forecast model developed for the energy efficiency potential studies. Development of the model began with a segmentation of Avista's electricity footprint to quantify energy use by sector, segment, end-use application, and the current set of technologies used. AEG utilized information from Avista, the Northwest Energy Efficiency Alliance (NEEA), and other secondary sources, as necessary. AEG used its Load Management Analysis and Planning tool (LoadMAP™) version 5.0 to develop the end use model and the resulting forecast. AEG developed LoadMAP™ in 2007 and has enhanced it over time, using it for the Electric Power Research Institute (EPRI) National Potential Study and numerous utility-specific forecasting and energy efficiency potential studies. Built in Excel, the LoadMAP™ framework is both accessible and transparent and has the following key features:

- Embodies the basic principles of rigorous end-use models (such as EPRI's REEPS[36] and COMMEND[37]) but in a more simplified, accessible form.
- Includes stock-accounting algorithms to treat older, less efficient appliance/equipment stock separately from newer, more efficient equipment. Equipment is replaced according to the measure life and appliance vintage distributions defined by the user.
- Balances the competing needs of simplicity and robustness. This is done by incorporating important modeling details related to equipment saturations, efficiencies, vintage, and the like, where market data is available, and treats end uses separately to account for varying importance and availability of data resources.
- Isolates new construction from existing equipment and buildings and treats purchase decisions for new construction and existing buildings separately.

[36] Residential end-use energy planning system
[37] Commercial-sector end-use planning system

- Uses simple logic for appliance and equipment decisions. Other models available for this purpose embody complex decision-choice algorithms or diffusion assumptions. The model parameters tend to be difficult to estimate or observe, and sometimes produce anomalous results that require calibration or even overriding. The LoadMAP™ approach allows the user to drive the appliance and equipment choices year by year directly in the model. This flexible approach allows users to import the results from diffusion models or to input individual assumptions. The framework also facilitates sensitivity analysis.
- Includes appliance and equipment models customized by end use. For example, the logic for lighting is distinct from refrigerators and freezers.
- Can accommodate various levels of segmentation. Analysis can be performed at the sector level (e.g., total residential) or for customized segments within sectors (e.g., housing type or income level).
- Can incorporate conservation measures, demand-response options, combined heat and power, distributed generation options, and fuel switching.

The model was calibrated to actual data for 2021 through 2023 and the medium-term forecast for years 2024 through 2028.

Segmentation for Modeling Purposes

The market assessment first defines the market segments (building types, end uses, and other dimensions) with relevance to the Avista service territory. The segmentation scheme for this project is presented in Table 3.3.

Table 3.3: Overview of Avista Analysis Segmentation Scheme

Model Inputs	Description	Key Sources
Customer growth forecasts	Forecasts of new construction in residential, commercial, and industrial sectors	Avista short term actuals and forecast from the U.S. Energy Information Administration Annual Energy Outlook (AEO) economic growth forecast
Equipment purchase shares for baseline projection	For each equipment/technology, purchase shares for each efficiency level; specified separately for existing equipment replacement and new construction	Shipment data from AEO and ENERGY STAR AEO regional forecast assumptions Appliance/efficiency standards analysis
Utilization model parameters	Price elasticities, elasticities for other variables (income, weather)	Electric Power Research Institute's REEPS and COMMEND models and AEO 2021

With the segmentation scheme defined, AEG then performed a high-level market characterization of electricity sales in the base year to allocate sales to each customer segment. AEG used Avista data and secondary sources to allocate energy use and customers to the various sectors and segments such that the total customer count, energy consumption, and peak demand matched the Avista system totals from billing data. This information provided control totals at a sector level for calibrating LoadMAP™ to known data for the base year.

Market Profiles

The next step was to develop market profiles for each sector, customer segment, end use, and technology. The market profiles provided the foundation for the development of the baseline projection. A market profile includes the following elements:

- Market size is a representation of the number of customers in the segment. For the residential sector, it is the number of households. In the commercial sector, it is floor space measured in square feet. For the industrial sector, it is overall electricity use.
- Saturations define the fraction of homes or square feet with the various technologies (e.g., homes with electric space heating).
- The unit energy consumption (UEC) or the energy use index (EUI) describes the amount of energy consumed in 2022 by a specific technology in buildings that have the technology. UECs are expressed in kWh/household for the residential sector, and EUIs are expressed in kWh/square foot for the commercial sector.
- Annual Energy Intensity for the residential sector represents the average energy use for the technology across all homes in 2022 and is the product of saturation and UEC. The commercial sector represents the average use for the technology across all floor space in 2022 and is the product of the saturation and EUI.
- Annual Usage is the annual energy use by an end-use technology in the segment. It is the product of the market size and intensity and is quantified in GWh.
- Peak demand for each technology, summer peak and winter peak, is calculated using peak fractions of annual energy use from AEG's Energy Shape library and Avista system peak data.

The market characterization and market profiles are presented in the report in Appendix C.

Baseline Projection

The following describes the development of the baseline projection of annual electricity use and peak demand for 2026 through 2045 by customer segment and end use without new utility programs. The savings from past programs are embedded in the forecast, but the baseline projection assumes past programs cease to exist in the future. Possible savings from future programs are captured by the potential estimates. The projection includes the known impacts of future codes and standards over the study timeframe. All such mandates defined as of May 2024 are included in the baseline. The baseline projection is the foundation for the load forecast. The load forecast is then developed utilizing the following:

- Current economic growth forecasts (i.e., customer growth, income growth).
- Electricity and natural gas retail price forecasts.
- Trends in fuel shares and equipment saturations.
- Existing and approved changes to building codes and equipment standards.
- Avista's internally developed short-term sector-level projections for electricity sales.
- AEG's estimates of electrification from Avista's natural gas system.

Data Application for Baseline Projection

Table 3.4 summarizes the LoadMAP™ model inputs required for the baseline projection. These inputs are required for each segment within each sector, as well as for new construction and existing dwellings/buildings.

Table 3.4: Overview of Avista Analysis Segmentation Scheme

Dimension	Segmentation Variable	Description
1	Sector	Residential, commercial, industrial
2	Segment	Residential: single family, multifamily, manufactured home, differentiated by income level Commercial: small office, large office, restaurant, retail, grocery, college, school, health, lodging, warehouse, and miscellaneous Industrial: total
3	Vintage	Existing and new construction
4	End uses	Cooling, lighting, water heat, motors, etc. (as appropriate by sector)
5	Appliances/end uses and technologies	Technologies such as lamp type, air conditioning equipment, motors by application, etc.
6	Equipment efficiency levels for new purchases	Baseline and higher-efficiency options as appropriate for each technology

The baseline also includes projected naturally occurring energy efficiency during the potential forecast period. AEG's LoadMAP™ efficiency choice model uses energy and cost data as well as current purchase trends to evaluate technologies and predict future customer equipment purchase shares. AEG also models the adoption of electrification measures for natural gas customers and includes the future effects of this additional electric equipment stock in Avista's territory. The customer equipment purchase data feeds into the stock accounting algorithm to predict and track equipment stock and energy usage for each market segment.

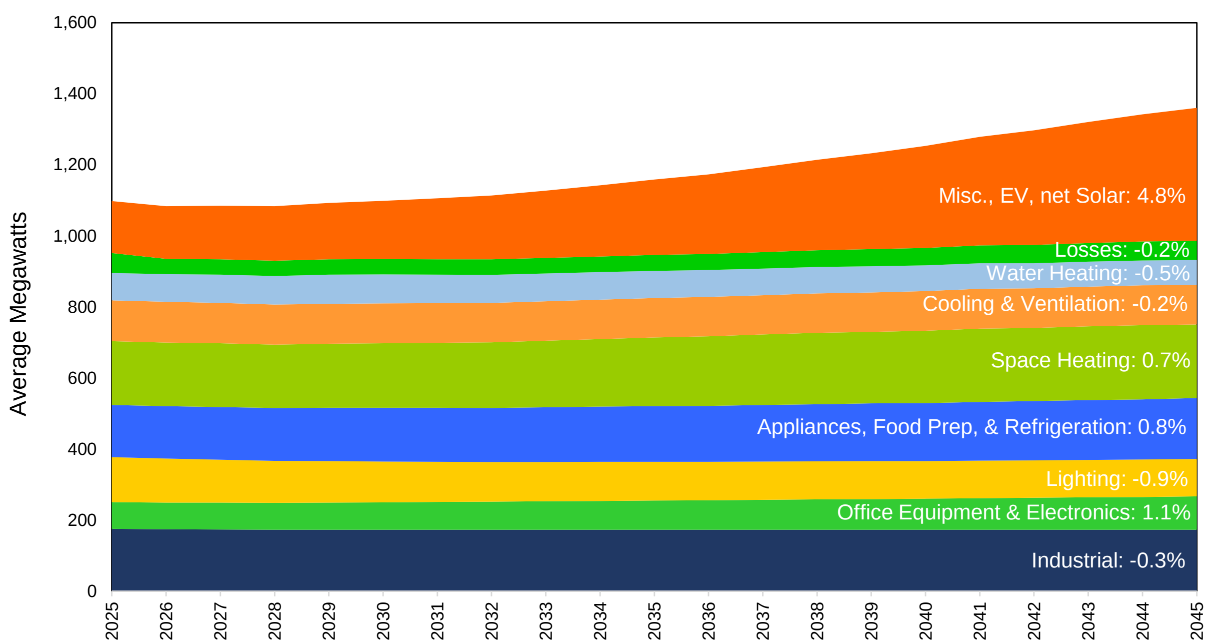
Use of the Baseline Forecast in IRP

AEG has been providing energy efficiency potential assessments for Avista since 2010. A new component of the partnership between AEG and Avista is that the end-use load forecast is now used to inform Avista's official load forecast for this IRP. The ability to capture specific end-use load movement and changes over time has become critical to Avista's understanding of the long-term changes to their load.

To facilitate IRP planning, AEG provided the hourly disaggregation of the annual end-use load forecast from the LoadMAP™ model. AEG carefully calibrated the projection to actual Avista system loads by month and hour from 2021-2023, then carried the average of those monthly calibration factors forward throughout the forecast period to create a long-term forecast with the greatest consistency with recorded history and Avista's short-term forecast.

While the main LoadMAP™ engines run on an annual basis, AEG used a combination of region-specific load shapes from the National Renewable Energy Laboratory's (NREL) end use load profiles, Avista's load research data and engineering simulations to further analyze the end-use loads at an hourly level. These load shapes were then calibrated to Avista's seasonal loads and normalized so the value for each hour represents 1/8760th of the year. The energy from the baseline projection for each end use and technology was applied to each shape to compute hourly profiles throughout the forecast period. Figure 3.11 presents the energy forecast for each end use category, and the percentage growth over the forecast period.

Figure 3.11: Change in Energy Use by End Use, 2025-2045



An important component of the load forecast is building electrification. New customers were modeled with new codes and standards favoring electric over natural gas heat. In addition, existing customers were modeled with the option to replace existing gas space or water heating equipment with electric alternatives, using purchase decision logic taken from the US DOE's National Energy Modeling System. Gas-to-electric conversion costs include the possibility of a panel upgrade and associated labor along with the tax benefits form the Inflation Reduction Act (IRA), but do not include any state incentives (as these are not known). The model compares the lifetime cost of ownership including upfront costs and associated lifetime fuel costs. Figure 3.12 and Figure 3.13 show the gas residential heating market transformation for the forecast period. In these forecasts, the electric system will be adding the areas in green and blue as new loads.

Figure 3.12: Washington Residential Gas Heating Market Transformation

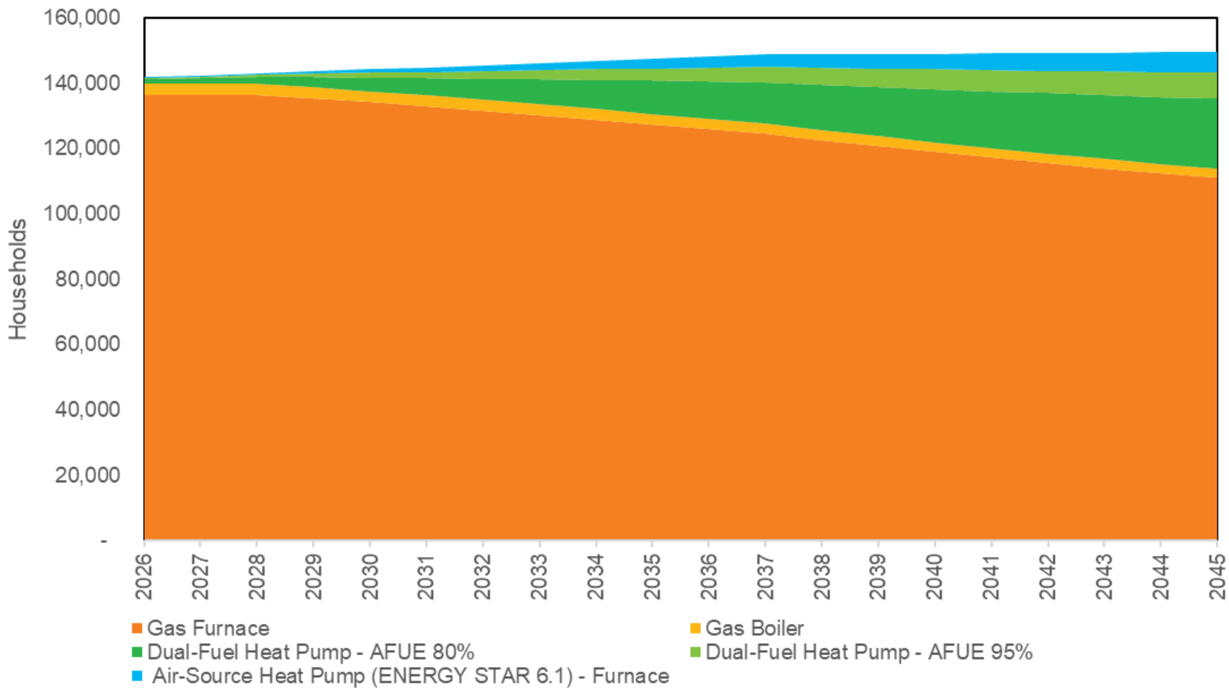
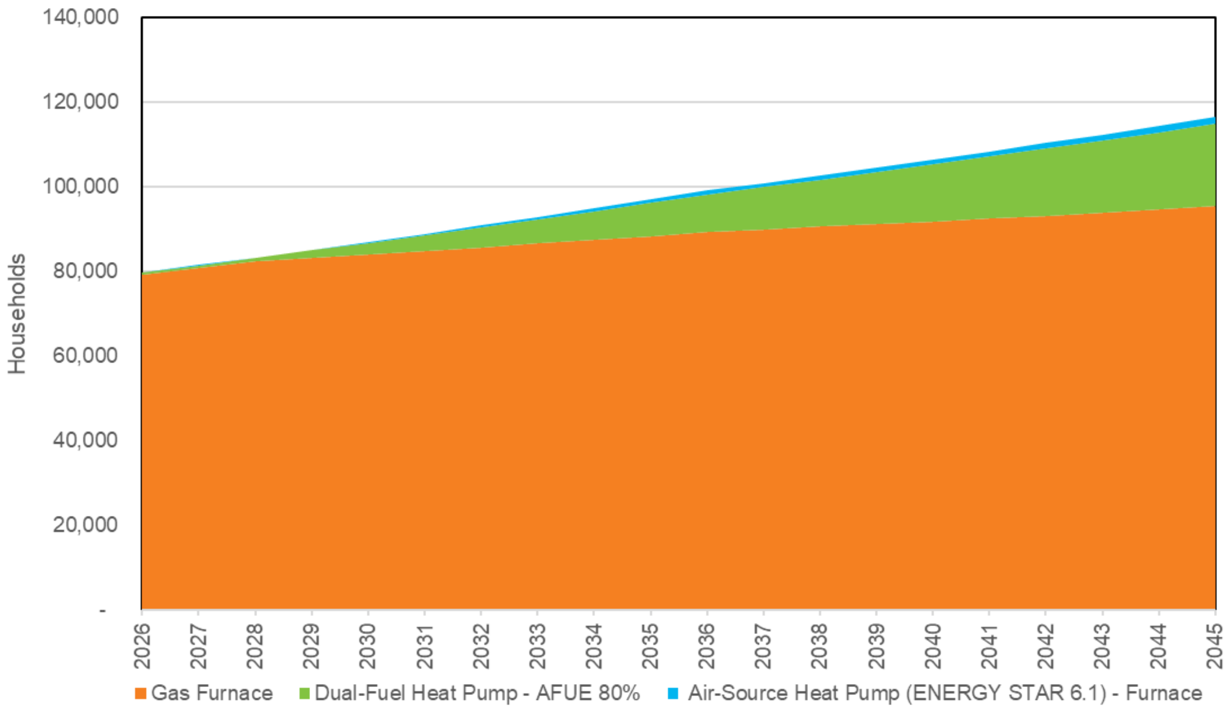


Figure 3.13: Idaho Residential Gas Heating Market Transformation



Load Forecast

The load forecast produced with the end use model does not address some aspects of the final load forecast, both for energy and peak. The following additional analyses were conducted to finalize the load forecast for the IRP analysis:

- Add large industrial loads,
- Add line losses occurring in the delivery of energy from a generator, through the transmission and distribution system to the end customer,
- Peak and energy were adjusted for weather normalization.

Weather Normalization

Weather has a significant impact on load. The AEG model only uses data from 2021 to 2023 to establish weather for their model, therefore a secondary weatherization step was conducted to accurately represent historical data and future weather forecasts. Avista applies weather data on a monthly basis. Each forecast month uses the average of the data from the same month for the previous 20 years, except in the case of winter peak (uses a 76-year rolling average). This is done to capture the full range of possible temperatures.

The energy forecast utilizes monthly HDDs and CDDs while the peak load model utilizes daily average temperature. The first year of the forecast uses historical data, but each subsequent year adds in forecasted weather and removes historical weather such that the last several years of the forecast is based entirely on forecasted weather, except in the case of the winter peak since the 76-year period still includes historical values. The energy forecast is adjusted by total number of monthly HDDs or CDDs, while peak is adjusted according to the coldest or hottest daily average temperature for each month as appropriate for the season. For planning purposes, winter peak is the lowest average daily temperature in January and the summer peak is the warmest average day in August. A seasonal peak for each year was developed in addition to the monthly peak values to reflect extreme events occurring anytime in the season rather than a specific month. This data takes the hottest or coldest day over the course of multiple months for each year, as it cooler and/or in other months rather than using January and August exclusively. The seasonal peak is used to validate the load forecast in reliability modeling and to compare with historical peak values. As described in Chapter 5, Avista uses the climate forecast data generated by the River Management Joint Operating Committee (RMJOC). Avista uses the RCP 8.5 for the summer months (June, July, August, September) and RCP 4.5 for the remaining months of the year.

Load Forecast

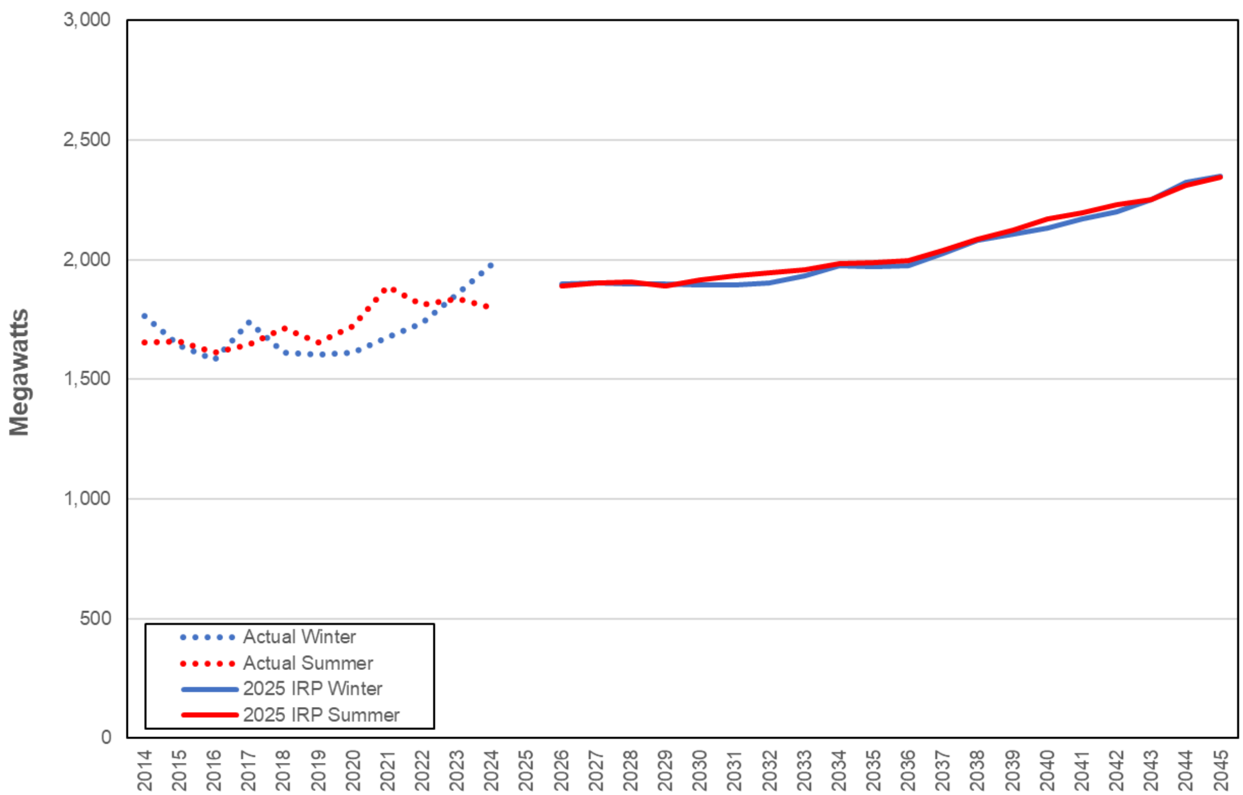
After combining the medium-term, end-use forecast, and weather normalization, the resulting load forecast is shown in Table 3.5 for the expected case's average annual energy in average megawatts (aMW) as well as summer and winter peaks in megawatts (MW). The forecast is for Avista's native load, referring to Avista's retail customers, and does not include other loads within the transmission balancing authority published in FERC or EIA data.

Table 3.5: Expected Case Energy and Peak Forecasts

Year	Energy (aMW)	January Peak (MW)	August Peak (MW)
2026	1,165	1,816	1,837
2027	1,167	1,821	1,846
2028	1,166	1,819	1,850
2029	1,165	1,821	1,835
2030	1,165	1,814	1,863
2031	1,166	1,818	1,870
2032	1,168	1,825	1,878
2033	1,177	1,852	1,884
2034	1,188	1,898	1,902
2035	1,200	1,893	1,905
2036	1,211	1,901	1,909
2037	1,227	1,949	1,948
2038	1,246	2,003	1,990
2039	1,263	2,028	2,023
2040	1,282	2,058	2,063
2041	1,305	2,093	2,090
2042	1,321	2,117	2,119
2043	1,344	2,168	2,135
2044	1,366	2,233	2,191
2045	1,379	2,261	2,217

Figure 3.14 presents the seasonal peak load forecast in comparison to historical peak loads[38] prior to 2022, where winter peaks were often less then summer peaks due to moderate winter temperatures until December 2022 and January 2024. The Spokane area's average coldest day used for planning is 4°, whereas in December 2022 (-3° with a low of -10°) and January 2024 (-4° with a low of -10°) were much colder than the 50th percentile coldest day used for planning.[39] The January 2024 event during Martin Luther King Jr. holiday weekend would have been Avista's all-time peak as shown in Figure 3.14, at a load of 1,981 MW, but industrial loads were curtailed resulting in an official peak load of 1,869 MW. Avista's all-time peak was set during the heat dome event in June 2021, with a peak load of 1,889 MW when temperatures were an average of 93° (high of 109°) compared to the planning temperature of 84°.

Figure 3.14: History and Forecast Peak Loads

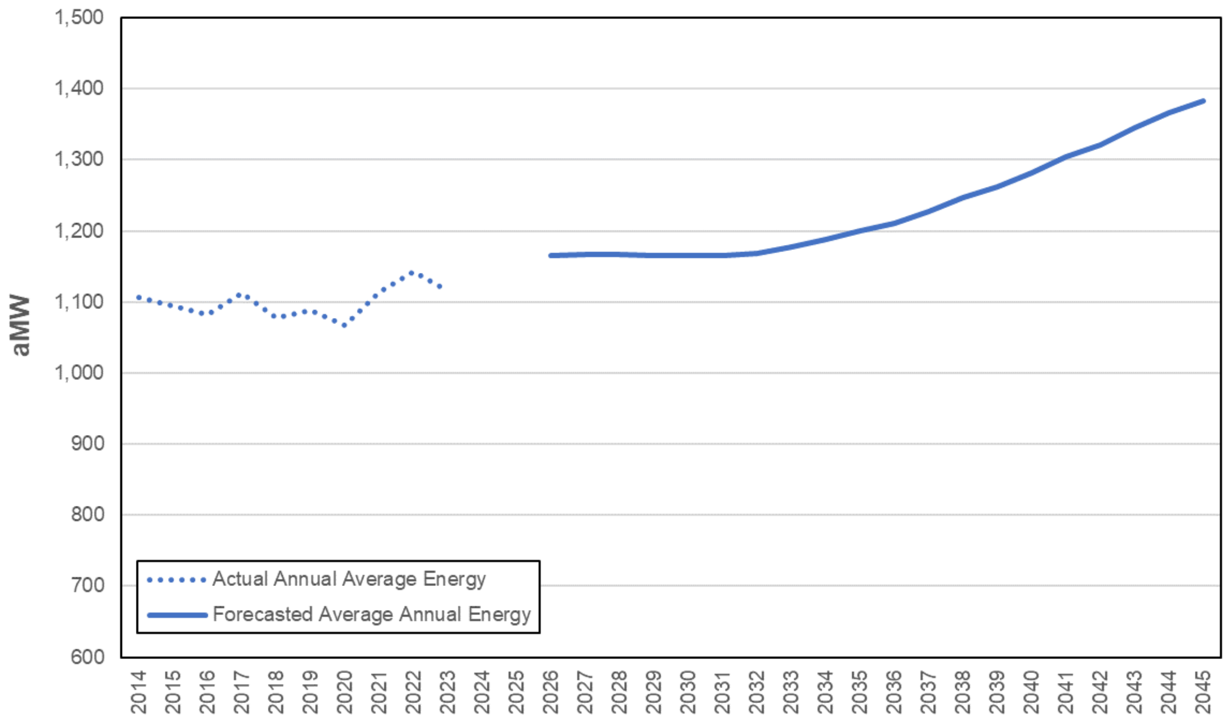


The annual average growth rate for the energy forecast is 0.91% between 2026 and 2045, going from 1,165 aMW to 1,383 aMW. The forecast steps up at the beginning of the forecast period as the result of a new large industrial load as compared to 2023. The forecast is then relatively flat until 2032 when the forecasted annual load increases at a greater rate due to building and transportation electrification beginning to show an impact. Also, as described above, Avista uses a 20-year rolling average temperature in its load

[38] Historical peak load data is corrected for known curtailed load or demand response.
[39] Avista planning margin cover loads when temperature vary from the 50th percentile.

forecast, therefore forecasted temperatures, rather than actual historical temperatures, have an increased impact on temperature dependent loads in the later years of the forecast.

Figure 3.15: History and Forecast Annual Energy Demand



Load Scenario Analysis

In addition to the expected case, additional load forecast scenarios were developed, including:

- *High growth*: assumes higher customer/population growth than the expected case.
- *Low growth*: assumes lower customer/population growth than the expected case.
- *RCP 8.5*: uses RCP 8.5 for the winter months as part of the future periods included in the forecast. RCP 8.5 temperature forecast between 2026-2045 is included in the historical average temperature calculation for peak load temperatures.
- *Washington Building Electrification*: This scenario reduces natural gas demand each year to achieve an 80% reduction by 2045. Where 75% of the gas energy is added to Avista's electric load, the remaining load would be applied to other utilities.
- *Washington Building Electrification and High EV forecast*: This scenario adds higher transportation electrification as compared to the

previous scenario's building electrification adjustment. It also includes electrifying an equivalent of 806,000 EVs in the Washington service area by 2045 as compared to 560,000 EVs equivalent in the expected case.

- *System Building Electrification and High EV*. This scenario is similar to Washington only electrification scenario but includes Idaho building and transportation electrification. In this scenario natural gas demand lowers each year to achieve an 80% reduction by 2045. (90% of this load is Avista electric load) and adding an equivalent of 300,000 EVs by 2045 as compared to 65,000 in the expected case forecast.

Figures 3.16, 3.17, and 3.18 present the annual energy, summer peak, and winter peak respectively for each of the load scenarios. Table 3.6 shows the incremental change between the expected case and each scenario in 2045. Energy in the high growth scenario is 19% higher than the expected case, while the low growth scenario is 10% lower. Use of the RCP 8.5 temperatures for the entire year lowers annual energy by 1%. This is due to higher temperatures during the winter months. Washington building electrification increases annual energy use by 8% and EV use that is greater than what is included in the expected case in Washington increases annual energy by 6%. The largest increase is 29% of annual energy resulting from building electrification and high EV use across the entire system, both Idaho and Washington. This scenario also increases winter peak by 41%.

Figure 3.16: Scenario Comparison of Annual Energy (aMW)

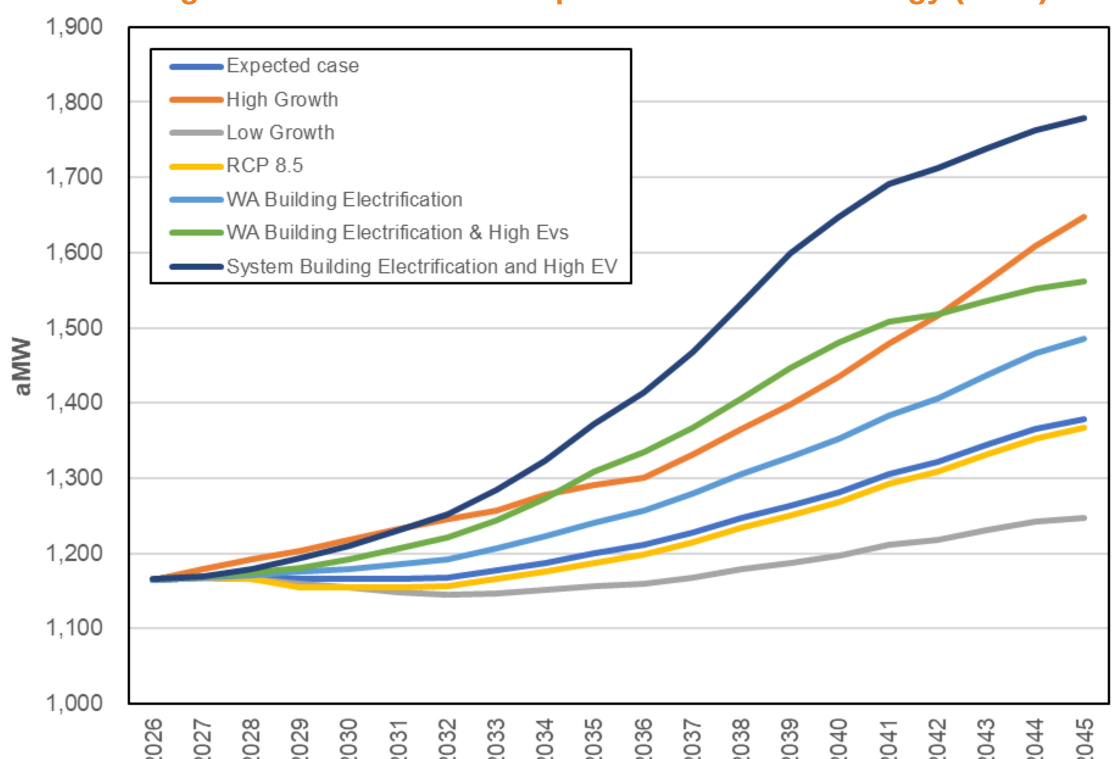


Figure 3.17: Scenario Comparison of Winter Peak (MW)

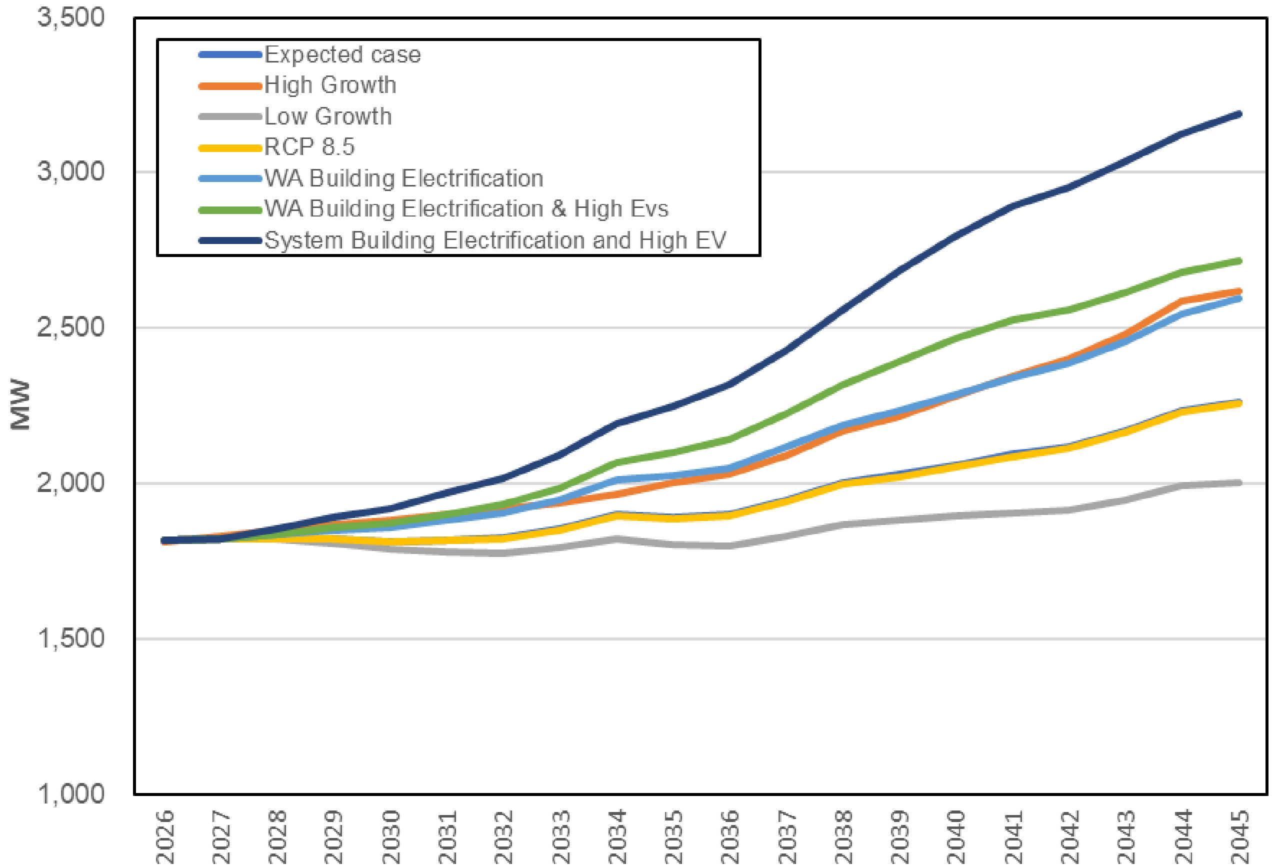


Figure 3.18: Scenario Comparison of Summer Peak (MW)

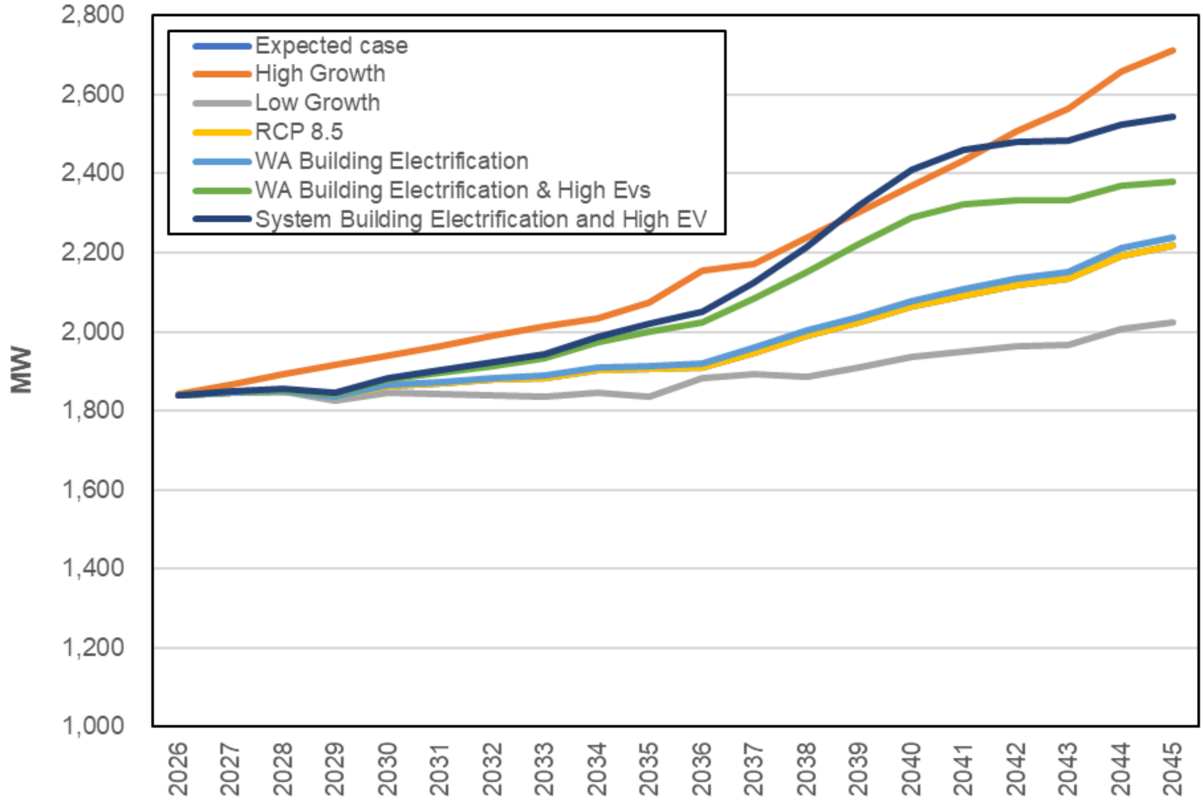


Table 3.6: Incremental Difference between Expected Case and Scenario in 2045

Scenario	Annual Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)
High Growth	+268	+357	+494
Low Growth	-132	-258	-193
RCP 8.5	-13	-23	0
WA Building Electrification	+107	+336	+21
WA Building Electrification & High EVs	+183	+456	+161
System Building Electrification & High EV	+401	+930	+325

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4. Existing Supply Resources

Avista relies on a diverse portfolio of assets to meet customer loads, including owning and operating eight hydroelectric developments on the Spokane and Clark Fork rivers. Its thermal assets include ownership of five natural gas-fired projects, a biomass plant. Avista also purchases energy from several independent power producers (IPPs) and regional utilities.

Section Highlights

- Hydroelectric resources provide approximately half of Avista's winter generating capability.
- Natural gas-fired plants continue to represent a fundamental element, both currently and into the clean energy future to maintain system reliability for Avista's generation portfolio.
- Avista will transfer its ownership of Colstrip Units 3 & 4 to NorthWestern Energy on January 1, 2026.
- The 97.5 MW Clearwater Wind project in Montana is commercially operational in September 2024.

Figure 4.1 shows how much annual energy may be generated on Avista's system. This annual energy chart represents the generation potential as a percentage of total supply; this calculation includes fuel limitations (for water, wind, and wood), maintenance, and forced outages. On an annual basis, natural gas-fired generation can produce more energy (48%) than hydroelectric (38%) because it is not constrained by river conditions. Avista's resource mix changes each year depending on streamflow conditions and market prices. Figure 4.2 shows how much generation capacity Avista can rely on during winter and summer peak. This winter and summer capability is the share of total capability of each resource type the utility can rely upon to meet winter (January) and summer (August) peak load. Avista's largest energy supply in the peak winter months is from hydroelectric at 55%, followed by natural gas-fired resources at 39%.

Avista reports its fuel mix annually in the Washington State Fuel Mix Disclosure.[40] The Washington State Department of Commerce calculates the resource mix used to serve load, rather than its generation potential. The report includes estimates for regional[41] market purchases without an identified energy source and Avista-owned generation minus renewable energy credit (REC) sales. Figure 4.3 shows Avista's 2023 Fuel Mix Disclosure for 2022 data. The Idaho fuel mix is nearly identical to Washington's except for its allocation of Public Utility Regulatory Policies Act (PURPA) generation. Each state

[40] 11A-Utility-Fuel-Mix-Market-Summary-20240108.pdf from Washington Department of Commerce.
[41] For 2022, the region is approximately 54% hydroelectric, 13% unspecified, 10% natural gas, 9% coal, 8% wind, 4% nuclear and 2% other. When Avista sells RECs from its resources the remaining generation is assigned a fuel mix and an emissions level in the report equal to regional average emissions.

is allocated RECs based on their current authorized share of the system (approximately 65% Washington and 35% Idaho). Avista may retain RECs, sell them to other parties, or transfer them between states. Avista transfers RECs from Idaho to comply with Washington's Energy Independence Act (EIA). Idaho customers are compensated for the value of RECs at market value whenever these transfers occur.

Figure 4.1: 2026 Annual Energy Capability (System)

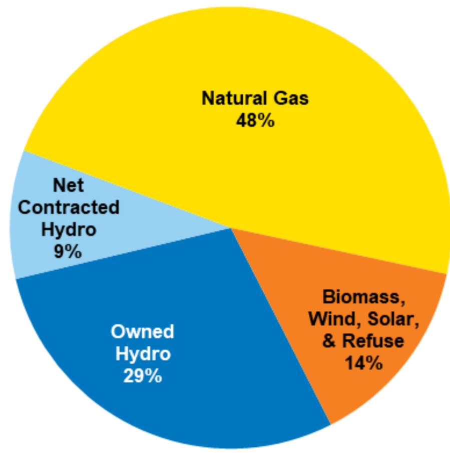


Figure 4.2: 2026 Avista System Seasonal Capability

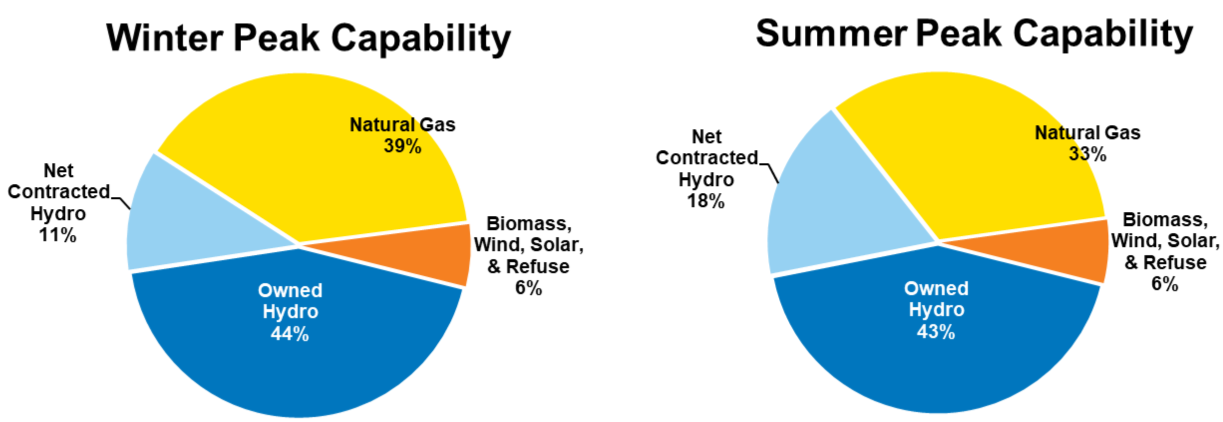
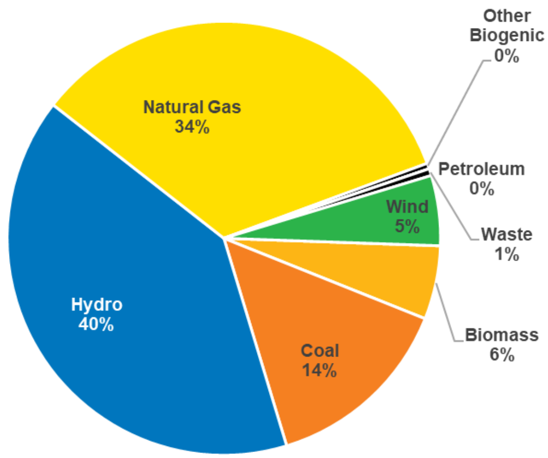


Figure 4.3: Avista's Washington State Fuel Mix Disclosure



Spokane River Hydroelectric Developments

Avista owns and operates six hydroelectric developments on the Spokane River. Five operate under a 50-year Federal Energy Regulatory Commission (FERC) operating license through June 18, 2059. The sixth, Little Falls, operates under separate authorization from the U.S. Congress because of its location on tribal land. This section describes the Spokane River hydroelectric developments and provides the maximum on-peak and nameplate capacity ratings for each plant. The maximum on-peak capacity of a generating unit is the total amount of electricity it can safely generate with its existing configuration and the current mechanical state of the facility. Unlike other generation assets, hydroelectric capacity is often above nameplate because of plant upgrades and favorable head or streamflow conditions. The nameplate, or installed capacity, is the original capacity of a plant as rated by the manufacturer. All six hydroelectric developments on the Spokane River connect directly to the Avista transmission system.

Post Falls

Post Falls is the hydroelectric facility furthest upstream on the Spokane River. It is located several miles east of the Washington/Idaho border. The facility began operating in 1906 and during summer months maintains the elevation of Lake Coeur d'Alene. Post Falls has a 14.75 MW nameplate rating but could produce up to 18.0 MW with its six generating units.

In February 2024, Avista's Post Falls Hydroelectric Dam was selected for U.S. Department of Energy grant funding, receiving a $5 million Hydroelectric Efficiency Improvement Incentive for improvements to increase the facility's efficiency. The goal of the Post Falls Modernization project is to replace existing aging equipment with modern, energy-efficient designs and equipment, and increase the useful life of the facility. The planned updates will not change operations nor capacity of the Post Falls dam and are estimated to be complete in 2029.

Upper Falls

The Upper Falls development is in downtown Spokane's Riverfront Park and began generating in 1922. The project is comprised of a single 10 MW unit on the north channel of the river.

Monroe Street

Monroe Street, Avista's first hydroelectric plant, began serving customers in 1890 in downtown Spokane at Huntington Park. Following a complete rehabilitation in 1992, the single generating unit has a 15 MW maximum capacity rating.

Nine Mile

A private developer built the Nine Mile hydroelectric plant in 1908 near Nine Mile Falls, Washington. Avista purchased the project in 1925 from the Spokane & Inland Empire Railroad Company. Nine Mile has undergone substantial upgrades with the installation of two new 8 MW units and two 10 MW units for a total nameplate rating of 36 MW.

Long Lake

The Long Lake development is located northwest of the City of Spokane and maintains the Lake Spokane reservoir or Long Lake. The project's four units have a maximum capacity of 88 MW of combined capacity.

Little Falls

The Little Falls development, completed in 1910 near Ford, Washington, is the furthest downstream hydroelectric facility on the Spokane River. The facility's four units generate 35.2 MW. As Little Falls is partially located on the Spokane Indian Reservation, it was congressionally authorized and is not under FERC jurisdiction. Avista operates Little Falls Dam in accordance with an agreement reached with the Spokane Tribe in 1994 to identify operational and natural resource requirements. Little Falls Dam is also subject to other Washington State environmental and dam safety requirements.

Clark Fork River Hydroelectric Development

The Clark Fork River Development includes two hydroelectric projects located near Clark Fork, Idaho, and Noxon, Montana, 70 miles south of the Canadian border on the Clark Fork River. The plants operate under a FERC license through 2046 and connect directly to Avista's transmission system.

Noxon Rapids

The Noxon Rapids development includes four generators installed between 1959 and 1960, and a fifth unit that entered service in 1977. Avista completed major turbine upgrades on units 1 through 4 between 2009 and 2012. The total capability of the plant is 610 MW under favorable operating conditions, although Avista uses 555 MW for planning purposes.

Cabinet Gorge

Cabinet Gorge started generating power in 1952 with two units, and two additional generators were added the following year. Upgrades to units 1 through 4 occurred in 1994, 2004, 2001, and 2007, respectively. The current maximum on-peak plant capacity is 270.5 MW, modestly above its 265.2 MW nameplate rating.

Total Hydroelectric Generation

In total, Avista's hydroelectric plants have nearly 1,080 MW of capacity. Table 4.1 summarizes the location and operational capacities of Avista's hydroelectric projects, and the expected energy output of each facility based on an 80-year hydrologic record.

Table 4.1: Avista-Owned Hydroelectric Resources

Project Name	River System	Location	Nameplate Capacity (MW)	Maximum Capability (MW)	Expected Energy (aMW)
Monroe Street	Spokane	Spokane, WA	15.0	15.0	11.2
Post Falls	Spokane	Post Falls, ID	14.8	18.0	9.4
Nine Mile	Spokane	Nine Mile Falls, WA	36.0	32.0	15.7
Little Falls	Spokane	Ford, WA	32.0	35.2	22.6
Long Lake	Spokane	Ford, WA	81.6	88.0	56.0
Upper Falls	Spokane	Spokane, WA	10.0	10.2	7.3
Noxon Rapids	Clark Fork	Noxon, MT	518.0	610.0	196.5
Cabinet Gorge	Clark Fork	Clark Fork, ID	265.2	270.5	123.6
Total			**972.6**	**1,078.9**	**442.3**

Thermal Resources

Avista owns six thermal generation assets located across the Northwest. These assets provide dependable energy and capacity serving base and peak-load obligations. Table 4.2 summarizes these resources by fuel type, online year, remaining design life, book value at the end of 2025 and the last year of expected service for IRP modeling purposes. Table 4.3 includes capacity information for each of the facilities along with the five-year historical forced outage rates used for modeling purposes.

Table 4.2: Avista-Owned Thermal Resources

Project Name	Location	Fuel Type	Start Date	Last Year of Service[42]	Book Value (mill. $)	Book Life (years)
Rathdrum	Rathdrum, ID	Gas	1995	2044	18.7	7.2
Northeast[43]	Spokane, WA	Gas	1978	2029	0.0	0.0
Boulder Park	Spokane, WA	Gas	2002	2040	12.8	15.7
Coyote Springs 2	Boardman, OR	Gas	2003	n/a	98.7	15.2
Kettle Falls	Kettle Falls, WA	Wood	1983	n/a	59.2	17.4
Kettle Falls CT	Kettle Falls, WA	Gas	2002	2040	1.9	9.9

Table 4.3: Avista-Owned Thermal Resource Capability

Project Name	Winter Maximum Capacity (MW)	Summer Maximum Capacity (MW)	Nameplate Capacity (MW)	Forced Outage Rate (%)
Rathdrum (2 units)	176.0	130.0	166.2	5.8
Northeast (2 units)	66.0	42.0	61.8	n/a
Boulder Park (6 units)	24.6	24.6	24.6	10.5
Coyote Springs 2	317.5	286.0	306.5	3.8
Kettle Falls	47.0	47.0	50.7	2.3
Kettle Falls CT	11.0	8.0	7.2	2.7
Total	**864.1**	**759.6**	**864.0**	

Rathdrum

Rathdrum consists of two identical simple-cycle combustion turbine (CT) units. This natural gas-fired plant located near Rathdrum, Idaho connects to the Avista transmission system. This facility entered service in 1995 and has a maximum combined capacity of 176 MW in the winter and 126 MW in the summer. The nameplate rating is 166.2 MW. Chapter 7, Supply-Side Resource Options, provides details about upgrade options under consideration at Rathdrum.

Northeast

The Northeast plant, located in Spokane, has two identical aero-derivative simple-cycle CT units completed in 1978. The plant can burn natural gas and oil, but current air permits preclude the use of fuel oil. The combined maximum capacity of the units is 66 MW in the winter and 42 MW in the summer, with a nameplate rating of 61.8 MW. The plant air permit limits run time to 50 hours per year, limiting its use to primarily serve reliability events. For the purposes of this IRP, Avista assumes this plant will retire in 2030, but no official retirement date has been set. The existing air permit for the Northeast plant expires at the end of 2032.

[42] The last year of service is estimated retirement or end of service for utility customers. This IRP assumes Coyote Springs 2 to be ineligible for Washington in 2045, but still eligible to serve Idaho customers.
[43] There is no remaining book life but there are five years of remaining tax depreciation impacts to customers.

Boulder Park

The Boulder Park project entered service in Spokane Valley in 2002. It connects directly to the Avista transmission system. The site uses six identical natural gas-fired internal combustion reciprocating engines to produce a combined maximum capacity and nameplate rating of 24.6 MW. For modeling purposes of this IRP, Avista assumes this plant will retire in 2040.

Coyote Springs 2

Coyote Springs 2 is a natural gas-fired combined cycle combustion turbine (CCCT) located near Boardman, Oregon. The plant connects to the Bonneville Power Administration (BPA) 500 kV transmission system under a long-term agreement. The plant began service in 2003 and has a maximum capacity of 317.5 MW in the winter and 285 MW in the summer with duct burners operating. The nameplate rating of the plant is 287.3 MW.

Kettle Falls Generation Station and Kettle Falls Combustion Turbine

The Kettle Falls Generating Station entered service in 1983 near Kettle Falls, Washington. It is among the largest biomass generation plants in North America and connects to Avista on its 115 kV transmission system. The open-loop steam plant uses waste wood products (hog fuel) from area mills and forest slash but can also burn natural gas on a limited basis. A 7.5 MW combustion turbine (CT), added to the facility in 2002, burns natural gas and increases overall plant efficiency by sending exhaust heat to the wood boiler when operating in combined-cycle mode.

The wood-fired portion of the plant has a maximum capacity of 50 MW and a nameplate rating of 50.7 MW. Varying fuel moisture conditions at the plant causes correlated variation between 45 and 50 MW. The plant’s capacity increases from 55 to 58 MW when operated in combined-cycle mode with the CT. The CT produces 8 MW of peaking capability in the summer and 11 MW in the winter. The CT can be limited in the winter when the natural gas pipeline is capacity constrained.

Colstrip

The Colstrip plant, located in eastern Montana, consists of two coal-fired steam plants (Units 3 and 4) connected to a double-circuit 500 kV line owned by each of the participating utilities. The utility-owned segment extends from Colstrip to Townsend, Montana. BPA’s ownership of the 500 kV line starts in Townsend and continues west. Energy moves across both segments of the transmission line under a long-term wheeling arrangement. Talen Montana, LLC operates the facilities on behalf of the six owners (see Table 3.4). Avista currently owns 15% of Units 3 and 4. Unit 3 began operating in 1984 and Unit 4 in 1986. Avista’s share of Colstrip has a maximum net capacity of 222 MW, and a nameplate rating of 247 MW. On January 1, 2026, ownership of Colstrip will be transferred to Northwestern Energy and therefore will no longer serve Avista customers. NorthWestern will assume all of Avista’s Colstrip ownership along with its related interest in the plant, plant equipment, rights, and obligations. Under the Agreement, Avista retains its existing remediation obligations and enters into a vote sharing agreement with NorthWestern to retain voting rights in regard to any decisions made with respect to remediation activities.

Small Avista-Owned Solar

Avista operates three small solar projects. The first solar project is three kilowatts located at its corporate headquarters. Second, Avista installed a 15-kilowatt solar system in Rathdrum, Idaho to supply its My Clean Energy™ (formerly Buck-A-Block) voluntary green energy program. Lastly, Avista has a 423-kW Community Solar project, located at the Boulder Park property, began service in 2015.

Table 4.4: Avista-Owned Solar Resource Capability

Project Name	Project Location	Project Capacity (kW-DC)
Spokane Headquarters Solar	Spokane, WA	4
Rathdrum Solar	Rathdrum, ID	15
Boulder Park Solar	Spokane Valley, WA	423
Total		**442**

Power Purchase and Sale Contracts

Avista uses purchase and sale arrangements of varying lengths to meet some of its load requirements. These contracts provide many benefits by adding clean generation from low-cost hydroelectric and wind power to the Company's resource mix. This section describes the contracts in effect during the IRP. Tables 4.5 and 4.6 summarize Avista's contracts.

Mid-Columbia Hydroelectric Contracts

During the 1950s and 1960s, Public Utility Districts (PUDs) in central Washington developed hydroelectric projects on the Columbia River. Each plant was large compared to loads served by the PUDs. Long-term contracts with public, municipal, and investor-owned utilities throughout the Northwest assisted project financing by providing a market for surplus power. The contract terms obligate the PUDs to deliver power to Avista points of interconnection. Avista originally entered long-term contracts for the output of five projects "at cost". Avista now competes in capacity auctions to retain the rights of these contracts as they expire. The Mid-Columbia contracts in Table 4.5 provide clean energy, capacity, and reserve capabilities.

Under the 1961 Columbia River Treaty and the 1964 Pacific Northwest Coordination Agreement (PNCA), the Mid-Columbia projects optimize hydroelectric project operations in the Northwest U.S. and Canada. In return for these benefits, Canada receives a share of the energy under the Canadian Entitlement. The Columbia River Treaty and the PNCA manage water storage in upstream reservoirs for coordinated flood control and power generation optimization. The Columbia River Treaty recently concluded negotiations in July 2024. At this time, no specific information is available pertaining to the generation impact, however it is expected less energy will be transferred to Canada under the Canadian Entitlement.

Columbia Basin Hydro

In December 2022, Avista reached an agreement to purchase the entire output from Columbia Basin Hydro's irrigation generation fleet through 2045. The agreement includes all generation and environmental attributes from their seven hydroelectric projects totaling 146.3 MW of capacity. Avista will begin taking delivery of projects as existing contracts with other utilities expire. Table 4.6 outlines the project delivery timeline, capacity, and energy deliveries for Columbia Basin Hydro. These projects are unique as they are based on the amount of irrigation used by central Washington farmers from March through October, with most of the generation occurring in May through August in a consistent firm energy delivery.

Table 4.5: Mid-Columbia Capacity and Energy Contracts[44]

Counter Party	Project(s)	Percent Share (%)	Start Date	End Date	On-Peak Capability (MW)	Annual Energy (aMW)	Canadian Entitle-ment
Grant PUD	Priest Rapids/ Wanapum	3.46	Dec-2001	Dec-2052	74.9	38.4	-1.4
Chelan PUD	Rocky Reach/ Rock Island	5.0	Jan-2016	Dec-2030	87.5	52.4	-1.9
Chelan PUD	Rocky Reach/ Rock Island	5.0	Jan-2024	Dec-2033	87.5	52.4	-1.9
Chelan PUD	Rocky Reach/ Rock Island	5.0	Jan-2026	Dec-2030	87.5	52.4	-1.9
Chelan PUD	Rocky Reach/ Rock Island	10.0	Jan-2031	Dec-2045	174.9	104.8	-3.8
Douglas PUD	Wells	1.53[45]	Oct-2018	Dec-2028	23.8	12.2	-0.4

[44] For purposes of long-term transmission reservation planning for bundled retail service to native load customers, replacement resources for each of the resources identified in Table 4.5 are presumed and planned to be integrated via Avista's interconnection(s) to the Mid-Columbia region.
[45] Percent share varies each year depending on Douglas PUD's load growth.

Table 4.6: Columbia Basin Hydro Projects

Project Name	Start Date	Capacity (MW)	Energy (aMW)
Russell D. Smith	1/1/2023	6.1	1.5
EBC 4.6	5/1/2023	2.2	0.9
Summer Falls	1/1/2025	94.0	41.4
PEC 66	3/1/2025	2.4	0.5
Quincy Chute	10/1/2025	9.4	3.6
Main Canal	1/1/2027	26.0	11.6
PEC Headworks	9/1/2030	6.2	2.3
Total		**146.3**	**61.8**

Public Utility Regulatory Policies Act (PURPA)

The passage of PURPA by Congress in 1978 required utilities to purchase power under standardized contracts from resources meeting certain size and fuel criteria. As shown in Table 4.7, Avista has many PURPA, or Qualifying Facility (QF) energy purchase contracts, totaling 139.9 MW, with a five-year average output of 73 aMW. Avista also has PURPA fully net metered generation from customer load shown in Table 4.8 for a total of 7.5 MW. Power from net metered facilities is only purchased if generation exceeds load. Based on Avista's experience with these contracts and ongoing communications with the project owners, the IRP assumes the renewal of these contracts after the term expires. Avista takes the energy as produced, does not control the output of any PURPA resources.

Table 4.7: PURPA Agreements

Contract	Fuel Source	Location	Contract End Date	Size (MW)	5 year avg. Gen. History (aMW)
Meyers Falls	Hydro	Kettle Falls, WA	12/2025	1.30	1.06
Spokane Waste to Energy	Waste	Spokane, WA	12/2037	22.70	13.63
Plummer Sawmill[46]	Wood Waste	Plummer, ID	12/2025	5.80	3.00
Deep Creek	Hydro	Northport, WA	12/2032	0.41	0.02
Clark Fork Hydro	Hydro	Clark Fork, ID	12/2037	0.22	0.11
Upriver Dam[47]	Hydro	Spokane, WA	12/2037	14.50	4.96
Big Sheep Creek Hydro	Hydro	Northport, WA	6/2025	1.40	0.82
Ford Hydro LP	Hydro	Weippe, ID	6/2026	1.41	0.36
John Day Hydro	Hydro	Lucile, ID	9/2041	0.90	0.24
Phillips Ranch	Hydro	Northport, WA	n/a	0.02	0.00
City of Cove	Hydro	Cove, OR	10/2038	0.80	0.36
Clearwater Paper	Biomass	Lewiston, ID	12/2026	93.80	48.67
Total				**143.26**	**73.23**

[46] The owner publicly announced it is shutting down the mill and generator and this resource is excluded from this plan.
[47] Energy estimate is net of the City of Spokane's pumping load. The City of Spokane owns this facility.

Table 4.8: Net PURPA Agreements

Contract	Fuel Source	Location	Contract End Date	Size (MW)
Spokane County Digester	Biomass	Spokane, WA	8/2030	0.26
Spokane Eco District[48]	Solar/BESS	Spokane, WA	4/2039	1.00
Great Northern	Solar	Spokane, WA	5/2035	0.25
U of Idaho Steam Plant	CHP Steam	Moscow, ID	2/2042	0.83
U of Idaho Solar	Solar	Moscow, ID	2/2026	0.13
Vaagen Brothers Lumber[49]	Biomass	Colville, WA	7/2039	5.00
Total				**7.47**

Lancaster

Avista originally acquired output rights to the Lancaster CCCT, located in Rathdrum, Idaho, after the sale of Avista Energy in 2007. Lancaster directly interconnects with the Avista transmission system at the BPA Lancaster substation. Under the contract, Avista pays a monthly capacity payment for the sole right to dispatch the plant through December 31, 2041. In addition, Avista pays an operational charge and arranges for all fuel needs of the plant.

Palouse Wind

Avista signed a 30-year power purchase agreement (PPA) in 2011 with Palouse Wind for the entire output of the 105 MW project starting in December 2012. The project directly connects to Avista's transmission system between Rosalia and Oaksdale, Washington in Whitman County. Avista has an annual right to purchase the Palouse project per the contract.

Rattlesnake Flat Wind

Rattlesnake Flat Wind located east of Lind, Washington in Adams County was selected in Avista's 2018 RFP as a 20-year PPA. It is 160.5 MW (but output is limited to 144 MW due to its interconnection agreement). The expected net annual output of 469,000 MWh (53.5 aMW). The project began operations in December 2020.

Clearwater Wind III

Clearwater Wind III located in Rosebud and Garfield Counties in eastern Montana was selected in the 2022 all-source RFP as a 30-year PPA. It is 97.5 MW and will begin operation in September 2024 with an estimated annual generation of 367,000 MWh.

Adams-Nielson Solar

Avista signed a 20-year PPA for the Adams-Nielson solar project in 2017. The 80,000 panel, single axis, solar facility can deliver 19.2 MW of alternating current (AC) power and

48 This size is a little over 254 kW solar and the battery is greater than 1 MW but is limited to 1 MW output by the inverter/interconnection.
49 This PPA was signed after the IRP analysis and therefore was not included in the IRP analysis.

entered service in December 2018. The project is located north of Lind, Washington in Adams County. The project provides energy for Avista's Solar Select program allowing commercial customers to voluntarily purchase solar energy through 2026. Through Washington state tax incentives participating customers do not pay additional costs for the clean energy attributes from the project.

Power Purchase and Contracts

Avista has intermediate power purchase and sale contracts to optimize Avista's energy position on behalf of customers, such as the Morgan Stanley contract. For resource planning purposes, Avista does not assume contract sale extensions. Table 4.9 describes Avista's other contractual rights and obligations.

Table 4.9: Other Contractual Rights and Obligations

Contract	Type	Fuel Source	End Date	Winter Capacity Contri-bution (MW)	Summer Capacity Contri-bution (MW)	Annual Energy (aMW)
Lancaster	Purchase	Natural Gas	2041	283.0	231.0	218.0
Palouse	Purchase	Wind	2042	5.3	5.3	36.2
Rattlesnake Flat	Purchase	Wind	2040	7.2	7.2	53.5
Clearwater Wind	Purchase	Wind	2056	29.7	19.2	42.0
Adams-Nielson	Purchase	Solar	2038	0.4	10.2	5.6
Morgan Stanley	Sale	QF Biomass	2026	-46.0	-46.0	-44.9
Total				**279.6**	**226.9**	**310.4**

Resource Environmental Requirements and Issues

Avista is subject to environmental regulation by federal, state, and local authorities. The generation, transmission, distribution, service, and storage facilities we own or may need to acquire or develop are subject to environmental laws, regulations and rules relating to construction permitting, air emissions, water quality, fisheries, wildlife, endangered species, avian interactions, wastewater and stormwater discharges, waste handling, natural resource protection, historic and cultural resource protection, and other similar activities. These laws and regulations require the Company to make substantial investments in compliance activities and to acquire and comply with a wide variety of environmental licenses, permits, approvals, and settlement agreements. These items are enforceable by public officials and private individuals. Some of these regulations are subject to ongoing interpretation, whether administratively or judicially, and are often in the process of being modified. Avista conducts periodic reviews and audits of pertinent facilities and operations to enhance compliance and to respond to or anticipate emerging environmental issues. The Company's Board of Directors has established a committee to oversee environmental issues and to assess and manage environmental risk.

Avista monitors legislative and regulatory developments at different levels of government for environmental issues, particularly those with the potential to impact the operation of generating plants and other assets. The Company continues to be subject to increasingly stringent or expanded application of environmental and related regulations from all levels of government.

Environmental laws and regulations may restrict or impact Avista's business activities in many ways, including, but not limited to, by:

- increasing the operating costs of generating plants and other assets,
- increasing the lead time and capital costs for the construction of new generating plants and other assets,
- requiring modification of existing generating plants,
- requiring existing generating plant operations to be curtailed or shut down,
- reducing the amount of energy available from generating plants,
- restricting the types of generating plants that can be built or contracted with,
- requiring construction of specific types of generation plants at higher cost, and
- increasing the costs of distributing, or limiting our ability to distribute, electricity and/or natural gas.

Compliance with environmental laws and regulations could result in increases to capital expenditures and operating expenses. The following sections describe applicable environmental regulations in more detail.

Policies and Other Impacts Related to Climate Change

Legal and policy changes responding to concerns about climate change, and the potential impacts of such changes, could have a significant effect on our business. Direct impacts of climate changes include, without limitation, variations in the amount and timing of energy demand throughout the year, variations in the level and timing of precipitation throughout the year, as well as variations in temperature, and the resulting impact on the availability of hydroelectric resources at times of peak demand as well as an increased risk of wildfire. Indirect impacts include, without limitation, changes in laws and regulations intended to mitigate the risk of, or alter, climate changes, including restrictions on the operation of power generation resources and obligations

Clean Energy Transformation Act

In 2019, the Washington State Legislature passed the CETA, requiring Washington utilities to eliminate the costs and benefits associated with coal-fired resources from their retail electric sales by December 31, 2025. This requirement effectively prohibits sales of energy produced by coal-fired generation to Washington retail customers after December 31, 2025. In addition, retail sales of electricity to Washington customers must be carbon-neutral by January 1, 2030 and requires that each electric utility demonstrate compliance with this standard by using electricity from renewable and other non-emitting resources for 100% of the utility's Washington retail electric load over consecutive multi-year compliance periods; provided, however, that through December 31, 2044 the utility may satisfy up to 20% of this requirement with specified payments, credits and/or investments in qualifying energy transformation projects.

As required under the CETA, in October 2021 Avista filed our first CEIP. Our CEIP is a road map of specific actions we proposed to take over the first four years (2022-2025) to show the progress being made toward clean energy goals and the equitable distribution of benefits and burdens to all customers as established by the CETA.

In June 2022, our CEIP was approved by the Washington Utility and Transportation Commission (UTC).

Some highlights of our approved plan include:

- Beginning in 2022, serve 40% of Washington retail customer demand with renewable (or zero carbon) energy, then the target increases to 62.5% by the end of 2025.
- Energy efficiency targets to reduce Washington retail customer load by approximately 2% over the next four years through incentives and programs to lower energy use without impacting the customer.
- A set of 14 CBIs to ensure the equitable distribution of energy and non-energy benefits and reduction of burden to all customers and Named Communities.
- A NCIF that will invest up to $5 million annually in projects, programs and initiatives that directly benefit customers residing in historically disadvantaged and vulnerable communities.

While the CEIP represented our objectives when filed, it is subject to change in the future as circumstances warrant including direct input from the UTC. We are required to file a CEIP every four years.

Emissions Performance Standard

Washington applies a GHG emissions performance standard to electric generation facilities used to serve retail loads, whether the facilities are located within Washington or elsewhere. The emissions performance standard prevents utilities from constructing or purchasing generation facilities or entering into power purchase agreements of five years or longer duration to purchase energy produced by plants that have emission levels higher than 925 pounds of GHG per MWh. The Washington State Department of Commerce reviews the standard every five years. The most recent review was completed in 2024 and a new rate of 875 pounds CO_2e per MWh will be adopted in October 2024.

Clean Air Act (CAA)

The CAA creates numerous requirements for our thermal generating plants. Colstrip, Kettle Falls, Coyote Springs 2, and Rathdrum CT all require CAA Title V operating permits. Boulder Park, Northeast CT and other operations require minor source permits or simple source registration permits. We have secured these permits and certify our compliance with Title V permits on an annual basis. These requirements can change over time as the CAA or applicable implementing regulations are amended and new permits are issued. Avista actively monitors legislative, regulatory and other program developments of the CAA that may impact our facilities.

Coal Ash Management/Disposal

In 2015, the EPA issued a final rule regarding coal combustion residuals (CCRs), also termed coal combustion byproducts or coal ash. Colstrip produces CCRs. The CCR rule has been the subject of ongoing litigation. In August 2018, U.S. Court of Appeals for the D.C. Circuit struck down provisions of the rule. In December 2019, a proposed revision to the rule was published in the Federal Register to address the D.C. Circuit's decision. The rule includes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act, the nation's primary law for regulating solid waste. The Colstrip owners developed a multi-year compliance plan to address the CCR requirements along with existing state obligations expressed through the 2012 Administrative Order on Consent (AOC) with the Montana Department of Environmental Quality (MDEQ). These requirements continue despite the 2018 federal court ruling.

The AOC requires MDEQ to review Remedy and Closure plans for all parts of the Colstrip plant through an ongoing public process. The AOC also requires the Colstrip owners to provide financial assurance, primarily in the form of surety bonds, to secure each owner’s pro rata share of various anticipated closure and remediation obligations. Avista is responsible for our share of two major areas: the Plant Site Area and the Effluent Holding Pond Area. Generally, the plans include the removal of boron, chloride, and sulfate from the groundwater, closure of the existing ash storage ponds, and installation of a new water treatment system to convert the facility to a dry ash storage. Our share of the posted surety bonds is $16.8 million. This amount is updated annually, with expected obligations decreasing over time as remediation activities are completed.

Washington Climate Commitment Act

The CCA, and its implementing regulations, established a cap-and-invest program to reduce GHG emissions and achieve the GHG limits previously established under Washington State law. The final rules implement a cap on emissions, provide mechanisms for the sale and tracking of tradable emissions allowances and establish additional compliance and accountability measures. The state issues allowances necessary to serve our Washington retail electric load; off-system wholesale sales may result in additional obligation costs. The CCA also directly impacts on our Idaho electric operations as it applies to wholesale power sales delivered to Washington or power generated in Washington for Idaho customers. In May 2023, a "lesser-than" model was approved for use in calculating the allowances needed for compliance allowing nonemitting generation to offset wholesale sales, therefore reducing the number of allowances required. Annually, the model and its resulting calculations must be certified by an independent third party and submitted to the Washington Department of Ecology (Ecology) for approval. If the independent third party or Ecology disagrees with the approach or any of the calculations, it could result in a change to the number of allowances needed for compliance and could result in changes to anticipated costs for our electric operations. For Washington electric, we are allowed to defer any incremental costs associated with the CCA in accordance with our regulatory accounting order; however, in Idaho we are not allowed to pass any costs associated CCA compliance to Idaho customers at this time.

EPA Regulations for Power Plants

On April 25, 2024, the EPA released a package of final regulations addressed to electric generation facilities. These include:

- Greenhouse gas regulations for new natural gas-based turbines and existing coal-based units, pursuant to section 111 of the CAA. This rule finalizes (a) the repeal of the Affordable Clean Energy rule; (b) guidelines for GHG emissions from existing fossil fuel-fired steam generating electric generating units; and (c) revisions to existing performance standards for new, reconstructed or heavily modified fossil fuel-fired stationary combustion turbine electric generating units.

- Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (ELG Rule). The ELG Rule applies to wastewater discharges from coal-based generating units and establishes pollution control requirements. The Rule builds upon the 2015 and 2020 ELG Rules. It includes a subcategory of requirements for coal plants retiring or repowering by the end of 2028 and provides additional compliance pathways for coal plants retiring by the end of 2034.

- Updated Mercury and Air Tox Standards, pursuant to section 112 of the Clean Air Act (MATS Rule). The MATS Rule sets emissions limits for filterable particulate matter for coal-based generating units. The Rule reduces those limits from the standards that were originally set in 2012.

- Disposal of Coal Combustion Residuals from Electric Utilities – Legacy CCR Surface Impoundments (CCR Rule). The CCR Rule builds on 2015 regulations, the rule applies to active power plants disposing coal combustion residuals in surface impoundments or landfills, by regulating inactive surface impoundments at inactive power plants and CCR management units at active and inactive power plants.

Avista is in the process of analyzing each of these rules to assess the impact, if any, it may have on existing generating units, including Colstrip and/or our natural gas-fired generating units. At this time, there are no indication the implementation of these rules would impact our agreement to transfer our Colstrip ownership to NorthWestern on December 31, 2025. The owners (including the operator) have assessed the CCR Rule and believe there will not be a material change to the asset retirement obligation for Colstrip.

Washington State Building Codes

In April 2022, the Washington State Building Code Council (SBCC) approved a revised energy code requiring most new commercial buildings and large multifamily buildings to install all-electric space heating. An amendment to the code allows natural gas to supplement electric heat pumps. In addition, in November 2022, the SBCC approved new building and energy codes for residential housing, requiring new residential buildings in Washington to use electricity as the primary heat source.

Both the commercial and residential building and energy codes were the subject of legal challenges in both Washington State Superior Court (the State Action) and in the Federal District Court for the Eastern District of Washington (the Federal Action). In the Federal Action, (Avista was a party), the plaintiffs challenged the amendments on the grounds that they were preempted by the federal Energy Policy and Conservation Act (EPCA), citing the Ninth Circuit's decision in California Restaurant Association v. Berkeley (the Berkeley Decision), which involved similar restrictions on the use of natural gas in new construction in Berkeley, California.

In May 2023, the SBCC voted to delay the effective date of the code amendments and commenced an emergency rulemaking process to evaluate additional amendments to the code considering the Berkeley Decision. As a result of this action, in July 2023, the Federal District Court declined to issue a preliminary injunction to prevent the amendments from taking effect. The plaintiffs in the Federal Action subsequently dismissed the action, without prejudice to their ability to refile after the SBCC rulemaking process is complete.

The SBCC has since voted to approve revised residential and commercial energy regulations to continue to require new residential and commercial buildings in Washington to use electricity as the primary heat source. Considering this action, the plaintiffs in the State Action amended their complaint to challenge the new regulations. The State Action remains pending.

In May 2024, Avista, along with Cascade Natural Gas Corporation, Northwest Natural Gas Company, and a coalition of homebuilders, heating unit dealers and other parties, filed a lawsuit challenging the approved building codes on the grounds that they are preempted by EPCA. The lawsuit was filed in the United States District Court for the Western District of Washington. This lawsuit remains pending.

On November 5th, 2024 Initiative 2066 was passed by voters, this measure would repeal or prohibit certain laws and regulations that discourage natural gas use, and/or promote electrification, and require certain utilities and local governments to provide natural gas to eligible customers. Given this initiative was passed after the IRP was prepared its impact is not included in this plan. Avista believes the impacts is a minimal change in the load forecast down as customers may decide to select natural gas during new construction.

Particulate Matter (PM)

Particulate Matter (PM) is the term used for a mixture of solid particles and liquid droplets found in the air. Some particles, such as dust, dirt, soot, or smoke, are large or dark enough to see with the naked eye. Others are so small they are only detectable with an electron microscope. Particle pollution includes:

- **PM_{10}:** inhalable particles, with diameters that are generally 10 micrometers and smaller; and
- **$PM_{2.5}$:** fine inhalable particles, with diameters generally 2.5 micrometers and smaller.

There are different standards for PM_{10} and $PM_{2.5}$. Limiting the maximum amount of PM to be present in outdoor air protects human health and the environment. The CAA requires EPA to set National Ambient Air Quality Standards (NAAQS) for PM, as one of the six criteria pollutants considered harmful to public health and the environment. The law also requires periodic EPA reviews of the standards to ensure that they provide adequate health and environmental protection and to update standards as necessary.

Avista owns and/or has operational control of the following generating facilities that produce PM: Boulder Park, Colstrip, Coyote Springs 2, Kettle Falls CT, Lancaster, Northeast and Rathdrum. Table 4.10 below shows each of the plants, status of the surrounding area with NAAQS for $PM_{2.5}$ and PM_{10}, operating permit, and PM pollution controls.

Appropriate agencies issue air quality operating permits. These operating permits require annual compliance certifications and renewal every five years to incorporate any new standards including any updated NAAQS status.

Table 4.10: Avista Owned and Controlled PM Emissions

Thermal Generating Station	$PM_{2.5}$ NAAQS Status	PM_{10} NAAQS Status	Air Operating Permit	PM Pollution Controls
Boulder Park	Attainment	Maintenance	Minor Source	Pipeline Natural Gas
Colstrip	Attainment	Non-Attainment	Major Source Title V OP	Fluidized Bed Wet Scrubber
Coyote Springs 2	Attainment	Attainment	Major Source Title V OP	Pipeline Natural Gas, Air filters
Kettle Falls	Attainment	Attainment	Major Source Title V OP	Multi-clone collector, Electrostatic Precipitator
Lancaster	Attainment	Attainment	Major Source Title V OP	Pipeline Natural Gas, Air filters
Northeast	Attainment	Maintenance	Minor Source	Pipeline Natural Gas, Air filters
Rathdrum	Attainment	Attainment	Major Source Title V OP	Pipeline Natural Gas, Air filters

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5. Resource Need Assessment

Avista plans its resource portfolio to meet multiple long-term objectives including serving peak loads, providing operational and planning reserves, meeting monthly energy needs, and meeting Washington's clean energy goals, as well as other applicable policies. This chapter presents the long-term load and resource position through 2045 to determine Avista's projected resource requirements. Notwithstanding future resource changes, there are several fundamental changes to Avista's Loads & Resources (L&R) since the 2023 IRP, including the following developments:

- A 30-year Power Purchase Agreement (PPA) (97.5 MW) with Clearwater Wind online in September 2024.
- Stimson Lumber co-gen (5.8 MW), a Qualifying Facility (QF) located in Plummer, Idaho closed in 2024.
- A new Washington industrial customer increased load by 34.3 aMW beginning in August 2024.
- Three Columbia Basin Hydro projects begin in 2025 totaling 105.8 MW of capacity.
- A 5% slice (87.5 MW) of the Chelan PUD PPA comes online in 2026.

Section Highlights

- Avista's Planning Reserve Margin (PRM) requirement is 24% in the winter and 16% in the summer.
- Avista's first long-term capacity and energy resource deficiency begins in January 2030.
- The Western Resource Adequacy Program's (WRAP) qualifying capacity credits (QCC) are used for Avista's resource capacity position.
- Under normal weather conditions, Avista has sufficient clean energy resources to meet its projected Washington's Clean Energy Transformation Act (CETA) targets through 2034.

Capacity Requirements

Avista must plan for its resource portfolio to have the capacity to reliably meet system demand at any given time. Significant uncertainty is inherent in this exercise due to situations when load exceeds the forecast and/or resource output falls below expectations due to adverse weather, forced outages, poor water conditions, variability in wind/ solar output, or other unplanned events. Under the PRM requirements, utilities are obligated to carry more generating capacity to address uncertainty and meet forecasted peak demand.

On average, reserve margins increase customer rates as compared to resource portfolios without reserve margins due to the extra cost of carrying rarely used generating capacity.

Traditionally, reserve resources have the physical capability to generate electricity, but most have higher operating costs, thus limiting revenue and dispatch. A balance must be achieved between carrying enough capacity to address potential events and the cost of carrying the unused capacity.

Prior to the development of the WRAP, Northwest electricity providers were operating without an industry-standard reserve margin level, as it is difficult to enforce standardization across systems with varying resource mixes, system sizes, and transmission interconnections. Although the North American Electric Reliability Council (NERC) defines reserve margins at 15% for predominately thermal systems and 10% for predominately hydroelectric systems, it does not provide an estimate for energy-limited hydroelectric systems such as Avista's. The WRAP is still in a non-binding trial phase, so Avista cannot reliably count on other utilities meeting their reserve margin requirements.

In IRPs prior to 2023, a PRM of 16% in the winter months and 7% in the summer months plus operating reserves and regulation requirements resulted in a total reserve margin of 24.6% in the winter months and 15.6% in the summer months. Those margins were derived from a study of resources and loads using 1,000 simulations of varying weather for loads, thermal generation capability, forced outage or derates on generation, water conditions for hydroelectric plants, and wind generation. The reserve margins ensure Avista's system can meet all expected load in 95% of the simulations, or a 5% Loss of Load Probability (LOLP).

To align its PRM methodology with the WRAP, the 2023 IRP used a 22% PRM in the winter and a 13% PRM in the summer along with reducing resource capabilities to account for outages and other derates by using the WRAP's QCC methodology. Avista did not conduct any additional reliability analysis to validate the PRM would result in a 5% LOLP due to the fact the region would be resource sufficient if all utilities met their WRAP targets.

For the 2025 IRP, Avista conducted a reliability analysis to ensure the planning margin creates an adequate system. Avista developed a LOLP study using Avista Resource Adequacy Model (ARAM)[50] to determine the ability of its system to meet load and reserves each hour when subjected to 1,000 iterations with differing combinations of water years, load, temperature, maintenance, forced outages, and VER production. The model optimizes storage hydro projects within parameters of each project's FERC license. This allows a realistic representation of the hydro system's capability to meet load. This study utilized the current expected portfolio of load and resources in 2030 along with the ability to purchase up to 330 MW from the market. Avista conducted multiple studies adding capacity resources (i.e., natural gas turbine) to achieve a 5% LOLP (see Table 5.1). The result of this analysis indicates a need of 50 MW by 2030 and infers a

[50] ARAM is an Excel-based model using VBA code and Excel's linear optimization add-in What's Best!

24% planning margin in the winter months to be resource adequate. The summer months reflect minimal resource adequacy shortfalls due to existing resource flexibility and the addition of the Columbia Basin Hydro projects. To ensure enough resource adequacy, Avista is using a summer planning margin based on its single largest contingency resource as a percentage of load. The largest single contingency is Coyote Springs 2 at 16% of summer peak load. The new study identifies a slightly larger PRM than the 2023 IRP value for winter months. Much of this change is due to accounting for reserves Avista must hold to participate in the Western Energy Imbalance Market (EIM) due to its renewable energy fleet. In addition to LOLP there are 5 other metrics used to evaluate reliability. The following defines how each is calculated[51]:

- **LOLP** – *Loss of Load Probability*: Calculated by counting the number of iterations where there is unserved load or unmet reserves and dividing by the total number of iterations. This metric can be used to determine the probability or likelihood of events due to insufficient capacity.
- **LOLE** – *Loss of Load Expectation:* Calculated by counting the days where there is unserved load or unmet reserves and dividing by the total number of iterations. The majority of entities conducting LOLE studies primarily use it to establish resource adequacy criteria. Industry standard is 0.1 days per year LOLE.
- **LOLEV** – *Loss of Load Expected Events*: Calculated by counting the number of consecutive blocks of unserved load or unmet reserves and dividing by the number of iterations. The LOLEV metric is useful in systems that are concerned with the frequency of events, regardless of duration or magnitude.
- **LOLH** – *Loss of Load Hours:* Calculated by summing the number of hours with unserved load or unmet reserves and dividing by the total number of iterations. The LOLH metric is computed by a large number of entities in North America. However, only one entity uses this metric as a reliability criterion, with their criterion set a 2.4 hours per year.
- **EUE** – *Expected Unserved Energy:* Calculated by summing all the unserved MWhs over the study period and dividing by the number of iterations. Two versions are presented, one with unmet reserves and one without. EUE is useful in estimating the size of the loss of load events so planners can estimate the cost and impact of the loss of load events.

[51] Reliability metric information from the NERC, Probabilistic Adequacy and Measures Report, July 2018

Table 5.1: 2030 Resource Adequacy Study

Metric	2030 without New Resources	2030 with 30 MW New Resources	2030 with 50 MW New Resources
LOLP	6.9%	5.5%	5.1%
LOLE	0.23	0.16	0.10
LOLH	2.59	1.92	1.56
LOLEV	0.50	0.40	0.33
EUE (with reserves)	488	338	268
EUE (without reserves)	468	325	256

Western Resource Adequacy Program

In response to the growing penetration of renewable variable energy resources and retirements of thermal generation in the West, the Western Power Pool (WPP) initiated an effort in 2019 to understand capacity issues in the region and identify potential solutions. The product of these efforts resulted in the WRAP. The WRAP's purpose is to leverage the diversity of loads and generation throughout the WECC so individual entities do not need to carry the full burden of supplying adequate capacity for their systems. The FERC filing to establish a tariff for the WRAP describes the program as follows:

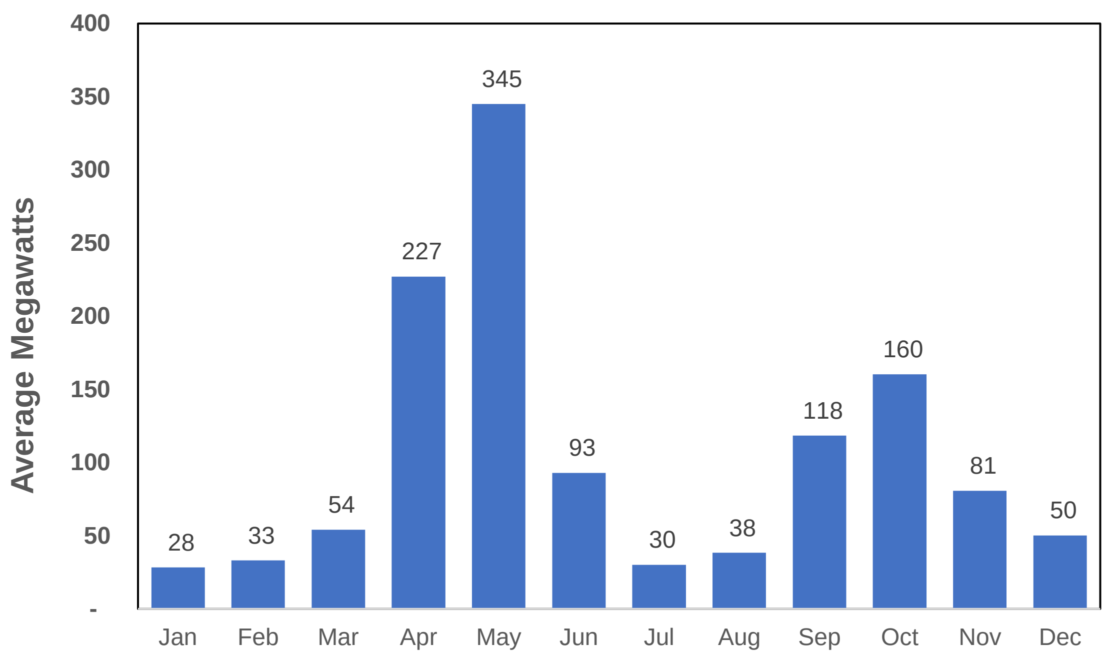
> *The WRAP leverages the existing bilateral market structure in the West to develop a resource adequacy construct with two distinct aspects: (1) a Forward Showing Program through which WPP forecasts Participants' peak load and establishes a Planning Reserve Margin ("PRM") based on a probabilistic analysis to satisfy a loss of load expectation ("LOLE") of not more than one event-day in ten years, and Participants demonstrate in advance that they have sufficient qualified capacity resources (and supporting transmission) to serve their peak load and share of the PRM; and (2) a real-time Operations Program through which Participants with excess capacity, based on near-term conditions, are requested to "holdback" capacity during critical periods for potential use by Participants who lack sufficient resources to serve their load in real-time.*

The WRAP is a resource adequacy planning and compliance framework where program participants voluntarily join. However, once committed, utilities are obligated to comply with requirements or be fined for non-compliance. To demonstrate compliance with the WRAP's Forward Showing Program (FSP), a participant must demonstrate its QCCs for resources and contracts are equal to or greater than peak demand, plus the assigned monthly PRM and less demand response programs. Load, hydro and renewable output, thermal resource capacity, forced outage data, and planned outage schedules are provided to the program operator who then provides QCC values for specific resources and an assigned peak load. Metrics for the winter and summer FSP for 2024 have been established and Avista has adequate resources to meet the requirement. The WRAP is continually updating its business practices to reflect best practices and updated data from historical operations.

Maintenance Planning

Avista generating units require periodic maintenance over the planning horizon. The challenge is forecasting when and what units will be unavailable due to future maintenance needs. Avista includes an adjustment to its peak planning forecast to account for unit maintenance using a combination of historical outages and a forecast of routine maintenance schedules. Avista's forecast shown in Figure 5.1 is a total of the maintenance from all plants on average. This amount is in additional adjustment above the PRM Avista includes when calculating its capacity position. Most maintenance occurs in the spring and fall months when loads are lower, while hydro maintenance is at higher levels in the spring allowing thermal units to go on maintenance due to extra generation supply.

Figure 5.1: Maintenance Adjustment for Capacity Planning



Avista's Capacity Need Assessment

Based on Avista's analysis of resource adequacy, Avista is temporarily short capacity in 2026 until a sale contract expires. After this contact expires, Avista is in a near balanced position until 2030. In 2030, between load growth, retirement of the Northeast CT, and expiration of a long-term PPA the utility will be deficient on a permanent basis until new resources are acquired. Figure 5.2 illustrates the winter capacity need by comparing the controlled resources in the blue bars compared to the peak load and PRM in the black line. Avista's summer position is similar to winter as the first permanent resource deficit also begins in 2030 and is shown in Figure 5.3.

Figure 5.2: Winter One-Hour Peak Capacity Load and Resources Balance

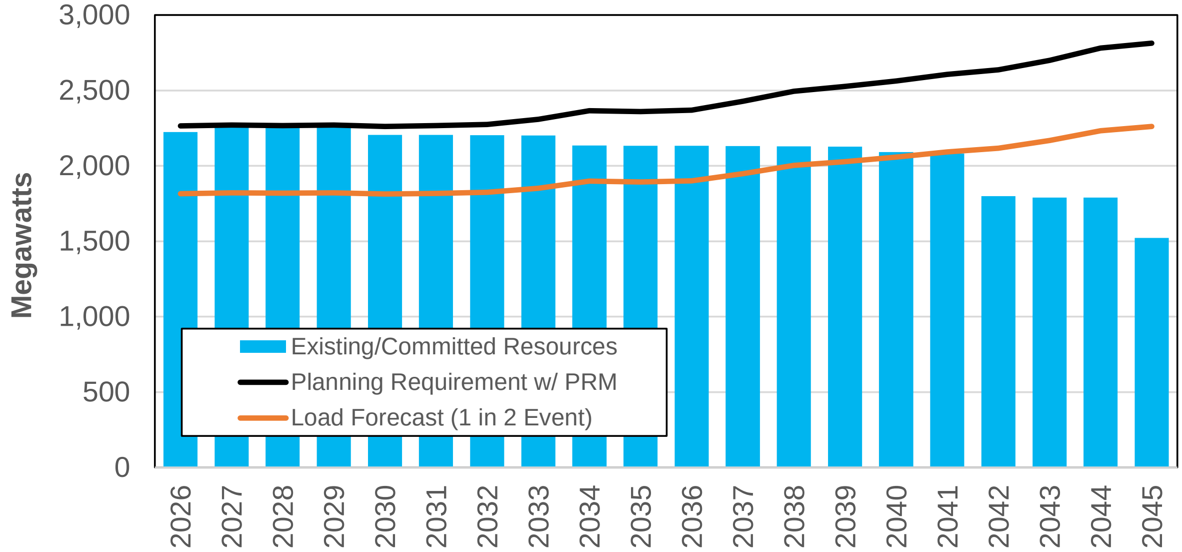
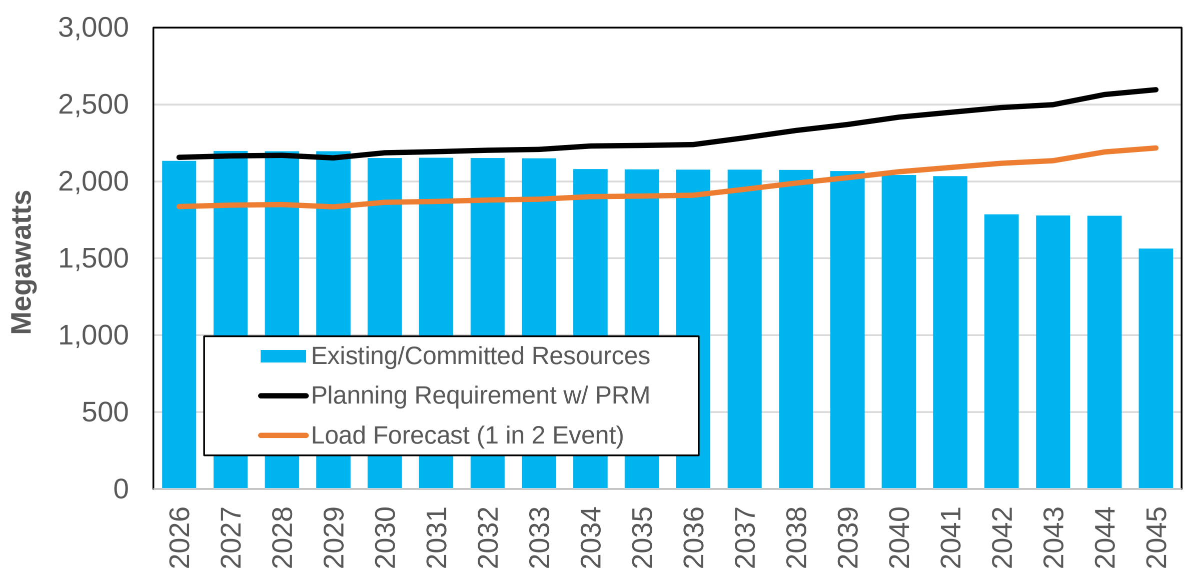


Figure 5.3: Summer One-Hour Peak Capacity Load and Resources Balance



Energy Requirements

In contrast to peak planning, energy planning determines the need based on customer demand with a time duration element. Avista evaluates energy planning on a monthly target basis for meeting customer demand, renewable targets, and evaluating generation risks. In the transition to renewable energy resources with differing energy delivery time periods, Avista is now using monthly energy requirements. This ensures Avista does not acquire too much energy in certain periods such as spring and not enough in higher expected load months such as August or January. This monthly planning creates significant generation length in spring and fall months as renewable resources typically do not only supply energy in the months needed.

The monthly energy analysis requires additional steps beyond capacity planning to account for what may happen to a resource's operations. Evaluation of monthly generation is specific to the resource in question, e.g., the factors impacting hydro generation are different than the factors impacting thermal generation. This section compares monthly generation and monthly demand to determine deficit and surplus conditions for the 2026 to 2045 period. A discussion of monthly demand is provided in Chapter 3. Table 5.2 details how monthly generation for each resource type is evaluated.

Table 5.2: Monthly Energy Evaluation Methodologies

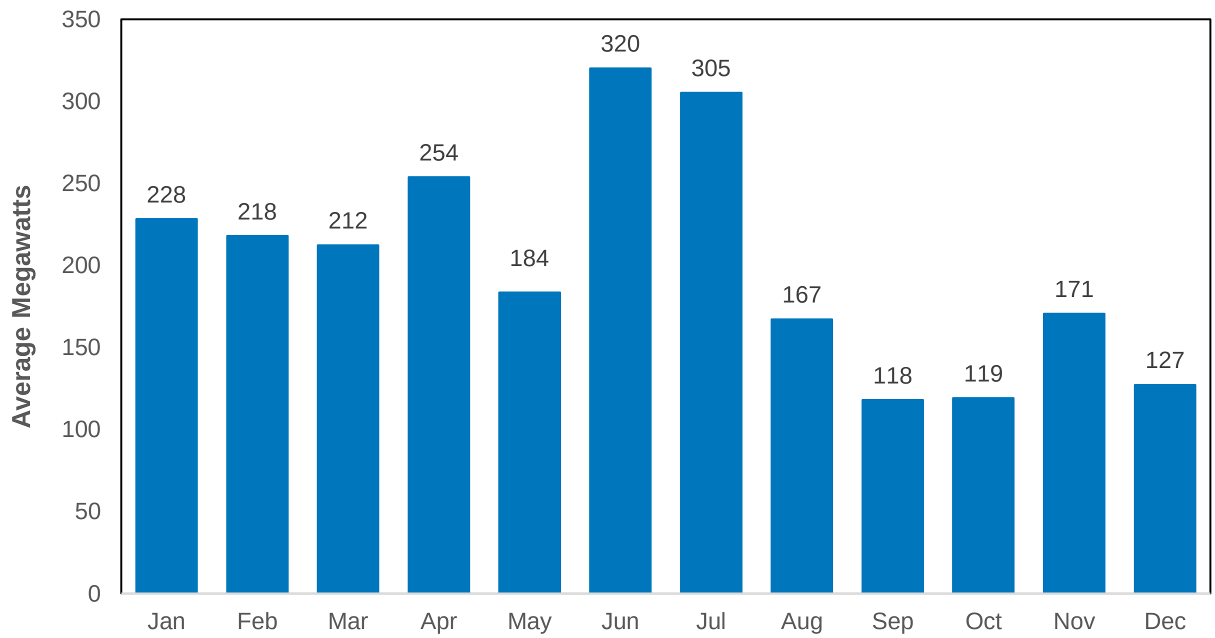
Resource Type	Evaluation Methodology
Biomass	Unit capacity reduced by a percentage according to planned and forced outage rates.
Natural Gas Combined Cycle	Unit capacity adjusted for monthly ambient average temperature and reduced by a percentage according to planned and forced outage rates and any runtime limitations imposed by operating permits.
Natural Gas Peaker	Unit capacity reduced by a percentage according to planned and forced outage rates and any runtime limitations imposed by operating permits.
Wind	Five year monthly average output if available, or average output estimates provided by facility operator.
Solar	Five year monthly average output if available, or average output estimates provided by facility operator.
Hydro	Monthly median generation of the previous 30 years. Future years include both historical and forecasted monthly generation.

Energy Risk/Contingency Evaluation

In addition, hydro generation and load both include the predicted impact of forecasted temperature changes and risk evaluation includes variability in all renewables rather than just hydro. Energy planning is based on average conditions. The load forecast utilizes 20-year average weather conditions, while the hydro generation estimates are based on the median over a 30-year period. There is a risk the load can be larger and/or hydro generation can be lower than forecasted. Additionally, in the last decade, Avista has added wind and solar generation to its portfolio – both having variable output period-to-period. Avista adds a contingency adjustment to the load and resource balance evaluation to address this risk.

Avista develops a monthly estimate of load and generation for each hydro, wind, and solar facility for weather conditions for each month between 1948 and 2019 for the contingency adjustment. Total generation is then subtracted from load for each month creating a monthly energy position of the at-risk components of the portfolio. A distribution of the variability is created with this historically based data set, and Avista uses the 95th percentile of the monthly values as compared to the expected position. The result represents the energy necessary to meet the risk of above average loads occurring during periods of low hydro, wind, and solar production. The result of this analysis is shown in Figure 5.4. These energy quantities are added to the load forecast to account for the variability.

Figure 5.4: Energy Contingency Assumption



Net Energy Position

Avista's net energy position is determined by summing all generation rights from Avista's facilities and PPAs and subtracting obligations including forecasted monthly load, contracted sales, and accounting for the energy contingency. Table 5.3 presents net monthly energy positions for selected years.

Table 5.3: Net Energy Position

Month	2030	2035	2040	2045
January	-26	-69	-168	-866
February	22	46	-13	-733
March	170	184	81	-578
April	345	328	216	-310
May	706	692	581	101
June	518	501	355	-143
July	173	142	-11	-672
August	74	41	-96	-725
September	198	191	83	-533
October	170	164	55	-565
November	59	27	-85	-744
December	16	-2	-147	-836

Forecasted Temperature & Precipitation Analysis

The 2023 IRP first included future climate forecasts for estimating load and hydro generation and the 2025 IRP uses the same forecasts. The forecast is based on the climate analysis developed for the Columbia River Basin by the River Management Joint Operating Committee (RMJOC) comprised of the Bonneville Power Administration (BPA), United States Army Corps of Engineers, and United States Bureau of Reclamation. The RMJOC, in conjunction with the University of Washington and Oregon State University, completed two studies (2018 and 2020) for the 2020-2100 study period utilizing downscaled global climate models (GCMs), hydrology and reservoir operation models to predict monthly river flows for locations throughout the Columbia River Basin, including all of Avista's hydroelectric facility locations. The RMJOC has not conducted any new analysis, nor has any other organization conducted similar analysis to replace the RMJOC dataset. Therefore the 2023 IRP dataset is being used in the 2025 IRP.

There is significant uncertainty in projecting future temperatures and precipitation and the subsequent impact on streamflow and reservoir operations. The RMJOC used an ensemble approach to capture a range of potential outcomes. The approach used unique combinations of two representative concentration pathways (RCPs), ten GCMs, three downscaling techniques and four hydrology models. In total there were 172 unique model combinations resulting in 172 streamflow datasets for each location. The streamflow data was then used in reservoir operation models generating monthly flows under current operating parameters for each of the Columbia Basin hydroelectric facilities. Flow data allows for an estimate of generation at each of the facilities.

Given the sheer volume of data, a method to select a representative set from the 172 modeling combinations was needed. Fortunately, BPA conducted this exercise and selected a subset of modeling combinations representing a sufficient cross section of outcomes to calculate expected generation. The subset represents 19 modeling combinations for both RCP 4.5 and RCP 8.5. RCPs represent different greenhouse gas (GHG) emission scenarios varying from no future GHG reductions to significant GHG reductions. The Intergovernmental Panel on Climate Change (IPCC) describes the following scenarios:

- RCP 2.6 – stringent GHG mitigation scenario
- RCP 4.5 & RCP 6.0 – intermediate GHG scenarios
- RCP 8.5 – very high GHG scenarios.

Table 5.4 provides a comparison of the temperature increases projected under the various scenarios.

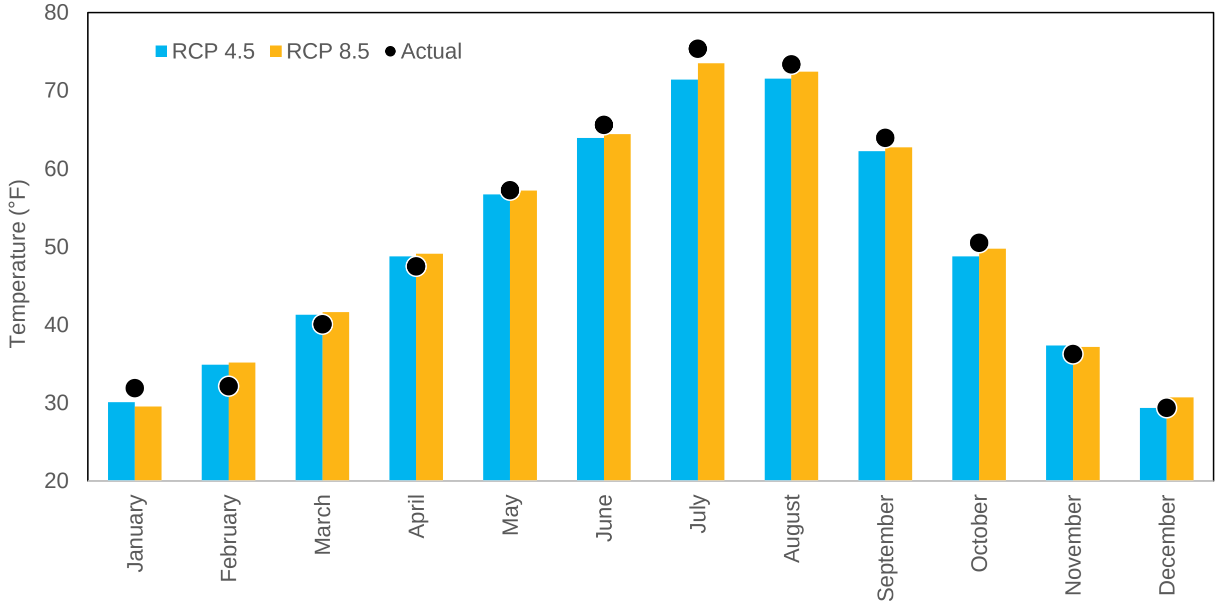
Table 5.4: Comparison of Temperature Increases by RCP

	Scenario	2046-2065		2081-2100	
		Mean	Likely range	Mean	Likely range
Global Mean Surface Temperature Change (°C)	RCP 2.6	1.0	0.4 to 1.6	1.0	0.3 to 1.7
	RCP 4.5	**1.4**	**0.9 to 2.0**	**1.8**	**1.1 to 2.6**
	RCP 6.0	**1.3**	**0.8 to 1.8**	**2.2**	**1.4 to 3.1**
	RCP 8.5	2.0	1.4 to 2.6	3.7	2.6 to 4.8

The RCP 4.5 and RCP 6.0 scenarios are similar during the current IRP planning horizon. Avista selected modeling results based on the RCP 4.5 for winter months and RCP 8.5 for summer months for load forecasting and RCP 4.5 for hydro forecasting. Avista chose this approach given:

- RCP 8.5 is at the high end of potential future GHG emissions,
- there are significant worldwide efforts to mitigate GHG emissions,
- the intermediate scenarios are similar during the IRP planning horizon,
- using RCP 8.5 temperatures for planning protects against higher summer temperatures,
- during time periods where both modeled and actual values are available, the RCP 4.5 and 8.5 have overestimated winter temperatures on average (except for January) but have underestimated summer temperatures for the Spokane region as shown in Figure 5.5.

Figure 5.5: Monthly Average Temperature RCP 8.5, RCP 4.5, and Actual 2020-24



Hydro Forecasting

Utilizing a regression modeling relating flow to generation, Avista converted each of the 19 BPA-selected monthly river flow modeling combinations for Avista facilities. The median of the 19 modeling combinations was selected to represent generation at each facility for each specific month and year.

Avista has contracts to receive a specified portion of generation from five facilities on the Columbia River – Wells, Rock Island, Rocky Reach, Wanapum, and Priest Rapids – these are owned and operated by Douglas PUD, Chelan PUD, and Grant PUD. BPA analyzed generation at each of these facilities for each of the RCP 4.5 scenarios. As with the Avista facilities, the median of the 19 modeling combinations was selected to represent generation at each facility for each month and year over the planning horizon.

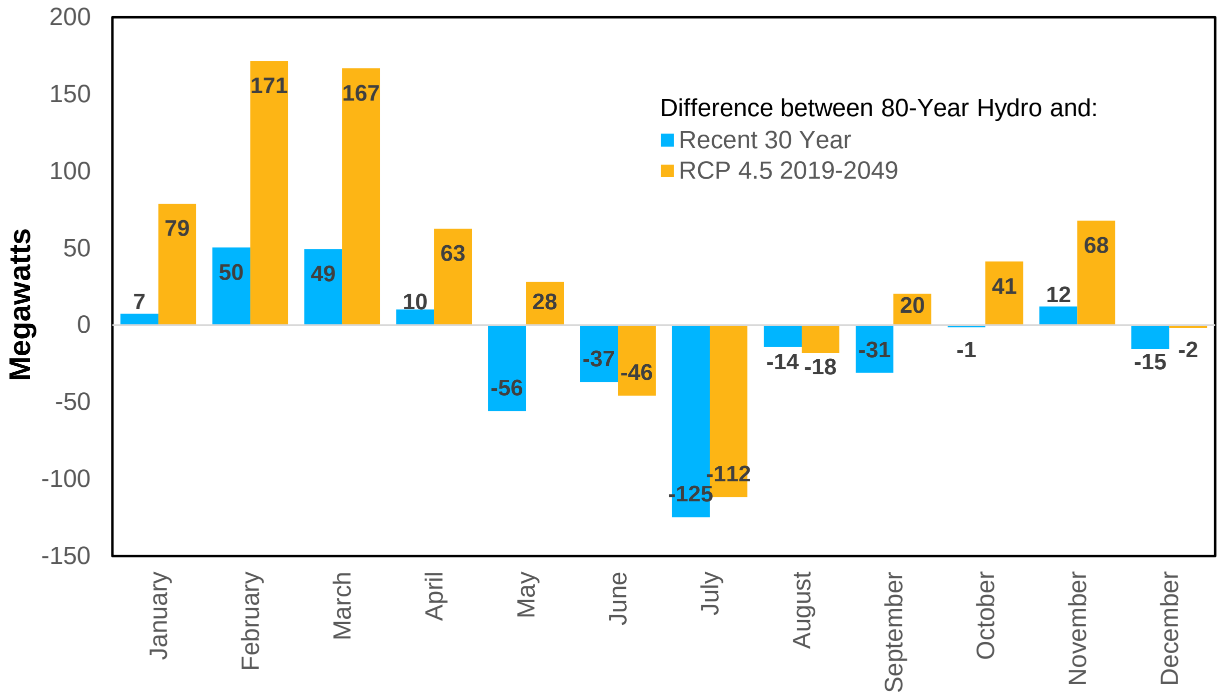
Prior IRPs used monthly hydro generation by estimating generation occurring under current operating parameters for each water year from 1929 to 2008 (80-year hydro record) and taking the median value for each month for each facility. In this analysis, Avista changed the methodology to use the median monthly value of the previous 30 years, e.g., 2022 estimated generation is the median of generation values from 1992-2021. Future years incorporate a mix of historical generation data and forecasted generation data.

Table 5.5 and Figure 5.6 present the differences between the 80-year hydro record and the recent 30-year record resulting from the RCP 4.5 analysis. Annual hydro generation is similar between the 80-year hydro record and recent 30-year record, as it is projected warming temperatures will increase annual hydro generation. On a monthly basis there is an increase in hydro generation during the winter and early spring months, and a decrease in the summer months. This is consistent with regional forecasts predicting an overall increase in annual precipitation with less snow fall and an earlier snowpack melt.

Table 5.5: Hydro Generation Forecast Comparison (aMW)

	80-Year Hydro (1929-2008)	Recent 30-Year (1992-2021)	RCP 4.5 (2019-2049)
Mean	598	595	645
Median	597	585	636
10th Percentile	424	437	447
90th Percentile	776	756	858
Standard Deviation	142	137	169

Figure 5.6: Comparison of Recent 30-Year, and RCP 4.5 Generation



In addition to impacting hydro generation, warming temperatures will also impact demand. Specifically, where the forecast assumes less heating required in the winter and more cooling required during the summer. To assess the load impacts, the temperature data sets used as the basis of the streamflow data sets were used in the load forecast and are described in Chapter 3.

Washington State Renewable Portfolio Standard

Washington's Energy Independence Act (EIA) promotes the development of regional renewable energy by requiring utilities with more than 25,000 customers to source 15% of their energy from qualified renewables by 2020. Utilities must seek to acquire all cost-effective energy efficiency. In 2011, Avista signed a 30-year PPA for Palouse Wind to help meet the EIA goal. In 2012, an EIA amendment allowed Avista's Kettle Falls biomass generation to qualify for the goals beginning in 2016. More recently, Avista acquired the Rattlesnake Flat Wind, Adams Nielson Solar,[52] and Clearwater Wind III adding to qualified generation.

Table 5.6 shows the forecasted Renewable Energy Credits (RECs)[53] Avista needs to meet the EIA's renewable requirements and the qualifying resources within Avista's current generation portfolio. This table does not reflect the EIA REC banking provision allowing a single year of retainment of RECs. Avista uses this banking flexibility as needed to manage variation in renewable generation.

Table 5.6: Washington State EIA Compliance Position Prior to REC Banking (aMW)

	2026	2028	2030
Two-Year Rolling Average WA Retail Sales Estimate	726.8	739.7	739.7
Renewable Goal	109.0	111.0	110.9
Incremental Hydro	18.0	18.0	18.0
Other Available RECs			
Palouse Wind with Apprentice Credits	46.0	46.0	46.0
Kettle Falls	36.1	36.1	46.8
Rattlesnake Flat with Apprentice Credits	60.6	60.6	60.6
Adams Neilson Solar	-	-	5.5
Boulder Community Solar	0.1	0.1	0.1
Rathdrum Solar	0.0002	0.0002	0.0002
Clearwater Wind	41.9	41.9	41.9
Excess Renewable Excess before rollover RECs	**93.7**	**91.7**	**108.0**

Washington State's Clean Energy Transformation Act

CETA requires Washington State electric utilities to serve 100% of Washington retail load with renewable and non-emitting electric generation by 2045. Beginning in 2030, at least 80% of generation must be from renewable and non-emitting electric generation and up

[52] Adams Nielson can be used for the EIA after the voluntary Solar Select program ends in 2028.
[53] These RECs are qualifying RECs within Avista's system. For state compliance purposes, Avista may transfer RECs from one state's allocation shares to another at market prices. Avista may also sell excess RECs to reduce customer rates.

to 20% can be met with alternative compliance options including alternative compliance payments, unbundled RECs, or investing in energy transformation projects. CETA requires the Washington Utilities & Transportation Commission (UTC) to adopt rules for implementation. In this IRP, the 20% alternative compliance component is assumed to decrease to zero in 5% increments by 2045.

A remaining unknown consideration for compliance with CETA relates to the UTC's determination of compliance with RCW 19.405.030(1)(a) defining "use" of clean energy. The UTC has an ongoing rulemaking proceeding[54] to determine the interpretation of "use" in CETA and recent submitted draft rules available for comment. While CETA rulemaking is still in development, Avista's 2021 Clean Energy Implementation Plan (CEIP) includes compliance targets approved by the UTC for 2022-2025. Avista's 2021 CEIP was conditionally approved in Order 01 of Docket UE-210628. The 2021 CEIP does not include a commitment or approved targets for the 2026-2029 or 2030-2044 periods. Between 2030 and 2044, all generation used to serve Washington electric retail load must be greenhouse gas neutral, while up to 20% can be met through alternative compliance options. Interim targets to meet the 2045 standard will be determined in a future CEIP after final "use" rules have been adopted. Table 5.7 presents the approved interim targets for 2022-2025 and preliminary targets through 2045.

Table 5.7: CETA Compliance Target Assumptions

Period	Compliance Target	Alternative Compliance
2022	**40.0%**	0%
2023	**47.5%**	0%
2024	**55.0%**	0%
2025	**62.5%**	0%
2026	66.0%	0%
2027	69.5%	0%
2028	73.0%	0%
2029	76.5%	0%
2030 – 2033	80.0%	20%
2034 – 2037	85.0%	15%
2038 – 2041	90.0%	10%
2041 – 2044	95.0%	5%
2045	100.0%	0%
Note: A commitment has been made in the CEIP for values in bold.		

Multijurisdictional utilities face unique challenges with CETA compliance as resource costs and benefits are allocated to each state using a ratio derived from load. The IRP proposes resource selections based on each state's policies, however, when resources

[54] Docket UE-210183.

are added to the system, the other state still receives its share of the costs and benefits. Until a new allocation methodology is approved by each Commission, Avista makes the following assumptions:

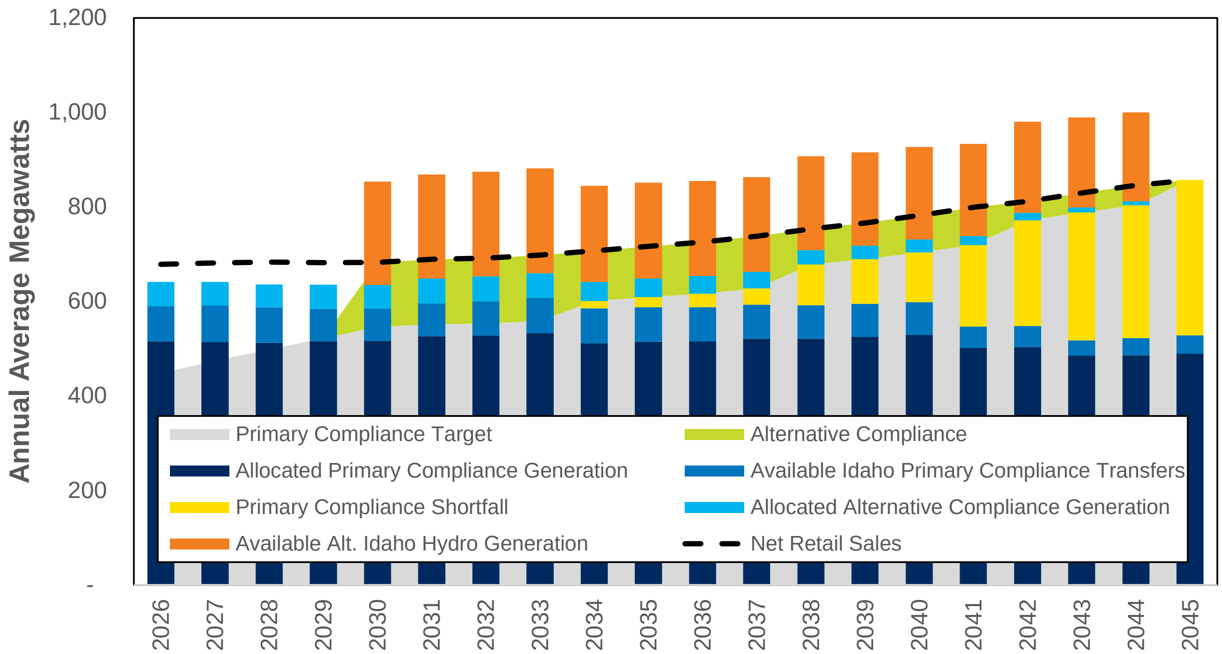
- Qualifying clean energy is determined by procurement and delivery of energy to Avista's system.
- The clean energy goal is applied to retail sales *less* in-state PURPA generation constructed prior to 2019 *plus* voluntary customer programs such as Solar Select.
- Voluntary customer REC programs, such as Avista's My Clean Energy™ program, do not qualify toward the CETA standard.
- Compliance generation includes:
- Washington's share of legacy hydro generation (defined the facility is operating or contracted with deliveries before 2022).
- All wind, solar, and biomass generation in Avista's portfolio. Nonpower attributes or RECs associated with Idaho's portion of generation, according to the established production transmission (PT) ratio, will be purchased by Washington at market rates <u>if</u> used for compliance in Washington.
- Newly acquired (post 2019) or contracted non-emitting generation including hydro, wind, solar, or biomass can be used for compliance using the same methodology as existing Avista-owned non-hydroelectric generation[55] when purchasing the nonpower attributes from Idaho to Washington.
- Avista is not planning to use Idaho's share of legacy hydroelectric to meet Washington's clean energy goals prior to 2030, however actual compliance may include them due to variability in clean resource availability (e.g., for a low water year). Avista may include these hydro resources toward alternative compliance if it is economic to acquire the renewable energy attributes.
- Avista uses total monthly generation to estimate if clean energy counts toward the compliance target or alternative compliance. If Washington's clean energy generation total is greater than its "net retail load," excess generation is applied toward alternative compliance. However, all generation below "net retail load" counts as compliant clean energy to meet the 4-year CEIP targets such as 80% by 2030.

A forecast based on a 30-year moving median of hydro conditions, average solar and wind generation, and the current load forecast is presented in Figure 5.7. The analysis demonstrates Avista has enough qualifying resources to meet primary compliance targets through 2033 using this methodology but will need additional energy for the 2034-2038 CEIP period. Depending on the outcome of the clean energy "use" rules, the shortfall

[55] Such as Palouse Wind and Kettle Falls with historical precedence of transferring between states for EIA compliance.

could change as well as actual production due to weather outside of average conditions. For alternative compliance, between generation exceeding retail load and legacy hydro energy from Idaho, Avista has enough qualifying energy to meet this requirement through 2044. (Alternative compliance is not required after 2045 by statute, but rather a goal of serving 100% of demand with clean energy). The light blue bar in Figure 5.7 represents the amount of energy transferable from Idaho for primary compliance. Avista's modeling selects this energy only if new generation is more expensive.

Figure 5.7: Washington State CETA Compliance Position



Reserves and Flexibility Assessment

Avista released a Request for Information (RFI) for a Variable Energy Resource (VER) integration study in February 2022. Energy Strategies was selected to develop a framework to quantify the incremental integration cost of a range of potential VER penetration levels as informed by Avista's 2023 IRP Preferred Resource Strategy (PRS) to serve Avista's projected load.

This VER integration study supports Avista's efforts toward carbon-neutrality goals and providing reliable, lowest cost energy. A prior VER integration study was performed in 2007 and updated in 2014, but changes regarding resource capital costs, Avista's current and projected resource mix, Avista's participation in the Western EIM, and state policies requiring greater VER penetration, all warranted an updated study.

Phase I

Integration cost is primarily driven by the need to hold higher levels of operating reserves caused by the variability and uncertainty of VER production. Energy Strategies developed data inputs for 12 VER scenarios for modeling in Avista's Decision Support System (ADSS) production cost model. These 12 production profiles were based on likely development locations informed from past generation proposals and utilized National Renewable Energy Laboratory's (NREL) Wind Integration National Dataset (WIND) and Solar Integration National Dataset (SIND) as well as the National Solar Radiation Database (NSRDB) to compile site-specific proxy production and forecast profiles for each VER site. Energy Strategies calculated reserve levels utilizing 2021 actual operations with confidence intervals via statistical analysis based on seven historical weather years. Energy Strategies also evaluated the impact of Western EIM on reserves and determined the diversity savings benefit to be approximately 50%. The results of their study are shown in Figure 5.8.

VER Integration Cost Estimates

Avista utilized its ADSS product cost model to study 12 VER scenarios (13 including the existing resource scenario) to calculate integration costs as well as high and low sensitivities. Energy Strategies' Phase 1 reserve amounts were adjusted for the diversity benefit and used as constraints in the ADSS model. The resulting integration costs $/kW-month and $/MWh for the scenarios and sensitivities are shown in Table 5.8.

Figure 5.8: Flexible Reserves Required by VER Future

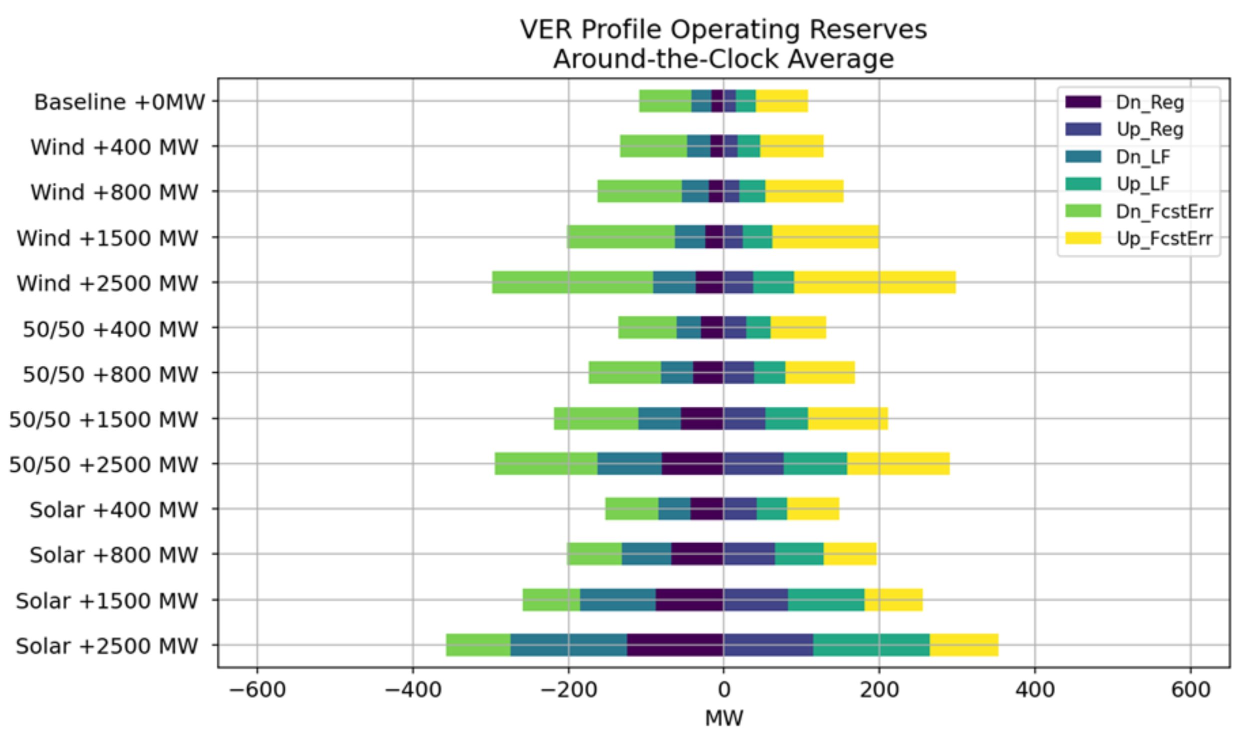


Table 5.8: VER Study Results

Scenario	Integration Cost ($/kW-month)			Integration Cost ($/MWh)		
	Base	High	Low	Base	High	Low
Existing Portfolio	0.19	0.40	0.15	0.54	1.12	0.44
50/50 + 400 MW	0.16	0.34	0.09	0.56	1.19	0.32
50/50 + 800 MW	0.19	0.39	0.11	0.69	1.43	0.40
50/50 + 1,500 MW	0.17	0.33	0.10	0.70	1.41	0.43
50/50 + 2,500 MW	0.22	0.39	0.20	0.98	1.74	0.90
Solar + 400 MW	0.12	0.26	0.07	0.40	0.85	0.23
Solar + 800 MW	0.12	0.25	0.07	0.43	0.90	0.25
Solar + 1,500 MW	0.11	0.23	0.07	0.43	0.87	0.27
Solar + 2,500 MW	0.21	0.33	0.22	0.84	1.33	0.90
Wind + 400 MW	0.22	0.48	0.13	0.89	1.90	0.50
Wind + 800 MW	0.27	0.56	0.16	1.21	2.50	0.70
Wind + 1,500 MW	0.25	0.48	0.19	1.25	2.44	0.94
Wind + 2,500 MW	0.85	1.21	0.79	4.92	7.05	4.56

Phase II

Energy Strategies validated the integration costs resulting from the ADSS modeling. In addition, a calculator for varying levels and combinations of VERs was created to aid in estimating integration costs for resource planning and selection. This work was completed by 2024.

Capacity Planning for Reserves and Flexibility

When Avista joined the Western EIM, it required the company to maintain flex ramp reserves prior to the operating hour. Flex ramp reserve amounts are based upon historical load, solar, and wind variations. As VERs are added to the system, if all other assumptions remain constant, Avista will need to increase the amount of flexible ramp resources it must carry. In addition to the flex ramp requirement, Avista must also carry operating reserves in the event of a generator outage. Other reserves the utility must maintain to handle generation is ramping hour-to-hour. Fortunately, for Avista, the hydro system provides much of its reserve capability along with its natural gas peaking fleet. When selecting the resource strategy, the model includes a requirement to carry enough reserves to meet the flexibility requirements using either existing resources or new resources. A summary of the flex ramp requirements assumed depending upon the new resources acquired are shown in Figure 5.8 as used in the integration cost estimate. For inclusion in the resource plan, Avista translated the finding from this study into an equation to calculate flexibility based on the amount of load and resources as follows:

Equation 5.1: Modeled Flex Ramp

Modeled Flex Ramp (MW) = 83.8 + Total Solar x 0.10 + Total Wind 0.12 + Load x 0.21

Natural Gas Pipeline Analysis

Avista transports fuel to its natural gas-fired generators using the Gas Transmission Northwest (GTN) pipeline owned by TC Energy (formally TransCanada). The pipeline runs between Alberta, Canada and the California/Oregon border at Malin, Oregon. Avista holds 60,592 dekatherms per day of capacity from Alberta to Stanfield, Oregon and controls another 26,388 dekatherms per day from Stanfield to Malin. Figure 5.9 below illustrates Avista's firm natural gas pipeline rights. This figure includes the theoretical capacity if the plants under Avista's control run at full capacity for the entire 24 hours in a day on the system. The maximum burn by Avista is 148,342 dekatherms per day based on the average of the top five historical natural gas burn days, as shown in Table 5.9.

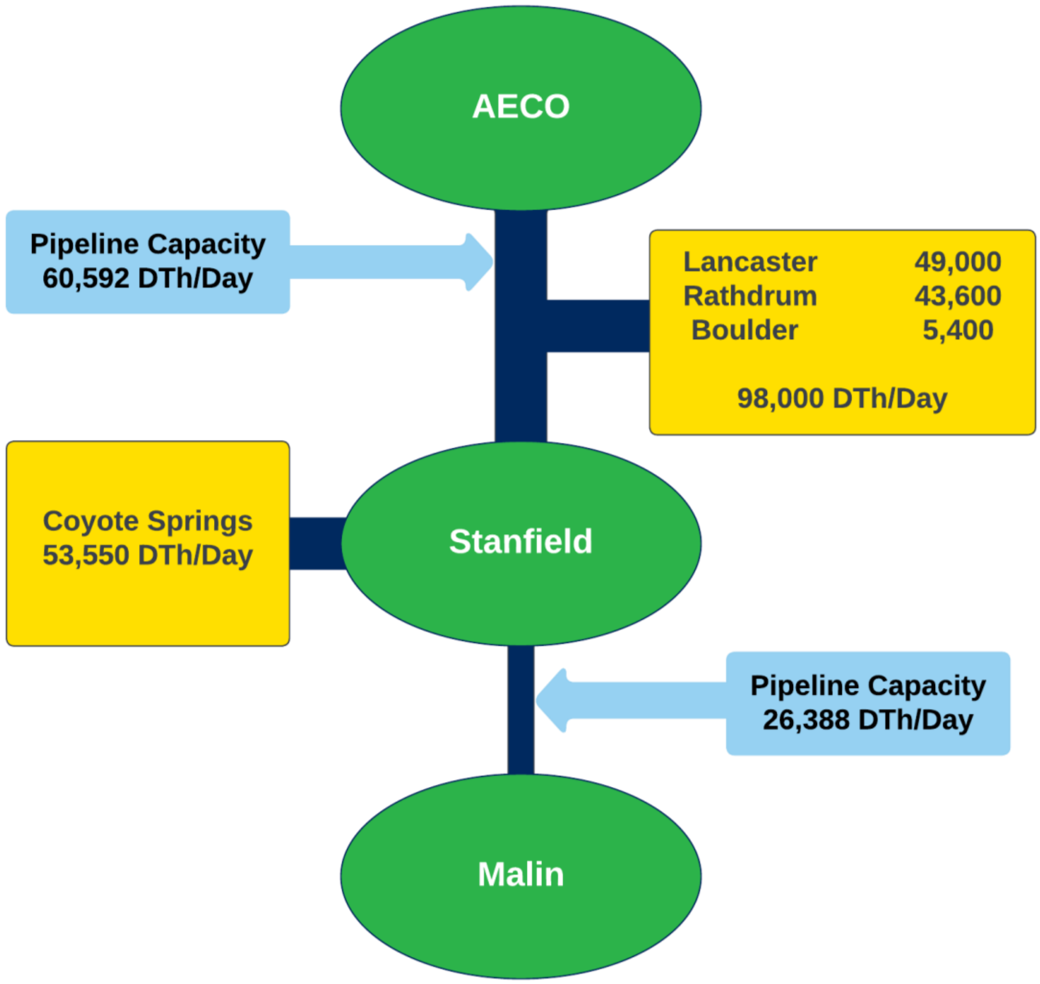
Avista does not have firm transportation rights for the entirety of its natural gas generation capacity but rather relies on short-term transportation contracts to meet needs above its firm contractual rights. Adequate surplus transportation has historically been available because the GTN pipeline was not fully subscribed. Natural gas producers have recently purchased all remaining rights on the system to transport their supply south to take advantage of higher prices in the U.S. compared to Canada. However, these suppliers do not appear to have firm off-takers of their product, and therefore a lack of transportation likely will not lead to a lack of fuel for Avista's natural gas plants, but this remains a risk.

Historically, when suppliers control the pipeline capacity, it has resulted in a pricing issue rather than a supply issue. In extreme winter conditions or if pipeline capacity is lost (as occurred in January 2024), the inability to control gas capacity could result in shutting off gas generation. Avista has identified three solutions to address this issue; 1) install on-site alternative fuel storage, i.e., fuel oil, 2) acquire or build new natural gas pipelines, or 3) develop regional Liquefied Natural Gas (LNG) storage. On-site fuel oil storage is possible for smaller natural gas turbines with modifications and air permit modifications. Either acquiring or building new natural gas pipelines is not a viable option. If Avista is going to solve this fuel supply risk, an LNG facility should be constructed. This solution could also alleviate pipeline delivery risk to the local gas delivery system.

Table 5.9: Top Five Historical Peak Day Natural Gas Usage (Dekatherms)

Date	Boulder Park	Coyote Springs 2	Lancaster	Rathdrum	GTN Total	Firm Rights
1/18/2024	4,573	51,540	46,806	45,931	148,849	60,592
1/30/2023	4,571	51,567	48,206	44,441	148,785	60,592
1/17/2024	5,349	51,455	45,273	46,651	148,728	60,592
2/16/2024	5,451	50,530	46,611	45,404	147,996	60,592
1/16/2024	5,372	51,939	43,781	46,260	147,351	60,592

Figure 5.9: Avista Firm Natural Gas Pipeline Rights



6. Distributed Energy Resource Options

Distributed Energy Resources (DERs) include energy efficiency, demand response, existing resources, and new resource options such as customer sited solar and energy storage. In WAC 480-100-605 DERs are defined as:

> *Distributed energy resource means a non-emitting electric generation or renewable resource or program that reduces electric demand, manages the level or timing of electricity consumption, or provides storage, electric energy, capacity, or ancillary services to an electric utility and that is located on the distribution system, any subsystem of the distribution system, or behind the customer meter, including conservation and energy efficiency.*

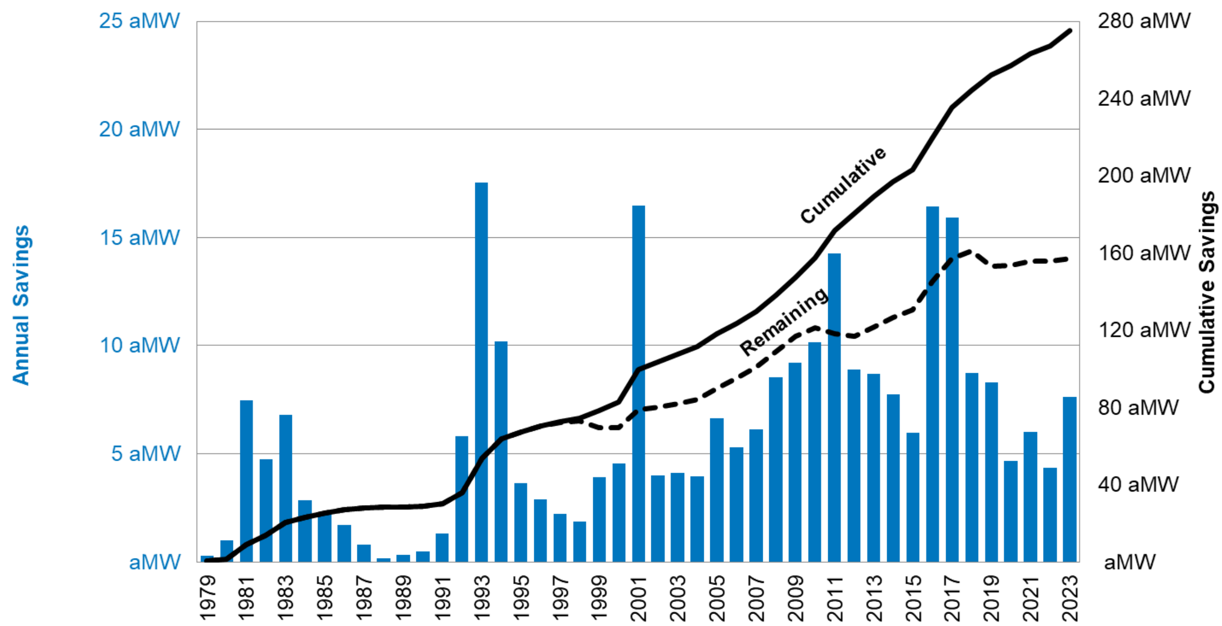
Section Highlights

- Energy efficiency programs currently serve 156 aMW of load, representing nearly 12.2% of customer demand.
- More than 3,000 energy efficiency measures and 16 demand response options are considered for resource selection.
- Avista's solar net metering program includes 4,433 customers generating with 29.9 megawatts of capacity.
- Community solar, roof-top solar, energy efficiency, demand response and distributed energy storage are options for utility resource selection.

Energy Efficiency

Avista's energy efficiency programs may provide cost-effective opportunities for customers to save energy by replacing old equipment with better performing, energy efficient equipment. The energy efficiency programs offer a wide array of low-cost measures to our customers. Since 1978, Avista has acquired 275 aMW of energy efficiency. Currently 156 aMW of this savings remains as a load reduction due to our efforts becoming code or standard practice. Figure 6.1 illustrates Avista's historical electricity conservation acquisitions using an average 18-year measure life. The 18-year measure life accounts for the difference between the cumulative (solid black line) and online trajectories (dotted black line) where program savings is no longer counted as energy efficiency. Currently 156 aMW of energy efficiency programs serve customers, representing nearly 12.2% of 2023 customer load.

Figure 6.1: Historical Conservation Acquisition (System)



Avista provides energy efficiency and educational offerings to the residential (inclusive of low-income and named communities) commercial and industrial customer segments. Program delivery mechanisms include prescriptive, site-specific, regional, upstream, midstream, behavioral, home energy audits, market transformation, and third-party direct install options. Prescriptive programs provide fixed cash rebate incentives based on an average savings assumption for the measure across the region. Prescriptive programs work best where uniform measures or offerings apply to large groups of similar customers. Examples of prescriptive programs include the installation of qualifying high-efficiency heating equipment or upgrades to lower U-value windows.

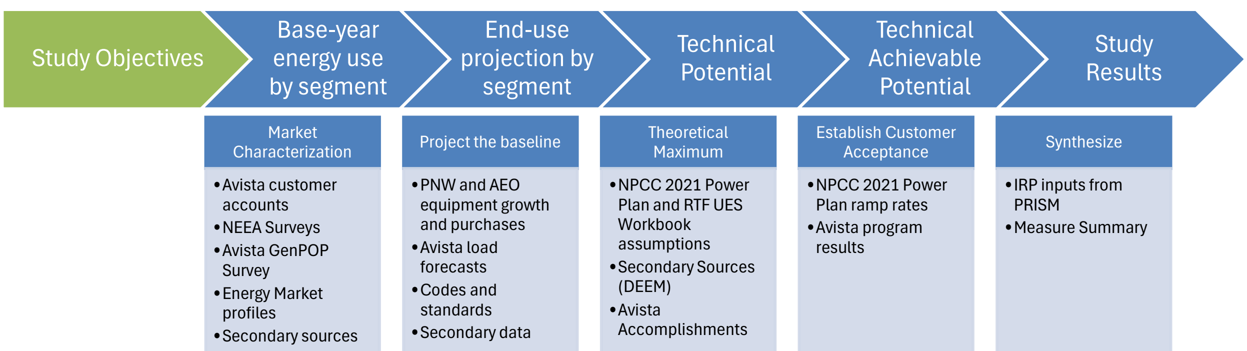
Site-specific programs, or customized offerings, provide cash incentives for cost-effective energy saving measures or equipment not meeting prescriptive rebate requirements. Site-specific programs require customized approaches for commercial and industrial customers because of the unique characteristics of each premise and/or process. Other delivery methods build off these offerings with up- and mid-stream retail buy-downs of low-cost measures, free-to-customer direct install programs or coordination with regional market transformation efforts. In addition to developing and delivering incentive offerings, Avista also provides technical assistance (in multiple languages where possible) in the forms of education, outreach, and other resources to customers to encourage participation in efficiency programs and measures.

The Conservation Potential Assessment

Avista retained Applied Energy Group (AEG) as an independent consultant to assist in developing a Conservation Potential Assessment (CPA). The CPA is the basis for the energy efficiency portion of this plan. The CPA identifies the 20-year potential for energy efficiency in accordance with the Energy Independence Act's (EIA) energy efficiency goals and provides data on resources specific to Avista's service territory for use in the resource selection process. The potential assessment considers the impacts of existing programs, the influence of known building codes and standards, technology developments and innovations, legislative policy changes to the long-term economic influences, and energy prices. The CPA report and list of energy efficiency measures is included in Appendix C.

AEG first developed estimates of *technical potential*, reflecting the adoption of all conservation measures, regardless of cost-effectiveness or customers' likeliness to participate. The next step identifies the estimated *achievable technical potential*; this measure modifies the technical potential by accounting for customer adoption constraints by using the Power Council's 2021 Plan ramp rates. The estimated achievable technical potential, along with associated costs, feed into the PRiSM model to select cost-effective measures. AEG took the steps shown in Figure 6.2 to assess and analyze energy efficiency and potential within Avista's service territory.

Figure 6.2: Analysis Approach Overview



AEG's CPA included the following steps:

1. Perform a market characterization to describe sector-level electricity use for the residential (inclusive of low income), commercial and industrial sectors for the 2023 base year.
2. Develop a baseline projection of energy consumption and peak demand by sector, by segment and by end use for 2026 through 2045.
3. Define and characterize several hundred conservation measures to be applied to all sectors, segments and end uses.
4. Estimate technical potential and achievable technical potential at the measure level in terms of energy and peak demand impacts from conservation measures for 2026-2045.

Market Segmentation

The CPA considers Avista customers by Washington and Idaho service territories and by sector. The residential sector includes single-family, multi-family, manufactured homes, and low-income customers[56] using Avista's customer data and U.S. Census data from the American Community Survey (ACS). For the residential sector, AEG utilized Avista's customer data and prior CPA ratios developed from census information. AEG incorporated information from the Northwest Energy Efficiency Alliance's (NEEA) Commercial Building Stock Assessment to assess the commercial sector by building type, installed equipment and energy consumption. Avista analyzed the industrial sector for each state because of their unique energy needs. AEG characterized energy use by end use within each segment in each sector, including space heating, cooling, lighting, water heating, or motors; and by technology, including heat pumps and resistance-electric space heating.

The baseline projection is a "business as usual" metric without future utility conservation or energy efficiency programs. It estimates annual electricity consumption and peak demand by customer segment and end use absent future efficiency programs. The baseline projection includes the impacts of known building codes and energy efficiency standards as of 2024 when the study began. Codes and standards have direct bearing on the amount of energy efficiency potential due to the reduction in remaining end uses with potential for efficiency savings. The baseline projection accounts for market changes including:

- customer and market growth;
- income growth;
- retail rates forecasts;
- trends in end use and technology saturation levels;
- equipment purchase decisions;
- consumer price elasticity;
- income; and
- persons per household.

For each customer class, AEG compiled a list of electric energy efficiency measures and equipment, drawing from the Northwest Power and Conservation Council's (NPCC or Council) 2021 Power Plan, the Regional Technical Forum, and other measures applicable to Avista. The individual measures included in the CPA represent a wide variety of end use applications, as well as devices and actions able to reduce customer energy consumption. The AEG study includes measure costs, energy and capacity savings and estimated useful life.

[56] The low-income threshold for this study is 200% of the federal poverty level. Low-income information is available from U.S. Census data and the American Community Survey data for Washington customers only.

Avista, through its PRiSM model, considers other performance factors for the list of more than 3,000 measures and performs an economic screening on each measure for every year of the study to develop the economic potential for Avista's service territory and individually by state. Avista supplements energy efficiency activities by including potentials for distribution efficiency measures consistent with EIA's conservation targets and the NPCC 2021 Power Plan.

Overview of Energy Efficiency Potential

AEG's approach adhered to the conventions outlined in the National Action Plan for Energy Efficiency Guide for Conducting Potential Studies.[57] The guide represents comprehensive national industry standard practice for specifying energy efficiency potential. As shown in Table 6.1, two types of potential results were specifically included in this study – technical potential and achievable technical potential by state.

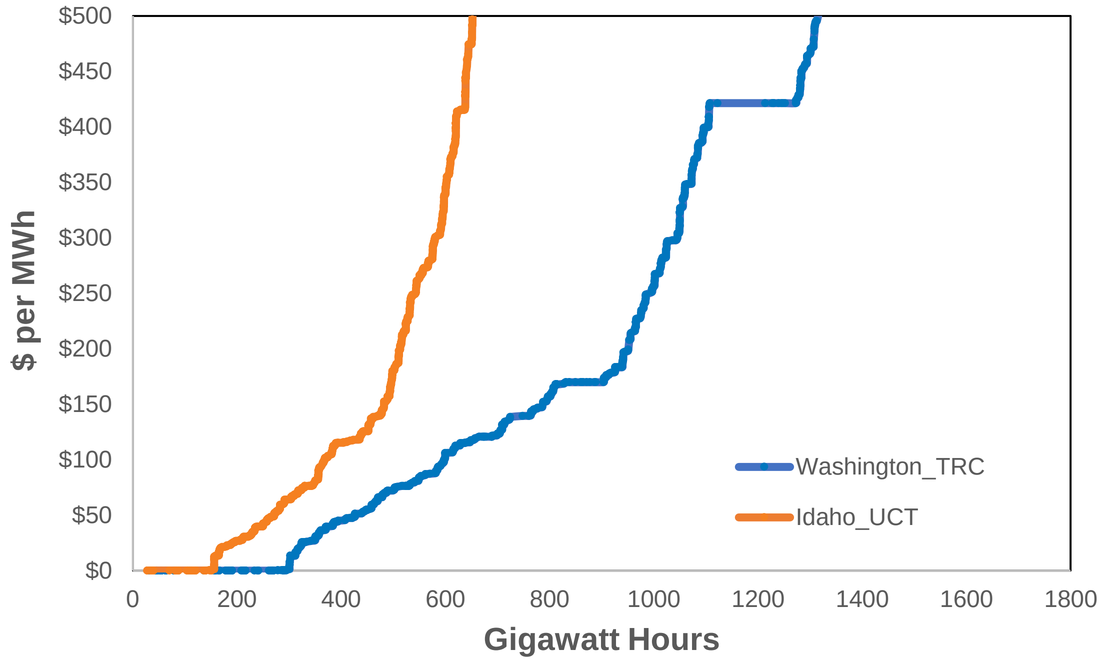
Table 6.1: Cumulative Potential Savings (Across All Sectors for Selected Years)

	2026	2027	2030	2040	2045
Technical Potential (GWh)	191.4	387.2	593.7	1,915.5	2,832.2
Washington	128.2	258.8	396.5	1,290.5	1,928.2
Idaho	63.1	128.4	197.2	625.0	904.0
Total Technical Potential (aMW)	**21.8**	**44.2**	**67.8**	**218.7**	**323.3**
Technical Achievable Potential	86.0	183.2	295.1	1,274.6	2,082.5
Washington	56.6	120.4	194.2	853.4	1,431.0
Idaho	29.4	62.8	100.9	421.2	651.6
Technical Achievable Potential (aMW)	**9.8**	**20.9**	**33.7**	**145.5**	**237.7**

Potential programs must be cost effective to be selected for future implementation. Figure 6.3 illustrates the supply curve of this potential using their associated price per MWh. For Idaho savings, the potential has a near zero cost using the Utility Cost Test (UCT) method until approximately 150 GWh, then quickly rises. As for Washington, using the Total Resource Cost (TRC) method, there is "no cost" energy efficiency until reaching approximately 300 GWh, then linearly increases until around 1,100 GWh, then goes up exponentially. The amount of energy efficiency the model selects will be where the supply curve meets the avoided cost. For example, if Washington's avoided cost were $100 per MWh, then 600 GWh of energy efficiency would be selected. Avista uses a more sophisticated resource selection approach, considering each program's individual cost and benefits compared to alternatives, but the supply curve demonstration is a simplified cost and benefit illustration of the available energy efficiency.

[57] National Action Plan for Energy Efficiency (2007). *National Action Plan for Energy Efficiency Vision for 2025:* Developing a Framework for Change. https://www.energy.gov/sites/default/files/2023-10/napee-vision_1.pdf

Figure 6.3: Jurisdiction Supply Curves



Technical Potential

Technical potential finds the most energy-efficient option commercially available for each purchase decision regardless of its cost. This theoretical case provides the broadest and highest definition of savings potential because it quantifies savings if all current equipment, processes, and practices in all market sectors were replaced by the most efficient and feasible technology. The technical potential case is provided for planning and informational purposes. Technical potential in the CPA is a “phased-in technical potential,” meaning only the current equipment stock at the end of its useful life is considered and changed out with the most efficient measures available. Non-equipment measures, such as controls and other devices (e.g., programmable thermostats) phase-in over time, just like the equipment measures. All measures are implemented according to ramp rates developed by the Council for its 2021 Power Plan and apply to 100% of the applicable market.

Technical Achievable Potential

The technical achievable potential refines the technical potential by applying customer participation rates accounting for market barriers, customer awareness and attitudes, program maturity, and other factors affecting market penetration of energy efficiency measures. AEG used ramp rates from the Council’s 2021 Power Plan in development of the technical achievable potential.

For the technical achievable potential case, a maximum achievability multiplier of 85% to 100% is applied to the ramp rate per Council methodology. This factor represents a reasonable achievable potential to be acquired through available mechanisms, regardless of how energy efficiency is achieved. Thus, the market applicability assumptions utilized in this study include savings outside of utility programs. Avista uses technical achievable potential as an input to its resource selection.

Integrating Results into Business Planning and Operations

The CPA and IRP energy efficiency evaluation processes provide high-level estimates of cost-effective acquisition opportunities. These results establish baseline goals for continued development and enhancement of energy efficiency programs, but do not provide enough detail to form an actionable acquisition plan. Avista uses results from both processes to establish a budget for energy efficiency measures, determine the size and skillsets necessary for future operations, and identify general target markets for energy efficiency programs. This section discusses recent operations of the individual sectors and energy efficiency business planning.

The CPA's economic potential is used for implementing energy efficiency programs to:

- Identify conservation resource potentials by sector, segment, end use, and measure. Energy efficiency staff uses CPA results to determine the segments and end uses/measures to target.
- Identify measures with the highest benefit-cost ratios to help the utility acquire the highest benefits for the lowest cost. Ratios evaluated include TRC in Washington and UCT in Idaho.
- Identify and target measures with large potential but significant adoption barriers that the utility may be well-positioned to address through innovative program design or market transformation efforts.
- Optimize the efficiency program portfolio by analyzing cost effectiveness, potential of current measures and programs; and by determining potential new programs, program changes and program sunsets.

The CPA's economic potential illustrates potential markets and provides a list of cost-effective measures to analyze through the ongoing energy efficiency business planning process. This review of both residential and non-residential program concepts and sensitivity provides more detailed assumptions feeding into program planning.

Residential Sector Overview

Avista's residential portfolio of efficiency programs engages and encourages customers to consider energy efficiency improvements for their home. Prescriptive rebate programs are the main component of this portfolio, augmented with other offerings, including midstream select distribution of low-cost lighting and weatherization materials, direct-install programs as well as multi-faceted, multichannel outreach and customer engagement.

Residential customers received more than $2.3 million in Avista rebates in 2023 to offset the cost of implementing energy efficiency measures. All programs within the residential portfolio contributed 7,122 MWh to the 2023 annual first-year energy savings.

Low-Income Sector Overview

Currently, Avista leverages the infrastructure of several network Community Action Agencies (CAAs) and one tribal weatherization organization to deliver energy efficiency programs for low-income residential customers in Avista’s service territory. CAAs have resources to income qualify, prioritize, and treat clients’ homes based upon several characteristics beyond Avista’s ability to reach. These agencies also have other resources to leverage for home weatherization and energy efficiency measures beyond Avista’s contributions. The agencies have in-house and/or contract crews available to install many of the efficiency program measures.

Avista’s general outreach for this sector is a “high touch” customer experience for vulnerable customer groups including, but not limited to seniors, low-income, and those in Named Communities. Each outreach encounter includes information about bill payment options and energy management tips, along with the distribution of low-cost weatherization materials. Avista partners with community organizations to reach these customers through community resource events, at area food banks/pantry distribution sites, senior activity centers, or affordable housing developments. Low-income energy efficiency programs contributed 622 MWh of annual first-year electricity savings in 2023.

Non-Residential Sector Overview

Non-residential energy efficiency programs deliver energy efficiency through a combination of prescriptive and site-specific offerings. Any measure not offered through a prescriptive program is eligible for analysis through the site-specific program, subject to the criteria for program participation. Prescriptive paths for the non-residential market are preferred for small and uniform measures, but larger measures may also fit where customers, equipment, and estimated savings lack uniformity.

More than 5,100 prescriptive and site-specific nonresidential projects received funding in 2023. Avista contributed approximately $21.1 million for energy efficiency upgrades to offset costs of non-residential applications and realized over 49,139 MWh in annual first-year energy savings in 2023.

Demand Response

Current Demand Response Programs and Pilots

Avista's current Demand Response (DR) resources include residential and general service Time-of-Use (TOU) rates and Peak Time Rebate (PTR) pilots, commercial Electric Vehicle (EV) TOU rates and one bilateral agreement with an industrial customer for 30 MW. The industrial customer agreement was executed in 2022 for a four-year term with provisions to extend it another six-years. Avista is also working with NEEA and other utilities in the region on an End Use Load Flexibility (EULF) pilot with a focus on direct load control for grid-enabled water heaters and line voltage thermostats. These pilots will influence future IRPs, just as past pilot experience influenced this IRP.

Historical Demand Response Programs and Pilots

Avista piloted DR technologies between 2007 and 2009, to examine cost-effectiveness and customer acceptance. The pilot tested scalable Direct Load Control (DLC) devices based on installations in approximately 100 volunteer households in Sandpoint and Moscow, Idaho. The sample allowed Avista to test DR with the benefits of a larger-scale project, but in a controlled, measurable, and customer-friendly manner. Avista installed DLC devices on residential heat pumps, water heaters, electric forced-air furnaces, and air conditioners to control operations during 10 scheduled events at peak times ranging from two-to-four hours. A separate group, within the same communities, participated in an in-home-display device study as part of the pilot. The program offered Avista and its customers hands-on experience with equipment that provides "near-real time" feedback on energy usage. The insights from the pilot study are detailed in a report submitted to the Idaho Public Utilities Commission.[58]

Avista was part of the 2009 to 2014 Northwest Regional Smart Grid Demonstration Project (SGDP) with Washington State University (WSU) and approximately 70 residential customers in Pullman and Albion, Washington. Residential customer assets included forced-air electric furnaces, heat pumps, and central air-conditioning units. A non-traditional DLC approach was used, meaning the DR events were not prescheduled, but rather Avista controlled customer load through an automated process based on utility or regional grid needs while using predefined customer preferences.[59] More importantly, the technology used in the DR portion of the SGDP predicted if equipment was available for participation in the control event, providing real time feedback of the actual load reduction due to the DR event. Additionally, WSU facility operators had instantaneous feedback due to the integration between Avista and their building management system. Residential customer notifications of the DR events occurred via customers' smart thermostat. Avista reported information gained from this project to the prime sponsor for use in the SGDP's final project report and compilation with other SGDP initiatives.[60]

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[58] 20100303FINAL REPORT.pdf (idaho.gov)

[59] For example, no more than a two-degree Fahrenheit offset for residential customers and an energy management system at WSU with a console operator.

[60] Front_Matter.pdf (energy.gov)

Experiences from both pilots showed high customer engagement; however, recruiting participants was challenging. Avista's service territory has a high level of natural gas adoption meaning many customers cannot participate in typical DLC electric space and water heat programs because they have natural gas appliances. Additionally, customers did not seem overly interested in the DLC programs offered. Bonneville Power Administration (BPA) found similar customer interest challenges in their regional DLC programs.[61]

Avista paid customers direct incentives for program participation in both DLC pilots. A premium incentive to recruit and retain customers was provided and was not intended to be scalable. Avista will need additional analysis to determine cost effective payment strategies beyond pilots to mass-market DLC programs. If Avista is not able to harness adequate customer interest at cost-effective incentive levels, the future of DR could be more limited than assumed in this plan.

Demand Response Potential Assessment Study

Avista retained AEG to study the DR potential for Avista's Washington and Idaho service territories for this IRP. The study estimates the magnitude, timing, and costs of DR resources likely available to Avista for meeting both winter and summer peak loads. Figure 6.4 outlines AEG's approach to determine the potential size of DR programs available in Avista's service territory. Many DR programs require Advanced Metering Infrastructure (AMI) for billing purposes. All DR pricing programs, behavioral and third-party contract programs included in this study require AMI as an enabling technology. The AMI deployment is complete in Washington, and AEG broadly assumes Avista would follow with AMI metering in Idaho beginning in 2026 (potentially) with a three-year ramp rate for full deployment, finishing in 2029.

AEG used the same market characterization for this potential assessment study as used in the CPA. This became the basis for customer segmentation to determine the number of eligible customers in each market segment for potential DR program participation and provided consideration for DR program interactions with energy efficiency programs. The study compared Avista's market segments to national DR programs to identify relevant DR programs for analysis.

Lastly, for the pilot programs included in the potential, AEG based on program roll-out beginning in 2024 and includes TOU rate options, PTR, and DLC of grid-enabled water heaters. AEG forecasted the potential program savings as if the programs matured and operated through 2045. Each pricing pilot will run for two years. The DLC grid-enabled water heater pilot is a project Avista is participating in with several other regional utilities and led by NEEA.

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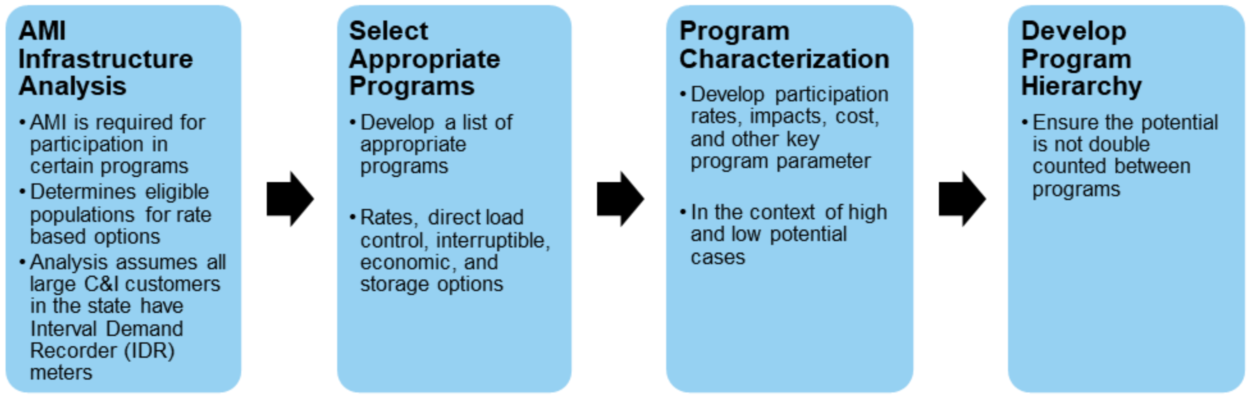
61 BPA's partnership with Kootenai Electric Coop, [Report (bpa.gov)](bpa.gov).

Figure 6.4: Program Characterization Process



Demand Response Programs

This potential process identifies several DR program options shown in Table 6.2. The different types of DR programs include two broad classifications: curtailable/controllable DR and rate design programs. Except for the behavioral program, curtailable/controllable DR programs represent firm, dispatchable and reliable resources to meet peak-period loads. This category includes DLC, Firm Curtailment (FC), thermal and battery storage (virtual power plant). Rate design options offer non-firm load reductions that might not be available when needed but still create a reliable pattern of potential load reduction. Pricing options include TOU, PTR, and variable peak pricing. Each option requires a new rate tariff for each state in Avista's service territory.

Table 6.2: Demand Response Program Options by Market Segment

DR Program		Participating Market Segment				Season Impacted	
Program Type	Program Option	Res.	Sm. Com.	Large. Com./ Ind.	Extra Large Com./ Ind.	Winter	Summer
Curtailable/ Controllable DR	DLC Central AC	X	X				X
	DLC Smart Thermostat – Cooling	X	X				X
	DLC Smart Thermostat – Heating	X	X			X	
	DLC CTA-2045 Water Heating	X	X			X	X
	DLC Water Heating	X	X			X	X
	DLC Smart Appliances	X	X			X	X
	EV VG1 Telematics (Behavioral)	X				X	X
	Third Party Contracts			X	X	X	X
	Thermal Energy Storage		X	X	X		X
	Battery Energy Storage	X	X	X	X	X	X
	Behavioral	X				X	X
	Ancillary Services	X	X	X	X	X	X
Rates	Time-of-Use Opt-in	X	X	X	X	X	X
	Time-of-Use Opt-out	X	X	X	X	X	X
	Variable Peak Pricing Rates	X	X	X	X	X	X
	Peak-Time Rebate	X	X			X	X
	Electric Vehicle Time-of-Use		X	X	X	X	X

Direct Load Control

DLC programs require an enabling technology to drive load change for Avista's residential and general service customers in Idaho and Washington and allow Avista to directly control a variety of customer end-use appliances during capacity constrained hours. For example, DLC smart thermostat programs would leverage a customer's smart thermostat installation and rely on the customer's Wi-Fi for communications with the grid and utility. Likewise, DLC smart appliances (refrigerators, clothes washers, and dryers), DLC central air conditioning, DLC water heating, and DLC CTA-2045 water heating programs assume controlling the device enables a version of a load control for the utility. Typically, DLC programs take five years to mature to maximum participation levels and AMI technology is preferred to evaluate and measure event response and system impacts.

Third Party Contracts - Firm Curtailment

Customers participating in a firm curtailment program agree to reduce demand by a specific amount or to a pre-specified consumption level during a capacity constrained event in exchange for fixed incentive payments. Customers receive payments while participating in the program even if they never receive a load curtailment request while enrolled in the program. This capacity payment typically varies with the firm reliability-commitment level. In addition to fixed capacity payments, participants receive compensation for reduced energy consumption. Because the program includes a contractual agreement for a specific level of load reduction, enrolled loads have the potential to replace a firm generation resource.

Customers with maximum demand greater than 200 kW and operational flexibility are attractive candidates for firm curtailment programs. Examples of customer segments with high participation possibilities include large retail establishments, grocery chains, large offices, refrigerated warehouses, water- and wastewater-treatment plants, and industries with process storage (e.g., pulp and paper, cement manufacturing). Customers with operations requiring continuous processes, or with relatively inflexible obligations, such as schools and hospitals, generally are not good candidates for curtailment programs. These assumptions determine the eligible population for participation in this program and the study assumes a third party would administer all aspects of the program.

Thermal Energy Storage

Thermal energy storage (TES) stores thermal energy (hot or cold) for later use and can be used to balance energy demand between different times of the day. It has primarily been used in non-residential buildings but, as technology advances, may have the potential for future use in residential applications. TES technologies can include sensible heat storage (storing energy by heating or cooling a material), latent heat storage (using phase-change materials to store energy from solid to liquid) and thermo-chemical storage (using chemical reactions to store and release energy). As an example of latent heat storage, a variable speed fan can automatically circulate the cool air throughout a room using the stored energy (ice) rather than having to draw energy from the grid during peak times to chill the air.

Battery Energy Storage (Virtual Power Plant)

Battery energy storage technologies draw electricity during low demand periods and store it for later use during capacity constrained periods. The program assumes customers own the batteries as part of their on-site renewable generation system. An incentive can be offered to help cover part of the installation costs of the battery system. Once enrolled in the program (i.e. virtual power plant), customers allow the utility to automatically manage (charge/discharge) the battery during capacity constrained periods in exchange for an annual participation payment.

Behavioral

A behavioral DR program is a voluntary reduction in response to digital behavioral messaging. The program sends notifications requesting customers to reduce usage via text or email messages. To minimize costs, the plan assumes the program would work in tandem with an energy efficiency behavioral reporting program. Also required for the program is AMI technology to evaluate and measure the impact of the program events.

Behavioral EV V1G Telematics

This concept pays a monthly incentive to change charging behavior using the EV on-board charging system. If customers charge during on-peak hours no more than three times per month a customer would receive an incentive. After one-year the incentives end, but it is assumed off-peak charging behavior is set and will continue.

Time of Use Rates (Opt-In)

A TOU rate is a time-varying energy rate. Relative to a revenue-equivalent flat rate, the TOU rate is higher during either higher load or price periods, while the rate during other periods is lower. This provides customers with an incentive to shift energy consumption out of the higher-price on-peak hours to the lower cost off-peak hours. TOU is not a DR option, per se, but rather a pricing program to encourage a change in behavior. Large price differentials are generally more effective than smaller differentials for TOU programs and AMI is required.

The DR study considered two types of TOU pricing options. In an opt-in rate, participants voluntarily enroll in the rate. An opt-out rate places all customers on the time-varying rate, but they may opt-out and select another rate later.

Two Opt-in TOU rate designs are being piloted in Washington State for residential and general service customers. The pilots began in June 2024 and will run for two years. Evaluations will be conducted to determine how Avista can deploy cost effective TOU programs more broadly post-pilot. Avista did not model TOU-opt out due to lower long-term capacity savings than the opt-in program design.

Variable Peak Pricing

The Variable Peak Pricing (VPP) is an option under a TOU program where the rate amount changes daily to reflect system conditions and costs for peak hours. Under a VPP program, on-peak prices for each weekday are made available the previous day. Through the VPP program, customers are billed for their actual consumption during the billing cycle at these prices. Over time, establishment of event-trigger criteria enables customers to anticipate events based on extreme weather or other factors. System contingencies and emergency needs are good candidates for VPP events. VPP program participants are required to be enrolled in a TOU rate option.

Peak Time Rebate

Participation in a Peak-Time-Rebate (PTR) program is voluntary. In an event, participants are notified a day in advance for a two- to six-hour event period during peak hours. If customers do not participate, there is no penalty. If they do participate, they receive a bill credit based on the amount of energy reduced as compared to a calculated baseline. PTR is dependent on enrollment in other DR programs to avoid double counting of savings, but like the other pricing programs, it does require AMI for billing purposes.

A PTR program is being piloted in Washington State for residential and general service customers. The pilots began in June 2024 and will run for two years. Evaluations will be conducted to determine how Avista can deploy cost effective PTR programs more broadly post-pilot.

Electric Vehicle Time of Use

Rather than a typical TOU rate applying on/off peak prices to the whole customer's usage, the EV TOU rate program applies on/off peak prices exclusively to the EV load. This program requires EVs to be metered separately. Avista currently offers this rate option in Wahington and when AMI is available in Idaho, a similar pricing program could be available.

Demand Response Program Participation

AEG's forecast for DR potential uses a database of existing program information and insights from market research results representing "best-practice" estimates for program participation. The industry commonly follows this approach for arriving at achievable potential estimates. However, practical implementation experience suggests there are uncertainties in factors such as market conditions, regulatory climate, the economic environment, and customer sentiments influencing participation in DR programs.

DR options require time to mature to a steady state because of the time needed for customer education, outreach, and recruitment. Further, the physical implementation and installation of any hardware, software, telemetry, or other enabling equipment will require time for implementation. DR programs included in the AEG study have ramp rates generally with a three-to-five-year timeframe before reaching the steady state.

Table 6.3 shows the steady-state participation rate assumptions for each DR program option. Space cooling is split between DLC central AC and smart thermostat options. Likewise, eligible EV charging for general service customers are split between the TOU (opt-in or opt-out) programs and the EV TOU program. Eligible customers for each customer class are calculated based on market characterization and equipment end use saturation.[62]

[62] See the Demand Response Potential Appendix found within the 2022-2045 Avista Electric CPA found in Appendix C.

Table 6.3: DR Program Steady-State Participation Rates (% of Eligible Customers)

DR Program	Residential Service	General Service/ Small Commercial	Large General Service	Extra Large General Service
Direct Load Control (DLC) of central AC	10%	10%	-	-
DLC of domestic hot water heaters (DHW)	15%	5%	-	-
Smart Thermostats DLC Heating	5%	3%	-	-
CTA-2045 hot water heaters	50%	50%	-	-
Smart Thermostats DLC Cooling	20%	10%	-	-
Smart Appliances DLC	5%	5%	-	-
Third Party Contracts	-		15%	15%
EV V1G Telematics	20%	-	-	-
DLC Electric Vehicle Charging	13%	7%		
Time-of-Use Pricing Opt-in	20%	20%		
Time-of-Use Pricing Opt-out	-	-	25%	25%
Variable Peak Pricing	15%	15%	-	-
Peak-Time Rebate	-	20%	10%	-
Electric Vehicle Time-of-Use	-	0.5%	1.5%	1.5%
Thermal Energy Storage	50%	50%		
Battery Energy Storage	20%	-	-	-
Behavioral	10%	10%	-	-

Cost and Potential Assumptions

Each DR program in this evaluation is assigned an average load reduction per participant per event, an estimated duration of each event, and a total number of event hours per year. Costs are also assigned to each DR program for annual marketing, recruitment, incentives, program development, and administrative support. These assumptions result in potential demand savings and total cost estimates for each program independently and on a standalone basis.

If Avista offers more than one DR program, the potential for double counting savings from DR programs exists. To address this possibility, a participation hierarchy assumes an integrated approach where program savings are based upon many programs being available. These savings and costs results were then used in Avista's modeling. See Appendix C for additional detail on DR resource assumptions used in developing potential savings and cost results.

The estimated savings for each program and its levelized costs are shown in Table 6.4. The cost of the programs within this table represents the on-going operations and capital cost required to start and maintain these programs for programs beginning in 2026. The capital costs are amortized and recovered over a 10-year period. These tables include the estimated potential megawatt savings for 2030 and 2045 to illustrate program potential. These estimates are the expected amount of demand reduction from all program participants using an "integrated" methodology, whereas potential may be higher for a program where only one program is in place. It is also worth noting these savings are net demand savings rather than the higher amount of load needed under contract to realize these savings.

Table 6.4: System Program Cost and Potential

Program	$/kW-Year	Winter (MW)		Summer (MW)	
		2030	2045	2030	2045
Battery Energy Storage	$35.6	3.1	13.0	3.0	12.7
Behavioral	$148.0	3.0	3.2	2.1	2.2
DLC Central AC	$166.7	-	-	11.6	15.4
EV V1G Telematics	$430.2	9.1	47.1	9.1	47.1
DLC Smart Appliances	$341.7	3.2	4.0	3.2	4.0
DLC Smart Thermostats - Cooling	$482.6	-	-	24.7	33.4
DLC Smart Thermostats - Heating	$30.6	9.2	14.6	-	-
DLC Water Heating	$634.7	2.8	3.5	2.8	3.5
CTA-2045 ERWH	$154.1	3.4	5.6	1.5	2.4
CTA-2045 HPWH	$538.1	0.5	13.2	0.3	8.5
Thermal Energy Storage	$783.7	-	-	0.6	0.6
Third Party Contracts	$101.4	17.7	21.0	22.4	26.6
Time-of-Use Opt-in	$217.1	3.4	4.2	2.4	3.0
EV TOU Opt-in	$40.4	1.2	9.6	1.2	9.6
VPP Rates	$21.6	4.8	5.7	6.1	7.2
Peak Time Rebate	$78.5	7.9	10.1	6.1	7.9
Total Potential		**69.2**	**154.8**	**97.1**	**184.2**

There are a few other factors Avista considers when evaluating DR programs, the first is the energy value of the program. Some program opportunities reduce energy usage permanently, but most programs have snap back load where additional energy usage returns after the DR event. Avista determined the net value of these load changes using hourly wholesale market prices discussed in Chapter 9 compared to a time series of how the load profile would change if the DR program was dispatched.

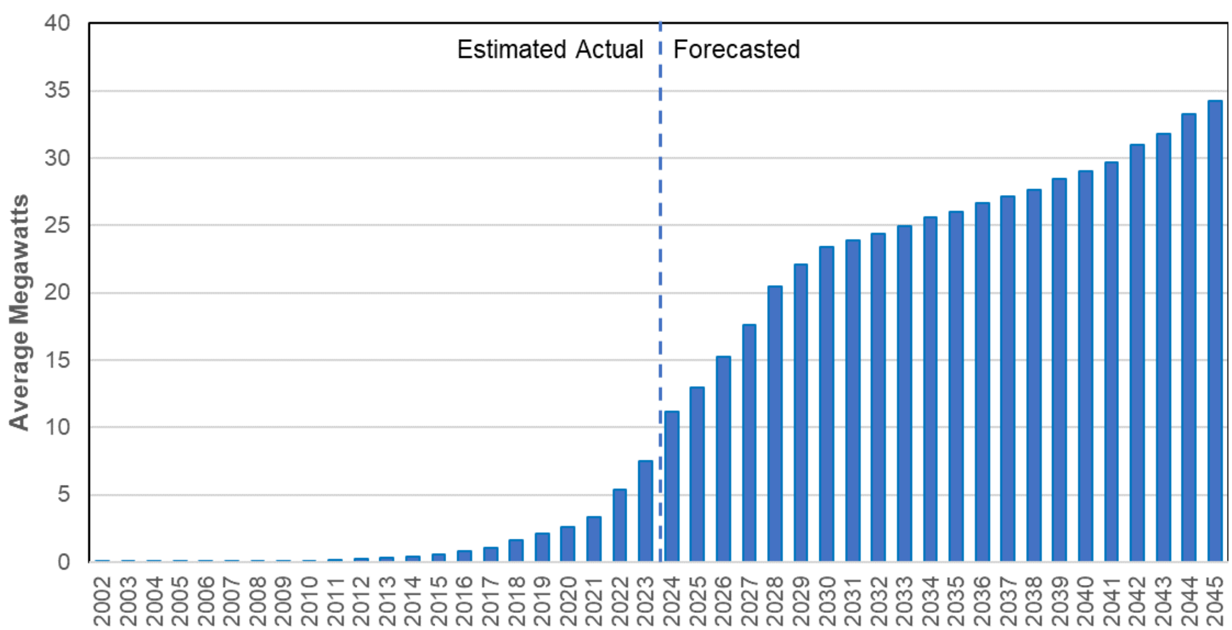
The second major factor related to whether a program is cost effective considers the program's ability, compared to alternatives, to qualify as load reduction or the program's Qualifying Capacity Credit (QCC). The QCC is uncertain for these types of programs in the future Western Resource Adequacy Market (WRAP). This analysis assumes a 6-hour reduction is required to receive 100% QCC, whereas the QCC is a percentage of the hour reduction. For example, a 4-hour program is 67% and a 3-hour program is 50%. The QCC values are increased by the PRM to account for peak load reduction. Effectively this new change gives DR programs a higher capacity benefit compared to the 2023 IRP analysis. Avista is uncertain if DR programs will be as valuable today as in the future when the region has more capacity limited resources. To account for this potential lost QCC value, DR is reduced 20% linearly between 2030 and 2045 from the 2026 value.

Distributed Generation Resources

Customer-Owned Generation

Avista has 4,433 customer-installed net-metered generation projects on its system as of December 2023, representing a total installed capacity of 29.9 MW. Approximately 89% percent of installations are in Washington; most are in Spokane County. Figure 6.5 shows annual energy production. The estimated actual is based on on-line capacity, while the forecasted generation is an estimate from the DER potential assessment study. Solar is the primary net metered technology followed by wind, combined solar and wind systems, and biogas. The average size of customer installations is 6.7 kilowatts. In Idaho, solar installation rates continue to increase without a major state subsidy, but as of December 2023, only 596 Idaho customers participate as compared to Washington's 3,837 customers.

Figure 6.5: Avista's Net Metering Generation (aMW)



Net-metered installations are exponentially increasing due to federal incentives, increasing solar vendor sales, environmental concerns, rising energy costs, and expiring state incentives. If the growth of net-metering customers continues to increase, Avista may need to adjust rate structures for these customers. Much of the cost of utility infrastructure to support reliable energy delivery is recovered in energy rates. Net metering customers continue to benefit from this infrastructure but are no longer purchasing as much energy, thereby transferring some of their grid infrastructure costs to customers not generating their own power.

Avista-Owned Solar

Avista operates three small solar DER projects. The first solar project is three kilowatts located at its corporate headquarters. Avista installed a 15-kilowatt solar system in

Rathdrum, Idaho to supply its My Clean Energy™ (formerly Buck-A-Block) voluntary green energy program. The 423-kW Avista Community Solar project, located at the Boulder Park property, began service in 2015.

Table 6.5: Avista-Owned Solar Resource Capability

Project Name	Project Location	Project Capacity (kW-DC)
Spokane Headquarters Solar	Spokane, WA	4
Rathdrum Solar	Rathdrum, ID	15
Boulder Park Solar	Spokane Valley, WA	423
Total		**442**

Solar Generation & Storage Opportunities

This IRP includes both utility owned distribution-sized solar generation and storage for residential, commercial, and community sized projects as resource options. Customer and distribution sized resources have gained traction to promote equitable outcomes for specific communities or to solve local supply issues. For this analysis these DERs are included as resource options for the Named Community Investment Fund (NCIF) but they can also be selected if cost effective without the additional funding. The resource configurations and costs are shown in Table 6.6. The costs are shown in nominal levelized cost dollars and include the benefits of the Inflation Reduction Act (IRA) through 2033, cost assumptions are based on information provided by TAC members and the 2023 National Renewable Energy Laboratory (NREL) resource cost study.[63] A low-income community solar option is based on the expected net cost to Avista customers after accounting for grants provided by the State of Washington. The costs are levelized cost of energy for solar resources over the life of the asset and costs for energy storage is the levelized cost of capacity over 20 years including battery reconditioning.

[63] NREL (National Renewable Energy Laboratory). 2023. 2023 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory. Technologies | Electricity | 2023 | ATB | NREL

Table 6.6: DER Generation & Storage Options Size and Cost

Project Name	2026$ /MWh	2035$ /MWh	2026$ / kW-Month	2035$ / kW-month
Existing res. building solar	166	287	-	-
Existing res. building solar with storage	166	287	24.99	42.51
New res. building solar	154	266	-	-
New res. building solar with storage	154	266	23.62	39.92
Com. building solar	120	140	-	-
Com. building solar with storage	120	140	26.88	38.19
Utility owned solar array	59	68	-	-
Utility owned solar array with storage	59	68	17.83	21.34
Stand-alone energy storage (4hr)	-	-	17.34	25.38
Stand-alone energy storage (8hr)	-	-	30.89	44.17
Low-income Community Solar Program	27	68	-	-

DER Evaluation Methodology

Avista models each of the DERs discussed in this chapter in the same economic selection model as other utility asset options. Avista's includes all known utility costs and, where required (i.e., Washington), known non-energy or social impacts. The Washington Utilities and Transportation Commission (UTC) is developing a proposal[64] for evaluating DERs as part of a workshop process with the assistance of Synapse Energy Economics. Currently, the UTC has put out draft proposals of the types of considerations utilities should use when conducting resource planning activities through a workshop series and has sought comments from utilities. While this concept continues to be in draft form, it provides an opportunity for Avista to demonstrate the types of costs and considerations used in the evaluation of these resources. The list of options from the strawman proposal is shown in Table 6.7 for those resources applicable to this plan.

Due to the complexity and size of the list of considerations, the answers within the boxes are high level. "Direct" means there is a value used within the PRiSM optimization model for this value. "Indirect" indicates this value is included by the savings compared to other resources; for example, if choosing energy efficiency lowers capacity needs from other resources. Items listed as "N/A" indicate the values are not applicable to the DER. "No" indicates the value is not included. Many of the values discussed are qualitative and difficult to quantify for use in modeling.

[64] Washington Cost-Effectiveness Test for Distributed Energy Resources, Straw Proposal for the Primary Test, November 7, 2022. Docket UE-210804.

Table 6.7: DER Cost and Benefit Impacts

Category	Impact	Energy Efficiency	Demand Response	Solar	Storage
Generation	Energy Generation	Direct	Direct	Direct	Direct
	Capacity	Indirect	Indirect	Direct	Direct
	Environmental Compliance	Indirect	Indirect	Indirect	Indirect
	Clean Energy Compliance	Indirect	Indirect	Direct	Indirect
	Market Price Effects	Direct	Direct	Direct	Direct
	Ancillary Services	Indirect	Indirect	Direct	Direct
Transmission	Transmission Capacity	Direct	Indirect	Direct	Direct
	Transmission System Losses	Direct	Direct	Direct	Direct
Distribution	Distribution Cost	Direct	Direct	Direct	Direct
	Distribution Voltage	No	No	Indirect	Indirect
	Distribution System Losses	Direct	Direct	Direct	Direct
General	Financial Incentives	N/A	Direct	No	No
	Program Admin Cost	Direct	Direct	Direct	No
	Utility Performance Incentives	No	No	No	No
	Compensation Mechanisms	No	No	No	No
	Credit and Collection Costs	Indirect	Indirect	Indirect	Indirect
	Risk	No	No	No	No
	Reliability	No	No	No	No
	Resilience	No	No	No	No
Host Customer Energy Impacts	Measure Costs	Direct	Direct	N/A	N/A
	Transaction Costs	Direct	Direct	N/A	N/A
	Interconnection Fees	N/A	N/A	Direct	Direct
	Risk	No	No	No	No
	Reliability	No	No	No	No
	Resilience	No	No	No	No
	Other Fuels	n/a	No	No	No
	Tax Incentives	Direct	No	Direct	Direct
Host Customer Non-Energy Impacts	Water	No	No	No	No
	Asset Value	Indirect	No	No	No
	Productivity	Direct	No	No	No
	Economic well-being	Direct	No	No	No
	Comfort	Direct	No	No	No
	Health & Safety	Direct	No	No	No
	Empowerment & Control	No	No	No	No
	Satisfaction & Pride	Indirect	No	No	No
	Low-Income NEIs	Direct	No	No	No
Societal Impacts	Greenhouse Gas Emissions	Direct	Indirect	Indirect	Indirect
	Other Environmental	No	No	No	No
	Public Health	Direct	No	Direct	Direct
	Economic & Jobs	Direct	No	Direct	Direct
	Resilience	No	No	No	No
	Energy Security	No	No	No	No

DER Potential Study

As part of the Washington CEIP approval process,[65] Avista agreed to conduct a distribution level analysis of DER opportunities within its Washington service territory. This includes a distribution feeder level analysis of future availability and likely adoption of resources and load changes. The analysis was completed in 2024 and will be used in future distribution planning activities. Avista hired AEG, who subcontracted with Cadeo, to conduct this analysis. The planned work covered both electric transportation and customer owned generation as shown in the list below. The study also included a scenario regarding upper limits of Named Community DER potential by removing income limitations. This scenario considers Named Community areas have the same DER penetration as non-Named Community areas to provide a high case scenario in the event of incentives for areas with lower incomes.

- EVs
  - Local charging: light, medium, heavy duty
  - Charging related to interstate travel

- New Generation and Storage
  - Residential and commercial solar
  - Residential and commercial storage
  - Other renewables (wind, small hydro, or other technologies)

The DER potential study contemplated a downscaled distribution level energy efficiency and DR forecast using the CPA/DR potential. Unfortunately, there is not a useful way to complete this task in a reasonable time and budget for the entire system. Avista proposes this future DER analysis should only include feeders with potential capacity constraints with needs reflecting either DR or energy efficiency as a solution.

DER Study Results

The reference scenario in Table 6.8 summarizes the 2045 DER potential results. The residential and fleet electric vehicle supply equipment (EVSE) will have the most significant load impacts in Avista's Washington service territory adding nearly 1,700 GWh of energy consumption in 2045. Customer solar will decrease energy consumption by almost 130 GWh in 2045. The term "peak" in the chart refers to a planning peak beginning at 17:00 and ending at 18:00 local time.

[65] Condition 14: Avista will include a Distributed Energy Resources (DERs) potential assessment for each distribution feeder no later than its 2025 electric IRP. Avista will develop a scope of work for this project no later than the end of 2022, including input from the IRP TAC, EEAG, and DPAG. The assessment will include a low-income DER potential assessment. Avista will document its DER potential assessment work in the Company's 2023 IRP Progress Report in the form of a project plan, including project schedule, interim milestones, and explanations of how these efforts address WAC 480-100-620(3)(b)(iii) and (iv).

Table 6.8: Summary Results for 2045, Reference Scenario

Resource	Capacity (MW)	Annual Load Impact (GWh)	Share of Nameplate Capacity in Named Community	July Peak Load impact (MW)	December Peak Load Impact (MW)
Customer Solar	105	-127	46%	-33	0
Customer Battery Storage	96	2	58%	-3	-9
Customer Wind	1	-0.3	45%	-0.1	0
Residential EVSE	1,544	853	38%	62	62
Fleet EVSE	692	841	67%	101	105
Public and Workplace EVSE	171	206	60%	33	33

Study Recommendations

As the team notes in the Utility Survey Memo (Appendix B of the DER study found in Appendix D), the current state of DER potential forecasting highlights many of Avista's data gaps. The AEG team recommends six actions Avista can take before the next iteration of the DER potential study to increase the fidelity and depth of insights from a future location-specific study.

1) **Address Fleet Data Gaps.** For this study, the team estimated the size and location of commercial fleets using two methods. First, Avista surveyed commercial vehicle fleets in its service territory, identifying dozens of smaller fleets. Additionally, the team used secondary data and satellite imagery to identify many larger fleets in the service territory, including school district buses and parcel delivery vehicles. While these efforts successfully obtained data from dozens of fleets, they are not comprehensive and likely undercount smaller light duty vehicle fleets. Three activities the team recommends Avista pursue to collect additional fleet data include:

   - **Continued outreach to fleet operators**. Avista has begun outreach to fleet operators in its service territory to understand their electrification plans and possible charging locations. Collecting and refining data from these outreach activities will advance Avista’s ability to inform forecasting studies.

   - **Analysis of satellite imagery**. Though an imperfect indicator of the presence of vehicle fleets, satellite imagery is a low-effort method of identifying fleets at Avista’s commercial and industrial service points. Collecting and enhancing data from an analysis of satellite imagery will advance Avista’s ability to inform forecasting studies.

   - **Acquire fleet inventory data**. Washington’s Department of Ecology is currently conducting a fleet inventory that requires fleets with five or more vehicles to register vehicle types, counts, and depot locations. The team recommends that Avista pursue this data source for its service territory when it becomes available.

2) **Develop Commercial EV Charging Profiles**. Limited data are available to characterize EVSE charging profiles, especially for commercial fleets. The AEG Team recommends that Avista conduct load research on commercial fleet charging.

3) **Develop Seasonal EV Charging Profiles**. The team did not have sufficient data to characterize seasonal differences in EV charging profiles (kW per hour) and driving patterns (vehicle miles traveled per day), so AEG assumed the summer and winter charging profiles are the same in Avista's service territory. However, the winter charging profile could be more significant due to vehicle cabin space heating or smaller because of less EV driving in the winter. Therefore, AEG recommended that Avista conduct load research on seasonal EV charging.

4) **Conduct Additional Scenario Analyses**. The DER adoption forecast analyzed two scenarios: a reference scenario and a high-incentive scenario. Consider adding additional scenarios to study the impacts of climate change (e.g., weather, customer grid resiliency) and ancillary services incentives on DER forecasting. Integrate the DER and DR Potential Studies. Some types of DERs, like EV charging and customer battery storage, can be leveraged in DR events. Therefore, it would benefit Avista to integrate its DER and DR potential studies to avoid overestimating or underestimating the combined potential.

5) **Consider Adding Building Electrification**. Building electrification and load flexibility can affect customer's decisions regarding DER installations. Therefore, including building electrification and associated load control measures (e.g., connected thermostats, heat pump water heater switches) in future DER potential studies would provide Avista with a more comprehensive understanding of customer load growth and opportunities to shape it with programs and rates.

6) **Consider Adding Emerging Technologies**. Emerging technologies, such as autonomous vehicles and vehicle-to-grid technologies, can change customer energy consumption patterns. Therefore, in future DER potential studies, Avista may want to consider emerging technologies as they become commercially available.

Named Communities Investment Fund

Chapter 4 of the Company's 2021 CEIP identified the specific actions Avista will undertake to meet the four-year interim targets to ensure community benefits are recognized and progress on Customer Benefit Indicators (CBIs) are addressed. This chapter outlines programs and initiatives demonstrating the Company's commitment of efforts and resources to ensure the benefits of the Company's transition to cleaner energy are extended to all, especially those who are members of Named Communities. As part of this commitment, Avista is investing 1% of total electric retail revenues or approximately $5 million through the NCIF annually as shown in Table 6.9.

Table 6.9: NCIF Spending by Category

NCIF Amount	NCIF Category
40% or up to $2 million	Energy Efficiency Supplement
20% or up to $1 million	Distribution Resiliency
20% or up to $1 million	Customer & Third-Party Grants & Incentives
10% or up to $0.5 million	Outreach & Engagement
10% or up to $0.5 million	Other Projects, Programs, or Initiatives

The utilization of the NCIF will include guidance from its equity and community-based partners, specifically the Equity Advisory Group (EAG). In its founding year, the EAG played a critical role in identifying CBIs and defining Vulnerable Populations. It continues to be a vital partner for providing equity guidance considerations for a variety of Avista's programs and projects to help assure an equitable clean energy transformation for all customers. Avista is enthusiastic about assisting and supporting all customers, especially those in Named Communities in the equitable transition to clean energy by leveraging the NCIF.

Early in 2023, the EAG participated in a Results Based Accountability (RBA) activity to identify and prioritize energy efficiency initiatives for Named Communities and identified the following priorities:

- Improve awareness and energy efficiency for Spokane Tribe, multi-family, and manufactured homes.
- Increase tree canopy.
- Increase access to energy efficiency products and appliances.
- Increase awareness and engagement in energy efficiency programs.
- Match funds for energy efficiency grant applications to community-based organizations and tribal partners.
- Improve energy efficiency for those without stable housing.

The group's prioritized initiatives for the energy efficiency NCIF grants focus to closely align with the Specific Actions identified in Chapter 4 of the 2021 CEIP (i.e., energy efficiency programs for multi-family split incentive between tenant and landlords, manufactured/mobile homes, single family weatherization and community and small business, with the Community Identified Projects being addressed with the EAG RBA). A few distinctions of the EAG's initiatives are callouts for those who are unhoused, tree canopy, and emphasis for tribal partners – the latter is a component of Highly Impacted Communities.

Avista continues to engage with and update the EAG on the progress of their identified NCIF initiatives above. The Company also provides updates to other interested parties through public participation meetings on spending, projects implemented, and the impact to Named Communities through the NCIF. The NCIF administration and governance includes an internal advisory group with representation from Avista's Energy Efficiency department and other interested parties such as regulatory, external communications, and the clean energy department to evaluate all NCIF awards for projects and programs.

In 2023, 21 projects were awarded or utilized NCIF funding totaling $1,382,129. This included 10 energy efficiency projects, two distribution resiliency projects, five customer or community grants, a pilot for medical battery back-up and outreach and engagement. The energy efficiency projects funded in the report year included health and safety for manufactured homes, efficiency upgrades at an affordable housing complex and homes in an area devasted by the wildfire, a lighting project at a rural fairground, and energy audits for the buildings located on tribal land. The information from the audits was used to submit a resiliency grant to a state organization. This project, funded by the grant award coupled with the NCIF, is expected to save approximately 340,000 kWh per year, while saving over $30,000 in annual energy costs for the one building alone. The upgrades are also expected to offset 3,091 pounds of CO_2e by replacing aging equipment and decommissioning outdated, high-emitting refrigerant.

In most cases, resiliency projects span multiple years. In 2023, NCIF committed to a community center project that is expected to be completed in 2025. This project received state funding along with an NCIF grant and is designed to help develop a neighborhood resilience center to provide shelter and resources during climate and other emergencies. As of June 2024, four awards were committed for workforce development, HVAC replacements, tree plotter software for planned tree canopy and air conditioner distribution to Avista electric customers were made, totaling $315,906. Avista will expand outreach activities to raise awareness of NCIF to engage underrepresented groups in the upcoming year.

Other Company Initiatives

Spokane Tribe Partnership

Avista continues to partner with the Spokane Tribe of Indians to design a grid resiliency solution in Wellpinit, Washington. This project is funded through a design grant from the Department of Commerce Clean Energy Fund, with matching funds provided by Avista. The goal is to develop an energy delivery platform to enhance grid resiliency for Wellpinit and surrounding areas. The solution, termed a "resiliency station," is envisioned as a modernized, centralized facility providing energy resiliency in Wellpinit through a microgrid solution with an integrated battery energy storage system. The microgrid will be a small-scale power system operating independently from the traditional grid to serve critical loads when source power is interrupted, allowing vital support services to remain functioning during outages, wildfire scenarios, and other natural disasters.

The resiliency station would create a "critical loads" circuit to prioritize power to three buildings identified by the Tribe as critical to operations during emergencies. They include the Spokane Tribal administrative building, the David C. Wynecoop Memorial Health Clinic, and the Tribal Public Safety building. This station would replace some of the existing stepdown infrastructure in Wellpinit, freeing up the area for future redevelopment while improving the aesthetics and functionality of the distribution system. Based on preliminary modeling, Avista estimates the resiliency station could leverage existing generation resources, including solar and diesel generators, to sustain typical summer building loads for all three buildings for up to seven days.

A site located in Wellpinit, along Agency Loop Road, has been identified as the preferred project site. The approximately 0.72 acre site is large enough to house a battery energy storage system, pad mount equipment, and a control enclosure for microgrid controls. Station components will be securely enclosed to isolate critical electrical components from the public, while simultaneously providing an innovative means to showcase the facility, educate the public, and support the Spokane Tribe's long-term vision of energy sovereignty.

Over the last few months, Avista has provided technical assistance to the Tribe as they completed an application for $2.75 million from the Washington State Department of Commerce Tribal Clean Energy grant fund towards construction of the resiliency station. Total project costs are expected to be approximately $6.65 million. Avista and the Spokane Tribe are committing to funding the balance of the project from a variety of sources including Avista's NCIF and a U.S. Department of Energy Grid Resiliency Formula Grant that has been awarded to the Spokane Tribe.

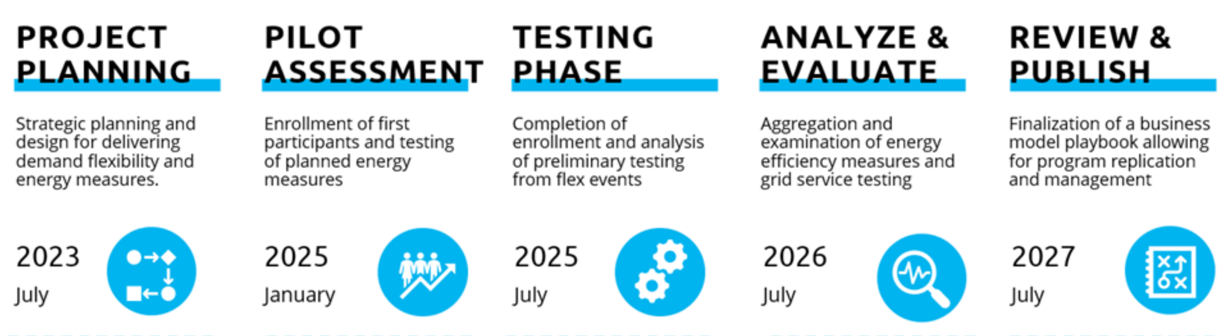
Connected Communities

Avista partnered with Edo, Pacific Northwest National Labs (PNNL), and Urbanova to create a business model to scale grid-enabled and efficient buildings to actively participate in offsetting electric production and the delivery of demand resources as an effort to elevate overloading a distribution feeder near its capacity. Edo, a business partnership between McKinstry and Avista Development, is the prime recipient of the Department of Energy's Connected Communities grant award. Edo represents the scalable business model for creating "Active Demand and Energy Management" services. Avista, a subrecipient in the grant award, is responsible for designing customer product solutions to combine energy efficiency, residential smart thermostats, commercial building energy optimization systems, managed EV charging, and residential battery technology to be aggregated into a locational targeted virtual power plant. Avista will operate "as an aggregator" to schedule, dispatch, and control the customer demand products to address system balancing requirements at the supply and delivery systems.

The project will recruit 20-25 commercial participants and 50 to 100 residential participants, with the goal of creating between 1 to 2.5 MW of flexible load. The utility will administer "flex events" where Avista will adjust dispatchable assets such as smart thermostats and residential batteries. Customers will retain the ability to "opt out" of flex events by manually overriding event set points. Customers will receive varying incentive payments depending on their level of participation.

Commercial and Industrial recruitment launched in the second quarter of 2024. Residential and small and medium business customer recruitment will launch in the third quarter of 2024. All participating customers must reside within the Third and Hatch substation service boundary for the Connected Communities pilot project to help with feeder capacity. The Third and Hatch substation has eight distribution feeders serving four distinct neighborhoods. Most of these neighborhoods are in the City of Spokane Opportunity Zone. Figure 6.6 outlines the timeline for the Connected Communities program.

Figure 6.6: Connected Communities Timeline



7. Supply-Side Resource Options

Avista evaluates several generation options including Distributed Energy Resources (DERs) and utility-scale resource options to meet future resource deficits. This resource plan evaluates upgrading existing resources, constructing utility-owned new generation facilities, and contracting with other energy companies. This chapter describes the costs and characteristics of the utility-scale resource options Avista is considering in the 2025 IRP. Most resource options are generic, as resources are typically acquired through competitive processes such as a Request for Proposal (RFP). Due to siting, engineering or financial requirements, this process may yield resources differing from this IRP in terms of resource type, size, cost, and operating characteristics. It may also result in securing output from existing resource options available in the region.

Section Highlights

- Future competitive acquisition processes may identify new or existing resources using different technologies with differing costs, sizes, or operating characteristics.
- The Inflation Reduction Act (IRA) tax incentives are included in resource costs.
- Solar, wind, and other renewable resource options are modeled as Power Purchase Agreements (PPA) instead of utility ownership.
- Avista models several energy storage options including pumped storage hydro, lithium-ion and flow batteries, hydrogen, iron-oxide, and ammonia.

New Resource Options

Resource options in this analysis include those commercially available and future resource technology options with a strong likelihood of commercial availability. The analysis does not include theoretical options or technologies in pre-commercial phases, nor does it consider variants of a technology, such as natural gas or wind plants made by different manufacturers. A representative plant for each technology type was chosen. Resource opportunities must be located within or near Avista's service territory with verifiable costs and generation profiles priced as if Avista developed and owned the generation or acquired generation from Independent Power Producers (IPPs) through a PPA. Resources using PPAs rather than ownership include pumped hydro storage, wind, solar (with and without storage), geothermal, and nuclear.

Resource options assuming utility ownership include natural gas-fired combined cycle combustion turbines (CCCT), simple cycle combustion turbines (SCCT), natural gas-fired reciprocating engines, ammonia- and renewable natural fueled gas-fired SCCTs, energy storage, hydrogen fuel cell, biomass, and upgrades to existing facilities. New coal-fired units were not included or considered. Modeling resources as PPAs or ownership does not preclude the utility from acquiring new resources in other manners but serves as a cost estimate for the new resources. Several other resource options described later in the chapter are not included in the portfolio analysis but are discussed as potential resource options as they may appear in a future RFP.

It is difficult to accurately model potential contractual arrangements with other energy companies as an option in the plan, specifically for existing units or system power, but such arrangements may offer a lower customer cost when a competitive acquisition process is completed. Avista plans to use a competitive RFP process for resource acquisitions where possible to ensure the lowest cost resource is acquired for customers. However, other acquisition processes may yield better pricing on a case-by-case basis, especially for existing resources available for shorter periods. Avista uses the IRP, RFPs, and market intelligence to determine and validate its upgrade alternatives when evaluating upgrades to existing facilities. Upgrades typically require competitive bidding processes to secure contractors and equipment.

The costs of each resource option described in this chapter do not include the cost related to upgrading the transmission or distribution system described in Chapter 8 or third-party wheeling costs. All costs are considered on Avista's side of the interconnection point. Avista excludes costs on the third-party side of the interconnection point to allow for consistent cost comparison as resource costs are highly dependent on the location in relation to Avista's system. These costs are included when Avista evaluates the resources for selection in an RFP and within the IRP portfolio analysis. All costs are levelized by discounting nominal cash flows by the 6.5% weighted average cost of capital approved by the Idaho and Washington Commissions.[66] All costs in this section are in 2026 nominal dollars unless otherwise noted. All cost calculations and operating characteristic assumptions for generic resources and PPA pricing calculations are available in Appendix G and on Avista's website.[67]

Avista relies on several sources for resource costs including the National Renewable Energy Laboratory (NREL)[68], Northwest Power and Conservation Council (NPCC or Council), publicly available energy consultant reports, press releases, regulatory filings, internal analysis, other publicly available studies, developer estimates, as well as Avista's experience with certain technologies to develop its generic resource assumptions. In addition, Avista's 2022 All-Source RFP was utilized to ensure assumed costs for solar, wind, combined solar and storage, and other resource options were in line with pricing available from actual projects within or near Avista's service territory.

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[66] Idaho Order No. 35909 in Case No AVA-E-23-01, Washington Dockets UE-220053 Final Order 10/4.
[67] www.myavista.com/about-us/integrated-resource-planning.
[68] NREL (National Renewable Energy Laboratory). 2023. 2023 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory. Technologies | Electricity | 2023 | ATB | NREL

Levelized resource costs illustrate the differences between generator types. The values reflect the cost of energy if the plants generate electricity during all available hours of the year. Plants do not generally operate at their maximum generating potential because of market and system conditions. Costs are separated between energy in $/MWh and capacity in $/kW-year to better compare technologies.[69] Without this separation of costs, resources operating infrequently during peak-load periods would appear more expensive than baseload CCCTs, even though peaking resources provide lower total cost when operating only a few hours each year. Avista levelizes the cost using the production capability of the resource. For example, a natural gas-fired turbine is available 92% to 95% of the time when accounting for maintenance and forced outages. Avista divides the cost by the amount of megawatt hours the machine is available to produce energy and not expected to operate. For generators limited by fuel availability, such as solar or wind, resource costs are divided by its expected production.

Distributed Energy Resources

This IRP includes several DER options. DERs are both supply-and-demand-side resources located at either the customer location or at a utility-controlled location on the distribution system. Demand side DERs include energy efficiency and demand response (DR), each are discussed in Chapter 6. Avista includes forecasts for customer-owned solar and electric vehicles as part of its load forecast discussed in Chapter 3.

In addition to demand-side DERs, supply-side resource options include small scale solar and battery storage. Avista includes specific cost estimates for smaller scale projects described in Chapter 6 along with the energy, capacity, and ancillary service benefits traditional utility scale projects offer. Any additional benefits due to project location, such as improving line loss with DERs over alternative utility scale projects are also included. Other locational benefits may be credited to the project if it alleviates distribution constraints. Projects on the customer side may also provide reliability benefits to the specific customer.

Natural Gas-Fired Combined Cycle Combustion Turbine

Natural gas-fired CCCT plants provide reliable capacity and energy for a relatively modest capital investment. The main disadvantages of CCCT generation are cost volatility due to reliance on natural gas (unless utilizing hedged fuel prices) and air emissions. This analysis models CCCTs as a “one-on-one” (1x1) configuration with duct fire capability, using hybrid air/water cooling technology and zero liquid discharge. The 1x1 configuration consists of a single gas turbine with a heat recovery steam generator (HRSG) and a duct burner to gain more generation from the steam turbine. While larger size plants with higher efficiencies are available such as 2x1 configuration, these are too large for Avista’s system without a partner. Avista prefers CCCT plants with nameplate capacity ratings between 180 MW and 312 MW unless it is sharing the facility with other utilities.

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[69] Storage technologies use a $ per kWh rather than $ per kW because the resource is both energy and capacity limited.

Cooling technology is a major cost driver for CCCTs. Depending on water availability, lower-cost water cooling technology could be an option similar to Avista's Coyote Springs 2 plant. Without access to water rights, a more capital-intensive and less efficient air-cooled technology is required. Avista assumes water is available for plant cooling based on its internal analysis, but only enough water rights for a hybrid system utilizing the benefits of combined evaporative and convective cooling technologies.

This analysis includes one CCCT plant option sized at 312 MW with 1x1 configuration and duct fire capability. Avista reviewed several CCCT technologies and sizes and selected this plant type as the best fit for the needs of Avista's customers for IRP planning. If Avista were to pursue a new CCCT, a competitive acquisition process will allow analysis of other CCCT technologies and sizes at both Avista's preferred and other locations. It is also possible Avista could acquire an existing CCCT resource from one of the units in the Pacific Northwest.

The most likely location for a new CCCT is in the Rathdrum, Idaho area, mainly due to Idaho's lack of an excise tax on natural gas consumed for power generation, a lower sales tax rate relative to Washington, and lack of state taxes or fees on carbon dioxide emissions, such as Washington's Climate Commitment Act (CCA) unless imported into the state of Washington.[70] Likely CCCT sites would be on or near Avista's transmission system to avoid third-party wheeling costs. Another advantage of siting a CCCT resource in Avista's Idaho service territory is access to relatively low-cost natural gas on the Gas Transmission Northwest (GTN) pipeline. Avista owns a site with these potential natural gas connection points if it needs to add additional capacity from a CCCT or other technology.

CCCT technology efficiency has improved since Avista's current CCCT generating fleet entered service with heat rates as low as 6,400 Btu/kWh for a larger facility and 6,700 for smaller configurations. Duct burners can add additional capacity with heat rates in the 7,200 to 8,400 Btu/kWh range.

The anticipated capital costs for the modeled CCCTs, located in Idaho on Avista's transmission system with allowance for funds used during construction (AFUDC) on a greenfield site, are approximately $1,422 per kW in 2026 dollars. These estimates exclude the cost of transmission and interconnection. Table 7.1 details the levelized plant cost assumptions, split between capacity and energy, for the combined cycle option discussed here and the natural gas peaking resources discussed in the next section. The costs include firm natural gas transportation, fixed and variable O&M, and transmission. Table 7.2 summarizes key cost and operating components of natural gas-fired resource options. Competition from alternative technologies and the need for additional flexibility

[70] Washington state applies an excise tax on all fuel consumed for wholesale power generation, the same as it does for retail natural gas service, at approximately 3.852%. Washington also has higher sales taxes and carbon dioxide mitigation fees for new plants.

for intermittent resources are likely to put downward pressure on future CCCT costs. Avista is not modeling carbon capture for natural gas facilities until proven technology can be demonstrated.

Natural Gas-Fired Peakers

Peaking resources, such as natural gas-fired simple cycle combustion turbines (SCCT) and reciprocating engines, provide low-cost capacity energy as needed. Technological advances coupled with a simpler design relative to CCCTs allow SCCTs to start and ramp quickly, providing regulation services and reserves for load following, and support for variable energy resource integration.

This analysis models frame and reciprocating engine technologies; however, other technologies would be considered in resource acquisition. Natural gas-fired peakers have different load following abilities, costs, generating capabilities, and energy-conversion efficiencies. Table 7.1 depicts the levelized cost for these technologies. Table 7.2 reflects the cost and operational characteristics based on internal engineering estimates. This analysis also considers using Renewable Natural Gas (RNG) as an alternative fuel in its CT analysis or offsetting natural gas use with Renewable Thermal Certificates.

Firm natural gas fuel transportation is an electric generation reliability issue with FERC and is also the subject of regional and extra-regional forums. For this plan, Avista includes the cost of on-site fuel storage such as liquified natural gas (LNG) for all natural gas turbine options within the capacity expansion model netted for the market arbitrage benefit the assets create. Avista assumes non-firm gas transportation is available except for short-term peak events requiring the use of on-site LNG storage. In addition to on-site fuel storage, other options could be available for existing and new natural gas resources to ensure plant availability for resource adequacy events, such as contracting for firm natural gas transportation rights, purchasing an option to exercise the rights of another firm natural gas transportation customer during peak demand times, or on-site fuel oil.

Table 7.1: Natural Gas-Fired Plant Levelized Costs

Plant Name/Location	Total $/MWh	$/kW-Yr Capability	Variable $/MWh	Winter Capacity (MW)
7F .04 CT Frame Greenfield (Idaho)	62.0	107.1	49.4	180
7F .04 CT Frame Greenfield (Washington)	64.0	109.7	51.1	
7F .04 CT Frame Greenfield + RNG (Idaho)	229.6	120.7	215.1	90
7F .04 CT Frame Greenfield + RNG (Washington)	229.9	123.3	215.1	
Reciprocating Engine (ICE) Machine (Idaho)	64.3	160.3	45.4	185
Reciprocating Engine (ICE) Machine (Washington)	66.2	164.2	46.8	
NG CCCT (1x1 w/DF) (Idaho)	60.3	193.7	37.5	312
NG CCCT (1x1 w/DF) (Washington)	61.9	197.7	38.7	

Table 7.2: Natural Gas-Fired Plant Cost and Operational Characteristics[71]

Plant Name/Location	Capital Cost with AFUDC ($2026/kW)	Fixed O&M ($2026/ kW- yr)	Heat Rate (Btu/ kWh)	Variable O&M ($/MWh)	Total Project Size (MW)	Total Cost (Mil$-2026)
7F .04 CT Frame Greenfield (Idaho)	929	5.6	10,040	3.3	180	168
7F .04 CT Frame Greenfield (Washington)	953					172
7F .04 CT Frame Greenfield + RNG (Idaho)	929	16.7	10,040	3.8	90	168
7F .04 CT Frame Greenfield + RNG (Washington)	953					172
Reciprocating Engine (ICE) Machine (Idaho)	1,422	5.6	8,190	6.9	185	264
Reciprocating Engine (ICE) Machine (Washington)	1,459					271
NG CCCT (1x1 w/DF) (Idaho)	1,422	33.0	6,820	5.5	312	443
NG CCCT (1x1 w/DF) (Washington)	1,459					455

Wind Generation

Wind resources have no direct air emissions or fuel costs but are not dispatchable to meet load. Avista models four general wind location options in this plan: Montana, Eastern Washington, the Columbia River Basin, and offshore. Configurations of wind facilities are changing given regional transmission limitations, federal tax credits, low construction prices, and the potential for energy storage. These factors allow sites to be built with

[71] Costs based on Idaho. Washington's costs would be slightly higher due to a higher sales tax rate of 8.9% compared with Idaho's 6.0% rate.

higher capacity levels than the transmission system can currently integrate. When wind facilities generate additional MWhs above the physical transmission limitations,[72] the generators typically feather (i.e., stop or reduce generation) or store energy using onsite energy storage. At this time, Avista is not modeling wind with onsite storage or wind facilities with greater output capabilities than can be integrated on the transmission system. Avista's modeling process allows for storage to be sited at a wind facility if cost effective.

Capital expenditures, including construction financing and O&M costs for onshore wind with start dates from 2026 to 2045 can be found in Tables 7.3 and 7.4, respectively. Fixed O&M does not include indirect charges to account for the inherent variation in wind generation, often referred to as variable wind integration. The cost of wind integration depends on the penetration and diversity of wind resources in Avista's balancing authority and the market price of power.

Wind capacity factors in the Northwest range between 35% and 38% depending on location and 42% to 52% range in Montana and offshore locations. This plan assumes Northwest wind (Washington and Oregon) has a 35% average capacity factor, while Montana and offshore wind have average capacity factors of 44% and 50%, respectively. A statistical method, based on regional wind studies was used to derive a range of annual capacity factors depending on the wind regime in each year (see Chapter 9, stochastic modeling assumptions subsection for details).

Offshore wind has higher expected annual capacity factors (50%), but development and operating costs are also much higher. At the time of this plan's analysis, developers have not been offering an offshore product in the Pacific Northwest and are still in the early stages of permitting and cost estimation.

Levelized wind costs change substantially due to the capacity factor but can also be impacted even more by tax incentives and ownership structure. Table 7.5 shows the nominal levelized prices with different start dates for each modeled location. These price estimates assume a 20-year PPA with a flat pricing structure, including the cost of the PPA, excise taxes, commission fees, and uncollectables[73] to customers. These prices do not include transmission costs for either capital investments or wheeling purchases nor integration costs. If a wind PPA is selected in Avista's resource strategy, the model assumes the PPA will extend through at least 2045.

[72] If transmission is limited due to contractual reasons, an additional option is to buy non-firm transmission to move the excess power.
[73] Uncollectables refer to additional revenue collected from customers to cover the payments not received from other customers.

Photovoltaic Solar

Avista models solar system configurations as resource options. Utility scale options are discussed here, while distributed systems under 5 MW located primarily on the customer side of the meter, are discussed in Chapter 6. Utility-scale on-system solar facilities assume a minimum capacity of 100 MW to take advantage of economies of scale and single axis systems. There are also two generic locations for resource selection, the first is local on-system resources within Avista's transmission system with a higher capacity factor potential, and the second option is further south either in Oregon or Idaho and requires transmission acquisition. Avista expects other locations to participate in future RFPs. Tables 7.3 and 7.4 show capital and fixed O&M forecasts for these resources, and the levelized prices for a 20-year PPA are detailed in Table 7.5. These costs do not include transmission costs associated with new construction, wheeling purchases, or integration costs.

Table 7.3: Forecasted Solar and Wind Capital Cost ($/kW)

Year	Utility Scale Solar	NW Wind (On-System)	Montana Wind	Off-Shore Wind
2026	1,469	1,592	1,680	5,730
2030	1,382	1,573	1,711	5,888
2035	1,231	1,670	1,827	6,230
2040	1,266	1,768	1,947	6,677
2045	1,292	1,867	2,070	7,210

Table 7.4: Forecasted Solar and Wind O&M ($/kW-yr.)

Year	Utility Scale Solar	NW Wind (On-System)	Montana Wind	Off-Shore Wind
2026	23.97	31.33	33.75	100.22
2030	23.49	32.14	35.27	102.74
2035	22.63	34.67	38.02	107.85
2040	24.16	37.35	40.93	114.63
2045	25.74	40.19	44.00	122.81

Table 7.5: Levelized Solar and Wind Prices ($/MWh)

Year	Utility Scale Solar	NW Wind (On-System)	Montana Wind	Off-Shore Wind
2026	37.62	34.89	28.32	127.83
2030	28.37	28.73	23.86	125.54
2035	45.26	47.50	42.59	147.74
2040	46.37	63.33	58.44	169.46
2045	47.23	66.75	61.94	180.69

Solar with Energy Storage (Lithium-ion Technology)

Solar paired with energy storage reduces costs attributable to sharing local infrastructure, it can also directly shift energy deliveries, manage intermittent generation, use common equipment, increase peak reliability, and can prevent energy oversupply by storing the excess generation.

Lithium-ion technology prices are declining and will likely continue to fall due to increasing manufacturing levels and product enhancements. Levelized costs for the three storage sizes and durations modeled as solar PPAs based on a 100 MW solar facility are shown in Table 7.6. Avista modeled 2- and 4-hour duration options. Avista's experience with solar generation from its 19.2 MW Adams-Neilson PPA reveals significant energy variation due to cloud cover and that on-site storage could be beneficial, but at this time other resources can provide this service at a lower cost. For this analysis, Avista considers the benefits for reducing the variable generation integration costs and enhanced resource adequacy of the storage device within the resource selection model. Currently, due to the complexity and range of potential storage configurations, the analysis considers only the 2- and 4-hour designs. In addition, Avista's modeling of solar plus storage allows the storage device to use grid power.

Table 7.6: Levelized Cost for Lithium-Ion Storage at a Solar Facility ($/kW-month)

Year	100 MW/ 400 MWh	100 MW/ 200 MWh	50 MW/ 200 MWh
2026	15.18	10.17	6.25
2030	14.72	10.08	6.20
2035	17.88	12.15	7.25
2040	18.17	12.44	7.40
2045	18.34	12.67	7.51

Stand-Alone Energy Storage

Energy storage resources are gaining significant traction to meet short-term capacity needs in the western U.S. Energy storage does not create energy but shifts it from one period to another in exchange for a portion of the energy stored. Avista modeled several energy storage options including pumped hydro, lithium-ion and flow batteries, and iron oxide. In addition to the technological differences, Avista also considers different energy storage durations for each technology. Pricing for energy storage is rapidly changing due to technological advancements and the 2022 Inflation Reduction Act (IRA), providing tax credits for all storage technologies through 2032.[74] In addition to changing prices for existing technologies, new technologies are entering the storage space with similar characteristics and pricing as those modelled in this IRP such as battery systems using

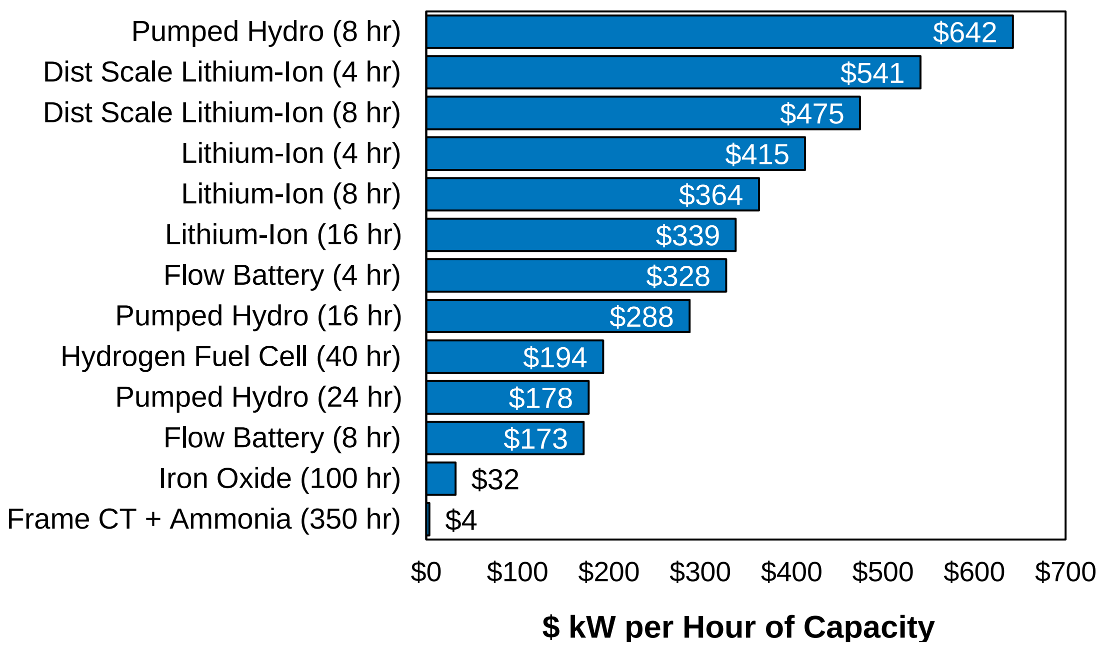
[74] The IRP does consider extension of the tax credits for safe-harbor construction where the tax credit can be available for projects under construction in 2032, but not complete.

sodium solid state technology. The rapid change in pricing and emergence of new technologies justify the need to update prices and technology options for each IRP.

Another challenge with energy storage concerns pumped hydro technology where costs and storage duration can be substantially different depending on the geography of the proposed project. Energy storage is also gaining attention to address transmission and distribution expansion, where the technology can alleviate conductor overloading and short duration load demands rather than adding physical line/transmission capacity. Please see Chapter 8 for more details about using storage as a non-wire alternative.

Energy storage cannot be shown in $ per MWh as with other generation resources because storage does not create energy, but rather stores it and incurs losses. The analysis shown in Figure 7.1 illustrates the cost differences between the technologies when capital cost (2030 dollars) is divided by duration of storage but does not consider the efficiency of the storage process or the pricing of the energy stored. This analysis is performed in the resource selection process within modeling the resource operations within Aurora.

Figure 7.1: Energy Storage Upfront Capital Cost versus Duration



Pumped Hydro Storage

Pumped hydro is the most prolific energy storage technology currently used in both the U.S. and internationally. This technology uses two or more water reservoirs at different elevations. When prices or loads are low, water is pumped to a higher reservoir and then released during periods of higher price or load. This technology may also help meet system integration needs from intermittent generation resources. Only one of these projects exists in the northwest and several more are in various stages of the permitting process. Advantages with pumped hydro include the technology's long service life and Avista's familiarity with the technology as a hydro generating utility. The greatest disadvantages are high capital costs and long permitting cycles.

Pumped hydro has good round trip efficiency rates; Avista assumes 80% for most options. Projects are designed to utilize the amount of water storage in each reservoir and the generating/pump turbines are sized for how long the capacity needs to operate. Avista models this technology with three different durations including 8, 16, and 24 hours. Durations are the number of hours the project can run at full capacity. Pricing and duration of these facilities are based on projects currently being developed in the Northwest. As an energy-limited water system, Avista includes different duration times to ensure resources have sufficient energy to provide reliable power over an extended period in addition to meeting single hour peaks. The complete range in levelized cost for pumped hydro is shown in Table 7.7. Options also include a $0.54 per MWh variable payment for each MWh generated (2021 base year, escalating with inflation).

Table 7.7: Pumped Hydro Options Cost ($/kW-month)

Year	8 hours	16 hours	24 hours
2026	25.37	23.01	21.47
2030	27.70	25.12	23.45
2035	30.91	28.04	26.17
2040	55.45	50.11	46.62
2045	61.89	55.93	52.04

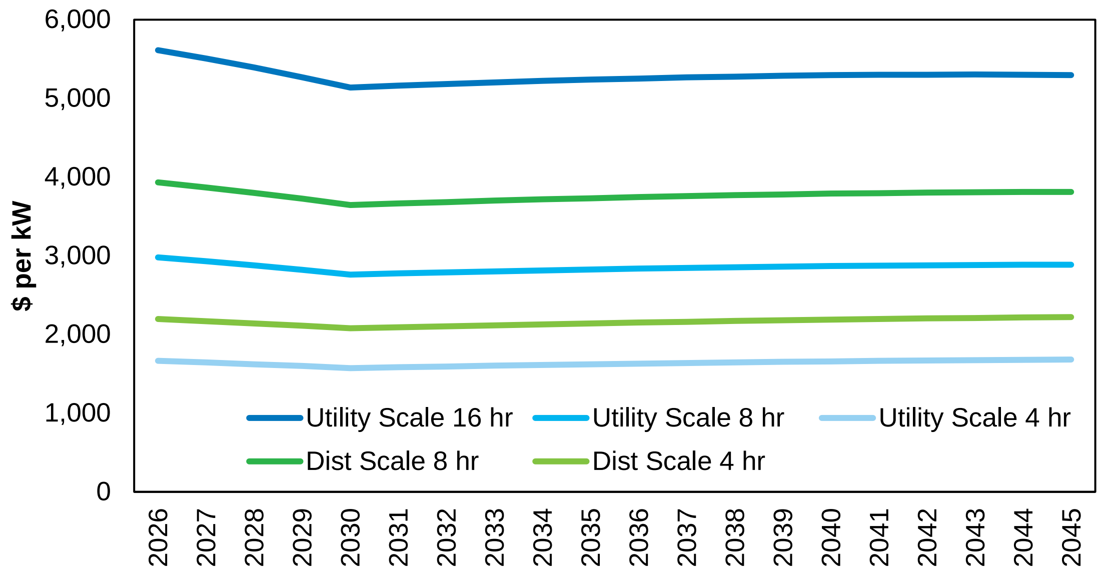
Lithium-Ion Batteries

Lithium-ion technology is one of the fastest growing segments of the energy storage space. This section focuses on energy storage as a stand-alone resource rather than coupled with solar as discussed earlier. For modeling purposes, lithium-ion assumes utility ownership, but it could be acquired through a PPA for a 20-year life with augmentation of the battery cells. Fixed O&M costs include replacement cells to maintain 80% energy conversion efficiency and capacity for this storage option. Estimated costs include 2022 IRA federal tax credits.

Lithium-ion technology is an advanced battery using ionized lithium atoms in the anode to separate their electrons. This technology can carry high voltages in small spaces making it a preferred technology for mobile devices, power tools, and electric vehicles. The large manufacturing sector of the technology is driving prices lower allowing the construction of utility scale projects. Avista expects lithium-ion technology to evolve over the planning horizon and new elements may be used to augment or replace lithium-ion. Future IRPs will identify any advancement in battery technology.

Avista modeled five stand-alone configurations for lithium-ion batteries. Two DER small-scale sizes (<5 MW) with 4- and 8-hour durations for modeling the potential for use on the distribution system and three larger systems (25 MW+), including 4- and 8-hour durations, as well as a theoretical 16-hour configuration. Modeling assumptions for these scenarios were derived from publicly available energy consultant sources. Figure 7.2 shows the capital cost forecast for each configuration of size and duration considered. Avista classifies the 4-hour battery as the standard technology with capital and fixed O&M costs in 2026 of $1,663 per kW and $41.57 per kW-year, respectively.

Figure 7.2: Lithium-ion Capital Cost Forecast



Storage technology is often displayed differently than other resources to illustrate the cost since it is not a traditional capacity resource. Table 7.8 shows the levelized cost per kW-month for each configuration. This calculation reflects the levelized cost for the capital, O&M, and regulatory fees, including capital reinvestments, over 20 years divided by the capacity. These costs do not consider any variable costs, such as energy purchases.

Table 7.8: Lithium-Ion Levelized Cost ($/kW-month)

Year	Utility Scale 4 hour	Utility Scale 8 hour	Utility Scale 16 hour
2026	13.25	23.61	44.33
2030	12.73	22.29	41.41
2035	19.41	33.79	62.55
2040	19.82	34.23	63.05
2045	20.07	34.35	62.93

Flow Batteries

This plan models flow batteries with 4-hour and 8-hour duration in 25 MW increments. Flow batteries have the advantage over lithium-ion because they do not degrade over time which leads to a longer operating life. The technology consists of two tanks of liquid solutions flowing adjacent to each other through a membrane to generate electrons moving back and forth for charging and discharging.

Flow battery capital costs in 2026 are $1,317 and $1,383 per kW for the 4-hour and 8-hour duration batteries, respectively, both falling 10% by 2035. Fixed O&M costs of $71.52 and $80.46 per kW-year increase with inflation. Flow batteries have round-trip efficiencies between 67% and 70%. Given Avista's recent experience with flow batteries at its pilot project in Pulman, Washington, these efficiency rates are highly dependent on the battery's state of charge and how quickly the system is charged or discharged. Table 7.9 shows the levelized cost per kW-month of capacity.

Iron Oxide Storage

Another new storage technology is an iron oxide battery where energy is stored using energy created through the oxidization process. Iron is less expensive and more readily available than lithium-ion or other storage technology elements. This technology uses oxygen inside the battery to convert iron to rust and later convert it back to iron. Due to the low cost of iron relative to other elements, a long-duration resource can be obtained at similar cost compared to what is currently available, shorter duration technologies.

This analysis assumes a 100 MW iron-oxide battery with a 36.5% round-trip efficiency with 100 hours, or 10,000 MWh, of storage. Capital costs are estimated at $3,037 per kW (2026 dollars) and increase due to inflation. The fixed O&M cost of $27.90 per kW-year and levelized cost of iron oxide storage is $248.04 per kW-year ($20.67 per kW-month) for iron oxide storage, increasing with inflation in future periods. The actual costs are uncertain given this resource is relatively new for commercial energy use.

Table 7.9: Storage Levelized Cost ($kW-month)

Year	Flow Battery 4-hour	Flow Battery 8-hour	Iron Oxide 100-hour
2026	15.01	16.31	20.67
2030	15.26	16.62	21.06
2035	20.46	22.15	33.66
2040	21.45	23.27	34.33
2045	22.54	24.50	35.05

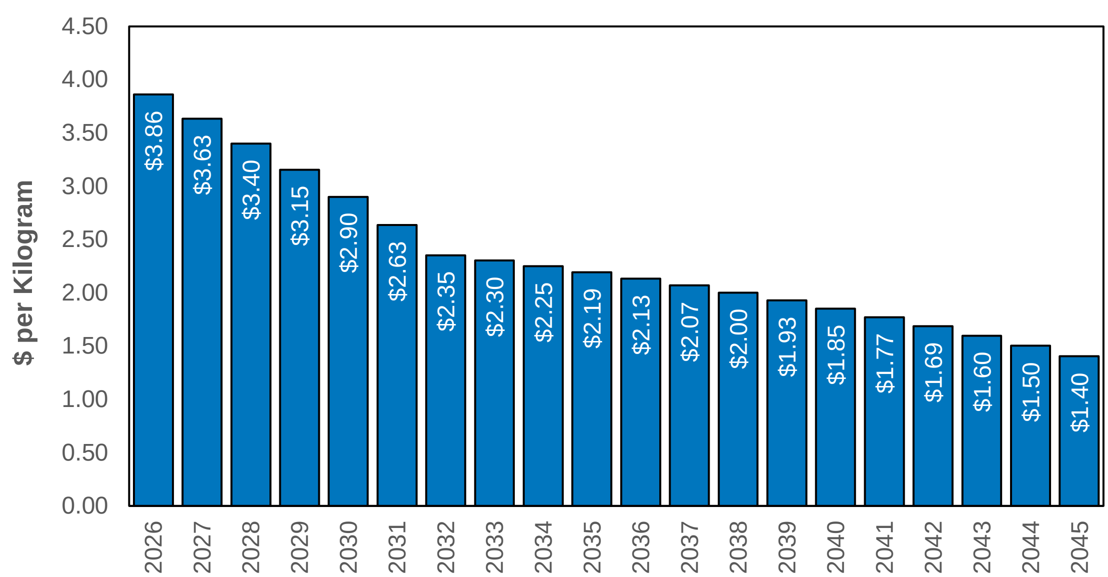
Renewable Green Hydrogen

The use of green hydrogen in the energy sector has been considered as a perennial option for the distant future. This technology allows long-duration energy storage with the potential to store enough power to continuously run for several days. Hydrogen can be delivered by pipeline, truck, or rail and stored in tanks or underground caverns before being converted back to power using a fuel cell or hydrogen-fueled turbine. The ability to store hydrogen in tanks similar to liquid air means medium term durations can be obtained. Significant research and development (R&D) dedicated to green hydrogen technologies in transportation and other sectors may result in reduced costs or increased operating efficiency. Transportation and other sectors could possibly utilize the electric power system to create a cleaner form of hydrogen to offset gasoline, diesel, propane, or natural gas.

Most hydrogen today uses methane-reforming techniques to remove hydrogen from natural gas or coal. This technology is primarily used in the oil and natural gas industries but, absent carbon sequestration, results may produce similar levels of greenhouse gas emissions (GHG) from the combustion of the underlying fuels. If hydrogen is obtained from clean energy through either electrolysis of water,[75] pyrolysis,[76] or even mined, the amount of associated GHG emissions can be greatly reduced and therefor considered green hydrogen. If renewable energy prices are low, the operating cost of creating green hydrogen could also fall if hydrogen producers have access to power with low wholesale electricity prices; however, capital costs would remain steady without significant technology enhancements.

Converting hydrogen back into power could be done with a hydrogen fuel cell or directly in a combustion turbine similar to natural gas-fired generation. Figure 7.3 shows the forecasted delivered price (nominal) of green hydrogen to a potential fuel facility in Avista's service territory[77]. The development and delivery of green hydrogen is estimated based on the projected cost of electrolyzer technology with reduction in costs expected due to scaling and access to low-cost renewable electric power and water.

Figure 7.3: Wholesale Green Hydrogen Costs per Kilogram



[75] Current estimates require 2-3 gallons of water to create 1 kilogram of hydrogen.
[76] Involves cracking natural gas into hydrogen and carbon black using electricity from clean resources.
[77] 1 kg of hydrogen is equivalent to 0.12 mmbtu natural gas or if hydrogen is $3.86 per kg is equal to $32.17 per mmbtu of natural gas equivalent.

The second step in the hydrogen fuel concept is to convert the hydrogen back to power. For this conversion, a fuel cell would be assembled for utility scale needs (Avista uses 25 MW increments for this resource). The estimated capital cost for a fuel cell is $7,095 per kW with a forty-hour storage vessel plus fixed O&M at $200 per kW-year (2026 dollars). Table 7.10 shows the all-in levelized cost of hydrogen including both the fuel cell capital recovery fixed cost and the fuel cost per MWh. Avista chose to use a fuel cell for hydrogen fuel rather than a CT to provide an emission free resource and due to likely limitations of storing the quantity of fuel required to operate a CT.

There are significant safety concerns relative to hydrogen to be resolved and mitigated as hydrogen fuel ignites more easily than gasoline or natural gas. Adequate ventilation and leak detection are important elements in the design of a safe hydrogen storage system. Hydrogen burns with a nearly invisible flame which requires special flame detectors. Some metals become brittle when exposed to hydrogen, so selecting the appropriate metal is important to the design of a safe storage system. Finally, appropriate training in hydrogen handling would be necessary to ensure safe use. Appropriate engineering along with safety controls and guidelines could mitigate the safety risks of hydrogen but would add to the high capital and operating costs of this resource option. Another option to generate power with hydrogen is to use it in a CT, currently co-firing is possible at Avista's Coyote Springs 2 and Rathdrum units if adequate cost-effective hydrogen supplies are available. While this is a viable option, Avista also considers an ammonia turbine to address storage and safety concerns with hydrogen.

Ammonia

An alternative resource option to hydrogen is clean ammonia.[78] Ammonia could be sourced from the same process as green hydrogen, but ammonia requires an additional step by adding nitrogen using the Haber-Bosch process. Current estimates, considering the hydrogen electrolysis process, estimate the round-trip efficiency of this technology with a CT for power production at 13%,[79] although with technology improvements the round-trip efficiency may reach 20%. The advantage of ammonia as a fuel over hydrogen is its ability to be stored in larger volumes in an aqueous form and transported in larger quantities at a lower cost. Hydrogen storage in large quantities requires large geologic storage and this is not known to exist near Avista's service area.

For this resource option, two 90 MW capacity combustion turbines (180 MW) using a common 30,000 metric ton storage tank could hold 55,812 MWh hours of energy storage, enough to generate power for 310 consecutive hours at full capacity. Ammonia storage

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[78] Using ammonia as a fuel is clean from a GHG perspective but burning it emits NOx as part of the combustion process. Manufacturers are currently working on SCR controls for ammonia fuel related NOx emissions, in the meantime, Avista assumes 0.015 lbs per mmbtu of combustion for this emission.

[79] This assumes one metric ton of ammonia requires 13.9 MWh of power from the upstream processes including electrolysis, desalination, pressure swing absorber, storage, and synthesis loops. Sagel, Rouwenhorst, Faria, Green ammonia enables sustainable energy production in small island developing states: A case study on the island of Curacao, 2022.

tanks are commonly used in the agricultural industry for fertilizer and modified natural gas turbines capable of ammonia combustion are actively being developed by turbine manufactures. Another advantage of this technology is the creation of green ammonia for use in agriculture. This secondary use can help offset the investment cost and risk to a utility by partnering with other industries needing ammonia.

Avista estimates ammonia gas turbine capital costs at $1,079 per kW (2026 dollars) and is expected to increase with inflation due to the use of mature technology. In 2026, fixed O&M costs are $16.74 per kW-year and carry a $3.75 per MWh variable charge in addition to the cost of the ammonia. The forecasted price of ammonia is based on the hydrogen price forecast shown in Figure 7.3 adjusted for conversion and transportation costs. As ammonia will be created from clean electric generation, the pricing of the hydrogen includes the associated power, water, and power delivery costs. The resulting levelized fixed and operating cost are shown in Table 7.10.

Table 7.10: Hydrogen Based Resource Option Costs

	Hydrogen Fuel Cell		Ammonia Turbine	
Year	Fixed Cost ($/kW-month)	Fuel & Variable Cost ($/MWh)	Fixed Cost ($/kW-month)	Fuel & Variable Cost ($/MWh)
2026	89.52	131.42	12.84	215.12
2030	97.75	103.95	14.02	234.38
2035	109.10	82.92	15.64	260.92
2040	121.77	63.70	17.46	290.49
2045	135.92	46.02	19.49	323.40

Woody Biomass Generation

Woody biomass generation projects use waste wood from lumber mills or forest management and are considered renewable and clean resources. In the biomass generation process, a turbine converts boiler-created steam into electricity. A substantial amount of wood fuel is required for utility-scale levels of generation. Avista's 50 MW Kettle Falls Generation Station consumes more than 350,000 tons of wood waste annually or about 48 semi-truck loads of wood chips per day. It typically takes 1.5 tons of wood to make one megawatt-hour of electricity, but this varies with the moisture content and quality of the fuel. The viability of another Avista biomass project depends on the long-term availability, transportation needs, and cost of the fuel supply. Unlike wind or solar, woody biomass can be stockpiled and stored for later use. Many announced biomass projects fail due to not being able to secure a reliable long-term fuel source.

Based on market analysis of fuel supply and the expected use of biomass facilities, a new facility could be a wood-fired "peaker". The capital cost for this type of facility would be $5,308 per kW in addition to the $32.09 per kW-year and $4.13 per MWh of fixed and variable O&M costs (2026 dollars). The levelized cost is $649.18 per kW-year ($54.10 per kW-month) for a 2026 project plus fuel and variable O&M costs. Avista modeled two methods of creating new biomass power for this IRP's analysis: the first is to upgrade the existing Kettle Falls facility by 10 MW and the second is to add a second unit to the facility.

Geothermal Generation

Geothermal energy provides predictable capacity and energy with minimal GHG emissions (zero to 200 pounds per MWh). Some forms of geothermal technology extract steam from underground sources to run through power turbines on the surface while others utilize an available hot water source to power an Organic Rankine Cycle installation. Due to the geologic conditions of Avista's service territory, no geothermal projects are likely to develop locally. Geothermal energy often struggles to compete economically due to high development costs stemming from having to drill several holes thousands of feet below the earth's crust with no guarantee of reaching geothermal resources. Ongoing geothermal costs are low, but the capital required for locating and proving viable sites is significant. The cost estimate for a future geothermal PPA is $57.90 per MWh in 2026 at Avista's transmission interconnection point.

Nuclear

Avista includes nuclear power as a non-emitting fuel resource option by modeling small modular reactors (SMRs). Given the uncertainty of their economics, regional political issues with the technology, U.S. nuclear waste handling policies, and Avista's modest needs relative to the size of modern nuclear plants, Avista will have challenges developing a nuclear project. In addition, a project may require partnerships with other utilities in the Western Interconnect who want to incorporate nuclear power into their resource mix and offer Avista a PPA.

The viability of nuclear power is changing as national policy priorities focus attention on decarbonizing the nation's energy supply. The limited amount of recent nuclear construction experience in the U.S. makes estimating construction costs difficult. Cost projections rely on industry studies, recent nuclear plant license proposals, and the small number of recently completed projects. SMR designs could increase the potential for additional nuclear generation by shortening the permitting and construction phase and making these traditionally large projects (over 1,000 MWs) a better fit for smaller utilities. Given this possibility, Avista included an option for small scale nuclear power in the IRP analysis. The estimated cost for nuclear per MWh on a levelized basis in 2030 is $143.76 per MWh assuming capital costs of $8,224 per kW (2026 dollars) as a PPA.

Other Generation Resource Options

Resources not specifically included as options in this analysis include cogeneration, landfill gas, anaerobic digesters, and central heating districts. This plan does not model these resource options explicitly, but continues to monitor their availability, cost, and operating characteristics to determine if the technologies become economically viable with any changes in state or federal incentives.

Exclusion from the analysis does not automatically exclude non-modeled technologies from Avista's future resource portfolio. The non-modeled resources can still compete with resources identified in the resource strategy through competitive acquisition processes when the Company solicits resources to fill known resource needs. Competitive acquisition processes can identify cost effective technologies to displace resources in the resource strategy. Another possibility includes acquisition through a Public Utility Regulatory Policies Act (PURPA) contract. PURPA allows developers to sell qualifying power to Avista at set prices and terms[80] outside of an RFP process.

Landfill Gas Generation

Landfill gas projects generally use reciprocating engines to burn methane collected at landfills. The costs of a landfill gas project depend on the site specifics. The Spokane area had a project at one of its landfills, but it was retired after the fuel source fell to an unsustainable level. Much of the Spokane area uses the Spokane Waste to Energy Plant instead of landfills for solid waste disposal. Using publicly available costs and the Northwest Power and Conservation Council (NPCC) estimates, landfill gas resources are economically promising, but are limited in their size, quantity, and location. Many landfills consider cleaning the landfill methane to create pipeline quality gas due to low wholesale electric market prices. This form of RNG has become an option for natural gas utilities to offer a renewable gas alternative to customers. The duration of this form of gas supply depends on the on-going disposal of trash, otherwise the methane could be depleted in six to nine years.

Anaerobic Digesters (Manure or Wastewater Treatment)

Plants with anaerobic digesters typically capture methane from agricultural waste, such as manure or plant residuals, and burn the gas in reciprocating engines to power generators or directly inject clean fuel into natural gas pipelines as RNG. These facilities tend to be significantly smaller than most utility-scale generation projects at less than five megawatts. Most digester facilities are at large dairy and cattle feedlots, but like landfill gas, many developers are opting to inject the gas into natural gas pipelines as RNG to achieve higher returns on their investment.

Wastewater treatment facilities can host anaerobic digesting technology. Digesters installed when a facility is initially constructed help the economics of a project significantly, although costs range greatly depending on system configuration. Retrofits to existing wastewater treatment facilities are possible but tend to have higher costs. Many of these projects offset energy use at the facility so there may be little, if any, surplus generation capability. Avista currently has a 260-kW wastewater digester system under a net metered PURPA contract with a Spokane County wastewater facility.

[80] PURPA rates, terms, and conditions are available at www.avistautilities.com under Schedule 62.

Small Cogeneration

Avista has few industrial customers with loads large enough to economically support a cogeneration project. If an interested customer developed a small cogeneration project, it could provide benefits including reduced transmission and distribution losses, shared fuel, capital, and emissions control costs, as well as credit toward Washington's EIA efficiency targets.

Another potentially promising option is natural gas pipeline cogeneration. This technology uses waste-heat from large natural gas pipeline compressor stations. Few compressor stations exist in Avista's service territory, but the existing compressors in the Company's service territory have potential for using this generation technology. A big challenge in developing any new cogeneration project is aligning the needs of the industrial facility with the utility need for power. The optimal time to add cogeneration is during development or retrofit of an industrial process, but the retrofit may not occur when the utility needs new capacity. Another challenge to cogeneration is estimating costs when such costs are driven by host operations. The best method for the utility to acquire this technology is likely through PURPA or through a future RFP.

Coal

New coal-fired plants are extremely unlikely due to current policies, emission performance standards, and the shortage of utility scale carbon capture and storage projects. The risks associated with future carbon legislation and projected low natural gas and renewables costs make investments in this technology highly unlikely. It is possible in the future there will be permanent carbon capture and sequestration technology at price points to compete with alternative fuels. Avista will continue to monitor this development for future IRPs.

Heating Districts

Historically, heating districts were preferred options to heat population dense city centers. This concept relies on a central facility to either create steam or hot water to distribute to buildings via a pipeline for end use space and water heating. Avista provided steam for downtown Spokane using a coal-fired steam plant, a concept still used in many cities and college campuses in the U.S. and Europe but using natural gas as a fuel source. Creating new heating districts necessitates suitable conditions, collaborative partners, and a forward-thinking approach, much like the developments seen in Spokane's University District.

Bonneville Power Administration

For many years, Avista received power from the Bonneville Power Administration (BPA) through a long-term contract as part of the settlement from Washington Nuclear Project Number 3 (WNP-3). Most of the BPA's power is sold to preference customers or in the short-term market. Avista does not have access to power held for preference customers but engages BPA on the short-term market. Avista has two other options for procuring

BPA power. The first is using BPA's New Resource rate. BPA's power tariff outlines a process for utilities to acquire power from BPA using this rate for one year at a time. Since this offering is short-term and variable priced, Avista does not consider it a viable long-term option for planning purposes; however, it is a viable alternative for short-run capacity needs. The other option to acquire power from BPA is to solicit an offer. BPA is willing to provide prices for periods when it has excess power or capacity. This process would likely parallel an RFP process for future capacity needs and likely take place after the current BPA agreements with public power customers ends in 2027. Purchasing power from BPA is advantageous as it's counted as nearly carbon free and can be used for compliance with Washington's Clean Energy Transformation Act (CETA) legislation and the CCA, but this benefit may result in a premium cost.

Existing Resources Owned by Others

Avista has purchased long-term energy and capacity from regional generation, specifically the Public Utility Districts in the Mid-Columbia region, Columbia Basin Hydro's irrigation projects, and a tolling agreement for the Lancaster Generating Station. Avista contracts are discussed in Chapter 4, but extensions or new agreements could be signed. If utilities are long on capacity, it is possible to develop agreements to increase Avista's capacity position. Since these potential agreements are based on existing assets, prices depend on future markets and may not be cost-based. Avista could acquire or contract for energy and capacity of existing facilities without long-term agreements. The Company anticipates these resources will be offered into future RFPs and may replace any selected resources.

Upgrade Opportunities

Avista has investigated opportunities to add capacity at existing facilities for the last several IRPs and implementing these projects if and when cost effective. The potential project upgrade opportunities for this IRP are outlined below.

Rathdrum CT

There are two options to upgrade the existing Rathdrum CT. The first is to uprate the combustion and turbine components at the Rathdrum CT, as the firing temperature can increase to 2,055 degrees from 2,020 degrees providing a 5 MW increase in output. The second project would install a new inlet evaporation system that could increase the Rathdrum CT capacity by 10 MW on a peak summer day, but no additional energy is expected during winter months.

Existing PPA Renewals and/or Repowering

Avista has three renewable energy PPAs expiring within the current IRP time horizon. The analysis includes the opportunity to repower facilities or renew the PPA at prices reflective of similar project pricing. For Palouse wind, the PPA is assumed to be able to be repowered to 120 MW in 2043. Although the Rattlesnake Flat Wind PPA does not assume a repower option due to transmission limitations, it is eligible for renewal in 2041. Adams-Neilson Solar remains at 20 MWs with a renewal option in 2039.

Qualifying Capacity Credits (QCC)

In order to differentiate between resources' ability to meet peak load, QCCs are estimated for both existing and new resources. QCCs are an estimate of the resources' ability to meet peak load hours for resource adequacy. They are not the estimated generation during the peak hour. QCCs are similar to Effective Load Carrying Capability (ELCC) estimates. Avista uses QCCs to simplify detailed hourly modeling results when modeling resources at a greater time granularity. Avista uses monthly time steps for capacity expansion analysis and therefore a QCC is estimated for each resource type by each month for each year. Table 7.11 is a summary of these QCC for winter (January) and Summer (August).

Table 7.11: Qualifying Capacity Credit for Certain Resources

	Winter			Summer		
Resource	2026	2035	2045	2026	2035	2045
Solar	3%	3%	3%	36%	24%	20%
NW Wind	6%	5%	4%	11%	10%	9%
Montana Wind	30%	27%	26%	20%	19%	18%
4 Hour Energy Storage	82%	56%	37%	74%	53%	40%
8 Hour Energy Storage	98%	83%	60%	98%	89%	76%
24 Hour Energy Storage	98%	92%	83%	98%	95%	90%
100 Hour Energy Storage	98%	98%	98%	98%	98%	98%
Demand Response (3 hour)[81]	62%	58%	50%	58%	54%	46%
Demand Response (6 hour)	124%	115%	99%	116%	108%	93%

Avista estimates the QCCs by utilizing estimates from two primary sources - the Western Power Pool's (WPP) Western Resource Adequacy Program (WRAP) and the Resource Adequacy in the Pacific Northwest (March 2019) study conducted by E3. Between the two sources Avista estimates the current QCC value for each resource and how the QCC may change over time given the region's forecasted generation capacity forecast (from the electric market price forecast). The QCCs are designed to estimate the resources' ability to meet regional demand as opposed to Avista's. The reason it estimates regional demand is to use the same QCC value for complying with the WRAP for consistency purposes and to simplify the process of estimating QCC values for each resource to save substantial Avista staff time. To validate whether these regional QCC values also meets Avista's resource adequacy requirements, Avista tests the resource portfolio using an hourly model (ARAM) to ensure the portfolio meets Avista's resource adequacy metrics.

[81] Avista did not have QCC values from either external study for demand response. To overcome this deficiency Avista assumes demand response will receive 100% QCC if the program can deliver 6 hours of load reduction, and if it is less then it will receive a proportionate amount. Further, Avista assumes DR is a load reduction and therefore gets an additional credit to the QCC value to cover the avoided planning reserve margin (PRM).

This is done by conducting a study of a future year (2030) load expectation and resources. Placeholder natural gas CT resources are added to the system until the system's reliability meets a 5% Loss of Load Probability (LOLP). Then using the total QCC in megawatts of the existing resources and the placeholder resource and comparing it to the expected peak load, Avista can estimate the PRM for planning purposes (i.e. 24% in the winter). For further detail on resource adequacy modeling see Chapter 5.

Non-Energy Impacts

Washington's CETA requires investor-owned utilities to consider equity-related non-energy impacts (NEIs) in integrated resource planning. Avista contracted with DNV for the 2023 IRP to perform a NEI study on supply-side resources to 1) conduct a jurisdictional scan to identify additional NEIs that were not specifically listed in Avista's scope, 2) identify NEIs available through federal and regulatory publications, 3) develop quantitative estimates on a $/MWh or $/kW basis as appropriate for each resource, and 4) conduct a gap analysis to provide recommendations to prioritize future research based on the necessary level of effort or anticipated value.

DNV completed a supply-side NEI database and final report on April 8, 2022. Avista includes NEIs using this study in the resource strategy analysis for the supply-side resources modeled. This is in addition to the NEIs that had previously been included on energy efficiency. These NEIs include the societal impacts of Avista's decision making when selecting new resources and represent quantifiable values to prioritize resource choices. By including these impacts, the analysis can prioritize resource decisions more equitably. For example, resources with air emissions versus those without emissions are evaluated to consider the environmental impact on local communities. The NEI values used for this analysis are in Table 7.11.

There were areas with insufficient information for DNV to provide estimated NEI values for any specific NEI types for specific supply-side resources. Where Avista did not have a value from DNV, it estimated values by using approximation techniques. For many of these areas, the research value and effort needed to address these gaps were significant. Examples of some of these areas with insufficient information were related to public health, safety, reliability and resiliency, energy security, environmental (wildfire, land use, water use, wildlife, surface air effects), economic, and decommissioning relative to some or all resource types (e.g., battery storage, hydrogen electrolyzer, etc.). Washington directives indicate a movement to require NEIs in resource planning and research, however quantifying these would require significant time and investment. It appears a more cost-effective consistent approach would be best conducted at a state-wide level.

As part of an effort to continue to enhance the use of NEIs in the IRP Avista acquired the IMPLAN model. IMPLAN is an economic model where the user inputs the direct impacts of investments, and the model calculates the indirect and induced economic and employment impacts of the investments. For example, the investment in a local wind project has a direct investment in the equipment and employment used to develop the project. The indirect effects are the impacts to the local economy of the related spending, such as construction workers and spending money at local restaurants and hotels during the development of the wind site. The induced effects are based on the multiplier process in the local economy where the local recipients of the hypothetical wind project would spend a portion of that money on local goods and services.

Avista used IMPLAN to estimate the economic effects to the local economy and then used the results in the NEI portion of the IRP analysis. IMPLAN was used to model the impacts of both capital spending and the operation of different types of resources. Avista also considered the economic effects of plant construction by placing an economic benefit for local generation resources compared to out-of-service area resources for selection in this plan. Table 7.12 shows the resource NEI values used in developing the IRP. The negative numbers indicated a benefit of the resource, and a positive value represents a cost. The economic benefits include the value of induced and indirect economic growth from operating the resource. Safety includes the estimated cost of potential injuries or deaths. Public health includes costs related to air emissions other than GHG. Lastly, operating jobs per MW is included as a reference point of the estimated long-term jobs created per MW of the resource.

Table 7.12: IRP Resource NEI Values

Resource	Economic Benefits ($/MWh)	Safety ($/MWh)	Public Health ($/MWh)	Operating Jobs (per MW)
Solar (Washington)	-0.71	0.23	N/A	0.02
Solar (Out of State)	-0.30			
Wind (Washington)	-0.57	0.44	N/A	0.04
Wind (Out of State)	-0.29			
Natural Gas SCCT	-4.81	0.14	5.28	0.51
Natural Gas CCCT			2.04	
Power to Gas SCCT			N/A	
Storage	-0.60	N/A	N/A	0.25
Wood Biomass	-4.69	0.19	14.85	0.32
Small Modular Nuclear Reactor	-0.50	0.13	N/A	0.60
Pumped Hydro	-0.37	0.30	N/A	0.07
Hydrogen Fuel Cell	-4.81	0.14	N/A	0.51
Geothermal	-3.20	0.14	N/A	0.53

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8. Transmission & Distribution Planning

This chapter introduces Avista's Transmission and Distribution (T&D) systems, provides a brief description of how Avista studies these systems, and recommends capital investments to maintain reliability while accommodating future growth. Avista's Transmission System is only one part of the networked Western Interconnection with specific regional planning requirements and regulations. This chapter summarizes planned transmission projects and generation interconnection requests currently under study and provides links to documents describing these studies in more detail. This chapter also describes how distribution planning is incorporated into the Integrated Resource Plan (IRP) and Avista's merchant transmissions system rights.

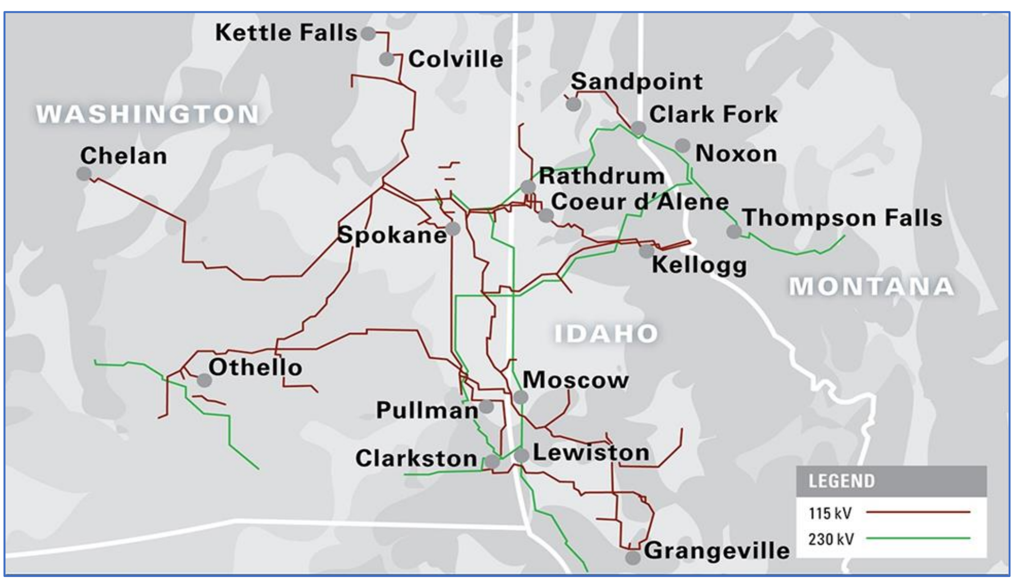
Section Highlights

- Transmission Planning estimates costs of locating new generation on Avista's system for the IRP.
- Avista formed a Distribution Planning Advisory Group (DPAG) for additional involvement of interested parties, education, and transparency.
- Avista's cluster study process for new generation connects includes 26 projects, including wind, solar, energy storage, natural gas, biomass, and hydro.

Avista Transmission System

Avista owns and operates a system of over 2,200 miles of electric transmission facilities including approximately 700 miles of 230 kV transmission lines and 1,600 miles of 115 kV transmission lines (see Figure 8.1).

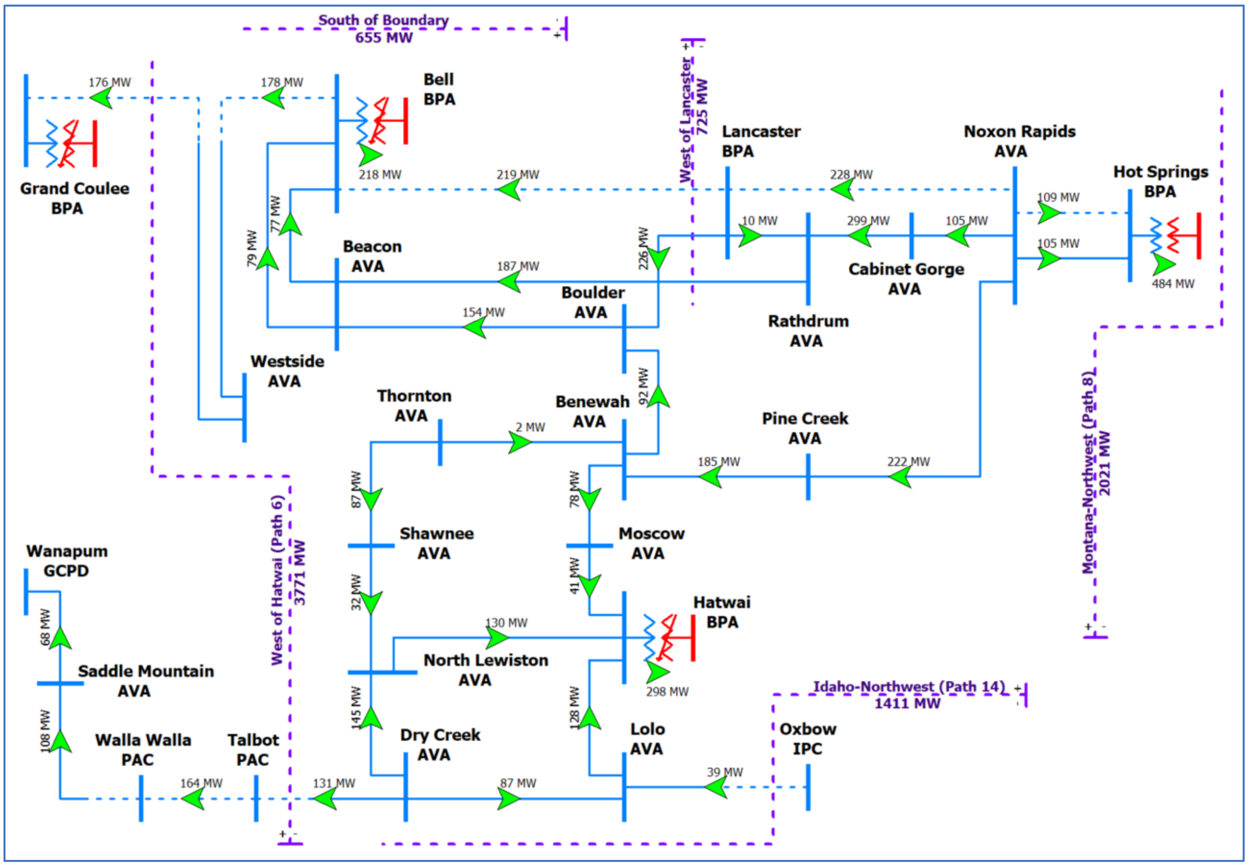
Figure 8.1: Avista Transmission System



230 kV Transmission System

The backbone of Avista's Transmission System operates at 230 kV. Figure 8.2 shows a station-level depiction of Avista's 230 kV Transmission System including network interconnections to neighboring utilities and relevant path boundaries. Avista's 230 kV Transmission System is interconnected to Bonneville Power Administration's (BPA) 500 kV transmission system at the Bell, Hatwai, and Hot Springs substations. In addition to providing enhanced transmission system reliability, network interconnections serve as points of receipt for power from generating facilities outside Avista's service area. These interconnections provide for the interchange of power with entities within and outside the Pacific Northwest, including integration of long- and short-term contract resources.

Figure 8.2: Avista 230 kV Transmission System



Transmission Planning Requirements and Processes

Avista coordinates transmission planning activities with neighboring interconnected transmission owners. Avista complies with Federal Energy Regulatory Commission (FERC) requirements related to both regional and local area transmission planning. This section describes several of the processes and forums important to Avista's transmission planning.

Western Electricity Coordinating Council

The Western Electricity Coordinating Council (WECC) is responsible for promoting bulk electric system reliability, compliance monitoring and enforcement in the Western Interconnection. This group facilitates the development of reliability standards and coordinates interconnected system operation and planning among its membership. WECC is the largest geographic territory of the regional entities with delegated authority from the National Electric Reliability Council (NERC) and the FERC. It covers all or parts of 14 Western states, the provinces of Alberta and British Columbia, and the northern section of Baja, Mexico.[82] See Figure 8.3 for the map of NERC Interconnections including WECC.

RC West

California Independent System Operator's (CAISO) Reliability Coordinator (RC) West performs the federally mandated reliability coordination function for a portion of the Western Interconnection. While each transmission operator within the Western Interconnection operates its respective transmission system, RC West has the authority to direct specific actions to maintain reliable operation of the overall transmission grid.

Western Power Pool

Avista is a member of the Western Power Pool (WPP)[83], an organization formed in 1942 when the federal government directed utilities to coordinate river and hydro operations to support war-time production. The WPP serves as a northwest electricity reliability forum, helping to coordinate present and future industry restructuring, promoting member cooperation to achieve reliable system operation, coordinating power system planning, and assisting the transmission planning process. WPP membership is voluntary and includes the major generating utilities serving the Northwestern U.S., British Columbia, and Alberta. The WPP operates several committees, including its Operating Committee, the Reserve Sharing Group Committee, the Western Frequency Response Sharing Group Committee, the Pacific Northwest Coordination Agreement (PNCA) Coordinating Group, and the Transmission Planning Committee (TPC) and Avista participates in each.

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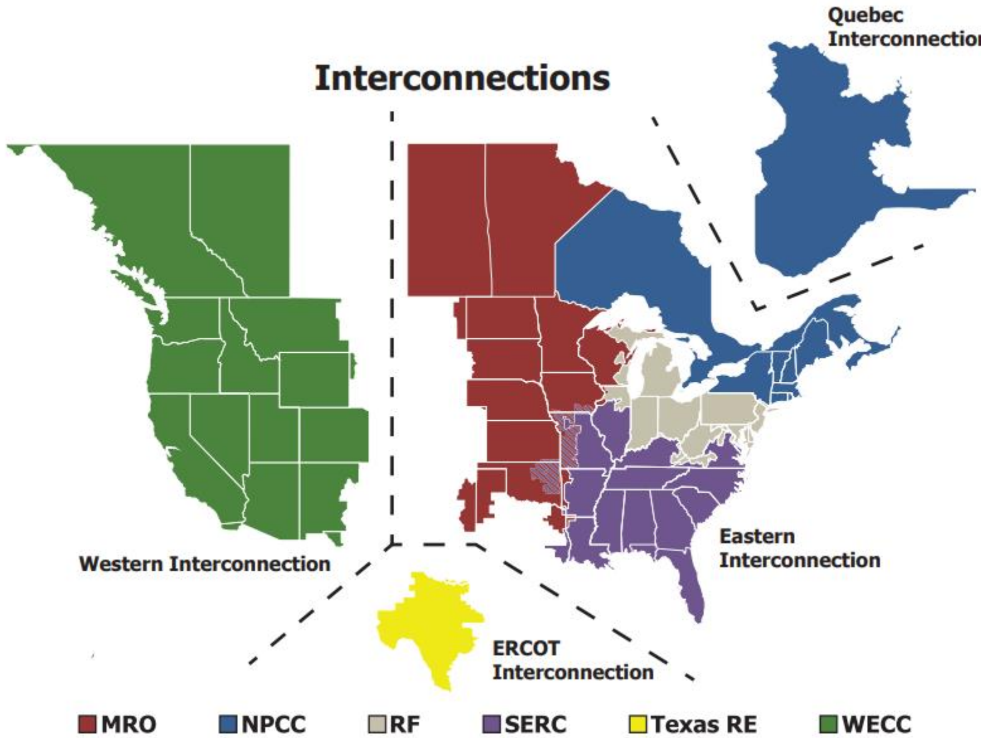
82 NERC Interconnections.pdf
83 The organization was formally named the Northwest Power Pool.

Figure 8.3: NERC Interconnection Map



NorthernGrid

NorthernGrid formed on January 1, 2020, and includes membership from fourteen utility organizations within the Northwest and many external parties. NorthernGrid aims to enhance and improve the operational efficiency, reliability, and planned expansion of the Pacific Northwest transmission grid. Consistent with FERC requirements issued in Orders 890 and 1000, NorthernGrid provides an open and transparent process to develop sub-regional transmission plans, assess transmission alternatives (including non-wires alternatives) and provide a decision-making forum and cost-allocation methodology for new transmission projects. NorthernGrid is a new regional planning organization created by combining the members of ColumbiaGrid and the Northern Tier Transmission Group.

System Planning Assessment

Development of Avista's annual System Planning Assessment (planning assessment) encompasses the following processes, which can be found on Open Access Same-time Information System (OASIS) at http://www.oatioasis.com/avat:

- Avista Local Transmission Planning Process – as provided in Attachment K, Part III of Avista's Open Access Transmission Tariff (OATT);
- NorthernGrid transmission planning process – as provided in the NorthernGrid Planning Agreement; and

- Requirements associated with the preparation of the annual planning assessment of the Avista portion of the Bulk Electric System.

The planning assessment, or local planning report, is prepared as part of a two-year process as defined in Avista's OATT Attachment K. The Planning Assessment identifies the Transmission System facility additions required to reliably interconnect forecasted generation resources, serve the forecasted loads of Avista's network customers and native load customers, and meet all other transmission service and non-OATT transmission service requirements, including rollover rights, over a 10-year planning horizon. The planning assessment process is open to all interested parties, including, but not limited to transmission customers, interconnection customers, and state authorities.

Additional information regarding Avista's system planning work is in the Transmission Planning folder on Avista's OASIS site noted above. Avista's most recent transmission planning document highlights several areas for additional transmission expansion work including:

- **Big Bend** - Transmission system capacity and performance has significantly improved with the completion of the Othello Substation and an interconnecting 115 kV Transmission Line. These projects are the last phase of the Saddle Mountain 230 kV system reinforcement adding a fourth source into the load center. The addition of communication, aided protection schemes, and other reconductor projects improved reliability and reduced the impacts of system faults. This project supports continued load growth in the area and integration of utility scale renewable generation.

- **Coeur d'Alene** - The completion of the Coeur d'Alene - Pine Creek 115 kV Transmission Line rebuild project and Cabinet - Bronx - Sand Creek 115 kV Transmission Line rebuild project improved transmission system performance in northern Idaho. The addition and expansion of distribution substations and a reinforced 115 kV transmission system were needed in the near-term planning horizon to support load growth and ensure reliable operations in this area.

- **Lewiston/Clarkston** - Load growth in the Lewiston/Clarkson area contributes to heavily loaded distribution facilities. Additional performance issues have been identified that impact the ability for bulk power transfer on the 230 kV transmission system. A system reinforcement project is under development to accommodate the load growth in this area.

- **Palouse** - Completion of the Moscow 230 kV station rebuild project added capacity and mitigated several performance issues. The remaining issue is a potential outage of both the Moscow and

Shawnee 230/115 kV transformers. An operational and strategic long-term plan is under development to determine how to best address a possible double transformer outage in this area.

- **Spokane** - Several performance issues exist in the Spokane area transmission system, and they are expected to get worse with additional load growth. The Westside 230 kV station capacity increase and Sunset Substation rebuild are complete. The staged construction of new facilities to support load growth in the West Plains is under development with the Blue-Bird – Garden Springs 230 kV project. A new 230 kV source into the greater Spokane area will offload the Beacon station, improving system performance for outages related to transmission lines terminating at the station.

Generation Interconnection

An essential part of the IRP is estimating transmission costs to integrate new generation resources onto Avista’s transmission system. A summary of proposed IRP generation options along with a list of Large Generation Interconnection Requests (LGIR) are discussed in the following sections. The proposed LGIR projects have independent detailed studies and associated cost estimates and are listed below for reference.

IRP Generation Interconnection Options and Estimates

A summary of the generation interconnection location, size, and associated costs for new and existing generation sites are listed in Tables 8.1 and 8.2 below. Further information regarding each alternative can be found in the detailed integration study in Appendix E. These studies provide a high-level view of generation integration, performance, and cost estimates, and are similar to the system impact studies performed under Avista’s generator interconnection process. In the case of third-party generation interconnections, FERC policy requires a sharing of costs between the interconnecting transmission system and the interconnecting generator. Accordingly, Avista anticipates all identified generation integration transmission costs will not be directly attributable to a new interconnected generator.

Table 8.1: New Generation Sites - Integration Cost Estimates

Point of Interconnection (POI) Station or Area of Integration	Request (MW)	POI Voltage	Cost Estimate ($ million)[84]
Big Bend area near Lind (Tokio)	100/200	230 kV	127.8
Big Bend area near Odessa	100/200/300	230 kV	170.5
Big Bend area near Othello	100/200	230 kV	216.8
Big Bend area near Othello	300	230 kV	258.7
Big Bend area near Reardan	50	115 kV	9.7
Big Bend area near Reardan	100	115 kV	12.8
Lewiston/Clarkston area	100/200/300	230 kV	1.9
Lower Granite area	100/200/300	230 kV	2.9
Palouse area, near Benewah (Tekoa)	100/200	230 kV	2.4
Rathdrum Prairie, north Greensferry Rd	100	230 kV	34.0
Rathdrum Prairie, north Greensferry Rd	200/300/400	230 kV	53.9
Sandpoint Area	50	115 kV	1.6
Sandpoint Area	100/150	115 kV	48.2
West Plains area north of Airway Heights	100/200/300	230 kV	2.4

Table 8.2: Existing Generation Sites - Integration Cost Estimates

Point of Interconnection (POI) Station or Area of Integration	Request (MW)	POI Voltage	Cost Estimate ($ million)
Kettle Falls Station	50	115 kV	1.6
Kettle Falls Station	100	115 kV	19.0
Northeast Station	50	115 kV	1.6
Northeast Station	100	115 kV	7.7
Northeast Station	200	230 kV	25.9
Palouse Wind, at Thornton Station	100/200	230 kV	1.4
Rathdrum Station	25/50	115 kV	11.1
Rathdrum Station	100	230 kV	15.9
Rathdrum Station	200	230 kV	48.4

Large Generation Interconnection Requests

Third-party generation entities may request transmission studies to understand the cost and timelines required for integrating potential new generation projects. These requests follow a defined FERC process to estimate the system impacts, the facility requirements, and cost estimates for project integration. After this process is completed, a contract to integrate the generation interconnection project may occur and negotiations can begin to enter into a transmission agreement, if necessary. Table 8.3 lists information associated with potential third-party resource additions currently in Avista's interconnection queue.[85]

[84] Cost estimates are in 2024 dollars and use engineering judgment with a 50% margin for error.
[85] OATI OASIS.

Table 8.3: Third-Party Large Generation Interconnection Requests

Serial or Cluster Number	Type	County	State	Size (MW)
Q59	Solar/Storage	Adams	WA	60
Q60	Solar/Storage	Asotin	WA	150
Q97	Solar/Storage	Nez Perce	ID	100
TCS-03	Solar/Storage	Adams	WA	80
TCS-14	Wind/Storage	Garfield	WA	375
CS23-06	Wind	Whitman	WA	256
CS23-12	Storage	Franklin	WA	199
CS23-13	Solar	Lincoln	WA	40
CS23-14	Solar	Spokane	WA	40
CS24-01	Solar	Adams	WA	1.1
CS24-02	Storage	Spokane	WA	0.5
CS24-03	Storage	Adams	WA	150
CS24-04	Storage	Spokane	WA	100
CS24-05	Natural Gas CT	Kootenai	ID	203
CS24-06	Natural Gas CT	Bonner	ID	120
CS24-07	Solar	Adams	WA	2
CS24-08	Solar/Storage	Franklin	WA	199
CS24-09	Solar	Adams	WA	9.5
CS24-10	Solar/Storage	Spokane	WA	80
CS24-11	Solar	Whitman	WA	70
CS24-12	Solar	Whitman	WA	40
CS24-13	Solar	Whitman	WA	95
CS24-14	Solar	Spokane	WA	40
CS24-15	Wind/Storage	Lincoln	WA	300

Future Transmission Projects Under Consideration

Blue Bird – Garden Springs 230 kV Project

Avista's system planning through the 10-year assessment planning horizon identified transmission system needs for load growth across the south and west of Spokane. Studies show system operability is strained and results in reduced system flexibility, affecting safety, system resiliency, and ultimately service to Avista customers. Continued load growth only amplifies this situation in the future.

The Blue Bird - Garden Springs 230 kV project was identified as the backbone piece of a broader West Plains Transmission Reinforcement. The project's primary goal is to develop a new and independent 230 kV source west of Spokane. The goal will be addressed by sourcing 230 kV from BPA Bell - Coulee #5 230 kV Transmission Line to improve contingency performance and increase system stability. The new 230 kV source will provide the required reliability and operational flexibility to serve current and forecasted loads.

Increased transmission service capability is an additional benefit of developing a new and independent 230 kV source west of Spokane. The location of this new 230 kV connection is anticipated to increase power transfer capability between Avista and BPA by 10-30% depending on the season.

North Plains Connector

This IRP considers a proposed regional transmission project to connect the Western Interconnect with the Eastern Interconnect as a resource option. The project consists of developing a 3,000 MW capacity direct current line between Colstrip, Montana, and North Dakota with an on-line date of 2033. The end points in North Dakota would give Avista access to both the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) markets to buy or sell power and provide access to generation resources in the mid-continent with different weather patterns. This IRP evaluates this resource as a 300 MW share utilizing the transmission path as a capacity only resource limited by the qualifying capacity credit (QCC) from Montana located generation.

Colstrip Transmission System Upgrade

Avista and the other owners of the Colstrip Transmission System are evaluating upgrades to the existing 500 kV transmission lines and supporting 230 kV and 115 kV infrastructure. These upgrades would increase power transfers out of Montana by approximately 900 MW. The purpose of this study is to better identify the simultaneous increase in transfer capability across the Montana to Northwest and West of Hatwai WECC rated paths. Montana to Washington 500 kV transmission system upgrades were last studied by NorthWestern, BPA, and Avista in May 2012, as part of the Colstrip to Mid-Columbia Upgrade Project Study.

Lolo - Oxbow Upgrade and Optimization

Avista, as a prime recipient, in partnership with Idaho Power Company, is seeking grant funding for their Lolo - Oxbow Transmission Upgrade and Optimization project. This project will upgrade the Lolo - Oxbow 230 kV Transmission Line with high-capacity conductors, as well as wildfire resilient designs and materials. Additionally, the project includes integrating Idaho Power’s new Pallette Junction Station and two SmartValve technology deployments. These improvements will increase interregional transfer capability by 450 MW between the Pacific Northwest and Mountain regions, presenting an opportunity to increase the build of renewable energy resources in the region.

The Lolo - Oxbow Upgrade and Optimization project would bring innovative technologies together resulting in improvements to interregional transfer capability by 450 MW from Avista to Idaho and up to 185 MW in the opposite direction. The two innovative technologies planned for this project are:

1) SmartValve technology opens the door to dynamically controlling and optimizing power flows, and

2) Infravision technology speeds transmission line construction with drone pull-line stringing instead of helicopter use.

The local communities and region would benefit from capacity upgrades enabling future generation interconnection opportunities to the Lolo - Oxbow 230 kV Transmission Line. If awarded, there will be community benefit funding available for up to $3.3 million. Additionally, through these upgrades, Avista will work towards further workforce development in energy-supportive roles, such as on-site equipment training, special operator training, and other job skill opportunities.

Distribution Resource Planning

Avista continually evaluates its distribution system for reliability, level of service, and future capacity needs. The distribution system consists of about 380 feeders covering 30,000 square miles, ranging from three to 73 miles. Avista serves 414,000 electric customers on its distribution grid.

The future of the distribution system is dynamic in terms of needs. Electric transportation, all-electric buildings, behind the meter generation and storage, and data centers are examples of modern disruptions to the distribution system. Understanding these applications and predicting the system impacts is challenging.

Over the last several IRP cycles, Avista has continuously developed and improved its processes and analytical abilities to allow distributed energy resources (DERs) to be fairly evaluated for their stacked benefits as a resource and their impact to the distribution grid. The growth of DERs on Avista's system has reached a point where incorporating DER impacts into the upcoming planning assessment (2025) will provide actionable insights.

Overall, the existing impact of DERs on the distribution system has been minimal. However, there are a few feeders approaching impactful levels of DER penetration (Table 8.4). The tools and confidence to analyze the future DER impacts has arrived just as the uptake of DERs is becoming significant. In addition, the DER Potential Study provides substantial pieces of missing data. These study results give Avista a reasonable estimate of future DER penetration of where new generation or even electric vehicle load could locate. The study is available in Appendix F.

As a point of reference, Idaho and Washington has about 4,500 generators and a total of 40 MW of installed generation on the distribution system. Total generation nameplate capacity is greater while actual generation will be less. A majority of the generators are net metered PV solar.

Table 8.4: Existing Generator (Top 10 Feeders)

Feeder ID	Total Feeder Generation (kW)	No. Installations	Total No. Customers	Penetration (%)
TUR112	1,041	44	2,483	1.8
BKR12F1	794	83	2,481	3.3
GRA12F2	604	63	1,997	3.2
MIL12F3	495	57	2,173	2.6
FOR12F1	495	42	672	6.3
SUN12F2	477	61	2,154	2.8
F&C12F2	473	65	2,274	2.9
BLD12F4	473	45	1,991	2.3
LIB12F2	464	36	827	4.4
EFM12F1	457	44	1,461	3.0

Currently, Avista's third-party integration requests are few with only four small integrations in the cluster study process ranging in size from 0.5 MW to 9.5 MW. The final disposition of projects remains to be seen.

The above summarizes the existing state of resources on the distribution grid. As more DER resources arrive in the future, the grid may become constrained. The extent of the constraints, if any, will be revealed during the next system assessment as the measures fitting the definition of DERs are hypothetically added to the system in future years based on the DER Potential Study results.

Regardless of the cause of the grid constraint/deficiency (load growth, DER uptake, etc.), a mitigation plan is needed. Mitigation projects may include "poles and wires" or possibly another DER commonly referred to as non-wire alternatives. Where it makes financial sense, non-wire alternatives have value such as the deferral of capital expenditures for upgrading the system.

Deferred Distribution Capital Investment Considerations

New technologies such as energy storage, photovoltaics, and demand response programs may help defer or eliminate capital investments to increase capacity of distribution and transmission systems. This benefit depends on the new technologies' ability to solve system constraints and meet customer expectations for reliability. An advantage in using these technologies may be additional benefits incorporated into the overall power system. For example, energy storage may help meet overall peak load needs or provide voltage support on a particular distribution feeder or at a distribution substation.

The analysis for determining the capital investment deferment value for DERs is not the same for all locations on the system. Feeders differ by whether they are summer-peaking or winter-peaking, the time of day when peaks occur, capacity thresholds, and the rate of local load growth. It is not practical to have a deferment estimate for each feeder in an

IRP, but it is helpful to have a representative estimate included in the IRP resource selection analysis.

To fairly evaluate and select the most cost-effective solutions to mitigate system deficiencies, the distribution planning process needs to identify the deficiency well in advance of it becoming a performance issue. Longer evaluation periods provide enough time for a comprehensive evaluation so the solution can take a holistic approach to include system resource needs. A shorter period can lead to immediate action not lending itself to a stacked value analysis due to time constraints for acquiring and/or constructing a non-wire alternative.

Identifying future deficiencies in a timely manner is a focus of System Planning. As previously mentioned, spatial forecasting, load data, time-series analysis, and accurate modeling are critical to making decisions as early as possible. For the next system assessment, Avista will use tools and data previously unavailable for the last assessment. The additional results will help facilitate the evaluation of DERs as mitigation options for any deficiencies identified.

Currently, Distribution Planning has not identified any projects meeting the criteria for an economic non-wire alternative. The identified near-term distribution projects require capacity increases and duration requirements exceeding reasonable DER capacity. However, the process is maturing and will identify system needs further out in time providing a longer runway needed to fully evaluate reasonable solutions including non-wire alternatives.

Reliability Impact of Distributed Energy Storage

Utility-scale batteries may offer benefits to grid operations including, but not limited to, reliability. This is particularly true in situations where the battery system is commissioned as a mitigation solution on the distribution system.

There is an industry trend to broaden the list of remedies available to alleviate grid deficiencies beyond traditional wires-based solutions. As discussed above, these solutions are typically referred to as non-wire alternatives, but it may be more informative to call them non-traditional alternatives. The motivation behind the trend is reasonable as non-traditional approaches may be less expensive than legacy options and may also incorporate other ancillary benefits, such as in the case of batteries. Utilities should consider all viable options to arrive at a least cost and reliable solution to distribution issues. In addition to solving grid issues, some non-wire alternatives may also serve as a system supply resource. These alternatives are referred to as DERs. Batteries, the subject of this section, are one such non-wire alternative with other benefits.

It is often presumed batteries increase system reliability. This may be true in some applications, but in the narrow sense of non-wire alternatives, this would typically not be the case. In the simplest of terms, reliability can decrease with the addition of a battery because the battery and its control system are additional failure points in the existing system chain. It is difficult to identify a scenario where a reduction in reliability results from adding potential failure points to a system.

A common issue on the distribution grid is feeder capacity constraints. A constrained feeder typically approaches the operational constraint during the daily peak load. The historical mitigation for this type of constraint is to increase the capacity of the constraining element by installing a larger conductor, different regulators, a larger transformer, or building a new substation. With the advent of utility-scale batteries, utilities have another option to mitigate these types of feeder constraints.

When DERs are used to solve a delivery constraint in this manner, the battery or other generating resource does not replace existing facilities, and this is a key point as the probability of failure of the existing facilities remains. The probability of failure of the battery or other non-wire alternative system is now an additional failure point. This is analogous to a feeder as a chain where each link is a potential failure point. If the chain consists of 100 links, there are 100 points of possible failure along the entire chain. In the same manner, adding a battery to a feeder to mitigate an issue simply adds another link, and another possible failure point in the chain. Instead of 100 possible points of failure, there are now 101 possible points of failure. Granted there are temporal aspects to this as well, but the battery will not always be a required solution to fix a constraint. If a failure occurs in the battery when there is no constraint, the feeder can continue operating as normal with no adverse impacts to the system. But there will be times when the battery is needed to meet a local peak event and during those times the battery becomes an additional failure point with the expanded system. The annual net effect on the feeder is potentially reduced reliability especially as the reliability of current battery technology is less than other traditional solutions.

The shift in reliability is more significant if a traditional solution was chosen. Existing older links in the failure chain would be replaced with new, often more robust, and more reliable, links. To take the chain analogy even further, if a new substation is built, links are removed from the failure chain as each affected feeder becomes shorter and has less environmental exposure. In addition, there is increased resiliency due to added operational flexibility and the ability to serve load from different directions. The net effect of a traditional solution is increased reliability, and it facilitates future DER resource additions because traditional solutions allow the grid to more readily accept additional DERs.

Quantifying the real effect of a grid-fixing battery or similar resource on reliability is difficult and situational. Indeed, it may not rise to a level of concern given the temporal nature of the decrease in reliability. The benefit of the resource may outweigh the short period of time it increases failure probability. However, if the probability of failure increases significantly, an alternate solution may be warranted. From an IRP perspective, the notion of solving a distribution grid deficiency while simultaneously providing a system resource is intriguing and worthy of consideration, but system reliability improvements cannot automatically be assumed with non-wire alternatives.

Electrification Impact Analysis

Avista's distribution system is not designed for a high penetration of electrification of existing customer's transportation and space/water heating loads. Many studies including this and past IRPs concentrate on the power supply and transmission requirements of these new loads, but do not estimate additional distribution system costs. Traditionally, distribution planning is outside the scope of an IRP as the IRP focuses on the generation of the power supply not the delivery, but the cost to change the distribution system is beneficial to understand the full impacts of a major transition policy decision for Avista's customers.

This IRP contemplates four electrification scenarios for plausible Washington State load changes within the IRP planning horizon (discussed in Chapter 10). The scenarios use alternative forecasts for higher rates of electric vehicle (EV) adoption and a transition to electric space and water heat of existing natural gas customers. Additional load requirements by existing customers will have an impact on the distribution system as the system was not designed for this additional load. The system changes and costs to accommodate new loads will be a time-consuming exercise requiring assumptions for the impacts of each individual customer for each of these scenarios. To shorten the requirements for such a study, Avista chose to estimate the system impacts for the highest load forecast scenario and base its estimate on high level assumptions for system requirements based on known costs to construct system components. This analysis gives an approximate estimate to add to the other power and transmission cost estimates traditionally estimated in a resource plan.

There are two options to increase distribution capacity, one is to increase voltage of the system; this option requires replacing all distribution underground cable, line insulation, substation power transformers, voltage regulators, and numerous other equipment. The second option is using the same distribution voltage to split the existing system up into additional feeders by adding additional substations along with replacing targeted conductors. For this analysis, the second option is used to estimate the system costs.

Avista estimated the required replacement components based on the judgement of Avista's planning engineers and construction personnel. The high electrification scenario adds 930 MW of additional winter peak load by 2045, but for system planning purposes this is increased to 1,100 MW to account for higher loads due to the power supply planning metric based on a 1-in-2 weather event and the distribution system must plan for lower temperature events at 1-in-10 year lowest daily temperature. To account for new transmission and distribution costs in these high load forecasts equates to $287 per kW of winter peak load on a levelized basis.

Distribution Planning Advisory Group Update

Avista formed the Distribution Planning Advisory Group (DPAG) following the 2021 Clean Energy Implementation Plan (CEIP). There have been five 2-hour long meetings covering various distribution topics including:

- March 2023: Power Delivery 101, Avista's Distribution System Overview
- June 2023: Performance Criteria, Planning Basics, System Assessment
- December 2023: System Needs, Solutions, DER Potential Study Update
- March 2024: DER Potential Study Results
- July 2024: Interconnection Process, Hosting Capacity Maps, DER Potential Assessment Maps
- December 2024: Weather dependent load modeling

The meetings have been well attended and the engagement is slowly ramping up as comfort level increases. The results of the next system assessment should provide for interesting and collaborative discussions with DPAG members. The previous assessment was already well underway when the group formed so going through the next assessment should be more fruitful for those attending.

Merchant Transmission Rights

Avista has two types of transmission rights – those owned by Avista and those purchased from third parties. The first type includes Avista-owned transmission which is reserved and purchased by Avista's merchant department to serve its customers. This type of transmission is also available to other utilities and power producers. FERC separates utility functions between merchant and transmission functions to ensure fair access to Avista's transmission system. The merchant department dispatches and controls Avista's generation and purchases transmission from the Avista transmission operator to ensure that energy can be delivered to customers. Avista must show a load serving need to reserve Network Transmission on the Avista-owned transmission system to ensure equitable access to the transmission capacity. Appendix J shows the projected need and future use of Avista's owned transmission system.

Avista also purchases transmission rights from other utilities to serve customers as listed in Table 8.5 below. This transmission is procured on behalf of the merchant side of Avista. The merchant group has transmission rights with BPA, Portland General Electric (PGE), and a few smaller local electric utilities.

Table 8.5: Merchant Transmission Rights

Counterparty	Path	Quantity (MW)	Expiration
BPA	Lancaster to John Day	100	6/30/2026
BPA	Coyote Springs 2 to Hatwai	97	8/1/2026
BPA	Coyote Springs 2 to Benton	50	8/1/2026
BPA	Garrison to Hatwai	196	8/1/2026
BPA	Coyote Springs 2 to Vantage	125	10/31/2027
BPA	Coyote Springs 2 to Vantage	50	7/30/2026
BPA	Townsend to Garrison	210	9/30/2027
PGE	John Day to COB	100	12/31/2028
Northern Lights	Dover to Sagle	As needed	n/a
Kootenai Electric	Rockford to Worley	As needed	12/31/2028
NorthWestern	Clearwater to AVA-System	100	9/1/2029

9. Market Analysis

A fundamental energy market analysis is an important consideration to support Avista's resource strategy over the next 20 years. Avista uses forecasts of future market conditions of the Western Interconnect to optimize its resource portfolio options. Electric price forecasts are used to evaluate the net operating margin of each supply-side resource and demand-side resource, including distributed energy resources (DER) options, for comparative analysis between each resource type. The model tests each resource in the wholesale marketplace to understand its profitability, dispatch, fuel costs, emissions, curtailment, and other operating characteristics.

Section Highlights

- Solar and wind dominate future generation across the West, while natural gas and increasing amounts of storage will ensure resource adequacy as existing coal and older natural gas plants retire or reduce dispatch.
- By 2045, this study assumes 94% of generation in the Pacific Northwest will be carbon free, compared to approximately 70-80% today (depending on hydro condition).
- Greenhouse gas emissions (GHG) will fall to historic lows with the expansion of renewables and continued coal and natural gas plant retirements. By 2045, expected emissions will be 62% less than 1990.
- The 20-year wholesale electric price forecast (2024-2045) is $44.14 per MWh, including costs from the Climate Commitment Act (CCA). Expansion of renewables reduces future mid-day prices, but evening and nighttime prices will be at a premium compared to today's pricing.
- Natural gas prices continue to remain low; for example, the levelized price at Stanfield (2024-2045) is $3.61 per dekatherm.

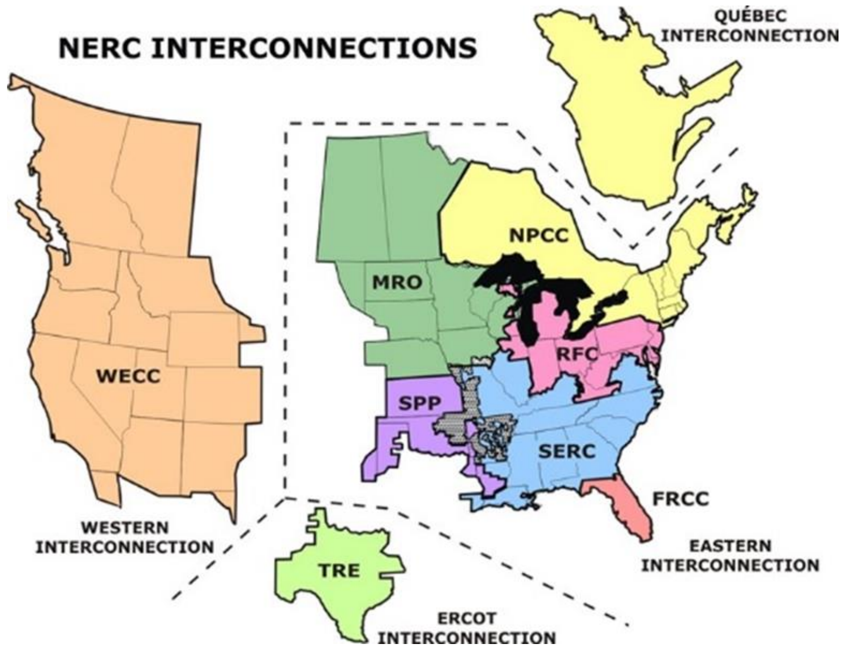
Background

Avista conducts its wholesale market analysis using the Aurora model by Energy Exemplar. The model includes generation resources, load estimates and transmission links within the Western Interconnect. This chapter outlines the modeling assumptions and methodologies for this Integrated Resource Plan (IRP) and includes Aurora's primary function of electric market pricing (Mid-Columbia for Avista), as well as operating results from the analysis. The expected case is an average of 300 simulations of future outcomes using the assumptions on policies, regulations, and resource costs considered with the Technical Advisory Group (TAC).

Electric Marketplace

Avista simulates the entire Western Interconnect electric system for its IRP; shown as Western Electricity Coordinating Council (WECC)[86] in Figure 9.1. The rest of the U.S. and Canada operate in separate electrical systems. The Western Interconnect includes the U.S. system west of the Rocky Mountains plus two Canadian provinces and the northwest corner of Mexico's Baja peninsula.

Figure 9.1: NERC Interconnection Map



The Aurora market simulation model represents each operating hour between 2026 and 2045. It simulates both load and generation dispatch for 19 regional areas or zones within the west. Avista's load and most of its generation was in the Northwest zone, but to better model the impacts of the CCA, Avista added granularity in the zones identified in Table 9.1. Each of these zones includes connections to other zones via transmission paths or links. These links allow generation trading between zones and reflect operational constraints of the underlying system, but do not model the physics of the system as a power flow model. Avista focuses on the economic modeling capabilities of the Aurora platform to understand resource dispatch and market pricing effects resulting in a wholesale electric market price forecast for the Northwest zone or Mid-Columbia marketplace. For this analysis, Avista modeled a Mid-Columbia marketplace both with and without the impacts of the CCA.

[86] WECC is the Western Electrical Coordinating Council. It coordinates reliability for the Western Interconnect.

Table 9.1: Aurora Zones

Avista	Southern Idaho
Bonneville Power Administration	Oregon
Eastern Montana	Washington
Northern California	Wyoming
Central California	Utah
Southern California	Arizona
Colorado	New Mexico
British Columbia	Alberta
North Nevada	Baja Mexico
South Nevada	

The Aurora model estimates its electric prices using an hourly dispatch algorithm to match the load in each zone with the available generating resources. Resource dispatch considers fuel availability, fuel cost, operations and maintenance costs, dispatch incentives/disincentives, and operating constraints. The marginal cost of the last generating resource needed to meet area load becomes the electric price. The IRP uses these prices to value each resource option (both supply and load side) and selects resources to achieve a least reasonable cost plan meeting all load and reliability obligations. Avista also conducts stochastic analyses for its price forecasting, where certain assumptions are drawn from 300 distributions of potential inputs. For example, each stochastic forecast randomly draws from an equally weighted probability distribution of the 30-year rolling hydro record.

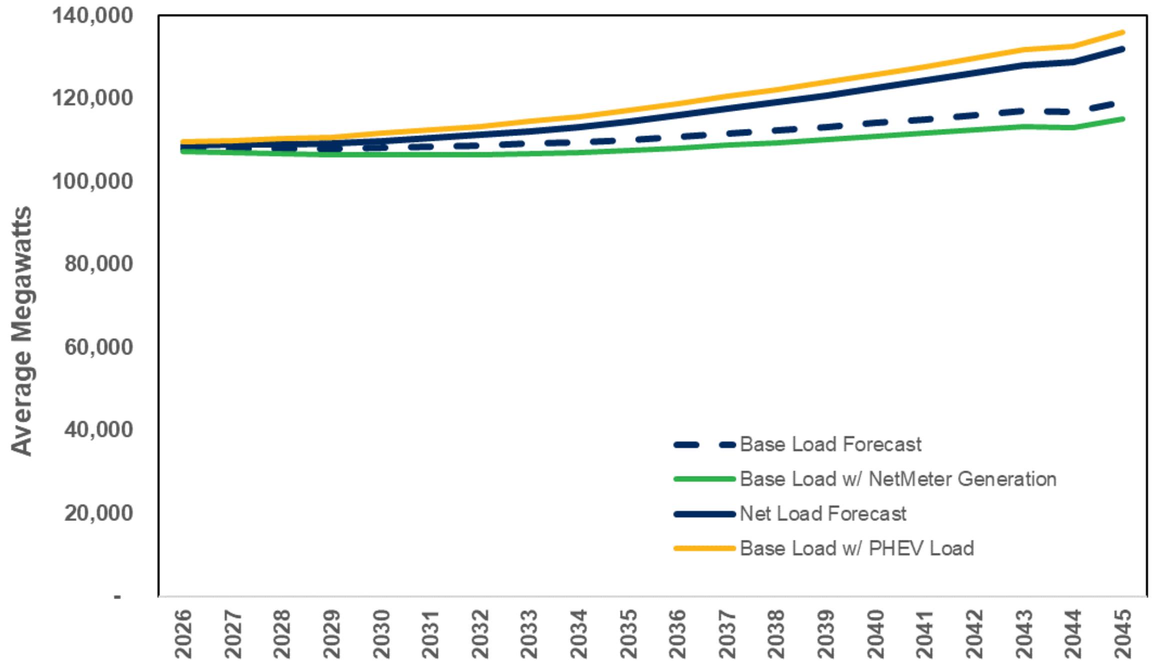
The following sections of this chapter discuss the assumptions used to derive the wholesale electric price forecast, resulting dispatch, and greenhouse gas emissions profiles of the west for the 300 stochastic studies.

Western Interconnect Loads

Each of the 19 zones in Aurora requires hourly load data for all 20 years of the forecast plus 300 different stochastic studies for weather variation. Future loads may not resemble past loads from an hourly shape point of view due to the continual increase in electric vehicles (EVs) and rooftop solar. Changes in energy efficiency, demand curtailment/ demand response, varying state policies, population migration, and economic activity increase the complexity. While each of these drivers are important to the power price forecast, it takes a large volume of analytical time to estimate and track these macro effects over the region. Avista uses the following methods to derive its regional load forecast for power price modeling to account for these complexities.

Avista begins with Energy Exemplar’s demand forecast included with the Aurora software package. This forecast includes an hourly load shape for each region along with annual changes to both peak and energy values. Avista updates the load forecast using a national consultant’s expectations on future loads. This base forecast is represented as the black dashed line in Figure 9.2. The WECC load grows 0.49% per year. Avista adjusts this initial forecast to account for changes in EV penetration and net-metered generation, including rooftop solar. Annual EV load grows at 12.4% and net-metered generation grows at 8.7%.[87] These adjustments increase the load forecast growth rate to approximately 1.0% per year. Within the year, the hourly load shapes adjust to reflect charging patterns of both residential and commercial vehicles in addition to most net-metered generation being modeled as fixed roof mount solar panels.

Figure 9.2: 20-Year Annual Average Western Interconnect Load Forecast



Regional Load Variation

Several factors drive load variability. The greatest short-run variability driver is weather. Long-run economic conditions, like the Great Recession, tend to have a larger impact on the load forecast. The load forecast increases on average at the levels in Figure 9.2, but risk analyses emulate varying weather conditions and base load impacts.

Avista continues its previous practice of modeling load variation using Federal Energy Regulatory Commission (FERC) Form 714 load data from 2018 to 2022. To maintain consistent west coast weather patterns, statistically significant correlation factors between the Northwest and other Western Interconnect load areas represent how electricity demand changes together across the system. This method avoids oversimplifying Western Interconnect loads. Absent the use of correlations, stochastic models may offset changes in one variable with changes in another, virtually eliminating

[87] Avista uses forecasts provided by a national consulting firm to assist in the development of these forecasts.

the possibility of broader load excursions witnessed by the electricity grid. The additional accuracy from modeling loads this way is crucial for understanding wholesale electricity market price variation, as well as the value and use of peaking resources in meeting system variation.

Tables 9.2 and 9.3 present load correlations for this IRP. Statistics are relative to the Northwest load area (Oregon, Washington and Idaho). "NotSig" indicates no statistically valid correlation existed in the data. "Mix" indicates the relationship was not consistent across the 2018 to 2022 period. For regions and periods with NotSig and Mix results, the IRP does not model correlations between the regions. Tables 9.4 and 9.5 provide the coefficient of determination values by zone.[88]

Table 9.2: January through June Load Area Correlations

Area	Jan	Feb	Mar	Apr	May	Jun
Alberta	Mix	Mix	24%	Not Sig	21%	Not Sig
Arizona	Mix	17%	Mix	Not Sig	Mix	8%
BPA	72%	Mix	73%	67%	18%	71%
British Columbia	79%	84%	76%	73%	Not Sig	89%
CA-Northern	8%	10%	Mix	Not Sig	Mix	9%
CA-Southern	8%	10%	Mix	Not Sig	Mix	9%
Colorado	Mix	Mix	Mix	Mix	Mix	Mix
Idaho South	73%	65%	87%	Not Sig	Mix	38%
Montana	81%	86%	79%	41%	Mix	47%
Nevada	8%	8%	Not Sig	Not Sig	Mix	18%
New Mexico	Mix	Not Sig	Mix	Mix	Mix	Mix
Oregon	72%	75%	62%	67%	8%	77%
Utah	37%	76%	69%	27%	Mix	38%
Washington	83%	90%	78%	78%	8%	84%
Wyoming	Not Sig	36%	53%	Not Sig	27%	Mix

[88] The coefficient of determination is the standard deviation divided by the average.

Table 9.3: July through December Load Area Correlations

Area	Jul	Aug	Sep	Oct	Nov	Dec
Alberta	Not Sig	Mix	Not Sig	41%	Mix	Not Sig
Arizona	Mix	Mix	Mix	-53%	Not Sig	18%
BPA	70%	74%	62%	Mix	77%	77%
British Columbia	85%	69%	Not Sig	71%	76%	81%
CA-Northern	25%	27%	Mix	-55%	Not Sig	Not Sig
CA-Southern	25%	27%	Mix	-55%	Not Sig	Not Sig
Colorado	Mix	Mix	Mix	Not Sig	Mix	Mix
Idaho South	19%	47%	44%	49%	73%	19%
Montana	75%	82%	76%	90%	86%	91%
Nevada	28%	26%	Mix	-43%	51%	38%
New Mexico	Mix	Mix	Not Sig	Not Sig	77%	17%
Oregon	79%	60%	39%	17%	77%	80%
Utah	71%	48%	41%	35%	77%	77%
Washington	83%	76%	64%	81%	87%	83%
Wyoming	Not Sig	8%	8%	Mix	70%	56%

Table 9.4: Area Load Coefficient of Determination (Standard Deviation/Mean)

Area	Jan	Feb	Mar	Apr	May	Jun
Alberta	5.5%	8.1%	6.8%	6.1%	4.8%	8.3%
Arizona	5.5%	8.1%	6.8%	6.1%	5.7%	10.0%
BPA	4.9%	5.5%	5.5%	7.0%	8.1%	10.0%
British Columbia	5.1%	5.3%	5.7%	7.5%	6.9%	9.3%
CA-Northern	5.1%	5.3%	4.5%	5.7%	3.3%	4.7%
CA-Southern	5.3%	5.6%	5.3%	5.7%	3.3%	4.7%
Colorado	4.7%	5.9%	6.2%	7.0%	10.0%	12.6%
Idaho South	4.4%	6.1%	5.8%	5.1%	3.4%	5.0%
Montana	4.4%	6.1%	5.8%	5.1%	3.4%	7.0%
Nevada	3.2%	4.7%	4.6%	4.0%	3.3%	7.0%
New Mexico	4.1%	5.7%	5.1%	4.2%	5.0%	8.8%
Oregon	4.1%	5.7%	4.2%	5.3%	7.6%	9.0%
Utah	4.3%	5.6%	3.9%	5.3%	7.6%	9.0%
Washington	5.1%	5.3%	3.4%	8.2%	8.8%	8.7%
Wyoming	3.6%	4.9%	5.0%	4.3%	5.5%	7.4%

Table 9.5: Area Load Coefficient of Determination (Standard Deviation/Mean)

Area	Jul	Aug	Sep	Oct	Nov	Dec
Alberta	8.3%	9.0%	5.9%	6.6%	6.7%	6.9%
Arizona	7.6%	7.8%	10.5%	7.8%	5.2%	5.0%
BPA	7.6%	7.8%	10.5%	8.5%	5.2%	5.2%
British Columbia	9.2%	9.1%	11.7%	9.7%	5.2%	5.2%
CA-Northern	5.2%	5.0%	3.3%	5.3%	4.9%	5.8%
CA-Southern	5.2%	7.3%	13.0%	5.0%	6.8%	5.8%
Colorado	6.0%	8.1%	13.0%	5.0%	6.8%	5.8%
Idaho South	6.0%	7.3%	4.7%	6.2%	5.0%	5.4%
Montana	5.2%	4.8%	7.2%	4.3%	4.2%	4.2%
Nevada	5.2%	4.8%	7.2%	4.4%	4.6%	4.8%
New Mexico	6.8%	5.9%	8.7%	4.8%	4.6%	4.8%
Oregon	6.3%	6.3%	8.4%	6.4%	4.0%	4.4%
Utah	6.3%	6.5%	10.1%	9.6%	3.8%	5.1%
Washington	8.9%	6.7%	10.1%	9.6%	3.8%	5.1%
Wyoming	5.1%	5.9%	7.5%	4.2%	4.9%	4.7%

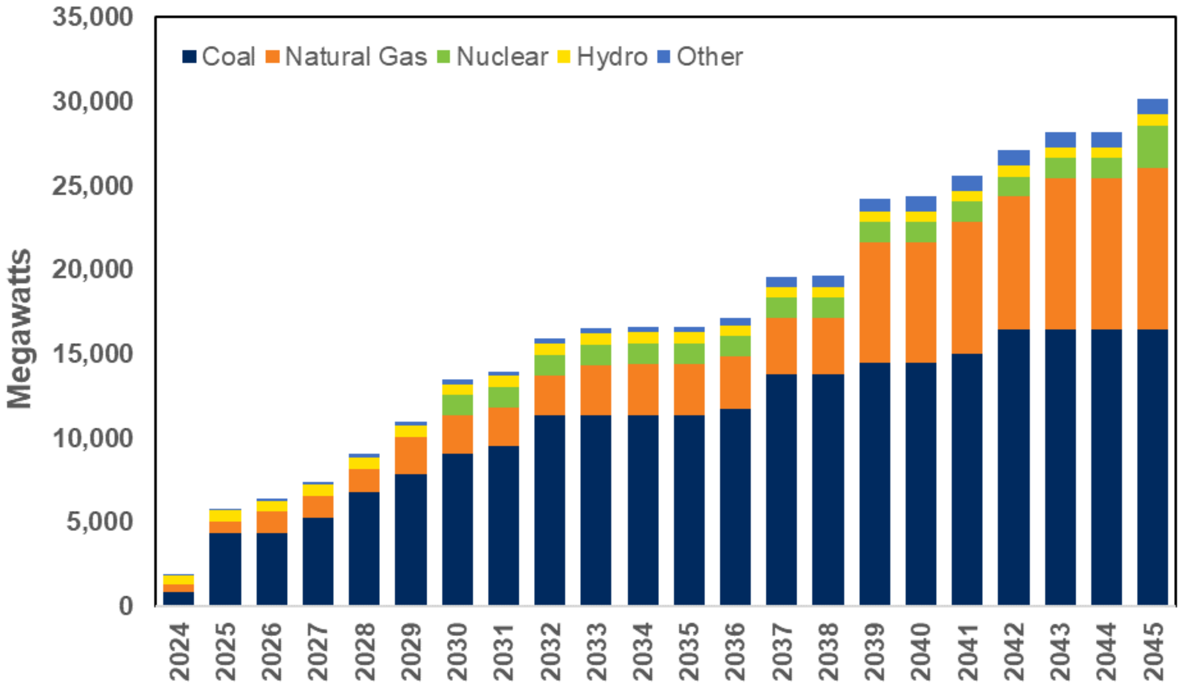
Generation Resources

The Aurora model needs a forecast of generation resources to compare and dispatch against the load forecast for each hour. A generation availability forecast includes the following components:

- Resources currently available or known upgrades;
- Resources retiring or converting to a new fuel source;
- New resources for capacity and load service;
- New resources for renewable energy compliance; and
- Fuel prices, fuel availability and operating availability.

Aurora contains a database of existing generating resources with the location, size and estimated operating characteristics for each resource. When a resource has a publicly scheduled retirement date, or is part of an approved provincial phase-out plan, it is retired for modeling purposes on the expected date. Avista does not project retirements beyond those with publicly stated retirement dates or phase out plans. Less economical plants operate fewer hours in the forecast. Several coal plant retirements have already or are expected to occur in the Northwest during this IRP; these include Boardman, Colstrip Units 1 and 2, North Valmy, and Centralia. Figure 9.3 shows the total retirements included in the electric price forecast. Approximately 16,500 MW of coal, 9,600 MW of natural gas, 2,500 MW of nuclear, and 1,600 MW of other Western Interconnect resources including biomass, hydro, and geothermal are known to be retiring by the end of 2045.

Figure 9.3: Cumulative Resource Retirement Forecast



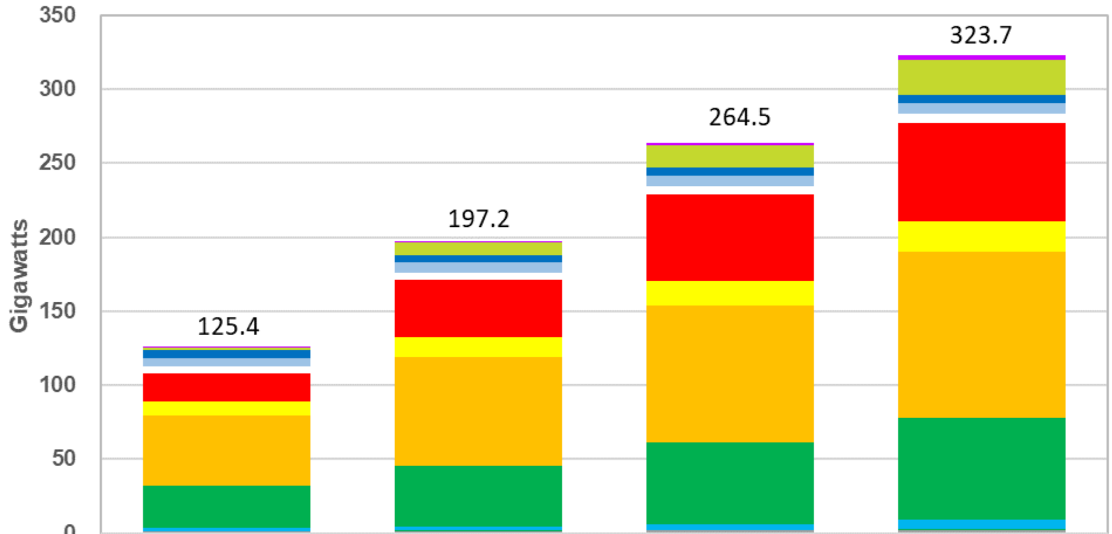
New Resource Additions

Considering state clean energy goals and the replacement of retired generation, a new generation forecast must include enough resources to meet future peak loads. Furthermore, some states include greenhouse gas (GHG) emission constraints or require GHG emission pricing or offsets for new resource additions. Avista uses a resource adequacy-based forecast for new resource additions along with data estimates provided by a third-party consultant. The process begins with a forecast of new generation by resource type from a national third-party consultant. Consultants with multiple clients and dedicated staff can, more efficiently research new resource costs and operating characteristics on likely resource construction in the West, especially in areas where Avista has no market presence or local market knowledge. These forecasts for new generation account for environmental policies and localized cost analysis of resource choices to develop a practical new resource forecast.

The last step runs the model for 300 simulations to see if each load area can meet a resource adequacy test. The goal is for each area to serve all load in at least 285 of the 300 iterations, with a 95% loss-of-load threshold measuring reliability.

Figure 9.4 shows the 324 GW of added generation included in this forecast. The added resources include 112 GW of utility-scale solar, 93 GW of wind, 5 GW of natural gas Combined Cycle Combustion Turbines (CTs), 67 MW of energy storage, 8 GW of natural gas CTs, and 39 GW of other resources including hydro, biomass, geothermal, and net-metering.

Figure 9.4: Western Generation Resource Additions (Nameplate Capacity)



	2030	2035	2040	2045
H2CCCT	0.3	0.3	1.5	3.1
H2CT	0.0	0.0	0.0	0.0
OSWind	1.5	8.3	15.2	23.9
CCCT	4.9	4.9	5.4	5.4
SCCT	5.7	7.0	7.5	7.5
DR	5.1	5.3	5.5	5.8
Storage	19.1	38.1	58.0	66.8
Net-Meter	9.1	13.5	16.8	20.8
Solar	47.6	73.4	92.6	112.0
Wind	28.8	41.1	55.1	69.2
Geothermal	1.8	2.8	4.1	6.0
Biomass	0.2	0.4	0.5	0.7
Hydro	1.3	1.5	1.8	2.1

Generation Operating Characteristics

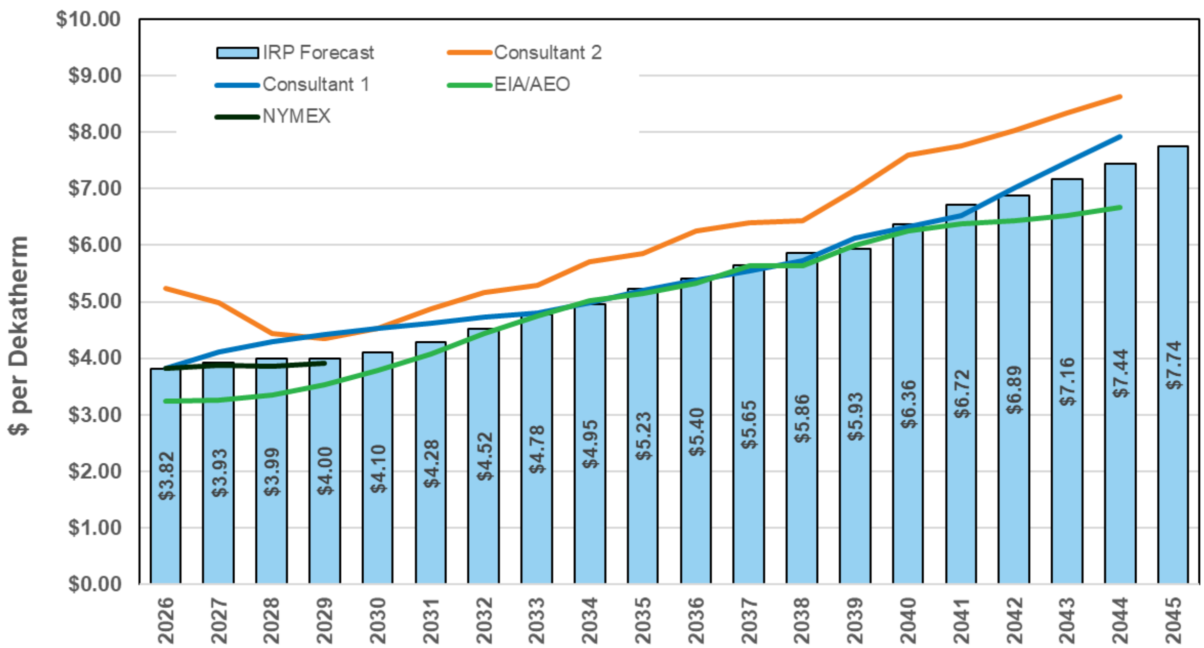
Several changes are made to the resources available to serve future loads to account for Avista's specific expectations, such as fuel prices, and to reflect variation of resource supply such as for wind and hydro generation.

Natural Gas Prices

Historically, natural gas prices were the greatest indicator of electric market price forecasts. Between 2003 and 2023 the correlation between natural gas and on-peak Mid-Columbia electric prices was 0.80, indicating a sizable decrease in correlation between the two prices than historically observed. Natural gas-fired generation facilities were typically the marginal resource in the northwest, except for times when hydro generation was high due to water flow. In addition, natural gas-fired generation met 34% of the load in the U.S. Western Interconnect in 2023. With the large increases in solar and wind generation in the west expected to continue, the number of hours where natural gas-fired facilities will set the marginal market price is expected to decline.

For modeling purposes, Avista uses a baseline of monthly natural gas prices and varying prices based on a distribution for each of the 300 stochastic forecasts. The forecasts begin with the Henry Hub forecast. Since Avista is not equipped with fundamental forecasting tools, nor is it able to track natural gas market dynamics across North America and the world, it uses a blend of market forward prices as of 12/15/2023, consultant forecasts, and the Energy Information Administration's (EIA) forecast. The EIA forecast is compared in Figure 9.5 against forecasted Henry Hub prices from two consultants with the capability to follow the fundamental supply and demand changes of the industry. The 20-year nominal levelized price of natural gas is $4.86 per dekatherm.[89]

Figure 9.5: 2025 IRP Henry Hub Natural Gas Price Forecast



Natural gas generation facilities in the West do not use Henry Hub as a fuel source, but natural gas contracts are priced based on the Henry Hub index using a basin differential. Northwest basins include Sumas for coastal plants on the William's Northwest pipe system. Power plants on the Gas Transmission Northwest (GTN) pipeline obtain fuel at prices based on AECO, Stanfield, or Malin depending on contracted delivery rights. Table 9.6 shows these basin differentials as a percent change from Henry Hub for the deterministic case. This table also includes basin nominal levelized prices for 20 years for the selected basins.

[89] The natural gas pricing data is available on the IRP website within Appendix F.

As described earlier, natural gas prices are a significant predictor of electric prices. Due to this significance, the IRP analysis studies prices described on a stochastic basis for the 300 iterations. The methodology to change prices uses an autocorrelation algorithm allowing prices to experience excursions, but to not move randomly. The methodology works by focusing on the monthly change in prices. The forecast's month-to-month expected case price change is used as the mean of a lognormal distribution; then for the stochastic studies, a monthly change in natural gas price is drawn from the distribution. The lognormal distribution shape and variability uses historical monthly volatility. Using the lognormal distribution allows for the large upper price excursions seen in the historical dataset.

Table 9.6: Natural Gas Price Basin Differentials from Henry Hub

Year	Stanfield	Malin	Sumas	AECO	Rockies	Southern CA
2030	87.6%	91.0%	86.8%	72.4%	95.2%	117.7%
2035	84.8%	87.6%	87.1%	70.7%	92.7%	112.6%
2040	80.9%	82.2%	83.1%	72.9%	88.5%	103.4%
2045	79.1%	80.3%	81.6%	68.9%	86.2%	98.5%
20-Year	**$3.61**	**$3.72**	**$3.65**	**$3.01**	**$3.93**	**$4.79**

The average of the 300 stochastic prices is similar to the expected price forecast described earlier in this chapter. Figure 9.6 illustrates the simulated data for the stochastic studies compared to the input data for the Henry Hub price hub. The stochastically derived nominal levelized price for 20 years is $5.03 per dekatherm. These values likely would converge to the expected price of $4.86 per dekatherm with a sample size much larger than 300. The median price is closely aligned with the input price of $4.82 per dekatherm. Another component of the stochastic nature of the forecast is the growth in variability. In the first year, prices vary 7% around the mean, or the standard deviation as a percent of the mean. This value is 39% by 2040 and 42% by 2045. Avista uses higher variation in later years because the accuracy and knowledge of future natural gas prices becomes less certain.

Figure 9.6: Henry Hub Natural Gas Price Forecast

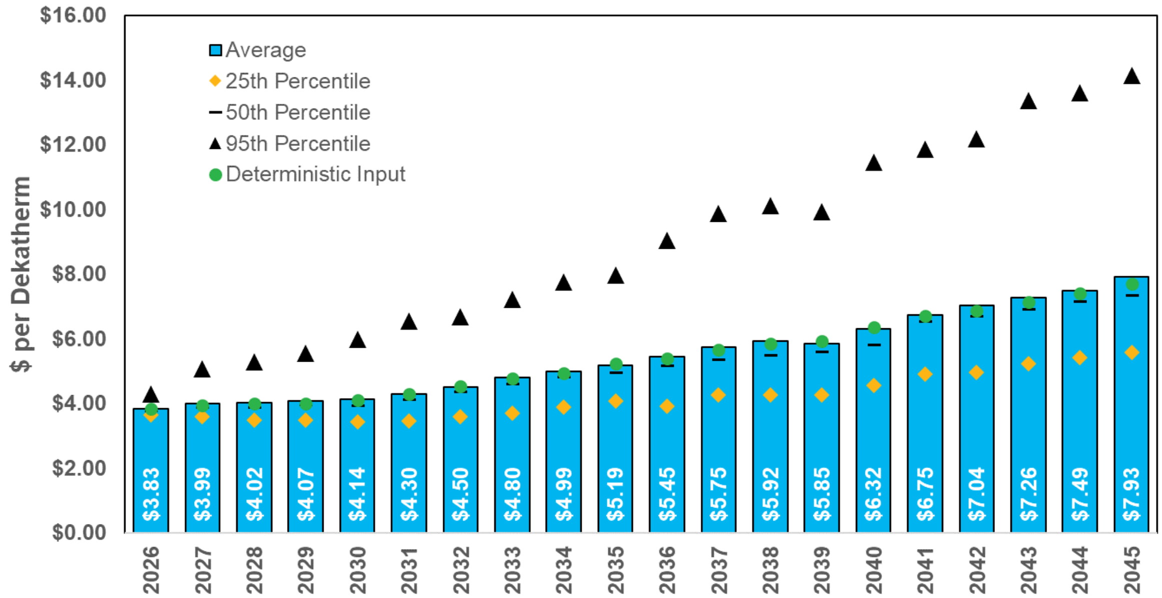
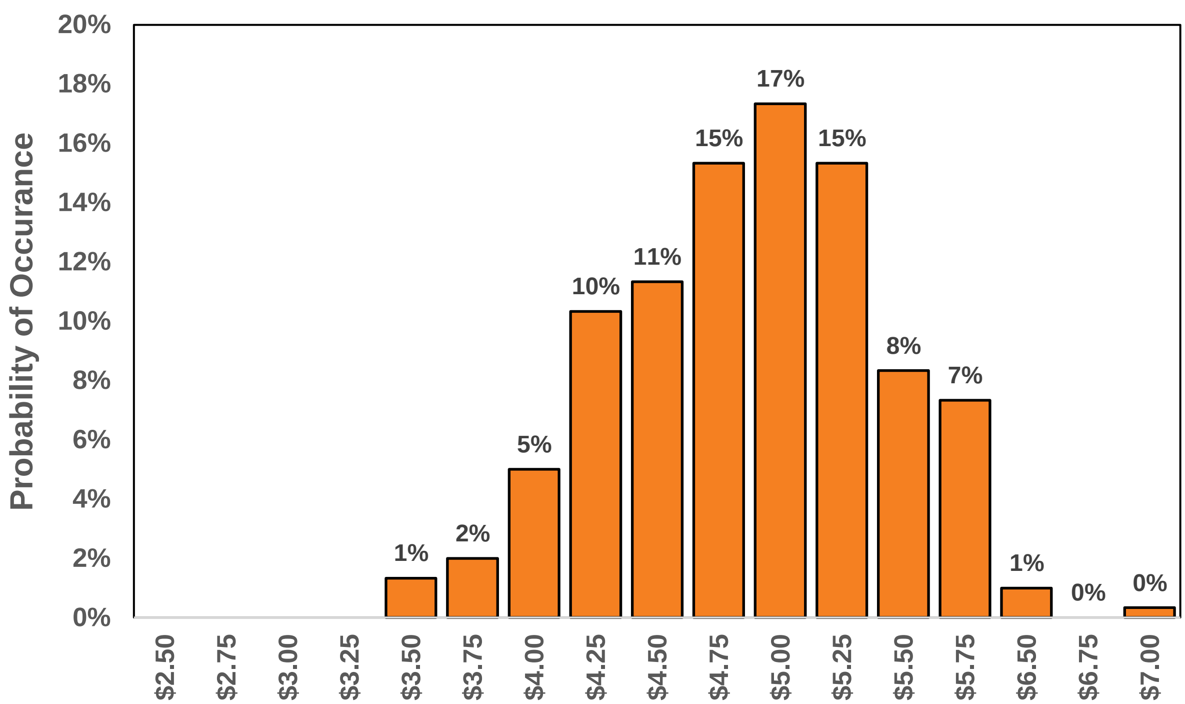


Figure 9.7 shows another visualization of Avista's natural gas price forecast assumptions. This chart shows a histogram of the 20-year nominal levelized prices for Henry Hub to demonstrate the skewness of the natural gas price forecast.

Figure 9.7: Henry Hub Nominal 20-Year Nominal Levelized Price Distribution



Regional Coal Prices

Coal-fired generation facilities are still an important part of the Western Interconnect. In 2023, coal met 14% of WECC loads – falling from 34% in 2001. Coal pricing typically differs from natural gas pricing, providing diversification, and thus mitigating price volatility risk. Natural gas is delivered by pipeline, whereas coal delivery is by rail, truck, or conveyor. Coal contracts are typically longer term and supplier specific. Avista uses the coal price forecast in Energy Exemplar's default database. Energy Exemplar's forecast is based on FERC filings for each of the coal plants and that data is used to determine historical pricing. Future prices are based on the EIA Annual Energy Outlook.

Coal price forecasts have uncertainty like natural gas prices, yet the effect on market prices is less because coal-fired generation rarely sets marginal prices in the Western Interconnect. While labor, steel, and transportation costs drive some portion of coal price uncertainty, transportation is its primary driver. There is also uncertainty in fuel suppliers as the coal industry is restructuring as less coal is mined. Given the relatively small effect on Western Interconnect market prices, Avista chose not to model coal prices stochastically.

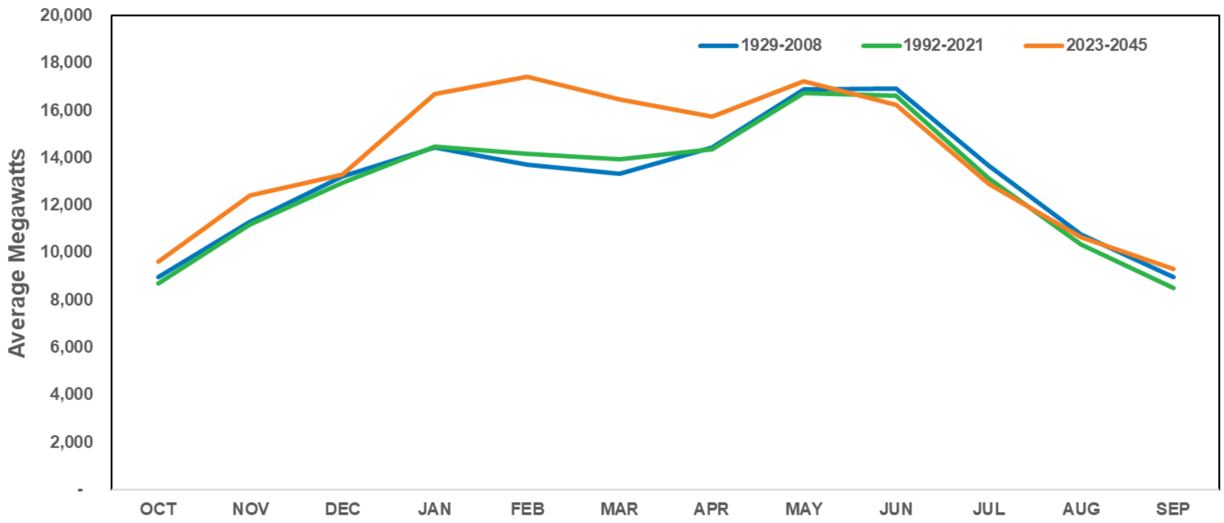
Hydro

The Northwest U.S., British Columbia, and California have substantial hydro generation capacity. Hydro resources accounted for 50% of generation in the Northwest in 2023, but only 19% of generation in the Western Interconnect. A favorable characteristic of hydro power with a reservoir is its ability to provide near-instantaneous generation up to and potentially beyond its nameplate rating. Hydro generation is valuable for meeting peak load, following general intra-day load trends, storing and shaping energy for sale during higher-valued hours, and integrating variable generation resources. The key drawbacks to hydro generation are its variability and limited fuel supply due to weather conditions.

The deterministic forecast uses a rolling 30-year median of hydro production including a combination of historic water years and forecasted generation incorporating the temperature change predictions in Representative Concentration Pathway (RCP) 4.5.[90] Throughout the 20-year planning horizon, there is a greater percentage of forecasted generation included in the 30-year period. For example, for planning year 2030, hydro is based on a median of historic water years from 2000-2021 and forecasted hydro for years 2022-2029. See Figure 9.8 for a hydro comparison of this methodology with the former average using an 80-year hydro record.

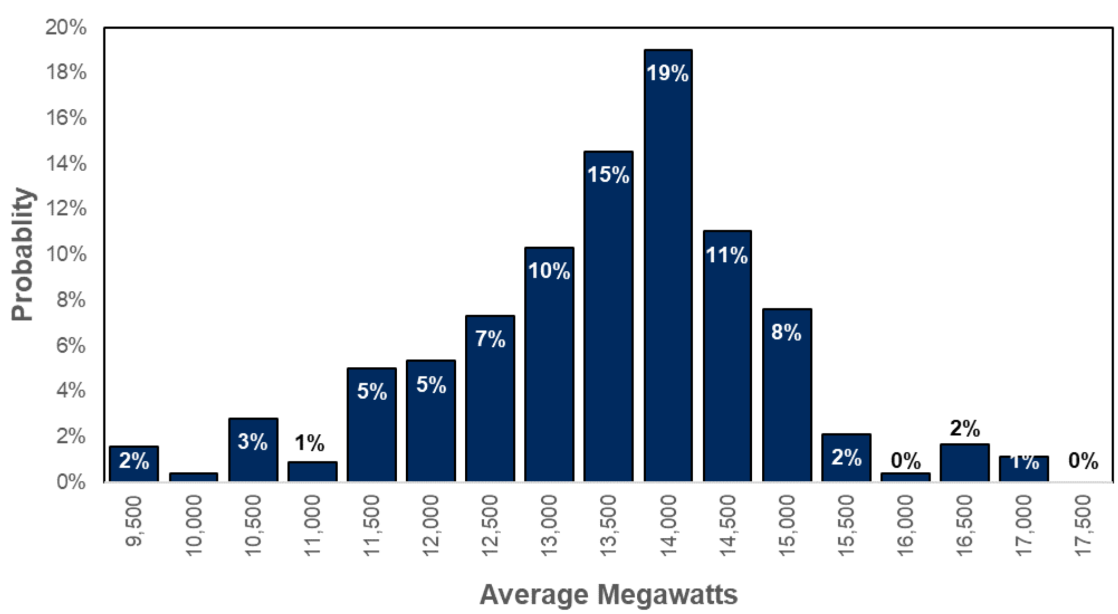
[90] See Chapter 7 for more detail on the hydro forecast and climate assumptions included.

Figure 9.8: Northwest Hydro Generation Comparison



Many forecasts use an average of the hydro record, whereas the stochastic study randomly draws from the historical record. Avista's stochastic forecast incorporates the same combination of the historic water years and forecasted hydro as used in the deterministic study, however, hydro is randomly selected for the 300 iterations to simulate risk of different hydro conditions. Figure 9.9 shows the average hydro energy is 13,230 aMW (median 13,426 aMW) in the Northwest over the 20-year study, defined here as Washington, Oregon, Idaho, and western Montana. The chart also shows the range in potential energy used in the stochastic study, with a 10th percentile water year of 11,320 aMW (-15%) and a 90th percentile water year of 14,735 aMW (+11%).

Figure 9.9: Northwest Expected Energy



Wind Variation and Pricing

Wind is a growing generation source used to meet customer load. Western Interconnect wind generation increased from nearly zero in 2001 to 11% in 2023.[91] Capturing the variation of hourly wind generation is an important fundamental for power supply models due to the volatility of its generation profile, and the effect this volatility has on other generation resources and electric market prices. Energy Exemplar recently populated a larger database of historical wind data points throughout North America. This analysis builds on previous work by incorporating a stochastic element to modify the wind pattern annually. Avista uses the same methodology for developing its wind variation in previous IRPs. The technique includes an auto correlation algorithm with a focus on hourly generation changes. It also reflects the seasonal variation of wind generation.

To keep the analysis manageable, Avista developed 15 different hourly wind generation profiles that are randomly drawn for each year of the 20-year forecast. By capturing volatility this way, the model can estimate hours with oversupply compared with using monthly average generation factors.

Solar

Solar is increasing its market share in the Western Interconnect. In 2023, solar was 9%[92] of the total generation in the Western Interconnect, up from 2% in 2014 (both estimates exclude behind the meter solar). The Aurora model includes multiple solar generation shapes with multiple configurations, including fixed and single-axis technologies, along with multiple locations within the 19 load areas. As solar grows, additional data will be available and incorporated into future IRP modeling. A future new technique may include multiple hourly solar shapes, like those used with wind, so the model can account for solar variation from cloud cover.

Other Generation Operating Characteristics

Avista uses Energy Exemplar’s database assumptions for all other generation types not detailed here, except for Avista’s owned and controlled resources. For Avista’s resources, more detailed confidential information is used to populate the model.

Forced outage and mechanical failure is a common problem for all generation resources. Typically, the modeling for these events is through de-rating generation. This means the available output is reduced to reflect the forced outages. Avista uses this method for solar, wind, hydro, and small thermal plants; but uses a randomized outage technique for larger thermal plants where the model randomly causes an outage for a plant based on its historical outage rate, keeping the plant offline for its historical mean time to repair.

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[91] Wind represented 11.5% of Northwest generation in 2023.
[92] Solar represented 2% of Northwest generation in 2023.

Negative Pricing and Oversupply

Avista adjusted the Aurora model to account for oversupply in the Mid-Columbia market, including negative price effects. Negative pricing occurs when available generation exceeds demand. This generally occurs in the Northwest when much of the hydro system is running at maximum capacity in the spring months due to high runoff and wind projects are also generating without an economic incentive to shut off due to their pressure to generate for the Production Tax Credit (PTC), environmental attributes (e.g., Renewable Energy Credits (RECs)), or for contract obligations. While hydro resources are dispatchable, they may not be able to curtail enough to prevent negative prices due to total dissolved gas constraints forcing hydro to generate instead of spilling. This phenomenon will likely increase as more wind and solar generation is added to the system with tax credits in place or where environmental attributes are needed to meet clean energy requirements. To model this oversupply effect in Aurora, Avista changes the economic dispatch prices for several resources that have dispatch drivers beyond fuel costs.

The first modeling change Avista made is to the hydro dispatch order by making hydro resources a “must run” resource or last resource to curtail. To do this, hydro generation is assigned a negative $30 per MWh price (2020$).[93] The next change assigns an $8 per MWh (2020$) reduction in cost for qualifying renewable resources to reflect a preference for meeting state renewable portfolio standards (RPS); this price adjustment accounts for the intrinsic value of the REC. The last adjustment is to include a PTC for resources with this benefit. After these three adjustments, the model turns off resources in a fashion similar to periods of excess generation seen today. In an oversupply condition such as this, the last resource turned off sets the marginal price.

Greenhouse Gas Pricing

Many states and provinces have enacted greenhouse gas emissions reduction programs with others considering such programs. Some states have emissions trading mechanisms, others chose clean energy targets, and some chose both. Aurora can model either policy, but different policy choices can result in varying impacts to electric wholesale pricing. Clean energy target programs, such as Washington’s Clean Energy Transformation Act (CETA), generally depress prices due to the bias for increasing the incentives to construct low marginal-priced resources. California’s cap and trade program has the opposite effect and pushes wholesale prices upwards. Avista includes known pricing programs in Washington, California, British Columbia, and Alberta in its modeling as a price adder. Oregon’s Clean Energy Targets (HB 2021) are modeled as a maximum emission constraint.

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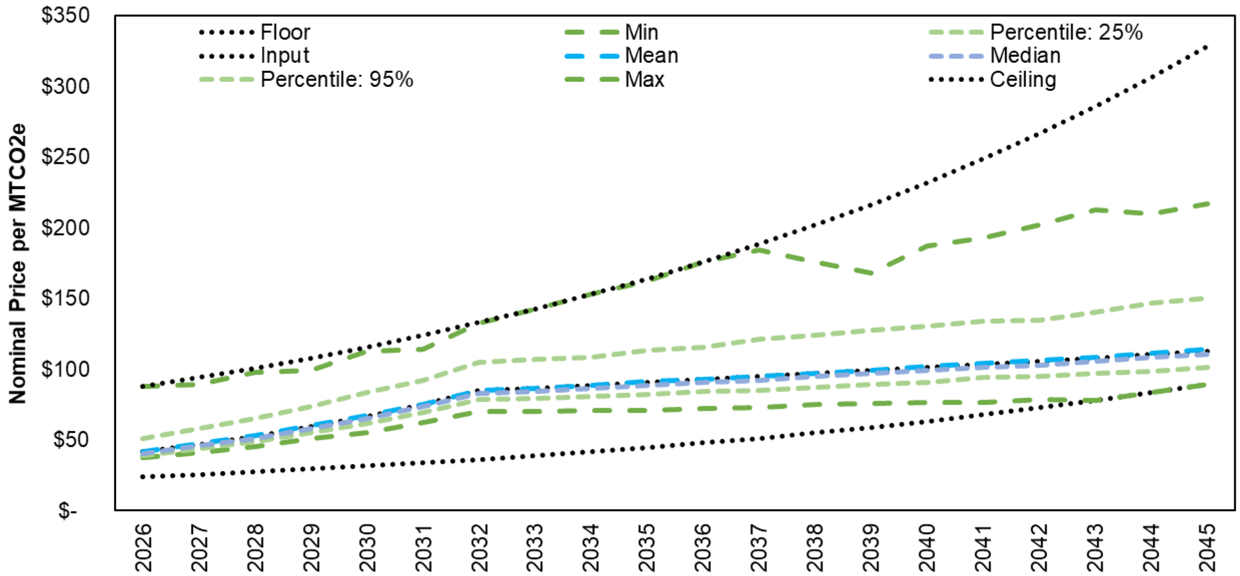
[93] These plants cannot be designated with a “must run” designation due to the “must run” resources being required to dispatch at minimum levels and for modeling purposes, hydro minimum generation is zero in the event of low stream flows.

Washington passed the Climate Commitment Act (CCA) in 2021 enacting the potential for carbon pricing on Washington generation resources beginning in 2023.[94] CCA rules were released October 2022, and regulated entities continue to refine their understanding of its complete impacts. The Washington State Department of Ecology (Ecology) is responsible for implementing the CCA. Ecology is working on providing detailed descriptions or examples to aid regulated entities such as Avista in how to accurately calculate compliance costs. It is unclear how the CCA will ultimately impact energy markets due to changes in linkage with California. Therefore, carbon pricing for Washington continues to be extremely uncertain. Modeling methodologies will be updated in a future resource plan once the full requirements are known. In the meantime, the prices included in the analysis assume Washington and California will link their markets and the CCA credit values are based on an independent consultant's price forecast.[95] The price ranges used in the stochastic modeling are shown in Figure 9.10 and the methodology[96] is described below.

1) **Utility controlled generation within Washington State** – These plants assume all GHG prices are included in the dispatch decision for all GHG emitting resources beginning in 2031.
2) **Non-utility owned generation within Washington State** – These plants assume all GHG prices are included in the dispatch decision for all GHG emitting resources beginning in 2026.
3) **Utility controlled generation within Washington State but serving other states** – This applies the pricing used from #2 above using the ratio of the utility's out of state load share starting in 2026.
4) **Northwest Imports** – Any power imported into California or Washington incurs a carbon price adder to transfer power and uses the pricing from #2 above based on the default 0.437 metric ton per MWh GHG intensity rate.

[94] Pricing relative to other emission sources was also enacted but is irrelevant to this IRP.
[95] The carbon price forecast used in Avista 2025 Electric IRP is the same carbon pricing assumption used in Avista's 2025 Natural Gas IRP.
[96] Various approaches were discussed with the TAC at multiple meetings and through email. Input and/or enhancements to this process were sought and were included based on the best available information at the time of the analysis.

Figure 9.10: Carbon Price Assumptions



Regional Generation Source Forecast

This forecast assumes a continuing shift to clean energy resources across the Western Interconnect over the next 20 years. Figure 9.11 shows the historical and forecast generation for the U.S. portion of the Western Interconnect.[97] In 2023, 58% of generation came from clean energy, and is expected to increase to 73% by 2030 and 81% by 2045. To achieve this clean-energy shift, while also serving new loads, solar and wind production will displace coal and natural gas. Absent significant new long-term storage technologies, some thermal resources will still be required to help meet system needs during peak weather events, especially in Northwest winters, and they may also be needed to recharge energy storage if wind or solar are not available after an event.

The Northwest will undergo significant changes in future generation resources. This forecast expects coal, natural gas, and nuclear generation to be limited by 2045, and the remaining requirements will be met with solar, wind, and hydro generation. As of 2023, 69% of the Northwest generation was clean, increasing to 88% in 2030 and 94% by 2045 as shown in Figure 9.12. Achieving these ambitious clean energy goals will require nearly tripling wind generation and a nearly 12-fold increase in solar energy from the 2023 generation levels. This results in solar providing 11% and wind 24% of future generation.

[97] Forecast is for the average of the 300 simulations.

Figure 9.11: U.S. Western Interconnect Generation

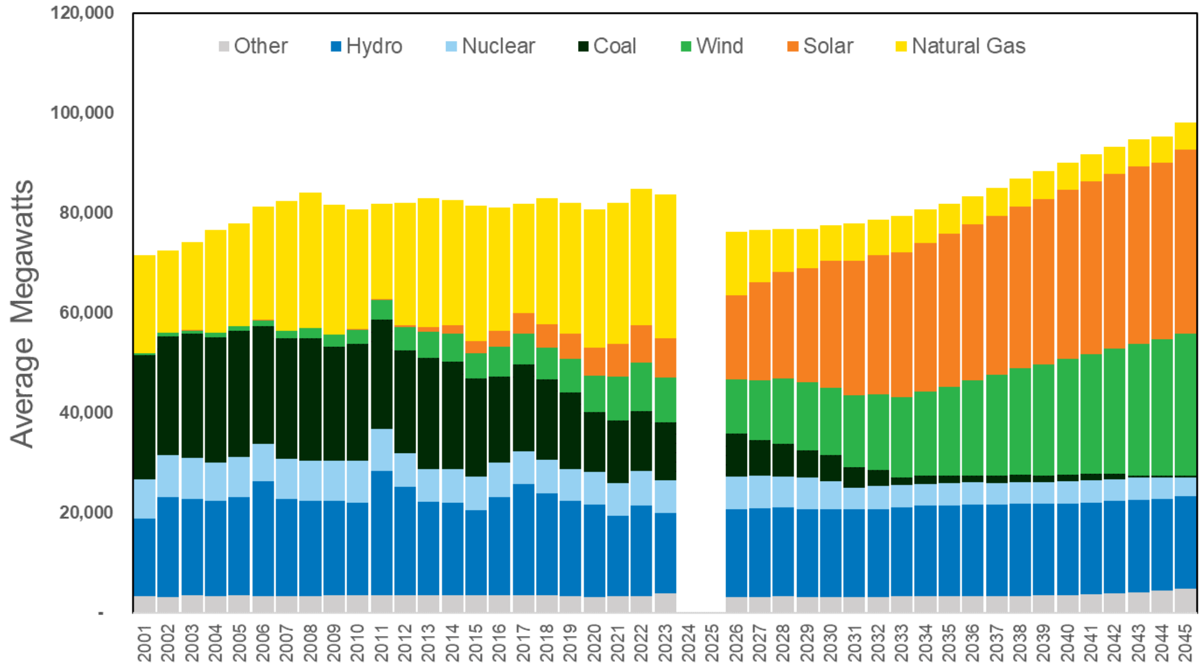
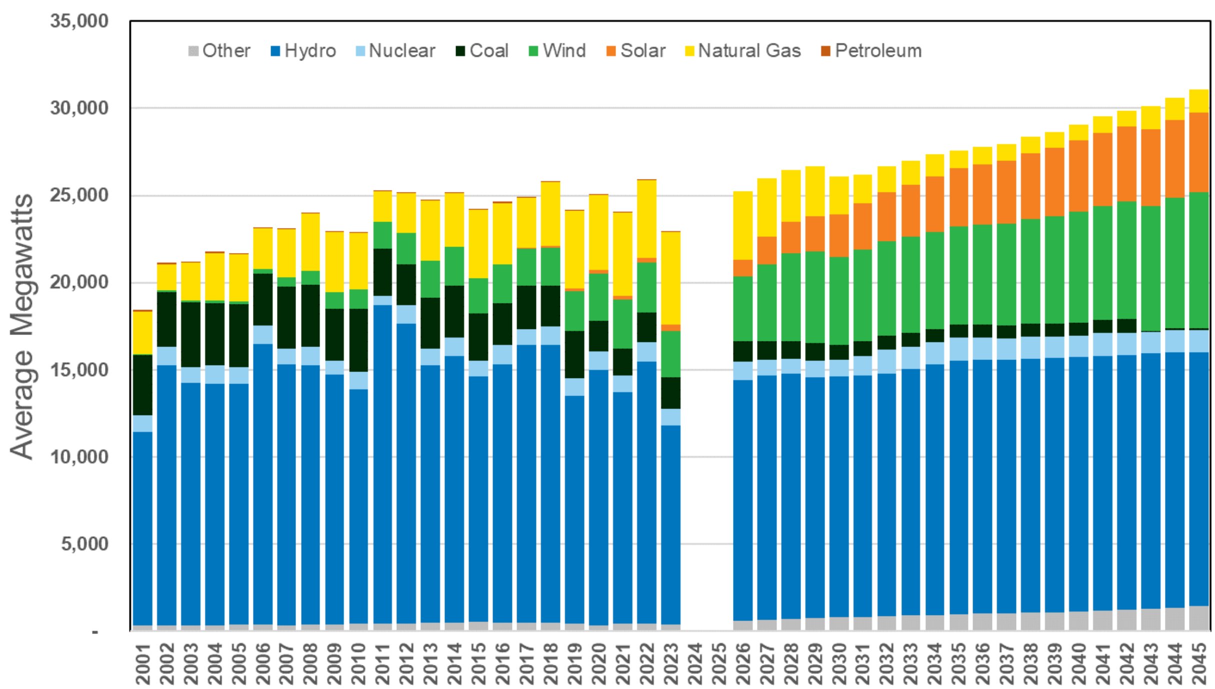


Figure 9.12: Northwest Generation



Regional Greenhouse Gas Emissions

GHG emissions are likely to significantly decrease with the retirement of coal generation and new solar/wind resources displacing additional natural gas-fired generation. Electric generation related GHG emissions within the U.S. Western Interconnect were approximately 229 million metric tons in 2022, a reduction from the 1990 emissions level of 234 million metric tons. Avista obtained historical data back to 1980 from the EPA; the emissions minimum since 1980 was 161 million metric tons in 1983.

Avista's energy market modeling only tracks emissions at their source and does not estimate assignment to each state from energy transfers, such as emissions generated in Utah for serving customers in California. Figure 9.13 shows the percent totals for 2022 and the 2045 forecast. The largest emitters by state are Arizona and California, followed by Wyoming, Colorado, and Utah. The four northwest states combined generate 14% of the total emissions in the Western Interconnect.

By 2045, Avista estimates GHG emissions will fall to 18% of 1990 levels as shown in Figure 9.14. All states will have a reduction in GHG emissions in this forecast. The greatest reductions by percentage are New Mexico (98%), Utah (95%), Arizona (89%), and Nevada (86%). The greatest reductions by metric tons are California (29 MMT), Arizona (29 MMT), Utah (28 MMT), and New Mexico (26 MMT).

Figure 9.13: 2022 and 2045 Greenhouse Gas Emissions

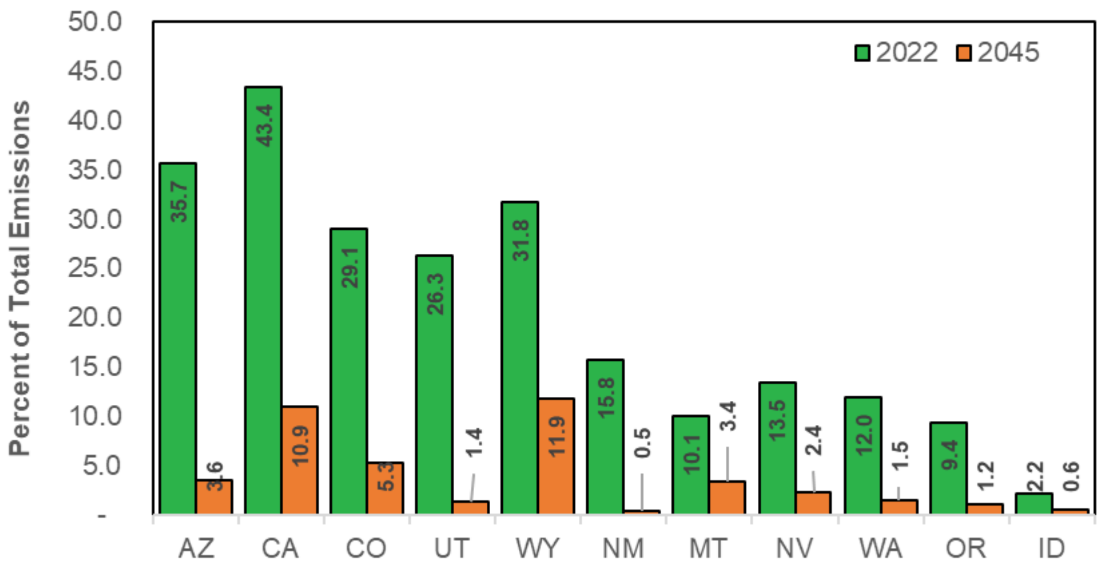
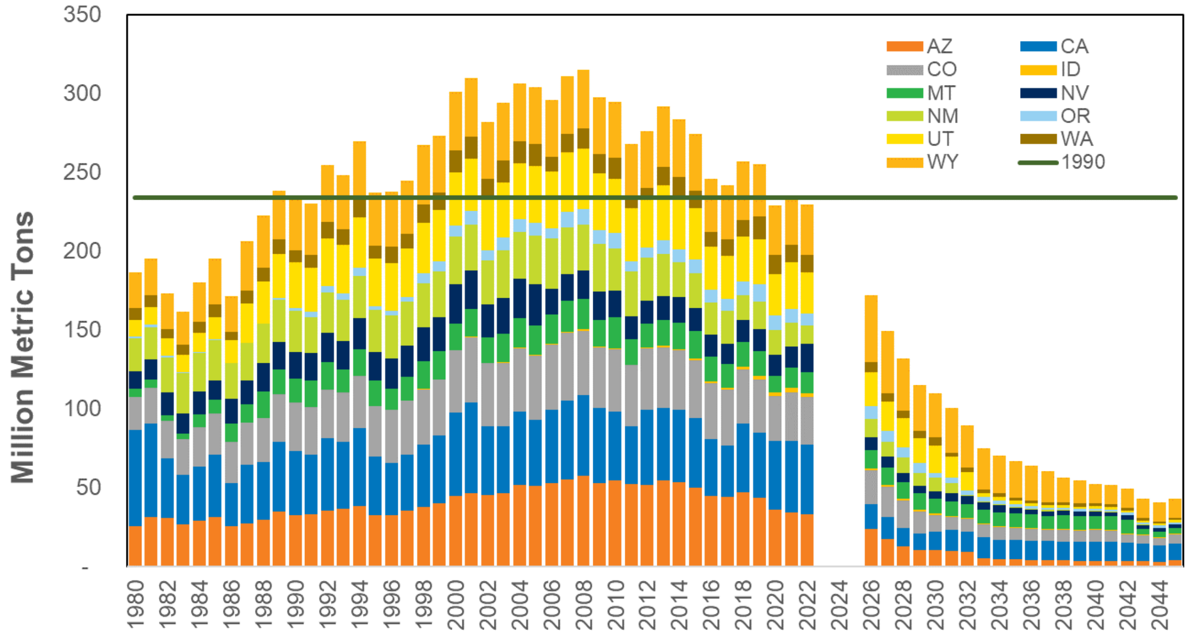


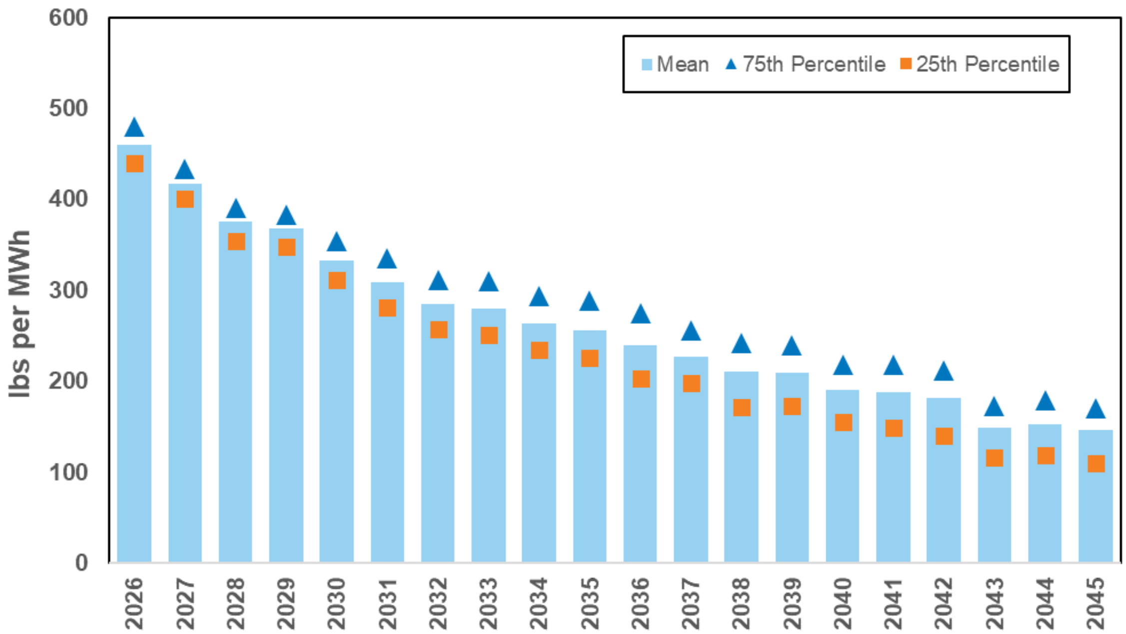
Figure 9.14: Greenhouse Gas Emissions Forecast



Regional Greenhouse Gas Emissions Intensity

To understand the GHG emissions from the regional market Avista may purchase power from, Avista uses regional emissions intensity per MWh to estimate the associated emissions from these short-term acquisitions. Avista uses the mean values shown in Figure 9.15 for each of the 300 simulations. Figure 9.15 below shows the mean, 25th and 75th percentiles for regional GHG emissions intensity. The GHG emissions are included from Washington, Oregon, Idaho, Montana, Utah, and Wyoming. Emissions intensity falls as renewables are added and coal and natural gas plants retire or decrease dispatch, but the intensity rate also depends on the year-to-year variation in hydro production. The locations for Avista's area for potential market purchases is consistent with Washington's Energy and Emissions Intensity report but is higher than Avista's likely counter parties for market purchases. This figure also includes incremental regional GHG emissions to evaluate efficiency programs. In this case, Avista determines the incremental regional GHG emissions per MWh using a second forecast with additional load within the Northwest system, then the change in emissions is compared to the change in load.

Figure 9.15: Northwest Regional Greenhouse Gas Emissions Intensity



Electric Market Price Forecast

Mid-Columbia Price Forecast

There are two wholesale prices forecasts within this resource plan, a deterministic version where all 8,760 hours for the 20-year period are simulated and a stochastic version simulating 300 of the 20-year hourly studies. Each study uses hourly time steps between 2026 and 2045. This process is time consuming when conducted 300 times for the stochastic forecast. The 300 future simulations take more than one week of continuous processing on 33 separate processor cores to complete. Time constraints limit the number of market scenarios Avista is ultimately able to explore in each resource plan. The increase in future storage resources within the marketplace requires optimization techniques to determine pricing. This process significantly increases the modeling time and requires the number of iterations to be reduced to 300. Analysis was performed to ensure the 300 iterations was sufficient to encompass most of the distribution of uncertainty.

The annual average of all hourly prices from both studies is shown in Figure 9.16. This chart shows the annual distribution of the prices using the 10th and 95th percentiles compared to the mean, median and deterministic prices. The pricing distribution is lognormal, as prices continue to be highly correlated with the lognormally distributed natural gas prices. The 20-year nominal levelized price of the stochastic study is $44.14 per MWh (with CCA) and $42.77 per MWh (without CCA) and is shown in Tables 9.7, 9.8 and 9.9. Tables 9.8 and 9.9 include the super peak evening (4 to 10 p.m.) period to illustrate how prices behave during this high-demand period where solar output is falling, and rising prices encourage the dispatch of other resources. Pricing with CCA represents the power price for the Washington zone, whereas the price without CCA is an average of the Avista and Mid-Columbia areas.

Figure 9.16: Mid-Columbia Electric Price Forecast Range

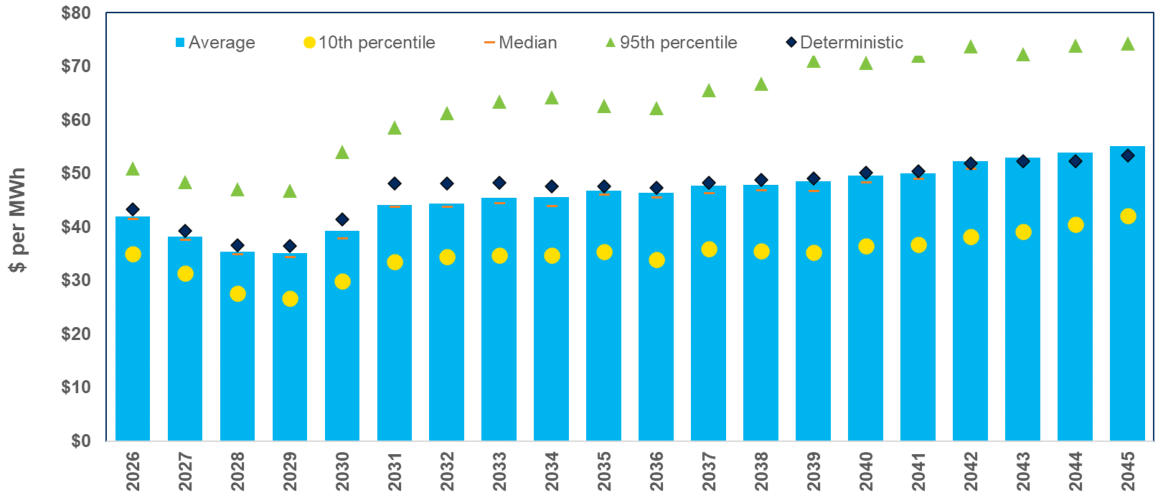


Table 9.7: Nominal Levelized Flat Mid-Columbia Electric Price Forecast

Metric	20-Year Levelized with CCA ($/MWh)	20-Year Levelized without CCA ($/MWh)
Deterministic	$45.45	$44.37
Stochastic Mean	$44.11	$42.77
10th Percentile	$36.86	$38.42
50th Percentile	$41.17	$42.85
95th Percentile	$47.06	$48.05

Average on-peak prices between 7 a.m. and 10 p.m. on weekdays plus Saturdays have historically been higher than the remaining off-peak prices. However, this forecast shows off-peak prices outpacing on-peak prices on an annual basis beginning in 2029 due to increasing quantities of solar generation expected to be placed on the system, thus depressing on-peak prices. As more solar is added to the system, this effect spreads into the shoulder months. Only in the winter season, where solar production is lowest, does the traditional relationship of today’s on- and off-peak pricing continue.

Depending on the future level of energy storage and its duration, market price shapes could flatten out rather than inverting the daytime price spread. Mid-day pricing will be low in all months going forward, driving on-peak prices lower. Super peak evening prices after 4 p.m., when other resources will need to dispatch to serve load, can be high if startup costs affect market pricing as expected in this forecast.

Table 9.8: Annual Average Mid-Columbia with CCA Electric Prices ($/MWh)

Year	Flat	Off-Peak	On-Peak	Super Peak Evening
2026	$41.98	$40.46	$43.12	$54.18
2027	$38.14	$38.58	$37.82	$50.78
2028	$35.40	$37.03	$34.18	$46.43
2029	$35.04	$36.64	$33.84	$45.19
2030	$39.18	$40.90	$37.89	$48.68
2031	$44.10	$46.40	$42.38	$53.18
2032	$44.33	$47.09	$42.27	$53.32
2033	$45.40	$48.29	$43.23	$54.77
2034	$45.55	$48.72	$43.17	$54.82
2035	$46.71	$49.96	$44.27	$56.59
2036	$46.40	$49.74	$43.90	$56.44
2037	$47.66	$51.45	$44.82	$57.60
2038	$47.77	$51.51	$44.98	$57.83
2039	$48.48	$52.35	$45.58	$58.86
2040	$49.59	$53.79	$46.43	$59.08
2041	$50.01	$54.44	$46.68	$59.91
2042	$52.31	$56.90	$48.88	$62.96
2043	$52.97	$57.66	$49.45	$64.16
2044	$53.84	$58.61	$50.27	$65.39
2045	$55.07	$59.83	$51.48	$67.76
20-Year	**$42.15**	**$44.51**	**$40.38**	**$52.11**

Table 9.9: Annual Average Mid-Columbia without CCA Electric Prices ($/MWh)

Year	Flat	Off-Peak	On-Peak	Super Peak Evening
2026	$41.61	$40.42	$42.50	$53.43
2027	$37.88	$38.70	$37.26	$50.15
2028	$35.13	$37.19	$33.57	$45.89
2029	$34.57	$36.64	$33.01	$44.51
2030	$38.56	$40.85	$36.84	$47.91
2031	$43.00	$45.74	$40.96	$52.00
2032	$42.74	$45.92	$40.36	$51.69
2033	$43.82	$47.20	$41.29	$53.10
2034	$43.92	$47.54	$41.19	$53.13
2035	$44.93	$48.59	$42.18	$54.75
2036	$44.50	$48.21	$41.72	$54.48
2037	$45.69	$49.82	$42.61	$55.59
2038	$45.66	$49.68	$42.64	$55.67
2039	$46.29	$50.42	$43.19	$56.64
2040	$47.28	$51.69	$43.96	$56.76
2041	$47.66	$52.29	$44.19	$57.58
2042	$49.92	$54.68	$46.35	$60.58
2043	$50.52	$55.38	$46.88	$61.73
2044	$51.24	$56.12	$47.58	$62.81
2045	$52.39	$57.26	$48.71	$65.12
20-Year	**$40.87**	**$43.58**	**$38.83**	**$50.70**

Figures 9.17 through 9.20 show the average prices for each hour of the four seasons for every five years of the price forecast. The spring and summer prices generally stay flat throughout the 20 years as these periods have larger quantities of hydro and solar generation to stabilize prices, but mid-day prices decrease over time while prices for the other time periods increase. Unless long-term energy storage materializes, winter and autumn prices will have larger price increases due to less available solar energy. With this analysis, current on/off-peak pricing will need to change into different products such as a morning peak, afternoon peak, mid-day, and night. Pricing for holidays and weekends likely will be less impactful on pricing except for the morning and evening peaks. Future pricing for all resources will need to reflect these pricing curves so they can be properly valued against other resources.

Figure 9.17: Winter Average Hourly Electric Prices (December – February)

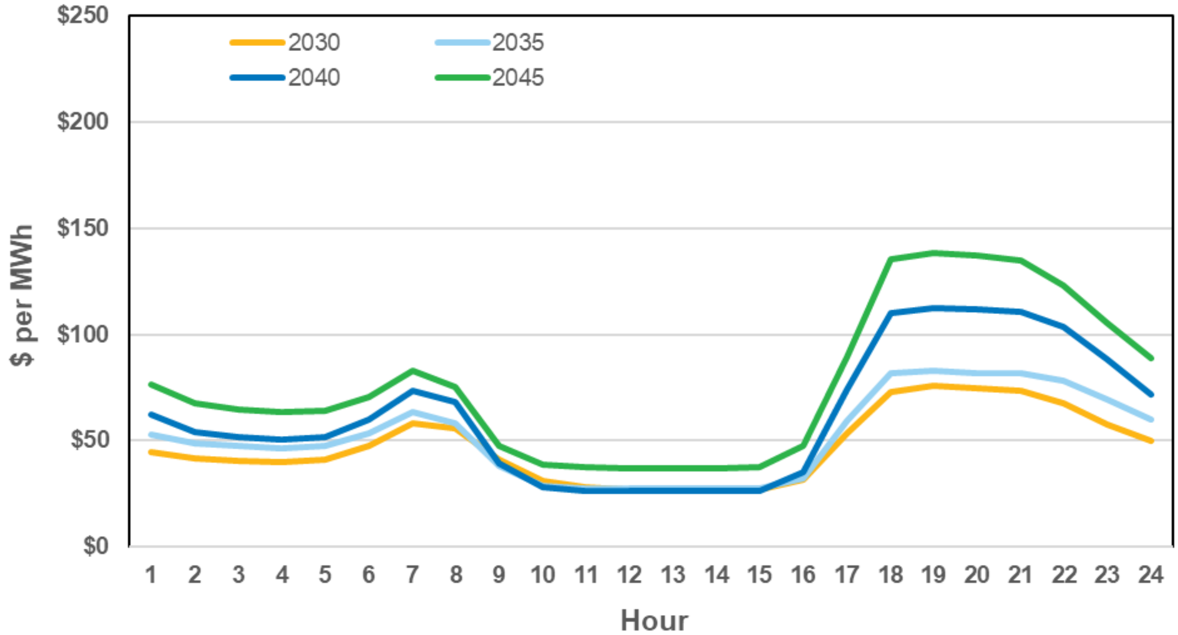


Figure 9.18: Spring Average Hourly Electric Prices (March – June)

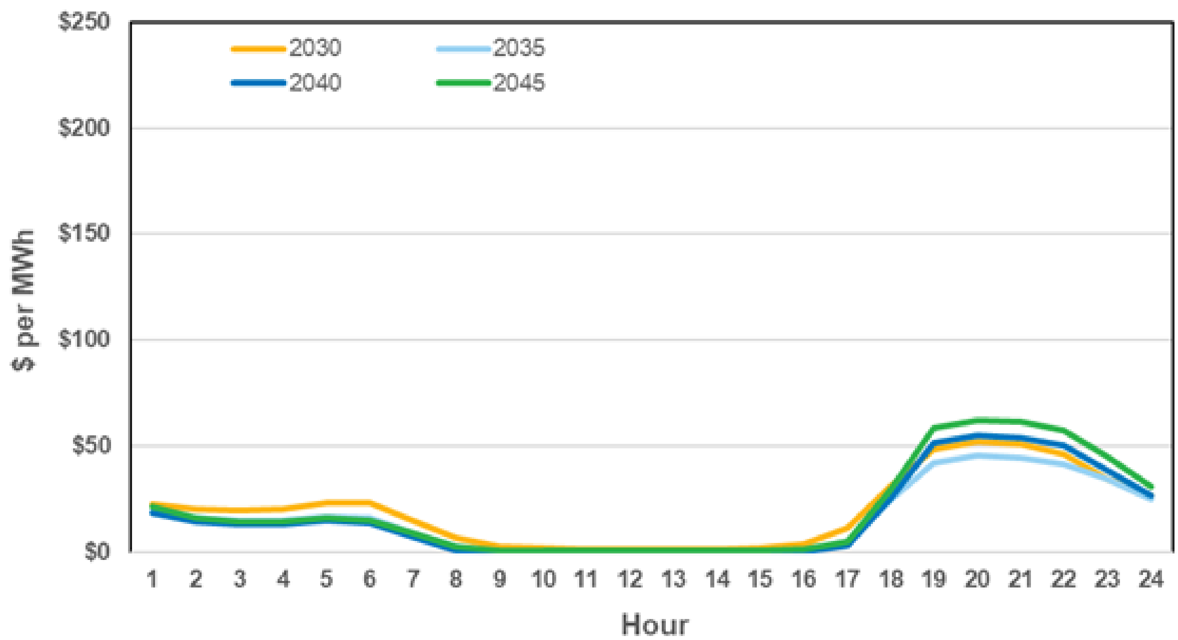


Figure 9.19: Summer Average Hourly Electric Prices (July - September)

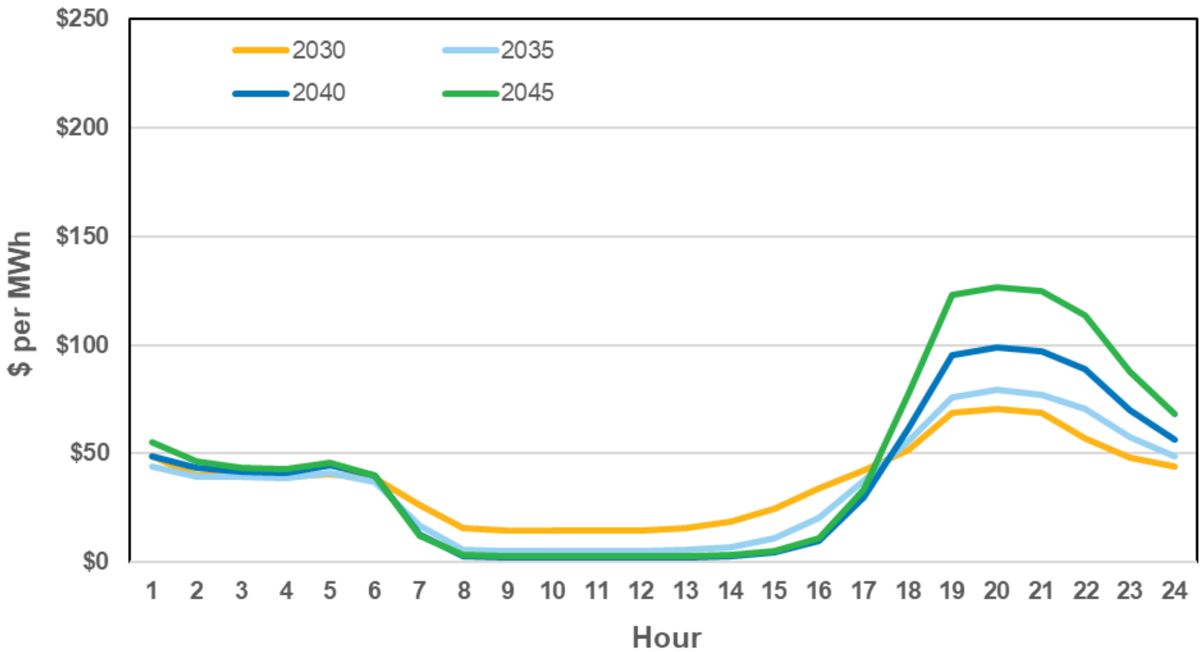
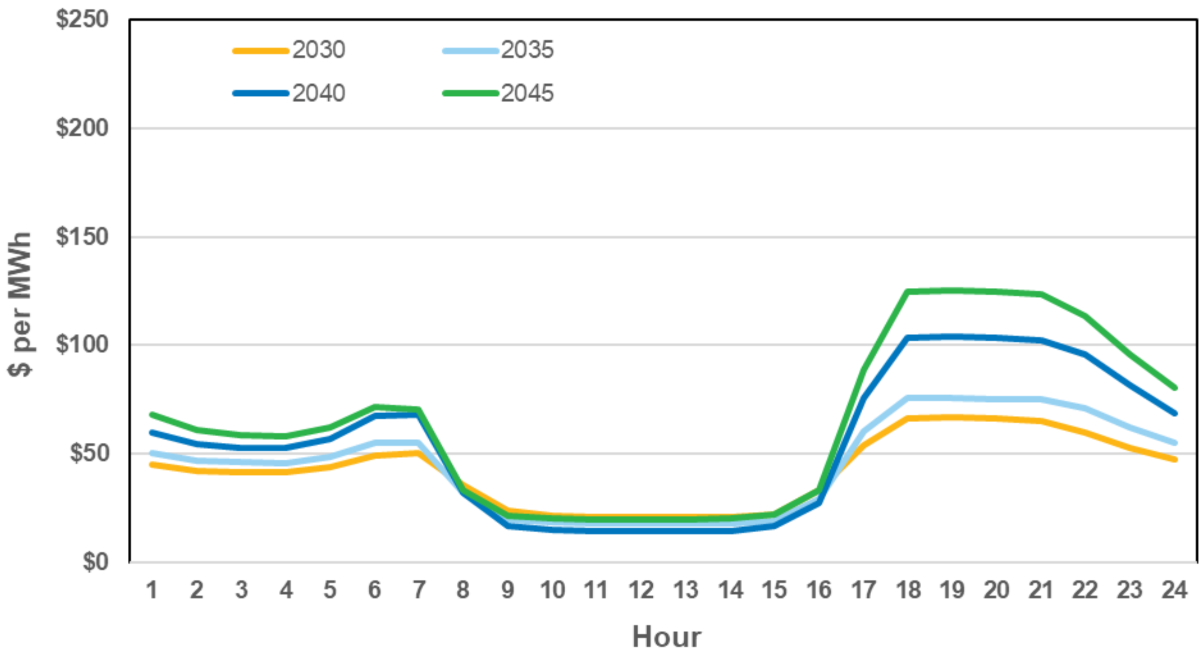


Figure 9.20: Autumn Average Hourly Electric Prices (October – November)



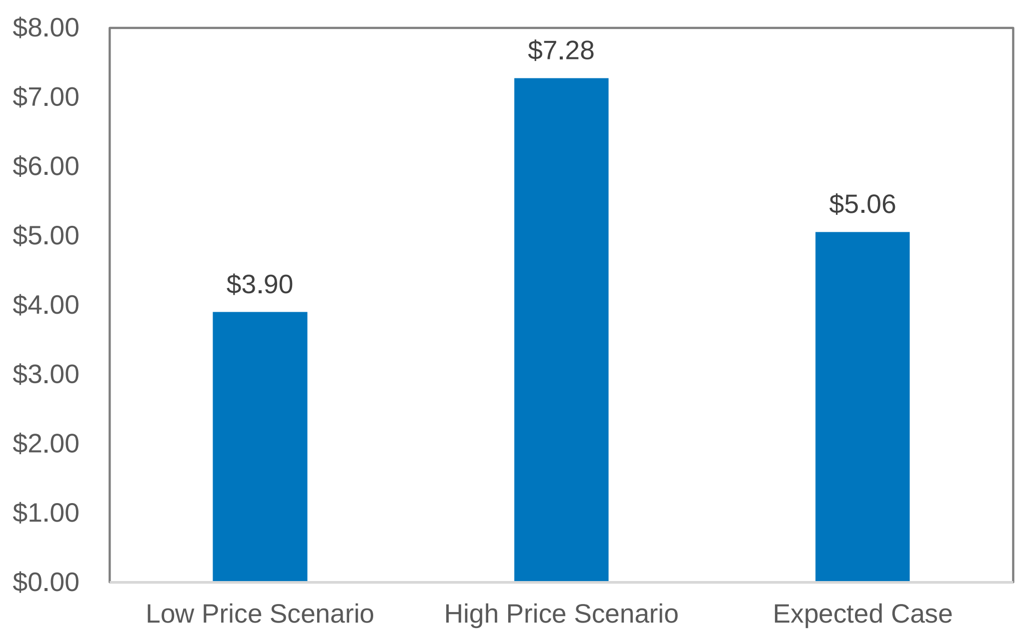
Scenario Analyses

Electric wholesale market prices will have an impact on this resource plan depending on how each resource option performs compared to other resources. This comparison uses market prices along with how each resource performs when customers need them (e.g., winter sustained peak). Market price forecasts can be rather computer processor and time intensive. However, understanding specific effects on the marketplace are important to understand the risks involved with resource choice. Avista studied three additional scenarios beyond the 300 simulations of the Expected Case. Avista modeled each scenario deterministically. Deterministic studies are sufficient because the objective of the scenarios is to understand the effect of the underlying change in assumption of the plan. The portfolio sensitivities and market scenarios conducted for this IRP are discussed below.

Natural Gas Pricing Scenario

Low natural gas prices will impact resource selection by lowering electric prices. This scenario assumes 25th percentile natural gas prices from the Expected Case stochastic study. The high pricing scenario uses the 90th percentile of the same Expected Case data set. Both scenarios rely on the Expected Case capacity expansion study. Figure 9.21 compares the 20-year levelized cost of these scenarios to the Expected Case at the Henry Hub natural gas price. The high gas price scenario is 144% above, while the low-price scenario is 26% below the Expected Case. These gas price scenarios are useful in determining the viability of future resource options given possible changes in natural gas prices. For example, low natural gas prices will make renewable projects less economic while high natural gas prices will make them relatively more economic.

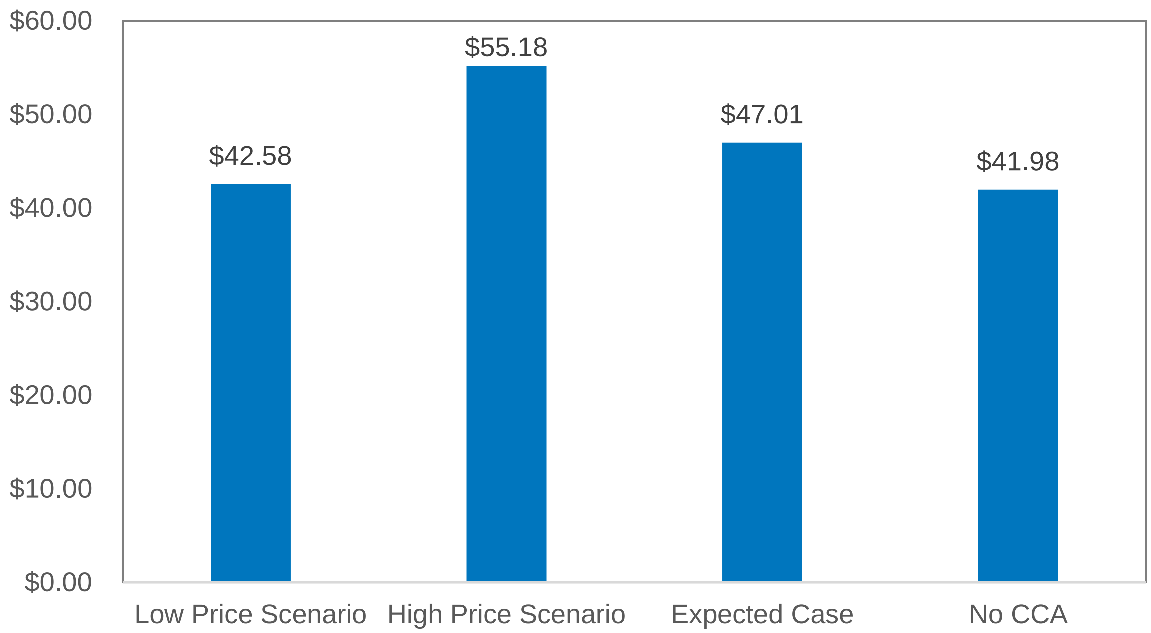
Figure 9.21: Change in Henry Hub Natural Gas Prices



Scenario Electric Price Results

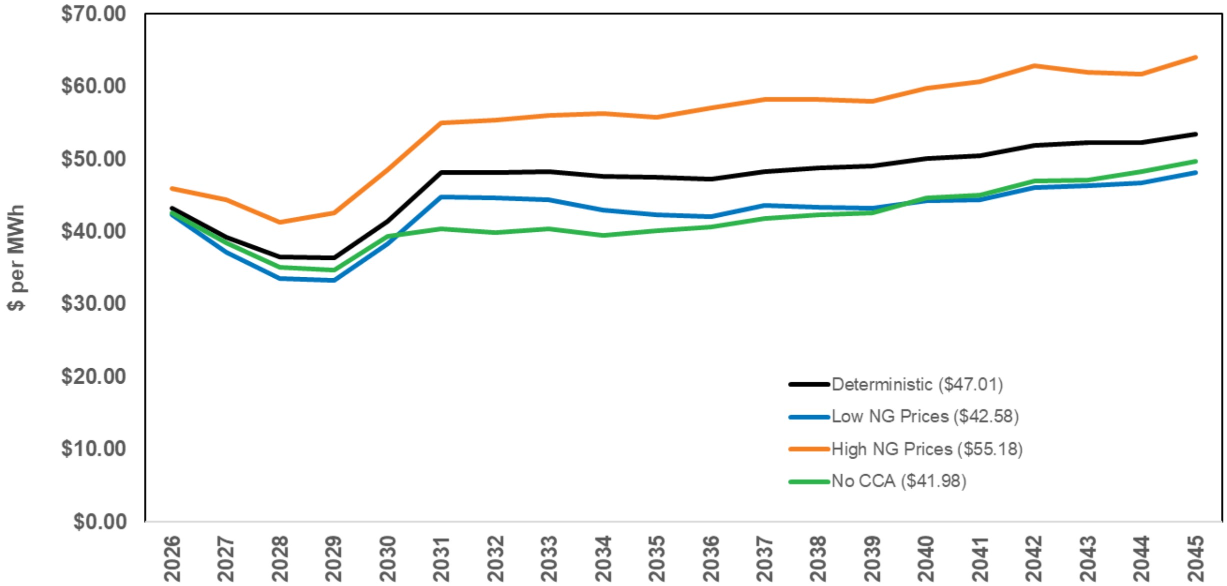
The results of these scenarios show a variety of market price impacts from changes in key assumptions. Figure 9.22 presents the nominal levelized prices for each scenario on a 20-year basis compared with the Expected Case's deterministic study assuming Washington delivery. The No CCA scenario assumes no CCA in Washington. The deterministic study is shown to eliminate other factors for the comparative analysis. For example, the only change in the study assumptions is the specific input rather than stochastic assumptions. The annual prices used to estimate the levelized costs for each scenario are shown in Figure 9.23.

Figure 9.22: Mid-Columbia Nominal Levelized Prices Scenario Analysis



The natural gas pricing scenarios show how a 144% increase in natural gas prices causes a 17% increase in electric market prices. When natural gas prices are 26% lower than the Expected Case, the resulting electric market prices are 9% lower.

Figure 9.23: Mid-Columbia Annual Electric Price Scenario Analysis



10. Portfolio Scenario Analysis

The 2025 Preferred Resource Strategy (PRS) is Avista's approach to meet future load growth and replace aging generation resources through 2045. The future's actual results are often different from the IRP's Expected Case forecast used to develop the PRS, because of this, the future resource strategy will change as time progresses to respond to new information about markets, resources, and regulations. This IRP identifies alternative optimized resource strategies for different underlying assumptions to understand how Avista may respond to new information. Resource decisions may change depending on how customers use electricity, the availability of existing resources, how the economy changes, and how greenhouse gas (GHG) emission policies evolve. This chapter investigates the cost and risk impacts to the PRS under different future scenarios the utility may face, as well as alternative resource portfolios.

Section Highlights

- Energy storage and demand response are the most viable options to meet new short-term capacity needs.
- Nuclear energy will be needed to meet extreme load growth scenarios.
- Early acquisition of wind generation is driven by the federal government's Inflation Reduction Act (IRA) and high wholesale electric market prices.
- The amount of wind energy selected in the PRS is sensitive to power market prices, the price of wind, and the availability of low-cost interconnects. A change in these parameters could shift resource choices.
- Natural gas resources remain the lowest cost capacity resource for Idaho customers so long as transmission and fuel storage are constructable.

Portfolio scenarios are representative of studies requested by the Technical Advisory Committee (TAC) or regulatory requirements. Most of the scenario studies address uncertainty such as: the Northeast Combustion Turbine's (CT) retirement date, a data center locating in the service area, warmer future weather conditions, significant economic condition changes, building electrification, transportation electrification, availability of local wind resources, loss of IRA tax benefits, future required planning reserve margins (PRM), and viability of new resource technologies. In addition to alternative portfolio choices, Avista tested a portfolio impact in which the Climate Commitment Act (CCA) is repealed and how the PRS is sensitive to much higher or lower natural gas prices. All portfolios are assigned a portfolio number based upon the order added to the list of studies. The full list of scenarios and assigned numbers are shown in Table 10.1 by load, resource availability, and other categories.

Avista plans to issue a Request for Proposal (RFP) for new resources in 2025 with an on-line date by the end of the decade. This RFP will help inform short-term risks such as resource availability, provide options to replace the Northeast CT, and additional time to measure load growth changes. Further, the RFP can be informative about serving a data center (if one requests service), and how it could elevate short-term load risks. Most of the significant risks identified in this analysis stem from higher load levels. The electrification of transportation and buildings poses the greatest long-term risk. Given the limited supply of infrastructure, manufacturing capacity and required workers, electrification changes will likely occur at a more gradual pace, giving utilities time to respond to trends and soften the shock to the power supply system. However, the high load scenarios are large enough to justify earlier planning for long lead items such as transmission and distribution system upgrades. A new large industrial load may require additional generation at a faster pace forcing larger system upgrades.

Another risk identified in the scenario analysis would occur if Avista needed to change course from the PRS due to a clean energy requirement in Idaho. The inability to site a new natural gas resource or higher natural gas construction costs could change Avista's resource choices. While natural gas-fired generation remains a cost-effective option for Idaho customers in this plan; technology, turbine pricing, or public policy changes could require a reduction of those resources to serve Idaho customers. Based on the current political environment, this would most likely come from a federal policy change or a significant cost reduction in non-gas generation and storage from new technologies.

Table 10.1: Scenario List

Load Scenarios	Resource Availability	Other
#5 - Low Growth	#4 - Clean Resource Portfolio by 2045	#2 - Alternative Lowest Reasonable Cost
#6 - High Growth	#11 - 500 MW Nuclear in 2040	#3 - Baseline Least Cost Portfolio
#7 - 80% Washington Building Electrification by 2045	#14 - Power to Gas Unavailable	#10 - Maximum Washington Customer Benefit
#8 - 80% Washington Building Electrification by 2045 & High Transportation Electrification	#21 - Regional Transmission not Available	
#9 - 80% System Building Electrification by 2045 & High Transportation Electrification, No New NG CTs	#22 - 2026 Northeast CTs Retirement	#13 - 30% PRM
#18 - 200 MW Data Center in 2030	#23 - On-System Wind Limited to 200 MW	#15 - Minimal Viable CETA Target
#19 - RCP 8.5 Weather	#24 - No IRA Tax Incentives	#16 - Maximum Viable CETA Target
#20 - 80% System Building Electrification by 2045 & High Transportation Electrification Scenario No New NG CTs with RCP 8.5 Weather	#25 - 2035 Northeast CTs Retirement	#17 - PRS Constrained to the 2% Cost Cap
		# 26- PRS w/ CCA repealed

Load Scenarios

Avista conducted eight future load growth scenarios to understand the impact on the resource portfolio. These load scenarios include changes in customer growth from population, understanding the impact of building electrification, quantifying high rates of transportation electrification, evaluating a new large system load (such as a data center), and lastly determining the impact of different future weather conditions on planning. Chapter 3 includes documentation regarding the impact of the load forecast.

Low and High Load Growth

The low economic growth scenario results in an annual average growth rate of 0.34% compared to the Expected Case's growth rate of 0.91% per year. The high economic growth scenario increases load at 1.75% per year. The change in load either increases or decreases the amount of generation selected in the PRS, but generally uses the same resource types to solve resource requirements, except for removing nuclear energy in the low growth scenario for Washington. Table 10.2 outlines the low and high growth resource selections compared to the PRS over the 20-year study period, the present value of revenue requirement (PVRR), and the 2030 and 2040 average energy rates.

Table 10.2: Low and High Load Growth Scenarios

		Washington			Idaho		
		1- Preferred Resource Strategy	5- Low Economic Growth Loads	6- High Economic Growth Loads	1- Preferred Resource Strategy	5- Low Economic Growth Loads	6- High Economic Growth Loads
Megawatts	Natural Gas	0	0	131	275	277	431
	Solar	311	149	310	0	0	0
	Wind	1,307	1,268	1,302	119	66	158
	Energy Storage	261	104	370	0	0	0
	Power to Gas	394	394	394	0	0	0
	Nuclear	100	0	349	0	0	0
	Geothermal	20	20	20	0	0	0
	Biomass	64	64	7	3	3	3
	Demand Response	70	61	120	17	17	11
	EE- Winter Capacity	156	156	156	49	49	49
	EE- Summer Capacity	111	111	111	38	38	38
PVRR (Millions)		$10,924	$10,641	$11,494	$4,758	$4,711	$4,964
2030 Rate ($/kWh)		$0.130	$0.131	$0.128	$0.112	$0.112	$0.109
2045 Rate ($/kWh)		$0.248	$0.242	$0.262	$0.180	$0.189	$0.167

By 2030, the rate impact between the scenarios is negligible, but generally higher loads reduce energy rates as the existing system's fixed costs are spread out over more load. The rate impact for Idaho customers follows, where higher loads reduce the energy rates (-7.3% in 2045) even though power costs are slightly higher. In the low load scenario, the opposite occurs for Washington customers, where resource options are limited or cost constrained to account for the social cost of greenhouse gas (SCGHG), and lower loads reduce the PVRR by avoiding higher priced resources. The high load scenario rates increase as more nuclear and energy storage is required.

Representative Concentration Pathways (RCP) 8.5 for Winter Planning

Avista uses both forecasted and historical temperatures to normalize future weather for estimating future customer loads. For the summer, Avista uses a temperature forecast with the RCP 8.5 climate future as described in Chapter 5, but in the winter months Avista uses RCP 4.5. The difference between these two temperature futures is the RCP 8.5 scenario has warmer temperatures. For the energy load forecast, a rolling 20 years of historical and forecasted temperatures are used for each month. But for peak planning, only the summer months use a 20-year rolling average and the winter uses a 76-year rolling average. Avista uses a wider range for winter due to the wider distribution in cold temperatures compared to the summer's narrower distribution of hottest temperatures.

Avista is relying on the RCP 8.5 temperatures for the summer season, as recent history (2020 to 2024) shows summer months are trending warmer than the RCP 8.5 forecast. But actual winter temperatures are colder than the RCP 8.5 climate forecasts. Due to the risk of cold winters and its impact on customers if Avista does not have adequate generation, Avista does not believe using a warmer temperature forecast for resource planning is prudent due to the significant risk of not being able to serve customers in the event of cold weather similar to the last two winters. Regardless of Avista's preference, this scenario shows the impact on the resource strategy of using RCP 8.5 year-round. The result of the study is in Table 10.3. In Washington, there is a shift to use less winter capable resources such as the reduction in power to gas and biomass generation, but this is offset with increases in solar, wind, energy storage, and nuclear. The lower winter loads reduce the need for both natural gas and wind for Idaho. Using the RCP 8.5 temperatures does lower costs due to the shift in generation and less energy sales, but due to lower energy sales, the cost per kWh is higher.

Table 10.3: RCP 8.5 Temperatures for Winter Planning

		Washington		Idaho	
		1- Preferred Resource Strategy	19- RCP 8.5 Weather	1- Preferred Resource Strategy	19- RCP 8.5 Weather
Megawatts	Natural Gas	0	0	275	229
	Solar	311	317	0	0
	Wind	1,307	1,322	119	111
	Energy Storage	261	325	0	0
	Power to Gas	394	364	0	30
	Nuclear	100	108	0	0
	Geothermal	20	20	0	0
	Biomass	64	7	3	3
	Demand Response	70	70	17	17
	EE- Winter Capacity	156	156	49	49
	EE- Summer Capacity	111	111	38	38
PVRR (Millions)		$10,924	$10,907	$4,758	$4,752
2030 Rate ($/kWh)		$0.130	$0.132	$0.112	$0.113
2045 Rate ($/kWh)		$0.248	$0.248	$0.180	$0.182

Electrification Studies

Several electrification studies were requested by the TAC to better understand the impact on the electric resource needs and cost of the system of extreme load changes. Building electrification studies were designed to estimate impacts to the total cost to serve customers considering fuel savings to the LDC[98] natural gas system. The four electrification scenarios include:[99]

- Washington Building Electrification (#7): Isolating building electrification for just the Washington portion of the system where natural gas LDC demand is 80% lower in 2045 than forecasted in 2026. Electric loads are 356 MW higher for winter peaks with an average load increase of 107 aMW.

- Washington Building Electrification & High Transportation Electrification (#8): uses the same building electrification assumptions as scenario #7 but adds an equivalent of 246,000 electric vehicles to the system by 2045 for a total of 806,000 EV equivalents. This adds 127 MW of winter peak load compared to #7 and 76 aMW of additional energy obligations by 2045.

[98] Local Distribution Company
[99] A summary of load forecasts is included in Chapter 3.

- Building Electrification & High Transportation Electrification w/o NG (#9): This scenario adds to #8 by also electrifying buildings for the Idaho LDC. In this case, Idaho's natural gas demand in 2045 is 80% less than its 2045 forecasted natural gas load. This adds 300,000 EV equivalents to the Idaho electric loads. In total, 1 million EV equivalents are included in this scenario. To electrify Idaho's buildings and transportation adds 520 MW to the 2045 winter peak and 219 aMW of energy.

- Building Electrification & High Transportation Electrification w/o NG with RCP 8.5 (#20): This scenario adjusts the load in scenario #9 to have warmer temperatures in the winter used in scenario #9 discussed above.

In the scenarios where the Idaho service area has heavy adoption of building and transportation electrification, the resource selection does not consider new natural gas as a resource option. While building natural gas generation to serve electric load is an option in Idaho, it is counter to the point of removing direct customer natural gas as the efficiency of creating energy in the natural gas turbine is less then burning directly for space heat. However, the study does retain Coyote Springs 2 for serving Idaho customers. Even though natural gas is not an option used in this study, preliminary analysis indicates it would be a lower cost option to serve the increased load than the portfolio results shown below.

The increasing electrification loads result in both higher costs and rates due to the lack of low-cost resources to serve new capacity and energy needs in addition to the added cost to improve the transmission and distribution system. To serve these higher loads, the capacity expansion model selects solar, nuclear, energy storage, and energy efficiency to meet this demand.

Looking at the impact on the electric system in isolation, shows the total cost impact to customers but does not show the impact to the natural gas system from the lost load. Avista created a simplified natural gas planning model within its electric capacity expansion model to consider the impacts to the natural gas LDC system. These impacts include increased load to non-Avista electric utilities serving Avista's natural gas customers[100] and the cost to building owners for converting an existing natural gas forced air and water heating system to electric. The most appropriate way to illustrate the cost and benefits of building electrification is to compare scenario #7 to the PRS, as it isolates the building electrification rather than including the transportation load. The levelized incremental total customer costs are 25% higher when using electric to space and water heat between 2043 and 2045 (this period is selected as it shows a high saturation of load

[100] Approximately 25% of Washington natural gas customers have a non-Avista electric provider.

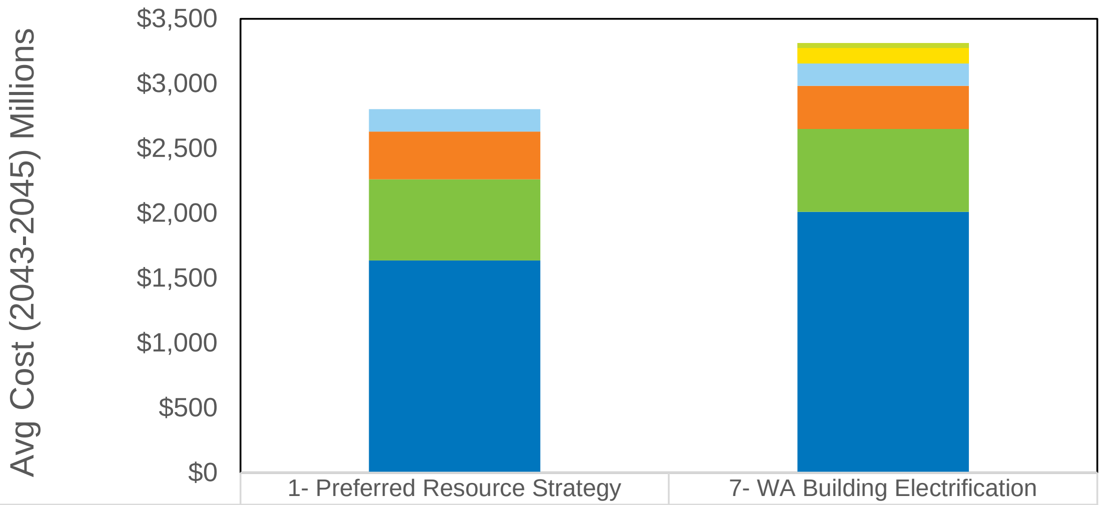
switching) as shown in Figure 10.1. This increase includes estimated costs on other electric utilities and the customers' site conversion costs.

Table 10.4: Electrification Scenarios

		Washington		
		1- Preferred Resource Strategy	12- 17% PRM	13- 30% PRM
Megawatts	Natural Gas	0	0	0
	Solar	311	210	311
	Wind	1,307	1,308	1,315
	Energy Storage	261	131	419
	Power to Gas	394	394	394
	Nuclear	100	108	100
	Geothermal	20	20	20
	Biomass	64	64	64
	Demand Response	70	73	73
	EE- Winter Capacity	156	156	156
	EE- Summer Capacity	111	111	111
PVRR (Millions)		$10,924	$10,880	$11,083
2030 Rate ($/kWh)		$0.130	$0.130	$0.132
2045 Rate ($/kWh)		$0.248	$0.244	$0.252
		Idaho		
		1- Preferred Resource Strategy	12- 17% PRM	13- 30% PRM
Megawatts	Natural Gas	275	213	300
	Solar	0	105	0
	Wind	119	123	125
	Energy Storage	0	0	25
	Power to Gas	0	0	0
	Nuclear	0	0	0
	Geothermal	0	0	0
	Biomass	3	3	3
	Demand Response	17	17	17
	EE- Winter Capacity	49	49	49
	EE- Summer Capacity	38	38	38
PVRR (Millions)		$4,758	$4,734	$4,781
2030 Rate ($/kWh)		$0.112	$0.112	$0.112
2045 Rate ($/kWh)		$0.180	$0.180	$0.183

The intent of the analysis is not only to identify what the system and customer costs of transiting customers to electric heating, but to understand how it lowers GHG emissions. In this case, between 2043 and 2045, the total emissions are 1.3 million metric tons lower or 22%, but the cost per ton is $1,144 per ton of savings. Overall, the study found the levelized cost per ton of savings is $828 per ton. As the cost of reducing emissions exceeds the social cost of greenhouse gases (SCGHG), the economic benefits of rapidly electrifying buildings are not justified.

Figure 10.1: 2043-2045 Washington Electrification Cost



	1- Preferred Resource Strategy	7- WA Building Electrification
Other Utility Cost Impacts	$0	$37
NG Site Conversion Cost	$0	$118
Natural Gas Idaho	$172	$175
Natural Gas Washington	$369	$332
Electric Idaho	$626	$639
Electric Washington	$1,636	$2,012
Total	$2,803	$3,313

Large Load/Data Center Scenario

Due to increasing artificial intelligence computing demand and growth in the technology space, large data centers are searching for electric service at any utility with the ability to accommodate their energy needs. Most data centers desire interconnection within 36 months but are finding few utilities able to accommodate the demand without building new generation resources. Data center size ranges between 100 MW and 500 MW of constant demand. Large new loads on the electric system have multiple impacts, such as meeting energy requirements, resource adequacy, interconnection, and rate design to isolate existing and future traditional customers from the incremental costs the large load brings to the system. This scenario illustrates the impact of a 200 MW load in the Washington service territory. The study assumes the existing cost allocation methodology where costs are shared based on load share includes this higher load, effectively moving existing generation from Idaho to Washington customers. Furthermore, the new load share must be met with renewable energy following CETA requirements, but with the change in the cost sharing ratio, Idaho customers would need additional capacity to offset previously allocated generation.

The results of the analysis, shown in Table 10.5, indicate Idaho must add an additional 95 MW of natural gas CTs and energy efficiency to offset the existing lost capacity (from the updated PT ratio allocation with an additional 200 MW of load in Washington) and replace the wind now needed to serve Washington's new load. For Washington, additional solar, energy storage, nuclear, and energy efficiency meets the resource need. Rates in Washington are lower as this load increase has a high load factor to absorb the higher system cost. Idaho has slightly higher rates due to losing a small amount of wind and increasing its energy efficiency programs.

Table 10.5: Large Load Impacts

		Washington		Idaho	
		1-Preferred Resource Strategy	18- Data Center in 2030	1-Preferred Resource Strategy	18- Data Center in 2030
Megawatts	Natural Gas	0	0	275	370
	Solar	311	632	0	0
	Wind	1,307	1,440	119	0
	Energy Storage	261	329	0	0
	Power to Gas	394	394	0	0
	Nuclear	100	197	0	0
	Geothermal	20	20	0	0
	Biomass	64	64	3	3
	Demand Response	70	73	17	17
	EE- Winter Capacity	156	163	49	58
	EE- Summer Capacity	111	116	38	44
PVRR (Millions)		$10,924	$11,794	$4,758	$4,871
2030 Rate ($/kWh)		$0.130	$0.131	$0.112	$0.112
2045 Rate ($/kWh)		$0.248	$0.237	$0.180	$0.187

The impact of the large load on the non-participating customers illustrates how a large new load will require a creative rate design structure to serve the demand. This scenario assumes a relatively small 200 MW data center, if the data center is closer to 500 MW without curtailment abilities, the impact to customers begins to add additional long-term complexity where the data center demand utilizes the lower cost resource alternatives and forces future load growth to be served with higher cost future technologies. It may also require significant transmission additions to bring generation to load centers.

Resource Availability Scenarios

The IRP resource options are uncertain in terms of the quantity available, and in some cases, the cost to bring those resources to the system. These scenarios quantify how specific resource assumption changes could impact resource selection or the cost of the portfolio. The resource availability scenarios include changes to the following assumptions:

- Northeast CT retirement date (#22 and #25)
- Limitation of wind availability without new transmission (#23)
- Not building regional transmission to SPP/MISO (#21)
- Excluding power to gas as a resource (#14)
- Elimination of the IRA incentives (#24)
- Adding nuclear energy early (#11)
- No longer utilizing natural gas generation (#4)

Northeast Retirement

Northeast is a two-unit combustion turbine built in 1978 and located in northeast Spokane. The facility's total capacity is 66 MW in the winter and 42 MW in the summer. The plant is fully depreciated and provides the system with non-spinning reserves as it is limited to 50 hours of annual operation by its air permit. In the summer of 2024, the plant passed its local emission's testing and is permitted to operate through 2029 and may be extend to 2032 if it passes its emission test in 2029. This IRP's PRS assumes the plant is available to the system through 2029. The Northeast site is a potential location for new future resources to re-use the interconnection. The site does have the benefit of being within a load center, lowering system energy losses. Avista studied two scenarios to illustrate the impacts of either retiring the resource early in 2025 or retaining the facility through 2034 as shown in Table 10.6.

Retiring the plant early changes the resource portfolio immediately, by requiring energy storage and an increase to demand response in 2026 along with moving wind generation to 2028. Due to the early replacement capacity, there is not enough time to develop a new natural gas resource to meet Idaho's load deficit. This early shutdown raises 2030 rates by 0.7% in Washington and 0.9% in Idaho compared to the PRS. Although in the long term, Washington's rates are 0.8% higher in 2045 and Idaho's are only 0.4% higher.

If Avista continues to operate the plant through 2034, the portfolio also selects resources in an analogous way to closing early, but the need for energy storage is reduced to 36 MW for Idaho and the natural gas CT is deferred to 2037, although additional demand response is needed by 2029. From an average cost of energy perspective, delaying retirement has no material rate impact for either state in 2030, but in 2045, Idaho sees rates 0.7% higher and Washington has no impact.

The results indicate shutting down early and later both have similar long term rate impacts on customers, but from a PVRR point of view, there is only 0.02% reduction in cost to shutting down the plant in 2034 versus 2029. Given the minimal cost differences from these scenarios, a 2029 shut down is a reasonable retirement date. Having a firm retirement date for this facility allows the utility to plan for its exit and elevates risks to maintain the aging facility when a failed emission test or breakdown could require the utility to quickly respond to its forced retirement. Avista will be seeking energy and capacity options in 2025 as part of its all-source RFP and will determine if replacing the lost capacity with energy storage, natural gas, or an unknown option is the best way to serve all customers.

Table 10.6: Northeast CT Analysis

		Washington			Idaho		
		1-Preferred Resource Strategy	22-Northeast Retires Early	25-Northeast Retires Late	1-Preferred Resource Strategy	22-Northeast Retires Early	25-Northeast Retires Late
Megawatts	Natural Gas	0	0	0	275	243	254
	Solar	311	311	312	0	0	0
	Wind	1,307	1,221	1,306	119	180	122
	Energy Storage	261	274	261	0	57	36
	Power to Gas	394	394	394	0	0	0
	Nuclear	100	122	100	0	0	0
	Geothermal	20	20	20	0	0	0
	Biomass	64	64	64	3	3	3
	Demand Response	70	73	70	17	17	19
	EE- Winter Capacity	156	156	156	49	49	49
	EE- Summer Capacity	111	111	111	38	38	38
PVRR (Millions)		$10,924	$10,993	$10,922	$4,758	$4,775	$4,758
2030 Rate ($/kWh)		$0.130	$0.131	$0.130	$0.112	$0.113	$0.112
2045 Rate ($/kWh)		$0.248	$0.250	$0.248	$0.180	$0.181	$0.182

Wind Limitations

Avista assumes 500 MW of wind is available on its system without major transmission expansion. It is possible other utilities or even data centers could consume a portion of the 500 MW and take the energy off Avista's system. The intent of this scenario is to understand resource selection changes if there is less low-cost interconnection wind available than assumed by the PRS. Future RFPs will determine if this risk materializes, but the impact to the portfolio results have minimal rate impacts in the short term. Energy rates increase by 2045 as higher cost resources will be required to replace wind, resulting in 3.3% higher rates for Washington and 0.5% higher for Idaho.

From a system perspective, the results of the study show (as shown in Table 10.7) a small increase from solar and natural gas due to losing 339 MW of wind, but a 54 MW increase in nuclear generation. Due to the nuclear additions, 53 MW less of energy storage is needed.

Table 10.7: On-System Wind Limitations

		Washington		Idaho	
		1- Preferred Resource Strategy	23- On-system wind limited to	1- Preferred Resource Strategy	23- On-system wind limited to
Megawatts	Natural Gas	0	0	275	287
	Solar	311	325	0	0
	Wind	1,307	994	119	93
	Energy Storage	261	208	0	0
	Power to Gas	394	394	0	0
	Nuclear	100	154	0	0
	Geothermal	20	20	0	0
	Biomass	64	64	3	3
	Demand Response	70	73	17	17
	EE- Winter Capacity	156	156	49	49
	EE- Summer Capacity	111	111	38	38
PVRR (Millions)		$10,924	$11,030	$4,758	$4,781
2030 Rate ($/kWh)		$0.130	$0.131	$0.112	$0.112
2045 Rate ($/kWh)		$0.248	$0.256	$0.180	$0.181

Regional Transmission

Avista included a 300 MW new transmission line to the eastern interconnect in the PRS and in the remaining scenario analyses. Avista assumes this line would allow Avista to import up to 300 MW (prior to energy losses) of energy when wind in eastern Montana is not available, and it may allow Avista to sell excess generation to other interconnects when prices are higher in the eastern interconnect. There are two main value streams for this project. The first is capacity value during reliability events. Avista studied this value early in the PRS development and found this benefit alone justified participation. The second major value is the ability to arbitrage the eastern markets with Mid-C power. Avista has not shared this value in the IRP as it will be prepared in the final decision making of this project. The intent of this scenario is not to look at the cost differences between this scenario and the PRS, but to focus on the resource changes if the project is cancelled or even delayed.

The results of this study indicate an increase in energy storage will be the main replacement capacity. While there are minor changes in other generation types, the model pushes the need forward in time for these resources. This includes acquiring wind, solar, and storage in 2032 for Washington instead of the transmission line, and for Idaho acquiring a larger natural gas turbine in 2030.

Table 10.8: No Regional Transmission

		Washington		Idaho	
		1- Preferred Resource Strategy	21- Regional Transmission not available	1- Preferred Resource Strategy	21- Regional Transmission not available
Megawatts	Natural Gas	0	0	275	287
	Solar	311	320	0	0
	Wind	1,307	1,274	119	93
	Energy Storage	261	419	0	0
	Power to Gas	394	394	0	0
	Nuclear	100	110	0	0
	Geothermal	20	20	0	0
	Biomass	64	64	3	3
	Demand Response	70	55	17	17
	EE- Winter Capacity	156	156	49	49
	EE- Summer Capacity	111	111	38	38

No Power to Gas Projects

The PRS includes both hydrogen and ammonia fueled projects for power to gas (P2G) resources. P2G options include co-firing hydrogen with natural gas at Coyote Springs 2 and building new ammonia fueled CTs. Both options are viable alternatives to provide dispatchable clean energy. This scenario is designed to understand the portfolio and cost changes without these resources as some parties advocate not to burn these fuels due to NO_X emissions. These fuels will require a new fuel supply chain and may include a hydrogen pipeline system and on-site storage of ammonia. Both supply chains are available in other parts of the country and world, not just in the northwest.

Without P2G as a fuel, the portfolio will require more energy storage (288 MW) and nuclear energy (122 MW), and less wind by 93 MW. Moving from P2G fuels to shorter term energy storage and nuclear increases energy rates in Washington by 11.1% in 2045 and 4.1% in Idaho. Idaho sees higher rates because the scarce wind resources are reallocated to Washington.

Table 10.9: No Power to Gas Resources

		Washington		Idaho	
		1- Preferred Resource Strategy	14- Power to Gas Unavailable	1- Preferred Resource Strategy	14- Power to Gas Unavailable
Megawatts	Natural Gas	0	0	275	287
	Solar	311	320	0	0
	Wind	1,307	1,240	119	93
	Energy Storage	261	549	0	0
	Power to Gas	394	0	0	0
	Nuclear	100	222	0	0
	Geothermal	20	20	0	0
	Biomass	64	64	3	3
	Demand Response	70	61	17	17
	EE- Winter Capacity	156	156	49	49
	EE- Summer Capacity	111	111	38	38
PVRR (Millions)		$10,924	$11,020	$4,758	$4,772
2030 Rate ($/kWh)		$0.130	$0.130	$0.112	$0.112
2045 Rate ($/kWh)		$0.248	$0.275	$0.180	$0.188

No Inflation Reduction Act (IRA)

This scenario shows how the resource portfolio and costs to the system would change if the IRA was repealed, and it also shows the impact of the policy to the portfolio. This analysis focuses on the resource impacts and does not estimate a change in the load forecast or energy efficiency impacts of losing the IRA. It is likely the load forecast would be lower due to less electrification of buildings.

Due to CETA and the CCA, the total amount of new renewable energy created is unchanged. Overall, the only material change in the portfolio is Kettle Falls unit 2 is removed and replaced with energy storage and a minimal amount of new renewable energy. The change takes place when renewable energy is chosen and allocated to a specific state. Without the IRA's Production Tax Credit, Idaho would not participate in any new wind resources. Furthermore, the timing of new wind would also be delayed until the resource needs of Washington's CETA requirements. As Avista anticipates it has already met its near term CETA compliance requirements, new wind acquisition is minimal (100 MW in 2030 and 200 MW in 2035), while all remaining wind is beyond 2039.

The cost impact of this policy is more important to Washington than Idaho customers. Washington would have 2.7% higher rates in 2045, and Idaho's rate increase is only 0.5%. Over the 20-year period, the system PVRR is 2.2% higher without the IRA. This scenario highlights most of the early wind acquisitions are due to economic selection rather than resource need. The need to acquire wind early will be dependent on the economic outlook of the energy price compared to the market rather than focus on meeting renewable energy targets. This implies early acquisition of wind energy is somewhat speculative and requires additional analysis beyond the IRP before adding large amounts of wind energy that will likely need to be sold in the energy market until the middle of the next decade.

Table 10.10: No IRA Impacts

		Washington		Idaho	
		1- Preferred Resource Strategy	24- No IRA Tax Incentives	1- Preferred Resource Strategy	24- No IRA Tax Incentives
Megawatts	Natural Gas	0	0	275	287
	Solar	311	318	0	0
	Wind	1,307	1,331	119	93
	Energy Storage	261	297	0	0
	Power to Gas	394	394	0	0
	Nuclear	100	100	0	0
	Geothermal	20	20	0	0
	Biomass	64	7	3	3
	Demand Response	70	73	17	17
	EE- Winter Capacity	156	156	49	49
	EE- Summer Capacity	111	111	38	38
PVRR (Millions)		$10,924	$11,266	$4,758	$4,754
2030 Rate ($/kWh)		$0.130	$0.131	$0.112	$0.112
2045 Rate ($/kWh)		$0.248	$0.255	$0.180	$0.181

500 MW Nuclear Energy

Between the PRS and many of the high load growth scenarios, nuclear energy is a common resource selection to solve the resource deficits once other resource options become limited or too expensive. One of the main concerns with nuclear energy is the high cost and time necessary to develop the resource due to permitting and construction. This scenario addresses what a portfolio would look like if 500 MW of nuclear energy is added to the system in 2040. The analysis assumes the energy is split between Idaho and Washington using the PT ratio and no other resources are retired.

The analysis indicates a significantly higher energy rate in 2045 for both Washington (9%) and Idaho (30%). The cost change for this scenario is immaterial as Avista would not endeavor a project this large unless its cost were recoverable and justified compared to other resources. These cost increases illustrate why nuclear is not chosen in the PRS in large amounts, but the 9% higher cost for Washington indicates it may be a viable resource to meet clean energy needs if enough other clean resources are not developed. The costs could be further reduced if the PTC for nuclear power is permanently extended. As for Idaho, nuclear energy is at a significant premium compared to natural gas CTs and wind energy.

The resource portfolio with a large amount of nuclear energy undergoes significant changes to reduce natural gas (-185 MW), solar (-300 MW), wind (-606 MW), energy storage (-200 MW), biomass (-58 MW), and demand response (15 MW). Effectively the 500 MW nuclear facility satisfies the need for 1,364 MW of other resources as shown in Table 10.11. Avista's reliability analysis also shows significantly less outage probability at 0.6%, effectively allowing for a lower PRM and could reduce costs.

Table 10.11: No Power to Gas Resources

		Washington		Idaho	
		1- Preferred Resource Strategy	11- Least Cost + 500 MW Nuclear in 2040	1- Preferred Resource Strategy	11- Least Cost + 500 MW Nuclear in 2040
Megawatts	Natural Gas	0	0	275	90
	Solar	311	11	0	0
	Wind	1,307	687	119	133
	Energy Storage	261	61	0	0
	Power to Gas	394	364	0	30
	Nuclear	100	334	0	166
	Geothermal	20	20	0	0
	Biomass	64	7	3	3
	Demand Response	70	55	17	17
	EE- Winter Capacity	156	156	49	49
	EE- Summer Capacity	111	111	38	38
PVRR (Millions)		$10,924	$11,697	$4,758	$5,124
2030 Rate ($/kWh)		$0.130	$0.131	$0.112	$0.111
2045 Rate ($/kWh)		$0.248	$0.270	$0.180	$0.234

Clean Energy Portfolio by 2045

This scenario studies a future where no new or existing natural gas generation serves electric customers in either jurisdiction by 2045. This scenario meets Avista's clean energy goal where all generation would be sourced from renewable or non-carbon emitting sources by 2045[101]. In this future scenario, jurisdictional allocation issues become less relevant as both states would have similar objectives by 2045. Avista found when conducting a 2030 reliability analysis for this scenario, it failed to meet the 5% loss of load probability threshold, and the PRM was increased to 26% for 2030 to ensure the portfolio is reliable. In addition, the 24% PRM in 2045 LOLP is well below the 5% threshold.

This clean energy portfolio shows significant energy rate increases for both states, even though the resource strategy is similar for Washington. In Washington's case, the 2045 energy rates are 17% higher due to sharing more of the lower cost clean energy resources

[101] Washington's Clean Energy Future (myavista.com)

to meet Idaho’s energy needs. Idaho’s 2045 energy rate is significantly higher at 56% compared to the RPS. Its average energy rate in 2045 is $0.28 per kWh versus $0.18 per kWh in the PRS. In exchange for the higher rates, greenhouse gas emissions fall from 0.55 million metric tons to zero. Over the 20 years, the levelized cost of GHG emissions reduction between this scenario and the PRS is $220 per metric ton, but in 2045 the cost increases to $1,230 per metric ton.

The major short-term change in this portfolio compared to the PRS is the elimination of the natural gas CT in 2030. This capacity is replaced by increasing demand response amounts and using Montana wind and energy storage to meet Idaho’s deficits. The total amount of wind acquired for this scenario by 2030 is effectively the same, only the jurisdictional allocation changes. Given the minimal rate impact in 2030, the possibility of not pursuing natural gas for Idaho customers could be a viable option to defer capacity needs to a later time with minimal impact. Avista’s RFP in 2025 should be able to validate this approach. Replacing Idaho’s share of the aging natural gas fleet and meeting new load growth without using new natural gas poses a significant challenge without a low-cost clean energy resource, but to achieve this objective, new nuclear energy is required.

The significant changes in resource strategy compared to the PRS are shown in Table 10.12, where significant increases in resources are needed to meet the resource deficits post 2035. In this period, Idaho relies on a similar portfolio of resources to Washington’s PRS, with ammonia fired CTs, solar, wind, energy storage, and nuclear together meet demand. In total, the portfolio requires the following additional resources compared to the PRS: 62 MW solar, 130 MW of wind, 93 MW of energy storage, 384 MW of nuclear, and 58 MW of biomass, and 14 MW of energy efficiency to offset the 275 MW of lost natural gas and 94 MW of hydrogen (associated with Coyote Springs 2).

Table 10.12: 2045 Clean Resource Portfolio

		Washington		Idaho	
		1- Preferred Resource Strategy	4- Clean Resource Portfolio	1- Preferred Resource Strategy	4- Clean Resource Portfolio
Megawatts	Natural Gas	0	0	275	0
	Solar	311	333	0	40
	Wind	1,307	1,058	119	498
	Energy Storage	261	231	0	124
	Power to Gas	394	240	0	60
	Nuclear	100	318	0	166
	Geothermal	20	20	0	0
	Biomass	64	45	3	22
	Demand Response	70	120	17	26
	EE- Winter Capacity	156	168	49	49
	EE- Summer Capacity	111	125	38	38
PVRR (Millions)		$10,924	$11,135	$4,758	$4,873
2030 Rate ($/kWh)		$0.130	$0.131	$0.112	$0.112
2045 Rate ($/kWh)		$0.248	$0.289	$0.180	$0.280

Other Portfolios

In addition to the load and resource changes, other scenarios were requested by either state IRP rules, the TAC, or by Avista. These scenarios are used for developing avoided costs, assisting in CETA targets for the CEIP, quantifying resource adequacy, and understanding the impact to the portfolio should the CCA is repealed[102]. Below is a list of the other portfolio scenarios.

- Alternative Lowest Reasonable Cost (#2)
- Baseline Least Cost (#4)
- Maximum Customer Benefits (#10)
- 17% PRM (#12)
- 30% PRM (#13)
- Minimal Viable CETA Targets (#15)
- Maximum Viable CETA Targets (#16)
- PRS Constrained by the 2% Cost Cap (#17)
- PRS w/ CCA Repealed (#26)

Counterfactual Studies

Avista creates two counterfactual studies for avoided cost development and for CETA cost cap calculations for the 2025 CEIP. The Alternative Lowest Reasonable Cost

[102] CCA was not repealed in the November 5, 2024 election.

portfolio (#2) is designed to set the baseline cost for calculating the 2% cost cap for the 2026-2029 CEIP period. This scenario assumes CETA's clean energy targets, and the Named Community Investment Fund (NCIF) do not exist, but it still requires the SCGHG in resource selection.

The second counterfactual study, Baseline Portfolio (#3), is similar but also removes the SCGHG and NEIs from the resource decision making process. This portfolio is similar to past IRPs where it solved for the least cost resource portfolio. The baseline scenario is primarily used to estimate avoided costs as it sets the baseline for determining the cost to meet energy and capacity, whereas the PRS stands in as the energy or clean energy premium. Lastly, the baseline scenario demonstrates the cost premium to meet the remaining clean energy goals for Washington from today's portfolio but does not quantify the cost of the clean energy choices it has made prior to 2026.

The cost changes of the Alternative Lowest Reasonable Cost scenario are not relevant to the IRP as they focus on the 2026-2029 period. In this case, the increased cost between this scenario and the PRS is $4 million or less than 1%. This small change is the result of less energy efficiency and not pursuing community solar. This portfolio will be discussed further in the 2025 CEIP.

The Baseline Portfolio shows some interesting results, for instance the Clean Energy Portfolio discussed above aligns the objectives of both states. In this case, Washington's rates in 2045 would be 17.4% less by not pursuing CETA, translating into an implied carbon reduction price of $71 per metric ton between 2026 and 2045. Most of the cost increase and emissions reduction savings come in 2045, where the average cost of GHG emission reduction is $341 per metric ton.

An interesting result of this study is that Idaho's energy rates slightly increase compared to the PRS by 2.4% due to a shifting of resources to Washington by effectively requiring Idaho customers to invest in energy storage, increasing rates compared to natural gas CTs. The Baseline Portfolio primarily shifts capacity to natural gas resources and away from P2G, solar, energy storage, biomass, and nuclear. Wind continues to be cost effective, but less wind is obtained.

Table 10.13: Counterfactual Scenarios

		Washington			Idaho		
		1- Preferred Resource Strategy	2- Alternative Lowest Reasonable Cost Portfolio	3- Baseline Portfolio	1- Preferred Resource Strategy	2- Alternative Lowest Reasonable Cost Portfolio	3- Baseline Portfolio
Megawatts	Natural Gas	0	66	535	275	298	266
	Solar	311	100	0	0	0	0
	Wind	1,307	894	367	119	66	453
	Energy Storage	261	117	1	0	8	31
	Power to Gas	394	364	60	0	30	30
	Nuclear	100	0	0	0	0	0
	Geothermal	20	20	0	0	0	0
	Biomass	64	7	0	3	3	0
	Demand Response	70	73	53	17	19	26
	EE- Winter Capacity	156	148	156	49	51	49
	EE- Summer Capacity	111	105	111	38	41	38
PVRR (Millions)		$10,924	$10,796	$10,851	$4,758	$4,766	$4,655
2030 Rate ($/kWh)		$0.130	$0.130	$0.131	$0.112	$0.112	$0.111
2045 Rate ($/kWh)		$0.248	$0.208	$0.205	$0.180	$0.189	$0.185

Resource Adequacy Scenarios

As part of the TAC discussion regarding the near resource adequacy event in January 2024, the topic of what level of reliability utilities should plan for, absent a specific requirement was considered. Further, with the creation of the Western Resource Adequacy Program (WRAP), utilities could lower their individual PRM levels by coordinating resources and adequacy methodologies. After this TAC discussion, it was proposed to conduct two scenarios: 1) would emulate near zero LOLP (30% PRM), and 2) would estimate a future PRM where the WRAP is fully operational (17% PRM). Effectively these scenarios require more capacity resources in the winter months for the 30% PRM and less for the 17% PRM. The result of the studies changed Idaho’s resource strategy to include more natural gas resources for the 30% PRM scenario and less for the 17% PRM scenario. Washington obtains more energy storage in the 30% PRM scenario and less in the 17% PRM scenario.

The energy rate and PVRR are most interesting for these two scenarios. On a PVRR basis, the 17% PRM scenario lowers costs by $69 million or 0.4%, and illustrates the benefits of the WRAP, if all utilities participate, in creating a reliable regional system. As for the 30% PRM, increasing reliability targets increase cost by $182 million or 1.2% PVRR. As shown in Table 10.14, this translates into a 1.7% increase to the 2045 energy rate for Washington and a 1.5% increase for Idaho. The results indicate a minimal cost increase for higher levels of reliability, but further analysis should be undertaken to understand the benefits of greater reliability. Also, in higher load scenarios, it is still possible higher reliability cases could increase rates at a more drastic rate.

Table 10.14: Resource Adequacy Scenarios

		Washington			Idaho		
		1- Preferred Resource Strategy	12- 17% PRM	13- 30% PRM	1- Preferred Resource Strategy	12- 17% PRM	13- 30% PRM
Megawatts	Natural Gas	0	0	0	275	213	300
	Solar	311	210	311	0	105	0
	Wind	1,307	1,308	1,315	119	123	125
	Energy Storage	261	131	419	0	0	25
	Power to Gas	394	394	394	0	0	0
	Nuclear	100	108	100	0	0	0
	Geothermal	20	20	20	0	0	0
	Biomass	64	64	64	3	3	3
	Demand Response	70	73	73	17	17	17
	EE- Winter Capacity	156	156	156	49	49	49
	EE- Summer Capacity	111	111	111	38	38	38
PVRR (Millions)		$10,924	$10,880	$11,083	$4,758	$4,734	$4,781
2030 Rate ($/kWh)		$0.130	$0.130	$0.132	$0.112	$0.112	$0.112
2045 Rate ($/kWh)		$0.248	$0.244	$0.252	$0.180	$0.180	$0.183

Maximum Customer Benefits

Washington State's IRP rules require a scenario to estimate the impacts of maximizing customer benefits. Avista proposed to model this scenario with the objective to improve each of the Customer Benefit Indicators (CBIs) the IRP has an impact on (see the CEAP for further information on CBIs). To do this, Avista made several changes to the capacity expansion model including:

- Includes 164 MW of distribution solar and 38 MW energy storage over the 20-year period. DER solar is designed to offset lower income customer's costs.
- Prohibit the model from selecting air emitting resources, such as no new biomass or power to gas CTs for Washington.
- Assumes the only new out of state resource to serve Washington customers is 200 MW of Montana wind along with the associated market resources from connecting the transmission line to the east.
- Increase the 10% Power Act adder for energy efficiency to 20% to incent more energy efficiency.
- Assume Named Communities have the higher level of roof top solar and electric vehicles from the DER Potential Study scenario where Named Communities had equal DER penetration as other communities.

The changes made to this scenario result in an increase in both PVRR to Washington by $264 million or 2.4%, although by 2045 the average energy rate is 12.7% higher as shown in Table 10.15. The impacts to Idaho are negligible. The model changes resource selection to include more solar (+284 MW), energy efficiency (+337 MW), nuclear (+189 MW), energy efficiency (+6 MW), and demand response (+50 MW). Reductions to the resource strategy include removing the power to gas CTs, geothermal, and biomass. Wind selection is 166 MW less. This scenario would require an immediate need for building DER solar and energy storage every year going forward. For the most part, the remaining resource changes are later in the IRP time horizon.

Table 10.15: Maximum Washington Customer Benefits

		Washington		Idaho	
		1-Preferred Resource Strategy	10-Maximum WA Customer Benefits	1-Preferred Resource Strategy	10-Maximum WA Customer Benefits
Megawatts	Natural Gas	0	0	275	278
	Solar	311	595	0	0
	Wind	1,307	1,160	119	100
	Energy Storage	261	598	0	0
	Power to Gas	394	0	0	0
	Nuclear	100	289	0	0
	Geothermal	20	0	0	0
	Biomass	64	0	3	0
	Demand Response	70	120	17	17
	EE- Winter Capacity	156	161	49	50
	EE- Summer Capacity	111	116	38	39
PVRR (Millions)		$10,924	$11,188	$4,758	$4,767
2030 Rate ($/kWh)		$0.130	$0.130	$0.112	$0.112
2045 Rate ($/kWh)		$0.248	$0.279	$0.180	$0.180

A summary of CBI metrics changes as compared to the PRS for 2045 is shown in Table 10.16. In this case, all CBIs improve, but some (i.e., customers with energy burden) do not improve materially due to the added cost of the portfolio resource additions and the requirement of additional subsidies from other customers to support the added cost. Appendix G includes CBI results for all portfolios and for each year if further details are needed.

Table 10.16: 2045 Customer Benefits Indicator Results

Customer Benefit Indicator	Measurement	PRS	Max Customer Benefits	Change
#2a: WA Customers with Excess Energy Burden	Customers	59,696	59,143	(553)
#2b: Percent of WA Customers with Excess Energy Burden	% Customers	21.2%	21.0%	-0.2%
#2c: Average Excess Energy Burden	$	1,998.3	1,801.6	(196.7)
#5a: Total MWh of DER <5MW in Named Communities	MWh	185,973	574,875	388,902
#5b: Total MWh Capability of DER Storage <5MW in NC	MW	2.4	306.4	304.0
#6: Approximate Low Income/NC Investment and Benefits	Annual Investment ($mill)	6.5	68.8	62.2
#6: Approximate Low Income/NC Investment and Benefits	Annual Utility Benefits ($mill)	21.6	37.0	15.4
#6: Approximate Low Income/NC Investment and Benefits	Annual NEI Benefits ($mill)	38.4	35.5	(3.0)
#7: Energy Availability- Reserve Margin	Winter %	20.0%	19.9%	-0.1%
#7: Energy Availability- Reserve Margin	Summer %	25.1%	28.2%	3.1%
#8: Generation in WA and/or Connected Transmission System	% of Generation	82.0%	83.7%	1.7%
#9a: SO2	Metric Tonnes	-	-	-
#9b: NOx	Metric Tonnes	0.0	0.0	(0.0)
#9c: Mercury	Metric Tonnes	407.5	148.4	(259.1)
#9d: VOC	Metric Tonnes	26.9	9.2	(17.6)
#10a: Greenhouse Gas Emissions	Direct Emissions (metric tonnes)	-	-	-
#10a: Greenhouse Gas Emissions	Net Emissions (metric tonnes)	(0.2)	(0.2)	(0.0)
#10b: Regional Greenhouse Gas Emissions	Metric Tonnes	8.8	8.8	(0.0)

CETA Targets

In the 2021 CEIP process, the CETA targets were discussed for the trajectory between 2022 and 2030. The 2022-2025 levels were approved at higher levels than Avista's original proposal. This led to a condition of the approved CEIP to study an alternative clean energy target. This requirement is documented as the 2021 CEIP Condition #33. In this condition "*Avista agrees to model a scenario in the 2025 Electric IRP meeting the minimum level of primary compliance requirements beginning in 2030 that will create the glide path to 2045. If the results of this modeling differ from the Company's PRS and Clean Energy Action Plan, it must explain why.*" Avista is providing this scenario as #15, the minimal viable CETA target scenario, and it is also conducting the counter to this scenario by including the maximum viable CETA target scenario (#16). Table 10.17 includes the targets for primary compliance for these two scenarios compared to the PRS.

Table 10.17: CETA Target Scenarios

Period	PRS		Minimal Viable		Maximum Viable	
	Primary	Alternative	Primary	Alternative	Primary	Alternative
2026	66.0%		62.5%		70.0%	
2027	69.5%		62.5%		73.0%	
2028	73.0%		62.5%		75.0%	
2029	76.5%		62.5%		78.0%	
2030-33	80.0%	20.0%	80.0%	20.0%	81.8%	18.2%
2034-37	85.0%	15.0%	82.0%	18.0%	86.8%	13.2%
2038-41	90.0%	10.0%	88.0%	12.0%	92.2%	7.8%
2042-44	95.0%	5.0%	92.0%	8.0%	97.1%	2.9%
2045	100.0%	0.0%	100.0%	0.0%	100.0%	0.0%

For the minimal viable CETA target scenario, there is no change in the resource selection and timing of resources until 2044. In this case the only change is less than 4 MW of resource selection. The reason for no change in the resource selection is due to the 2030 and 2045 targets and the financial incentive to acquire resources early due to both pricing and meeting capacity needs. With the IRP designed to achieve 100% clean energy in 2045 and acquire clean resources on a long-term basis without risk of disallowance, the model design builds only renewable energy. With the 2045 CETA target requiring more renewable energy than load, the model is incented to build resources to comply with 2045 goals. Even if the interim targets are lower, the model still sees the 2045 objective and the physical energy and capacity needs required to be met with clean energy. If the 100% target was moved from 2045 to 2050, the resource plan would possibly change in the outer years of the plan.

Another reason for a lack of resource selection change when lowering targets is due to the availability of resources today combined with those selected for acquisition exceeding CETA targets due to economic viability or capacity needs. If this scenario was conducted with either a lower market price forecast or without the IRA incentives, it is possible wind resource additions could be delayed in a low target scenario. Further, the final use rules could impact the results of these scenarios depending on how the utility must show compliance with the clean energy standards or “use” rules.

In the maximum viable clean energy targets scenario (#16), the capacity expansion model did not change from the PRS to meet the 100% goal in 2045 with only utilizing clean energy resources to meet future resource needs. This lack of change is based on the same reasons in the minimal viable scenario (#15). Lastly, there is an impact not modeled in the IRP, but will be handled in the CEIP process. This issue is the quantification and valuation of Renewable Energy Credits (RECs) or the ability to sell specified clean power.[103] If Avista has lower targets given its long clean energy position (as compared to the targets), Avista could sell this excess generation to others, and it will lower customer rates. Higher clean energy targets result in higher energy rates due to less opportunity of sales.

PRS Constrained to the Cost Cap

The PRS analysis does not limit the cost of the portfolio to comply with CETA’s 2% cost cap, but rather demonstrates the costs and portfolio selection needed to comply with the targets. The cost cap consideration will likely be conducted through the CEIP review process after the four-year period. The IRP can be a good tool to estimate when a cost cap is potentially going to be reached. In this and the prior IRP, Avista identified the 2045 resource section in the PRS is expected to be above the cost cap. The reason to exclude

[103] The IRP does not include the Renewable Energy Certificate (REC) revenue a resource could earn if sold on the market. This is due to the IRP not being developed to build resources for non-customer needs, but rather quantify the value of resources needed for load. However, it does consider the benefits of selling resources in the energy market when it is resource long.

the cost cap in the PRS is due to the Alternative Lowest Reasonable Cost (#2) portfolio needing to be available for comparison. In this case, while the IRP analyzes this portfolio scenario, the portfolio is only valid for the 2026-2029 CEIP period. It is not relevant beyond this period, because the decisions in the CEIP will be included in the future “Alternative Lowest Reasonable Cost” portfolio. The 2% cost cap builds on decisions previously made to comply with CETA. The 2% cost cap is not applied to what rates would be absent CETA, but rather 2% higher than what rates were last year considering decisions already made to comply with CETA.

To address this cost cap scenario, an Alternative Lowest Reasonable Cost portfolio for 2045 must be made assuming the PRS resource selection for 2026 through 2043 are made. Then the model solves for the resource needs without CETA targets in 2045. With this information, a cost cap for 2045 is calculated by taking the 2044 cost and multiplying it by 2% and then by four. The cost is multiplied by four to account for a 2045 through 2048 compliance period, although statute does not address compliance windows beyond 2044.

The model results of this scenario show the PRS exceeds the cost cap and different resource decisions are made in 2045 as compared to the PRS. The results show the Company will pursue less wind, energy storage, and nuclear while increasing solar and P2G resources. The analysis also includes retaining Coyote Springs 2 beyond 2045 and using hydrogen to fuel 30% of the plant. Idaho would be impacted by retaining Coyote Springs 2 beyond 2045, and as it was assumed, Idaho would pick up this resource from Washington customers. The total resource changes and costs are shown in Table 10.18. The results lower the average energy rate for Washington customers by $0.02 per kWh for a 9.3% decrease compared to the PRS. Although for Idaho there is a 3.5% increase in average rate due to the need for new gas turbines.

Avista is not proposing to use this scenario as its PRS, but its intent is to highlight the potential issue with compliance in 2045. Furthermore, clarification of compliance mechanisms for 2045 will be needed to address how the cost cap will be treated after 2044. Avista may include the methodology for estimating the post 2044 cost cap in the 2027 IRP and only plan for what can be implemented in the cost increase range of the statute and conduct the “capless” study as a scenario. Further, the 2027 IRP will model years 2046 and 2047, and will show more future years with the 100% clean energy goal to illustrate how the Company could comply with the goal given the cost constraint. Avista has several hydroelectric contracts expiring at the end of 2045, thus creating a significant resource need in 2046 if these contracts are not renewed.

Table 10.18: CETA 2045 Cost Cap Scenario

		Washington		Idaho	
		1- Preferred Resource Strategy	17- PRS Constrained to 2% Cost Cap	1- Preferred Resource Strategy	17- PRS Constrained to 2% Cost Cap
Megawatts	Natural Gas	0	0	275	362
	Solar	311	395	0	0
	Wind	1,307	999	119	119
	Energy Storage	261	232	0	0
	Power to Gas	394	439	0	0
	Nuclear	100	0	0	0
	Geothermal	20	20	0	0
	Biomass	64	7	3	3
	Demand Response	70	73	17	17
	EE- Winter Capacity	156	156	49	49
	EE- Summer Capacity	111	111	38	38
PVRR (Millions)		$10,924	$10,867	$4,758	$4,767
2030 Rate ($/kWh)		$0.130	$0.130	$0.112	$0.112
2045 Rate ($/kWh)		$0.248	$0.225	$0.180	$0.187

CCA Repealed

At the time of this drafting of this IRP, the Climate Commitment Act (CCA) is law in the State of Washington. On November 5, 2024, voters rejected the initiative to repeal the law. Since at the time of the draft IRP filing, Avista didn't not know the outcome of Initiative 2117, Avista conducted a simplified study to better understand the impact to the resource plan if voters repealed CCA. The CCA has macro-economic impacts on energy prices in the Northwest. The repealing of this law assumes a major change for this study and conducts a new wholesale electric price forecast without the CCA (see Chapter 9). The scenario results in lower wholesale electric prices. With lower market prices, the economics of certain resources change, but the driver to acquire "clean" resources for Washington State does not change due to the 100% clean energy goals in CETA. Therefore, the impact on the plan is timing of renewable resource acquisition for Washington and if the wind resources selected for Idaho in the PRS remain. If the CCA was repealed, the timing of wind would be delayed, and fewer projects are likely to be cost effective for Idaho customers.

Avista is not able to compare the cost of this portfolio to the PRS due to the unknown nature of how the CCA's free allowances will be distributed to electric customers. However, it is known that wholesale electric prices will fall, and this will lower the potential revenue from selling excess clean energy resources to the market.

Table 10.19 outlines the change in resource selection without the CCA. For Idaho customers, the amount of wind falls by 52 MW. For Washington, ending the CCA changes resource selection, but it generally selects the same type of resources where solar, energy storage, and nuclear are increased, but wind, and biomass generation decrease. The first wind acquisition in the PRS is delayed from 2029 to 2030. The minimal impact is due to CETA targeting the acquisition more than the overall market price of power.

Table 10.19: CCA Repealed Scenario

		Washington		Idaho	
		1- Preferred Resource Strategy	26- No CCA	1- Preferred Resource Strategy	26- No CCA
Megawatts	Natural Gas	0	0	275	273
	Solar	311	319	0	0
	Wind	1,307	1,294	119	66
	Energy Storage	261	288	0	0
	Power to Gas	394	394	0	0
	Nuclear	100	134	0	0
	Geothermal	20	20	0	0
	Biomass	64	7	3	3
	Demand Response	70	73	17	17
	EE- Winter Capacity	156	156	49	49
	EE- Summer Capacity	111	111	38	38

Reliability Analysis Summary

Avista conducted reliability studies on specific scenarios to understand the impact to reliability based on resource choices. Avista uses the same PRM and qualifying capacity credits (QCC) for all scenarios. Avista's current reliability metric is to achieve at least a 5% LOLP to be reliable. A second metric is to be below 0.10 Loss of Load Expectation (LOLE). The capacity expansion modeling requires a minimum of 24% planning margin calculated by the total QCC of resources as compared to peak load. The result of the capacity expansion modeling shows by 2045 the there is more QCC than needed in 2045.

Avista also provides other reliability metrics for informational purposes. The results of this analysis (shown in Table 10.20) demonstrate the scenario portfolios generally result in resource adequate systems and are below the 5% LOLP threshold. This is a result of the PRM of the portfolios generally being higher than the minimum threshold. Although the #12 scenario - 17% PRM, results in a 21.5% PRM in 2045 and a 4.7% LOLP. This indicates Avista could be using a PRM of 21% to 22%, but a secondary indicator of LOLE is higher than 0.1 and indicating a non-reliable portfolio with this metric. Overall, Avista's 24% PRM and associated QCC values seem reasonable considering both LOLP and LOLE metrics. Although depending on the resource selection a lower PRM could be justified, such as a future with high nuclear energy additions.

Table 10.20: Reliability Results

Scenario	Year	Actual Selected January PRM	Loss of Load Probability (LOLP)	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)	Loss of Load Expected Events (LOLEV)	Expected Unserved Energy (EUE) with reserves	Expected Unserved Energy (EUE) without reserves
#1- Preferred Resource Strategy	2030	29.6%	3.20%	0.072	0.7	0.176	114	107
	2045	28.6%	3.30%	0.093	1.1	0.304	172	116
#2- Alternative Lowest Reasonable Cost	2030	29.5%	2.70%	0.071	0.7	0.222	117	60
	2045	25.8%	1.40%	0.037	0.4	0.126	57	2
#3- Baseline	2045	25.9%	2.90%	0.046	0.3	0.071	47	38
#4- Clean Resource Portfolio 2045	2030	27.8%	6.00%	0.194	2.1	0.435	359	339
	2045	25.8%	1.70%	0.025	0.1	0.051	18	16
#9- System Building and Transportation Electrification	2045	26.4%	1.10%	0.035	0.3	0.122	56	1
#11- 500 MW Nuclear	2045	28.7%	0.60%	0.007	0.0	0.009	2	0
#12- 17% Planning Reserve Margin	2030	26.1%	4.50%	0.127	1.4	0.293	232	221
	2045	21.5%	4.70%	0.103	0.9	0.260	149	145
#13- 30% Planning Reserve Margin	2030	34.8%	1.60%	0.034	0.5	0.115	81	80
	2045	34.4%	0.80%	0.017	0.1	0.035	18	17
#14- Power to Gas Unavailable	2045	25.9%	4.00%	0.137	1.6	0.375	324	323
#18- Data Center	2030	26.3%	5.20%	0.132	1.4	0.323	261	256
#19- RCP 8.5 Load	2045	29.6%	4.60%	0.106	0.6	0.169	76	49

Cost & Rate Impact Summary

The preceding portfolio summary gave contextual changes to each portfolio. This section provides tables and charts to summarize the results of the studies. Table 10.21 outlines PVRRs for each of the 25 portfolios for each state, and the 2030 and 2045 average energy rates per kWh. The yellow bar indicators show the cost or rate of the category is within 3% of the PRS value, the green arrow pointing up indicates the category exceeds a 3% increase compared to the PRS, and the red arrow pointing down indicates a 3% or greater reduction.

The costs of each portfolio are summarized by jurisdiction and sorted by total system cost impact in Figure 10.2. The higher cost scenarios include higher loads or higher clean energy objectives, while lower cost scenarios have less loads or renewables. The ranking order does not reflect the additional load served by these scenarios, therefore Figures 10.3 and 10.4 show the ranking of the energy rates for 2030 and 2045, sorted by 2045 rates. The 2030 rates do not materially differ since most resource decisions occur after 2030.

Table 10.21: Jurisdiction Cost and Rate Summary

Scenario	WA- PVRR ($ Mill)	ID-PVRR ($ Mill)	TOTAL PVRR ($ Mill)	WA 2030 Rate ($/kWh)	WA 2045 Rate ($/kWh)	ID 2030 Rate ($/kWh)	ID 2045 Rate ($/kWh)
1- Preferred Resource Strategy	10,924	4,758	15,682	0.130	0.248	0.112	0.180
2- Alternative Lowest Reasonable Cost Portfolio	10,796	4,766	15,562	0.130	0.208	0.112	0.189
3- Baseline Portfolio	10,851	4,655	15,506	0.131	0.205	0.111	0.185
4- Clean Resource Portfolio	11,135	4,873	16,007	0.131	0.289	0.112	0.280
5- Low Economic Growth Loads	10,641	4,711	15,352	0.131	0.242	0.112	0.189
6- High Economic Growth Loads	11,494	4,964	16,458	0.128	0.262	0.109	0.167
7- WA Building Electrification	11,825	4,793	16,617	0.131	0.278	0.112	0.184
8- WA Building Electrification & High Trans. Electrification	12,374	4,791	17,165	0.130	0.276	0.112	0.185
9- Building Electrification & High Trans. Electrification w/o NG	13,295	6,195	19,490	0.131	0.310	0.111	0.245
10- Maximum WA Customer Benefits	11,188	4,767	15,956	0.130	0.279	0.112	0.180
11- Least Cost + 500 MW Nuclear in 2040	11,697	5,124	16,822	0.131	0.270	0.111	0.234
12- 17% PRM	10,880	4,734	15,614	0.130	0.244	0.112	0.180
13- 30% PRM	11,083	4,781	15,864	0.132	0.252	0.112	0.183
14- Power to Gas Unavailable	11,020	4,772	15,792	0.130	0.275	0.112	0.188
15- Minimal Viable CETA Target	10,923	4,758	15,681	0.130	0.248	0.112	0.180
16- Maximum Viable CETA Target	10,923	4,758	15,681	0.130	0.248	0.112	0.180
17- PRS Constrained to 2% Cost Cap	10,867	4,767	15,634	0.130	0.225	0.112	0.187
18- Data Center in 2030	11,794	4,871	16,666	0.131	0.237	0.112	0.187
19- RCP 8.5 Weather	10,907	4,752	15,659	0.132	0.248	0.113	0.182
20- Building Electrification & High Trans. Electrification w/o NG w/ RC	13,342	5,941	19,283	0.132	0.317	0.112	0.228
21- Regional Transmission not available	10,902	4,717	15,620	0.130	0.250	0.112	0.181
22- Northeast Retires Early	10,993	4,775	15,768	0.131	0.250	0.113	0.181
23- On-system wind limited to 200 MW	11,030	4,781	15,811	0.131	0.256	0.112	0.181
24- No IRA Tax Incentives	11,266	4,754	16,019	0.131	0.255	0.112	0.181
25- Northeast Retires Late	10,922	4,758	15,680	0.130	0.248	0.112	0.182

Figure 10.2: PVRR Summary

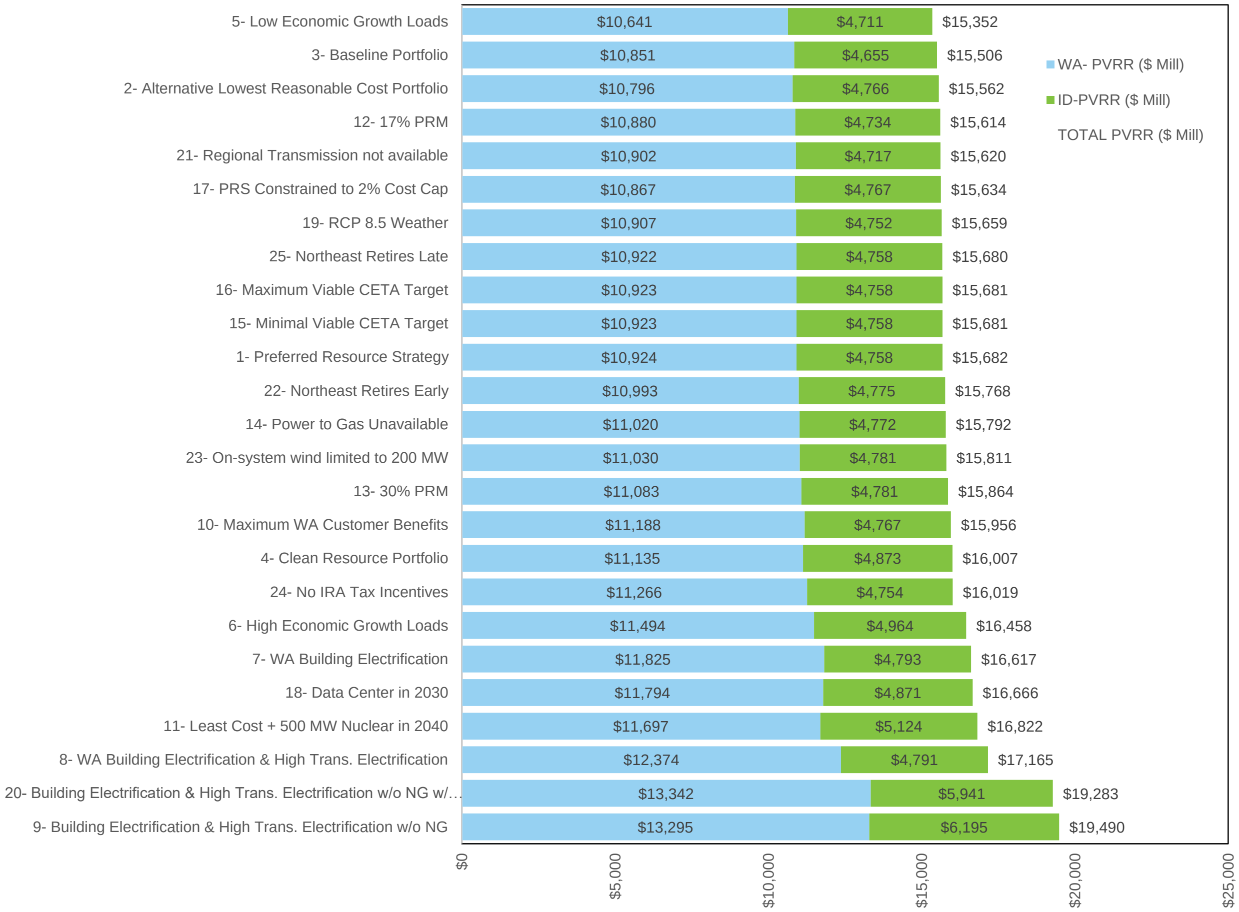


Figure 10.3: Washington Energy Rate Comparison

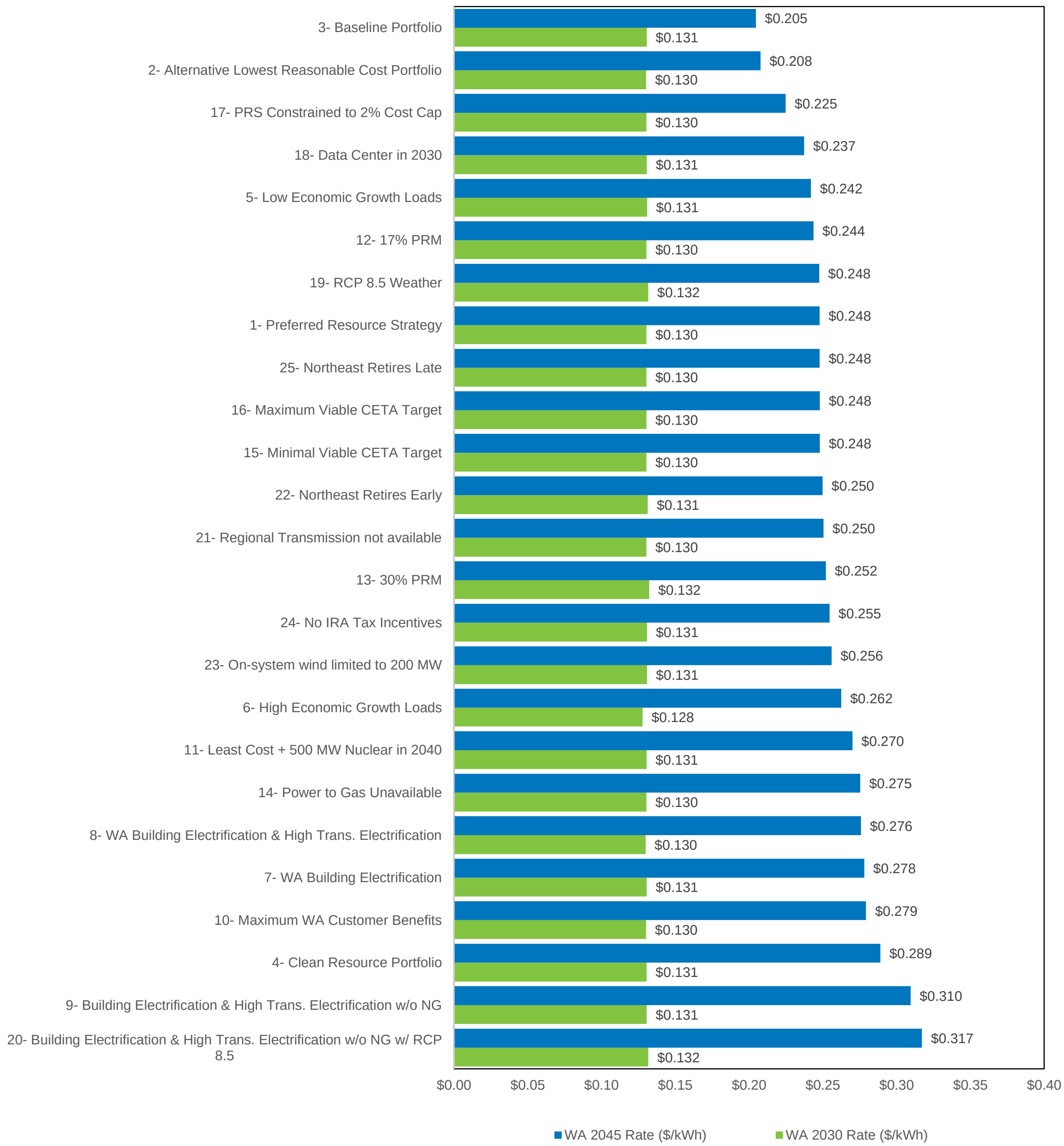
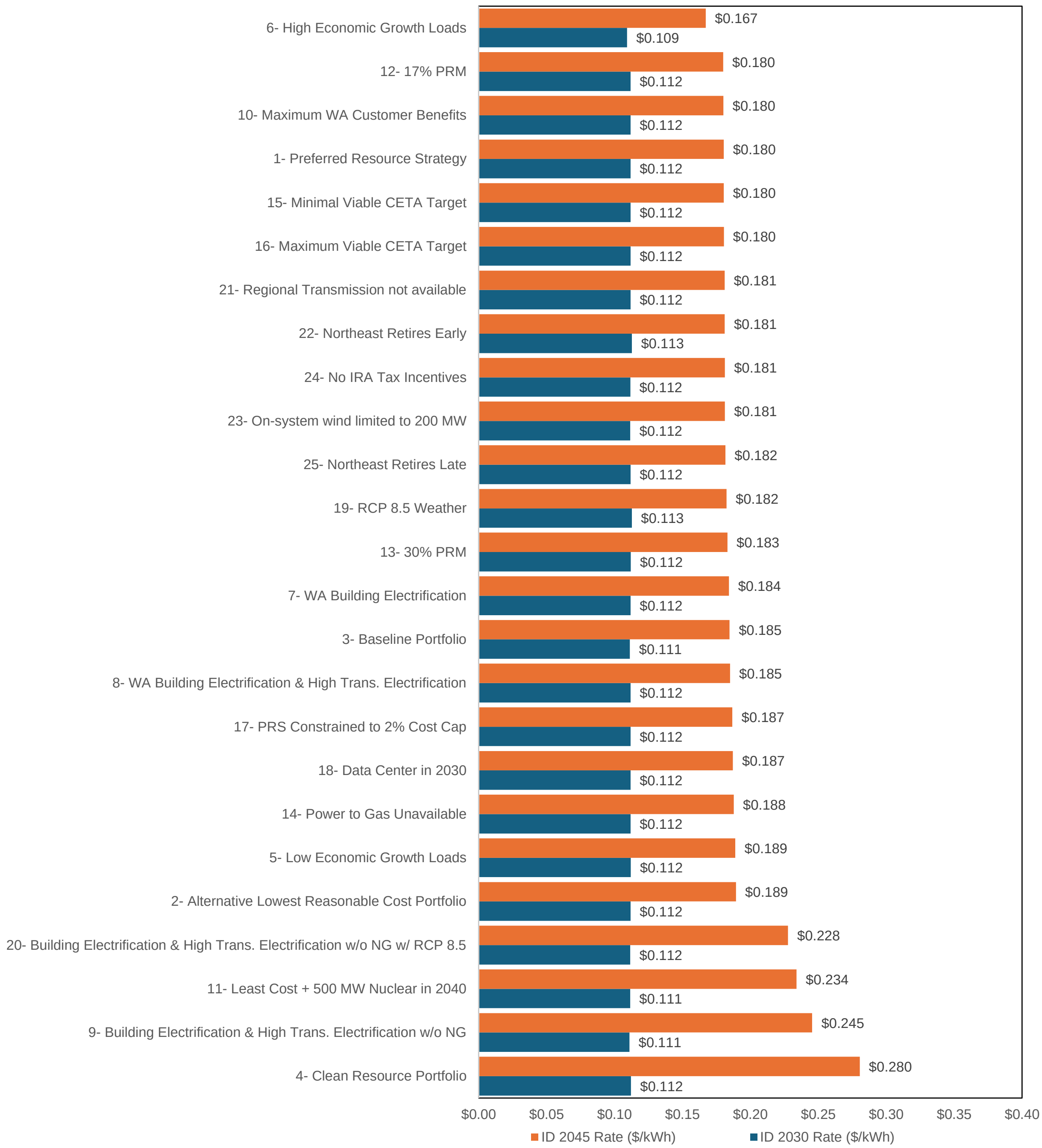


Figure 10.4: Idaho Energy Rate Comparison



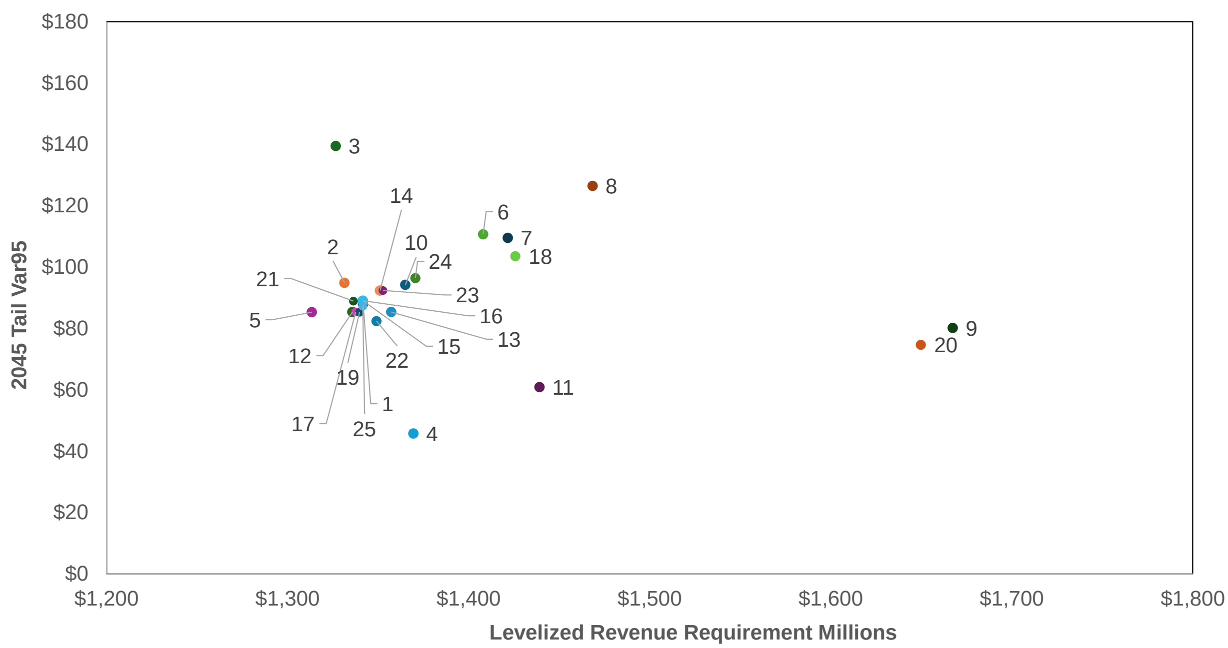
Market Risk Analysis

In addition to costs or energy rates, the IRP provides insights into the energy market risks of the portfolios by showing how much of the portfolio selection is impacted by changes in the wholesale electric market. Figure 10.5 compares the 2045 market risk to the PVRR of the portfolio cost (excluding additional distribution costs for electrification scenarios). The 2045 market risk used in this analysis is TailVar95 and is calculated by the 95th

percentile of portfolio costs subtracting the average portfolio cost for 300 simulations. The market risks included are from varying loads, natural gas prices, emission pricing, hydro conditions, and wind conditions. The portfolios with greater risk typically have a higher dependance on either natural gas resources, market power purchases, or added load.

The only portfolios reducing market risk for Idaho are those investing in additional renewable energy resources. As shown below, the lower risk comes at an added cost to the system. For example, in the #4 Clean Portfolio by 2045 scenario, the extreme market risk is $43 million or 48% lower, but the incremental cost to Idaho customers in 2045 is $356 million, reflecting a $0.10 per kWh premium or 55% higher.

Figure 10.5: System Cost versus Risk Comparison



Another metric used to evaluate portfolio risk combines the PVRR and Tail-Var95 values. This is done by summing the levelized PVRR and levelized Tail-Var95. The results shown in Figure 10.6 are sorted from the highest total cost to the lowest cost. Due to most of the resource acquisitions occurring toward the end of the plan and the differing amounts of load included in each of the portfolios, this metric is not as informative for scenarios with differing loads. Figure 10.7 was created for 2045 to address these concerns. In this case, the total cost of the year is divided by the energy sales to estimate an average energy rate, then the TailVar95 risk value is added. The values shown in this figure are in cents per kWh. This methodology demonstrates each of the scenarios on a more equal footing. In this view, the risk additions compared to the total costs are low due to the overall size of the rate base of the total utility cost. In addition, most of the resources serving load have volumetric risk rather than natural gas price risk, except for the Idaho portion of load.

Figure 10.6: Portfolio PVRR with Risk Analysis

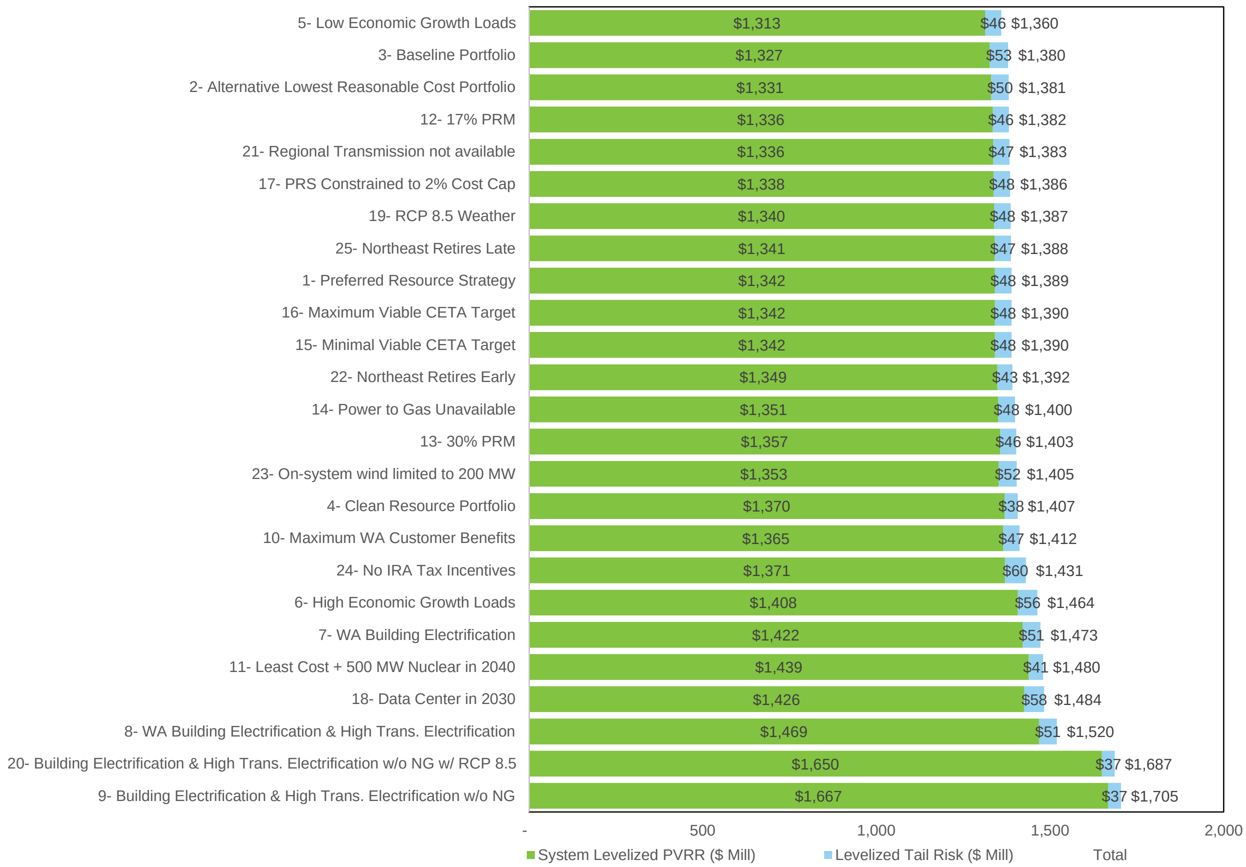
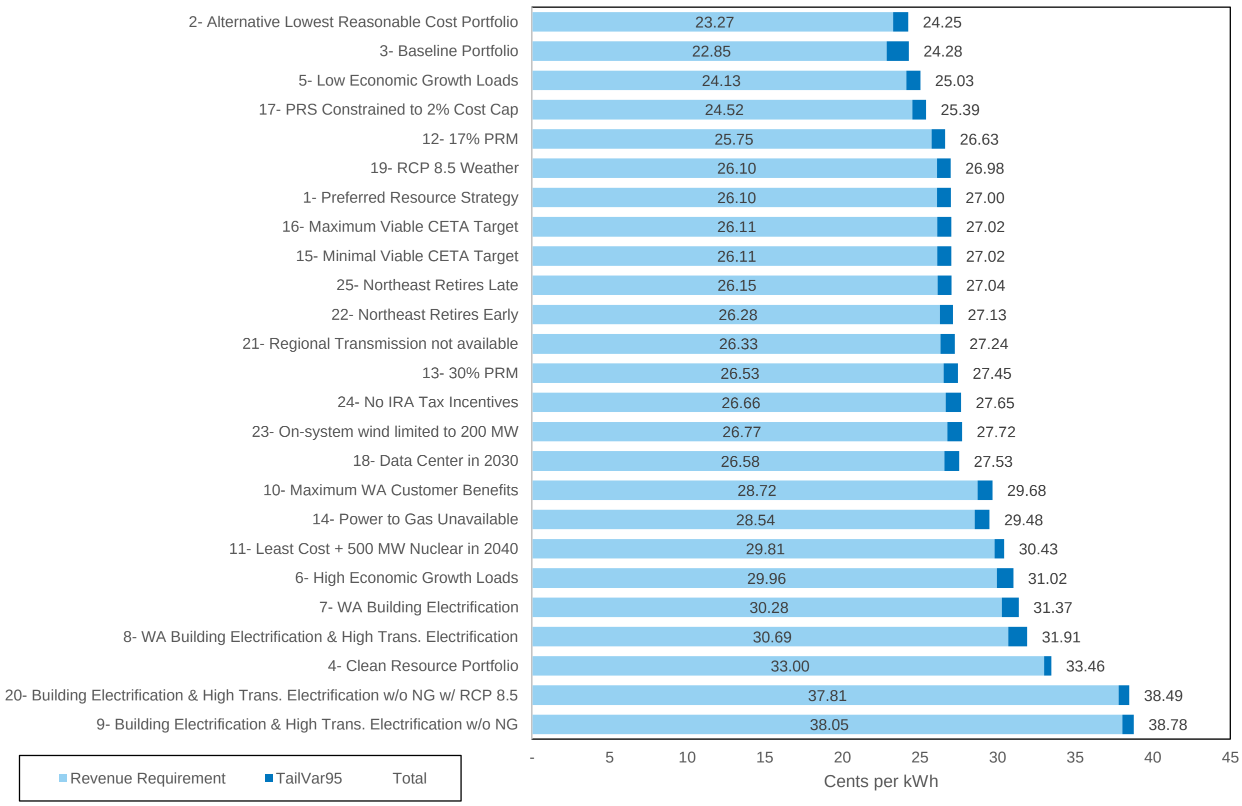


Figure 10.7: 2045 System Energy Cost with Risk

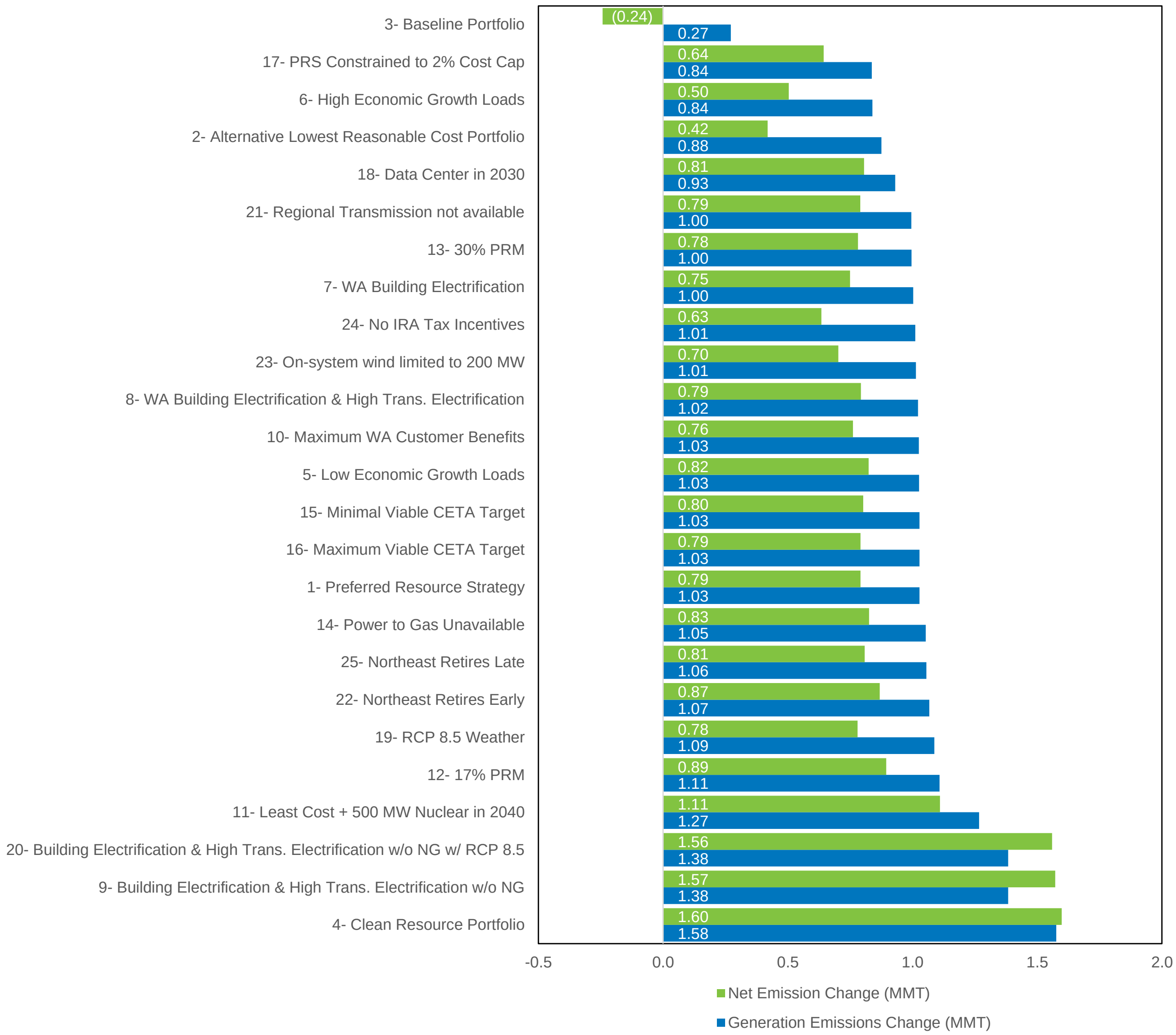


Greenhouse Gas Emission Comparison

All resource strategies going forward will have GHG emission reductions compared to current emissions. The reductions are largely due to Colstrip Units 3 & 4 leaving the system at the end of 2025. Further reductions will be from reduced dispatch of existing natural gas facilities due to Washington's CCA and Lancaster's PPA ending in 2041. While each portfolio has GHG reductions, the reduced amounts are not all equal. Each portfolio's 20-year reduction levels are shown in Figure 10.8. The data used for this chart display gross emissions from Avista's existing and controlled generating resources in blue and the green bars represent the net emissions when there are sales or purchases in the wholesale energy market. Market transactions include an emissions rate factor of 0.437 metric tons per MWh as defined by the CCA, while market sales use the estimated emission intensity of the Avista facilities.

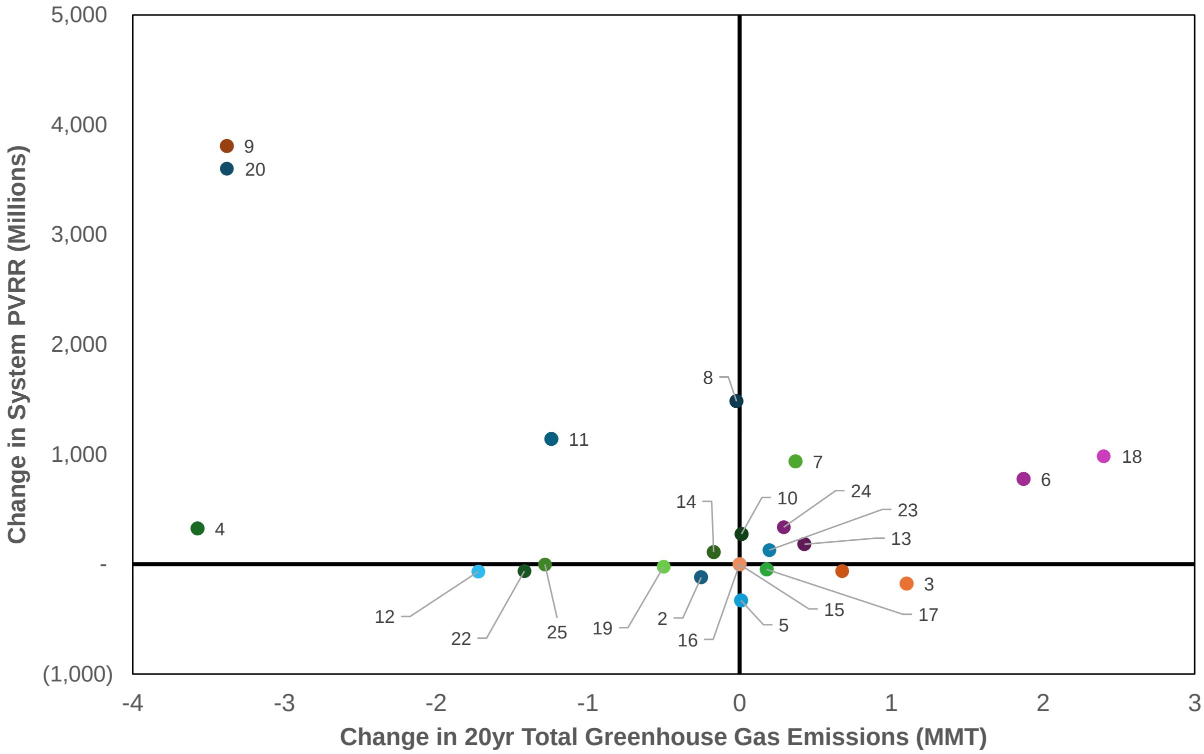
The #4 Clean Portfolio by 2045 has the greatest GHG reduction levels using both metrics and the #3 Baseline Portfolio has the least reduction on a gross level. It is worth noting the 0.437 metric ton per MWh intensity rate is an incremental rate and likely does not represent the average emission intensity rate of market purchases especially as the system decarbonizes.

Figure 10.8: Emission Reduction (Millions of Metric Tons (2045 compared to 2026)



The second metric for evaluating GHG emissions regards the cost and emission reductions compared to the PRS. Figure 10.9 shows the added PVRR cost compared to the PRS and to the total GHG emission changes over the 20-year study horizon. The emission quantification used is derived from gross emissions generated from Avista controlled facilities. For example, the #18 scenario, the 200 MW Data Center, increases cost by $983 million PVRR over the PRS and the GHG emissions are 2.4 million metric tonnes higher than the PRS. Portfolios in the bottom left quadrant have lower costs and lower GHG emissions compared to the PRS.

Figure 10.9: Change in Emissions Compared to Portfolio PVRR



Market Price Sensitivities

This IRP considers three alternative market price sensitivities to understand the impact on the portfolio choices. These market sensitives are discussed in Chapter 9 and in Table 10.22 below and include the specific assumption changes and the resulting market price effects. This section shows how portfolios with different resource selections perform in these future market scenarios. Avista only studied the market impacts for the low and high natural gas price scenarios against four portfolios. Avista did not study the impacts of the portfolio without the CCA due to the difficulty in accounting for emission allowances in the CCA program.

The first analysis represented in Table 10.22 shows the impact to natural gas pricing in the four resource portfolio scenarios including the PRS, Baseline, Clean Resource, and the nuclear scenarios. These portfolios were selected because they would show the most impact to natural gas pricing based upon their portfolio's resource selection. The results show portfolios with higher natural gas resources have higher overall costs due to natural gas pricing as well as the opposite when prices fall. The total sensitivity of gas prices to total portfolio costs over 20 years is small due to the small amount of electric utility cost influenced by natural gas pricing. Furthermore, depending on the year, higher natural gas prices could benefit the utility if the utility has excess energy to sell on the market. The results of this study are over the 20-year period.

Table 10.22: Jurisdiction PVRR Sensitivity Analysis

Portfolio	Change in PVRR vs Expected Case Market Pricing					
	Washington		Idaho		System	
	High NG Prices	Low NG Prices	High NG Prices	Low NG Prices	High NG Prices	Low NG Prices
1- Preferred Resource Strategy	0.8%	-0.1%	3.1%	-1.7%	1.5%	-0.6%
3- Baseline Portfolio	2.1%	-0.9%	1.3%	-0.6%	1.8%	-0.8%
4- Clean Resource Portfolio	1.0%	-0.2%	0.3%	-0.1%	0.9%	-0.2%
11- Least Cost + 500 MW Nuclear in 2040	0.7%	-0.1%	0.9%	-0.4%	1.1%	-0.4%

The second analysis shown in Table 10.23 shows the changes in GHG emissions. The top half of the table shows how the portfolio's total emissions change over the 20 years depending on natural gas pricing. High gas prices reduce the demand for natural gas generation and thus lower emissions, whereas low natural gas prices increase natural gas generation dispatch increasing emissions. The bottom half of this table shows how the change in emissions compare to the PRS, where the #4 Clean Resource Portfolio has the biggest GHG emission change compared to the PRS due to it removing and excluding natural gas resources.

Table 10.23: PVRR and Emission Changes

Portfolio	Total GHG Emissions vs Expected Prices	
	High NG Prices	Low NG Prices
1- Preferred Resource Strategy	-13.0%	7.7%
3- Baseline Portfolio	-14.0%	8.8%
4- Clean Resource Portfolio	-9.4%	5.7%
11- Least Cost + 500 MW Nuclear in 2040	-11.8%	6.8%

Portfolio vs PRS	Total GHG Emissions vs PRS	
	High NG Prices	Low NG Prices
3- Baseline Portfolio	-2.3%	-0.1%
4- Clean Resource Portfolio	-9.4%	-14.6%
11- Least Cost + 500 MW Nuclear in 2040	-1.8%	-4.0%

Table 10.24: Portfolio #1: Preferred Resource Strategy

Portfolio #1 Preferred Resource Strategy

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	198.4
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100.0	100.0
Wind	-	-	-	200.0	200.0	165.9	66.0	104.0	-	-	-	-	-	-	-	140.0	-	120.0	108.4	200.0	1,304.3
Solar	-	0.5	0.6	0.6	0.7	0.8	0.8	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	180.5	120.5	0.6	311.1
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.0	60.0	-	150.0
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26.1	85.3	111.4
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	20.0
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	94.3
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.2	-	209.8	-	-	-	300.0
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	64.4	64.4
Load Control	10.4	-	-	-	-	-	-	-	-	-	-	-	1.9	20.0	-	5.6	-	9.8	-	-	47.8
Retail Pricing	14.2	-	-	-	-	-	-	-	-	6.0	-	-	2.5	-	-	-	-	-	-	-	22.7
Total	**24.6**	**0.5**	**0.6**	**200.6**	**200.7**	**166.7**	**66.8**	**303.4**	**0.5**	**6.5**	**0.5**	**0.5**	**5.0**	**20.5**	**90.7**	**146.1**	**210.3**	**400.4**	**314.9**	**564.6**	**2,526.0**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	101.6
Natural Gas	-	-	-	-	90.2	-	-	-	-	-	-	-	-	-	90.2	-	94.9	-	-	-	275.4
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	34.1	34.0	53.3	-	-	-	-	-	-	-	-	-	-	-	-	121.4
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	3.2
Load Control	-	-	-	-	-	-	-	-	-	2.8	-	-	-	-	-	-	-	1.3	6.6	-	10.7
Retail Pricing	-	-	-	2.6	-	-	-	-	-	-	-	-	-	-	4.2	-	-	-	-	-	6.8
Total	**-**	**-**	**-**	**2.6**	**90.2**	**34.1**	**34.0**	**155.0**	**-**	**2.8**	**-**	**-**	**-**	**-**	**94.4**	**-**	**94.9**	**1.3**	**6.6**	**3.2**	**417.4**
Grand Total	**24.6**	**0.5**	**0.6**	**203.2**	**290.9**	**200.8**	**100.8**	**458.4**	**0.5**	**9.3**	**0.5**	**0.5**	**5.0**	**20.5**	**185.2**	**146.1**	**305.1**	**401.6**	**321.5**	**567.8**	**2,943.4**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.25: Portfolio #2: Alternative Lowest Reasonable Cost

Portfolio #2 Alternative Lowest Reasonable Cost

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	198.4
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.6	32.0	-	67.7
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	200.0	200.0	165.9	66.0	-	-	-	-	-	-	-	-	140.0	-	120.0	-	-	891.9
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100.0	-	-	-	100.0
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50.0	-	-	-	50.0
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17.1	50.4	67.5
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	-	-	-	-	20.0
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	94.3
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	61.5	-	209.2	-	-	-	270.6
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8	-	6.8
Load Control	10.4	-	-	-	-	-	-	-	-	-	25.6	-	1.9	-	-	-	12.4	-	-	-	50.3
Retail Pricing	14.2	-	-	-	-	-	-	-	8.5	-	-	-	-	-	-	-	-	-	-	-	22.7
Total	**24.6**	**-**	**-**	**200.0**	**200.0**	**165.9**	**66.0**	**198.4**	**8.5**	**-**	**25.6**	**-**	**1.9**	**-**	**61.5**	**160.0**	**371.5**	**155.6**	**56.0**	**144.7**	**1,641.9**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	101.6
Natural Gas	-	-	-	-	90.2	-	-	-	-	-	-	-	-	-	-	-	107.6	16.6	14.8	67.3	296.5
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	34.1	34.0	-	-	-	-	-	-	-	-	-	-	-	-	-	68.1
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.9	-	7.9
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.4	-	-	-	-	-	29.4
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	-	3.2
Load Control	-	-	-	2.8	-	-	-	-	-	-	-	-	-	6.6	1.3	-	-	-	-	-	10.7
Retail Pricing	-	-	-	0.9	-	1.8	-	-	-	-	4.2	-	1.7	-	-	-	-	-	-	-	8.5
Total	**-**	**-**	**-**	**3.7**	**90.2**	**35.8**	**34.0**	**101.6**	**-**	**-**	**4.2**	**-**	**1.7**	**6.6**	**30.6**	**-**	**107.6**	**16.6**	**25.8**	**67.3**	**424.1**
Grand Total	**24.6**	**-**	**-**	**203.7**	**290.2**	**201.8**	**100.0**	**300.0**	**8.5**	**-**	**29.8**	**-**	**3.6**	**6.6**	**92.1**	**160.0**	**479.1**	**172.2**	**81.8**	**212.0**	**2,066.0**

Cumultive Energy Efficiency (aMW)																					
Washington	3.3	6.9	10.9	15.4	19.2	23.4	28.3	33.5	38.6	43.1	47.6	51.9	55.9	59.3	62.5	65.5	67.9	70.5	72.9	75.0	851.8
Idaho	1.2	2.6	4.1	5.9	7.1	8.6	10.4	12.3	14.3	15.9	17.7	19.4	21.0	22.4	23.8	25.1	26.1	27.2	28.3	29.4	322.7
Total	**4.6**	**9.5**	**15.0**	**21.3**	**26.3**	**31.9**	**38.7**	**45.8**	**52.9**	**59.1**	**65.4**	**71.4**	**76.9**	**81.7**	**86.3**	**90.6**	**94.0**	**97.7**	**101.2**	**104.3**	**1,174.5**

Table 10.26: Portfolio #3: Baseline

Portfolio #3 Baseline

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	**198.4**
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	69.1	-	65.7	-	264.9	-	61.8	83.0	**544.5**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Wind	-	-	-	65.8	-	200.0	100.0	-	-	-	-	-	-	-	-	-	-	-	-	-	**365.8**
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	1.3	-	-	-	-	-	-	-	-	-	-	-	-	-	**1.3**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	61.8	**61.8**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Load Control	10.4	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	-	-	-	-	-	**30.5**
Retail Pricing	14.2	-	-	-	-	-	-	-	-	-	-	-	8.5	-	-	-	-	-	-	-	**22.7**
Total	**24.6**	**-**	**-**	**65.8**	**-**	**200.0**	**101.3**	**198.4**	**-**	**-**	**-**	**-**	**77.6**	**-**	**85.7**	**-**	**264.9**	**-**	**61.8**	**144.8**	**1,026.6**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	**101.6**
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	33.8	-	31.4	-	124.3	-	28.5	38.2	**256.2**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Wind	-	-	-	134.2	200.0	-	-	-	-	-	-	-	-	-	-	-	-	120.0	-	-	**454.2**
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	2.0	3.0	-	-	-	-	-	-	-	-	26.3	-	-	-	-	**31.3**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28.4	**28.4**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Load Control	-	-	-	2.8	-	6.6	-	-	-	-	1.3	-	-	-	-	-	-	-	-	7.1	**17.7**
Retail Pricing	-	-	-	2.6	-	-	4.2	1.7	-	-	-	-	-	-	-	-	-	-	-	-	**8.5**
Total	**-**	**-**	**-**	**139.6**	**200.0**	**8.6**	**7.2**	**103.3**	**-**	**-**	**1.3**	**-**	**33.8**	**-**	**31.4**	**26.3**	**124.3**	**120.0**	**28.5**	**73.7**	**796.3**
Grand Total	**24.6**	**-**	**-**	**205.4**	**200.0**	**208.6**	**108.5**	**301.7**	**-**	**-**	**1.3**	**-**	**111.4**	**-**	**117.1**	**26.3**	**389.2**	**120.0**	**90.2**	**218.4**	**1,822.9**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.27: Portfolio #4: Clean Resource Portfolio

Portfolio #4 Clean Resource Portfolio

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	317.7	317.7
Wind	-	-	-	165.8	-	200.0	166.0	129.6	-	-	-	-	-	-	-	140.0	68.1	120.0	68.5	-	1,058.0
Solar	-	0.5	0.6	0.6	3.0	3.0	3.0	3.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	4.9	208.0	1.1	100.7	1.0	332.8
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100.0	-	50.0	-	150.0
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	81.8	-	81.8
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	-	-	-	20.0
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	60.6	-	61.1	-	119.5	-	-	-	241.2
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8	39.3	-	-	46.1
Load Control	10.4	-	-	-	-	-	-	-	-	-	-	-	-	5.6	20.0	11.7	2.5	-	47.1	-	97.5
Retail Pricing	14.2	-	-	-	-	-	-	-	-	-	-	-	8.5	-	-	-	-	-	-	-	22.7
Total	**24.6**	**0.5**	**0.6**	**166.5**	**3.0**	**203.0**	**169.0**	**331.0**	**0.5**	**0.5**	**0.5**	**0.5**	**69.6**	**6.1**	**81.6**	**156.6**	**524.9**	**160.4**	**348.1**	**318.7**	**2,367.8**

Idaho	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	101.6
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	166.3	166.3
Wind	-	-	-	34.2	200.0	-	34.0	66.4	-	-	-	-	-	-	-	-	131.9	-	31.5	-	498.0
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.0	5.0	10.0	10.0	10.0	40.0
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	2.2	6.0	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	5.0	16.3
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	82.6	-	24.1	-	106.7
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	29.7	-	29.2	-	-	-	-	-	58.8
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	18.3	-	-	21.5
Load Control	1.3	-	-	9.4	-	-	-	-	-	-	-	-	-	-	-	5.6	-	1.4	-	-	17.7
Retail Pricing	-	-	-	2.6	-	-	-	-	-	-	-	-	4.2	1.7	-	-	-	-	-	-	8.5
Total	**1.3**	**-**	**-**	**48.4**	**206.0**	**3.0**	**34.0**	**168.1**	**-**	**-**	**-**	**-**	**33.8**	**1.7**	**29.2**	**10.6**	**222.7**	**29.7**	**65.7**	**181.3**	**933.8**
Grand Total	**25.9**	**0.5**	**0.6**	**214.9**	**209.0**	**206.0**	**203.0**	**499.0**	**0.5**	**0.5**	**0.5**	**0.5**	**103.4**	**7.8**	**110.8**	**167.2**	**747.6**	**190.1**	**413.8**	**500.0**	**3,301.5**

Cumultive Energy Efficiency (aMW)																					
Washington	3.6	7.5	11.9	16.8	21.1	25.8	31.4	37.3	43.1	48.4	53.6	58.6	63.2	67.1	71.0	74.6	77.5	80.6	83.4	85.9	962.4
Idaho	1.7	3.6	5.7	8.2	10.1	12.4	15.2	18.2	21.1	23.7	26.3	28.8	31.1	33.2	35.1	37.0	38.5	40.1	41.6	43.1	474.8
Total	**5.3**	**11.1**	**17.6**	**25.0**	**31.2**	**38.3**	**46.6**	**55.4**	**64.2**	**72.0**	**79.9**	**87.4**	**94.3**	**100.3**	**106.1**	**111.6**	**116.1**	**120.8**	**125.1**	**129.0**	**1,437.2**

Table 10.28: Portfolio #5: Low Load Forecast

Portfolio #5 Low Load

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	**198.4**
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Wind	-	-	-	200.0	200.0	165.9	66.0	-	-	-	-	-	-	-	-	140.0	-	120.0	174.3	200.0	**1,266.2**
Solar	-	0.5	0.6	0.6	0.7	0.8	0.8	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	-	0.5	0.6	139.0	0.7	**149.2**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.3	-	-	69.2	-	**74.5**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.1	**29.1**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	**20.0**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	**94.3**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	151.9	-	-	148.1	**300.0**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	64.4	**64.4**
Load Control	10.4	-	-	-	-	-	-	-	-	-	5.6	-	-	-	-	20.0	1.9	-	-	-	**38.0**
Retail Pricing	14.2	-	-	-	-	-	-	-	-	-	-	-	-	8.5	-	-	-	-	-	-	**22.7**
Total	**24.6**	**0.5**	**0.6**	**200.6**	**200.7**	**166.7**	**66.8**	**199.4**	**0.5**	**0.5**	**6.1**	**0.5**	**0.5**	**9.0**	**0.5**	**165.4**	**154.4**	**120.6**	**382.4**	**556.7**	**2,058.5**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	**101.6**
Natural Gas	-	-	-	-	90.2	-	-	-	-	-	-	-	-	-	90.2	-	96.6	-	-	-	**277.1**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Wind	-	-	-	-	-	34.1	34.0	-	-	-	-	-	-	-	-	-	-	-	-	-	**68.1**
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	**3.2**
Load Control	-	-	-	-	-	-	2.8	-	-	-	-	-	-	-	-	-	-	1.3	6.6	-	**10.7**
Retail Pricing	-	-	-	2.6	-	-	-	-	-	-	-	-	-	-	4.2	-	-	-	-	-	**6.8**
Total	**-**	**-**	**-**	**2.6**	**90.2**	**34.1**	**36.8**	**101.6**	**-**	**-**	**-**	**-**	**-**	**-**	**94.4**	**-**	**96.6**	**1.3**	**6.6**	**3.2**	**365.8**
Grand Total	**24.6**	**0.5**	**0.6**	**203.2**	**290.9**	**200.8**	**103.6**	**301.0**	**0.5**	**0.5**	**6.1**	**0.5**	**0.5**	**9.0**	**94.9**	**165.4**	**251.0**	**121.8**	**389.0**	**559.8**	**2,424.3**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.29: Portfolio #6: High Load Forecast

Portfolio #6 High Load

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	198.4
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100.0	100.0
Wind	-	-	-	200.0	200.0	165.9	66.0	104.0	-	-	-	-	-	-	-	140.0	-	120.0	108.4	200.0	1,304.3
Solar	-	0.5	0.6	0.6	0.7	0.8	0.8	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	180.5	120.5	0.6	311.1
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.0	60.0	-	150.0
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26.1	85.3	111.4
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	20.0
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	94.3
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.2	-	209.8	-	-	-	300.0
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	64.4	64.4
Load Control	10.4	-	-	-	-	-	-	-	-	-	-	-	1.9	20.0	-	5.6	-	9.8	-	-	47.8
Retail Pricing	14.2	-	-	-	-	-	-	-	-	6.0	-	-	2.5	-	-	-	-	-	-	-	22.7
Total	**24.6**	**0.5**	**0.6**	**200.6**	**200.7**	**166.7**	**66.8**	**303.4**	**0.5**	**6.5**	**0.5**	**0.5**	**5.0**	**20.5**	**90.7**	**146.1**	**210.3**	**400.4**	**314.9**	**564.6**	**2,526.0**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	101.6
Natural Gas	-	-	-	-	90.2	-	-	-	-	-	-	-	-	-	90.2	-	94.9	-	-	-	275.4
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	34.1	34.0	53.3	-	-	-	-	-	-	-	-	-	-	-	-	121.4
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	3.2
Load Control	-	-	-	-	-	-	-	-	-	2.8	-	-	-	-	-	-	-	1.3	6.6	-	10.7
Retail Pricing	-	-	-	2.6	-	-	-	-	-	-	-	-	-	-	4.2	-	-	-	-	-	6.8
Total	**-**	**-**	**-**	**2.6**	**90.2**	**34.1**	**34.0**	**155.0**	**-**	**2.8**	**-**	**-**	**-**	**-**	**94.4**	**-**	**94.9**	**1.3**	**6.6**	**3.2**	**417.4**
Grand Total	**24.6**	**0.5**	**0.6**	**203.2**	**290.9**	**200.8**	**100.8**	**458.4**	**0.5**	**9.3**	**0.5**	**0.5**	**5.0**	**20.5**	**185.2**	**146.1**	**305.1**	**401.6**	**321.5**	**567.8**	**2,943.4**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.30: Portfolio #7: Washington Building Electrification

Portfolio #7 WA Building Electrification

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	**198.4**
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	240.8	**240.8**
Wind	-	-	100.0	200.0	200.0	200.0	100.0	200.0	-	-	-	-	-	-	-	140.0	100.0	120.0	100.0	-	**1,460.0**
Solar	-	0.5	0.6	0.6	2.0	3.0	145.4	3.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	2.0	167.6	104.6	113.2	5.0	**550.9**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	71.2	-	-	-	-	-	-	-	-	-	78.8	-	-	-	**150.0**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25.0	-	-	**25.0**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.8	182.8	-	79.0	69.9	**362.5**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	-	-	-	**20.0**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	**94.3**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	90.2	98.5	-	111.2	-	-	-	-	-	**300.0**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8	57.6	-	-	**64.4**
Load Control	12.4	-	-	-	-	-	-	-	20.0	-	-	5.6	-	-	-	-	-	-	-	-	**38.0**
Retail Pricing	14.2	-	-	-	-	8.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**22.7**
Total	**26.5**	**0.5**	**100.6**	**200.6**	**202.0**	**211.5**	**316.6**	**401.4**	**20.5**	**0.5**	**0.5**	**96.3**	**99.0**	**0.5**	**111.7**	**172.8**	**556.0**	**307.2**	**292.2**	**410.0**	**3,328.6**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	**101.6**
Natural Gas	-	-	-	-	90.2	-	-	-	-	-	-	-	90.2	-	-	-	114.4	-	-	-	**294.9**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	-	-	-	**3.2**
Load Control	-	-	-	-	-	-	-	-	-	2.8	-	-	-	-	-	-	-	1.3	6.6	-	**10.7**
Retail Pricing	-	-	-	2.6	-	-	-	-	-	-	-	-	-	-	4.2	-	-	-	-	-	**6.8**
Total	**-**	**-**	**-**	**2.6**	**90.2**	**-**	**-**	**101.6**	**-**	**2.8**	**-**	**-**	**90.2**	**-**	**4.2**	**-**	**117.6**	**1.3**	**6.6**	**-**	**315.6**
Grand Total	**26.5**	**0.5**	**100.6**	**203.2**	**292.2**	**211.5**	**316.6**	**503.0**	**20.5**	**3.3**	**0.5**	**96.3**	**189.3**	**0.5**	**115.9**	**172.8**	**673.5**	**308.5**	**298.8**	**410.0**	**3,644.2**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.31: Portfolio #8: WA Building and Transportation Electrification

Portfolio #8 WA Building & High Transportation Electrification

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	**198.4**
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	117.5	-	-	204.5	**322.0**
Wind	-	-	100.0	200.0	200.0	200.0	100.0	162.5	-	-	-	-	-	-	-	140.0	100.0	220.0	-	-	**1,422.5**
Solar	-	0.5	0.6	0.6	3.0	3.0	200.8	3.0	0.5	0.5	0.5	0.5	0.5	0.5	2.0	0.6	111.1	13.0	-	205.5	**546.7**
Storage	-	-	-	-	-	-	-	-	-	100.0	116.3	-	-	-	-	-	-	-	-	-	**216.3**
Lithium-Ion Storage	-	-	-	-	-	-	98.9	-	-	-	-	-	-	-	-	-	51.1	-	5.1	-	**155.1**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	61.2	67.8	51.8	-	81.2	**262.0**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	-	-	-	**20.0**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	**94.3**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	90.2	93.3	116.5	-	-	-	-	-	**300.0**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8	-	57.6	-	**64.4**
Load Control	10.4	-	20.0	-	-	-	1.9	-	-	5.6	-	-	-	-	-	-	12.4	-	-	-	**50.3**
Retail Pricing	14.2	-	-	6.0	-	-	-	-	-	2.5	-	-	-	-	-	-	-	-	-	-	**22.7**
Total	**24.6**	**0.5**	**120.6**	**206.6**	**203.0**	**203.0**	**401.6**	**363.9**	**0.5**	**108.6**	**116.8**	**0.5**	**90.7**	**93.8**	**118.5**	**201.8**	**486.7**	**284.8**	**62.7**	**585.5**	**3,476.4**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	**101.6**
Natural Gas	-	-	-	-	92.9	-	-	-	-	-	-	-	-	46.4	-	-	149.8	-	-	-	**289.0**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	0.0	-	-	-	**3.2**
Load Control	-	-	-	2.8	-	-	-	-	-	6.6	-	1.3	-	-	-	-	-	-	-	-	**10.7**
Retail Pricing	-	-	-	2.6	-	-	-	4.2	1.7	-	-	-	-	-	-	-	-	-	-	-	**8.5**
Total	**-**	**-**	**-**	**5.4**	**92.9**	**-**	**-**	**105.8**	**1.7**	**6.6**	**-**	**1.3**	**-**	**46.4**	**-**	**3.2**	**149.8**	**-**	**-**	**-**	**311.4**
Grand Total	**24.6**	**0.5**	**120.6**	**212.0**	**295.9**	**203.0**	**401.6**	**469.7**	**2.2**	**115.2**	**116.8**	**1.8**	**90.7**	**140.1**	**118.5**	**205.0**	**636.5**	**284.8**	**62.7**	**585.5**	**3,787.8**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.32: Portfolio #9: System Building and Transportation Electrification

Portfolio #9 System Building & Transportation Electrification - no new Natural Gas

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	198.4
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	100.0	67.8	-	-	188.8	68.3	-	131.9	556.8
Wind	-	-	-	100.0	165.9	131.3	-	-	-	-	-	-	-	-	-	140.0	-	81.9	-	100.0	719.1
Solar	3.0	3.0	3.0	3.0	3.0	68.9	106.0	3.0	0.6	0.5	2.0	5.0	2.0	0.7	8.0	8.0	108.0	1.2	200.6	117.4	646.9
Storage	-	-	-	-	-	-	-	-	77.9	-	75.8	-	-	-	0.0	-	-	-	-	-	153.7
Lithium-Ion Storage	-	-	-	-	-	33.0	50.0	-	-	-	-	-	-	-	-	-	50.0	-	98.8	-	231.8
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60.9	17.7	-	-	150.7	229.2
Geothermal	-	-	-	-	-	-	-	-	-	-	-	20.0	-	-	-	-	-	-	-	-	20.0
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	94.3
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	64.6	-	-	110.6	-	-	-	-	-	175.3
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	6.6	-	-	-	-	-	-	-	-	-	-	6.6
Load Control	10.4	20.0	-	-	-	-	-	-	1.9	-	5.6	-	-	12.4	-	-	-	-	-	-	50.3
Retail Pricing	20.2	-	-	-	2.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22.7
Total	**33.6**	**23.0**	**3.0**	**103.0**	**171.4**	**233.2**	**156.0**	**201.4**	**80.4**	**7.2**	**83.4**	**89.6**	**102.0**	**80.8**	**118.6**	**208.9**	**364.5**	**151.4**	**299.4**	**594.3**	**2,906.7**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	101.6
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	32.8	104.9	-	100.0	31.7	-	-	269.4
Wind	-	-	100.8	100.0	34.1	67.9	-	153.8	-	-	-	-	-	-	-	-	-	38.1	-	-	494.7
Solar	-	-	-	-	-	34.1	102.0	-	-	-	-	-	3.0	5.0	-	205.0	100.0	5.0	10.0	-	464.1
Storage	-	-	-	-	-	-	-	-	39.6	-	37.9	-	-	-	0.0	-	-	-	-	-	77.5
Lithium-Ion Storage	-	-	-	2.0	93.9	23.0	50.0	-	-	-	-	-	-	-	-	100.0	50.0	-	-	-	318.9
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25.0	-	-	-	25.0
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	28.9	64.6	-	101.8
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	124.7	-	-	-	-	-	-	-	-	124.7
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	3.4	-	57.6	-	-	-	-	-	-	-	-	61.0
Load Control	-	-	1.3	9.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.7
Retail Pricing	-	-	-	6.8	-	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.5
Total	**-**	**-**	**102.1**	**118.2**	**128.0**	**126.6**	**152.0**	**255.5**	**39.6**	**3.4**	**37.9**	**182.3**	**3.0**	**37.8**	**104.9**	**305.0**	**283.3**	**103.7**	**74.6**	**-**	**1,956.4**
Grand Total	**33.6**	**23.0**	**105.1**	**221.2**	**299.4**	**359.9**	**308.0**	**456.8**	**120.0**	**10.5**	**121.3**	**272.0**	**105.0**	**118.6**	**223.5**	**513.9**	**647.8**	**255.1**	**374.0**	**594.3**	**4,863.1**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.33: Portfolio #10: Washington Max Customer Benefits

Portfolio #10 WA Max Customer Benefits

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	198.4
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	289.3	289.3
Wind	-	-	100.0	100.0	200.0	165.9	100.0	132.2	-	-	-	-	-	-	-	140.0	-	120.0	-	100.0	1,158.2
Solar	-	2.5	4.6	4.6	4.7	4.8	6.8	7.0	6.5	6.5	10.5	14.5	16.5	18.5	20.5	24.5	30.5	216.9	154.2	40.6	595.1
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	95.2	62.8	4.0	226.0
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25.0	-	-	-	-	-	25.0
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25.2	218.6	-	37.1	66.1	346.9
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Load Control	10.4	-	-	-	-	-	-	-	-	-	-	5.6	20.0	1.9	-	-	-	12.4	47.1	-	97.5
Retail Pricing	14.2	-	-	-	-	-	-	-	-	-	8.5	-	-	-	-	-	-	-	-	-	22.7
Total	**24.6**	**6.5**	**108.6**	**108.6**	**208.7**	**174.7**	**110.8**	**341.6**	**10.5**	**10.5**	**23.0**	**24.1**	**40.5**	**24.4**	**49.5**	**193.7**	**253.1**	**444.4**	**301.2**	**500.0**	**2,760.7**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	101.6
Natural Gas	-	-	-	-	90.3	-	-	-	-	-	-	-	-	-	90.2	-	97.0	-	-	-	277.6
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	34.1	-	67.8	-	-	-	-	-	-	-	-	-	-	-	-	101.8
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Load Control	-	-	-	2.8	-	-	-	-	-	-	-	-	-	6.6	-	-	-	1.3	-	-	10.7
Retail Pricing	-	-	-	2.6	-	-	-	-	-	4.2	-	-	-	-	-	-	-	-	-	-	6.8
Total	**-**	**-**	**-**	**5.4**	**90.3**	**34.1**	**-**	**169.4**	**-**	**4.2**	**-**	**-**	**-**	**6.6**	**90.2**	**-**	**97.0**	**1.3**	**-**	**-**	**396.9**
Grand Total	**24.6**	**6.5**	**108.6**	**114.0**	**299.0**	**208.8**	**110.8**	**511.0**	**10.5**	**14.7**	**23.0**	**24.1**	**40.5**	**31.0**	**139.7**	**193.7**	**350.1**	**445.7**	**301.2**	**500.0**	**3,157.6**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.34: Portfolio #11: 500 MW of Nuclear in 2040

Portfolio #11 500 MW of Nuclear

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	198.4
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338.3	-	-	-	-	-	338.3
Wind	-	-	-	131.7	200.0	165.9	66.0	-	-	-	-	-	-	-	-	-	-	120.0	-	-	683.6
Solar	-	0.5	0.6	0.6	0.7	0.8	0.8	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	11.1
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25.0	-	-	25.0
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	36.5	36.5
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	20.0
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	94.3
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	61.8	209.8	271.5
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8	6.8
Load Control	10.4	-	-	-	-	-	-	-	-	-	-	20.0	1.9	-	-	-	-	-	-	-	32.4
Retail Pricing	14.2	-	-	-	-	-	-	-	2.5	6.0	-	-	-	-	-	-	-	-	-	-	22.7
Total	**24.6**	**0.5**	**0.6**	**132.3**	**200.7**	**166.7**	**66.8**	**199.4**	**3.0**	**6.5**	**0.5**	**20.5**	**2.4**	**0.5**	**338.8**	**0.5**	**0.5**	**145.5**	**62.3**	**368.0**	**1,542.3**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	101.6
Natural Gas	-	-	-	-	90.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.4
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	161.7	-	-	-	-	-	161.7
Wind	-	-	-	68.3	-	34.1	34.0	-	-	-	-	-	-	-	-	-	-	-	-	-	136.4
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28.5	-	28.5
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	3.2
Load Control	-	-	-	-	2.8	-	-	-	-	-	-	-	-	-	-	-	1.3	6.6	-	-	10.7
Retail Pricing	-	-	-	2.6	-	-	-	-	-	-	-	-	-	4.2	-	-	-	-	-	-	6.8
Total	**-**	**-**	**-**	**71.0**	**93.2**	**34.1**	**34.0**	**101.6**	**-**	**-**	**-**	**-**	**-**	**4.2**	**161.7**	**-**	**1.3**	**6.6**	**28.5**	**3.2**	**437.5**
Grand Total	**24.6**	**0.5**	**0.6**	**203.2**	**293.8**	**200.8**	**100.8**	**301.0**	**3.0**	**6.5**	**0.5**	**20.5**	**2.4**	**4.7**	**500.5**	**0.5**	**1.8**	**152.1**	**90.8**	**371.2**	**1,979.8**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.35: Portfolio #12: 17% PRM

Portfolio #12 17% PRM

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	198.4
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	108.0	108.0
Wind	-	-	-	200.0	165.9	165.9	100.0	112.9	-	-	-	-	-	-	-	140.0	-	120.0	100.0	200.0	1,304.7
Solar	-	0.5	0.6	0.6	0.7	0.8	0.8	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	-	0.5	0.5	195.3	5.0	209.8
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	-	-	97.4	5.0	105.6
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25.0	-	-	-	-	-	25.0
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	-	-	20.0
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	94.3
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200.8	-	-	99.2	300.0
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8	-	57.6	64.4
Load Control	10.4	-	-	-	-	-	-	-	-	-	5.6	-	-	-	-	20.0	1.9	2.5	9.8	-	50.3
Retail Pricing	14.2	-	-	-	-	-	-	-	-	-	-	-	-	8.5	-	-	-	-	-	-	22.7
Total	**24.6**	**0.5**	**0.6**	**200.6**	**166.5**	**166.7**	**100.8**	**312.3**	**0.5**	**0.5**	**6.1**	**0.5**	**0.5**	**9.0**	**25.5**	**163.3**	**203.2**	**149.9**	**402.5**	**569.2**	**2,305.0**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	101.6
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	90.2	-	-	-	122.9	-	-	-	213.2
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	34.1	34.1	-	57.9	-	-	-	-	-	-	-	-	-	-	-	-	126.1
Solar	-	-	-	-	104.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	104.5
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	-	-	3.2
Load Control	-	-	-	2.8	-	-	-	-	-	-	-	-	-	-	-	-	-	1.3	6.6	-	10.7
Retail Pricing	-	-	-	2.6	-	-	-	-	-	-	-	-	-	-	4.2	-	-	-	-	-	6.8
Total	**-**	**-**	**-**	**5.4**	**138.6**	**34.1**	**-**	**159.5**	**-**	**-**	**-**	**-**	**90.2**	**-**	**4.2**	**-**	**122.9**	**4.4**	**6.6**	**-**	**464.4**
Grand Total	**24.6**	**0.5**	**0.6**	**206.0**	**305.2**	**200.8**	**100.8**	**471.8**	**0.5**	**0.5**	**6.1**	**0.5**	**90.7**	**9.0**	**29.7**	**163.3**	**326.1**	**154.4**	**409.1**	**569.2**	**2,769.4**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.36: Portfolio #13: 30% PRM

Portfolio #13 30% PRM

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	198.4
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100.0	100.0
Wind	-	65.7	-	200.0	200.0	165.9	-	116.0	-	-	-	-	-	-	-	140.0	-	120.0	104.5	200.0	1,312.1
Solar	-	0.5	0.6	0.6	0.7	0.8	0.8	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	200.5	100.5	0.6	311.1
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	86.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100.0	50.0	-	236.6
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	30.4	-	-	26.6	-	-	-	57.0
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28.2	96.7	124.9
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	20.0
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	94.3
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91.5	-	208.5	-	-	-	300.0
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8	57.6	64.4
Load Control	12.4	-	-	-	-	-	-	-	-	5.6	20.0	-	-	-	-	12.4	-	-	-	-	50.3
Retail Pricing	14.2	-	-	-	-	-	2.5	-	6.0	-	-	-	-	-	-	-	-	-	-	-	22.7
Total	113.2	66.2	0.6	200.6	200.7	166.7	3.4	315.4	6.5	6.1	20.5	0.5	0.5	30.9	92.0	152.9	235.6	420.5	290.1	569.2	2,693.5

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	101.6
Natural Gas	-	-	-	-	91.9	-	-	-	-	-	-	-	90.2	-	-	-	117.8	-	-	-	300.0
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	34.3	-	-	-	34.1	-	59.5	-	-	-	-	-	-	-	-	-	-	-	-	127.9
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25.0	-	25.0
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	-	3.2
Load Control	1.3	-	-	2.8	-	-	-	-	-	-	-	-	-	-	-	-	6.6	-	-	-	10.7
Retail Pricing	-	-	-	2.6	-	-	4.2	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8
Total	1.3	34.3	-	5.4	91.9	34.1	4.2	161.1	-	-	-	-	90.2	-	-	-	124.4	-	28.2	-	473.5
Grand Total	114.5	100.5	0.6	206.0	292.6	200.8	7.5	476.5	6.5	6.1	20.5	0.5	90.7	30.9	92.0	152.9	360.0	420.5	318.2	569.2	3,167.0

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	4.5	9.4	14.9	21.1	26.1	31.7	38.5	45.6	52.7	59.0	65.4	71.5	77.1	82.0	86.6	91.1	94.6	98.4	101.9	105.1	1,176.9

Table 10.37: Portfolio #14: Power to Gas Unavailable

Portfolio #14 Power to Gas Unavailable

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	**198.4**
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	-	**0.0**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221.8	**221.8**
Wind	-	-	-	200.0	200.0	165.9	100.0	89.4	-	-	-	-	-	-	-	140.0	-	120.0	100.0	122.9	**1,238.3**
Solar	-	0.5	0.6	0.6	0.7	0.8	0.8	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	100.5	100.5	100.5	10.0	**320.5**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50.0	50.0	50.0	-	**150.0**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	49.7	-	-	-	-	-	**49.7**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28.5	198.2	25.0	31.4	66.2	**349.3**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	**20.0**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	64.4	**64.4**
Load Control	10.4	-	-	-	-	-	-	-	-	-	-	25.6	-	1.9	-	-	-	-	-	-	**38.0**
Retail Pricing	14.2	-	-	-	-	-	-	-	-	-	8.5	-	-	-	-	-	-	-	-	-	**22.7**
Total	**24.6**	**0.5**	**0.6**	**200.6**	**200.7**	**166.7**	**100.8**	**288.8**	**0.5**	**0.5**	**9.0**	**26.1**	**0.5**	**2.4**	**50.2**	**169.0**	**348.7**	**295.5**	**281.9**	**505.4**	**2,474.7**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	**101.6**
Natural Gas	-	-	-	-	90.2	-	-	-	-	-	-	-	-	-	46.4	-	118.6	-	92.3	-	**347.4**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Wind	-	-	-	-	-	34.1	-	45.8	-	-	-	-	-	-	-	-	-	-	-	-	**79.9**
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	**3.2**
Load Control	-	-	-	2.8	-	-	-	-	-	-	-	-	7.9	-	-	-	-	-	-	-	**10.7**
Retail Pricing	-	-	-	2.6	-	-	-	-	4.2	-	-	-	-	-	-	-	-	-	-	1.7	**8.5**
Total	**-**	**-**	**-**	**5.4**	**90.2**	**34.1**	**-**	**147.5**	**4.2**	**-**	**-**	**-**	**7.9**	**-**	**46.4**	**-**	**118.6**	**-**	**92.3**	**4.8**	**449.7**
Grand Total	**24.6**	**0.5**	**0.6**	**206.0**	**290.9**	**200.8**	**100.8**	**436.3**	**4.7**	**0.5**	**9.0**	**26.1**	**8.4**	**2.4**	**96.6**	**169.0**	**467.3**	**295.5**	**374.2**	**510.2**	**2,924.4**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.38: Portfolio #15: Minimum CETA Target

Portfolio #15 Minimum CETA Target

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	**198.4**
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100.0	**100.0**
Wind	-	-	-	200.0	200.0	165.9	66.0	104.0	-	-	-	-	-	-	-	140.0	-	120.0	106.8	200.0	**1,302.8**
Solar	-	0.5	0.6	0.6	0.7	0.8	0.8	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	180.5	120.5	5.0	**315.5**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.0	60.0	-	**150.0**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26.2	85.1	**111.3**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	**20.0**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	**94.3**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.2	-	209.8	-	-	-	**300.0**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	64.4	**64.4**
Load Control	10.4	-	-	-	-	-	-	-	-	-	-	-	1.9	20.0	-	5.6	-	9.8	-	-	**47.8**
Retail Pricing	14.2	-	-	-	-	-	-	-	-	6.0	-	-	2.5	-	-	-	-	-	-	-	**22.7**
Total	**24.6**	**0.5**	**0.6**	**200.6**	**200.7**	**166.7**	**66.8**	**303.4**	**0.5**	**6.5**	**0.5**	**0.5**	**5.0**	**20.5**	**90.7**	**146.1**	**210.3**	**400.4**	**313.5**	**568.9**	**2,528.8**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	**101.6**
Natural Gas	-	-	-	-	90.2	-	-	-	-	-	-	-	-	-	90.2	-	94.9	-	-	-	**275.4**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Wind	-	-	-	-	-	34.1	34.0	53.3	-	-	-	-	-	-	-	-	-	-	-	-	**121.4**
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	**3.2**
Load Control	-	-	-	-	-	-	-	-	-	2.8	-	-	-	-	-	-	-	1.3	6.6	-	**10.7**
Retail Pricing	-	-	-	2.6	-	-	-	-	-	-	-	-	-	-	4.2	-	-	-	-	-	**6.8**
Total	**-**	**-**	**-**	**2.6**	**90.2**	**34.1**	**34.0**	**155.0**	**-**	**2.8**	**-**	**-**	**-**	**-**	**94.4**	**-**	**94.9**	**1.3**	**6.6**	**3.2**	**417.4**
Grand Total	**24.6**	**0.5**	**0.6**	**203.2**	**290.9**	**200.8**	**100.8**	**458.4**	**0.5**	**9.3**	**0.5**	**0.5**	**5.0**	**20.5**	**185.2**	**146.1**	**305.1**	**401.6**	**320.1**	**572.0**	**2,946.2**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.39: Portfolio #16: Maximum CETA Target

Portfolio #16 Max CETA Target

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	198.4
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100.0	100.0
Wind	-	-	-	200.0	200.0	165.9	66.0	104.0	-	-	-	-	-	-	-	140.0	-	120.0	108.4	200.0	1,304.3
Solar	-	0.5	0.6	0.6	0.7	0.8	0.8	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	180.5	120.5	0.6	311.1
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.0	60.0	-	150.0
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26.1	85.3	111.4
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	20.0
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	94.3
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.2	-	209.8	-	-	-	300.0
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	64.4	64.4
Load Control	10.4	-	-	-	-	-	-	-	-	-	-	-	1.9	20.0	-	5.6	-	9.8	-	-	47.8
Retail Pricing	14.2	-	-	-	-	-	-	-	-	6.0	-	-	2.5	-	-	-	-	-	-	-	22.7
Total	**24.6**	**0.5**	**0.6**	**200.6**	**200.7**	**166.7**	**66.8**	**303.4**	**0.5**	**6.5**	**0.5**	**0.5**	**5.0**	**20.5**	**90.7**	**146.1**	**210.3**	**400.4**	**314.9**	**564.6**	**2,526.0**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	101.6
Natural Gas	-	-	-	-	90.2	-	-	-	-	-	-	-	-	-	90.2	-	94.9	-	-	-	275.4
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	34.1	34.0	53.3	-	-	-	-	-	-	-	-	-	-	-	-	121.4
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	3.2
Load Control	-	-	-	-	-	-	-	-	-	2.8	-	-	-	-	-	-	-	1.3	6.6	-	10.7
Retail Pricing	-	-	-	2.6	-	-	-	-	-	-	-	-	-	-	4.2	-	-	-	-	-	6.8
Total	**-**	**-**	**-**	**2.6**	**90.2**	**34.1**	**34.0**	**155.0**	**-**	**2.8**	**-**	**-**	**-**	**-**	**94.4**	**-**	**94.9**	**1.3**	**6.6**	**3.2**	**417.4**
Grand Total	**24.6**	**0.5**	**0.6**	**203.2**	**290.9**	**200.8**	**100.8**	**458.4**	**0.5**	**9.3**	**0.5**	**0.5**	**5.0**	**20.5**	**185.2**	**146.1**	**305.1**	**401.6**	**321.5**	**567.8**	**2,943.4**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.40: Portfolio #17: PRS Cost Cap Constrained

Portfolio #17 PRS Cost Cap Constrained

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	198.4
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0
Wind	-	-	-	200.0	200.0	165.9	66.0	104.0	-	-	-	-	-	-	-	140.0	-	120.0	-	-	996.0
Solar	-	0.5	0.6	0.6	0.7	0.8	0.8	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	180.5	0.5	205.0	395.5
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.0	-	-	90.0
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	31.1	110.9	142.0
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	-	20.0
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	139.1	139.1
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.2	-	209.8	-	-	-	300.0
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8	-	6.8
Load Control	10.4	-	-	-	-	-	-	-	-	-	-	-	1.9	20.0	-	5.6	-	9.8	2.5	-	50.3
Retail Pricing	14.2	-	-	-	-	-	-	-	-	6.0	-	-	2.5	-	-	-	-	-	-	-	22.7
Total	**24.6**	**0.5**	**0.6**	**200.6**	**200.7**	**166.7**	**66.8**	**303.4**	**0.5**	**6.5**	**0.5**	**0.5**	**5.0**	**20.5**	**90.7**	**146.1**	**210.3**	**400.4**	**61.0**	**455.0**	**2,162.5**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	101.6
Natural Gas	-	-	-	-	90.2	-	-	-	-	-	-	-	-	-	90.2	-	91.7	-	-	90.2	362.4
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	34.1	34.0	53.3	-	-	-	-	-	-	-	-	-	-	-	-	121.4
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	-	3.2
Load Control	-	-	-	-	-	-	-	-	-	2.8	-	-	-	-	-	-	-	1.3	6.6	-	10.7
Retail Pricing	-	-	-	2.6	-	-	-	-	-	-	-	-	-	-	4.2	-	-	-	-	-	6.8
Total	**-**	**-**	**-**	**2.6**	**90.2**	**34.1**	**34.0**	**155.0**	**-**	**2.8**	**-**	**-**	**-**	**-**	**94.4**	**-**	**91.7**	**1.3**	**9.8**	**90.2**	**504.4**
Grand Total	**24.6**	**0.5**	**0.6**	**203.2**	**290.9**	**200.8**	**100.8**	**458.4**	**0.5**	**9.3**	**0.5**	**0.5**	**5.0**	**20.5**	**185.2**	**146.1**	**301.9**	**401.6**	**70.7**	**545.3**	**2,666.9**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.41: Portfolio #18: Data Center Load (200 MW in 2030)

Portfolio #18 Data Center Load

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	198.4
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	196.8	196.8
Wind	-	-	-	200.0	200.0	200.0	200.0	200.0	-	-	-	-	-	-	-	140.0	180.0	120.0	-	-	1,440.0
Solar	-	0.5	0.6	0.6	122.8	3.0	3.0	3.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	2.0	178.9	113.0	0.7	200.9	632.4
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	60.8	-	-	-	-	-	-	-	-	-	-	-	89.2	-	-	-	150.0
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	43.8	38.4	-	96.6	178.7
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	-	-	-	20.0
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	94.3
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	90.2	-	90.2	-	119.5	-	-	-	300.0
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8	57.6	-	64.4
Load Control	10.4	20.0	1.9	-	-	-	-	-	-	-	-	-	-	5.6	-	-	12.4	-	-	-	50.3
Retail Pricing	20.2	-	-	-	-	-	2.5	-	-	-	-	-	-	-	-	-	-	-	-	-	22.7
Total	**30.6**	**20.5**	**2.5**	**200.6**	**383.6**	**203.0**	**205.5**	**401.4**	**0.5**	**0.5**	**0.5**	**0.5**	**90.7**	**6.1**	**90.7**	**142.0**	**643.8**	**278.2**	**58.3**	**588.6**	**3,149.8**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	101.6
Natural Gas	-	-	-	-	180.3	-	-	-	-	-	-	-	90.2	-	-	-	99.7	-	-	-	370.2
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	0.0	-	3.2
Load Control	-	-	-	2.8	-	-	-	-	6.6	-	-	-	-	-	-	-	-	1.3	-	-	10.7
Retail Pricing	-	-	-	2.6	-	-	4.2	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8
Total	**-**	**-**	**-**	**5.4**	**180.3**	**-**	**4.2**	**101.6**	**6.6**	**-**	**-**	**-**	**90.2**	**-**	**-**	**-**	**99.7**	**4.4**	**0.0**	**-**	**390.9**
Grand Total	**30.6**	**20.5**	**2.5**	**206.0**	**563.9**	**203.0**	**209.7**	**503.0**	**7.1**	**0.5**	**0.5**	**0.5**	**181.0**	**6.1**	**90.7**	**142.0**	**743.5**	**282.6**	**58.3**	**588.6**	**3,540.7**

Cumultive Energy Efficiency (aMW)																					
Washington	3.6	7.5	11.8	16.8	20.9	25.4	30.9	36.5	42.1	47.1	52.0	56.7	60.9	64.6	68.2	71.5	74.1	76.9	79.5	81.8	928.8
Idaho	1.3	2.7	4.4	6.3	7.6	9.1	11.2	13.3	15.4	17.3	19.2	21.2	23.0	24.5	26.0	27.5	28.6	29.8	30.9	32.1	351.4
Total	**4.9**	**10.2**	**16.2**	**23.0**	**28.5**	**34.6**	**42.0**	**49.8**	**57.5**	**64.3**	**71.2**	**77.8**	**83.9**	**89.2**	**94.2**	**98.9**	**102.7**	**106.7**	**110.5**	**113.9**	**1,280.1**

Table 10.42: Portfolio #19: RCP 8.5 Temperatures for Load

Portfolio #19 RCP 8.5 Load

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	**198.4**
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	107.7	**107.7**
Wind	-	-	-	200.0	200.0	165.9	66.0	88.3	-	-	-	-	-	-	-	140.0	-	120.0	138.6	200.0	**1,318.9**
Solar	-	0.5	0.6	0.6	0.7	0.8	0.8	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	142.3	155.2	10.0	**316.9**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70.9	77.3	-	**148.2**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25.0	-	**25.0**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	151.8	**151.8**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	**20.0**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	**94.3**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	61.1	-	209.8	-	-	-	**270.8**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8	-	-	-	**6.8**
Load Control	10.4	-	-	-	-	-	-	-	-	-	-	-	-	5.6	29.8	1.9	-	-	-	-	**47.8**
Retail Pricing	14.2	-	-	-	-	-	-	-	-	-	-	6.0	2.5	-	-	-	-	-	-	-	**22.7**
Total	**24.6**	**0.5**	**0.6**	**200.6**	**200.7**	**166.7**	**66.8**	**287.7**	**0.5**	**0.5**	**0.5**	**6.5**	**3.0**	**6.1**	**91.4**	**142.4**	**217.1**	**333.2**	**396.2**	**583.9**	**2,531.0**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	**101.6**
Natural Gas	-	-	-	-	90.2	-	-	-	-	-	-	-	-	-	-	-	139.1	-	-	-	**229.3**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Wind	-	-	-	-	-	34.1	34.0	45.3	-	-	-	-	-	-	-	-	-	-	-	-	**113.3**
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.2	-	-	-	-	-	**29.2**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	-	-	-	**3.2**
Load Control	-	-	-	-	-	2.8	-	-	-	-	-	-	-	-	-	-	-	1.3	6.6	-	**10.7**
Retail Pricing	-	-	-	2.6	-	-	-	-	-	-	-	-	-	-	4.2	-	-	-	-	-	**6.8**
Total	**-**	**-**	**-**	**2.6**	**90.2**	**36.9**	**34.0**	**146.9**	**-**	**-**	**-**	**-**	**-**	**-**	**33.4**	**-**	**142.3**	**1.3**	**6.6**	**-**	**392.5**
Grand Total	**24.6**	**0.5**	**0.6**	**203.2**	**290.9**	**203.6**	**100.8**	**434.6**	**0.5**	**0.5**	**0.5**	**6.5**	**3.0**	**6.1**	**124.8**	**142.4**	**359.3**	**334.4**	**402.8**	**583.9**	**2,923.5**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.43: Portfolio #20: System Bldg & Transportation Electrification- RCP 8.5

Portfolio #20 System Building and Transporation Electrification, No New Natural Gas with RCP 8.5

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	198.4
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	107.8	-	78.4	67.9	178.0	-	-	164.8	596.9
Wind	-	-	65.8	200.0	-	131.9	-	-	-	-	-	-	-	-	-	140.0	-	-	68.5	-	606.2
Solar	3.0	3.0	3.0	3.0	3.0	103.0	103.0	3.0	0.5	0.5	0.5	2.0	5.0	3.0	5.5	8.0	108.0	108.7	213.0	123.0	801.7
Storage	-	-	-	-	-	-	-	-	73.9	-	66.7	-	-	-	-	0.0	-	-	-	-	140.6
Lithium-Ion Storage	-	-	-	-	1.3	50.0	50.0	-	-	-	-	-	-	-	-	-	50.0	50.0	59.3	50.0	310.7
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.4	-	27.8	25.0	25.0	111.7	219.8
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	94.3
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	60.4	-	80.0	-	-	-	-	-	-	140.4
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	6.7	-	-	-	-	-	-	-	-	6.7
Load Control	10.4	20.0	1.9	-	-	-	-	-	-	-	5.6	-	-	12.4	-	-	-	-	-	-	50.3
Retail Pricing	22.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22.7
Total	**36.1**	**23.0**	**70.8**	**203.0**	**4.3**	**284.9**	**153.0**	**201.4**	**74.5**	**0.5**	**72.7**	**69.0**	**112.8**	**95.4**	**114.3**	**215.9**	**363.8**	**183.7**	**365.8**	**543.8**	**2,990.3**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	101.6
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37.5	32.1	113.6	-	-	-	183.2
Wind	-	-	34.2	-	200.0	68.1	-	199.8	-	-	-	-	-	-	-	-	-	120.0	31.5	-	653.7
Solar	-	-	-	-	100.0	-	-	-	-	-	-	-	-	5.0	2.5	-	100.0	104.3	-	-	311.9
Storage	-	-	-	-	-	-	-	-	37.6	-	33.3	-	-	-	-	0.0	-	-	-	-	70.9
Lithium-Ion Storage	-	-	-	-	78.1	6.0	-	-	-	-	-	-	-	-	2.5	-	50.0	50.0	-	-	186.6
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	30.7	-	-	-	-	-	-	-	-	43.9	-	25.5	60.1	-	160.3
Geothermal	-	-	-	-	-	-	-	-	-	-	-	20.0	-	-	-	-	-	-	-	-	20.0
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	29.9	91.0	38.7	-	-	-	-	-	-	159.6
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	3.3	-	57.6	-	-	-	-	-	-	60.9
Load Control	-	-	-	2.8	7.9	-	-	-	-	-	-	-	7.1	-	-	-	-	-	-	-	17.7
Retail Pricing	-	-	-	6.8	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.5
Total	**-**	**-**	**34.2**	**9.6**	**387.6**	**74.1**	**30.7**	**301.5**	**37.6**	**-**	**33.3**	**53.2**	**98.1**	**101.3**	**42.6**	**76.1**	**263.6**	**299.9**	**91.7**	**-**	**1,833.4**
Grand Total	**36.1**	**23.0**	**104.9**	**212.6**	**392.0**	**359.0**	**183.7**	**502.8**	**112.1**	**0.5**	**106.1**	**122.2**	**210.9**	**196.7**	**156.8**	**291.9**	**627.4**	**483.5**	**457.4**	**543.8**	**4,823.6**

Cumultive Energy Efficiency (aMW)																					
Washington	4.3	9.0	14.3	20.4	25.9	32.1	39.1	46.5	53.9	60.5	66.8	72.7	78.1	82.7	87.1	91.3	94.5	98.0	101.0	103.6	1,181.9
Idaho	2.4	5.0	8.1	11.5	14.6	18.2	22.2	26.5	30.6	34.2	37.7	40.8	43.5	45.8	48.0	50.2	51.8	53.6	55.2	56.8	656.8
Total	**6.7**	**14.0**	**22.4**	**31.9**	**40.6**	**50.2**	**61.3**	**73.0**	**84.4**	**94.7**	**104.5**	**113.5**	**121.6**	**128.5**	**135.1**	**141.4**	**146.3**	**151.6**	**156.3**	**160.5**	**1,838.6**

Table 10.44: Portfolio #21: No Regional Transmission

Portfolio #21 No Regional Transmission

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	109.8	**109.8**
Wind	-	-	-	200.0	200.0	165.9	132.0	112.5	-	-	-	-	-	-	-	140.0	-	120.0	-	200.0	**1,270.5**
Solar	-	0.5	0.6	0.6	0.7	0.8	100.8	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	200.1	10.0	**320.1**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	50.0	-	-	-	-	-	-	-	-	-	-	-	99.8	-	**149.8**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25.0	-	**25.0**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	116.1	42.2	-	86.2	**244.5**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	**20.0**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	**94.3**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	102.4	-	-	90.2	-	106.6	-	-	-	**299.2**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8	-	57.6	**64.4**
Load Control	10.4	-	-	-	-	-	-	-	-	-	20.0	-	1.9	-	-	-	-	-	-	-	**32.4**
Retail Pricing	14.2	-	-	-	-	-	-	-	8.5	-	-	-	-	-	-	-	-	-	-	-	**22.7**
Total	**24.6**	**0.5**	**0.6**	**200.6**	**200.7**	**166.7**	**282.9**	**113.5**	**9.0**	**0.5**	**20.5**	**102.9**	**2.4**	**0.5**	**90.7**	**140.5**	**223.2**	**169.6**	**324.9**	**577.9**	**2,652.7**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas	-	-	-	-	98.0	-	-	-	-	-	-	90.2	-	-	-	-	112.5	-	-	-	**300.8**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	34.1	68.0	57.7	-	-	-	-	-	-	-	-	-	-	-	-	**159.7**
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.0	25.5	-	**33.5**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	-	0.0	**3.2**
Load Control	-	-	-	2.8	-	-	-	-	-	-	-	-	-	6.6	-	1.3	-	-	-	-	**10.7**
Retail Pricing	-	-	-	2.6	4.2	-	-	-	-	-	-	-	1.7	-	-	-	-	-	-	-	**8.5**
Total	**-**	**-**	**-**	**5.4**	**102.2**	**34.1**	**68.0**	**57.7**	**-**	**-**	**-**	**90.2**	**1.7**	**6.6**	**-**	**1.3**	**112.5**	**11.2**	**25.5**	**0.0**	**516.3**
Grand Total	**24.6**	**0.5**	**0.6**	**206.0**	**302.9**	**200.8**	**350.8**	**171.2**	**9.0**	**0.5**	**20.5**	**193.2**	**4.1**	**7.1**	**90.7**	**141.8**	**335.6**	**180.7**	**350.4**	**577.9**	**3,169.0**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.45: Portfolio #22: Retire Northeast in 2026

Portfolio #22 Retire Northeast in 2026

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	**198.4**
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	122.1	**122.1**
Wind	-	-	65.8	200.0	131.7	200.0	93.1	66.1	-	-	-	-	-	-	-	140.0	-	120.0	0.0	200.0	**1,216.8**
Solar	-	0.5	0.6	0.6	0.7	0.8	0.8	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	101.3	199.2	0.6	**310.6**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	51.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50.4	101.7	-	**203.8**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	69.5	**69.5**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	**20.0**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	**94.3**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.2	-	209.8	-	-	-	**300.0**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8	57.6	**64.4**
Load Control	10.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25.6	12.4	1.9	-	-	**50.3**
Retail Pricing	14.2	-	-	-	-	-	-	-	-	-	-	-	-	8.5	-	-	-	-	-	-	**22.7**
Total	**76.3**	**0.5**	**66.4**	**200.6**	**132.4**	**200.8**	**94.0**	**265.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**9.0**	**90.7**	**166.1**	**222.6**	**273.6**	**307.8**	**564.2**	**2,474.6**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	**101.6**
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	92.8	-	-	-	-	150.5	-	-	-	**243.3**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Wind	-	-	34.2	-	68.3	-	47.9	33.9	-	-	-	-	-	-	-	-	-	-	-	-	**184.2**
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	27.2	-	-	-	25.0	5.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**57.8**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	0.0	**3.2**
Load Control	1.3	-	-	9.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**10.7**
Retail Pricing	-	-	-	6.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**6.8**
Total	**28.5**	**-**	**34.2**	**16.2**	**93.3**	**5.6**	**47.9**	**135.5**	**-**	**-**	**-**	**92.8**	**-**	**-**	**-**	**-**	**150.5**	**-**	**3.2**	**0.0**	**506.1**
Grand Total	**104.8**	**0.5**	**100.6**	**216.8**	**225.7**	**206.4**	**141.9**	**401.0**	**0.5**	**0.5**	**0.5**	**93.3**	**0.5**	**9.0**	**90.7**	**166.1**	**373.1**	**273.6**	**310.9**	**564.2**	**2,980.7**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.46: Portfolio #23: 200 MW Wind Limit

Portfolio #23 200 MW Low Cost Wind Limit

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	**198.4**
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	153.7	**153.7**
Wind	-	-	-	-	200.0	200.0	66.0	118.4	-	-	-	-	-	-	-	140.0	-	120.0	-	147.2	**991.6**
Solar	-	0.5	0.6	0.6	0.7	0.8	0.8	1.0	2.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	100.5	200.5	13.0	**325.0**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50.0	100.0	-	**150.0**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	58.1	**58.1**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	-	-	-	**20.0**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	**94.3**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	90.2	-	209.7	-	-	-	**300.0**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8	57.6	**64.4**
Load Control	10.4	-	-	-	-	-	-	-	-	-	-	-	-	20.0	-	-	5.6	1.9	12.7	-	**50.7**
Retail Pricing	14.2	-	-	-	-	-	-	-	-	-	-	-	-	-	8.5	-	-	-	-	-	**22.7**
Total	**24.6**	**0.5**	**0.6**	**0.6**	**200.7**	**200.8**	**66.8**	**317.8**	**2.0**	**0.5**	**0.5**	**0.5**	**0.5**	**20.5**	**99.3**	**140.5**	**235.8**	**272.4**	**320.1**	**524.0**	**2,230.6**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	**101.6**
Natural Gas	-	-	-	-	90.3	-	-	-	-	-	-	-	-	90.2	-	-	105.9	-	-	-	**286.5**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Wind	-	-	-	-	-	-	34.0	60.7	-	-	-	-	-	-	-	-	-	-	-	-	**94.7**
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	0.0	**3.2**
Load Control	-	-	-	-	-	-	-	2.8	-	-	7.9	-	-	-	-	-	-	-	-	-	**10.7**
Retail Pricing	-	-	-	2.6	-	-	-	4.2	-	-	-	-	-	-	-	-	-	-	-	-	**6.8**
Total	**-**	**-**	**-**	**2.6**	**90.3**	**-**	**34.0**	**169.3**	**-**	**-**	**7.9**	**-**	**-**	**90.2**	**-**	**-**	**105.9**	**-**	**3.2**	**0.0**	**401.8**
Grand Total	**24.6**	**0.5**	**0.6**	**3.2**	**291.0**	**200.8**	**100.8**	**487.1**	**2.0**	**0.5**	**8.4**	**0.5**	**0.5**	**110.8**	**99.3**	**140.5**	**341.7**	**272.4**	**323.3**	**524.0**	**2,632.4**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.47: Portfolio #24: No IRA Tax Incentives

Portfolio #24 No IRA Tax Incentives

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	**198.4**
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	-	**0.0**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100.0	**100.0**
Wind	-	-	-	-	100.0	-	-	-	-	200.0	-	-	-	100.0	-	240.0	100.0	220.0	170.7	200.0	**1,330.7**
Solar	-	0.5	2.7	3.0	3.0	3.0	3.0	3.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	101.8	0.6	192.6	0.7	**318.0**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	50.6	0.0	96.0	-	**146.6**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150.4	**150.4**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	**20.0**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	**94.3**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	90.2	-	-	-	209.8	-	-	-	**300.0**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8	-	**6.8**
Load Control	10.4	-	-	-	-	-	-	-	-	-	-	-	25.6	1.9	-	9.8	-	2.5	-	-	**50.3**
Retail Pricing	14.2	-	-	-	-	-	-	-	-	-	6.0	2.5	-	-	-	-	-	-	-	-	**22.7**
Total	**24.6**	**0.5**	**2.7**	**3.0**	**103.0**	**3.0**	**3.0**	**201.4**	**0.5**	**200.5**	**6.5**	**3.0**	**116.4**	**102.4**	**0.5**	**250.4**	**462.1**	**223.1**	**466.2**	**565.5**	**2,539.9**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	**101.6**
Natural Gas	-	-	-	-	102.2	-	-	-	-	-	-	-	-	-	90.2	-	96.2	-	-	-	**288.7**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	-	**3.2**
Load Control	-	-	-	2.8	-	-	-	-	-	-	6.6	-	1.3	-	-	-	-	-	-	-	**10.7**
Retail Pricing	-	-	-	2.6	-	-	-	-	5.9	-	-	-	-	-	-	-	-	-	-	-	**8.5**
Total	**-**	**-**	**-**	**5.4**	**102.2**	**-**	**-**	**101.6**	**5.9**	**-**	**6.6**	**-**	**1.3**	**-**	**90.2**	**-**	**96.2**	**-**	**3.2**	**-**	**311.0**
Grand Total	**24.6**	**0.5**	**2.7**	**8.4**	**205.2**	**3.0**	**3.0**	**303.0**	**6.4**	**200.5**	**13.1**	**3.0**	**117.6**	**102.4**	**90.7**	**250.4**	**558.4**	**223.1**	**469.4**	**565.5**	**2,850.9**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.48: Portfolio #25: Northeast Retires in 2035

Portfolio #25 2035 NE Retire

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	198.9	199.4	200.0	200.6	201.4	202.1	203.0	203.6	204.2	204.8	205.4	205.5	**2,627.3**
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100.0	**100.0**
Wind	-	-	-	200.0	331.7	531.9	632.0	743.9	744.5	745.2	745.9	746.7	747.6	748.5	749.6	890.3	891.0	1,011.8	1,112.5	1,312.6	**12,885.9**
Solar	-	0.5	1.1	1.7	2.3	3.1	3.9	4.9	5.4	5.9	6.4	6.9	7.4	7.9	8.4	8.9	9.4	191.1	310.5	312.5	**898.5**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.6	150.0	150.0	**390.6**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26.2	111.3	**137.5**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	**20.0**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	**94.3**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.2	90.2	300.0	300.0	300.0	300.0	**1,380.5**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	64.4	**64.4**
Load Control	0.0	0.1	0.2	0.9	2.5	3.4	3.8	4.3	4.8	5.4	5.6	5.8	6.9	13.6	17.5	21.4	24.7	28.6	33.4	38.9	**222.1**
Retail Pricing	0.5	1.5	3.2	4.7	5.6	6.1	6.5	6.9	7.3	7.9	9.0	10.2	12.6	14.8	16.8	17.8	19.3	20.4	21.5	22.3	**215.1**
Total	**0.6**	**2.1**	**4.5**	**207.3**	**342.2**	**544.5**	**646.3**	**958.3**	**960.9**	**963.9**	**966.8**	**970.3**	**976.1**	**987.0**	**1,085.6**	**1,232.4**	**1,448.6**	**1,847.4**	**2,159.5**	**2,731.8**	**16,409.0**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	101.1	100.6	100.0	99.4	98.6	97.9	97.0	96.4	95.8	95.2	94.6	94.5	**1,272.7**
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	101.6	101.6	101.6	101.6	101.6	254.5	254.5	254.5	254.5	**1,526.0**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Wind	-	-	-	-	68.3	68.1	68.0	125.0	124.3	123.6	123.0	122.2	121.2	120.3	119.3	118.5	117.8	117.0	116.3	116.2	**1,769.1**
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	27.1	31.4	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	**566.5**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	**3.2**
Load Control	-	-	-	0.0	0.0	2.6	4.2	5.9	7.1	7.8	8.3	8.5	8.7	8.7	8.8	9.1	9.0	9.1	9.3	9.5	**116.5**
Retail Pricing	-	-	-	0.2	0.4	1.2	2.0	3.0	4.9	6.3	7.5	7.7	7.6	7.6	7.5	7.5	7.6	7.8	7.9	8.0	**94.7**
Total	**-**	**-**	**-**	**0.2**	**95.8**	**103.3**	**110.4**	**271.8**	**273.7**	**274.6**	**275.1**	**375.5**	**374.0**	**372.5**	**370.4**	**369.4**	**521.0**	**519.9**	**518.9**	**522.1**	**4,075.9**
Grand Total	**0.6**	**2.1**	**4.5**	**207.5**	**438.0**	**647.9**	**756.8**	**1,230.1**	**1,234.6**	**1,238.5**	**1,242.0**	**1,345.9**	**1,350.0**	**1,359.5**	**1,456.0**	**1,601.8**	**1,969.5**	**2,367.3**	**2,678.4**	**3,253.9**	**20,484.9**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

Table 10.49: Portfolio #26: No Climate Commitment Act

Portfolio #26 No CCA Pricing

Washington:	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	-	-	-	-	-	-	-	-	-	-	**198.4**
Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	134.1	**134.1**
Wind	-	-	-	-	131.7	200.0	200.0	100.0	-	-	-	-	-	-	-	140.0	100.0	120.0	100.0	200.0	**1,291.7**
Solar	-	0.5	0.6	0.6	0.7	0.8	0.8	2.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	188.3	112.7	7.0	**319.1**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	93.9	56.1	-	**150.0**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28.8	109.5	**138.3**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.0	**20.0**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94.3	**94.3**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.2	-	209.8	-	-	-	**300.0**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8	**6.8**
Load Control	10.4	-	-	-	-	-	-	-	-	-	-	20.0	-	-	-	-	-	7.5	12.4	-	**50.3**
Retail Pricing	14.2	-	-	-	-	-	-	-	6.0	-	-	-	2.5	-	-	-	-	-	-	-	**22.7**
Total	**24.6**	**0.5**	**0.6**	**0.6**	**132.4**	**200.8**	**200.8**	**300.9**	**6.5**	**0.5**	**0.5**	**20.5**	**3.0**	**0.5**	**90.7**	**140.5**	**310.3**	**409.7**	**310.0**	**571.8**	**2,527.4**

Idaho	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	-	-	-	-	-	-	-	-	-	-	**101.6**
Natural Gas	-	-	-	-	46.5	-	-	-	-	-	-	-	90.2	-	-	-	90.2	46.4	-	-	**273.4**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Wind	-	-	-	-	68.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**68.3**
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Lithium-Ion Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Flow Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Iron Oxide	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
PtoG- Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
RNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2	**3.2**
Load Control	-	-	-	2.8	-	6.6	1.3	-	-	-	-	-	-	-	-	-	-	-	-	-	**10.7**
Retail Pricing	-	-	-	2.6	-	-	4.2	-	-	-	-	-	-	-	-	-	-	-	-	-	**6.8**
Total	**-**	**-**	**-**	**5.4**	**114.7**	**6.6**	**5.4**	**101.6**	**-**	**-**	**-**	**-**	**90.2**	**-**	**-**	**-**	**90.2**	**46.4**	**-**	**3.2**	**362.3**
Grand Total	**24.6**	**0.5**	**0.6**	**6.0**	**247.1**	**207.4**	**206.3**	**402.6**	**6.5**	**0.5**	**0.5**	**20.5**	**93.3**	**0.5**	**90.7**	**140.5**	**400.5**	**456.2**	**310.0**	**574.9**	**2,889.7**

Cumultive Energy Efficiency (aMW)																					
Washington	3.4	7.1	11.2	15.9	19.8	24.1	29.2	34.6	39.8	44.5	49.2	53.6	57.7	61.2	64.5	67.7	70.1	72.8	75.3	77.4	879.1
Idaho	1.1	2.2	3.6	5.2	6.3	7.6	9.3	11.1	12.9	14.5	16.2	17.9	19.4	20.8	22.1	23.4	24.4	25.5	26.6	27.7	297.8
Total	**4.5**	**9.4**	**14.9**	**21.1**	**26.1**	**31.7**	**38.5**	**45.6**	**52.7**	**59.0**	**65.4**	**71.5**	**77.1**	**82.0**	**86.6**	**91.1**	**94.6**	**98.4**	**101.9**	**105.1**	**1,176.9**

11. Action Items

The IRP continues to be an iterative and collaborative process balancing regular publication timelines while pursuing the best resource strategy for the future as the market, laws, and customer needs evolve. The biennial publication date provides opportunities to document ongoing improvements to the modeling and forecasting procedures and tools, as well as enhance the process with new research as the planning and regulatory environment changes. This section provides an overview of the progress made on the 2023 Action Items and details the 2025 IRP Action Items for the 2027 IRP.

2023 IRP Action Items

- Incorporate the results of the DER potential study where appropriate for resource planning and load forecasting.

  The DER potential study included a spatial forecast of electric vehicles and customer owned generation. The study results for additional load and load reductions were included in the long-term load forecast used for resource selection within this IRP. The DER potential study is available in Appendix F.

- Finalize the Variable Energy Resource (VER) study. This study outlines the required reserves and cost of this energy type. Results of this study will be available for use in the 2025 IRP.

  Avista hired Energy Strategies to develop an estimate for capacity reserves to be held by the utility for differing levels of VERs such as wind and solar. With these reserve estimates, Avista was able to calculate the incremental cost of holding these reserves. Furthermore, the reserves were also considered in the capacity planning of the system. Additional information about this study can be found in Chapter 5. The analysis concludes a cost of \$0.15 to \$0.19 per kW-month to integrate existing VER variability on the system, the study evaluated future portfolios with up to 2,500 MW of new wind and/or solar.

- Study alternative load forecasting methods, including end use load forecast considering future customer decisions on electrification. Avista expects this Action Item will require the help of a third-party. Further, studies shall continue the range in potential outcomes.

  For this IRP, Avista utilized Applied Energy Group's (AEG) end use model to estimate future loads. This methodology is critical for modeling potential electrification and efficiency improvements over time. The study was used for the load forecast between 2030 and 2045. This was a drastic modeling change compared to previous methods, highlighting many issues to address in future forecasts, such as weather normalization and how to merge short-term versus long-term forecasting methodologies and incorporating end uses to better estimate *impacts of building electrification. Avista will perform a plus delta review to improve and build upon for the next load forecast.*

- Investigate the potential use of PLEXOS for portfolio optimization, transmission, and resource valuation in future IRPs.

  Avista acquired PLEXOS to test its viability for use in long-term planning. Avista conducted a back-cast to validate performance of the tool. The back-cast found the PLEXOS model can sufficiently model Avista's system and has capabilities other models do not have, such as a more detailed hydro modeling capability. Avista found the tool could be used for resource planning including resource evaluation, capacity planning, and resource adequacy testing. The PLEXOS software comes at the expense of lost customization, added license fees, and additional employee time versus Avista's current modeling methodology. Avista chose not to use PLEXOS during the 2025 IRP for any analysis due to these factors and will continue to use Aurora and internally developed tools for the 2027 IRP.

- Continue to work with the Western Power Pool's WRAP process to develop both Qualifying Capacity Credits (QCC) and Planning Reserve Margins (PRM) for use in resource planning.

  Avista continues to participate in the Western Power Pool's WRAP and continues to include the QCC estimates in this IRP. As the program develops and more information comes from the various studies conducted by Southwest Power Pool (SPP), Avista will follow the progress and incorporate study results as appropriate. In addition, Avista is participating in a regional study performed by E3 where it will simulate regional resource needs to comply with the 100% clean energy goals. Between the WRAP and this regional study, Avista should have QCC for future IRPs.

- Evaluate long-duration storage opportunities and technologies, including pumped hydro, iron-oxide, hydrogen, ammonia storage, and any other promising technology.

  Generic long-duration storage opportunities and technologies were included in this plan as resource options, a discussion of technologies included and can be found in *Chapter 7**. Avista will continue to participate in webinars, consultations with vendors and developers, and participate in other educational forums to follow developments in long duration storage technologies as they develop. Furthermore, Avista anticipates gaining additional information on storage and other related technology specific to our service territory as part of the 2025 all source RFP.*

- Determine if the Company can estimate energy efficiency for Named Communities versus low-income.

  Avista met with its energy efficiency consultant to understand the requirements for dividing energy efficiency savings potential by geographic area. Conducting such a study will require significant data currently not available for individual neighborhoods. Given the expense of developing useful estimates, Avista recommends keeping the current methodology by estimating the low income share of total energy efficiency potential and using these values as a proxy for Named Community potential. Avista still commits to exploring alternative means to estimate energy efficiency on the local level. One option, discussed in Chapter 6, is to validate if energy efficiency could offset the need for system improvements in specific communities when a potential distribution constraint may exist in the future.

- Study transmission access required to access energy markets as surplus clean energy resources are developed.

  As mentioned in Chapter 2 and Chapter 8 of this plan, Avista has an opportunity to explore access to new markets such as Midcontinent Independent System Operator (MISO) and SPP, along with adding capability to southern Idaho resources via upgrading the Lolo - Oxbow line. Avista will continue to evaluate the cost and benefit of these opportunities. Further information regarding transmission can be found in Appendix D.

- Further discuss planning requirements for Washington's 2045 100% clean energy goals.

  Avista is awaiting final rules for the Clean Energy Transformation Act (CETA) as it relates to the "use" of clean energy. Until final rules are approved, Avista is planning its system to generate enough clean energy on a monthly basis to cover Washington load (including losses). Furthermore, the Company is including an hourly analysis based on dispatch of resources in future markets and if the markets do not exist, to identify if it can meet load on an hourly basis in Chapter 2. Another issue regarding the 100% clean energy goal is related to the cost cap and how it will be applied.

2025 IRP Action Items

To prepare for the 2027 IRP planning process, the 2025 Action Plan considers input from Commission Staff, Avista's management team, and members of the IRP Technical Advisory Committee (TAC) regarding additional analysis and further development of projects for inclusion. These action items include both Company actions related to results of this plan and planning items to enhance the 2027 IRP.

Company Actions

- Determine the Northeast CTs retirement date and develop a plan for replacing the lost capacity.

- Pursue transmission expansion opportunities within Avista's service territory and those connecting to Avista's transmission system.

- Develop an all-source Request for Proposal (RFP) in 2025 for the new resources needed to meet future capacity deficiencies and determine if the renewable energy identified in the PRS is cost effective. The RFP will request proposals for demand response opportunities.

- Investigate options to increase natural gas availability and resiliency for existing and potential new natural gas generation without additional natural gas pipelines.

IRP Planning Actions

- Incorporate future policy requirements regarding CETA and/or the Climate Commitment Act (CCA) implementation as directed by the Washington Commission, legislature, or voter initiatives.

- Explore how end use load forecasting should or should not be included in the 2027 plan by reviewing lessons learned from the new load forecast process completed in the 2025 IRP.

- Consider an Integrated System Plan methodology coordinating resource, transmission, and distribution planning to ensure lowest cost plan for both natural gas and electric customers

- Work with the TAC to determine the best strategy for engagement, such as meeting frequency (as experimented in this IRP), along with best available technologies to facilitate communication and data availability.

- Determine Avista's resource need impact of new generation and/or loads within Avista's balancing authority not associated with Avista's load service.

- Incorporate any new Customer Benefit Indicators (CBIs), targets, or directives from the 2025 Clean Energy Implementation Plan (CEIP).

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Washington Clean Energy Action Plan

Introduction

Avista's 10-year Clean Energy Action Plan (CEAP) is the lowest reasonable cost plan of resource acquisition given societal costs, clean energy, and reliability requirement targets over the IRP's 20-year time horizon, including known information and assumptions regarding the future. Avista developed this CEAP in conjunction with its IRP Technical Advisory Committee (TAC) to meet the capacity, energy, and clean energy needs of both Idaho and Washington. The resources described in this CEAP are specific to Washington's portion of Avista's system needs for compliance with the Clean Energy Transformation Act (CETA). This plan describes how Avista will meet the key considerations required by the Washington Utilities and Transportation Commission (UTC). Details regarding the methodology and assumptions for this plan are included in the 2025 IRP. This CEAP is the basis for the 2025 Clean Energy Implementation Plan (CEIP). Table 1[104] illustrates annual resource additions, including demand response (DR) and energy efficiency, for 2026 through 2035.

Table 1: Resource Acquisition Forecast

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Supply Resources (MW)										
Washington Allocated Wind	-	-	-	200.0	200.0	100.0	-	-	-	-
System Allocated Wind (WA share)	-	-	-	-	-	65.9	66.0	103.8	-	-
Distributed Solar	-	0.5	0.6	0.6	0.7	0.8	0.8	1.0	0.5	0.5
Total Resources	**-**	**0.5**	**0.6**	**200.6**	**200.7**	**166.7**	**66.8**	**104.8**	**0.5**	**0.5**
Cumulative Demand Response (MW)										
Battery Energy Storage	0.0	0.1	0.2	0.9	2.5	3.4	3.8	4.3	4.8	5.4
EV Time of Use Rates	0.1	0.3	0.5	0.8	1.1	1.4	1.7	2.0	2.4	2.8
Variable Peak Pricing	0.3	1.0	2.2	3.2	3.7	3.9	3.9	3.9	3.9	3.9
Peak Time Rebate	-	-	-	-	-	-	-	-	-	0.2
Total Demand Response	**0.5**	**1.4**	**3.0**	**4.9**	**7.2**	**8.7**	**9.4**	**10.2**	**11.1**	**12.4**
Cumulative Energy Efficiency										
Energy Savings (aMW)	4.2	8.4	12.6	16.8	21.0	25.2	29.4	33.6	37.8	42.1
Winter Peak Reduction (MW)	8.5	17.0	25.6	34.1	42.6	51.1	59.7	68.2	76.7	85.2
Summer Peak Reduction (MW)	7.1	14.2	21.3	28.4	35.5	42.6	49.6	56.7	63.8	70.9

[104] Energy efficiency savings totals 44.5 aMW when considering savings from line losses.

Avista proposes annually increasing its clean energy target until the 2030 greenhouse gas (GHG) emissions neutral target and then continuing the trajectory adding more clean resources each year toward the 2045 target of 100% clean energy. Table 2 shows proposed target percentages, starting with a 66% clean energy target in 2026 and increasing to 76.5% by 2029, the last year of the 2025 CEIP. The table shows Avista can meet the targets on an annual basis with existing Washington allocated resources through 2033. Attaining clean energy goals beyond 2033 will require using Idaho allocated renewable energy unless new clean energy resources are added. On an annual average basis, with the new resource additions described in this plan, in 2030 and thereafter, Avista's Washington customers will have net clean energy exceeding 100% of its retail load. As discussed in the 2025 IRP, the amount of clean energy generated within a year will exceed clean energy targets for the following reasons:

- Early acquisition of renewable energy to take advantage of lower cost, lower complexity transmission interconnection projects, and the Inflation Reduction Act (IRA) tax credits to lower customer costs compared to building later. Early acquisitions will offset future load growth and later higher renewable energy targets.
- The "use" rules of clean energy are subject to final WUTC determination. It is possible any renewable energy generation exceeding load within a defined period, such as a month or a period of the day and may not qualify as clean energy and therefore requiring additional renewable energy to ensure generation in other periods either for compliance of planning.
- Planning for the 100% clean energy goal in 2045 requires additional clean energy resources for contingency planning in the event of low renewable energy production years and to meet 100% of load rather than "retail" load, where load includes line losses.

Table 2: Clean Energy Load and Resource Balance (aMW)

Item	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Retail Sales	704.9	708.1	709.3	708.4	708.7	709.8	711.9	718.8	727.5	737.1
PURPA	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9
Solar Select	5.7	5.7	5.6	5.5	5.5	-	-	-	-	-
Net Requirement	**678.2**	**681.5**	**682.9**	**681.9**	**682.3**	**688.8**	**691.1**	**697.9**	**706.5**	**716.2**
Target Clean % for Primary Compliance	66.0%	69.5%	73.0%	76.5%	80.0%	80.0%	80.0%	80.0%	85.0%	85.0%
Clean Energy Goal	**447.6**	**473.6**	**498.5**	**521.6**	**545.8**	**551.1**	**552.9**	**558.3**	**600.6**	**608.8**
Washington Allocated Share										
Clark Fork & Spokane River Hydro	297.1	288.5	289.3	296.8	299.2	304.1	305.6	308.6	310.9	312.8
Mid-Columiba and CBH Hydro	159.9	167.2	165.4	165.0	162.2	163.2	164.5	165.6	130.8	131.0
Kettle Falls	23.3	21.1	18.7	17.7	17.8	18.8	17.8	17.5	16.8	16.3
Wind PPAs	86.6	87.0	87.0	87.3	87.3	87.4	87.3	87.6	87.9	88.1
Solar PPA	-	-	-	-	-	5.3	5.3	5.3	5.2	5.2
Available Resources	**566.9**	**563.9**	**560.4**	**566.8**	**566.5**	**578.8**	**580.5**	**584.7**	**551.5**	**553.4**
Position Before Idaho Transfers	**119.3**	**90.2**	**61.9**	**45.2**	**20.7**	**27.7**	**27.6**	**26.3**	**(49.0)**	**(55.4)**
Idaho Transfers (Wind, Biomass, Hydro PPA)	118.6	121.3	119.0	119.0	119.1	142.4	142.2	142.6	142.1	141.7
Position After Available Idaho Transfers	**237.9**	**211.5**	**180.9**	**164.2**	**139.8**	**170.1**	**169.8**	**168.9**	**93.1**	**86.3**
Proposed Wind Additions	-	-	-	75.9	152.0	221.6	253.2	288.2	288.6	289.4
Proposed Solar Additions	-	0.1	0.2	0.3	0.4	0.5	0.7	0.8	0.9	1.0
Total Proposed Clean Energy Additions	**-**	**0.1**	**0.2**	**76.2**	**152.5**	**222.1**	**253.9**	**289.0**	**289.5**	**290.4**
Net Position w/ Idaho Transfers	**237.9**	**211.6**	**181.1**	**240.3**	**292.2**	**392.3**	**423.7**	**458.0**	**382.6**	**376.7**
Net Postion w/o Idaho Transfers	**119.3**	**90.3**	**62.1**	**121.3**	**173.1**	**249.9**	**281.5**	**315.4**	**240.5**	**235.0**
WA Allocated Resources as % Retail Load	84%	83%	82%	94%	105%	116%	121%	125%	119%	118%

Clean Energy Action Plan Requirements

CETA commits Washington to greenhouse gas emission free electricity supply by 2045. RCW 19.280.030 provides requirements for a CEAP and WAC 480-100-620 expanded these requirements for Investor-Owned Utilities. Avista's CEAP meets the following requirements:

A. Be at the lowest reasonable cost;
B. Identify and be informed by the utility's ten-year cost-effective conservation potential assessment as determined under RCW 19.285.040;
C. Identify how the utility will meet the requirements in WAC 480-100-610 (4)(c) including, but not limited to:
    - Describing the specific actions the utility will take to equitably distribute benefits and reduce burdens for highly impacted communities and vulnerable populations;
    - Estimating the degree to which such benefits will be equitably distributed and burdens reduced over the CEAP's ten-year horizon; and

- Describing how the specific actions are consistent with the long-term strategy described in WAC 480-100-620 (11)(g).

D. Establish a resource adequacy requirement;
E. Identify the potential cost-effective demand response and load management programs that may be acquired;
F. Identify renewable resources, non-emitting electric generation, and distributed energy resources that may be acquired and evaluate how each identified resource may reasonably be expected to contribute to meeting the utility's resource adequacy requirement;
G. Identify any need to develop new, or to expand or upgrade existing, bulk transmission and distribution facilities;
H. Identify the nature and possible extent to which the utility may need to rely on an alternative compliance option identified under RCW 19.405.040 (1)(b), if appropriate; and
    a. Incorporate the social cost of greenhouse gas emissions as a cost adder as specified in RCW 19.280.030(3).

A. Lowest Reasonable Cost

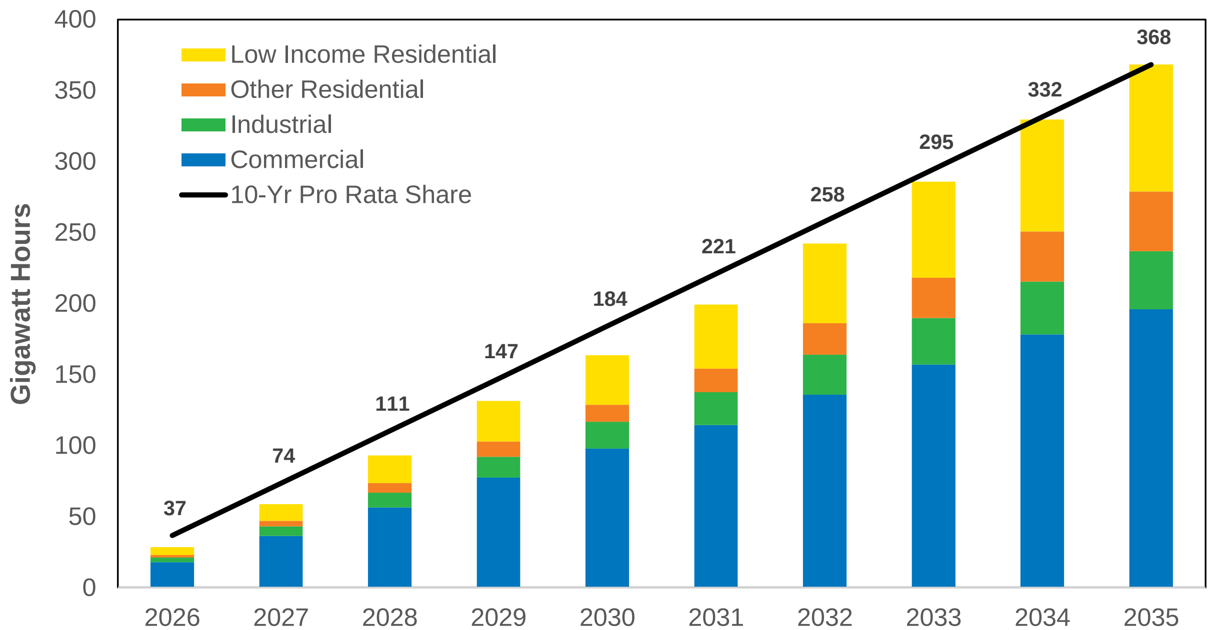
The CEAP is a derivative of the 2025 Electric IRP. The IRP selects the lowest cost resource portfolio given policy constraints, such as available resource types and lower emissions requirements for new resources. A Mixed Integer Program (MIP) optimizes resource options to choose the lowest cost portfolio given resource needs and available options. The model simultaneously selects both supply- and demand-side resources to reach a solution. It also considers transmission costs, availability of resources, and all identified non-energy impacts to evaluate the social cost of different resource choices. Chapter 2 of the 2025 IRP describes the Preferred Resource Strategy (PRS) over the next 20 years and covers the needs for Avista's customers. This CEAP identifies the expected resources for the 2026-2035 period meeting only Washington's policy requirements and needs. Avista currently does not allocate supply-side resources by state. New resources identified in this plan will be allocated to Washington using Avista's Production Transmission (PT) ratio unless a new allocation methodology is developed and approved by each state commission.

B. Energy Efficiency

Avista contracted with Applied Energy Group (AEG) to conduct an independent conservation potential assessment (CPA) of Avista's service area. A summary of the study is in the 2025 IRP's Chapter 6 and AEG's report is available in Appendix C. AEG identified 1,486 programs for both Avista and the Northwest Energy Efficiency Alliance (NEEA) to implement (if cost effective). If all these programs were successfully implemented and customers agreed to fully participate, energy sales would reduce by 903 GWh (103 aMW) through 2035. Not all potential program measures are economic for

Avista's customers. To identify the cost-effective measures for implement, the IRP capacity expansion model conducts a Total Resource Cost (TRC) test of each energy efficiency measure compared to other resource alternatives. The analysis found 368.4 GWh (42.1 aMW) to be cost effective on a cumulative basis if customers participate as forecasted. In addition to the energy savings, peak loads winter peak load is reduced by 85 MW in December and 71 MW lower in the August peak by the end of 2035. Figure 1 shows the annual cost-effective energy efficiency expected for each customer group. Avista's 2026-2027 target is 73,672 MWh

Figure 1: 10-Year Cost Effective Conservation Potential Assessment



C. Equity and Customer Benefits

Equity and incorporating the tenets and principles of Energy Justice, including recognition, procedural, distributive and restorative, are crucial in the transition to clean energy and form the core of the CEAP.[105] The CETA guidelines not only focus on the advantages of energy usage, but also on the benefits and opportunities it brings, including economic growth, social health and safety improvements, and the reduction of GHG emissions benefiting the environment. There is an emphasis on how these benefits are distributed among communities. Utilities are required by CETA to address these topics when planning to acquire resources to minimize unequal access to benefits or disproportionate burden of risks – allowing all customers to share in the benefit and

[105] The Company defines equity as fair and just inclusion, treating all customers fairly, recognizing that each person has a unique circumstance, and allocating resources and opportunities in a manner which achieves an equal outcome.

burden. Specifically, CETA requires all customers to benefit from the transition to clean energy:

> "through (i) the equitable distribution of energy and nonenergy benefits and reduction of burdens to vulnerable populations and highly impacted communities, (ii) long-term and short-term public health and environmental benefits and reduction of costs and risks; and (iii) energy security and resiliency."[106]

CETA also has a strong public participation focus to ensure customers and communities can provide input on clean energy decisions. While not specifically defined as "energy justice tenets," the nature of CETA requirements align with the definition of energy justice, which is as follows:

> "Energy justice refers to the goal of achieving equity in both the social and economic participation in the energy system, while also remediating social, economic and health burdens on marginalized communities. Energy justice explicitly centers the concerns of frontline communities and aims to make energy more accessible, affordable, clean and demographically managed for all communities."[107]

These requirements create a broader consideration of benefit types, increase input of interested parties regarding equity issues, and promote continuous progress for resource evaluations and the overall delivery of the energy system within the traditional planning process. To ensure Avista is effectively planning for equitable outcomes, the four tenets of energy justice – recognition, procedural, distributive, and restorative – are included in the development of the CEAP and selection of resources.

Recognition Justice

Recognition justice primarily focuses on whose energy service has been, or is currently, impacted in a disproportional manner. It is primarily concerned with the historical context and seeks to understand how previous actions or policies have resulted in disproportional outcomes. This "… requires an understanding of historic and ongoing inequalities and prescribes efforts that seek to reconcile these inequalities."[108]

A key aspect of CETA includes a focus on Named Communities. These communities are either socially or economically disadvantaged or sensitive to environmental impacts on their health. Avista incorporated recognition justice into the IRP and CEAP through its

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[106] RCW 19.405.060(1)(c)(iii).

[107] Shalanda Baker, Subin DeVar, and Shiva Prakash, "The Energy Justice Workbook" (Boston, MA: Initiative for Energy Justice, December 2019), https://iejusa.org/wp-content/uploads/2019/12/The-Energy-Justice-Workbook-2019-web.pdf.

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[108] Final Order No. 09 in UG-210755, paragraph 56.

work on the Named Community mapping tool. These maps overlay the Washington State Department of Health (DOH) Environmental Disparities map of Avista's Washington service territory. In addition, the White House's Justice 40 Initiative map, identifying community burdens in the areas of climate change, energy, health, housing, legacy pollution, transportation, water and wastewater, and workforce development, was incorporated. These maps provide insight for identification of communities who may have, or continue to, receive a disproportionate benefit or burden. This is more fully described in the "Named Community Identification" section below.

Beyond a contextual understanding of disparities, recognition justice also validates lived experiences, encourages constructive dialogue regarding methods for addressing inequities, and ensures new policies do not exacerbate existing situations or create unintended consequences. The Equity Advisory Group (EAG) was established in 2021 to support these efforts. The EAG members have been instrumental in validating inequalities in known Named Community areas and identifying additional communities or individuals who have or are experiencing disparities within Avista's Washington service territory. Through conversations with the EAG, public outreach and engagement efforts, Avista began incorporating recognition equity into its planning efforts.

Procedural Justice

Procedural justice focuses on impartial, accessible, and inclusive decision-making. Incorporating procedural justice into the IRP and CEAP process involves ensuring all interested parties, especially those from Named Communities, have meaningful opportunities to provide input to the decisions impacting them.

Throughout the IRP and CEAP's development, Avista promoted procedural equity in a variety of ways:

- Engaged several advisory groups and encouraged participation in the areas of equity, energy efficiency/demand response, energy assistance, resource planning and the IRP's TAC, and Distribution Planning Advisory Group (DPAG).
- Modified the TAC meeting's frequency and duration based on feedback from participant's feedback.
- Reviewed and modified presentations to ensure more use of common language (non-technical) where possible.
- Recorded presentations for ease of access at later dates/times.
- Posted IRP calculation workpapers to provide transparency.
- Posted presentations several days before meetings to provide more time to develop questions and share concerns.
- Developed CBIs informing resource selection in consultation with the EAG and reviewed publicly with the TAC.
- Ensured participation from customer advocates to represent customers who may not be able to attend.

- Evaluated baseline CBIs in relation to resource planning to track progress, recognize, and acknowledge there are disparities and to support transparency in Avista's actions and impacts.
- Enabled language translation and closed captioning on the Zoom platform for public participation meetings.
- Posted input received from public meetings to support transparency of feedback.

Avista's Public Participation Plan (PPP)[109] informed tactics and strategies to facilitate meaningful engagement. The PPP supports broad representation from interested parties and customer advocates, providing additional opportunities for identifying and considering policies or procedures going forward.

Distribution Justice

Distribution equity in the IRP and CEAP pertains to the allocation of advantages and disadvantages of interim clean energy goals and targets and ensures they are allocated between different communities or across generations. It not only focuses on the actions taken but also on the communities affected, considering variations among them, such as between Named Communities and the general customer base.

The foundation of energy equity emphasizes identifying benefits going beyond traditional energy-related benefits. In IRP modeling, resource selection is based on either a constraint (forcing an action) or a financial driver (cost or benefit) to incentivize resource selection. Recent IRP's resource selection used additional modeling of non-financial benefits, or Non-Energy Impacts (NEIs), to highlight the interconnectedness of economic, social, and environmental issues from resource selection.

To measure the distributional impacts of resource selection, CBI metrics are monitored. The CBIs are designed to provide a transparent, consistent, and measurable way to track progress and ensure accountability in equity areas including affordability, accessibility, reliability, and environmental impacts. The inclusion of CBIs in resource modeling may not fully inform economic resource selection, as the cost may exceed the financial benefits, or may negatively impact a CBI metric. For example, affordability may be negatively impacted if there is an increase in distributed energy resources (DERs). Avista included an IRP scenario to maximize all CBIs regardless of the cost to the system. This Maximum Customer Benefit scenario is described in Chapter 10 of the IRP. A forecast of CBI changes relevant to this plan and the full 20-year IRP are discussed later in this document.

Avista's approach to distributional justice and energy equity is comprehensive and multifaceted. By focusing on CBIs and NEIs, and addressing affordability, accessibility,

[109] See Docket No. UE-210295 for Avista's 2021 Public Participation Plan and Docket UE-210628 for its 2023 Public Participation Plan.

reliability, and environmental sustainability, Avista aims to ensure the transition to clean energy is just, inclusive, and beneficial for all customers. See information below for more about CBIs and their associated metrics.

Restorative Justice

Restorative justice focuses on systematic approaches to prevent harm from occurring or continuing in the future. Striving to minimize disparities between Named Communities and all customers, particularly in relation to areas of affordability, availability, and accessibility, amongst others. Avista incorporates restorative equity in the following ways:

- **Climate change impacts**: The CEAP includes consideration for future weather impacts in the load and hydro forecast. Avista also accounts for the Social Cost of Greenhouse Gas (SCGHG) in resource decisions as directed by CETA.
- **Energy Efficiency efforts**: Energy efficiency provides significant value in support of clean energy goals and as a method for restorative equity. By supporting more energy efficiency in Named Communities, Avista provides opportunities to mitigate disparities. As previously mentioned, "fairness" is the act of being fair, impartial, and just. Through these additional energy efficiency efforts, Avista is essentially meeting customers where they are – seeking to "close the gap" in disparities.
- **Named Community Investment Fund (NCIF)**: Avista created the NCIF to fund projects for customers in Highly Impacted Communities or from Vulnerable Populations, jointly referred to as Named Communities. This approximately $5 million annual fund enables energy and non-energy projects for these communities where they may not be able to complete or fund on their own. Avista accounts for these energy impacts in the CEAP by including an additional $2 million of annual energy efficiency spending for Named Communities in the energy efficiency target. Further, it includes an additional spending requirement for local DERs as a placeholder for future NCIF selected projects. These investments in Named Communities will influence local economic development and provide specific opportunities for people in these communities.

Achieving equity in Washington's clean energy transformation is not limited to IRP/CEAP planning. A broader, Company-focused effort is being made to ensure an equitable transition – one that is fair, impartial, and provides opportunities for all customers regardless of their unique circumstance. Avista has several efforts in progress to help incorporate equity throughout Avista's operations. These efforts include an equity focus on capital planning, energy efficiency and weatherization, affordability, and distribution planning.

Challenges to Implement Energy Equity Tenets

While Avista has taken several steps to incorporate energy equity tenets throughout its resource planning efforts, challenges remain regarding these efforts. The Company briefly discusses these challenges below and will provide additional details pertaining to specific actions to overcome these challenges and identified inequities in its Clean Energy Implementation Plan (CEIP). Incorporating equity tenants and implementing strategies to address inequities is not a one-and-done activity but is an iterative improvement process as Avista continues to engage with the communities it serves. Avista will consider the equity impacts of business decisions, and where feasible or practical to benefit all customers, implement equity-related improvements. Operationalizing equity and energy justice principles – moving from theory to practice – has inherent challenges including, but not limited to, the following:

Data availability and quality

Obtaining accurate data on energy usage, demographics, and socio-economic factors is crucial. In many areas, such data may be incomplete, outdated or only available through a third-party, making it difficult to identify and address disparities.

> ***Specific Action:*** *To improve data availability and quality, where possible, Avista contracts with a third-party data provider for personal identifiable information such as income, if they rent or own a home, age, marital status, etc., and match that data with internally available customer data. To enhance data integrity and accuracy, Avista has improved data collection and validation efforts for CBI reporting and other metric obligations through a centralized data analytics team. Further, the Company recognizes there is a need for accurate, complete data which is consistent across all business units.*

Engaging interested parties

Effective outcomes require collaboration among all interested parties, beyond those who have historically participated in how Avista generates and delivers energy now and into the future. Directly engaging customers or advocates on their behalf is often difficult due to several factors, including having a desire to participate, or the ability to participate based on existing priorities and resource constraints within external organizations.

> ***Specific Action:*** *To mitigate public awareness barriers, Avista hosts quarterly public participation meetings, provides social media campaigns to increase public meeting awareness, attends and participates in community engagement events, and contracts with a third-party to deploy customer engagement strategies and improve outreach effectiveness. Additionally, Avista is developing videos to support its clean energy initiatives to broaden awareness and increase customer participation. The Company continues to include its EAG in conversations regarding methods for contacting “hard to reach” customers and those in Named Communities. Although the Company has an obligation to promote awareness and conduct engagement efforts in good faith, a decision to participate in the activities must come from the customer or the advocacy groups. Avista's 2025 Public Participation Plan, due by May 1, 2025, will outline specific actions to overcome barriers to customer engagement and participation.*

Funding and Resources

Implementing equity-focused initiatives often requires significant investment. Limited funding can hinder the development, operation and awareness of programs supporting Named Communities.

> ***Specific Action:*** *In the Company's 2022-2025 CEIP, Avista implemented its Named Community Investment Fund (NCIF), spending up to $5 million annually for direct investments in Named Communities, including investments in resiliency and additional energy efficiency. In addition, Avista has expanded its Low-Income Rate Assistant Program (LIRAP) to include a tiered bill discount program, known as My Energy Discount, an Arrearage Forgiveness Program, and an Arrearage Management Program, all with the intention of reducing energy burden and making energy service more affordable. Avista is actively working on ways to increase participation in these energy assistance programs and on continued investments in Named Communities.*

Technical Expertise

Customers may want to participate to a greater extent in resource planning Technical Advisory Committee (TAC) meetings; however, due to the technical nature of long-term system planning and inherent complexities, do not feel they have the skillset to do so.

> ***Specific Action:*** *Avista recognizes the IRP TAC process is highly technical in nature with complex terminology and lengthy meeting times. To reduce meeting fatigue, the Company pivoted from half day meetings once a month, to shorter meetings every two to three weeks during the planning phase. Additionally, various components of the Company's IRP are discussed throughout the CEIP public participation meetings where the language and discussion topics are shared using customer friendly terminology, instead of technical verbiage that is used during the TAC meeting process. Overcoming technical barriers is broader than a single Company's specific action and will take a collaborative approach between utilities, the Commission and its Staff, customer advocate groups, and other interested parties.*

Named Community Identification

Avista identified communities who are disproportionally impacted by adverse socioeconomic conditions, pollution, and climate change, among others, to ensure planning and implementation processes are fair and to equitably distribute clean energy transition benefits. Avista identified two types of community groups, Highly Impacted Communities and Vulnerable Populations (WAC 480-100-605), or collectively Named Communities, defined as follows:

- **Highly Impacted Community** is designated by the Washington Department of Health (DOH) based on cumulative impact analyses in section 24 of this act or a community located in census tracts that are fully or partially on "Indian country" as defined in 18 U.S.C. Sec. 1151.12.

- **Vulnerable Populations** are communities experiencing more risk from environmental burdens due to:
  - Adverse socioeconomic factors, including unemployment, high housing and transportation costs relative to income, access to food and health care, and linguistic isolation; and
  - Health sensitivity factors, such as low birth weight and higher rates of hospitalization.

Avista relies on information provided by the Washington State Health Disparities Map from the DOH to identify Highly Impacted Communities. For each census tract in the state, the DOH developed a score to measure disparities ranked between 1 and 10 for Environmental Exposure, Environmental Effects, Socioeconomic Factors, and Sensitive Populations. Communities where the combined average score of the four categories was nine or higher are considered Highly Impacted Communities. The DOH also includes any areas fully or partially within “Indian Country”.[110]

In Avista’s 2021 CEIP, its methodology to determine Vulnerable Population characteristics was conditionally approved.[111] The EAG and other advisory groups helped Avista determine the geographic boundaries of Vulnerable Populations for the 2021 CEIP by using the Health Disparities Map[112] community rating system for Socioeconomic Factors and Sensitive Population. The maps identify areas on a scale of 1 to 10, where 10 is an area with the most significant health disparity. Avista focused on identifying census tracts not otherwise identified as a Highly Impacted Community whose socioeconomic factor or sensitive population score was 9 or 10. This methodology was conditionally approved contingent upon the incorporation of additional metrics as identified by Avista and the EAG. The criteria for determination of Vulnerable Populations (as developed by DOH) was reviewed to ensure these socioeconomic or sensitivity factors applied specifically to Avista’s customers. Beyond inclusion of those indicators, additional collaboration with its EAG members resulted in a review of other traits that could be considered in the final determination of Avista’s Vulnerable Populations. Avista also overlayed the Justice40 map of disadvantaged communities on its Named Community map to provide additional insights into challenges within its service territory. The Justice40 map provides a more in-depth look at indicators that are directly impacted by the energy industry. In combination, these maps provide an opportunity to further improve recognition justice, as well as monitoring, tracking and allocating resources to help ensure equity through energy transformation.

[110] The DOH’s list of Highly Impacted Communities originally included areas misidentified as “Indian” country due to GIS borderline errors. Avista excluded these census tracts from its list for this report.
[111] Docket No. UE-210628.
[112] https://fortress.wa.gov/doh/wtnibl/WTNIBL/Map/EHD

The maps of both types of Named Communities are shown in Figures 2 through 4 below. Avista is working with the EAG to determine other ways to identify Vulnerable Populations.

Figure 2: Washington Service Area Named Communities

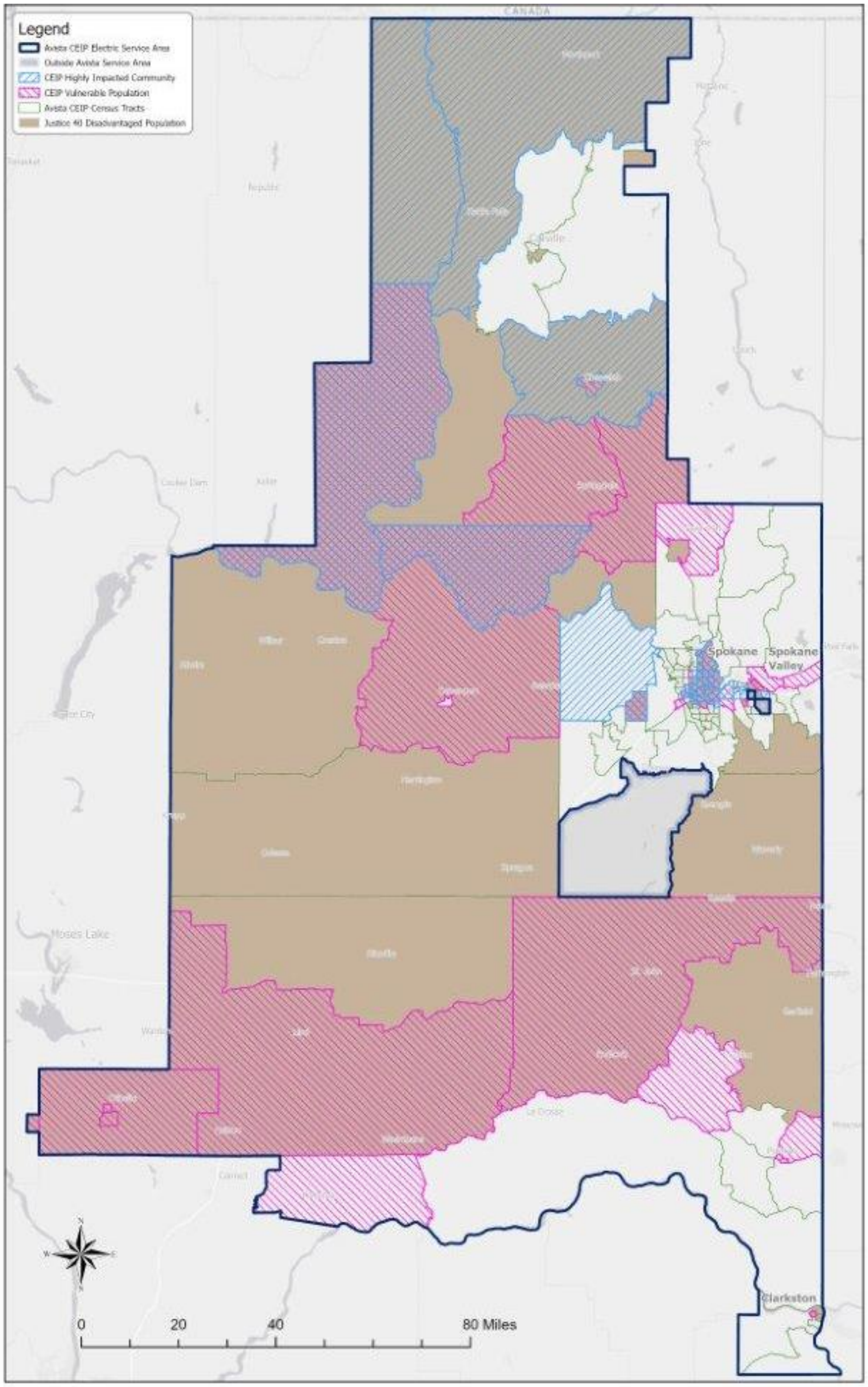


Figure 3: Spokane Named Communities

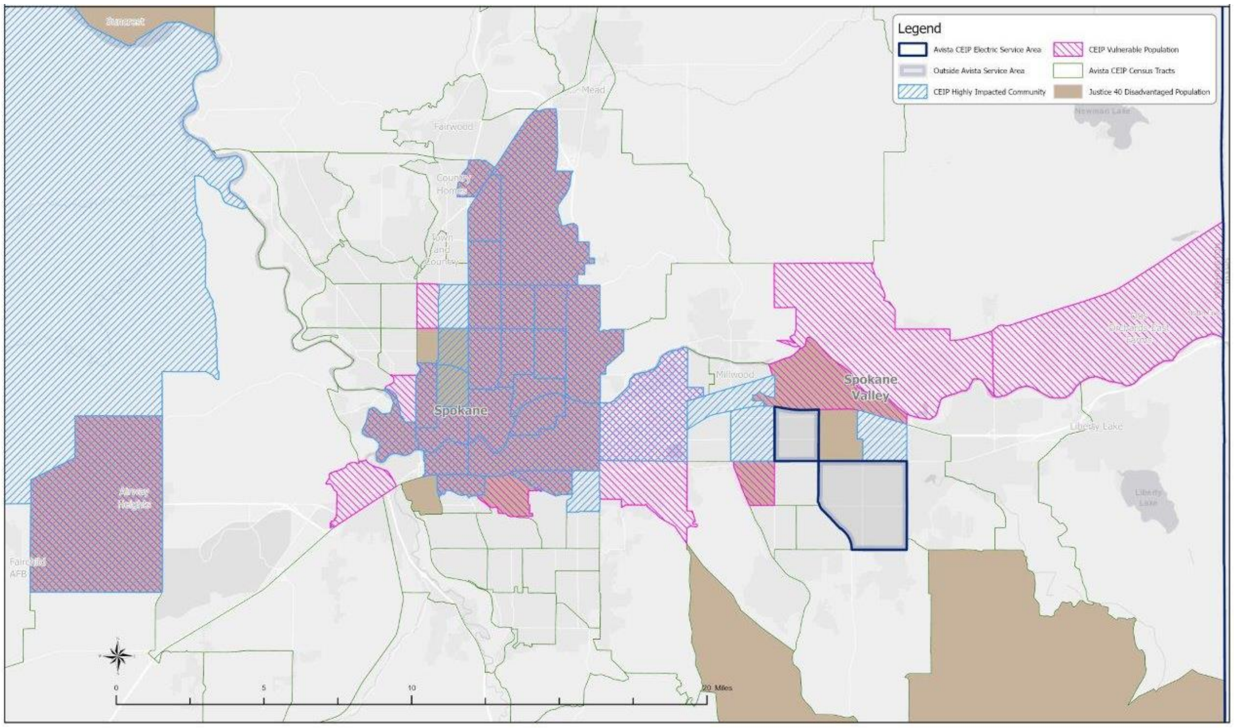
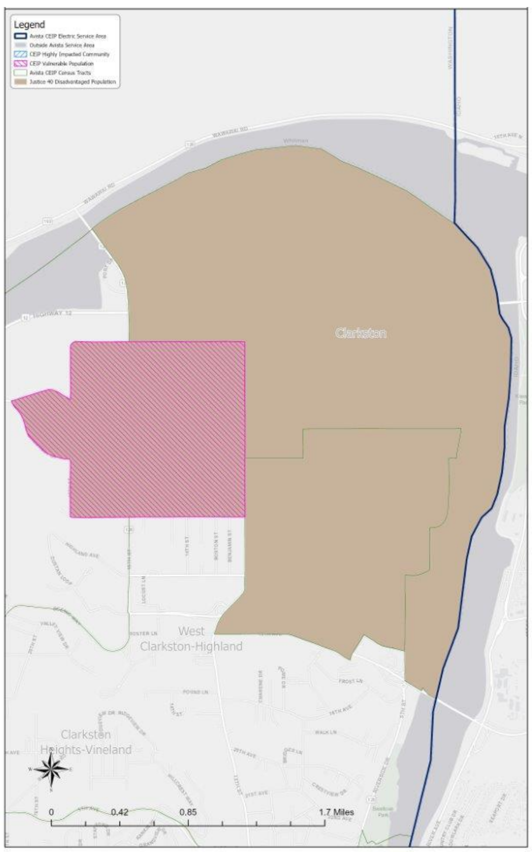


Figure 4: Clarkston Area Named Communities



D. Resource Adequacy

Avista must maintain enough resources to reliability serve current and future customers. Planning an electric system using a geographic footprint greater than a single utility take may take advantage of load and resource diversity of load and resources of other utilities. To address this, Avista is participating in the development of Western Power Pool's Western Resource Adequacy Program (WRAP)[113]. Participation in regional resource adequacy efforts is important because Avista can benefit from the diversity and availability of other utilities resources, resulting in deferring the need for new resources. Until the WRAP is operational and binding, Avista continues to use its own planning standard of ensuring a 5% Loss of Load Probability (LOLP) including the ability to access 330 MW of market power. This LOLP planning standard results in a 24% planning margin added to the 1-in-2 peak load forecast, positioning Avista to withstand energy uncertainties. For summer planning, Avista uses the size of its single largest contingency resource (Coyote Springs 2) to determine the summer planning reserve margin, this results in a metric of 16%.

The 2025 IRP included an analysis of Avista's resource position in 2030 and finds with the current resources and projected retirements to cover both Washington and Idaho load, the system will not meet the resource adequacy requirement. With the resources identified in this CEAP for Washington, combined with additional resources needed for Idaho customers, the system would be resource adequate. These additional resources include a 90 MW natural gas-fired Combustion Turbine (CT), energy efficiency, and DR programs. With these additions, the system is resource adequate in 96.8% of future weather conditions (above the 95% threshold) assuming 330 MW of market reliance. In 3.2% of future scenarios where resource adequacy is not met, Avista would be dependent on the energy market or load curtailment beyond the 330 MW threshold. While the CEAP is directed at resource decisions for Washington, the resources needed for Idaho directly affect Washington due to the unique position where resources are allocated to each state using the production transmission (PT) ratio as opposed to which state's need drives the resource as modeled in the IRP. When Avista acquires resources, regardless of the primary driver, both states share the benefits and the costs using a pre-approved allocation methodology through the PT ratio. Avista will need to issue a Request for Proposal (RFP) of at least 90 MW of winter capacity with on-line delivery by the winter of 2029/2030 to maintain a reliable system. The new capacity addresses load growth, expiration of a long-term PPA, and the potential retirement of the Northeast CT. However, based on the circumstances of these factors this resource need could change.

[113] The WRAP is currently operated by the Southwest Power Pool (SPP) on the behalf of WPP.

E. Demand Response & Load Management Programs

Avista and a large industrial customer agreed to a 30 MW DR program after the 2021 IRP. Following the 2021 CEIP, Avista began multiple DR pilots including an electric Time of Use (TOU) rate for residential and commercial customers, a Peak Time Rebate (PTR) for residential customers, and a partnership with NEEA to test grid-enabled CTA-2045 water heaters.[114] The 2025 IRP includes a biennial assessment of the DR potential programs within Avista's service area conducted by a third-party – Applied Energy Group (AEG). The potential assessment identified 101 MW of potential winter peak savings could be realized by 2035 if all programs were started by 2026. However, similar to the energy efficiency potential, not all programs are cost effective. Further, DR programs should only be implemented when the utility has a capacity need. In some cases, programs are cost effective within the plan, but not within every year of the 20-year study. Overall, nine programs within the 20-year plan are selected, but only four programs within the first 10-years of the plan. A summary of these programs and their expected peak savings is shown in Table 3. As behavioral DR programs are designed to affect energy usage behavior during peak usage events, it is nearly impossible to measure total program savings and the amount of customer load changes.

Table 3: Cumulative Demand Response (MW)

Year	Battery Energy Storage	EV Time of Use Rates	Variable Peak Pricing	Peak Time Rebate	Total Demand Response
2026	0.03	0.09	0.35	-	0.47
2027	0.10	0.30	1.00	-	1.40
2028	0.24	0.54	2.19	-	2.97
2029	0.92	0.80	3.17	-	4.89
2030	2.47	1.06	3.70	-	7.23
2031	3.44	1.35	3.88	-	8.67
2032	3.83	1.68	3.92	-	9.43
2033	4.28	2.02	3.92	-	10.22
2034	4.75	2.41	3.93	-	11.09
2035	5.39	2.85	3.95	0.20	12.38

[114] According to the Customer Technology Association (CTA), the CTA-2045 standard is a modular communications interface to facilitate two-way communications with residential devices for energy management.

F. Clean Energy Acquisitions

The 2025 IRP identifies multiple clean energy additions including community solar and utility scale wind. Currently, Avista is not proposing non-emitting electric generation (energy storage) unless capacity needs change due to unexpected load growth or generation capability/availability changes. The selected resources within the PRS will contribute to meeting the clean energy standards of CETA and provide minimal resource adequacy capacity to the system. While the assigned Qualifying Capacity Credits (QCCs) are relatively small for meeting peak load, one exception is Montana wind. Although, if there is a future downward QCC revision based upon recent cold weather performance, Avista may need a traditional capacity resource.

Avista's system capacity need by 2035 is estimated to be 225 MW for winter peak and 155 MW for summer peak, while the capacity need for its Washington portion of the portfolio is estimated to be 107 MW for winter peak and 93 MW for summer peak (prior to the DR selections covered earlier in this plan). As discussed earlier, Avista currently does not have an allocation methodology outside of the PT ratio for cost recovery of assets using a fixed ratio. This results in the 2025 IRP assuming a greater resource need for Idaho over Washington due to less PURPA generation and DR within the Idaho jurisdiction, even though Washington load is larger. Until an agreement is reached regarding resource allocation, the new resources resolving these deficits will continue to be split using the existing cost recovery methodology rather than the IRP methodology.

Community Solar

Avista's 2025 IRP includes a placeholder for community solar ranging from 0.5 MW to 1 MW annually. The forecasted first addition begins in 2027 utilizing grants from the Department of Commerce and Avista's NCIF. Within the CEAP time horizon, a total of 5.9 MW of distributed solar could be installed, contributing 0.2 MW to winter and up to 1.8 MW toward summer resource adequacy. Depending on location, grant availability and need, energy storage could also be added to the final resource configuration. To ensure the best locations and needs are met, this CEAP is not prescriptive about how solar will be added to the system but will seek the best use of available grant funds in achieving energy burden reductions. Avista will continue its community solar development efforts and may provide a proposal in its 2025 CEIP.

Wind

Over the 10-year CEAP period, as seen in Table 4, 736 MW (257 aMW) of wind is selected for Washington in the 2025 IRP. Including Idaho, total system wind additions are 857 MW. Wind resources selected by the planning model includes wind within Avista's service area, on Montana and other transmission systems. Procuring wind early in the planning horizon makes this resource more economic due to low wind PPA pricing forecasts, the availability of tax incentives from the Inflation Reduction Act (IRA), and high forecasted wholesale electric prices allowing the use of surplus energy sales to reduce customer costs. However, if the tax credits were not available, wind selection would occur later in the planning horizon, closer to the energy needs of the system.

The actual amount of wind over the CEAP period is subject to multiple risks and may be reduced and/or delayed as a result of transmission access or changes in energy markets. While Avista's service area has significant wind potential, the ability to interconnect and deliver the wind to customers is limited without major transmission investments. If other utilities or developers export projects from Avista's transmission balancing area, Avista's ability to acquire low-cost wind projects for its customers will be limited until new transmission can be built.

Table 4: Wind Selections (MW)

Year	Washington Allocated Wind	System Allocated Wind (WA share)
2026	-	-
2027	-	-
2028	-	-
2029	200	-
2030	200	-
2031	100	66
2032	-	66
2033	-	104
2034	-	-
2035	-	-
Total	**500**	**236**

As mentioned earlier, Avista is not proposing any GHG-emitting resources or energy storage to directly serve Washington due to the wind, DR, and energy efficiency additions contributing to the additional resource adequacy needed to meet load growth.[115] For the wind additions, the total QCC is small compared to the total wind capacity, but it does satisfy most of the resource need meeting 63 MW toward the winter and 74-83 MW toward the summer resource adequacy metrics. However, wind does have a significant risk of not performing in severe cold and excessive heat. Regardless of contribution to capacity needs, relying on wind for resource adequacy creates risk to customers. As regional resource adequacy planning matures through the WRAP process in the WECC, energy storage may enter the resource need assessment to account for any lost capacity formally attributed to wind energy.

[115] Avista does not model jurisdiction reliability metrics due to the system functions as one. It is possible without the 90 MW CT allocated to Idaho, the Washington portion of resources is not adequate if only Washington load and resources were available.

Resource Acquisition

The wind acquisitions discussed in this plan will be managed through a request for proposal (RFP) process. An all-source RFP is likely to be issued in 2025 to evaluate all resource options to meet specific energy and capacity requirements. Through this process, Avista may find an alternative to wind energy such as acquiring more regional hydroelectric generation, a combination of solar and energy storage, or a different wind source than included in this plan. Furthermore, the RFP may show the cost of new wind generation is not economic due to higher net customer costs, resulting in delayed acquisition.

The RFP process will also be combined with meeting system needs (i.e., Idaho) where other capacity resources such as natural gas, energy storage, or DR aggregation could be considered for meeting either the Washington or Idaho portion of system load. Based on information in this plan, and subject to changes due to load and resource availability, the all-source RFP will seek 116 MW of winter capacity by November 2029 and 125 aMW[116] of renewable energy as early as 2029. Avista's RFP release will provide specific requirements subject to updated information once this IRP process is finalized.

G. Transmission & Distribution

Avista is planning significant changes to its transmission system over the next 10 plus years to enable access to energy markets and to integrate new resources. Large transmission development exceeds the planning horizon of this CEAP and often changes over time. The transmission projects under consideration are included in this plan, but not all are committed.

10-Year System Planning

Avista's system planning team develops a detailed 10-year System Plan and System Assessment with updates every two years. The System Assessment covering local planning, was released in November 2023, followed by the System Plan in February 2024. Both plans are in Appendix D.

The 10-year System Plan shows Avista's strategy to develop system reinforcements required to meet transmission system needs for load growth, adequate transfer capability, requests for generation interconnections, line and load interconnections, and long-term firm transmission service. The two-year System Assessment provides technical analysis demonstrating system performance and describes conceptual solutions to mitigate operational issues to maintain expected performance.

[116] Renewable generation is preferred between July and March as the other months typically have excess renewable energy from hydroelectric production.

Blue Bird – Garden Springs 230 kV Project

Avista's system planning through the 10-year assessment identified transmission system needs for load growth across the south and west of Spokane. Studies show system operability is strained and results in reduced system flexibility, affecting safety, system resiliency, and ultimately service to customers. Continued load growth will amplify this situation.

The Blue Bird - Garden Springs 230 kV project was identified as the backbone segment of a broader West Plains Transmission Reinforcement project. The project's primary goal is to develop a new and independent 230 kV source west of Spokane. This goal will be addressed by sourcing 230 kV from BPA Bell - Coulee #5 230 kV Transmission Line to improve contingency performance and to increase system stability. The new 230 kV source will provide the required reliability and operational flexibility needed to serve current and forecasted loads.

An additional benefit of developing a new and independent 230 kV source west of Spokane is the increased transmission service capability this project is expected to bring. The location of this new 230 kV connection is anticipated to increase power transfer capability between Avista and BPA by 10-30% depending on the season.

North Plains Connector

The 2025 IRP evaluated a proposed regional transmission project to connect the Western and Eastern Interconnects. The project is developing a 3,000 MW capacity DC line between Colstrip, Montana and North Dakota with an on-line date of 2033. The end points in North Dakota would give Avista access to both the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) markets to buy or sell power and provide access to generation resources in the mid-continent with different weather patterns. Avista studied this project in the IRP as a capacity only resource for resource adequacy to validate if the project cost could be justified based on this portion of the benefit.[117] An additional significant benefit is energy arbitrage by taking advantage of higher or lower prices in other markets and the Mid-Columbia market. These arbitrage benefits were not evaluated in the IRP as the analysis was still being conducted during the development phase. The capacity benefits from market access indicates participating in at least 300 MW of capacity from the North Plains Connector is beneficial to customers and was included in the 2025 IRP. If this project can be completed by 2033, it could replace capacity resources identified in the 2025 IRP's portfolio scenario analysis. Avista has not committed to this project but is actively following its progress and studying potential participation.

[117] The IRP analysis was conducted prior to the announcement by the DOE to allocate a $700 million Grid Resilience and Innovation Partnership (GRIP) grant to the project.

Colstrip Transmission System Upgrade

Avista and the other owners of the Colstrip Transmission System are evaluating upgrades to the existing 500 kV transmission lines and supporting its 230 kV and 115 kV infrastructure. These upgrades would increase power transfers out of Montana by approximately 900 MW. The purpose of this study is to better identify the simultaneous increases in transfer capability across the Montana to the Northwest and West of Hatwai WECC rated paths. Montana to Washington 500 kV transmission system upgrades were last studied by NorthWestern, BPA, and Avista in May 2012, as part of the Colstrip to Mid-Columbia Upgrade Project Study.

Lolo-Oxbow Upgrade and Optimization

Avista, as a prime recipient, in partnership with Idaho Power Company, is seeking grant funding for the Lolo - Oxbow Transmission Upgrade and Optimization project. This project will upgrade the Lolo - Oxbow 230 kV Transmission Line with high-capacity conductors, as well as wildfire resilient designs and materials. Additionally, the project includes integrating Idaho Power's new Pallette Junction Station and two SmartValve technology deployments. These improvements will increase interregional transfer capability by 450 MW between the Pacific Northwest and Mountain regions, presenting an opportunity to increase the build of renewable energy resources in the region.

The Lolo - Oxbow Upgrade and Optimization project would bring innovative technologies together resulting in improvements to interregional transfer capability by 450 MW from Avista to Idaho and up to 185 MW in the opposite direction. The two innovative technologies planned for this project are:

3) SmartValve technology that opens the door to dynamically controlling and optimizing power flows, and
4) Infravision technology that speeds transmission line construction with drone pull-line stringing instead of helicopter use.

The local communities and region would benefit from capacity upgrades enabling future generation interconnection opportunities to the Lolo - Oxbow 230 kV Transmission Line. If awarded, there will be community benefit funding available for up to $3.3 million. Additionally, through these upgrades, Avista will work towards further workforce development in energy-supportive roles, such as on-site equipment training, special operator training, and other job skill opportunities.

New Resource Interconnection

New resources may require an interconnect and additional reinforcements elsewhere in the system. When evaluating generic resources in the IRP, estimated costs are assigned to these resources as a placeholder for potential upgrades, but until specific resources are committed, the transmission upgrades are unknown. Further, the IRP identifies if there is not enough local capacity within an area where it is likely new resources would be located. Avista identified upgrades in Rathdrum, Idaho as a necessary improvement if additional generation capacity is chosen in northern Idaho. When Avista evaluates projects within the RFP process, it ensures projects are progressing through the transmission cluster study process to confirm the project is deliverable to the system within necessary timelines. The cluster study process outlines the necessary system upgrades, construction timing, and costs to integrate proposed resources and the studies can be found on the Avista's transmission (OASIS) website.[118]

H. Alternative Compliance & Social Cost of Greenhouse Gas

Beginning in 2030, Avista's Washington electric retail sales must be greenhouse gas neutral, this means up to 20% of Washington's retail load can be offset with alternative compliance.[119] There are four main types of alternative compliance:

1. Compliance payment
2. Unbundled Renewable Energy Credits (RECs)
3. Investing in transformation projects
4. Using energy from a municipal solid waste facility[120]

To make progress toward the 2045 target, Avista assumes the amount of alternative compliance allowed will be lower each compliance period with 20% allowed for the 2030-2033 period and 15% between 2034 and 2037. Avista plans to use unbundled RECs or excess clean energy it controls to meet the 2030 neutral standard. Avista has access to three types of unbundled RECs:

1. RECs from excess energy beyond what will count toward "primary" compliance under the final clean energy "use" rules,
2. Renewable energy Avista owns and is allocated to Idaho customers, and
3. RECs purchased on the open market. (absent a federal or state law requiring retirement of those RECs).

Avista will have significant RECs available from Idaho to sell to Washington customers at market prices. Table 5 is an estimate of the amount of alternative compliance Avista could utilize to meet the 2030 carbon neutral requirements.

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[118] (Open Access Same-Time Information System), https://www.oasis.oati.com/avat/index.html.
[119] RCW 19.405.040 (1)(b).
[120] Using electricity from an energy recovery facility using municipal solid waste as the principal fuel source, where the facility was constructed prior to 1992, and the facility is operated in compliance with federal laws and regulations and meets state air quality standards. An electric utility may only use electricity from such an energy recovery facility if the department and the department of ecology determine that electricity generation at the facility provides a net reduction in greenhouse gas emissions compared to any other available waste management best practice. The determination must be based on a life-cycle analysis comparing the energy recovery facility to other technologies available in the jurisdiction in which the facility is located for the waste management best practices of waste reduction, recycling, composting, and minimizing the use of a landfill.

Table 5: Alternative Compliance

Year	Alternative Compliance Percentage	Retail Load (aMW)	Maximum Alternative Compliance (aMW)
2030	20%	682	136
2031	20%	689	138
2032	20%	691	138
2033	20%	698	140
2034	15%	707	106
2035	15%	716	107

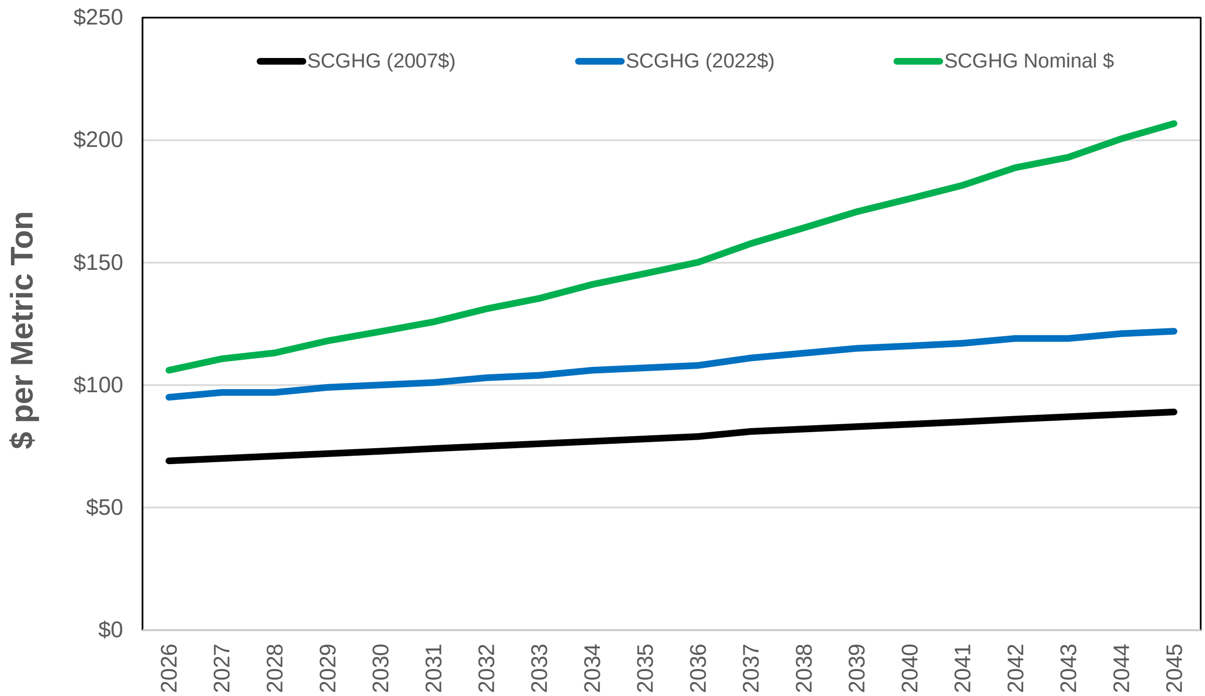
Transformation projects could be used for alternative compliance if cost-effective compared to unbundled RECs. To date, the transformation project requirements and accounting of the benefits toward alternative compliance are unknown, but Avista expects it may have some cost-effective options to use this mechanism from efforts in its Transportation Electrification Plan.

The last alternative compliance option is energy from a municipal solid waste facility, but this option has challenges. Avista currently purchases energy from a municipal solid waste facility, and it may meet this qualification in the future, but the output from the project is currently purchased as a PURPA resource through 2037. As a PURPA resource, it is deducted from retail load so counting the facility as alternative compliance would be double counting the resource.

Social Cost of Greenhouse Gas

Avista includes the Social Cost of Greenhouse Gas (SCGHG) within the portfolio model when it optimizes resource selection. Each resource with GHG emissions is assessed the cost as part of the portfolio optimization – see Figure 5 (green line) for pricing. The Washington share of existing resources and the potential new resources serving Washington are assessed this charge when optimizing the portfolio. The SCGHG is not included in Washington's share of resource dispatch within the modeling framework, but rather the cost of the Climate Commitment Act (CCA) emission allowances beginning in 2031. Due to uncertainty of how CCA allowance costs will be effectively "charged" to customers, Avista does not include the CCA or SCGHG costs when forecasting future rates shown in the 2025 IRP Chapter 2.

Figure 5: Social Cost of Greenhouse Gas Prices



Customer Benefit Indicator Analysis

This CEAP includes forecasts of the relevant CBI impacts for supply- and demand-side resource selections from the 2025 IRP. The 2021 CEIP contained 14 CBIs, including 31 metrics for measuring the impact of those CBIs. Not all metrics are related to resource planning, but 11 do relate. This section demonstrates how the metrics may change with the 2025 IRP's resource strategy. Table 6 includes all metrics from the 2021 CEIP. Bolded CBIs are forecasted in this plan since they are relevant to resource planning. These metrics help measure the effects of the clean energy transition and broaden the focus on equity among customers.

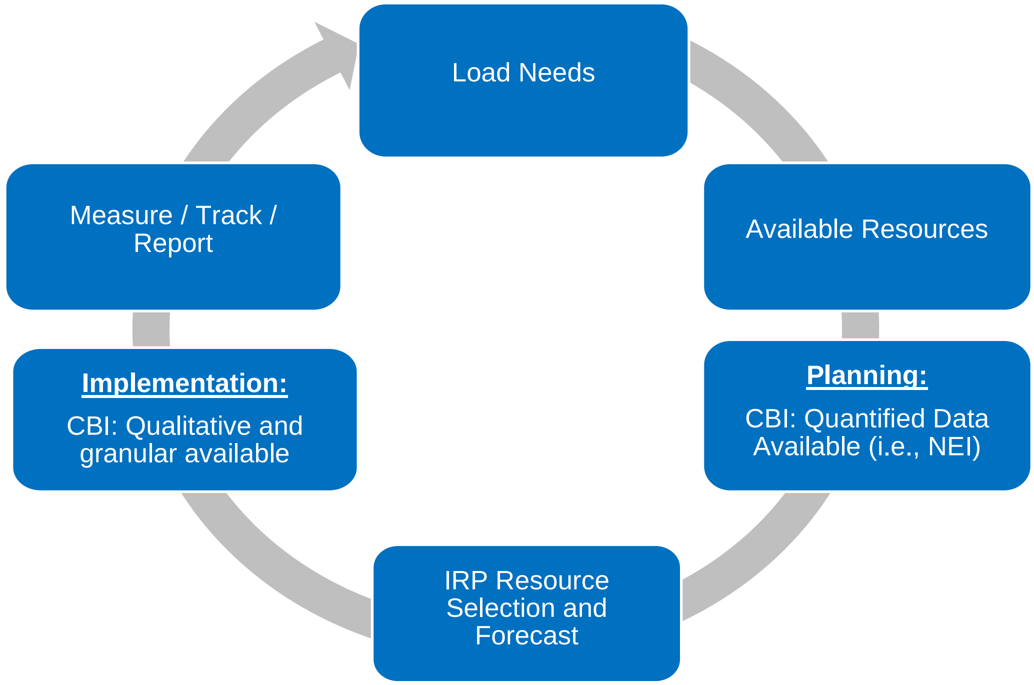
Table 6: Customer Benefit Indicators

Equity Area	Customer Benefit Indicator	Measurement / Metric
Affordability	(1) Participation in Company Programs	– Participation in weatherization programs and energy assistance programs (all and Named Communities)
		– Residential rebates provided to customers residing in Named Communities and rental units (Condition #17)
		– Saturation of energy assistance programs (all and Named Communities)
	(2) Number of households with a High Energy Burden (>6%)	– **Number and percent of households** (all customers, known low-income customers and Named Communities) (Condition #18)
		– **Average excess burden per household** (all customers, known low-income customers and Named Communities)
		– Number of households with high energy burden by Named Community subset (Condition #38)
Accessibility	(3) Availability of Methods/Modes of Outreach and Communication	– Number of outreach contacts
		– Number of marketing impressions
		– Increase in translation services
	(4) Transportation Electrification	– Number of trips provided by Community Based Organizations
		– Number of public charging stations located in Named Communities
	(5) Named Community Clean Energy	– **Total MWh of distributed energy resources 5 MW and under**
		– **Total MWh of energy storage resources under 5 MW and under**
		– Number of distributed renewable energy resources and energy storage resources (sites, projects, etc.,).
	(6) Investments in Named Communities	– Incremental spending each year in Named Communities
		– Number of customers/and/or Community Based Organizations served
		– **Quantification of energy/non-energy benefits from investments (if applicable)**
Energy Resiliency	(7) Energy Availability	– Average outage duration
		– **Planning reserve margin (resource adequacy)**
		– Frequency of customer outages

Energy Security	(8) Energy Generation Location	– **Percent of generation located in Washington or connected to Avista transmission**
	(9) Residential Arrearages and Disconnections for nonpayment (also found in Equity Area of Affordability)	– Number and percent of residential electric disconnections for nonpayment
		– Residential arrearages as reported to commission in Docket U-200281
		– Numbers and percent residential electric disconnects for non-payment by Named Community subset (Condition #22)
Environmental	(10) Outdoor Air Quality	– Weighted average days exceeding healthy levels
		– **Avista plant air emissions**
		– Decreased use of wood heat for home heating
	(11) Greenhouse Gas Emissions	– **Regional GHG emissions**
		– **Avista GHG emissions**
Public Health	(12) Employee Diversity	– Employee diversity representatives of communities served by 2035
	(13) Supplier Diversity	– Supplier diversity at 11 percent by 2035
	(14) Indoor Air Quality (Condition #24)	– Rank causes of indoor air quality (all and Named Communities)
		– Percentage of weatherization indoor air quality measures (all and Named Communities)

While Avista is committed to ensuring the equitable implementation of the specific actions identified in the 2021 CEIP and future CEIPs, there are circumstances where CBIs are not applicable to the resource planning process. In circumstances where CBIs are applicable to resource planning, Non-Energy Impacts (NEIs) and CBIs are utilized for evaluation and selection. Additionally, CBIs may be applicable to program implementation processes, which are outside the resource planning process. Figure 6 illustrates the planning process for resource needs, how those resources are secured and implemented, and how they impact the next IRP's load and resource needs. The applicability and timing of CBI inclusion is described below. Avista measures and tracks the impact of business decisions to focus on equitable outcomes.

Figure 6: Planning Process



CBIs Applicable to Resource Selection

While most of Avista's CBIs are not related to resource planning, this section addresses those CBIs related to resource planning. Avista's resource selection methodology uses resource costs and benefits, the NCIF, CETA requirements, and NEI values to inform resource outcomes, while avoiding any preconceived CBI targets or expectations. Constraints or requirements can be created in the PRiSM model to ensure certain metrics are met such as the PRM requirements or including financial incentives such as NEIs to incent certain decisions. These constraints may drive different outcomes as compared to traditional planning. The following section outlines CBI forecasts, while the specific data used to estimate the metrics and CBI values are included with the PRiSM model in the 2025 IRP Appendix G. These results can also be measured against a "Maximum Customer Benefits" scenario and are achieved through increasing CBI values to theoretical levels instead of cost-effective levels. In the end, it will be discretionary if resource selection and the expected CBI outcomes are justified as equitable.

CBI No. 2 – Number of Households with High Energy Burden

There are three forecastable metrics[121] related to household energy burden included within resource selection modeling, each excluding energy assistance funds:

[121] Separate tracking on a forecasted basis for known low-income and Named Communities cannot be completed until additional data is gathered.

- The number of households with energy burden exceeding 6% of income,
- Percentage of customers with excess energy burden, and
- Average excess energy burden.

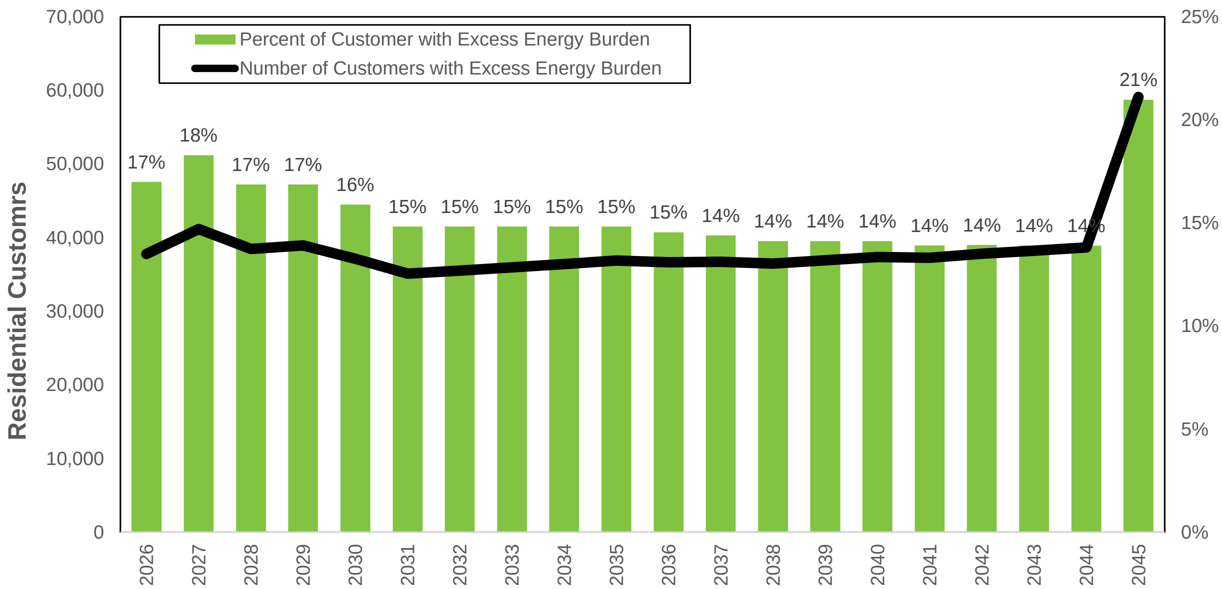
To assess current and future energy burden, data for customer income, energy usage, and energy rates is required. Customer income data was derived from a spatial analysis of incomes reported to Avista by customers enrolled in programs with income limits, census and third-party income data and was matched with usage and billing data. Total energy burden includes all fuels, natural gas and electric, at a specific location.[122] Forecasting this CBI requires assumptions regarding individual customer income and usage along with the cost of non-electric household fuels. To forecast energy burden in this analysis, customers are grouped by income, electric energy usage, and whether customers have electric only or combined electric and natural gas services. Customer income is escalated using the 2002-2022 historical income growth rate for each income group and customer usage[123] is forecasted using current energy use reduced by the amount of energy efficiency selected for a specific income group.[124] Lastly, the cost of the energy used by the customer is estimated using a rate forecast based on the resources selected through the IRP. The analysis does not consider additional energy assistance beyond the assistance provided by the development of a low-income community solar facility.

The first metric illustrates the forecast of the number of customers with excess energy burden (see Figure 7) over the IRP planning horizon. These customers have a combined energy bill between electric and natural gas exceeding 6% of their income to be included in this metric. Customers can fall into this metric due to high usage or low income. In 2026, approximately 38,000 customers in Washington out of 250,000 will be energy burdened. The absolute number of customers stays relatively flat until 2045, but as a percentage of energy total, customers with energy burden decreases until 2045. The increase in 2045 is due to high expected costs to comply with the 100% clean energy standard when significant resources are retired, and additional clean generation is added to ensure reliability and 100% clean energy in all hours. The 2045 costs are expected to create a disproportional energy burden to lower income customers to pay for 100% clean energy. To address this expected burden. Avista may not meet the 100% clean energy target and seek compliance through CETA's cost cap through future CEIP processes. Further, the main mechanism Avista can address this challenge is to deploy financial energy assistance to energy customers, but given the potential need due to high costs of meeting the 100% clean energy goal, energy assistance may reach 5% of revenue

[122] Currently the only non-electric household fuel expense included is natural gas. Estimated costs for other fuels such as fuel oil, propane, and wood should be included, but are not available at this time.
[123] This analysis does not include EV load in the energy usage calculation as it would unfairly place higher electric costs on the customer without considering other transportation costs not included in the calculation.
[124] Typical increases to energy usage (i.e., adding new technology and devices) for this purpose is being ignored.

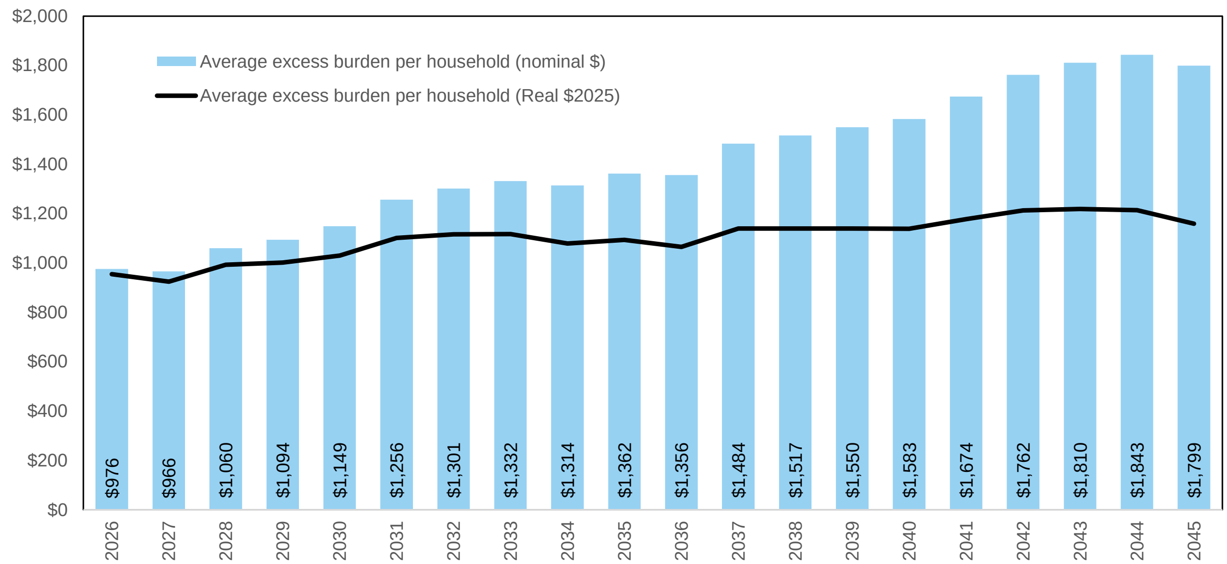
requirement cap. The only other ways to address energy burden within a resource plan is to use energy efficiency to lower energy use and develop dedicated resources for low-income customers. Both of these strategies are presumed in this plan, but all result in financial energy assistance, further creating pressures on retail energy pricing.

Figure 7: WA Customers with Excess Energy Burden (Before Energy Assistance)



The last customer energy burden metric is the amount of dollars per year of energy assistance the customer would need to reduce their energy burden to achieve the 6% level. The average excess energy burden growth is shown in Figure 8. This metric is expected to increase both in nominal and real (2025 dollars) values though the real increase is modest compared to the nominal increase at 1% a year above inflation. The difference between the two demonstrates the impact of inflation compared to the impact of rate increases.

Figure 8: Average Washington Customer Excess Energy Burden



CBI No. 5 – Named Community Clean Energy

This CBI monitors and prioritizes investments in DERs under 5 MW; specifically, generation and storage resource opportunities in Named Communities. This CBI has three metrics:

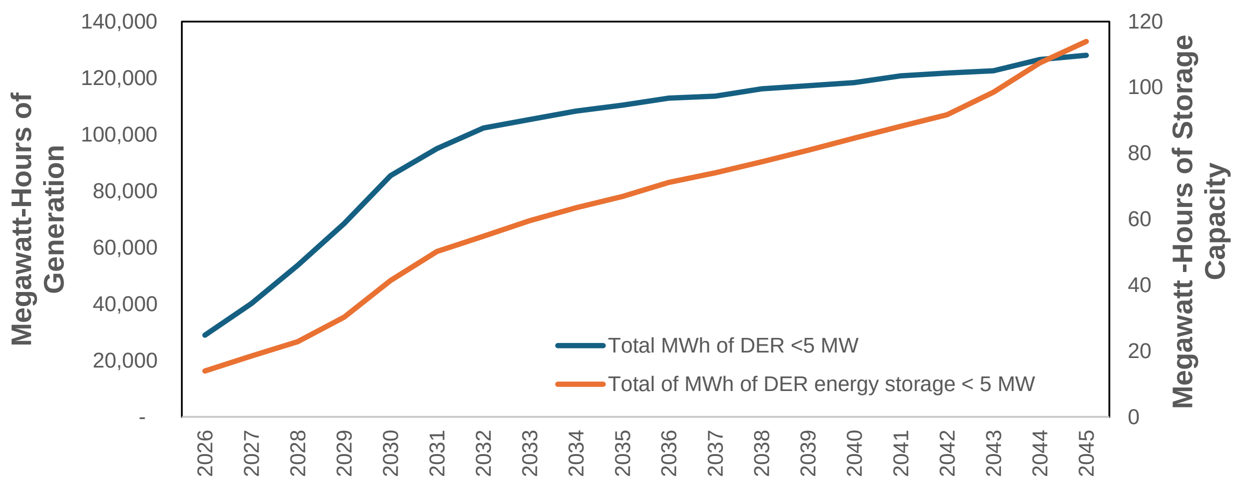
- Energy produced from DERs,
- DER energy storage capability, and
- Number of projects under 5 MW in Named Communities.

The 2025 IRP includes DER production and capacity, but identifying the number of projects is outside the planning scope and cannot be accurately forecasted. There are three methods for bringing these resources to the system. The first is through PURPA development. Historically, this method has brought the most non-solicited energy to Avista from developers building resources and selling the output to Avista using the federal regulation requiring utilities to purchase the output from qualifying facilities at the published avoided cost rates. The second method is from customers participating in Avista's net metering program. These customer resources are behind-the-meter and the energy produced is netted against their consumption.[125] The amount of these resources is outside of utility control and is based on whether the customer chooses to own their own generation. The last category is small generation owned or contracted by Avista, typically this includes community solar projects, but could also include other investments from the NCIF or cost-effective resource additions typically selected through an RFP process.

[125] The amount of net metered generation in a Named Community was not available at the time of this report.

Named Community DER generation is shown in Figure 9 as the dark line. Most of the historical DER generation is hydro-based and incremental additions are projected to be from community solar projects funded by state incentives and Avista's NCIF, along with a forecast for net metered generation as part of the DER forecast (2025 IRP Appendix F). The orange line is the distributed energy storage forecast. In this case it is flat, as the IRP did not identify any new projects. However, projects funded by the NCIF, or projects determined by the Distribution Planning process, may increase this forecast. For example, the NCIF is contributing funds for a 250 kW/ 500 kWh battery at the Martin Luther King Jr. Center in Spokane, WA., along with a 100 kW of solar at the Family Outreach Center with 150 kW backup natural gas generation. Updates to this project can be found on Avista's website.[126]

Figure 9: Total MWh of DER in Named Communities



CBI No. 6 – Investments in Named Communities

This plan includes high level estimates for investments and benefits in Named Communities. This CBI includes three metrics:

- Incremental spending each year in Named Communities,
- Number of customers and/or CBOs served, and
- Quantification of energy/nonenergy benefits from investments (if applicable).

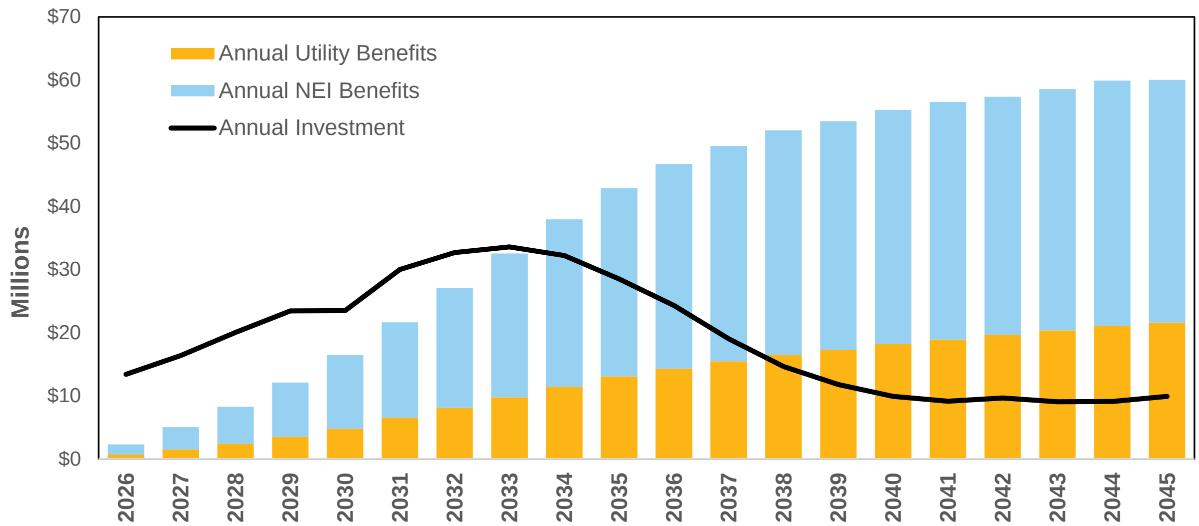
To address these CBIs, Avista includes the annual utility invested cost of resources in the 2025 IRP and compares these values to the annual utility benefits and non-energy impacts in Figure 10. The resources are selected based on a cost-effectiveness analysis including utility benefits (energy/capacity) and NEIs, except for the minimum spending constraint from the NCIF. Resource selection choices are driven by high non-energy

[126] https://www.myavista.com/about-us/projects/mlk-community-center.

impacts for energy efficiency in low-income areas. The total annual investments are driven by energy efficiency projects. Investments peak in 2033[127] and then decrease thereafter as there are fewer energy efficiency opportunities.

This CBI includes a third metric accounting for the number or sites and projections of future DERs. This forecast does not include this metric as the number of project sites will be determined during implementation.

Figure 10: Named Community Investment and Benefits



CBI No. 7 – Energy Availability

This CBI is designed to ensure Avista has a reliable system for all customers including Named Communities. It has three metrics:

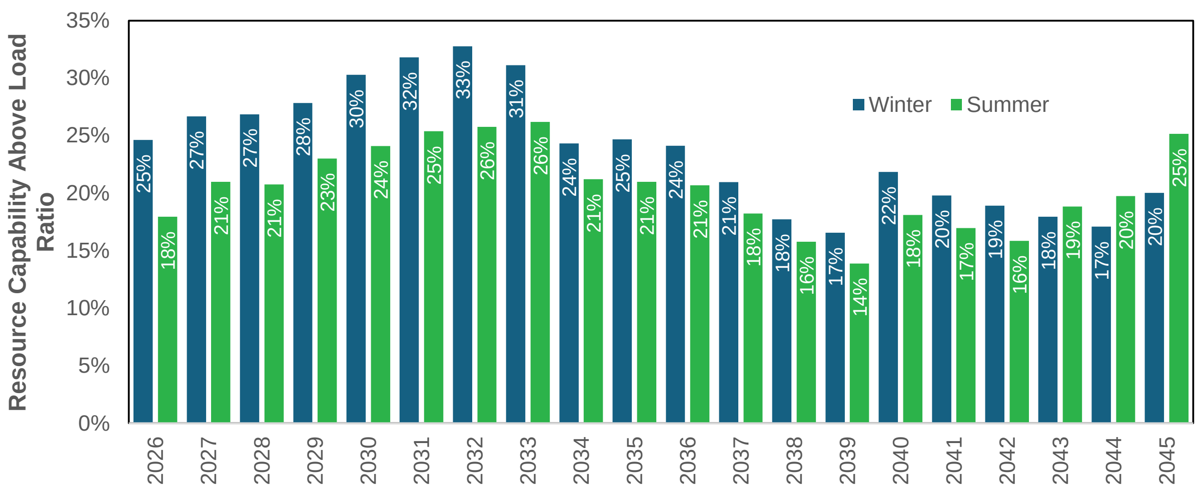
- Average Outage Duration,
- Planning Reserve Margin (PRM) (Resource Adequacy), and
- Frequency of Customer Outages.

These metrics highlight customer reliability, but only one is related to resource planning. The other two are impacted by distribution system reliability from delivery system issues. The item applicable to IRP planning is the PRM where it is a minimum requirement for resource capability during peak events. This metric is one of a few CBIs applying to the full Avista system rather than just the State of Washington. Figure 11 shows the forecasted expected peak hour resource capability versus load. The PRM is a forecast comparing future peak loads and expected generation capability during peak hours using

[127] 2030 investment is nearly the same as 2029 due to the incremental energy efficiency in 2030 being similar to 2029, but by 2031 investment increases again.

QCC values.[128] The PRM target for the resource plan is 24% in the winter and 16% in the summer. As seen in this chart, the winter PRM goes below the target due to more reliance on energy markets using the North Plains Connector transmission project beginning in 2033. Avista generally does not include market purchases in the PRM calculation explaining the reduced value while maintaining reliability. If this project is completed, Avista will increase its market power allowance and therefore result in lower PRM once the project is complete. If the North Plains Connector project is delayed or cancelled, the plan will be short capacity and alternative capacity resources will be required. Avista addresses this risk with a scenario in the 2025 IRP Chapter 10, by requiring additional energy storage.

Figure 11: Planning Reserve Margin



CBI No. 8 – Energy Generation Location

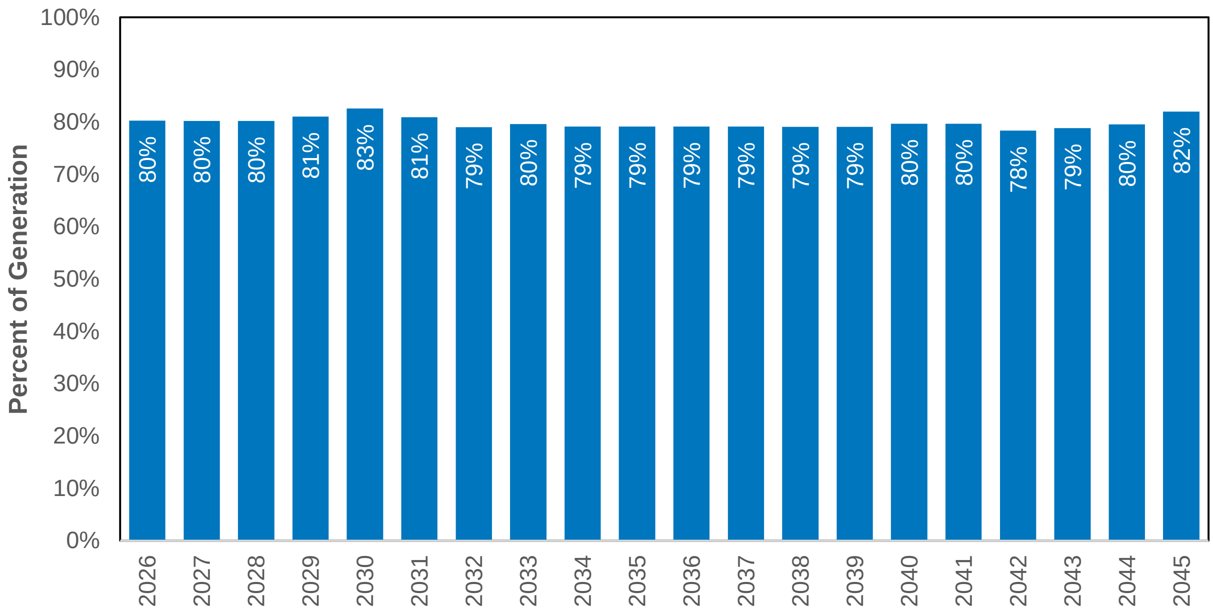
CETA encourages the use of local resources to enhance energy security. As such, this CBI will address the following metric:

- Percent of generation located in Washington or connected to Avista's transmission system.

To address energy security, Avista quantifies the amount of generation located within Washington State or directly connected to Avista's transmissions system used for customer needs. This metric is energy agnostic rather than clean energy focused. Figure 12 shows the IRP selected resource mix of energy created in either Washington or connected to Avista's transmission system. The amounts are shown as a percentage of total generation. New wind projects in Montana, outside Avista's system, keep the forecast stable over time.

[128] QCC values were derived by the WRAP with input from participating utilities and compiled by the program administrator – SPP.

Figure 12: Generation in Washington and/or Connected to Avista Transmission



CBI No. 10 – Outdoor Air Quality[129]

Avista's generation air emissions are forecastable within an IRP. The Outdoor Air Quality CBI measures the following:

- Weighted average days exceeding healthy levels, and
- Avista's Washington plant air emissions.

The impacts of unhealthy days within local communities are typically related to events outside of Avista's control and are after the fact calculations conducted by a third party. From an IRP perspective the "weighted average days exceeding healthy levels" metric cannot be forecasted in an IRP as multiple factors drive this metric, such as local weather conditions and wildfires.

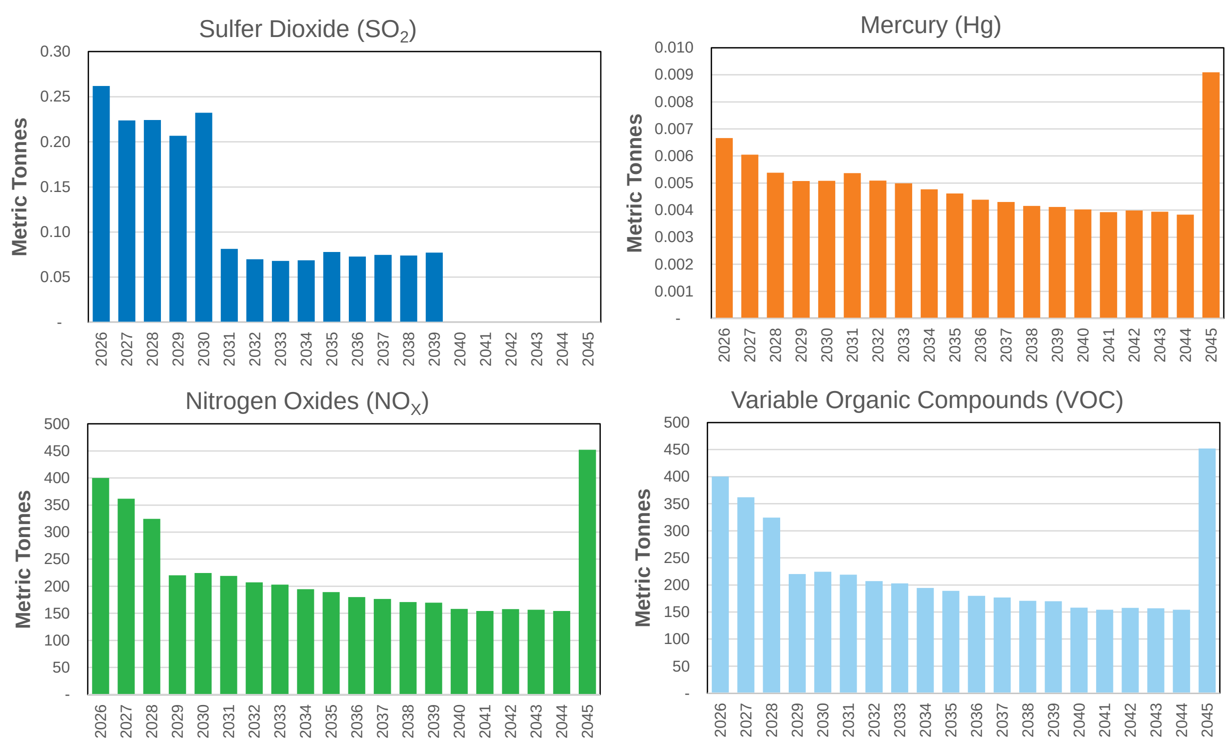
The forecastable metrics include SO_2, NO_X, Mercury, and VOC emissions from Avista's Washington based plants. These forecasts are based on emission rates per unit of fuel burned. These emissions are regulated by local air authorities and plants meet all local laws and regulations for air emissions and are found to be at levels safe for the local population by the federal, state, and local regulating authorities. To ensure the emissions

[129] The Company discussed the wood stove replacement program and proposed outdoor air quality metrics with its EEAG during its October 2021 and 2022 sessions, and with its EAG during its February 2022 Equity Lens session. The Department of Ecology joined the EAG's session to present outdoor air quality monitoring availability options. No additional metrics were identified through these sessions. Avista anticipates continued conversations with its advisory groups and the public pertaining to all CBIs as it works to develop its 2025 CEIP.

are safe, plants must either add controls to reduce emissions or have daily or annual operational limitations. Avista includes associated NEIs to ensure air quality improvements are considered in resource selection.

The Outdoor Air Quality metric measures total annual emission levels for Washington State based thermal facilities including the Kettle Falls Generating Station (KFGS), Kettle Falls CT, Boulder Park, and the Northeast CT. All metric results are forecasted to decline over the IRP planning horizon due to lower expected thermal dispatch hours and potential retirements of existing gas units through 2045 as shown in Figure 13. The significant increase in 2045 is due to additional biomass generation forecasted to assist in meeting the 100% clean energy target in 2045. Biomass generation is considered GHG neutral by Washington law, but biomass does have other air emissions. Furthermore, NO_X emissions do not rapidly fall due to the forecasted need of green hydrogen-based fuels, such as ammonia, to assist in meeting peak demand and replace aging natural gas resources. The amount of NO_X emissions will depend on technology and control systems once turbine manufacturers make hydrogen-fueled resources commercially available (post 2030) and the expected emissions from these plants will likely need to be revised in future resource plans due to new technology to capture these emissions.

Figure 13: Washington Located Air Emissions



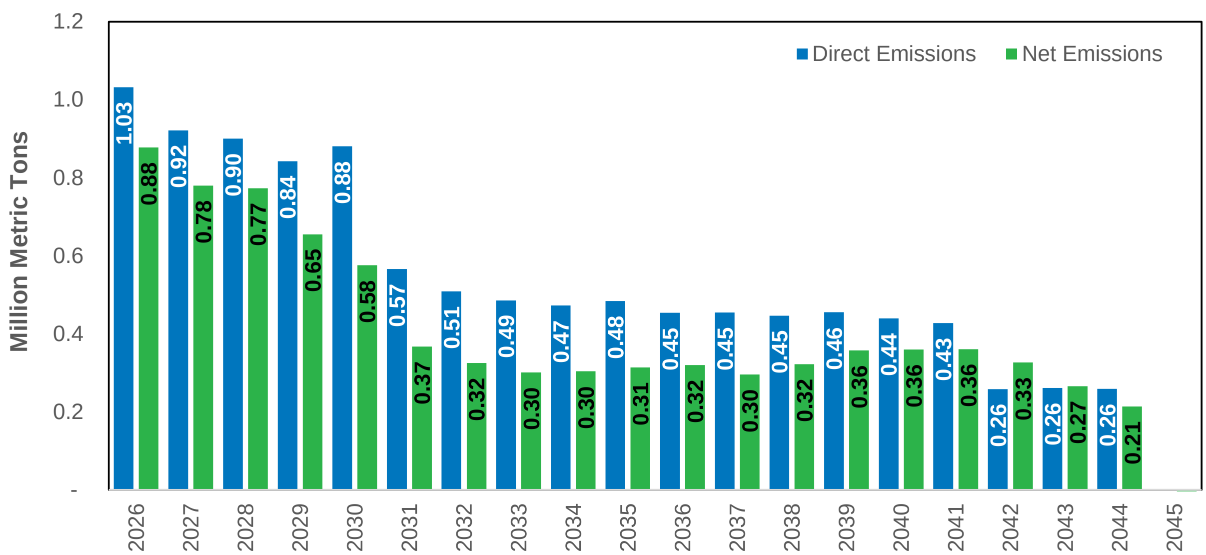
CBI No. 11 – Greenhouse Gas Emissions

There are two metrics for GHG Emissions covered in this section:

- Avista's GHG emissions, and
- Regional GHG emissions.

The first metric estimates the amount of direct emissions from Washington's share (utilizing the PT ratio) of power plants and how those GHG emissions change considering market transactions (labeled as "net emissions"). Figure 14 shows declining GHG emissions due to additional clean energy resources expected to be added to the Western Interconnect system and in turn will drive down the wholesale electric price and the need for GHG emitting resources in as many hours as the past. Net emissions are lower than direct emissions in the near-term as the calculation removes emissions related to power sold off the system. Later in the planning horizon, when surplus system sales decrease, Avista may need to purchase power causing net emissions to increase. This forecast includes emissions associated with those purchases. This CBI may be modified in the 2025 CEIP to reflect the required methodology of reporting emissions for the CCA.

Figure 14: Washington Direct and Net Emissions

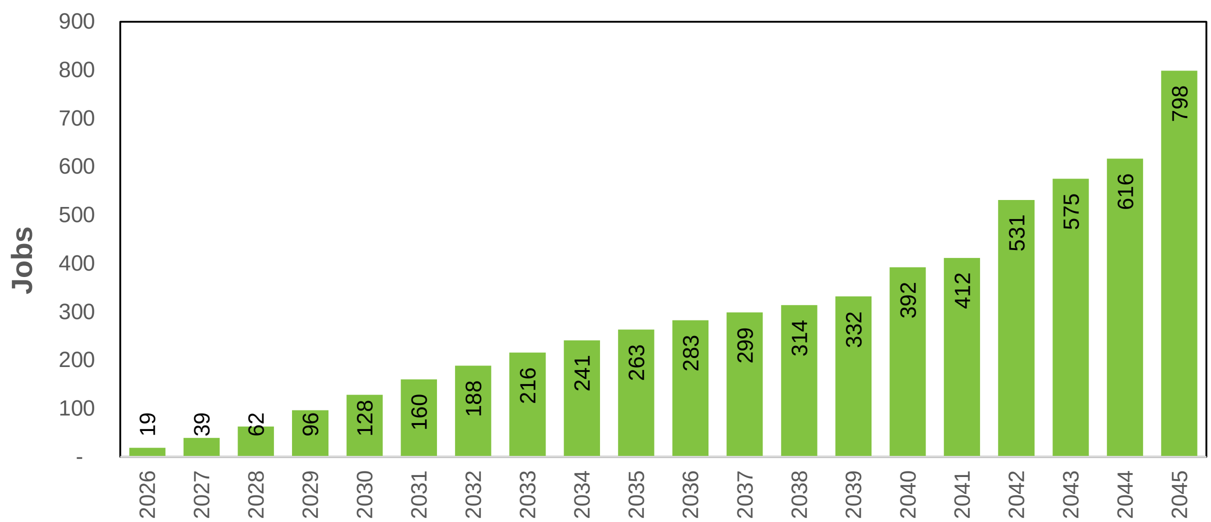


One of CETA's main purposes is to reduce state level GHG emissions. Electric power specifically related to eastern Washington is small in relation to total state emissions. The goal of the regional GHG metric is to place Avista's emissions in the context of all emissions allowing for a holistic analysis of GHG reductions. This CBI is to view the effects of electrification in reducing emissions from other sectors. Most of the information needed to track this CBI is not available on a regional basis or in a timely manner. Additionally, the Avista cannot forecast emissions for industries outside of Avista. Due to these factors, Avista will be proposing to remove this metric in its 2025 CEIP as it should be tracked at the state level as part of statewide CBIs.

Job Creation

Through the IRP's TAC and other customer engagement forums, an additional metric was discussed to estimate the number of jobs created by IRP resource decisions. Avista temporarily acquired the IMPLAN model to estimate economic benefits of new resources. IMPLAN is an economic impact model designed to estimate the impacts of investments in new generation or energy efficiency including job creation due to expected changes in the local economy. This model was used to estimate permanent jobs per million-dollar investment in each of the generation or energy efficiency technology areas of IRP resources. Created jobs include both direct and induced jobs. The job creation results are shown in Figure 15. This chart does not show lost jobs from resource retirements or for alternative resource choices. Avista will not propose to make this a CBI in the 2025 CEIP due to the significant cost to develop and maintain this metric and is reviewing alternative methods to address job creation within the 2025 CEIP process.

Figure 15: Job Creation



CBIs Not Applicable to Resource Planning

The following CBIs are not related to the resource planning phase and will be further discussed in the 2025 CEIP. These items will be utilized in resource selection, program implementation, or evaluation. In accordance with the 2021 CEIP Condition No. 35, the following information is applicable to these CBIs.

CBI No. 1 – Participation in Company Programs

This CBI aims to increase overall participation levels for all customers in Avista's energy efficiency and energy assistance programs, with special emphasis on Named Communities. While the priority is to increase participation within Named Communities specifically, Avista will also consider the current participation levels in energy efficiency and energy assistance programs of all Washington customers as part of its baseline when measuring how participation increases. The intent of these efforts is to prioritize distributional equity by helping to address direct or indirect barriers impacting a customer's ability to participate in energy efficiency or energy assistance programs.

This metric emphasizes overall participation; however, the impact of these efforts is directly related to reducing customers' overall energy burden and making energy more affordable. Energy efficiency and energy assistance efforts have known energy and NEI values with direct benefits to customers from both affordability and overall wellbeing. When combined with CBI No. 3 concerning availability of communication, Avista can monitor the successful steps contributing to increased participation. The Company will monitor the following metrics included in this CBI:

- Participation in weatherization, efficiency, and energy assistance programs for all customers and Named Communities,
- Saturation of energy assistance programs for all customers and Named Communities, and
- Residential appliance and equipment rebates provided to customers residing in Named Communities and rental units (Condition No. 17).

Tracking the metrics for CBI No. 1 requires data for individual customers, as well as each customer in a Named Community. This requires extensive data analysis utilizing Avista's Customer Care and Billing system (CC&B). In IRP planning, energy efficiency is forecasted based on a total energy savings by program type and by customer segment (i.e., residential and commercial customers) not at the customer level. Avista's advisory groups, such as the Equity Advisory Group (EAG), Energy Assistance Advisory Group (EAAG), and Energy Efficiency Advisory Group (EEAG) will continue to be instrumental in developing a method for prioritizing energy efficiency and energy assistance programs to ensure they are equitably distributed.

CBI No. 3 – Availability of Method/Modes of Communication

CBI No. 3 focuses on increasing access to clean energy and reaching customers who have not participated in Avista's energy efficiency and energy assistance programs due to language barriers or other limitations, such as not knowing about the programs or understanding the application process. Increased outreach should increase participation which will lead to lower energy usage and costs, while positively impacting accessibility and affordability. This CBI seeks to increase participation in energy efficiency and energy assistance programs by improving how customers hear about these programs. The metrics for this CBI are:

- Number of outreach contacts,
- Number of marketing impressions, and
- Translation services.

Barriers may limit access to participation in Company programs and make it more difficult and expensive for customers in Named Communities to receive assistance. Increased and expanded customer outreach will grow energy efficiency and energy assistance participation making energy service more affordable. Further, increased energy efficiency participation benefits all customers by reducing the need for more generation. This CBI is not relevant to resource planning but rather to program implementation. Avista continually works with its advisory groups to improve upon its methods and modes of communication to increase participation.

CBI No. 4 – Transportation Electrification

CBI No. 4 considers Transportation Electrification efforts and the impacts on customers in Named Communities. Avista's Transportation Electrification Plan (TEP)[130] provides a path to a cleaner energy future by 2045 by electrifying transportation. The TEP outlines guiding principles, strategies, and an action plan with detailed program descriptions, cost and benefit estimates, and regular reporting details. The TEP has an aspirational goal of investing 30% of Avista's total transportation electrification spend on programs benefiting Named Communities. Avista's Tariff Schedule 77 and the TEP commit to regular reporting of Transportation Electrification (TE) efforts through several metrics.

Avista will track transportation electrification in Named Communities with three metrics:

- Annual trips provided by Community Based Organizations (CBOs) using electric transportation,
- Annual passenger miles provided by CBOs using electric transportation, and
- Public charging ports available in Named Communities.

The impacts of transportation electrification are embedded in Avista's load forecast and resource planning processes. Program implementation requires focus on where the impacts of efforts will be located. Avista will continue collaboration with its advisory groups and collaborating with CBOs to ensure a focus on Named Communities throughout the TEP implementation process.

CBI No. 7 – Energy Availability

CBI No. 7 aims to ensure customers in Named Communities are not disproportionally impacted by delivery system or resource adequacy power outages due to their socio-economic or sensitivity factors. This CBI tracks the location of outages and will inform future implementation and system development to minimize the potential for outages.

Avista will measure the following metrics:

- Average Outage duration by Customer Average Interruption Duration Index (CAIDI) - Not included in resource planning,

[130] UTC Docket UE-200607, acknowledged by the Washington UTC on October 15, 2020.

- Frequency of Customer Outages by Customer Experiencing Multiple Interruptions (CEMI) - Not Included in resource planning, and
- Planning Reserve Margin (Resource Adequacy) - Included in resource planning.

Avista has a duty to provide safe and reliable energy to its entire customer base. Historical customer outage information provides customers with a measure of resiliency and reliability by calculating the time it takes to restore a customer's service from an outage but does not include the cause of the outage. Most outages are related to the distribution system and service can be interrupted by weather, equipment failure, maintenance, or other factors. Monitoring these two metrics will provide data to inform Avista where new distribution resources may be located to best address inequities. The newly formed Distribution Planning Advisory Group (DPAG) will provide insight into this distribution planning process.

CBI No. 9 – Residential Arrearages and Disconnections for Non-Payment

CBI No. 14 tracks residential arrearages and disconnections for non-payment. Connection to energy service was identified by interested parties as a key element of energy security. This CBI is not applicable to resource planning. For planning purposes, a certain level of price elasticity is included relating to the cost of resource selection and may ultimately impact arrearages and disconnections for non-payment. Resource decisions include the cost of arrearages, while energy efficiency evaluations include these savings by way of the NEI. Reporting this CBI keeps the issue at the forefront of affordability and/or energy burden conversations during implementation of future investments. Avista includes a utility NEI for a decrease in contact center calls for certain low-income energy efficiency measures to account for reductions in future disconnects.

CBI No. 12 – Employee Diversity and No. 13 Supplier Diversity

The purpose behind CBIs No. 11 and No. 12 are to generate awareness and to promote recognitional equity. Tracking employee and supplier diversity is a first step in recognizing the potential of systemic racism embedded within existing processes and procedures. Tracking these metrics will result in an increased focus towards identifying and changing policies to increase employee and supplier diversity to help eliminate inequities. This CBI is not intended to be utilized as a resource planning metric; however, as an implementation tool Avista includes diversity metrics in its selection criteria for resource selection as part of long-term resource procurement.

The EAG raised ending systemic racism as a major concern and discussed what Avista could do to help with this wide-ranging issue. CBI No. 11 is an initial attempt to track and improve Avista's employee diversity to match the diversity and genders of the communities it serves. This aspirational goal will be tracked by craft, non-craft, managers and directors, and executives for race and gender with a goal of matching the communities being served by 2035. CBI No. 12 focuses on the supplier side of diversity to help make the diversity of our suppliers closer to the communities we serve.

CBI No. 14 – Indoor Air Quality

In accordance with Avista's CEIP Condition 24, in its 2023 Biennial CEIP Update, it proposed and received approval to apply a new CBI for energy efficiency programs that helps to identify, measure, and apply metrics to existing low-income weatherization programs and energy efficiency programs. The Indoor Air Quality (IAQ) metrics are part of a Health and Safety NEI used to assess economic, health, and environmental burdens. The health and safety metrics include HVAC mechanical ventilation, natural ventilation, air infiltration, indoor air pollution contributors, and overall health and safety total home assessments. Based on the Washington Department of Commerce and ASHREA's 62.2 standard for low-income weatherization program metrics, Avista is now tracking the following data for this metric:

- Ranking of causes of IAQ (within & outside Named Communities),
- Percentage of weatherization IAQ measures (within & outside Named Communities).

Avista is currently tracking data for these metrics and will provide its first set of data in its 2025 CEIP.

EXHIBIT 50-3

2021 PSE Integrated Resource Plan

Chapters 1-9

April 2021

FINAL

pse.com

PSE PUGET SOUND ENERGY

About PSE

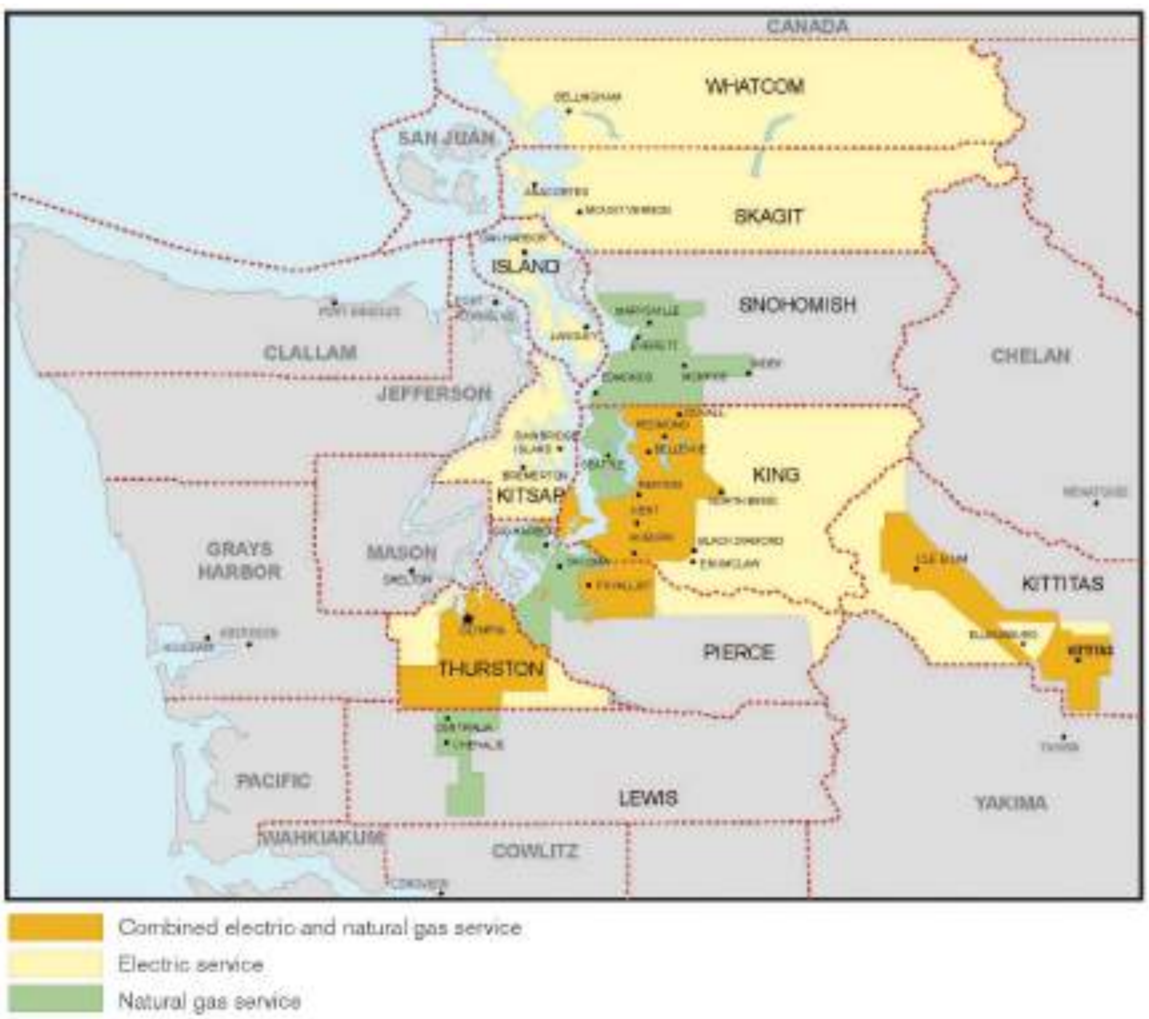
As Washington state's oldest local energy company, Puget Sound Energy serves more than 1.1 million electric customers and more than 840,000 natural gas customers in 10 counties. Our service territory includes the vibrant Puget Sound area and covers more than 6,000 square miles, stretching from south Puget Sound to the Canadian border, and from central Washington's Kittitas Valley west to the Kitsap Peninsula.

Electric service: All of Kitsap, Skagit, Thurston, and Whatcom counties; parts of Island, King (not Seattle), Kittitas, and Pierce (not Tacoma) counties.

Natural gas service: Parts of King (not Enumclaw), Kittitas (not Ellensburg), Lewis, Pierce, Snohomish, and Thurston counties.

PSE meets the energy needs of its customers, in part, through incremental, cost-effective energy efficiency, procurement of sustainable energy resources and farsighted investment in the energy-delivery infrastructure. PSE employees are dedicated to providing great customer service and delivering energy that is safe, dependable and efficient.

Figure i-1: PSE's Service Area



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Definitions and Acronyms

Term/ Acronym	Definition
A4, A5	A standard for converting gases to carbon dioxide equivalents using the Intergovernmental Panel on Climate Change global warming protocols.
AARG	average annual rate of growth
AB 32	California Global Warming Solutions Act of 2006, which mandates a carbon price to be applied to all power generated in or sold into that state.
ACE	Area Control Error
ACE Rule	Affordable Clean Energy Rule. Adopted in 2018, EPA's replacement for the Clean Power Plant Rule.
ADMS	Advanced Distribution Management System, a computer-based, integrated platform that provides the tools to monitor and control distribution networks in real time.
AECO	Alberta Energy Company, a natural gas hub in Alberta, Canada.
AMI	advanced metering infrastructure
AMR	automated meter reading
aMW	The average number of megawatt-hours (MWh) over a specified time period; for example, 175,200 MWh generated over the course of one year equals 20 aMW (175,200 / 8,760 hours).
AOC	Administrative Order of Consent
ARMA	autoregressive moving average
ATC	available transmission capacity
AURORA	One of the models PSE uses for electric resource planning. AURORA uses the western power market to produce hourly electricity price forecasts of potential future market conditions. AURORA is also used to test electric portfolios to evaluate PSE's long-term revenue requirements.
BA	Balancing Authority, the area operator that matches generation with load.
BAA	Balancing Authority area
BACT	Best available control technology, required of new power plants and those with major modifications, pursuant to EPA regulations.
balancing reserves	Reserves sufficient to maintain system reliability within the operating hour; this includes frequency support, managing load and variable resource forecast error, and actual load and generation deviations. Balancing reserves must be able to ramp up and down as loads and resources fluctuate instantaneously each hour.
BART	Best available retrofit technology, an EPA requirement for certain power plant modifications.

Base Scenario	In an analysis, a set of assumptions that is used as a reference point against which other sets of assumptions can be compared. The analysis result may not ultimately indicate that the Base Scenario assumptions should govern decision-making.
Baseload combustion turbines	Baseload combustion turbines are designed to operate economically and efficiently over long periods of time, which is defined as more than 60 percent of the hours in a year. Generally combined-cycle combustion turbines (CCCTs).
baseload resources	Baseload resources produce energy at a constant rate over long periods at lower cost relative to other production facilities; typically used to meet some or all of a region's continuous energy need.
BAU	business-as-usual
Bcf	billion cubic feet
BEM	Business Energy Management sector, for electric energy efficiency programs.
BES	bulk electric system
BESS	battery energy storage system
BPA	Bonneville Power Administration
BSER	Best system of emissions reduction, an EPA requirement for certain power plant construction or modification.
BTU	British thermal units
CAA	Clean Air Act
CAISO	California Independent System Operator
capacity factor	The ratio of the actual generation from a power resource compared to its potential output if it was possible to operate at full nameplate capacity over the same period of time.
CAP	Corrective action plan, a series of operational steps used to prevent system overloads or loss of customer power.
CAR	Washington State Clean Air Rule
CARB	California Air Resources Board
CBI	customer benefit indicator
CCCT	Combined-cycle combustion turbine. Baseload generating plant that consists of one or more combustion turbine generators equipped with heat recovery steam generators that capture heat from the combustion turbine exhaust and use it to produce additional electricity via a steam turbine generator.
CCR	coal combustion residuals
CCS	carbon capture and sequestration
CDD	cooling degree day

CEAP	Clean Energy Action Plan
CEC	California Energy Commission
CEIP	Clean Energy Implementation Plan
CETA	Clean Energy Transformation Act
CFS	conditional firm service, a new transmission product offered by BPA.
CHP	combined heat and power
CI	confidence interval
CIA	cumulative impact analysis
CIA	community impact assessment
C&I	commercial and industrial
CNG	compressed natural gas
CO2	carbon dioxide
CO2e	carbon dioxide equivalents
COE	U.S. Army Corps of Engineers
contingency reserves	Reserves added in addition to balancing reserves; contingency reserves are intended to bolster short-term reliability in the event of forced outages and are used for the first hour of the event only. This capacity must be available within 10 minutes, and 50 percent of it must be spinning.
CPA	conservation potential assessment
CPI	consumer price index
CPP	federal Clean Power Plan
CPP	critical peak pricing or dynamic pricing
CPUC	California Public Utilities Commission
CRAG	PSE's Conservation Resource Advisory Group
C&S	codes and standards
CT	combustion turbine
CVR	conservation voltage reduction
DA	distribution automation
DE	distribution efficiency
DER	distributed energy resources
demand response	Flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.
demand-side resources	These resources reduce demand. They include energy efficiency, distribution efficiency, generation efficiency, distributed generation and demand response.

DER	Distributed energy resources. Electricity generators like rooftop solar panels that are located below substation level.
DERMS	Distributed Energy Resource Management System
deterministic analysis	Deterministic analysis identifies the least-cost mix of demand-side and supply-side resources that will meet need, given the set of static assumptions defined in the scenario or sensitivity.
DG	distributed generation
distributed energy resources	Small-scale electricity generators like rooftop solar panels, located below substation level.
DLC	direct load control, one of several demand response programs
DMS	distribution management system
DOE	U.S. Department of Energy
DOH	Washington State Department of Health
DR	demand response
DSM	demand-side measure
DSM	demand-side management
DSO	Dispatcher Standing Order
DSP	Delivery System Planning
DSR	demand-side resources
Dth	dekatherms
dual fuel	Refers to peakers that can operate on either natural gas or distillate oil fuel.
EDAM	extended day-ahead market
EE	energy efficiency
EEI	Edison Electric Institute
EHD	environmental health disparities
EHEB	Economic, Health and Environmental Benefits Assessment
EIA	U.S. Energy Information Agency
EIA	Washington State Energy Independence Act
EIM	The Energy Imbalance Market operated by CAISO
EIS	environmental impact statement
EITEs	energy-intensive, trade-exposed industries

ELCC	Effective load carrying capacity. The peak capacity contribution of a resource calculated as the change in capacity of a perfect capacity resource that results from adding a different resource with any given energy production characteristics to the system while keeping the 5 percent LOLP resource adequacy metric constant.
EMC	PSE's Energy Management Committee
energy need	The difference between forecasted load and existing resources.
energy storage	A variety of technologies that allow energy to be stored for future use.
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
EPS	Washington state law RCW 80.80.060(4), GHG Emissions Performance Standard
ERU	Emission reduction units. An ERU represents one MtCO2 per year.
ESS	energy storage systems
EUE	Expected unserved energy, a reliability metric measured in MWhs that describes the magnitude of electric service curtailment events (how widespread outages may be).
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
FIP	final implementation plan
FLISR	Fault Location, Isolation, Service Restoration
GDP	gross domestic product
GENESYS	The resource adequacy model used by the Northwest Power and Conservation Council (NPCC).
GHG	greenhouse gas
GIS	Geographic Information System
GPM	gas portfolio model
GRC	General Rate Case
GTN	Gas Transmission Northwest
GW	gigawatt
HB 1257	Clean Buildings for Washington Act
HDD	heating degree day
HIC	Highly impacted communities
HILF	high-impact, low-frequency events
HVAC	heating, ventilating and air conditioning

I-937	Initiative 937, Washington state's renewable portfolio standard (RPS), a citizen-based initiative codified as RCW 19.285, the Energy Independence Act.
IAP2	International Association of Public Participation
iDOT	Investment Optimization Tool. An analysis tool that helps to identify a set of projects that will create maximum value.
IGCC	Integrated gasification combined-cycle, generally refers to a model in which syngas from a gasifier fuels a combustion turbine to produce electricity, while the combustion turbine compressor compresses air for use in the production of oxygen for the gasifier.
intermittent resources	Resources that provide power that offers limited discretion in the timing of delivery, such as wind and solar power.
IOU	investor-owned utility
IPP	independent power producer
IRP	integrated resource plan
ISO	independent system operator
ITA	independent technical analysis
ITC	investment tax credit
KORP	Kingsvale-Oliver Reinforcement Project pipeline proposal
kV	kilovolt
kW	kilowatt
kWh	kilowatt hours
LAES	liquid air energy storage
LNG	liquified natural gas
load	The total of customer demand plus planning margins and operating reserve obligations.
LOLE	Loss of load expectation, a reliability metric that measures the number of days per year with loss of load due to load exceeding available system capacity.
LOLH	Loss of load hours (or loss of load energy), a reliability metric that measures the duration of electric service curtailment events (how long outages may last).
LOLP	Loss of load probability, a reliability metric that measures the likelihood of an electric service curtailment event happening.
LP-Air	vaporized propane air
LSR	Lower Snake River Wind Facility
LTCE	long-term capacity expansion model
LTF	long-term firm transmission

LTF PTP	long-term firm point-to-point transmission
MATS	Mercury Air Toxics Standard
MDEQ	Montana Department of Environmental Quality
MDQ	maximum daily quantity
MDth	thousand dekatherms
MEIC	Montana Environmental Information Center
MESA	Modular Energy Storage Architecture. A protocol for communications between utility control centers and energy storage systems.
Mid-Columbia (Mid-C) market hub	The principle electric power market hub in the Northwest and one of the major trading hubs in the WECC.
MMBtu	million British thermal units
MMtCO2e	million metric tons of CO2 equivalent
MSA	metropolitan statistical area
MW	megawatt
MWh	megawatt hour
NAAQS	National Ambient Air Quality Standards, set by the EPA, which enforces the Clean Air Act, for six criteria pollutants: sulfur oxides, nitrogen dioxide, particulate matter, ozone, carbon monoxide and lead.
nameplate capacity	The maximum capacity that a natural gas fired unit can sustain over 60 minutes when not restricted to ambient conditions.
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
net maximum capacity	The capacity a unit can sustain over a specified period of time – in this case 60 minutes – when not restricted by ambient conditions or deratings, less the losses associated with auxiliary loads.
net metering	A program that enables customers who generate their own renewable energy to offset the electricity provided by PSE.
NGV	natural gas vehicles
NO2	nitrogen dioxide
NOAA	National Oceanic and Atmospheric Administration
NOS	Network Open Season, a BPA transmission planning process.
NO_x	nitrogen oxides
NPCC	Northwest Power & Conservation Council
NPV	net present value
NRC	Nuclear Regulatory Commission

NREL	National Renewable Energy Laboratories
NRF	Northwest Regional Forecast of Power Loads and Resources, the regional load/balance study produced by PNUCC.
NSPS	New source performance standards, new plants and those with major modifications must meet these EPA standards before receiving permit to begin construction.
NTTG	Northern Tier Transmission Group
NUG	non-utility generator
NWA	non-wires analysis
NWE	NorthWestern Energy
NWGA	Northwest Gas Association
NWP	Northwest Pipeline
NWPP	Northwest Power Pool
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OMS	outage management system
OTC	once-through cooling
PACE	PacifiCorp East
PACW	PacifiCorp West
PCA	power cost adjustment (electric)
PCORC	power cost only rate case
peak need	Electric or gas sales load at peak energy use times.
peaker (or peaking plants)	Peaker is a term used to describe generators that can ramp up and down quickly in order to meet spikes in need. They are not intended to operate economically for long periods of time like baseload generators.
peaking resources	Quick-starting electric generators that can ramp up and down quickly in order to meet short-term spikes in need, or gas sales resources used to meet load at times when demand is highest.
PEFA	ColumbiaGrid's planning and expansion functional agreement, which defines obligations under its planning and expansion program.
PEV	plug-in electric vehicle
PG&E	Pacific Gas and Electric Company
PGA	purchased gas adjustment
PGE	Portland General Electric
PHES	pumped hydro energy storage

PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES Act	Pipeline Inspection, Protection, Enforcement, and Safety Act (2006)
planning margin or PM	These are amounts over and above customer peak demand that ensure the system has enough flexibility to handle balancing needs and unexpected events.
planning standards	The metrics selected as performance targets for a system's operation.
PLEXOS	An hourly and sub-hourly chronological production simulation model that utilizes mixed-integer programming (MIP) to simulate unit commitment of resources at a day-ahead level, and then simulate the re-dispatch of these resources in real time to match changes in supply and demand on a 5-minute basis.
PM	particulate matter
PNUCC	Pacific Northwest Utilities Coordinating Committee
PNW	Pacific Northwest
POD	point of delivery
portfolio	A specific mix of resources to meet gas sales or electric load.
PPA	Purchased power agreement. A bilateral wholesale or retail power short-term or long-term contract, wherein power is sold at either a fixed or variable price and delivered to an agreed-upon point.
PRP	pipeline replacement program
PSCAA	Puget Sound Clean Air Agency
PSE	Puget Sound Energy
PSEM	Puget Sound Energy Merchant, the part of PSE responsible for obtaining and scheduling the transmission needed to serve PSE loads.
PSIA	Pipeline Safety Improvement Act (2002)
PSRC	Puget Sound Regional Council
PTC	Production Tax Credit, a federal subsidy for production of renewable energy that applied to projects that began construction in 2013 or earlier. When it expired at the end of 2014, it amounted to $23 per MWh for a wind project's first 10 years of production.
PTP	Point-to-point transmission service, meaning the reservation and transmission of capacity and energy on either a firm or non-firm basis from the point of receipt (POR) to the point of delivery (POD).
PTSA	Precedent Transmission Service Agreement
PUD	public utility district

pumped hydro	Pumped hydro facilities store energy in the form of water, which is pumped to an upper reservoir from a second reservoir at a lower elevation. During periods of high electricity demand, the stored water is released through turbines to generate power in the same manner as a conventional hydropower station.
PV	photovoltaic
R&D	research and development
RA	resource adequacy
RAM	Resource Adequacy Model. RAM analysis produces reliability metrics (EUE, LOLP, LOLH) that allow us to assess physical reliability.
rate base	The amount of investment in plant devoted to the rendering of service upon which a fair rate of return is allowed to be earned. In Washington state, rate base is valued at the original cost less accumulated depreciation and deferred taxes.
RCRA	Resource Conservation Recovery Act
RCW	Revised Code of Washington
RCW 19.285	Washington's state's Energy Independence Act, commonly referred to as the state's renewable portfolio standard (RPS)
RCW 80.80	Washington state law that sets a generation performance standard for electric generating plants that prohibits Washington utilities from building plants or entering into long-term electricity purchase contracts from units that emit more than 970 pounds of GHGs per MWh.
REC	Renewable energy credit. RECs are intangible assets, which represent the environmental attributes of a renewable generation project – such as a wind farm – and are issued for each MWh of energy generated from such resources.
REC banking	Washington's renewable portfolio standard allows for RECs unused in the current year to be "banked" and used in the following year.
redirected transmission	"Redirecting" transmission means moving a primary receipt point on BPA's system. According to BPA's business practice, PSE can redirect an existing long-term or short-term, firm or non-firm transmission that it has reserved on BPA's transmission system. BPA will grant the redirect request as long as there is sufficient capacity on the system to accommodate the change.
regulatory lag	The time that elapses between establishment of the need for funds and the actual collection of those funds in rates.
REM	Residential Energy Management sector, in energy efficiency programs.

repowering	Refurbishing or renovating a plant with updated technology to qualify for Renewable Production Tax Credits under the PATH Act of 2015.
revenue requirement	Rate Base x Rate of Return + Operating Expenses
RFP	request for proposal
RHA	Renewable Hydrogen Alliance
RNG	renewable natural gas
RPS	Renewable portfolio standard. A requirement that electricity retailers acquire a minimum percentage of their power from renewable energy resources. Washington state mandates 3 percent by 2012, 9 percent by 2016 and 15 percent by 2020.
RTO	regional transmission organization
SCADA	Supervisory control and data acquisition that provides real-time visibility and remote control of distribution equipment
SCCT	Simple-cycle combustion turbine, a generating unit capable of ramping up and down quickly to meet peak resource need. Also called a peaker.
scenario	A consistent set of data assumptions that defines a specific picture of the future; takes holistic approach to uncertainty analysis.
SCC	social cost of carbon, also called SCGHG, social cost of greenhouse gases
SCGHG	social cost of greenhouse gases
SCR	selective catalytic reduction
SEIA	Solar Energy Industries Association
SENDOUT	The deterministic gas portfolio model used to help identify the long-term, least-cost combination of integrated supply- and demand-side resources that will meet stated loads.
sensitivity	A set of data assumptions based on the Mid Scenario in which only one input is changed. Used to isolate the effect of a single variable.
SEPA	Washington State Environmental Policy Act
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO2	sulfur dioxide
SOFA system	separated over-fire air system
Solar PV	solar photovoltaic technology

Stochastic analysis	Stochastic risk analysis deliberately varies the static inputs to the deterministic analysis, to test how different portfolios perform with regard to cost and risk across a wide range of potential future power prices, natural gas prices, hydro generation, wind generation, loads, plant forced outages and CO2 prices.
supply-side resources	Resources that generate or supply electric power, or supply natural gas to natural gas sales customers. These resources originate on the utility side of the meter, in contrast to demand-side resources.
T&D	transmission and distribution
TailVar90	A metric for measuring risk defined as the average value of the worst 10 percent of outcomes.
TCPL-Alberta	TransCanada's Alberta System (also referred to as TC-AB)
TCPL-British Columbia	TransCanada's British Columbia System (also referred to as TC-BC)
TC-Foothills	TransCanada-Foothills Pipeline
TC-GTN	TransCanada-Gas Transmission Northwest Pipeline
TC-NGTL	TransCanada-Nova Gas Transmission Pipeline
TEPPC	WECC Transmission Expansion Planning Policy Committee
TF-1	Firm gas transportation contracts, available 365 days each year.
TF-2	Gas transportation service for delivery or storage volumes generally intended for use during the winter heating season only.
thermal resources	Electric resources that use carbon-based or alternative fuels to generate power.
TOP	transmission operator
transmission redirect	"Redirecting" transmission means moving a primary receipt point on BPA's system. According to BPA's business practice, PSE can redirect an existing long-term or short-term, firm or non-firm transmission that it has reserved on BPA's transmission system. BPA will grant the redirect request as long as there is sufficient capacity on the system to accommodate the change.
Transport customers	Customers who acquire their own natural gas from third-party suppliers and rely on the natural gas utility for distribution service.
TSR	transmission service request
TSEP	Bonneville Power Administration's transmission service request study and expansion process.
UPC	use per customer
VectorGas	An analysis tool that facilitates the ability to model price and load uncertainty.
VERs	variable energy resources

VPP	virtual power plant
VVO	volt-var optimization
WAC	Washington Administrative Code
WACC	weighted average cost of capital
WCI	Western Climate Initiative
WCPM	Wholesale Purchase Curtailment Model
WECC	Western Electricity Coordinating Council
WECo	Western Energy Company
WEI	Westcoast Energy, Inc.
Westcoast	Westcoast Energy, Inc
Wholesale market purchases	Generally short-term purchases of electric power made on the wholesale market.
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
ZLD	zero liquid discharge

The Integrated Resource Plan (IRP) is best understood as a planning exercise that evaluates a range of potential future outcomes, considering customer needs, policies, costs, economic conditions and the physical energy system. It's the starting point for making decisions about what resources PSE may procure in the future.

Contents

1. OVERVIEW

The Integrated Resource Plan (IRP) is a planning exercise that evaluates how a range of potential future outcomes could affect PSE's ability to meet our customers' electric and natural gas supply needs. The analysis considers policies, costs, economic conditions and the physical energy system, and proposes the starting point for making decisions about what resources may be procured in the future.

Plan Highlights

The 2021 PSE electric and natural gas IRPs have been developed during a time of extraordinary change as policy makers, the utility industry and the public confront the challenge of climate change and the necessity to transition to a clean energy future.

PSE is committed to reaching the goals of the Clean Energy Transformation Act (CETA) and achieving carbon neutrality by 2030 and carbon free electric energy supply by 2045, and the electric resource plan presented here reflects these changes and goals. It includes:

- significant investments in renewable resources
- accelerated acquisition of energy conservation
- increased use of demand response
- integration of distributed energy resources like residential solar and battery energy storage
- reduced reliance on short-term market purchases in response to the changing western energy market
- inclusion of alternative fuels to operate new generating plants

The preferred portfolio reduces direct carbon emissions from PSE's electric supply by over 70 percent by 2029 and achieves carbon neutrality by 2030 through clean investments that enable a significant decrease in the generation from fossil fuel-based resources, and through alternative compliance options that may include additional renewable resources, energy efficiency, unbundled renewable energy credits or other energy transformation projects.

Legislation enacted in 2019 requires total natural gas costs to include the social cost of greenhouse gasses and related upstream carbon emissions. As a result of this policy change, the natural gas resource plan focuses on significant, aggressive acquisition of conservation due to the increase in total natural gas costs. Since the natural gas IRP analysis was completed prior to the conclusion of the 2021 Washington state legislative session, it does not include new legislation that may, if enacted, substantially change the use of natural gas in certain sectors. The requirements of any new legislation will be included in the 2023 natural gas IRP.

It is important to recognize that the IRP does not make resource or program implementation decisions. The IRP is a long-term view of what appears to be cost effective based on the best information we have today about the future. The electric IRP analysis is repeated every four years and updated every two years. The IRP’s forecasts and resource additions will change as technology advances, clean fuel options increase, resource costs decline, the wholesale energy market evolves and new policies are established. The IRP includes the Clean Energy Action Plan (CEAP). The Clean Energy Implementation Plan (CEIP) starts where the IRP/CEAP ends and develops specific four-year targets for solutions proposed in the IRP/CEAP, taking into account the equitable distribution of customer benefits and the feasibility of implementation.

Public Participation

Public and stakeholder engagement is an essential part of developing an IRP, and the engagement generated valuable feedback and suggestions from organizations and individuals that helped inform the IRP analysis. Despite the challenges posed by the pandemic, this IRP has been developed with an increased level of public participation:

- 13 public webinars were hosted, recoded and documented, between May 2020 and April 2021.
- 32 email communications were distributed to an IRP audience of over 1,400 members.
- On average, 68 participants joined the webinars and 212 unique individuals participated at least once in the process.
- The re-designed IRP website generated over 14,500 visits.
- 303 stakeholder feedback forms, with 683 stakeholder comments, were received and responded to by PSE.
- 43 scenarios and portfolio sensitivities, developed in partnership with the IRP stakeholders, were analyzed and are documented in Chapters 8 and 9.

All webinar registration information, agendas, presentation materials, technical data files, webinar recordings, chat logs and transcripts, stakeholder feedback forms, and documentation of how stakeholder feedback influenced the IRP are available online at pse.com/irp and in Appendix A.

Public involvement will continue to increase as PSE applies lessons learned from the IRP to development of the CEIP, expands public participation in the delivery system planning process and establishes an Equity Advisory Group to advise PSE as it works to ensure that all PSE customers benefit from the transition to clean energy.

Beyond Net Zero by 2045

In January 2021, PSE pledged to become a **Beyond Net Zero Carbon** energy company by 2045. The goals are aspirational, but the commitment to statewide carbon reduction is steadfast. We pledge to:

- Reduce emissions from PSE electric and natural gas operations and electric supply to net zero by 2030.
- Reach net zero carbon emissions for natural gas sales by 2045 for customer use in homes and businesses, with an interim target of a 30 percent reduction by 2030.
- Go beyond PSE’s own emissions to reduce carbon emissions in other sectors by partnering with customers and industry to identify programs and products that will enable a decarbonized region.

We do not have all of the answers yet, but with the right combination of legislative, regulatory, commercial and technological enablers, we think this degree of emission reduction is possible. PSE will leverage its decades of experience with renewable energy projects, conservation and innovation, but we will also need support and cooperation from our partners, stakeholders, developers and the community to achieve success.

Knowing the complexity of the issues involved and the need to meet many different interests, PSE is convening an external advisory committee with representation from a diverse set of community members, partners, technical experts and others.

2. CHANGES IN THE WHOLESALE ELECTRIC MARKET

While the western energy market has had surplus capacity for more than a decade, PSE's 1,500 MW of firm transmission to the Mid-Columbia market hub has served as a cost-effective means of meeting demand by accessing energy supply from the regional power market. However, the supply/demand fundamentals of the wholesale electric market have changed significantly in recent years in two important ways: Region-wide, the wholesale electric market is experiencing tightening supply and increasing volatility.

TIGHTENING SUPPLY. As customers, corporations and state legislatures across the Western Interconnect prefer or require power from clean energy sources, the market's resource mix has changed. Since 2016, nearly 15,000 MW of clean energy resources, namely intermittent wind and solar, and 500 MW of batteries have been added to the Western Interconnect, while at the same time, 12,000 MW of traditional, dispatchable coal and natural gas resources have been retired or mothballed. With less dispatchable generation capacity within the Western Interconnect, market supply/demand fundamentals have tightened.

INCREASING VOLATILITY. In response to tighter supply/demand conditions, volatility has also increased. While wholesale electricity prices remain low, on average, in the Pacific Northwest, the region is starting to experience energy price spikes when there is limited supply. Notable events include the summer of 2018, when high regional temperatures coincided with forced outages at Colstrip, and March 2019, when regional cold temperatures coincided with reduced Westcoast pipeline and Jackson Prairie storage availability. Most recently, in August 2020, a west-wide heat wave caused many entities in the region to take a range of actions from energy alerts to rolling blackouts.

As a result of tightening supply and increasing volatility, regional power suppliers are changing how they plan with regard to resource adequacy. Addressing resource adequacy issues on a regional basis, rather than utility by utility, could be an important step toward improving reliability in the region. Numerous regional entities, including PSE, are collaborating on development of a regional resource adequacy program. Should PSE determine the program meets the needs of PSE customers, it will be incorporated into future resource planning activities.

In the past, PSE's firm transmission capacity from the Mid-Columbia market hub has been assumed to provide PSE with access to reliable market purchases under WSPP, Schedule C[1] contracts through which physical energy can be sourced in the short-term bilateral power markets. Historically, PSE has effectively assumed this 1,500 MW of transmission capacity as equivalent to generation capacity available to meet demand. For this IRP, PSE conducted a market risk assessment to evaluate the ongoing availability of these short-term power contracts. The assessment resulted in a recommendation to limit the amount of WSPP, Schedule C contracts for the real-time, day-ahead and term market purchases within the three-year purview of PSE's Energy Supply Merchant. This recommendation will transition the historical 1,500 MW limit to a 500 MW limit by the year 2027. To replace those short-term contracts, PSE will seek firm resource adequacy qualifying capacity contracts, compliant with CETA, that meet PSE's resource adequacy requirements and align with a potential regional resource adequacy program. The peak capacity resource need and the preferred portfolio in this IRP reflect the addition of firm resource adequacy qualifying capacity contracts, while reducing the amount of short-term market purchases.

PSE's recommended approach allows PSE to survey the market for available resource adequacy qualifying agreements, and it allows for the development of the regional resource adequacy program requirements, which will help inform PSE's future needs. PSE commits to ongoing review and evaluation of resource adequacy needs as the region addresses capacity deficits, and we expect to continue to address this high-priority issue in the 2023 IRP progress report. Ongoing technology advancements, the outcome of the All-source Request for Proposal (RFP), and regional resource adequacy program developments are expected to inform the IRP progress report.

1/ https://www.wspp.org/pages/Agreement.aspx

3. ELECTRIC RESOURCE PLAN

The preferred electric portfolio is the result of IRP analyses that evaluate a range of potential future resource portfolios to identify the lowest reasonable cost, least risk portfolios that meet customer needs, policy requirements and support the equitable transition to a clean energy future, while maintaining affordability and reliability for customers. PSE's commitments to these objectives are embodied in the preferred portfolio.

The preferred portfolio should be interpreted as a forecast of resource additions that look like they will be cost effective in the future, given what we know about resource and technology trends today. PSE does not make resource decisions in the context of the IRP; actual resource decisions are based on real costs and feasibility discovered through the resource acquisition process and the Clean Energy Implementation Plan.

Electric Resource Need

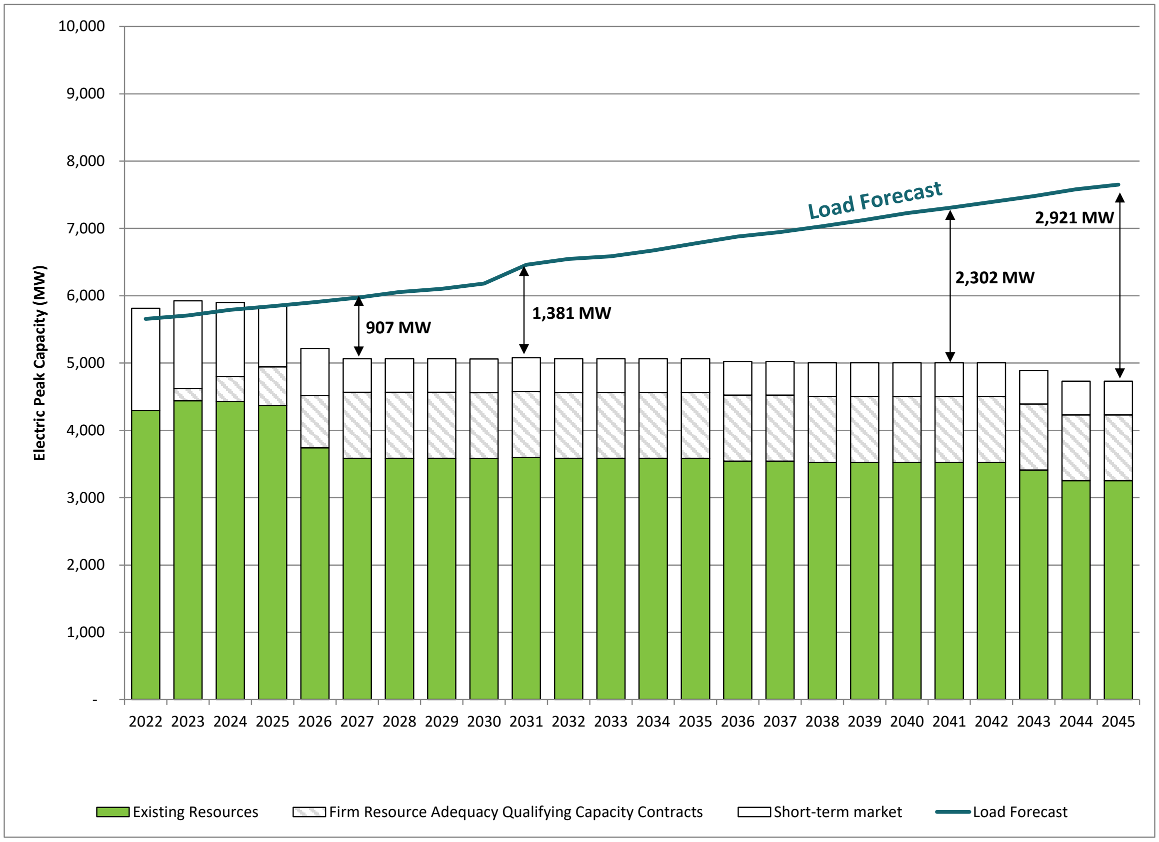
Meeting our customers' needs reliably is the cornerstone of PSE's energy supply portfolio. For resource planning purposes, the physical electricity needs of our customers are simplified and expressed as three resource needs:

1. **Peak hour capacity reliability**: PSE must have the capability to meet customers' electricity needs reliably during peak demand hours;
2. **Hourly energy**: PSE must have enough energy available in every hour of the year to meet customers' electricity needs; and
3. **Renewable energy**: PSE must have enough renewable and non-emitting (clean) resources to meet the legal requirements of the Energy Independence Act and the Clean Energy Transformation Act.

Peak Hour Capacity Need

Peak hour capacity need is determined through a resource adequacy analysis that evaluates existing PSE resources compared to the projected peak need over the planning horizon. Due to the retirement of exiting coal resources, PSE may begin to experience a peak capacity shortfall starting in 2026. Before any conservation, the peak capacity need plus the planning margin required to maintain reliability is 907 MW by 2027. The 907 MW is the difference between the load forecast (the demand forecast plus the required planning margin) and the total peak capacity credit of existing resources. Figure 1-1 shows peak capacity need through 2045. After reducing short-term market purchases as discussed in the previous section, the peak capacity need increases to 1,853 MW by the year 2027.

Figure 1-1: Electric Peak Hour Capacity Need

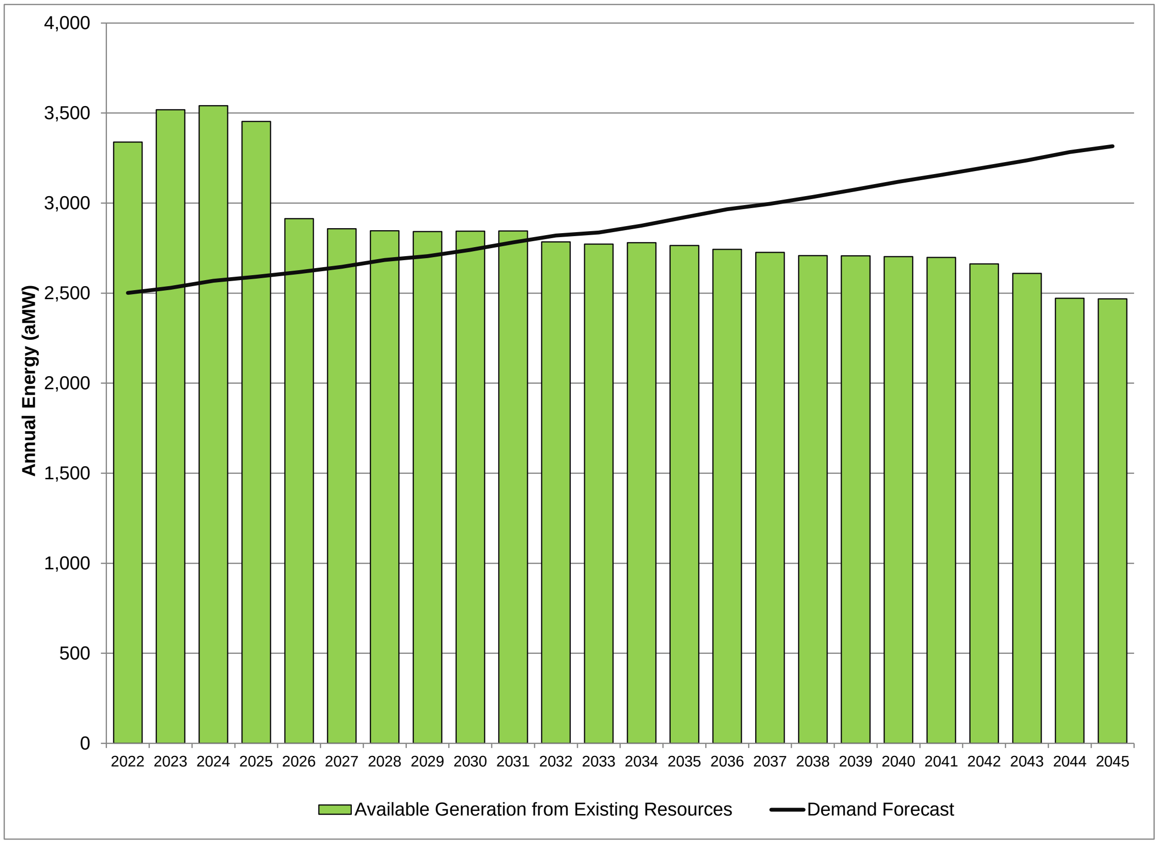


Energy Need

Customer energy needs must also be met in every hour of the year. PSE IRP models require portfolios to supply the amount of energy needed to meet physical loads, and also examine how to do this most economically through existing resources, new resources and purchasing and selling electricity on the energy market. PSE's existing portfolio of supply-side and demand-side resources could generate more energy than needed to meet load on an hourly basis through to 2031; however, it is often more cost-effective to purchase energy from the market than dispatch our existing resources.

Figure 1-2 illustrates the company's energy position across the planning horizon, based on the availability of energy resources. This chart does not represent the dispatch of resources or how they will be used to meet PSE's loads, it simply looks at how much energy all the available resources that PSE owns or contracts can potentially generate. For example, PSE's thermal resources are dispatched based on economics, but this chart shows how much energy they could produce if they were run for the entire year. This chart shows that without any additional demand-side or supply-side resources, PSE could generate enough energy on an annual basis through 2031.

Figure 1-2: Annual Energy Position with Energy from All Existing Resources

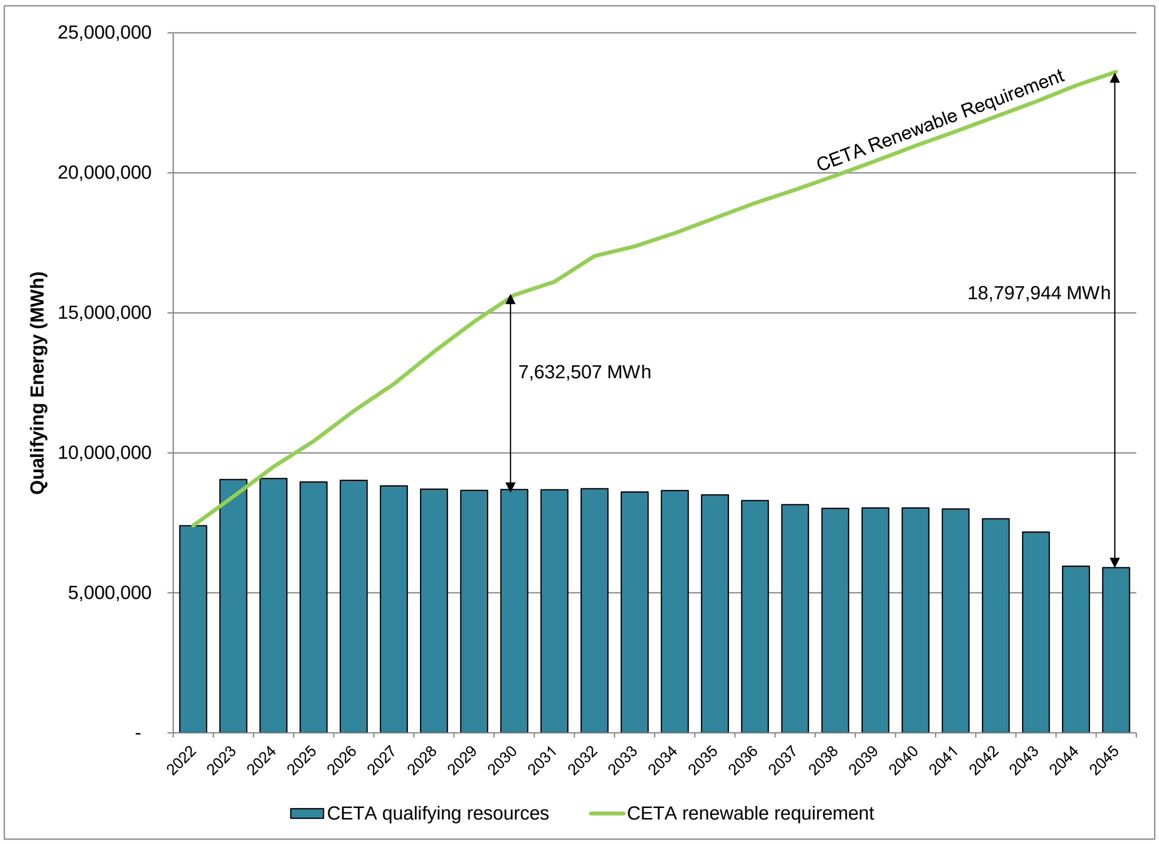


Renewable Energy Need

In addition to reliably meeting the physical needs of our customers, Washington State's Clean Energy Transformation Act (CETA) requires that at least 80 percent of electric sales (delivered load) in Washington state be met by non-emitting or renewable resources by 2030 and 100 percent by 2045.

Figure 1-3 illustrates PSE's renewable energy need. For the long-term IRP analysis, a linear ramp to achieve the Clean Energy Transformation Standards in 2030 and 2045 is assumed; however, actual resource acquisitions and the CEIP likely will produce a less linear pathway than shown here. Before any conservation, the renewable energy need is over 7.6 million MWh in 2030. The renewable need is the difference between the green line and the teal bars.

Figure 1-3: Renewable Energy Need



Electric Preferred Portfolio

The IRP preferred portfolio provides a 24-year resource outlook. As explained above, it is not an action plan; rather, it is a forecast of resource additions developed by the modeling that appears most cost effective over the 24-year period given the resource and market trends observed today, while meeting the needs described above and considering customer benefits. Updates will be made every two years and a new long-term IRP analysis will be completed every four years.

The electric preferred portfolio complies with the Clean Energy Transformation Act and is consistent with PSE’s beyond net zero carbon goals.

- **ACCELERATED ACQUISITION OF ENERGY CONSERVATION**. The portfolio includes aggressive, accelerated investment in helping customers use energy more efficiently.
- **INCREASED DEMAND RESPONSE**. Compared to previous plans, increased acquisition of demand response appears as a cost-effective resource earlier in the planning horizon. From the 16 demand response programs evaluated in this IRP, 14 were found to be cost effective over the 24-year timeframe.
- **INTEGRATION OF DISTRIBUTED ENERGY RESOURCES**. Distributed energy resources, such as battery energy storage and rooftop and ground-mounted solar, play an important role in mitigating transmission constraints. These resources may also provide non-wire solutions to meeting specific long-term needs identified on the transmission and distribution systems.
- **SIGNIFICANT INVESTMENTS IN RENEWABLE RESOURCES**. Meeting the Clean Energy Transformation Standards will require large amounts of utility-scale renewable resources located both inside and outside of Washington state. This IRP evaluated several wind and solar locations, along with hybrid combinations such as solar plus battery storage, and wind plus battery storage. Montana wind power is expected to be more cost effective than wind and solar from the Pacific Northwest because it makes a higher contribution to peak capacity needs.
- **ADDITIONAL NEED FOR FLEXIBLE CAPACITY**. A large capacity deficit is created when 750 MW of coal is removed from PSE’s portfolio in 2026. Renewable resources, distributed energy resources and demand response will contribute to meeting peak hour capacity need, but simple-cycle combustion turbines operated on biodiesel (a CETA complaint fuel) was found to be the most cost-effective way of maintaining system reliability. Given the limited run-time expected of these turbines, it is estimated that existing Washington state biodiesel production could meet the annual fuel supply needs.
- **FIRM RESOURCE ADEQUACY QUALIFYING CAPACITY CONTRACTS.** To reduce exposure to the increasingly supply challenged and volatile wholesale energy market, this

IRP recommends that up to 1,000 MW of PSE's Mid-C transmission should be filled with firm resource adequacy qualifying capacity contracts that meet PSE's reliability requirements for resource adequacy.

Figure 1-4 summarizes the forecast for additions to the electric resource portfolio in terms of peak hour capacity over the next 24 years. The preferred portfolio is a diverse mix of demand- and supply-side resources that meet the projected capacity, energy and renewable resource needs described above and considers customer benefits. Incremental resource additions are shown across three time horizons along with the total resource additions for the 24-year planning horizon.

Figure 1-4: Electric Preferred Portfolio,
Incremental Nameplate Capacity of Resource Additions

Resource Type	Incremental Resource Additions			Total
	2022-2025	2026-2031	2032-2045	
Distributed Energy Resources				
Demand-side Resources[1]	256 MW	440 MW	1,061 MW	1,757 MW
Battery Energy Storage	25 MW	175 MW	250 MW	450 MW
Solar	80 MW	180 MW	420 MW	680 MW
Demand Response	29 MW	167 MW	21 MW	217 MW
DSP Non-wire Alternatives[2]	22 MW	28 MW	68 MW	118 MW
Total Distributed Energy Resources	412 MW	990 MW	1,820 MW	3,222 MW
Renewable Resources				
Wind	400 MW	1100 MW	1750 MW	3,250 MW
Solar	-	398 MW	300 MW	698 MW
Biomass	-	-	105 MW	105 MW
Renewable + Storage Hybrid	-	-	375 MW	375 MW
Total Renewable Resources	400 MW	1,498 MW	2,530 MW	4,428 MW
Peaking Capacity with Biodiesel	-	255 MW	711 MW	966 MW
Firm Resource Adequacy Qualifying Capacity Contracts	574 MW	405 MW	-	979 MW

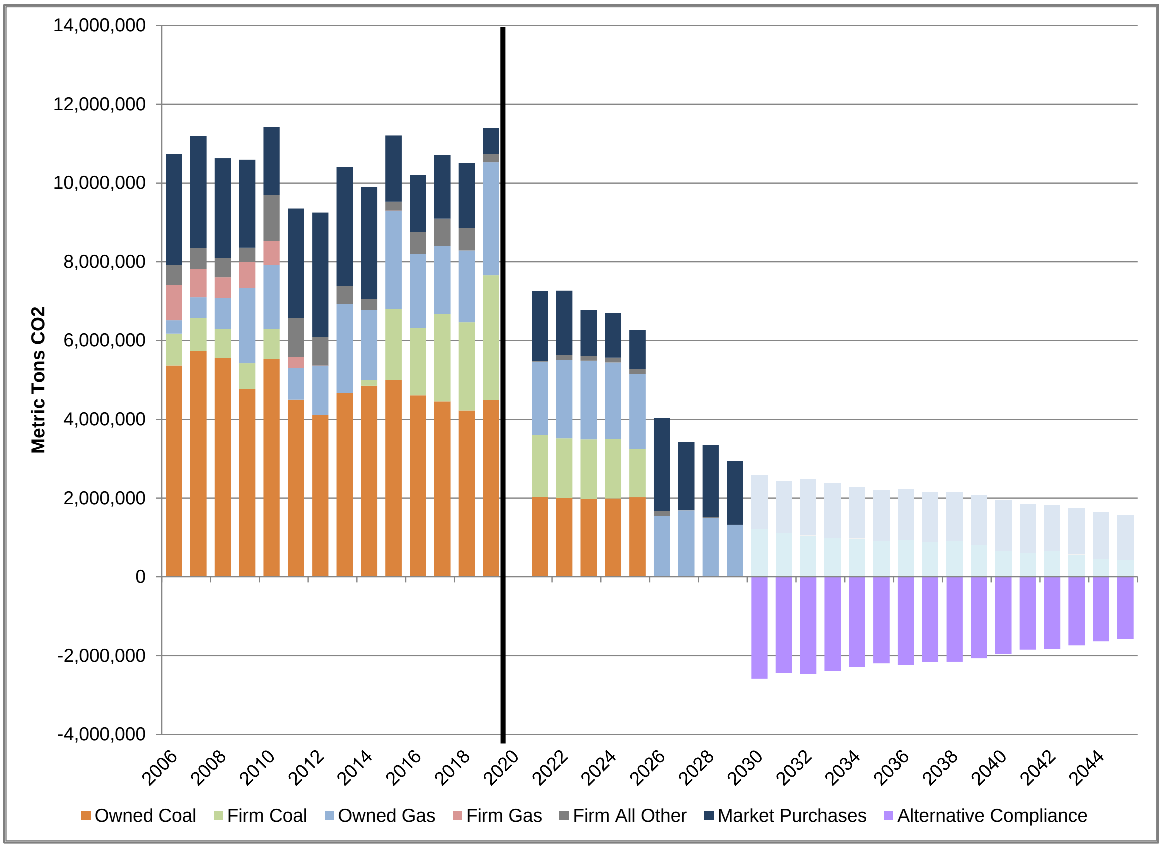
NOTES
1. Demand-side resources include energy efficiency, codes and standards, distribution efficiency and customer solar PV.
2. DSP Non-wire Alternatives are resources such as energy storage systems and solar generation that provide specific benefit on the transmission and distribution systems and simultaneously support resource needs.

PSE will work to optimize use of its existing regional transmission portfolio to meet our growing need for renewable resources in the near term, but in the long term, the Pacific Northwest transmission system may need significant expansion, optimization and possible upgrades to keep pace with the growing demand for clean energy. Investments in the delivery system are also needed to deliver energy to PSE's customers from the edge of PSE's territory and support the integration of distributed energy resources and demand response within the delivery grid.

Greenhouse Gas Emissions

PSE's resource plan achieves significant greenhouse gas emission reductions. By 2030, PSE will drastically decrease direct greenhouse gas emissions when Colstrip Units 3 and 4 retire and the coal-transition contract with TransAlta ends, along with a significantly lower economic dispatch of existing fossil-fuel resources. A substantial drop in emissions also occurred at the end of 2019 when Colstrip Units 1 and 2 retired. In 2030, PSE will achieve a carbon neutral electric portfolio through compliance mechanisms which are not yet determined but may include additional renewable resources, energy efficiency, unbundled renewable energy credits or other energy transformation projects. Figure 1-5 shows the reduction in emissions through to the end of the planning horizon.

Figure 1-5: Reduction in PSE Greenhouse Gas Emissions



Electric Short-term Action Plan

1. Acquire Energy Efficiency

Develop two-year targets and implement reliable programs that put PSE on a path to achieve an additional 53.4 aMW of energy efficiency by the end of 2023 through program savings.

Under the Energy Independence Act (EIA), Utilities must pursue all conservation that is cost-effective, reliable and feasible. They need to identify the conservation potential over a 10-year period and set two-year targets. This 10-year cost-effective savings of 266 aMW divided by 5 is called the pro-rata share, so PSE's draft 2021 EIA target for the 2022-2023 biennium is the 10-year pro-rata share, which is 53.4 aMW. If we were to look at just the 2-year savings from the cost-effective energy efficiency instead of the 10-year pro-rata share, the 2-year energy efficiency saving is only 41.7 aMW.

2. Equity Advisory Group

Convene and engage an Equity Advisory Group to provide guidance from a diversity of voices in the development of PSE's short-term and long-term strategies, initiatives and programs to ensure the equitable distribution of benefits and reduction of burdens to highly impacted communities and vulnerable populations in the transition to clean energy.

3. Mitigate Risk of Short-term Energy Market

Update internal policies for market transaction limits for PSE's Energy Supply Merchant and begin to secure firm resource adequacy qualifying capacity contracts to reduce the risk associated with short-term bilateral energy market purchases.

4. Supply-side Resources: Issue an All-source RFP

Determine and execute the appropriate resource acquisition strategy to meet the 2021 IRP resource needs with CETA-complaint resources. Ensure that all resources are evaluated across a consistent set of criteria and that appropriate enabling technologies sufficiently address the requirements necessary to support both distributed energy and utility-scale renewable resources.

5. Demand-side Resources: Develop and Issue a Demand Response and Distributed Energy Resources RFP

File a targeted RFP with the Washington Utilities and Transportation Commission no later than November 15, 2021 for both distributed energy resources and demand response resources.

Additional specific actions for the next four years will be developed and communicated in the CEIP. The electric action plan is discussed in further detail in Chapter 2, Clean Energy Action Plan.

4. ELECTRIC RESOURCE PLAN NEXT STEPS

The IRP determines the capacity, renewable and energy resource needs which set the supply-side targets for detailed planning in the Clean Energy Implementation Plan and the resource acquisition process. The CEIP will prescribe four-year targets for resources by adding near-term detail concerning resource assumptions, modeling, sensitivities and costs to PSE's 24-year IRP outlook and Clean Energy Action Plan. These costs may be derived from projects submitted through the RFP process or through other program plans, though this may be challenging in 2021 due to the compressed timeframe of the first CEIP cycle.

The formal Request for Proposal (RFP) resource acquisition processes for demand-side and supply-side resources are just one source of information for making acquisition decisions. Market opportunities outside the RFP should also be considered when making prudent resource acquisition decisions.

CETA adds a new dynamic to resource planning in the form of evaluating and determining equitable distribution of benefits for all customers, specifically in identifying highly impacted communities and vulnerable populations. In developing the CEIP, PSE will also consider the equitable distribution of benefits to customers for the proposed projects and programs, including the equitable distribution of non-energy impacts. The IRP/CEAP includes an assessment of current conditions based on economic, health, environmental, energy security and resiliency, and other metrics, and the CEIP will use the criteria from this assessment in determining the programs and projects to implement over the next four years. The CEIP takes into consideration the mix of resources from the IRP, and applies the layer of customer benefits.

5. NATURAL GAS RESOURCE PLAN

PSE develops a separate integrated resource plan to address the needs of more than 840,000 retail natural gas sales customers. This plan is developed in accordance with the Washington Administrative Code (WAC) 480-90-238, the IRP rule for natural gas utilities. The natural gas sales analysis is described in detail in Chapter 9 and supported by several Appendices.

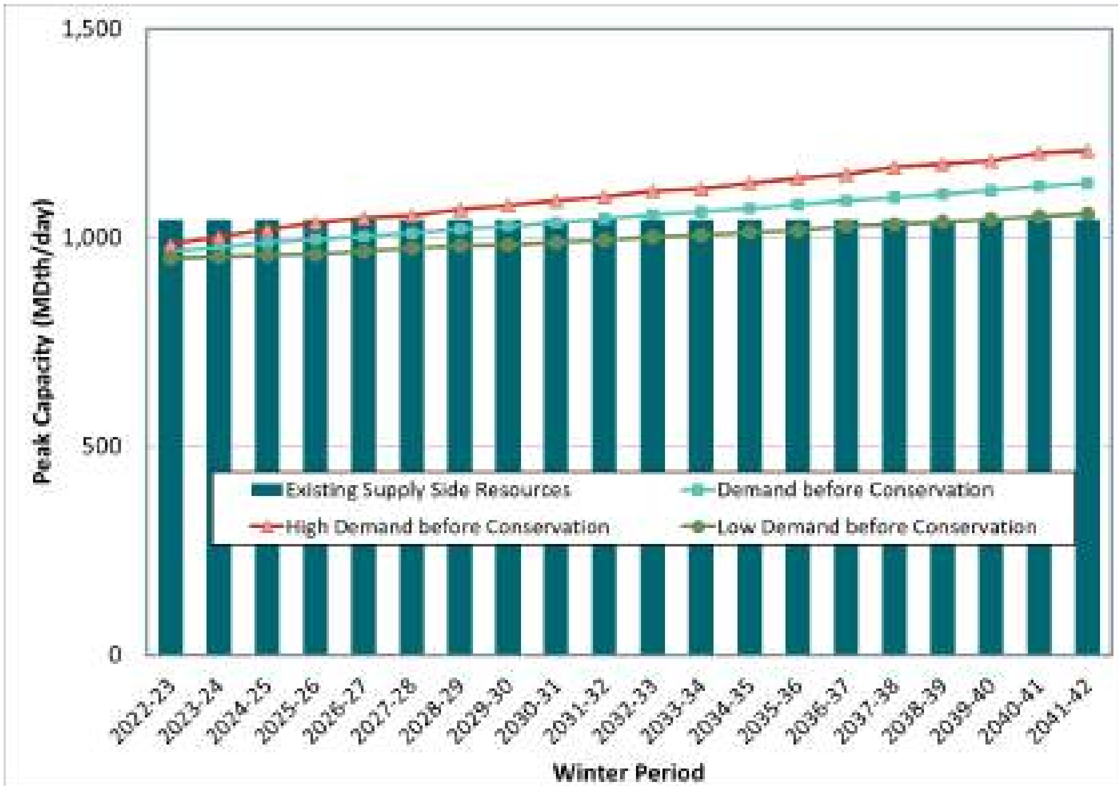
Since most of the natural gas analysis was completed prior to the 2021 Washington State legislative session, it does not include new legislation that may substantially reduce the use of natural gas in certain sectors, if enacted. While the resource plan accounts for uncertainty in demand, costs, regulations and policies, it does not account for a transformative change that could have a drastic impact on the use of natural gas. Any new legislation enacted in the 2021 legislative session that pertains to the natural gas sector will be included in the 2023 natural gas IRP.

PSE already integrates some renewable natural gas (RNG) into the delivery system to decrease carbon emissions, and PSE will continue to look for innovative ways to harvest more RNG. PSE has also begun to evaluate opportunities to partner in testing and learning how hydrogen can be blended into the natural gas system to reduce carbon emissions. This will prepare PSE to leverage the technology as supply increases, cost decreases and the technology matures.

Natural Gas Sales Resource Need

Natural gas sales resource need is driven by design peak day demand. Natural gas service must be reliable every day and the design peak demand drives the need to ensure that PSE plans for meeting firm supply on a 13-degree day. Figure 1-7 illustrates the load-resource balance for the gas sales portfolio. The lines above the bars represent three different demand scenarios analyzed in this IRP, and the bars represent firm natural gas supply. The chart demonstrates PSE has a small resource need beginning in the winter of 2031-2032, where the bars are below the Mid Demand line. Demand is shown prior to conservation since the cost-effective amount of conservation is an optimized result from the natural gas analysis.

Figure 1-7: Natural Gas Sales Design Peak Day Resource Need



Natural Gas Sales Resource Additions Forecast

The natural gas resource plan is a forecast of resource additions that look like they will be cost effective in the future given what we know about resource and market trends today. It calls for increased and continued investment in conservation to meet all future peak day capacity needs. Figure 1-8 summarizes the conservation that PSE forecasts to be cost effective in the future in terms of peak day capacity and MDth per day.

Figure 1-8: Natural Gas Resource Plan Forecast

	Cumulative Reduction to Demand (MDth/day)		
	2025-2026	2030-2031	2041-2042
Conservation	21	53	107

Conservation

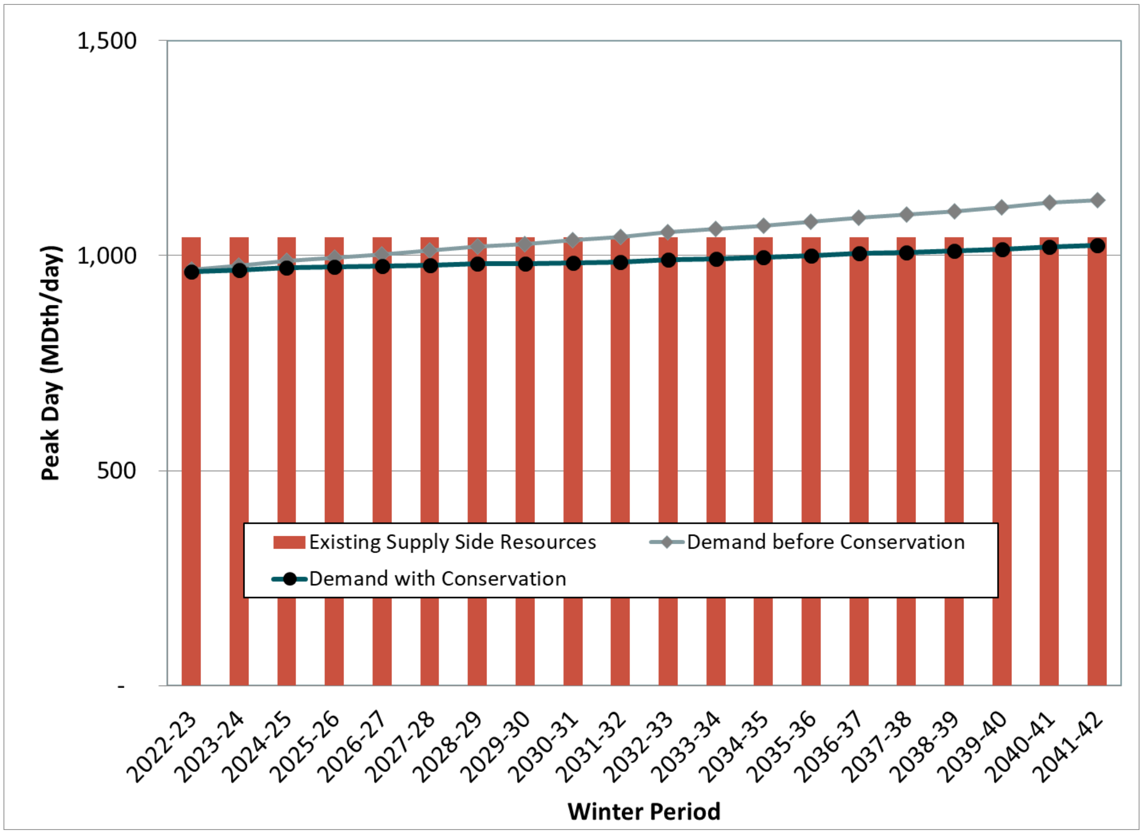
The social cost of greenhouse gases (SCGHG) has a big impact on the amount of cost-effective conservation. In 2019, the state of Washington passed new legislation that requires the inclusion of SCGHG and related upstream carbon emissions in determining cost-effective conservation. When the costs of SCGHG and upstream emissions added to natural gas prices, the resulting total cost is more three times the cost of the natural gas itself. As a result, the cost-effective amount of conservation almost doubles compared to recent energy efficiency savings and current targets, as shown in Figure 1-9.

Figure 1-9: Short-term Comparison of Natural Gas Energy Efficiency

Natural Gas Energy Efficiency	Energy Efficiency over 2-year program (MDth)
2018-2019 Actual Achievement	699
2020-2021 Target	795
2022-2023 Economic Potential in 2021 IRP	1,192

The important role that cost-effective, reliable conservation plays in moderating the need to add supply-side natural gas resources in the future can be seen in the black demand line in Figure 1-10. The bars represent the firm natural gas supply and the two lines above the bars represent natural gas demand with and without conservation.

Figure 1-10: Natural Gas Sales Resource Plan



Natural Gas Sales Short-term Action Plan

1. Acquire Energy Efficiency

Develop two-year targets and implement programs to acquire conservation, using the IRP as a starting point for goal-setting. This includes 12 MDth per day of capacity by 2024 through program savings and savings from codes and standards.

2. Renewable Natural Gas

Meet customer interest in carbon reduction programs through program development and implementation. Evaluate and develop strategies and pursue cost-effective opportunities for renewable natural gas (RNG) acquisition to support voluntary customer RNG programs and future carbon reduction.

3. Emission Reduction Strategy and Planning

Explore potential and voluntary carbon reduction opportunities, and develop and evaluate associated strategies for implementation. Bring the electric and natural gas modeling processes into closer alignment to improve the evaluation of future fuel use for power and the gas-to-electric end-use conversions. Explore the potential for the blending of clean fuels (hydrogen) with existing pipeline infrastructure and customer end use applications. Investigate a range of appliances that may assist with both reducing carbon and helping to ensure natural gas and electric system reliability on peak load days.

2 Clean Energy Action Plan

This chapter describes the 10-year Clean Energy Action Plan for implementing the Clean Energy Transformation Standards.

Contents

1. OVERVIEW

The Clean Energy Transformation Act (CETA) introduced the CEAP as a new aspect of the IRP designed to identify likely action over the next 10 years to meet the goals of CETA. The content of the Clean Energy Action Plan (CEAP) is specifically defined in WAC 480-100-620 subsection 12. This chapter follows the structure defined in subsection 12 and short-term actions are outlined in Chapter 1. This is the first IRP to include a CEAP, and as with any new requirement or assessment, the CEAP will evolve over time, and future IRPs will benefit from the lessons learned in this first implementation of the new planning process.

PSE is committed to achieving the goals of the Clean Energy Transformation Act (CETA) and achieving carbon neutrality by 2030 and carbon free electric energy supply by 2045, and CEAP presented here reflects these changes and goals. Specifically, the CEAP provides a 10-year outlook that refines the IRP preferred portfolio. In turn, the CEAP informs the Clean Energy Implementation Plan (CEIP), which develops specific targets, interim targets and actions over a 4-year period per RCW 19.405.060.

2. EQUITABLE TRANSITION TO CLEAN ENERGY

Assessment of Current Conditions

CETA sets out important new planning standards that require utility resource plans to ensure that all customers benefit from the transition to clean energy. To achieve this goal, PSE performed an Economic, Health and Environmental Benefits (EHEB) Assessment (or “the Assessment”) to provide guidance for development of the utility’s CEAP and CEIP. The purpose of the Assessment is two-fold: first, to identify highly impacted communities and vulnerable populations within PSE’s service territory; and second, to measure disparate impacts to these communities using specific customer benefit indicators.

At the November 2020 IRP meeting, PSE outlined the methodology and proposed customer benefit indicators to be used in the Assessment and solicited stakeholder feedback. This feedback was incorporated into the development of the Assessment, as well as insights gained from the WUTC’s December 2020 final rulemaking language and associated adoption order and the February 2021 Cumulative Impact Analysis completed by the Washington Department of Health. A full description of the methods, results and future plans for the Assessment are available in Appendix K.

PSE recognizes the importance of developing a process in which all voices are included and heard, and acknowledges that the IRP public participation process is only the first incremental step in seeking stakeholder feedback on the Assessment. Many populations and communities are not represented in the IRP public participation process. This will be an important part of the evolution of the resource planning process, and PSE anticipates additional engagement through the CEIP public participation process and in future IRP cycles.

The initial qualitative and quantitative customer benefit indicators developed through the Assessment provide a snapshot in time of the economic, health, environmental, and energy security and resiliency impacts of resource planning on highly impacted communities and vulnerable populations within PSE’s service territory. Due to the timing of the IRP process and the new CETA regulations, the initial customer benefit indicators included in the CEAP should be viewed as preliminary and likely to change through public participation and input from PSE’s Equity Advisory Group. The initial customer benefit indicators will be modified and evaluated over time to measure progress towards achieving an equitable distribution of benefits and reduction of burdens.

Role of the Equity Advisory Group

As part of the CEIP public participation process, PSE is establishing an Equity Advisory Group to provide specific input on the first CEIP, due in October of 2021, as well as on the implementation of that plan. In future planning cycles, the Equity Advisory Group's input will be important to incorporate starting with the planning for the IRP process. This will be an important area of learning and improvement through the entire planning cycle from the IRP through to the CEIP.

Customer Benefit Indicators

A key component to ensuring the equitable distribution of burdens and benefits in the transition to a clean energy future is to include customer benefit indicators in the preferred portfolio development process. For this IRP, due to the timing of the rulemaking and establishment of the Equity Advisory Group, PSE was only able to incorporate feedback during the IRP public process. Future IRPs will have the benefit of input from the Equity Advisory Group and the CEIP public participation process.

To reflect customer benefit indicators in the development of the preferred portfolio, the customer benefit indicators were first linked to specific portfolio modeling outputs. These outputs were then combined into broader customer benefit indicator areas which provided a context for interpreting the portfolio outputs. Each portfolio from the sensitivity analyses was ranked on how well it performed in each of the customer benefit indicator areas to get an understanding of which benefits or burdens it may confer upon PSE's customers. Portfolios had to score well in several customer benefit indicator areas to be considered a preferred portfolio. The customer benefit indicator framework is described in more detail in Chapters 3 and 8.

In summary, PSE is taking several preliminary actions to ensure that all customers benefit from the transition to clean energy:

1. Establishing the Equity Advisory Group
2. Developing a public participation plan for the CEIP to obtain input on equitable distribution of benefit and burdens
3. Refining customer benefit indicators and metrics with the EAG and the CEIP public participation process
4. Updating the Customer Benefits Analysis to incorporate the customer benefit indicators and related metrics in the CEIP and future IRPs

3. 10-YEAR CLEAN RESOURCE ADDITIONS

10-Year Clean Resource Summary

In alignment with the IRP 24-year outlook, Figure 2-1 below summarizes the 10-year outlook for the resource mix in the preferred portfolio. The customer benefit indicators informed the final selection of resources while also ensuring the preferred portfolio met PSE's peak capacity, energy and renewable needs and addressed market risk.

Figure 2-1: 10-year Annual Resource Additions Preferred Portfolio

Resource Type	Incremental Nameplate Resource Additions (MW)										Total (MW)
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
Distributed Energy Resources											
Demand-side Resources											
Energy Efficiency	36	39	41	42	44	47	50	50	54	56	458
Distributed Generation – Solar PV	0.2	0.4	0.7	1.2	2.1	3.6	6.1	10	16	18	58
Distribution Efficiency	1.2	0.3	0.7	1.8	1.2	1.3	1.3	1.3	1.3	1.3	12
Codes & Standards	37	24	19	12	15	14	25	13	4	6	169
Total Demand-side Resources	74	64	61	57	63	66	82	75	75	81	696
Battery Energy Storage	-	-	-	25	25	25	25	25	50	25	200
Solar - ground and rooftop	-	-	-	80	30	30	30	30	30	30	260
Demand Response	-	5	6	18	27	34	40	27	26	13	196
DSP Non-wire Alternatives	3	6	9	4	3	5	6	5	4	4	50
Total Distributed Energy Resources	78	75	75	184	148	160	183	161	185	153	1,402
Renewable Resources											
Wind	-	-	-	400	200	400	-	200	200	100	1,500
Solar	-	-	-	-	-	100	-	100	198	0	398
Total Renewable Resources	-	-	-	400	200	500	-	300	398	100	1,898
Peaking Capacity with Biodiesel	-	-	-	-	255	-	-	-	-	-	255
Firm Resource Adequacy Qualifying Capacity Contracts	-	185	187	202	202	203	-	-	-	-	979

Conservation Potential Assessment

Demand-side resource (DSR) alternatives are analyzed in a Conservation Potential Assessment and Demand Response Assessment (CPA) to develop a supply curve that is used as an input to the IRP portfolio analysis. Then the portfolio analysis determines the maximum amount of energy savings that can potentially be captured without raising the overall electric portfolio cost. This identifies the cost-effective level of DSR to include in the portfolio. The full assessment is included in Appendix E.

PSE included the following demand-side resource alternatives in the CPA that was performed by The Cadmus Group for this IRP. While the IRP evaluates demand-side resources through the CPA process, the CEIP will establish the specific targets for renewable energy, energy efficiency and demand response, and may evaluate programs aligned with those targets.

- **ENERGY EFFICIENCY MEASURES.** This includes a wide variety of measures that result in a smaller amount of energy being used to do a given amount of work. These include retrofitting programs such as heating, ventilation and air conditioning (HVAC) improvements, building shell weatherization, lighting upgrades and appliance upgrades.
- **DEMAND RESPONSE (DR).** Demand response resources are comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost. The achievable technical potential for demand response was assessed through the CPA, and the cost-effective demand response programs identified in this IRP are described in a separate section below.
- **DISTRIBUTED GENERATION.** Distributed generation refers to small-scale electricity generators located close to the source of the customer's load on customer's side of the utility meter. The CPA identifies combined heat and power (CHP) and customer-owned rooftop solar as distributed generation. Other distributed energy resources are also evaluated in this IRP and described in a separate section below.
- **DISTRIBUTION EFFICIENCY (DE).** Distribution efficiency addresses conservation voltage reduction (CVR), which is the practice of reducing the voltage on distribution circuits to reduce energy consumption, since many appliances and motors can perform properly while consuming less energy. Phase balancing is required for CVR to eliminate total current flow energy losses.
- **CODES AND STANDARDS (C&S).** These are no-cost energy efficiency measures that work their way to the market via new efficiency standards set by federal and state codes and standards. Only those in place at the time of the CPA study are included.

Figure 2-2 shows the achievable technical potential of demand-side resource savings in PSE's service territory. The year 2031 savings represent the 10-year potential starting in 2022.

Figure 2-2: 10-year Achievable Technical Potential Demand Side Resource Savings

Demand-Side Resources	Nameplate 2031	Energy Savings 2031	Peak Capacity Savings 2031
Energy Efficiency	458 MW	263 aMW	458 MW
Distributed Generation: Solar PV	58 MW	7 aMW	0 MW
Distribution Efficiency	12 MW	11 aMW	12 MW
Codes and Standards	169 MW	93 aMW	177 MW
Total Achievable Technical Potential	696 MW	374 aMW	646 MW

NOTES
1. Demand response is not included in the cost-effective DSR. It is included separately below.
2. Customer solar PV is the only distributed resource modeled as a separate measure, CHP is included in energy efficiency.
3. Given the nature of the IRP, assumptions for the models need to be set months before the IRP is finalized. This is simply of forecast of best known information at the time. Some of these forecast may have changed since the IRP inputs were finalized.

The IRP analysis evaluates the amount of demand-side resources (conservation) that is cost effective to meet the portfolio's capacity and energy needs, optimizing lowest cost and considering both distributed and centralized resources. The final analysis indicates that although current market power prices are low, accelerating the acquisition of DSR continues to be a least-cost strategy to meet renewable requirements. CETA renewable requirements result in significant increases in avoided cost, and this impacts the amount of cost-effective DSR. The large amounts of renewable resources needed to meet CETA move higher cost demand-side resources into the portfolio because conservation reduces load, thereby reducing the amount of renewable resources needed to meet requirements. Figure 2-3 shows the cost-effective amount of demand-side resources identified in the IRP by category (energy efficiency, customer solar PV forecast, distribution efficiency and codes and standards).

Figure 2-3: Cost-effective Demand-side Resources Incremental Nameplate Additions

Demand-Side Resources	Incremental Nameplate Additions		10-year Total
	2022-2025	2026-2031	
Energy Efficiency	157 MW	301 MW	458 MW
Distributed Generation: Solar PV	2 MW	56 MW	58 MW
Distribution Efficiency	4 MW	8 MW	12 MW
Codes and Standards	92 MW	77 MW	169 MW
Total Demand-side Resources	256 MW	440 MW	696 MW

NOTES
1. Demand Response is not included in the cost-effective DSR. It is included separately below.
2. Customer solar PV is the only distributed resource modeled as a separate measure, CHP is included in energy efficiency. Additional distributed energy resources were evaluated in this IRP and are described below.

Resource Adequacy

PSE has established a 5 percent loss of load probability (LOLP) resource adequacy metric to assess physical resource adequacy risk. LOLP measures the *likelihood* of a load curtailment event occurring in any given simulation regardless of the frequency, duration and magnitude of the curtailment(s). Therefore, the likelihood of capacity being lower than the load, occurring anytime in the year, cannot exceed 5 percent.

Assessing the amount of peak capacity each resource can reliably provide is an important part of resource adequacy analysis. To quantify the peak capacity contribution of renewable resources (wind, hydro and solar), PSE calculates the effective load carrying capacity, or ELCC, for each of those resources. The ELCC of a resource is unique to each utility and dependent on load shapes and supply availability, so it is hard to compare the ELCC of PSE's resources with those of other entities. Some of the ELCCs are higher and some are lower, depending on PSE's needs, demand shapes and the availability of supply-side resources. A full description of the peak capacity and ELCC values is in Chapter 7.

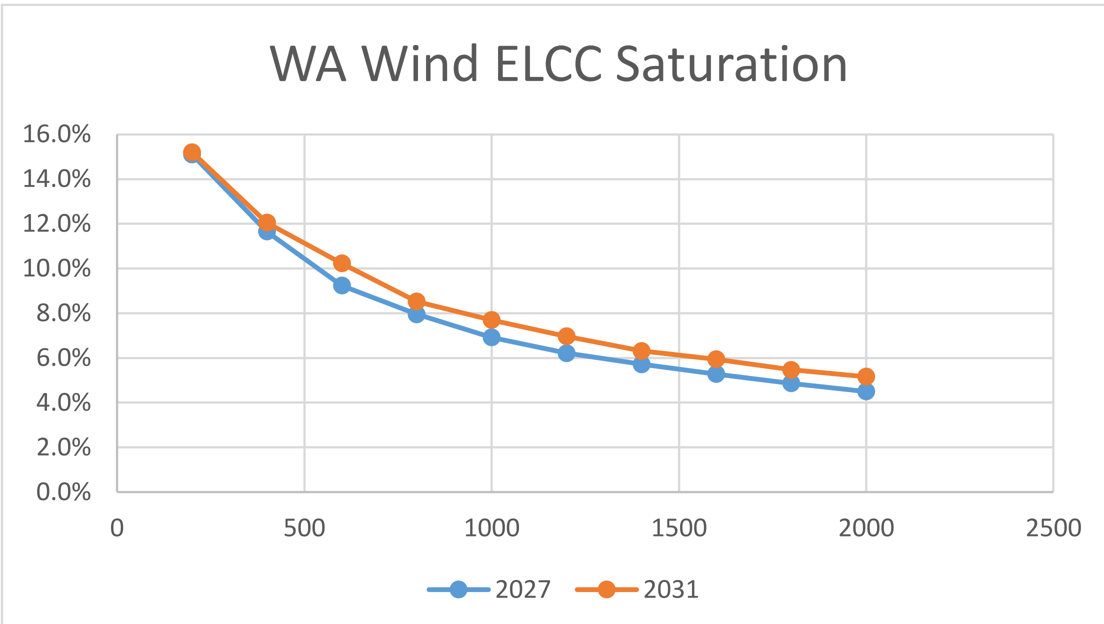
Figure 2-4 shows the estimated peak capacity credit or ELCC of the wind and solar resources included in this IRP. The order in which the existing and prospective projects were added in the model follows the timeline of when these projects are acquired or about to be acquired. The concept of resource saturation is also important to the ELCC calculation. Each incremental resource added in the same geographical area provides less effective peak capacity because it provides more of the same resource profile rather than increasing the diversity of the resource profile. The ELCC calculation for the first 100 MW of the resource is shown below in Figure 2-4, and the full saturation curve for up to 2,000 MW of Washington wind and solar is shown in Figure 2-5.

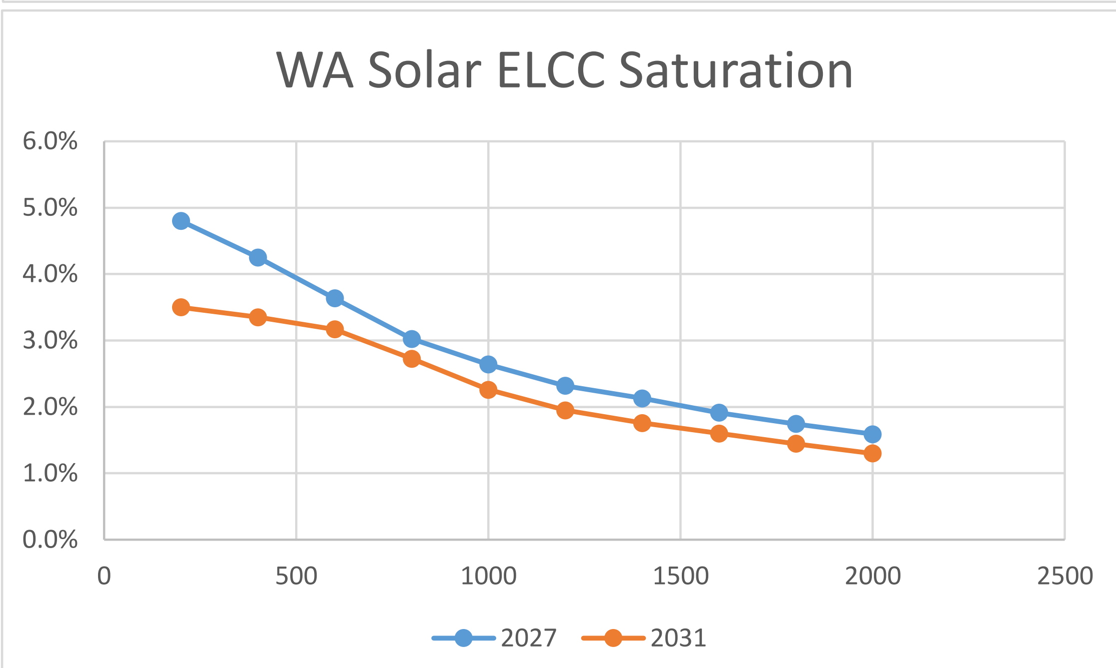
Figure 2-4: Peak Capacity Credit for Wind and Solar Resources

WIND AND SOLAR RESOURCES	Capacity (MW)	ELCC Year 2027	ELCC Year 2031
Existing Wind	823	9.6%	11.2%
Skookumchuck Wind	131	29.9%	32.8%
Lund Hill Solar	150	8.3%	7.5%
Golden Hills Wind	200	60.5%	56.3%
Generic MT East Wind1	350	41.4%	45.8%
Generic MT East Wind2	200	21.8%	23.9%
Generic MT Central Wind	200	30.1%	31.3%
Generic WY East Wind	400	40.0%	41.1%
Generic WY West Wind	400	27.6%	29.4%
Generic ID Wind	400	24.2%	27.4%
Generic Offshore Wind	100	48.4%	46.6%
Generic WA East Wind[1]	100	17.8%	15.4%
Generic WY East Solar	400	6.3%	5.4%
Generic WY West Solar	400	6.0%	5.8%
Generic ID Solar	400	3.4%	4.3%
Generic WA East Solar	100	4.0%	3.6%
Generic WA West Solar – Utility scale	100	1.2%	1.8%
Generic WA West Solar – DER Roof	100	1.6%	2.4%
Generic WA West Solar – DER Ground	100	1.2%	1.8%

ELCC SATURATION CURVES. The table above shows the peak capacity credit for the first 100 MW of installed nameplate capacity for Washington state wind and solar. Below, Figure 2-5 plots the peak capacity credit for the next 200 MW and then the next 200 MW after that and so on, showing how the peak capacity credit decreases as more wind or solar is added in the same region. Wind or solar nameplate capacity is shown in MW on the horizontal axis, and peak capacity credit as a percent of nameplate capacity is shown on the vertical axis.

Figure 2-5: Saturation curves for Washington Wind and Solar





STORAGE CAPACITY CREDIT. The estimated peak capacity credit of two types of batteries were modeled as well as pumped storage hydro. The lithium-ion and flow batteries modeled can be charged or discharged at a maximum of 100 MW per hour up to two, four or six hours duration when the battery is fully charged. For example, a four-hour duration, 100 MW battery can produce 400 MWh of energy continuously over four hours. Thus, the battery is energy limited. Figure 2-6 shows the peak capacity credit of the types of storage resources modeled in the IRP. The peak capacity credit for battery storage is low because batteries are relatively short-duration resources. Unlike generating resources, battery storage resources have to recharge; therefore, when long-duration needs for energy occur as in winter peaks, batteries provide little contribution compared to generating resources. Longer duration storage resources provide higher peak capacity credits.

Figure 2-6: Peak Capacity Credit for Energy Storage

BATTERY STORAGE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Lithium-ion, 2-hr, 82% RT efficiency	100	12.4%	15.8%
Lithium-ion, 4-hr, 87% RT efficiency	100	24.8%	29.8%
Flow, 4-hr, 73% RT efficiency	100	22.2%	27.4%
Flow, 6-hr, 73% RT efficiency	100	29.8%	35.6%
Pumped Storage, 8-hr, 80% RT efficiency	100	37.2%	43.8%

DEMAND RESPONSE CAPACITY CREDIT. The estimated peak capacity credit of demand response is shown in Figure 2-7.

Figure 2-7: Peak Capacity Credit for Demand Response

DEMAND RESPONSE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Demand Response, 3-hr duration, 6-hr delay, 10 calls per year	100	26.0%	31.6%
Demand Response, 4-hr duration, 6-hr delay, 10 calls per year	100	32.0%	37.4%

Wholesale Electric Market Risk

The wholesale electric market has changed significantly in recent years and is now experiencing tighter supply and increasing price volatility. As a result, regional power suppliers, including PSE, are making changes to how they plan with regard to resource adequacy. Addressing resource adequacy issues on a regional basis, rather than utility-by-utility, has the potential to increase reliability for all providers in the region, and as a result, numerous regional entities, including PSE, are collectively developing a regional resource adequacy program. At this time, the program has not been included in the IRP analysis because sufficient details are not yet known. However, it is important that PSE takes appropriate steps in its resource planning to allow for future participation in a regional resource adequacy program once established.

For this IRP, PSE conducted a market risk assessment to evaluate the use of its 1,500 MW of firm transmission to the Mid-Columbia market hub with short-term energy purchase agreements. . The assessment resulted in a recommendation that part of PSE's Mid-C transmission be dedicated to firm resource adequacy qualifying capacity contracts to ensure reliable service. The recommendation includes limiting the amount of real-time, day-ahead and term market purchases and replacing a portion of those energy contracts with firm resource adequacy qualifying capacity contractual arrangements to meet PSE's resource adequacy requirements as well as those of a future regional resource adequacy program. PSE has a strong preference for clean resources and contractual arrangements.

Ensuring Resource Adequacy

PSE must meet capacity need over the planning horizon with firm capacity resources or contractual arrangements to maintain reliability. All resources, including renewable resources, distributed energy resources and demand response, contribute to meeting the capacity needs of PSE's customers, but they make different kinds of contributions. This IRP determined that the limited-run use of simple-cycle combustion turbines (peakers) operated on biodiesel (a CETA complaint fuel) is the most cost effective means of ensuring resource adequacy. Chapters 3, 5 and 8 describe the numerous clean resource combinations PSE analyzed as an alternative to the biodiesel peaker solution and the significant increases in portfolio costs that resulted. Figure 2-8 summarizes the capacity needed to meet reliability requirements across the first ten years of the planning horizon. The recommended approach from the market risk assessment is also included and shown as firm resource adequacy qualifying capacity contracts.

Figure 2-8: Capacity Additions to meet Reliability

Resource Type	Incremental Resource Additions		10-year Total
	2022-2025	2026-2031	
Peaking Capacity with Biodiesel	0 MW	255 MW	255 MW
Firm Resource Adequacy Qualifying Capacity Contracts	574 MW	405 MW	979 MW

Demand Response

Demand response programs are voluntary, and once enrolled, customers usually receive notifications in advance of forecasted peak usage times requesting them to reduce their energy use. Some program types require action by the customer, others can be largely automated. For example, an automated program might warm a customer's home or building earlier than usual with no action required. In a program that requires customer action, a wastewater plant may be asked to curtail pumping during certain peak energy need hours if they can operationally do so. Because customers can always opt out of an event, demand response programs include some risk. If PSE is relying on a certain amount of load reduction from demand response to handle a peak event but customers opt out, then PSE must use generating resources to fill the customer's needs.

Demand response programs modeled for this IRP are organized into four categories. These include:

- Direct Load Control (DLC)
- Commercial and Industrial (C&I) Curtailment
- Dynamic Pricing or Critical Peak Pricing (CPP)
- Behavioral Demand Response

Figure 2-9 lists the estimated achievable technical potential for all winter demand response programs modeled for the residential, commercial and industrial sectors in this IRP. The table shows the achievable potential of each demand response program in MW and the percentage of winter peak need it fills to illustrate the total potential impact of demand response on system peak. The winter percent of system peak load was calculated as the average of PSE's hourly loads during the 20 highest-load hours in the winter of 2019. The total demand response nameplate achievable potential is 228 MW. The peak capacity credit of demand response programs is shown above in Figure 2-7. Further details about demand response programs modeled in this IRP can be found in Appendix D and E. The program costs shown include a transmission and distribution (T&D) benefit that reflects the value of the program to the distribution system non-wires alternatives. Some programs have a negative cost because the benefits they deliver are greater than their cost to the system.

Figure 2-9: Demand Response Achievable Potential and Levelized Cost by Product Option

Program	Product Option	Winter Achievable Potential (MW)	Winter Percent of System Peak	Levelized Cost ($/kW-year)
Residential CPP	Res CPP-No Enablement	64	1.28%	-$3
	Res CPP-With Enablement	2	0.04%	-$8
Residential DLC Space Heat	Res DLC Heat-Switch	50	1.00%	$71
	Res DLC Heat-BYOT	3	0.06%	$61
Residential DLC Water Heat	Res DLC ERWH-Switch	11	0.21%	$126
	Res DLC ERWH-Grid-Enabled	58	1.15%	$81
	Res DLC HPWH-Switch	< 1	< 0.1%	$329
	Res DLC HPWH-Grid-Enabled	1	0.02%	$218
Commercial CPP	C&I CPP-No Enablement	1	0.03%	$86
	C&I CPP-With Enablement	1	0.02%	$81
Commercial DLC Space Heat	Small Com DLC Heat-Switch	7	0.13%	$64
	Medium Com DLC Heat-Switch	5	0.10%	$29
Commercial and Industrial Curtailment	C&I Curtailment-Manual	3	0.06%	$95
	C&I Curtailment-Auto DR	3	0.06%	$127
Residential EVSE	Res EV DLC	9	0.17%	$361
Residential Behavioral	Res Behavior DR	9	0.17%	$76

This IRP evaluated 16 different demand response programs and 14 of those were found to be cost effective. Demand response takes a couple of years to set up before savings are achieved, so with five programs starting in 2023, the total nameplate capacity by 2025 is 29 MW due to the time it takes to establish the programs and enroll customers; by 2031, this grows to 196 MW. Figure 2-9 summarizes the cost-effective demand response nameplate capacity.

Figure 2-9: Cost-effective Demand Response Incremental Nameplate Capacity

Resource Type	Incremental Resource Additions		10-year Total
	2022-2025	2026-2031	
Demand Response	29 MW	167 MW	196 MW

Renewable Resources

For this IRP, wind was modeled in seven locations throughout the northwest United States, including eastern Washington, central Montana, eastern Montana, Idaho, eastern Wyoming, western Wyoming and off the coast of Washington. Solar was modeled as a centralized, utility-scale resource at several locations throughout the northwest United States.

Energy storage resources were modeled separately and in combination with the renewable resources. Two battery storage technology systems were analyzed, lithium-ion and flow technology. These systems are modular and made up of individual units that are generally small. Batteries provide both peak capacity and sub-hourly flexibility value. Pumped storage hydro resources were also analyzed. These are generally large, on the order of 250 to 3,000 MW, and the analysis assumes PSE would split the output of a pumped storage hydro project with other interested parties. PSE analyzed an 8-hour pumped storage hydro resource and modeled the project in 25 MW increments. In addition to standalone generation and energy storage resources, PSE modeled hybrid resources that combine two or more resources at the same location to take advantage of synergies between the resources. Three types of hybrid resources were modeled: eastern Washington solar plus 2-hour lithium-ion battery, eastern Washington wind plus 2-hour lithium-ion battery and Montana wind plus pumped storage hydro.

This IRP found that Montana and Wyoming wind power is expected to be more cost effective than wind and solar from the Pacific Northwest. Given transmission constraints, resources from the Pacific Northwest region may be limited. The timing of renewable resource additions is driven by CETA renewable requirements and is shown in Figure 2-10 below. Hybrid resources were shown to be cost effective later in the planning horizon so they are not shown in the first ten years.

Figure 2-10: Renewable Resources Incremental Nameplate Capacity

Resource Type	Incremental Resource Additions		10-year Total
	2022-2025	2026-2031	
Wind Resources	400 MW	1,100 MW	1,500 MW
Solar Resources	-	398 MW	398 MW
Total Renewable Resources	400 MW	1,498 MW	1,898 MW

Distributed Energy Resources

While the adoption of distributed energy resources (DER) is still low in PSE's service territory, about 1 percent of PSE customers are participating in net-metered solar, with an installed capacity of approximately 85 MW. As DER technology evolves and prices decline, customer adoption will likely increase. DERs will play an important role in balancing utility-scale renewable investments and transmission constraints while also meeting local distribution system needs. To accomplish this, PSE will file a draft targeted RFP with the WUTC no later than November 15, 2021 for both distributed energy resources and demand response resources, consistent with Order 05 in Docket UE-200413.

In this IRP, PSE specifically included several different types of distributed energy resources. In addition, demand response, which is considered a distributed energy resource, was also modeled in this IRP as discussed above.

BATTERY ENERGY STORAGE. Two distributed battery storage technology systems were analyzed: lithium-ion and flow technology. These battery storage systems are modular and made up of individual units that are generally small. Batteries provide both peak capacity and sub-hourly flexibility value. In addition, since they are small enough to be installed at substations or on the distribution system, they can potentially defer local transmission or distribution system investments. PSE analyzed 2-hour and 4-hour lithium-ion batteries and 4-hour and 6-hour flow battery systems.

DISTRIBUTED SOLAR GENERATION. Distributed solar generation refers to small-scale rooftop and ground-mounted solar panels located close to the source of the customer's load. Distributed solar was modeled as a residential-scale resource in western Washington.

NON-WIRES ALTERNATIVES. The role of DERs in meeting delivery system needs is changing and the planning process is evolving to reflect that change. Non-wires alternatives are being considered when developing solutions to specific, long-term needs identified on the transmission and distribution systems. The resources under study have the benefit of being able to address system deficiencies while simultaneously supporting resource needs, and they can be deployed across both the transmission and distribution systems, providing some flexibility in how system deficiencies are addressed. The non-wires alternatives considered during the planning process include energy storage systems and solar generation.

Figure 2-11 shows the battery energy storage, solar and non-wire alternatives distributed energy resources.

Figure 2-11: Distributed Energy Resources Incremental Nameplate Capacity

Resource Type	Incremental Resource Additions		10-year Total
	2022-2025	2026-2031	
Battery Energy Storage	25 MW	175 MW	200 MW
Solar	80 MW	180 MW	260 MW
Non-Wire Alternatives	22 MW	28 MW	50 MW
Total Distributed Energy Resources	127 MW	383 MW	510 MW

4. DELIVERABILITY OF RESOURCES

PSE will work to optimize use of its existing regional transmission portfolio to meet our growing need for renewable resources in the near term, but in the long term, the Pacific Northwest transmission system may need significant expansion, optimization and possible upgrades to keep pace. The main areas of high-potential renewable development are east of the Cascades (Washington and Oregon), in the Rocky Mountains (Montana, Wyoming), in the desert southwest (Nevada, Arizona) and in California. The specific opportunities for expanding transmission capabilities and regional efforts to coordinate transmission planning and investment are described in detail in Appendix J. The 10-year delivery system plan is described in Appendix M.

Investments in the delivery system are needed to deliver energy to PSE's customers from the edge of PSE's territory and to support DERs within the delivery grid. The delivery system 10-year plan described in Appendix M identifies work that is needed to ensure safe, reliable, resilient, smart and flexible energy delivery to customers, irrespective of resource fuel source. These include specific upgrades to the transmission system to meet NERC compliance requirements and other evolving regulations related to DER integration and markets and to the distribution system to enable higher DER penetration. Specific delivery system investments will become known when energy resources, whether centralized or DERs, begin siting through the established interconnection processes. The readiness of the grid and customers for DER integration will decrease the cost for interconnection and increase the number of viable locations. Proactive investments in grid modernization are also critical to support the clean energy transition and maximize benefits. The key investment areas are summarized below.

Visibility, Analysis, and Control

Data availability, integrity and granularity are critical aspects to planning for and operating DERs. Through PSE's ongoing investment in Advanced Metering Infrastructure (AMI) and SCADA at distribution substations, PSE will have new data and visibility that can be utilized for delivery system planning, customer program planning and operational analytics. AMI is an integrated system of smart meters, communications networks and data management systems that enables two-way communication between utilities and customers. AMI meters will serve to provide significant enhancements to the types and granularity of data PSE can collect to proactively plan for growth, integrate new technologies, offer services to customers, respond more quickly to system needs and operate the system safely. PSE is currently implementing an Advanced Distribution Management System (ADMS). ADMS is a computer-based, integrated platform that provides the tools to monitor and control our distribution network in real time. The implementation of ADMS will ultimately lead to advanced operational capabilities for DERs including an integrated Distributed Energy Resource Management System (DERMS). Prior to implementation of a fully integrated DERMS, PSE anticipates the need for a virtual power plant (VPP). Virtual power plants forecast and aggregate different types of DERs in order to coordinate dispatch to meet system resource needs. VPPs can aggregate DERs including demand response, EV charging management, CHP, solar PV (smart inverters) and distributed storage. Some VPPs can also manage alternative pricing programs such as Peak Time Rebates. In order to realize the dispatchable capacity benefits of the DER additions expected over the next 5 years, PSE needs a VPP to manage DER customer acquisition, forecasting, dispatch and settlement. needs a VPP to manage DER customer acquisition, forecasting, dispatch and settlement. PSE will develop the technical and operational requirements for a VPP platform in mid-2021. In addition to AMI and ADMS, SCADA provides real-time visibility and remote control of distribution equipment to reduce duration of outages, improve operational flexibility and enhance overall reliability of the distribution system.

PSE also recognizes the importance of maintaining and augmenting the data that we already have, particularly the asset data within our Geographic Information System (GIS). PSE is working to evolve GIS processes so that changes in the field can be quickly incorporated and so that data such as DER asset information is collected and displayed. GIS connects with many enterprise systems, and GIS data will be increasingly central to the ability to plan for and operate DERs. Finally, data analytics programs will support optimization of customer service and system operations including predicting asset replacement needs before failure as DERs are added to the grid.

PSE also plans to implement a geospatial load forecasting tool that includes DER forecasting capabilities as well as end-use forecasting information that supports our energy efficiency and demand response programs. With this tool we can understand not only the anticipated growth of DERs, but also the specific feeder locations. This will enable proactive system investments and potentially uncover targeted demand-side management options and support non-wires alternatives. PSE will continue to enhance its modeling tools and capabilities to ensure grid stability.

Reliability and Resiliency

To avoid reactive investments due to unanticipated DER adoption and integration and in addition to the work already described, PSE will pursue targeted, proactive asset management and system upgrades to enable DER integration and transportation electrification through ensuring a healthy system, managing load and DERs, and ensuring reliable operation. Grid modernization investments will improve the reliability of PSE systems, improve their ability to withstand and recover from extreme events, and enable smart and flexible grid capabilities. Ongoing and site-specific asset investments are needed such as pole replacement, tree-wire conductor and cable remediation programmatic transformer replacements as DERs and electric vehicles propagate, and substation and circuit enhancements that ensure or expand DER effectiveness.
Managing increasing loads will be intentional with advanced capabilities such as Volt-Var Optimization (VVO) and enabling faster system outage restoration through use of Fault Location, Isolation Service Restoration (FLISR), all enabled through the ADMS platform and additional investments in reclosers, switches, voltage regulators, capacitors banks and network communications infrastructure. FLISR will support grid reliability to enable battery energy storage charging and transportation electrification. VVO will manage voltage and reactive power as loads shift due to DER implementation.

PSE will also pursue energy security and resiliency investments such as microgrids or infrastructure hardening where specific locations require increased resilience. These locations could include highly impacted communities, transportation hubs, emergency shelters and areas at risk for isolation during significant weather events or wildfires.

DER Integration Processes

In addition to the enabling technologies, analytical capabilities and system component upgrades, PSE is investigating options and requirements for an enhanced web-based interconnection portal that would streamline the interconnection process for both customers and developers by prescreening applications. Additional customer tools, such as modifications to billing systems and program administration and design, may be needed as PSE's operating model moves from traditional one-way power flow to two-way energy flow and delivery. PSE continues to integrate non-wire alternative analysis in developing investment plans to meet various energy needs of our customers.

Security, Cybersecurity and Privacy

While pursuing our grid modernization strategy, PSE will continue to put a strong focus on cyber-security. PSE applies the same level of due diligence across the enterprise to ensure risks are consistently addressed and mitigated in alignment with the rapidly changing security landscape. PSE utilizes a variety of industry standards to measure maturity as each standard approaches security from a different perspective. As critical infrastructure technology becomes more complex, it is even more crucial for PSE to adapt and mature cyber-security practices and programs allowing the business to take advantage of new technical opportunities such as Internet of Things (IoT) devices. In addition, we continue to foster strong working relationships with technology vendors to ensure their approach to cyber-security matches PSE's expectations and needs.

Backbone Infrastructure Projects

Finally, PSE will continue to upgrade its local transmission system in order to meet NERC compliance requirements and evolving regulations related to DER integration and markets and meet peak demand reliably. PSE will deploy identified, project-specific non-wires solutions to support the near-term integration of DERs and continue to validate the DER forecast to realize predicted solutions to meet resource needs.

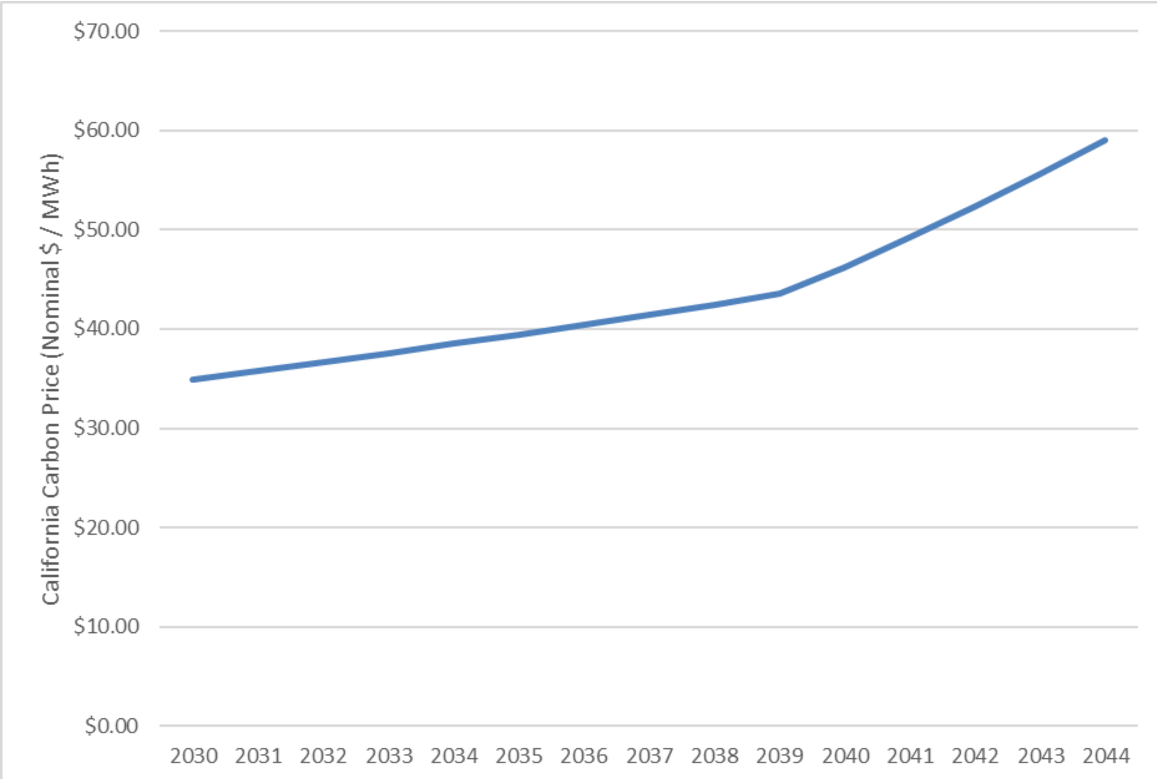
5. ALTERNATIVE COMPLIANCE OPTIONS

Under CETA, up to 20 percent of the 2030 greenhouse gas neutral standard can be met with an alternative compliance option. These alternative compliance options can be used beginning January 1, 2030 and ending December 31, 2044. An alternative compliance option includes any combination of the following:

- making an alternative compliance payment in an amount equal to the administrative penalty
- purchasing unbundled renewable energy credits
- investing in energy transformation projects that meet criteria and quality standards developed by the Department of Ecology, in consultation with the Department of Commerce and the Commission

In this IRP, PSE evaluated two alternative compliance options. For the first option, PSE assumed that unbundled renewable energy credits would be purchased for 20 percent of load not met by renewable generation starting in 2030 and decreasing linearly to zero in 2045. Because there is no a transparent forecast of the future price of unbundled renewable energy credits, PSE used the California carbon price as a proxy, as this may align with the requirement for greenhouse gas neutral electricity. The forecasted prices start at over $34 per MWh in 2030 and increase to $59 per MWh in 2044 as shown on Figure 2-12. The costs are included in all the portfolios as part of meeting the 2030 standard and in the preferred portfolio.

Figure 2-12: California Carbon Price Forecast (nominal $ per MWh)



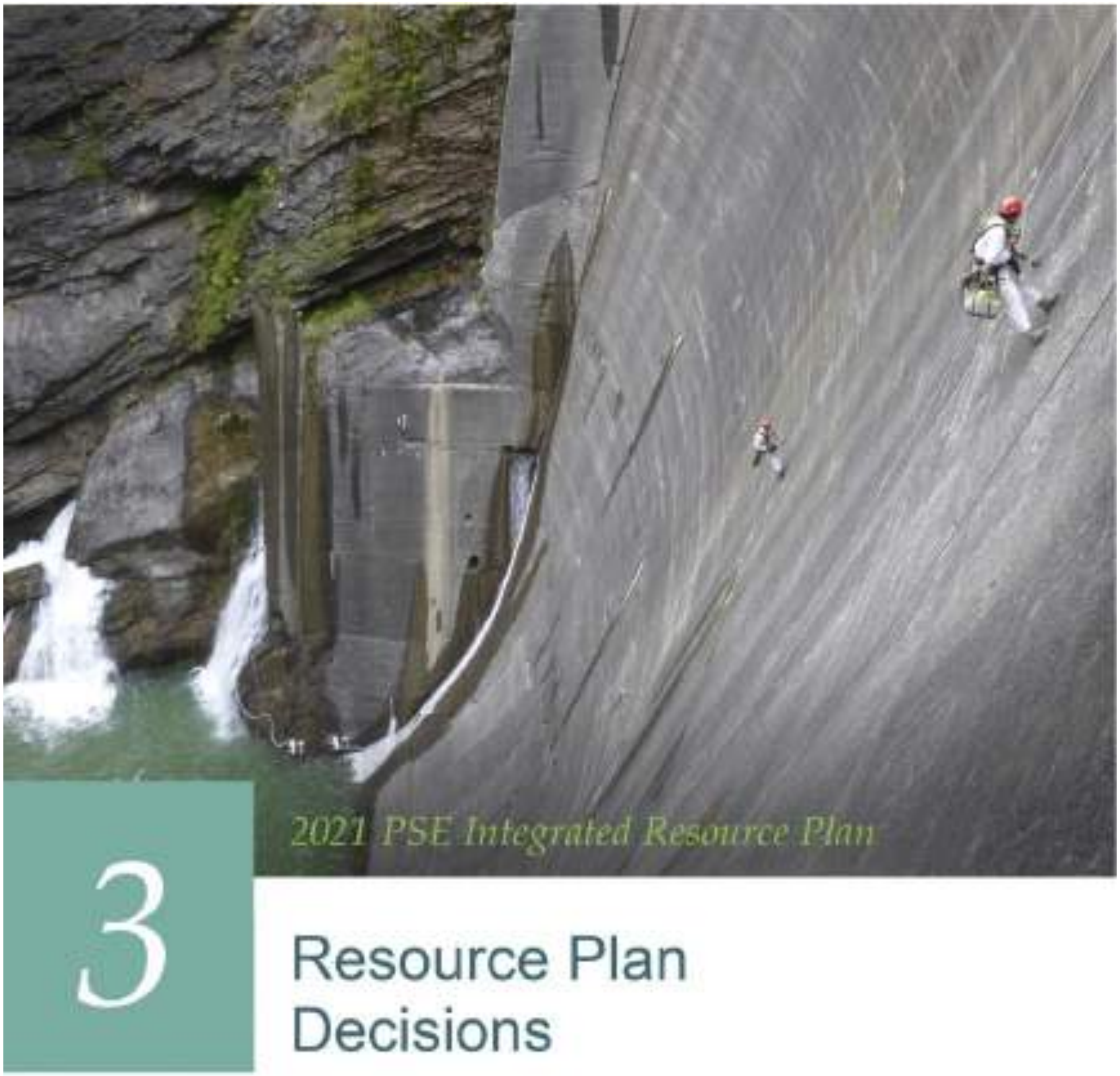
In addition to using carbon prices as a proxy price for unbundled renewable energy credits, PSE also wanted to understand the impact of meeting the 20 percent of load with renewable resources such that 100 percent of PSE's load is met with renewable resources by 2030. PSE modeled two ways of meeting this requirement; with battery energy storage and with pumped storage hydro. The total 24-year NPV of this compliance option is $32 billion with batteries and $66 billion with pumped storage hydro. The costs of these two portfolios are between $16 billion and $50 billion higher than the preferred portfolio. Chapter 8 describes these portfolios in detail in Sensitivity N.

Actual compliance may be met through other mechanisms that are still under development and will be determined in the first CEIP that includes 2030, the year the greenhouse gas neutral standard takes effect. PSE will analyze these mechanisms as the Department of Ecology develops guidance on methods for assigning greenhouse gas emission factors for electricity, establishes a process for determining what types of projects qualify as energy transformation projects, and includes other options such as transportation electrification.

6. SOCIAL COST OF GREENHOUSE GASES

The social cost of greenhouse gases (SCGHG) is applied as a cost adder in the development of the electric price forecast and in the portfolio modeling process when considering resource additions. The SCGHG is not included in the final dispatch of resources because it is not a direct cost paid by customers. CETA explicitly instructs utilities to use the SCGHG as a cost adder when evaluating conservation efforts, developing electric IRPs and CEAPs, and evaluating resources options. The SCGHG cost adder is included in planning decisions as part of the fixed operations and maintenance costs of that resource, but not in the actual cost and dispatch of any resource. A SCGHG adder is also applied to the unspecified market purchases.

The SCGHG in CETA comes from the Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document, August 2016 update. It projects a 2.5 percent discount rate, starting with $62 per metric ton (in 2007 dollars) in 2020. The document lists CO_2 prices in real dollars and metric tons. PSE has adjusted the prices for inflation (nominal dollars) and converted to U.S. tons (short tons). This cost ranges from $69 per ton in 2020 to $189 per ton in 2045. Further details can be found in Chapter 5.



This chapter summarizes the reasoning for the additions to the electric and natural gas resource plans and demonstrates how the electric resource plan meets the clean energy transformation standards.

Contents

1. OVERVIEW

The preferred portfolio is the outcome of robust IRP analyses developed with stakeholder input. It meets the requirements of the Clean Energy Transformation Act and is informed by deterministic portfolio analysis, stochastic portfolio analysis and the Customer Benefit Analysis. The preferred portfolio is a new requirement in the IRP, and this first preferred portfolio marks a significant shift in PSE's resource direction since the 2017 IRP. The preferred portfolio focuses on clean resources to meet CETA requirements, as well as increases in distributed energy resources.

To support the portfolio analysis to arrive at the preferred portfolio, three distinct types of analysis are used. Deterministic portfolio analysis solves for the least cost solution and assumes perfect foresight about the future. The stochastic analysis assesses the risk of potential future changes in hydro or wind conditions, electric and natural gas prices, load forecasts and plant forced outages. The Customer Benefit Analysis incorporates the equitable distribution of burdens and benefits into the resource planning process. All three of these analytic methods are used to identify and evaluate the preferred portfolio.

Further information on the analyses discussed here can be found in Chapters 5, 6, 7, 8, 9 and the Appendices.

2. ELECTRIC RESOURCE PLAN

Resource Additions Summary

Figure 3-1 summarizes the forecast of resource additions to the preferred electric portfolio. This portfolio prioritizes cost-effective, reliable conservation and demand response, and distributed and centralized renewable and non-emitting resources at the lowest reasonable cost to our customers. It reduces direct PSE emissions by more than 70 percent by 2029 and achieves carbon neutrality by 2030 through clean investments and projected compliance options. While implementing this highly decarbonized portfolio, the portfolio maintains the reliability required with the addition of flexibility capacity starting in 2026.

Figure 3-1: Electric Preferred Portfolio,
Incremental Nameplate Capacity of Resource Additions

Resource Type	Incremental Resource Additions			Total
	2022-2025	2026-2031	2032-2045	
Distributed Energy Resources				
Demand-side Resources[1]	256 MW	440 MW	1,061 MW	1,757 MW
Battery Energy Storage	25 MW	175 MW	250 MW	450 MW
Solar	80 MW	180 MW	420 MW	680 MW
Demand Response	29 MW	167 MW	21 MW	217 MW
DSP Non-wire Alternatives[2]	22 MW	28 MW	68 MW	118 MW
Total Distributed Energy Resources	412 MW	990 MW	1,820 MW	3,222 MW
Renewable Resources				
Wind	400 MW	1100 MW	1750 MW	3,250 MW
Solar	-	398 MW	300 MW	698 MW
Biomass	-	-	105 MW	105 MW
Renewable + Storage hybrid	-	-	375 MW	375 MW
Total Renewable Resources	400 MW	1,498 MW	2,530 MW	4,428 MW
Peaking Capacity with Biodiesel	-	255 MW	711 MW	966 MW
Firm Resource Adequacy Qualifying Capacity Contracts	574 MW	405 MW	-	979 MW

NOTES
1. Demand-side resources include energy efficiency, codes and standards, distribution efficiency and customer solar PV.
2. DSP Non-wire Alternatives are resources such as energy storage systems and solar generation that provide specific benefit on the transmission and distribution systems and simultaneously support resource needs.

Compliance with Clean Energy Transformation Standards

Electric utilities must meet the clean energy standards set by CETA at the lowest reasonable cost. In addition, safety, reliability and the balancing of the electric system must be protected, and electric utilities must ensure that all customers are benefiting from the transition to clean energy.

The clean energy transformation standards state that:

1. On or before December 31, 2025, each utility must eliminate coal-fired resources from its allocation of electricity to Washington retail electric customers;
2. By January 1, 2030, each utility must ensure all retail sales of electricity to Washington electric customers are greenhouse gas neutral; and
3. By January 1, 2045, each utility must ensure that non-emitting electric generation and electricity from renewable resources supply 100 percent of all retail sales of electricity to Washington electric customers.

CETA also contains an incremental cost of compliance mechanism that can be used for compliance purposes. In this IRP, PSE does not rely on the incremental cost of compliance mechanism to comply with CETA. All clean energy transformation standards are met with new resources.

MEETING CETA 2025 REQUIREMENTS. Colstrip is removed from PSE's electric supply portfolio by the end of 2025 and replaced with a combination of renewable resources, conservation, demand response, battery energy storage and a simple-cycle combustion turbines (a frame peaker) operated on biodiesel. Biodiesel fuel that is not derived from crops raised on land cleared from old growth or first growth forests is a CETA-compliant renewable resource; all new peaking resources modeled in this analysis are operated with biodiesel fuel, and it is the only fuel used for new peaking resources in the preferred portfolio. The October 2020 U.S. Department of Energy report on alternative fuel prices calculated the price of B99/B100 biodiesel for the west coast at $3.88/gallon.[1] PSE currently operates several peaking plants that can run a back-up fuel (distillate fuel oil) and therefore has experience with storage and transportation for diesel fuels. Given the limited run-time expected of the new turbines, the IRP analysis estimates that existing Washington state biodiesel production could meet new peaking resource fuel supply needs.

1 / Clean Cities Alternative Fuel Price Report, October 2020 (energy.gov)

MEETING CETA 2030 REQUIREMENTS. The preferred portfolio achieves 100 percent greenhouse gas neutrality by 2030 through coal plant retirements in 2025 and by replacing most of the energy produced by existing natural gas plants with renewable resources and projected alternative compliance options. The preferred portfolio meets 80 percent of sales with renewable resources by 2030 and the remaining 20 percent with clean investments and projected compliance options. The projected 20 percent alternative compliance is included as an additional cost starting in 2030.

Figure 3-2 shows the emissions by resource type for the preferred portfolio. There is a direct relationship between emissions and the dispatch of thermal resources. Direct emissions decreased with the retirement of Colstrip 1 & 2 in 2019 and will further decline with a projected lower economic dispatch of thermal resources and the exit of Colstrip 3 & 4 and Centralia from the PSE portfolio. The retirement of resources and forecasted drop in dispatch decreases the total portfolio emissions by more than 70 percent from 2019 to 2029. Through projected compliance mechanisms, the portfolio achieves carbon neutrality starting in 2030 through to 2045.

PSE also evaluated the costs associated with achieving 100 percent renewable resources by 2030. Reducing emissions and even achieving a 100 percent renewable portfolio by 2030 is possible with existing technologies, but the cost to do so is high. The massive investment in energy storage required to replace thermal resources results in portfolio costs that are $16 billion to $50 billion higher than the preferred portfolio.

Figure 3-2: Historical and Projected Annual Total PSE Portfolio CO_2 Emissions

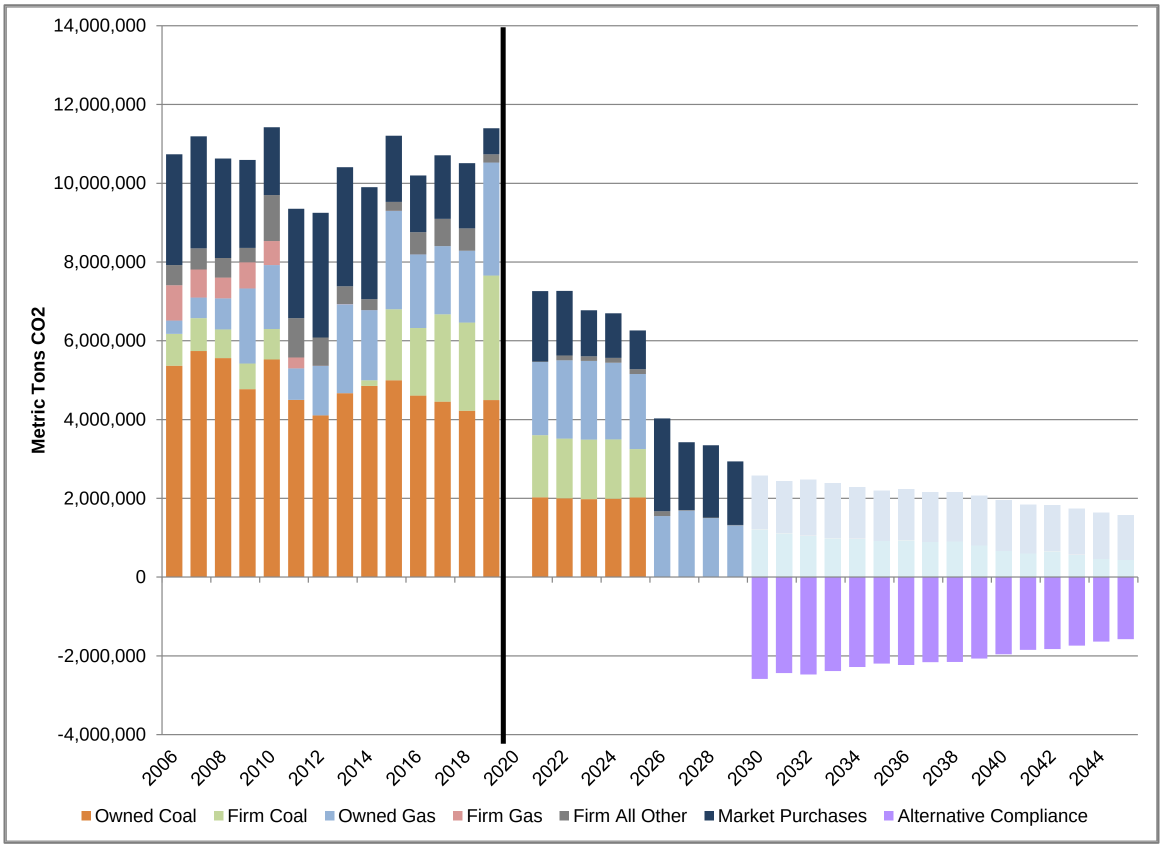
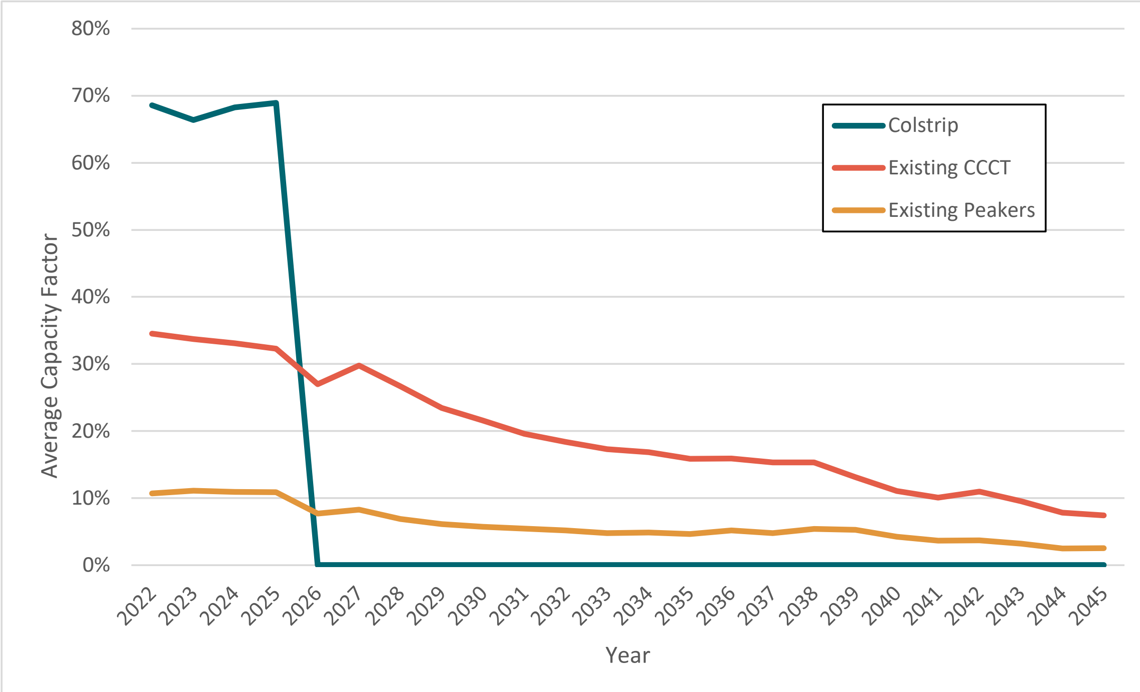


Figure 3-3 shows the annual percentage of time that the thermal resources dispatch, known as the capacity factor. Historically Colstrip dispatched around 85 percent to 90 percent of the time, but with increased costs, its dispatch has dropped below 70 percent. The existing natural gas CCCT plants average around a 35 percent capacity factor, with the highest dispatching units projected to run 60 percent to 70 of the time at the beginning of the time horizon. As new renewable resources are added to the portfolio, the projected dispatch of the existing natural gas CCCT decreases to around 7 percent by the end of the planning horizon. Existing natural gas peaking plants have always had low dispatch, since they are mostly used to maintain reliability during times of peak demand. The dispatch of the new peaking plants has an annual average capacity factor of 10 percent at the beginning of the planning horizon that drops to around 2 percent by the end of the planning horizon.

Figure 3-3: Projected Annual Thermal Resources Dispatch for PSE Existing Resources



MEETING CETA 2045 REQUIREMENTS. By 2045, 100 percent of retail sales is met by non-emitting and renewable resources. Retail sales is the total amount of energy delivered to customers. The preferred portfolio reduces the amount of energy delivered to customers by adding over 6.5 million MWh of new demand-side resources that include conservation and customer programs, and by adding almost 14.9 million MWh of new renewable resources. After demand-side resources and customer programs, PSE needs an additional 13.5 million MWh of non-emitting and renewable resources by 2045 to reach 100 percent of retail sales. The new wind, solar, biomass and hybrid resources in the preferred portfolio add 14.9 million MWh of non-emitting and renewable resources, making the preferred portfolio compliant with the 2045 CETA goal. Figure 3-4 breaks down how the preferred portfolio meets the 100 percent non-emitting and renewable resource requirement.

Figure 3-4: Calculation of 2021 IRP Preferred Portfolio CETA Compliance for 2045

	MWh
2045 Estimated Sales before Conservation[1]	29,051,232
Demand-side Resources	(6,565,285)
Line Losses	(1,529,044)
Load Reducing Customer Programs & PURPA	(1,493,096)
Sales Net of Conservation and Customer Programs	19,463,807
Existing Non-emitting and Renewable Resources[2]	(5,904,043)
Need for New Renewable/Non-emitting Resources	13,559,765
New Non-emitting and Renewable Resources	
Wind	10,767,902
Solar – Utility-scale	1,461,402
Solar – distributed ground and rooftop	963,861
Biomass	778,334
Hybrid renewable and energy storage	917,022
Total New Resources	14,888,520

NOTES
1. 2021 IRP base demand forecast with no new conservation starting in 2022.
2. Generation from existing resources assumes normal hydro conditions and P50 wind and solar.

Electric Resource Need

Reliability is the cornerstone of PSE's energy supply portfolio. For resource planning purposes, the physical electricity needs of our customers are simplified and expressed as three resource needs:

1. **Peak hour capacity for resource adequacy (reliability)**: PSE must have the capability to meet customer's electricity needs during periods of peak demand;
2. **Hourly energy**: PSE must have enough energy available in every hour to meet customer's electricity needs; and
3. **Renewable energy**: PSE must have enough renewable and non-emitting (clean) resources to meet the requirements of the Clean Energy Transformation Act.

Meeting Peak Capacity Need

Peak hour capacity need is determined through a resource adequacy analysis that evaluates existing PSE resources compared to the projected peak need over the planning horizon. Due to the retirement of existing coal resources, PSE is forecast to begin to experience a peak capacity shortfall starting in 2026. PSE uses a loss of load probability (LOLP) consistent with the Northwest Power and Conservation Council to determine the peak capacity need for its service territory. Using the LOLP methodology, before any new demand-side resources, it was determined that 907 MW of capacity would be needed by 2027 and 1,381 MW of capacity by 2031. A full discussion of the peak capacity need is presented in Chapter 7, Resource Adequacy Analysis.

The resource adequacy analysis is complex and ensures the system has enough flexibility to handle balancing needs and unexpected events, such as variations in temperature, hydro, wind and solar generation, equipment failure and plant forced outages, transmission interruption, potential curtailment of wholesale power supplies, or any other sudden departure from forecasts. Resource adequacy requires that the full range of potential demand conditions are met, even if the potential of experiencing those conditions is relatively low.

Assessing the amount of peak capacity each resource can reliably provide is an important part of resource adequacy analysis. To quantify the peak capacity contribution of renewable resources (wind, hydro and solar) and energy limited resources (batteries, pumped hydro storage and demand response), PSE calculates the effective load carrying capacity, or ELCC, for each of those resources. The ELCC of a resource is unique to each utility because it depends upon interactions between the various resources that make up each utility's unique system and is dependent on load shapes and supply availability. As a result, it is hard to compare the ELCC of PSE's resources with those of other entities and even PSE's ELCC's will change over time as system conditions change. A full description of the peak capacity and ELCC values is in Chapter 7.

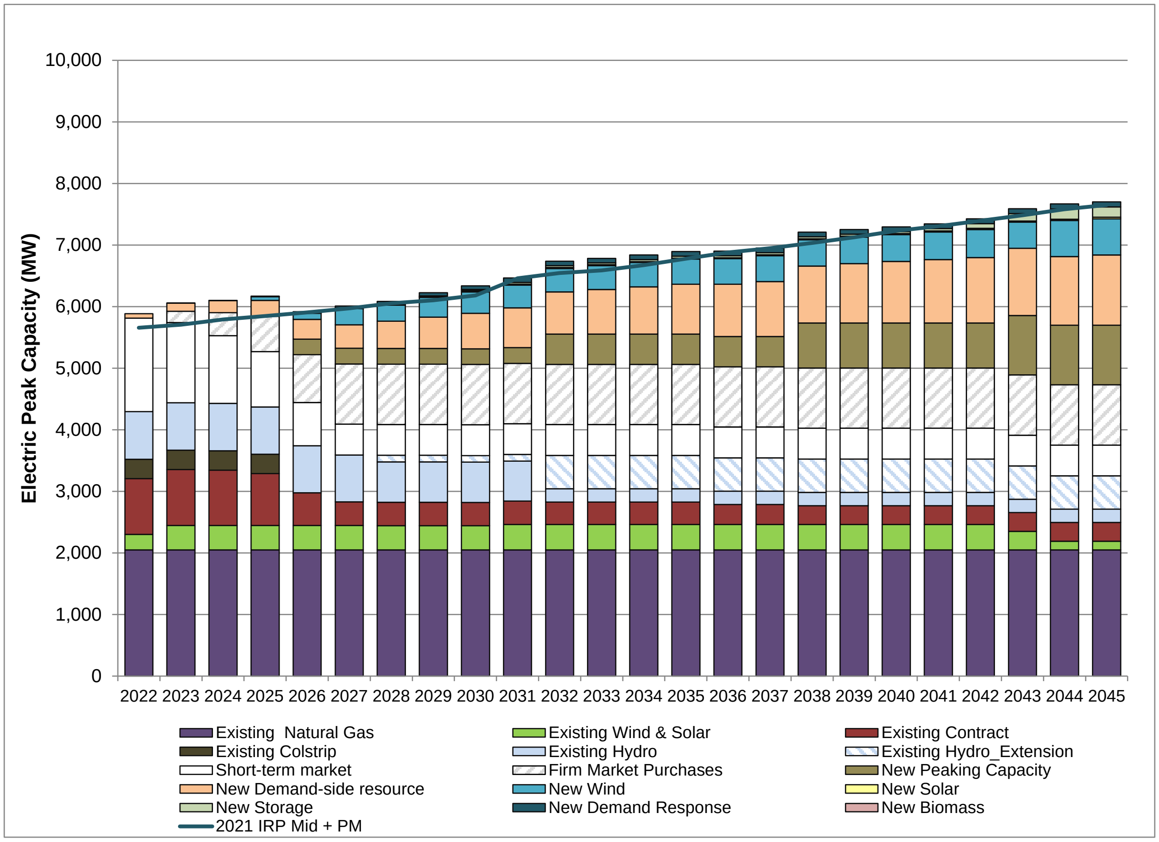
In addition to firm resources, PSE currently relies on market purchases from Mid-C to meet capacity needs. Evaluation of the existing wholesale electric market resulted in a recommendation that a portion of the available Mid-C transmission be used for firm resource adequacy (RA) qualifying capacity contracts or a reliable firm capacity resource in place of short-term energy purchases. Figure 3-5 shows, in annual increments, the conversion from short-term energy purchases to firm RA qualifying capacity purchases. As a result, in this IRP reliance on the availability of short-term market purchases at peak gradually declines over a 5-year period by 200 MW per year through the year 2027. The gray area shows PSE's total available transmission to the Mid-C market. After 2026, short-term market purchases stabilize at 500 MW and firm RA qualifying capacity purchases at 979 MW.

Figure 3-5: Short Term Market converted to Firm Resource Adequacy Qualifying Capacity Purchases

Year	Available Mid-C transmission	Short Term Market	Firm RA Qualifying Capacity Purchases
2022	1,518	1,518	-
2023	1,485	1,300	185
2024	1,472	1,100	372
2025	1,474	900	574
2026	1,476	700	776
2027	1,479	500	979
2028	1,479	500	979
2029	1,479	500	979
2030	1,479	500	979
2031	1,479	500	979

Figure 3-6 shows the preferred portfolio combination of new and existing resources required to meet the peak capacity need for the IRP mid demand forecast with an appropriate planning margin, and it reflects the peak capacity contribution of these resources. The graph also shows the market risk adjusted firm capacity (in the gray shaded bars) that will replace existing short-term Mid-Columbia energy contracts.

Figure 3-6: Preferred Portfolio Meeting Electric Peak Capacity and Reducing Market Risk



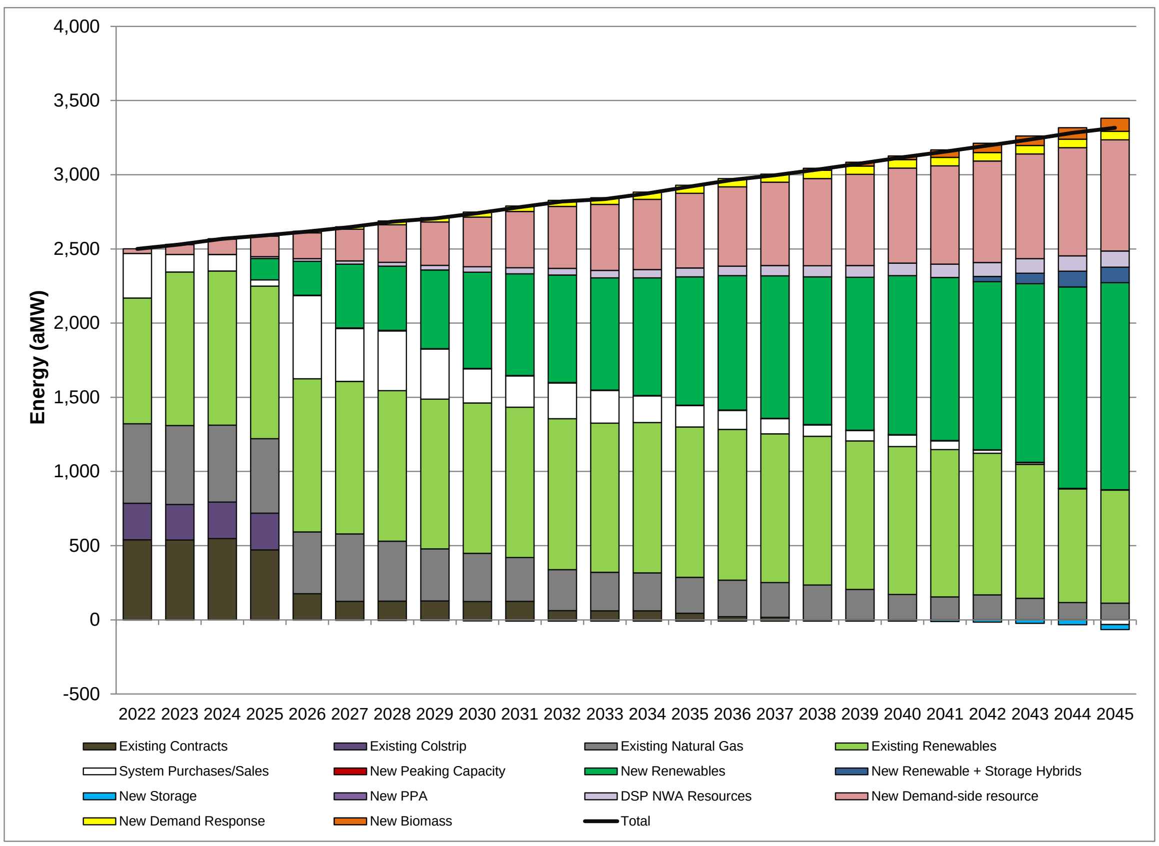
Renewable and distributed resources contribute to meeting peak capacity needs, however, peaking capacity is also needed to maintain reliability and meet required resource adequacy standards. The more than 750 MW of coal removed from PSE's portfolio by the end of 2025 is first replaced by demand-side resources, distributed energy resources and wind generation. Just 255 MW of new flexible, dispatchable capacity is added by 2026 to maintain reliability. The capacity need increases because an increase in balancing requirements is required to support the new intermittent renewable resources added to comply with CETA.

PSE evaluated early economic retirement of existing resources but that appears to increase cost. However, the economic dispatch of existing resources decreases significantly through the planning horizon as seen Figure 3-3 and is discussed further below.

Meeting Energy Need

Figure 3-7 shows the preferred portfolio combination of resources needed to meet the 2021 IRP mid demand forecast. Most of the energy need is met with renewable and distributed energy resources. The use of market purchases and sales declines over time. None of the energy requirements are satisfied with coal resources after 2025. The use of existing thermal resources significantly declines, with the capacity factor of PSE's combined-cycle combustion turbines decreasing from 70 percent for the highest dispatch units at the beginning of the planning horizon to 7 percent by the end. The pink bars represent demand-side resources, which significantly reduce total load. The black line on the chart is PSE's mid demand forecast and represents the demand at the generator, so it is grossed up for sales. This is different than the renewable need which is based on retail sales. Distributed energy storage resources are included in the portfolio but are barely visible in this chart because they are a net zero resource, meaning they do not produce any energy but rather store the energy produced by other generators. The storage resources appear as a negative value, below the line towards the end of the time horizon, and represent the energy stored.

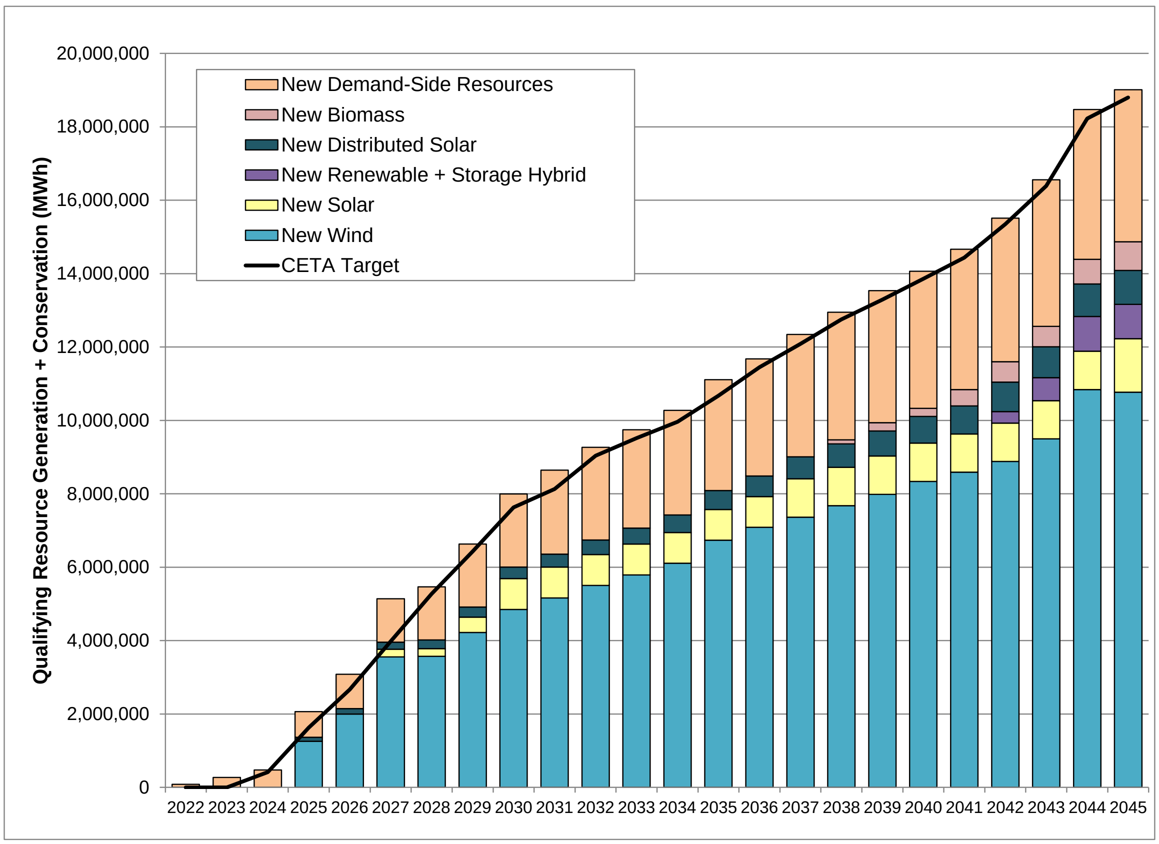
Figure 3-7: Preferred Portfolio Meeting Energy Requirements



Meeting Renewable Energy Need

The renewable energy need for both RCW 19.285 and CETA, based on the 2021 IRP mid demand forecast, is described in Chapter 8. The preferred portfolio assumes a linear ramp to achieve the 80 percent Clean Energy Transformation Standard in 2030 and 100 percent standard in 2045. Figure 3-8 shows how the new renewable resources meet the 7.6 million MWh renewable requirement in 2030 and 17.1 million MWh renewable requirement in 2045. Demand-side resources (DSR) significantly reduce loads and lower the renewable need; these include cost-effective energy efficiency, codes and standards, distribution efficiency and customer solar PV. The majority of the remaining renewable resource need is met by new wind, and then solar. Wind additions include in Montana, Wyoming and eastern Washington wind. Solar additions include utility-scale solar in eastern Washington, and distributed energy solar resources include delivery system non-wire alternatives and ground-mounted and rooftop solar PV. The chart below shows the total annual energy (MWh) produced by these resources.

Figure 3-8: Preferred Portfolio Meeting Renewable Energy Requirements



Key Findings by Resource Type

Distributed Energy Resources

There is no single perfect answer or resource that will solve all of the peak, energy and renewable needs. That is why a balanced portfolio is important, one that includes a mix of utility-scale and distributed energy resources, and a mix of intermittent, energy-limited and firm capacity resources. All of these are important components when determining the portfolio mix. The role of DERs in meeting system needs is changing, and the planning process is evolving to reflect that change. DERs make lower peak capacity contributions and have higher costs, but they play an important role in balancing utility-scale renewable investments and transmission constraints while also meeting local distribution system needs and improving customer benefits.

ENERGY EFFICIENCY. PSE has never limited the funding needed to meet energy savings targets and has consistently met and exceeded the energy savings targets called for in the Energy Independence Act (RCW 19.285). In each two-year program period from 2014 through 2019, PSE set electric savings targets that were 13 percent, 9 percent and 10 percent higher than required by the Energy Independence Act, and PSE's actual savings were 20 percent, 14 percent and 14 percent higher, respectively, than PSE's targets.

PSE encourages customers to bundle as many energy efficiency measures together as possible. This is true in both the business and residential efficiency programs. In fact, the residential program offers a bonus financial incentive for including multiple measures in a single application. PSE's program for commercial new construction and deep retrofits offers higher incentive rates for deeper reductions in energy use. The preferred portfolio includes 793 MW of the 840 MW estimated technical potential for energy efficiency found in the Conservation Potential Assessment.

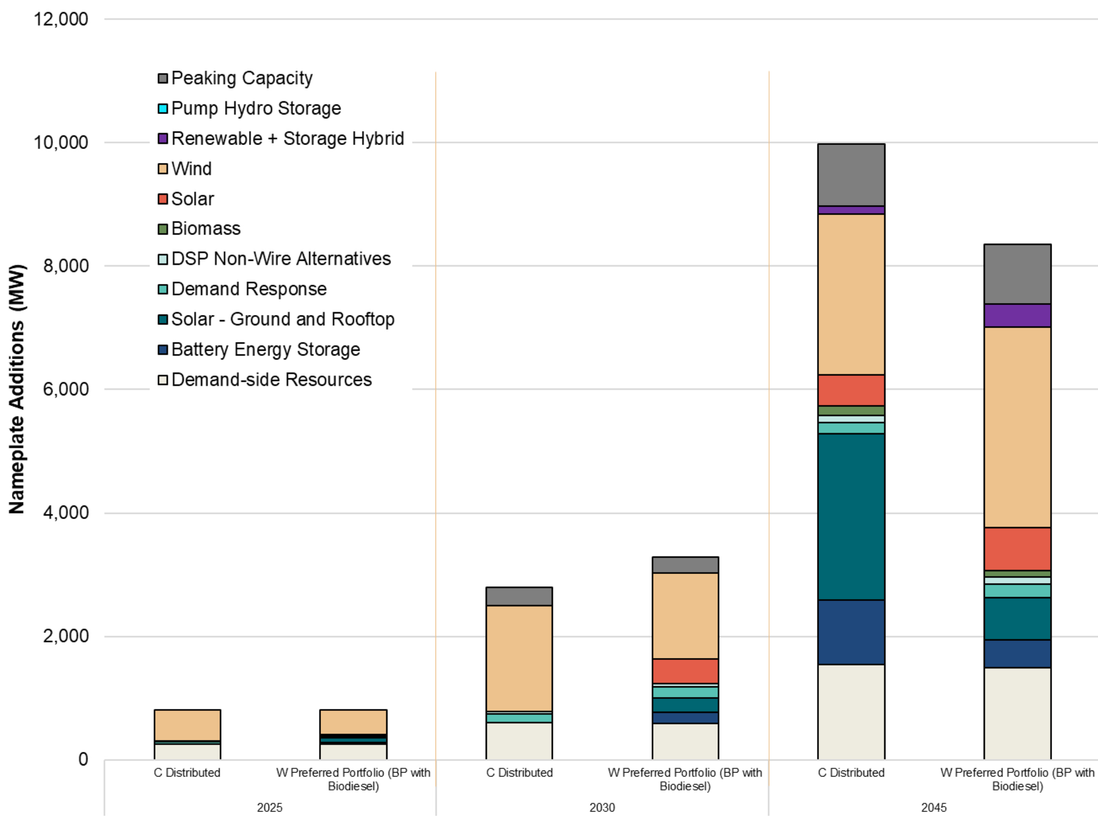
Energy efficiency is just one of the demand-side resources analyzed in this IRP. All of the demand-side resources are described in Chapter 2 and Appendix D.

BATTERY ENERGY STORAGE. The preferred portfolio includes four battery energy storage systems that range in duration from 2 to 6 hours and pumped storage hydro with a duration of 8 hours. Batteries are scalable, and fit well in a portfolio with small needs of short duration. Batteries also work as a solution for local distribution upgrades and capacity needs. In the optimized portfolio results, additional energy storage was not part of the optimized portfolio solution until the last 5 to 10 years of the planning horizon when the renewable requirement increased to more than 90 percent of delivered load. However, taking into account risk of transmission and additional customer benefits, battery energy storage is accelerated in the preferred portfolio. The lower peak capacity credit of energy storage means significantly more battery energy storage resources are needed to match the capacity provided by combustion turbines (the lowest cost resource). The preferred portfolio adds some distributed battery storage resources starting at 25 MW in 2025 and increasing to 175 MW by 2031.

SOLAR – GROUND AND ROOFTOP. Though utility-scale solar is a lower cost option for meeting CETA renewable requirements, given the transmission constraints involved in bringing remote resources to PSE's service territory, distributed solar resources have become an important part of the solution. PSE modeled both ground-mount and rooftop solar as an option to both meet CETA renewable requirements and local distribution system needs. The distributed solar includes options for both customer-owned solar (net-metering) and PSE-owned solar resources.

In Sensitivity C, which restricts transmission availability compared to the Mid Scenario portfolio, PSE analyzed the risk of obtaining new transmission contracts to eastern Washington and the availability of re-using existing transmission contracts. Based on these restrictions, more renewable resources are needed in western Washington to meet CETA renewable requirements, and the portfolio model waited until the end of the planning period to add a significant amount of distributed resources. The preferred portfolio takes the same amount of distributed resources and ramps them in over time starting in 2025 for a total of 680 MW of distributed solar. This is in addition to the 622 MW of net-metered, customer-owned solar for a total of 1,302 MW of distributed solar by 2045. Distributed solar is a good way to meet the CETA renewable requirements given transmission constraints, but it makes limited contributions toward meeting peak capacity need because it provides very little peak capacity value since PSE is a winter peaking utility. Figure 3-9 compares the preferred portfolio and Sensitivity C resource builds.

Figure 3-9: Resource Builds – 2021 IRP Preferred Portfolio and Sensitivity C (Transmission Build Constraint), Cumulative Additions by Nameplate (MW)



DEMAND RESPONSE. PSE modeled 16 demand response programs totaling 222 MW in nameplate capacity. Of those 16 programs, there are 4 different direct load control (DLC) hot water heater programs, along with critical peak pricing, DLC heating, EV charging, curtailment and critical peak pricing (CPP). The CPP programs are similar to a time-of-use (TOU) program.

To reflect the time needed to enroll customers in programs, five of the programs are ramped in starting in 2023, two programs are ramped in starting in 2025, and the remaining seven programs are ramped in starting in 2026. The five programs starting in 2023 were part of the least cost optimization in most of the portfolio sensitivities. Demand response takes a couple of years to set up before savings are achieved, so with five programs starting in 2023, the total nameplate by 2025 is 29 MW due to the time it takes to establish the programs and enroll customers. The total demand response program grows to 195 MW nameplate capacity by 2031. By 2045, an additional 21 MW of demand response is cost effective for a total of 217 MW of the 222 MW technically available.

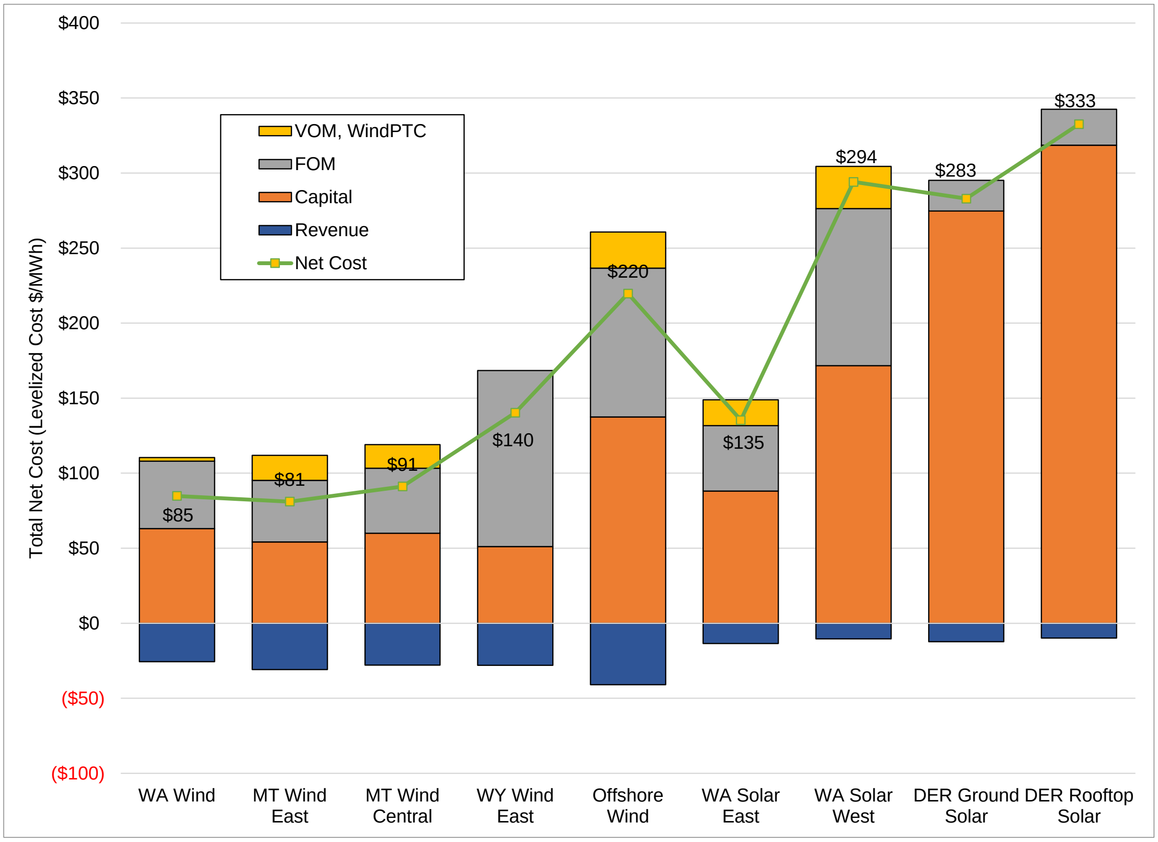
GRID MODERNIZATION. Proactive investments in grid modernization are critical to support the clean energy transition and maximize benefits. Investments in the delivery system are needed to deliver energy to PSE customers from the edge of PSE's territory and to support DERs within the delivery grid. Specific delivery system investments will become known when energy resources, whether centralized or distributed, begin to be sited through the established interconnection processes. The 10-year delivery infrastructure plans are described in Appendix M.

Utility-scale Renewable Resources

Significant investment in utility-scale renewable resources, in addition to DERs, will be needed to ensure that 100 percent of all retail electricity sales is served with renewable resources.

WIND AND SOLAR RESOURCES. The timing of renewable resource additions is driven by CETA renewable requirements. Although renewable resources also contribute to meeting capacity needs, compared to the existing, retiring coal-fired resources and other dispatchable resources, a portfolio that relies on increasing amounts of renewable resources has higher portfolio balancing requirements, which can drive up the portfolio cost. Increased renewable diversity can improve contribution to capacity needs, however resources outside of the Pacific Northwest region are limited given transmission constraints. After Montana and Wyoming wind, the costs of eastern Washington wind and solar are very close. Figure 3-10 illustrates that the levelized cost of Montana and Wyoming wind are the lowest cost renewable resources to meet CETA renewable requirements, followed by eastern Washington wind and solar. The levelized costs are calculated based on total resource costs; these include capital costs, variable operations and maintenance, and fixed operations and maintenance. Some resources include benefits from the production tax credit (PTC), and the investment tax credit (ITC). A full description of the ranges for the PTC and ITC is included in Appendix G. All resources include a benefit called revenue. This is the value of the resource in the market and is calculated as generation times the electric power price for every hour. The revenue and costs of the resources are calculated for every hour and then aggregated up to annual costs and benefit. These costs are then levelized by using net present value in 2022 dollars. Actual resource costs obtained through an RFP process could yield a different conclusion.

Figure 3-10: Levelized Cost of Wind and Solar Resources



TRANSMISSION CONSTRAINTS. Transmission capacity constraints have become an important consideration as PSE transitions away from thermal resources and toward clean, renewable resources to meet the clean energy transformation targets. Thermal resources can generally be sited in locations convenient to transmission, produce power at a controllable rate, and be dispatched as needed to meet shifting demand. In contrast, renewable resources are site-specific and have variable generation patterns that depend on local wind or solar conditions, therefore they cannot always follow load. The limiting factors of renewable resources have two significant impacts on the power system: 1) a much greater quantity of renewable resources must be acquired to meet the same peak capacity needs as thermal resources, and 2) the best renewable resources to meet PSE's loads may not be located near PSE's service territory. This makes it important to consider whether there is enough transmission capacity available to carry power from remote renewable resources to PSE's service territory. Transmission within PSE service territory will also be needed, but was assumed to be unconstrained due to delivery system planning processes and the specific projects identified in Appendix M.

The available transmission to eastern Washington can range from 700 MW to over 3,200 MW depending on the availability of new transmission contracts, upgrades on the system and the repurposing of existing contracts. PSE modeled a potentially available 750 MW of transmission from Montana and 400 MW of transmission from Wyoming. The full 750 MW of Montana wind and 400 MW of Wyoming wind appear to be cost-effective in this portfolio. There is significant risk with Wyoming wind because new transmission will need to be constructed to Wyoming, and PSE will also need to acquire new firm transmission contracts. After Montana and Wyoming wind are added to the portfolio, there is still an additional 600 MW of eastern Washington wind and 400 MW of eastern Washington solar needed by 2030. Given the risk in available transmission, over 200 MW of distributed solar is added to the portfolio to meet the 80 percent CETA renewable target in 2030. The actual location and type of renewable resources will depend on available transmission.

BIOMASS. Between 2035 and 2045, over 100 MW of biomass is added to the preferred portfolio. Although biomass has a higher capital cost than wind and solar, it is a baseload resource with an 85 percent capacity factor, which means that fewer biomass resources are needed to produce the same amount of energy that a resource such as solar can produce. PSE modeled wood waste biomass connected to lumber mills. Given the total number of mills located in western Washington, PSE estimates that around 150 MW of biomass may be feasible.

HYBRID RESOURCES. After 2040, 375 MW of hybrid wind and battery resources are added to the portfolio. Connecting a battery to an intermittent renewable resource helps to firm the capacity of the renewable resource so that it is more reliable during peak events and has a higher peak capacity contribution. However, with the battery being used to firm up the capacity of the wind resource, it is not available to meet flexibility needs, and it does not provide benefits to the transmission and distribution system. As a result, using the battery as an independent, distributed resource has more benefits to PSE than connecting it directly to a renewable resource. Hybrid resources are not cost competitive until the end of the time horizon.

Peaking Capacity with Biodiesel

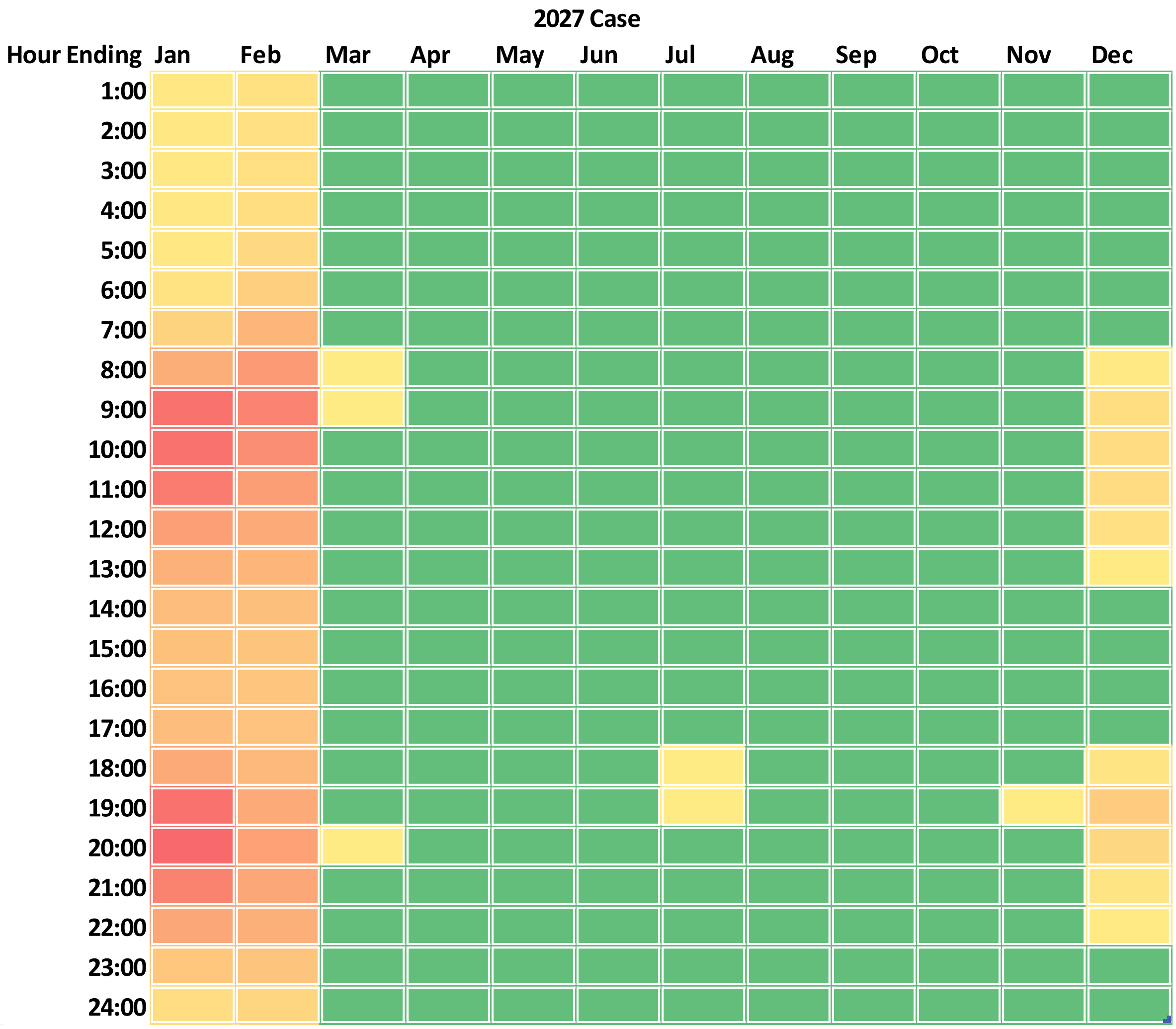
Beyond 2025, all sensitivities show a need for flexible, peaking capacity when 750 MW of coal generation is removed from PSE's portfolio in 2026. PSE is committed to pursuing all clean capacity resources first. The current modeling results show alternative fuel enabled combustion turbines as the most cost-effective resource to meet the capacity resource needs that cannot be otherwise met by demand-side resources and distributed and renewable resources. The model selected dispatchable combustion turbines as the least cost resource in particular to meet peak reliability needs, especially during periods of high load due to extremely cold weather conditions when renewable generation may be limited.

FUEL SUPPLY. In the resource adequacy analysis, PSE evaluated the biodiesel fuel supply needed for the peakers to maintain reliability. In 95 percent of simulations, the peakers are needed to run for 10,000 MWh or less to maintain resource adequacy, which is around 15 hours of run time annually. The maximum dispatch needed is 150,000 MWh, or approximately 205 hours of run time. In a report by the U.S. Energy Information Administration[2] on biofuel production, the total annual production of biodiesel in Washington state is 114 million gallons per year. To fuel 10,000 MWh of generation, peaking resources would require around 828,000 gallons of biodiesel, or about 0.7 percent of Washington State's 2020 annual production.

PEAK CAPACITY. The 12x24 table in Figure 3-11 shows the loss of load hours prior to the addition of new resources. The plot represents a relative heat map of the number of hours of lost load summed by month and hour of day. The majority of the lost load hours occur in the winter months. In this chart, the large blocks of yellow, orange, and red in January and February illustrate long duration periods, 24 hours or more, with a loss of load event. The portfolio optimization model must meet these long duration capacity shortfall events by adding new resources. Current technologies, energy storage and demand response do not completely meet the peak capacity needs because of their short duration of availability. The portfolio model needs to meet the loss of load events with resources that can be dispatched for 24 hours or more. Further discussion of the resource adequacy analysis can be found in Chapter 7.

2 / *https://www.eia.gov/biofuels/biodiesel/production/*

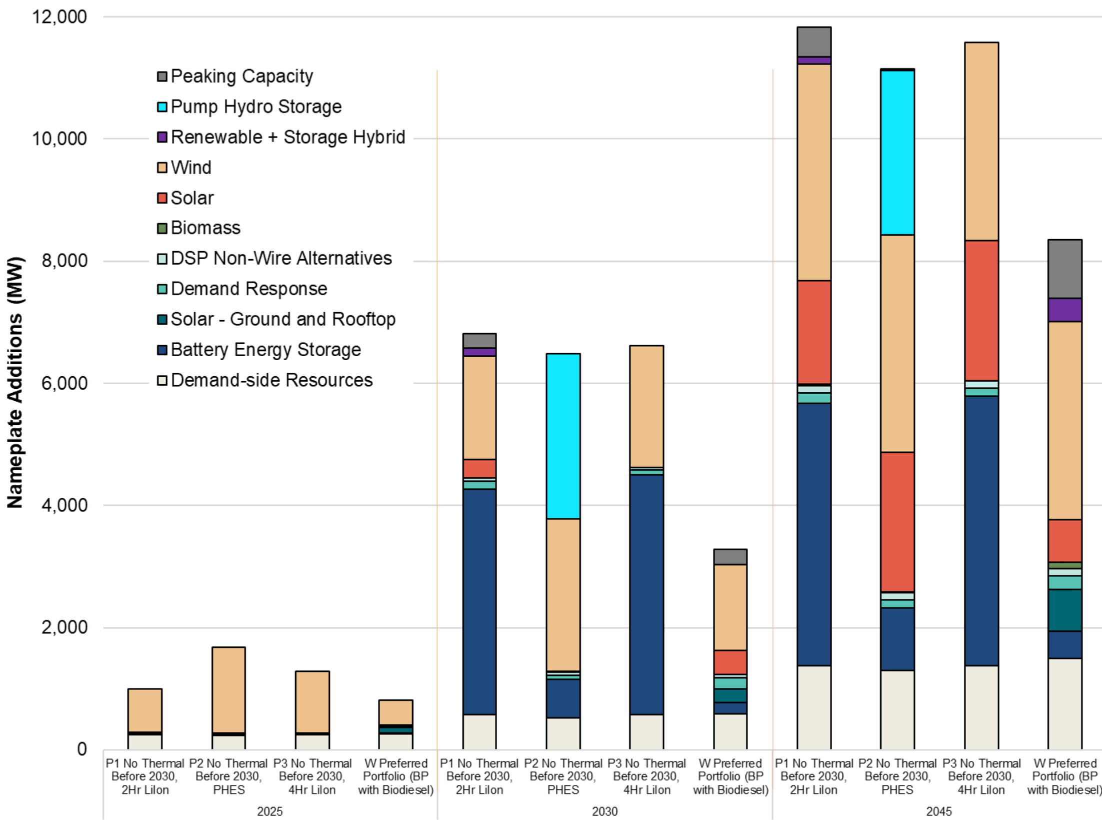
Figure 3-11: Loss of Load Hours for 2027



PSE's winter peak has notably different characteristics than a summer peak in other parts of the Western Interconnect. Summer peaking events occur in the late afternoon/evening when the day is the hottest and only last a few hours in the evening. Energy storage is a good solution for summer peaking events. In contrast, winter events can last several days at a time and temperatures can drop low during the night and stay low throughout the day. Since energy storage is a short duration resource that has a low peak capacity credit, it is not a good fit for winter peaks. With lower peak capacity credit, more energy storage resources are needed to replace the new peaking capacity added in the portfolio.

To better understand how energy storage can meet PSE's peak needs, PSE evaluated several portfolios in Sensitivity P. Sensitivity P removed new peakers as an option and forced the model to find alternative solutions. In the P1 portfolio, the first resource selected to fill peak need was 2-hour lithium-ion batteries. In the P2 portfolio, 2-hour lithium-ion and flow batteries were removed as an option and the model optimized to a solution involving a combination of pumped hydro storage and 4-hour lithium-ion batteries. The P3 portfolio removed the pumped hydro storage option and just added 4-hour lithium-ion batteries to meet peak needs. Figure 3-12 shows the total builds for the preferred portfolio and portfolios P1, P2 and P3. It takes a significant amount of energy storage and associated cost to replace the biodiesel peaker.

Figure 3-12: Resource Build for 2021 IRP Preferred Portfolio and Sensitivity P, Transmission Build Constraint, Cumulative Additions by Nameplate (MW)



Without access to the biodiesel peaker, Sensitivity P produced much higher portfolio costs. Figure 3-13 compares the total portfolio costs for 2045 for the preferred portfolio and portfolios P1, P2 and P3. The lowest cost portfolio is portfolio P2 at $22.85 billion, $6.7 billion more than the preferred portfolio.

Figure 3-13: Portfolio Cost for the Preferred Portfolio and P1, P2 and P3 Portfolios

Portfolio	Portfolio Cost (Billion $, 24-year levelized)
Preferred Portfolio	$16.11
P1: 2-hr Li-Ion	$30.84
P2: Pumped storage hydro	$22.85
P3: 4-hr Li-Ion	$39.01

While PSE hopes technology innovations in energy efficiency, demand response, energy storage and renewable resources will eclipse the need for additional peaking capacity plants of any kind in the future, alternative fuel peakers appear to be the least cost resource for meeting peak reliability needs at the time of this analysis. In all sensitivities that allowed the addition of new combustion turbines, at least one combustion turbine is added by 2026 and a second combustion turbine is added by 2030. Combustion turbines have the highest peak capacity value because of their ability to dispatch as needed with no duration limits. PSE is further exploring renewable and alternative fuel supply availability and technology.

Preferred Portfolio Decisions

A full discussion of all portfolios modeled in the 2021 IRP can be found in Chapter 8. This section focuses on the preferred portfolio and captures the decisions that informed the 10-year clean energy action plan and the 24-year resource plan.

Customer Benefits Analysis and Costs

The Clean Energy Transformation Act requires utility resource plans to ensure that all customers benefit from the transition to clean energy. As a result, the analysis of the equitable distribution of burdens and benefits is new to the resource planning process in the 2021 IRP. PSE is excited to incorporate these new ideas into the process, but acknowledges that stakeholder input and institutional learning must be allowed to evolve the process. A full discussion of how the customer benefit indicators were established is included in Chapter 8. Figure 3-14 shows the results of the

Customer Benefits Analysis and the overall portfolio rankings at the 24-year time horizon. These outputs have been color coded from red (least benefit) to green (most benefit). The Mid portfolio is the lowest cost portfolio that meets CETA requirements at $15.53 billion, but in terms of customer benefit indicators, it ranks at number 14 out of 22. To be included in the Customer Benefit Analysis portfolios must maintain consistency across demand and electric price forecasts, meet CETA requirements and represent current carbon regulation; therefore, not all portfolios were included.

Figure 3-14: Customer Benefits Analysis –Overall Portfolio Rank and Costs for 2045

Portfolio Sensitivity	Overall Rank	24-year Levelized Portfolio Cost (Billion $)
1 Mid	14	$15.53
A Renewable Overgeneration	13	$17.11
C Distributed Transmission	20	$16.35
D Transmission/build constraints - time delayed (option 2)	11	$15.54
F 6-Yr DSR Ramp	17	$15.54
G NEI DSR	10	$15.24
H Social Discount DSR	8	$15.77
I SCGHG Dispatch Cost - LTCE Model	3	$15.41
K AR5 Upstream Emissions	12	$15.56
M Alternative Fuel for Peakers – Biodiesel	1	$15.44
N1 100% Renewable by 2030 Batteries	6	$32.03
N2 100% Renewable by 2030 PSH	15	$66.64
O1 100% Renewable by 2045 Batteries	9	$23.35
O2 100% Renewable by 2045 PSH	5	$46.95
P1 No Thermal Before 2030, 2Hr Li-Ion	21	$30.84
P2 No Thermal Before 2030, PHES	18	$22.85
P3 No Thermal Before 2030, 4Hr Li-Ion	22	$39.01
V1 Balanced portfolio	4	$16.06
V2 Balanced portfolio + MT Wind and PSH	16	$16.61
V3 Balanced portfolio + 6 Year DSR	7	$16.26
W Preferred Portfolio (BP with Biodiesel)	2	$16.11
AA MT Wind + PHSE	19	$15.84

As shown in Figure 3-14, the Customer Benefit Analysis suggests Sensitivity M is the portfolio that provides the greatest benefit to PSE customers. PSE recognizes that this portfolio has many desirable attributes, including low cost, low climate change impacts and low impacts on air quality. However, Sensitivity M does not include very many distributed energy resources, which reduce transmission risk and may provide benefits on the distribution system.

Comparing the costs of Sensitivity M with Sensitivity W yields only a relatively small increase in costs and provides a greater investment in distributed energy resources, thus balancing transmission risks. Therefore, PSE has selected Sensitivity W, the Balanced Portfolio with biodiesel fuel, as the preferred portfolio.

Figure 3-15 compares the portfolio M and W builds by 2030. Portfolio W is a balanced portfolio that takes earlier action on DERs and includes more distributed solar and battery energy storage in the first 10 years of the plan than portfolio M.

Figure 3-15: Resource Build for 2021 IRP Preferred Portfolio and Sensitivity M, Transmission Build Constraint Cumulative Additions by Nameplate (MW)

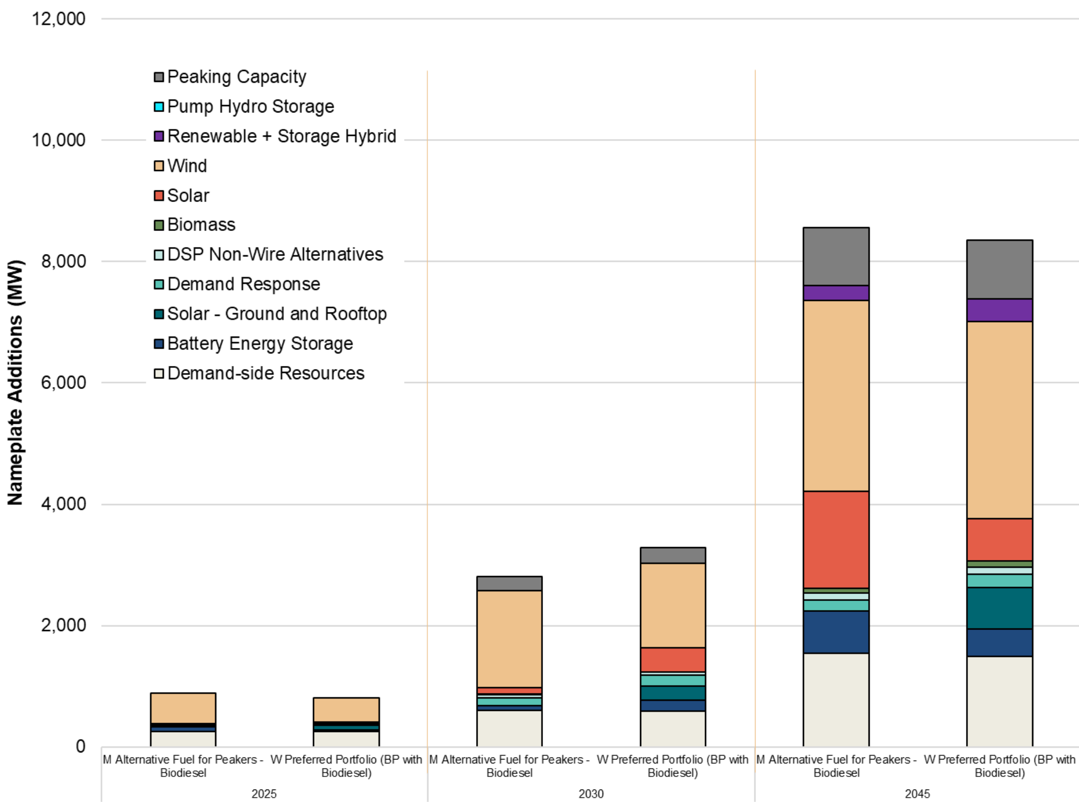


Figure 3-16 shows the results of the Customer Benefits Analysis for the 10-year time horizon. With the addition of the distributed energy resources in the early part of the planning horizon, Sensitivity W ranked number 1 in the 10-year rankings.

Figure 3-16: Customer Benefits Analysis –Overall Portfolio Rank for 2031

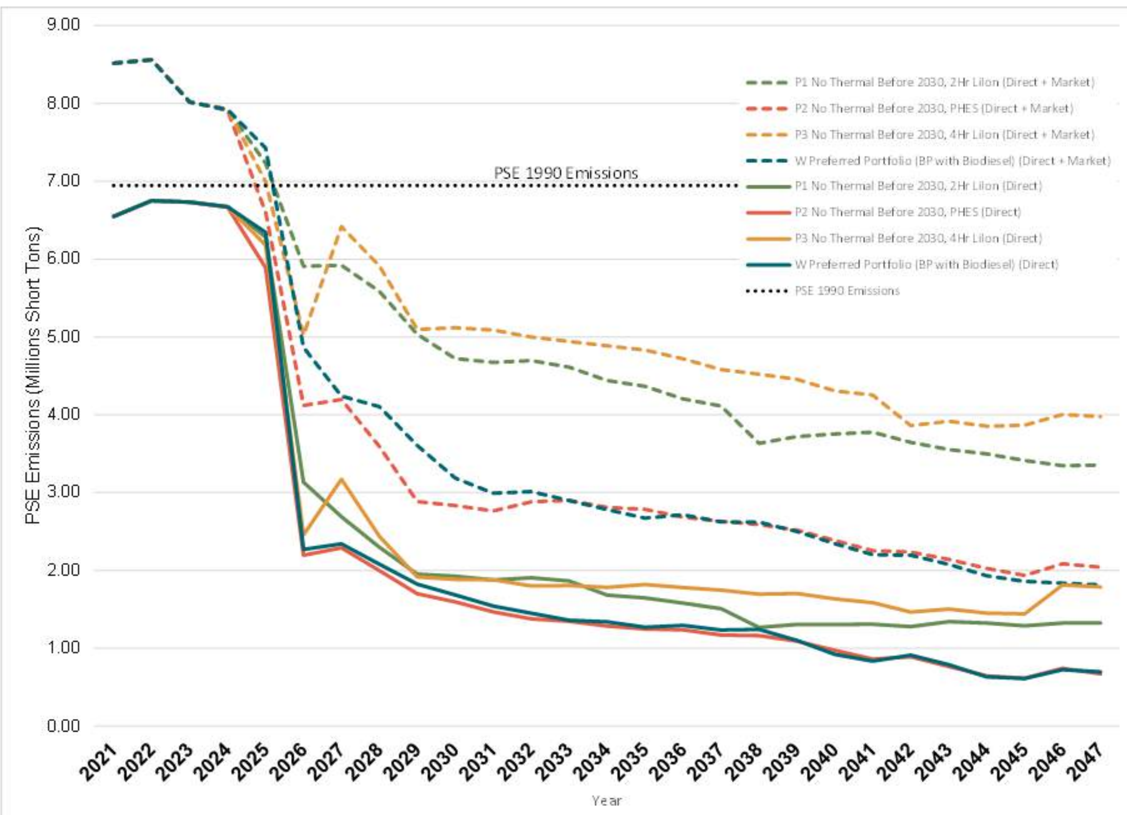
Portfolio Sensitivity	Overall Rank	10-year Levelized Portfolio Cost (Billion $)
1 Mid	12	$6.65
A Renewable Overgeneration	9	$7.09
C Distributed Transmission	20	$6.65
D Transmission/build constraints - time delayed (option 2)	15	$6.68
F 6-Yr DSR Ramp	11	$6.50
G NEI DSR	16	$6.37
H Social Discount DSR	18	$6.47
I SCGHG Dispatch Cost - LTCE Model	17	$6.61
K AR5 Upstream Emissions	19	$6.71
M Alternative Fuel for Peakers – Biodiesel	8	$6.67
N1 100% Renewable by 2030 Batteries	5	$10.86
N2 100% Renewable by 2030 PSH	14	$19.92
O1 100% Renewable by 2045 Batteries	13	$7.51
O2 100% Renewable by 2045 PSH	4	$11.77
P1 No Thermal Before 2030, 2Hr Li-Ion	21	$13.36
P2 No Thermal Before 2030, PHES	7	$9.94
P3 No Thermal Before 2030, 4Hr Li-Ion	22	$15.38
V1 Balanced portfolio	2	$6.90
V2 Balanced portfolio + MT Wind and PSH	6	$7.13
V3 Balanced portfolio + 6 Year DSR	3	$6.84
W Preferred Portfolio (BP with Biodiesel)	1	$6.91
AA MT Wind + PHSE	10	$6.78

Portfolio Emissions

All sensitivities that meet CETA renewable requirements show significant reduction in emissions throughout the planning horizon. Figure 3-17 compares CO_2 emissions for Sensitivity W, preferred portfolio with Sensitivity P portfolios, where the peaking capacity is replaced with different combination of renewable or non-emitting resources. The chart shows direct emissions from the generating resources plus upstream emissions in the solid lines, and direct emissions plus upstream emissions plus market purchases in the dashed lines. The graph does not account for alternative compliance mechanisms to achieve the carbon neutral standard from 2030 to

2045. Rather direct emissions are shown for analysis. Direct emissions decrease over time as thermal resources are replaced with renewable generation. In Sensitivity P, more energy storage resources are added to the portfolio and market purchases are used to charge the storage resources since there is not enough surplus energy in PSE's portfolio. The market purchases cause a large increase in emissions; as can be seen by the difference between the solid and dashed lines for the Sensitivity P portfolios. Also, comparing the solid lines for Sensitivity W, preferred portfolio, and Sensitivity P shows that the direct emissions from PSE's resources are lower in Sensitivity W, preferred portfolio. This is because the heat rate of the new peaking resource, run on biodiesel fuel, is more efficient than the older thermal generators in PSE's fleet, the new peaking resource has lower emissions. When new energy storage resources are added in Sensitivity P portfolios, the increased generation from the existing fleet increases direct emissions.

Figure 3-17: CO_2 Emissions – Preferred Portfolio and Sensitivity P
(Solid lines show direct emissions plus upstream emissions, dotted lines show direct emissions plus upstream emissions plus market purchases. Does not include alternative compliance to meet carbon neutral standard in 2030 and beyond)



COST OF CARBON REDUCTIONS. To calculate the cost of reducing carbon emissions, PSE divided the difference in the 24-year levelized cost between the sensitivity and the Mid Scenario by the difference in 24-year levelized emissions between the Mid Scenario and the sensitivity:

$$\frac{Sensitivity\ 24yr\ Levelized\ Cost\ - Mid\ Sc\ 24\ yr\ Levelized\ Cost}{Mid\ 24yr\ Levelized\ Emissions - \ Sensitivity\ 24yr\ Levelized\ Emissions}$$

Figure 3-18 compares the results of this calculation for the preferred portfolio, Sensitivity N (100 percent renewable resources by 2030), Sensitivity O (where all thermal resources are retired by 2045), and Sensitivity P (new peaking capacity is replaced with alternative resources). The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. The preferred portfolio is very efficient at reducing portfolio emissions because it uses new peaking capacity fueled with biodiesel to meet peak capacity needs.

Figure 3-18: Cost of Emissions Reductions Compared – Mid Scenario, Preferred Portfolio and Sensitivities N, O and P

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / Billion $)
1 Mid Scenario Portfolio	53.87	$15.53	-
Preferred Portfolio	52.77	$16.10	0.52
N1 100% Renewable by 2030 - Batteries	42.16	$32.03	1.41
N2 100% Renewable by 2030 - PHES	30.65	$66.64	2.20
O1 100% Thermal resources retired by 2045 - Batteries	51.83	$23.35	3.83
O2 100% Thermal resources retired by 2045 – PHES	43.54	$46.95	3.04
P1 No New Thermal Before 2030 – 2hr Li-Ion	64.73	$30.84	higher cost & higher emissions
P1 No New Thermal Before 2030 – PHES	50.60	$22.85	2.24
P1 No New Thermal Before 2030 – 4hr Li-Ion	67.00	$39.01	higher cost & higher emissions

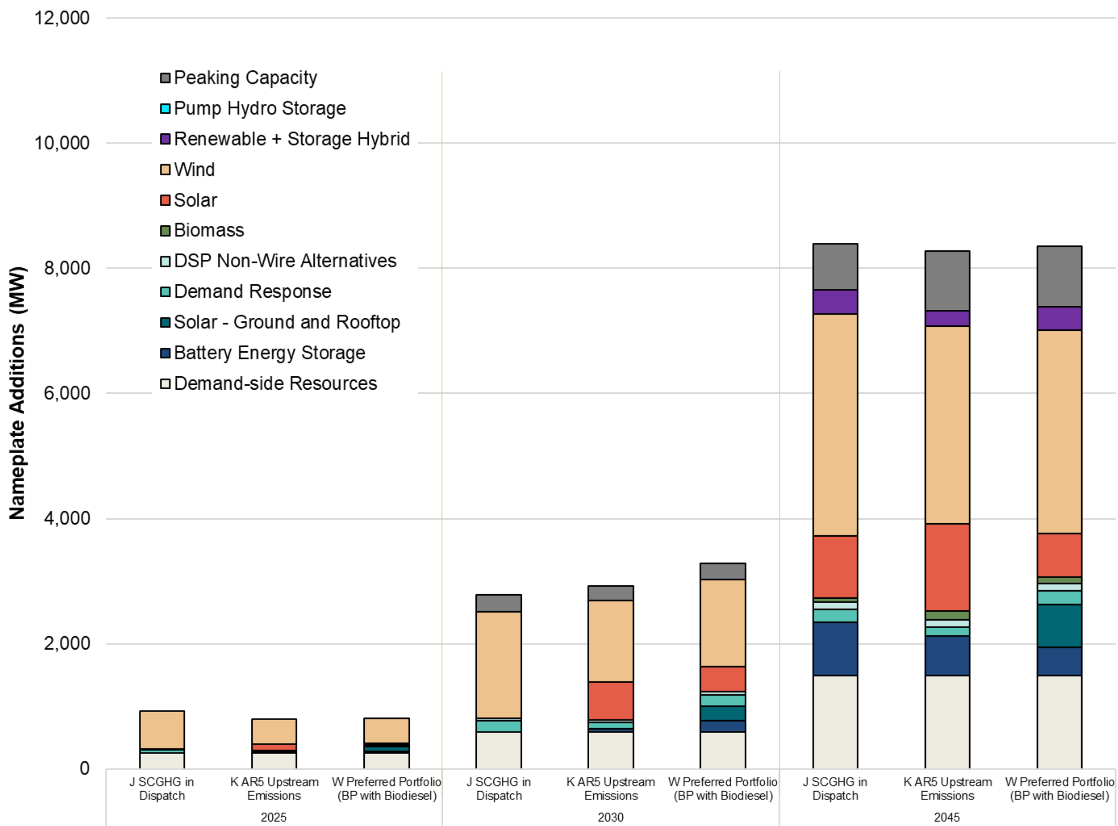
Social Cost of Greenhouse Gases (SCGHG)

CETA explicitly instructs utilities to use the SCGHG as a cost adder when evaluating conservation efforts, developing electric IRPs and CEAPs, and evaluating resource options. As a result, PSE has modeled SCGHG as an adder in the portfolio model. The SCGHG is described in more detail in Chapter 5.

In response to stakeholder requests, PSE modeled different SCGHG approaches. Utilizing different SCGHG modeling approaches does not have a material impact on the cost-effective amount of conservation, demand response and other resource additions or retirements. Renewable resource requirements to comply with CETA are the key constraint that drives portfolio resource additions and costs. The different SCGHG modeling approaches are described in detail in Chapter 8.

In response to stakeholder requests, PSE also modeled an alternate upstream emission content. PSE applied upstream emission rate consistent with Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (AR4) in all portfolio modeling, and then evaluated a sensitivity using upstream emissions consistent with IPCC’s Fifth Assessment Report (AR5). While AR5 increased upstream emissions for natural gas, it did not change resource builds or retirements compared to AR4. Figure 3-19 is a comparison of builds for the different modeling methodologies.

Figure 3-19: Resource Build for 2021 IRP Preferred Portfolio and Sensitivities J and K (Transmission Build Constraint), Cumulative Additions by Nameplate (MW)



Temperature Variations and Fuel Conversion Impacts

PSE evaluated temperature variations that increased the summer loss of load events. This temperature sensitivity is one model of possible weather changes and provides a preliminary view of a possible impact of warming temperatures as a result of climate change. The lessons from this sensitivity are useful as PSE plans for future resource adequacy analyses, but limited conclusions can be made to inform the preferred portfolio. Details are provided in Chapter 7 for the resource adequacy analysis, and portfolio results are presented in Chapter 8.

PSE will continue to model weather trends under different scenarios to better understand how summer extreme events can affect resource adequacy, but also to ensure that PSE continues to plan for winter extreme events. While average temperatures may be increasing over time due to climate change, extreme events (both hot and cold) may still occur. Further climate change modeling is needed to drive resource planning changes. In the past three years, three separate regional events outside of PSE's control have occurred, two in the winter (February 2019 and February 2021), and one in the summer (August 2020). PSE anticipates future changes to the resource adequacy analysis will include both winter and summer resource adequacy analyses, and PSE will also work to develop a winter and summer peak capacity credit to understand how different resources can contribute to both needs.

In the 2021 Washington State legislative session, some proposals have been introduced that propose to convert from natural gas to electricity for power supply. This would significantly increase electric loads and associated peak loads. Since this would convert natural gas heating to electric heating, the majority of the increased loads would happen in the winter. PSE ran a sensitivity in this IRP to examine large-scale conversion of natural gas heating to hybrid electric heat pumps. This sensitivity increased electric loads by over 35 percent by 2045 and winter peak loads by over 17 percent by 2045. Natural gas sales decreased by 74 percent by 2045. This sensitivity assumed conversion to hybrid air-source heat pumps with natural gas backup that switch from electric space heating to natural gas when the outdoor air temperature is equal to or less than 35 degrees Fahrenheit. This had little impact on natural gas peak demand since the hybrid heat pump still relies on natural gas as a backup fuel. More details on the Gas to Electric sensitivity results are presented in Chapters 8 and 9.

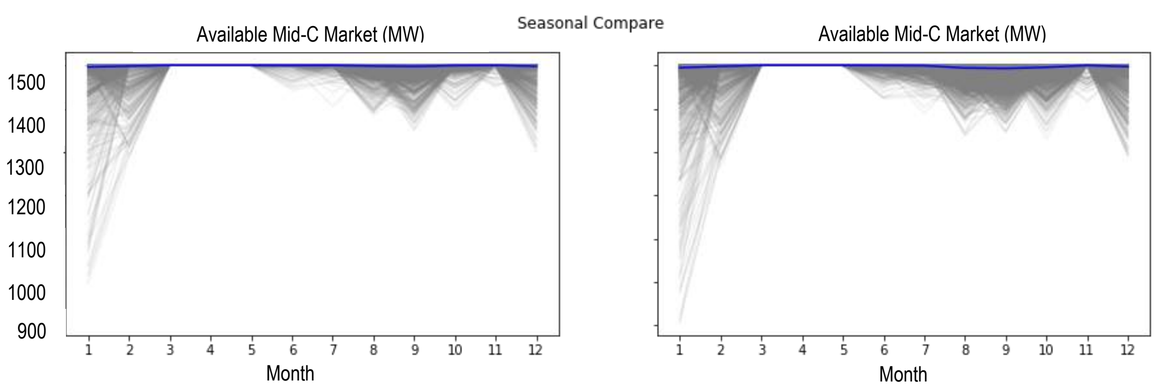
For future IRP work, PSE will look at integrating several of these scenarios to include temperature variations, gas-to-electric conversion and increased electric vehicle loads. Separately, each of these factors can change PSE's load shapes in different ways, but it is important to plan for how combined changes may affect PSE's load shapes.

Firm Resource Adequacy Qualifying Capacity Contracts

PSE has 1,500 MW of firm transmission capacity from the Mid-C market hub to access supply from the regional power market. To date, this transmission capacity has been assumed to provide PSE with access to reliable firm market purchases where physical energy can be sourced in the day-ahead or real-time bilateral power markets. PSE has effectively assumed this 1,500 MW of transmission capacity as equivalent to generation capacity available to meet demand. Historically, this assumption has reduced PSE's generation capacity need and the ensuing procurement costs. Given the market events of the past three years, PSE conducted a market risk assessment to evaluate this assumption in addition to the evaluation completed with the resource adequacy model.

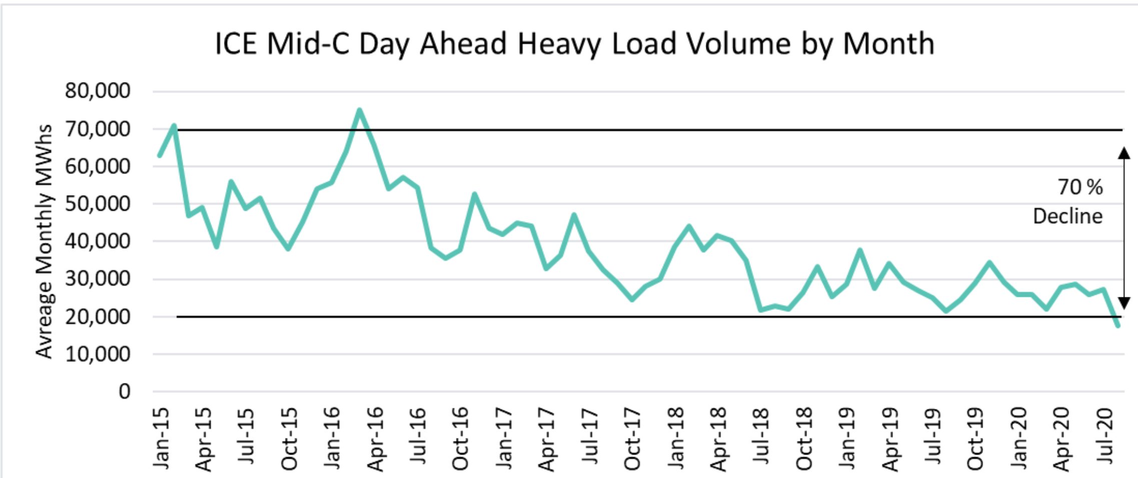
Figure 3-20 shows the results of the resource adequacy modeling. Over the last few years, several studies from regional organizations show that the Pacific Northwest may experience a capacity shortfall in the near term. PSE's resource adequacy model takes curtailment events from the Northwest Power and Conservation Council's resource adequacy model and allocates a portion of the curtailments to PSE's portfolio. The chart illustrates the average of PSE's share of the regional deficiency. The results show the deficiency in each of the 7,040 simulations (gray lines) and the mean of the simulations (blue line). The mean deficiency is close to zero, but in some simulations the market purchases may be limited by 500 MW (in January 2027) and 600 MW (in January 2031). This means that of the 1,500 MW of available Mid-C transmission, PSE was only able to fill 1,000 MW in January 2027.

Figure 3-20: Reduction to Available Mid-C Market



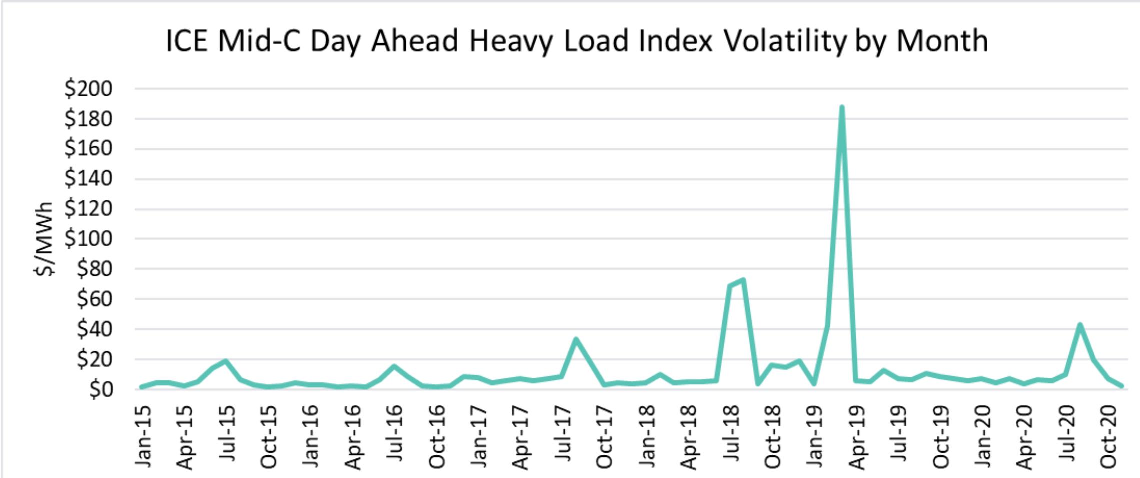
In the market risk assessment, PSE took this assessment further and analyzed the availability of the market during more recent events. Reductions in traded volume in the day-ahead market indicate constrained market supply/demand fundamentals; less generation is available, so there is less capacity available for market participants to trade. This also is suggestive of more energy being transacted before the month of delivery, so it is not available to be traded in the day-ahead market. Trading volume in the day-ahead market has declined 70 percent since 2015. Figure 3-21 shows the average monthly trading volume between January 2015 and July 2020 on the Intercontinental Exchange.

Figure 3-21: Mid-C Day-ahead Heavy Load Volume Timeline



The market risk analysis also shows that price volatility has increased since 2015 in response to tighter supply/demand fundamentals, with energy prices spiking precipitously when there is limited supply. Such increases in market volatility were notable in the summer of 2018, when high regional temperatures coincided with forced outages at Colstrip; in March 2019, when regional cold coincided with reduced Westcoast pipeline and Jackson Prairie storage availability; and most recently in August 2020, during a west-wide heat event. The volatility of day-ahead heavy load prices is shown in Figure 3-22.

Figure 3-22: Volatility of Heavy Load Mid-C Day-ahead Prices



Coinciding with the retirement of legacy baseload capacity and the decline of market availability, several regional investor-owned utilities (IOUs) have reduced their assumptions of available market purchases in their IRPs. Compared with other IOUs in the region, PSE's market purchases are much higher than other IOUs, putting PSE at risk if short-term market purchases are not available.

Taking into account the results from the resource adequacy analysis, the downward trend in trading volumes over the last five years and the low availability of market during regional events, PSE proposes to reduce its reliance on short-term market purchases to 500 MW by 2027 and convert a portion of its 1,500 MW of Mid-C transmission to firm resource adequacy qualifying capacity contracts instead of relying on the short-term market. This means that the firm transmission is still available and will be evaluated during the RFP process for the lowest reasonable cost way to firm up the resources behind the transmission.

Reducing market purchases to 500 MW increases the peak capacity deficit in 2027 from 906 MW to 1,853 MW. In Sensitivity WX, PSE evaluated a portfolio in which available transmission to Mid-C was reduced and replaced with new peakers to address the capacity deficit. The result was a portfolio that added approximately 1,000 MW of peaking resources. One of the modeling limitations in this IRP, is that new contracts are not modeled. Resources are modeled since they have a set procurement cost and build schedule, but future costs of contractual arrangements are more difficult to predict. PSE's transmission can be used to procure new firm contracts or resources that can be delivered to Mid-C market hub and then used to deliver energy to PSE. The total cost of the preferred portfolio already includes estimates of the wholesale market price for the firm contracts proposed, but does not include any capacity premium that may be added. It is this premium that is difficult to predict, and PSE will learn more about those costs and what is available in the next RFP.

The regional resource adequacy program is currently under development and will impact PSE's capacity need should PSE decide to participate. Sufficient program design details are not yet available to evaluate the program's impact on PSE's resource adequacy analysis, however, we know that the program will define the types of contracts that will qualify to meet resource adequacy. PSE will be able to assess program impacts in time for the IRP update in two years.

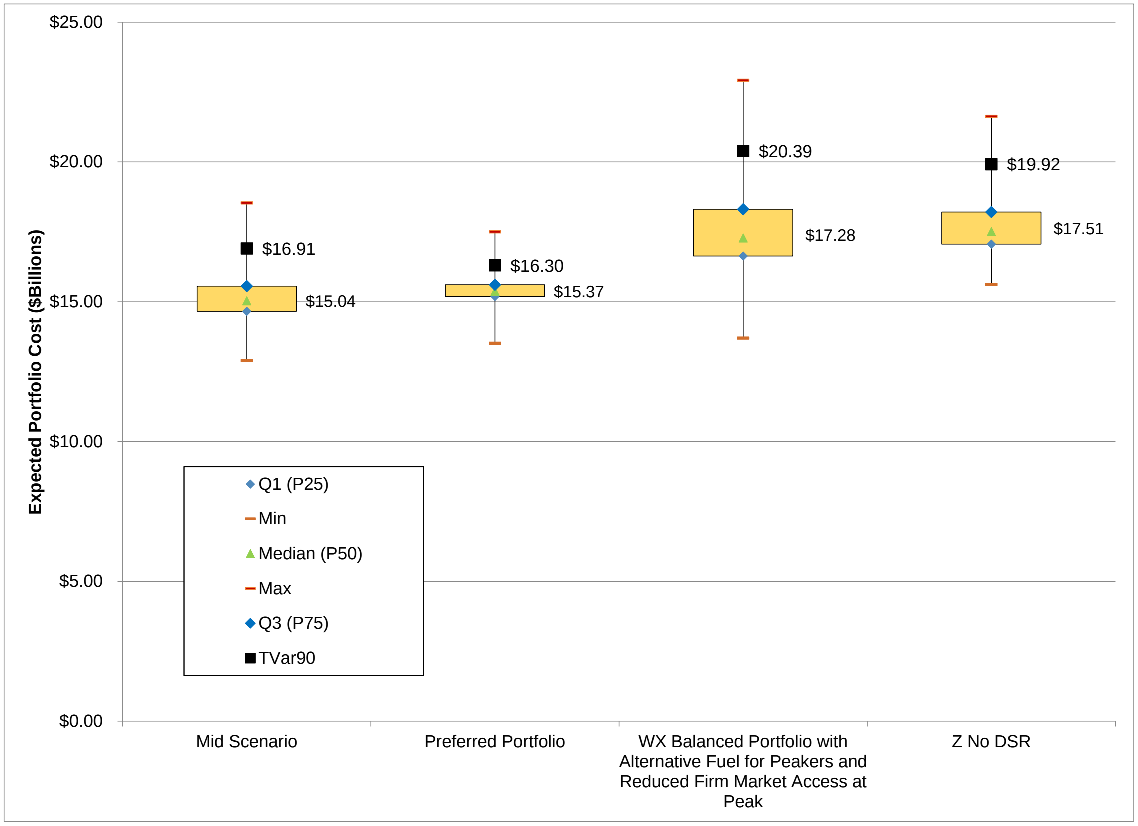
Summary of Portfolio Risk

With stochastic risk analysis, PSE tests the robustness of different portfolios. In other words, PSE seeks to know how well the portfolio might perform under a range of different conditions. For this purpose, PSE takes the portfolios (drawn from the deterministic scenario and sensitivity portfolios) and runs them through 310 draws[3] that model varying power prices, natural gas prices, hydro generation, wind generation, solar generation, load forecasts (energy and peak), and plant forced outages. From this analysis, PSE can observe how risky the portfolio may be and where significant differences occur when risk is analyzed.

PSE's approach to the electric stochastic analysis hold portfolio resource builds constant across the 310 simulations. In reality, these resource forecasts serve as a guide, and resource acquisitions will be made based on the latest information. Nevertheless, the result of the risk simulation provide an indication of portfolio costs risk range under varying input assumptions. In Figure 3-23, the expected portfolio costs for each portfolio are being compared across four portfolios; Mid, Preferred Portfolio, Sensitivity WX (Balanced portfolio with Market reduction), and Sensitivity Z (No DSR). The left axis represents the costs and the right axis represents the portfolio. The green triangle on each of the boxes represents the median for that particular portfolio and is a measure of the center of the date. The interquartile range box represents the middle 50% of the data. The whiskers extending from either side of the box represent the minimum and maximum data values for the portfolio. The black square represents the TailVar90 which is the average value for the highest 10 percent of outcomes.

3 / Each of the 310 simulations is for the twenty four-year IRP forecasting period, 2022 through 2045.

Figure 3-23: Range of Portfolio Costs across 310 Simulations



The interquartile range for the Preferred Portfolio with Biodiesel is comparatively narrow and has the lowest TailVar90 at $16.3 billion dollars suggesting that the overall expected portfolio costs is the least variable compared to the other portfolios. The smaller range on the preferred portfolio indicates that this portfolio has the lowest volatility and the lowest risk than the other portfolios tested. Including conservation in the portfolio reduces both costs and risks, as can be seen in the comparison of costs and ranges with Sensitivity Z, No DSR. Sensitivity WX replaces the 1,000 MW of short-term market with frame peakers. In this portfolio, the costs are higher because of the cost of new resources, which is why the median cost is higher than the preferred portfolio. This portfolio also has a large range in costs, indicating higher volatility and risk. The conclusion of this simulation is that replacing the short-term market with natural gas plants does not reduce risk, it is simply exchanging market price risk for natural gas fuel risks. Further study is needed and PSE will continue to evaluate the impacts of different types of resources.

3. NATURAL GAS SALES RESOURCE PLAN

Resource Additions Summary

The additions to the natural gas sales portfolio are summarized in Figure 3-24, followed by a discussion of the reasoning that led to the plan. Peak use during the winter heating seasons must be met in the natural gas analysis. PSE's winter heating season is from November to February; as a result, the years shown here reference the natural gas year, so 2025/26 means the natural gas year from November 2025 through October 2026.

Figure 3-24: Natural Gas Sales Resource Plan – Cumulative Capacity Additions (MDth/day)

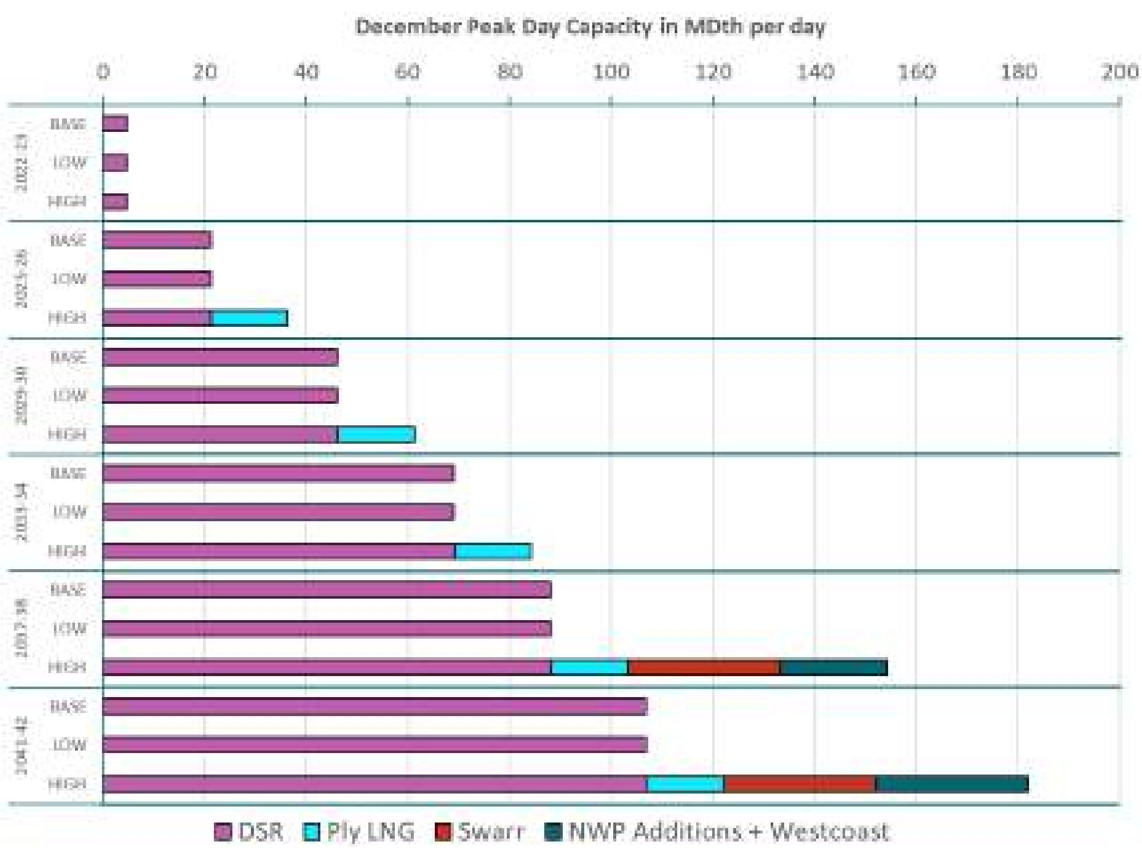
	2025/26	2030/31	2041/42
Conservation	21	53	107

The natural gas sales resource plan integrates demand-side and supply-side resources to arrive at the lowest reasonable cost portfolio capable of meeting customer needs over the 20-year planning period. In the draft 2021 IRP, conservation was the most cost effective resource, and it alone was enough to meet the need over the entire study period.

Natural Gas Sales Results across Scenarios

As with the electric analysis, the natural gas sales analysis examined the lowest reasonable cost mix of resources across a range of scenarios. Three scenarios were tested in the 2021 IRP: Mid, Low and High. Figure 3-25 illustrates the lowest reasonable cost portfolio of resources across these three potential future conditions.

Figure 3-25: Natural Gas Sales Portfolios by Scenario (MDth/day)

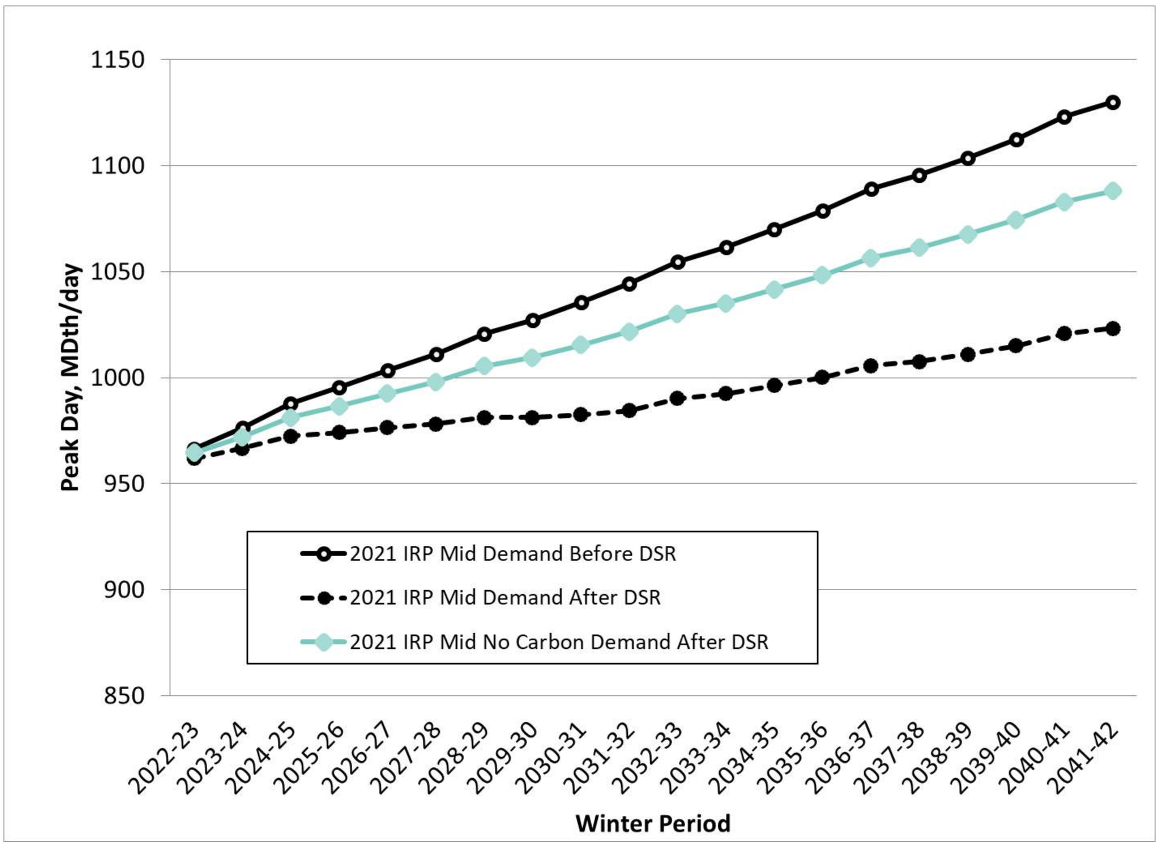


Key Findings by Resource Type

Demand-side Resources

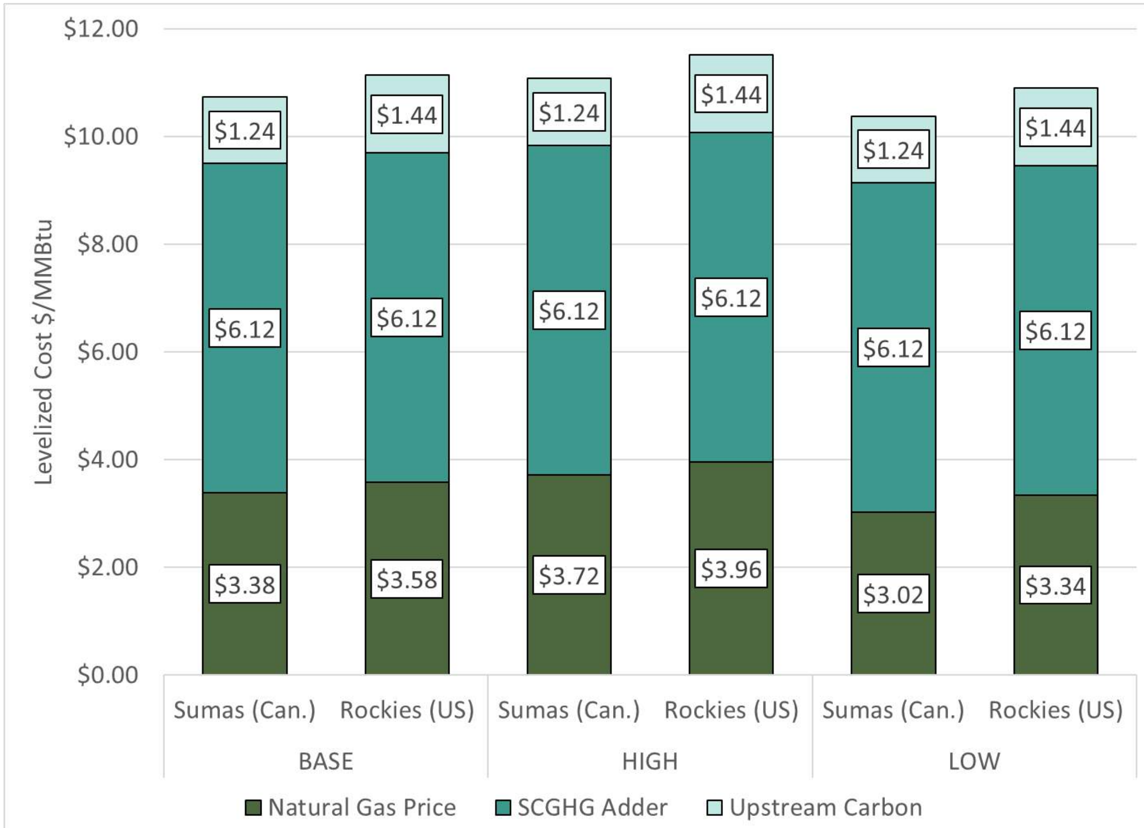
Cost-effective DSR (conservation) does not vary across scenarios. In other words, the same level of conservation is chosen in all of the scenarios. The conservation is driven by the total natural gas costs, which now includes additional costs for upstream emissions, more than by other factors such as resource need. Figure 3-26 shows the results of cost-effective DSR for the Mid Scenario with and without the carbon adders, and that the amount of cost-effective DSR is significantly lower when the total cost of natural gas consists of only the natural gas commodity costs.

Figure 3-26: DSR Cost Effective Levels are Driven by Total Natural Gas Costs



Conversely, in Figure 3-27, When the carbon adders are included, the total cost of natural gas varies only slightly from one scenario to the next, and this results in the same level of DSR being selected in all three scenarios.

Figure 3-27: Total Cost of Natural Gas (Commodity + SCGHG + Upstream Emissions)



Swarr Upgrades

Upgrades to PSE's propane injection facility, Swarr, is a least cost resource in the High scenario. The timing of the Swarr upgrade is driven by the load forecast. In the High load scenario, Swarr is needed by 2037/38. Upgrades to Swarr are essentially within PSE's ability to control, so PSE has the flexibility to fine-tune the timing. PSE has less control over pipeline expansions, since expansions often require a number of shippers to sign up for service in order for an expansion to be cost effective. The Swarr upgrade has a short lead-time, and PSE has the flexibility to adjust it as the future unfolds.

Plymouth LNG

The Plymouth LNG peaker contract was selected as a least cost resource in the High Scenario. The plant is in PSE's electric portfolio, and the contract is up for renewal in April 2023, at which point the natural gas sales portfolio could buy the contract. In the High load scenario, the plant was selected to start service in the 2023/24 winter, and it has an associated pipeline capacity of 15 MDth per day on Northwest Pipeline to deliver the natural gas to PSE.

NWP + Westcoast Pipeline Additions

Additional firm pipeline capacity on Northwest and Westcoast Pipelines north to Station 2 is cost effective in the High Scenario, which adds 21 MDth/day in 2034/35, increasing to 30 MDth/day by the end of the planning horizon.

Resource Plan Forecast – Decisions

The forecast additions described above are consistent with the optimal portfolio additions produced for the Mid Scenario by the SENDOUT gas portfolio model. SENDOUT is a helpful tool, but its results must be reviewed based on judgment, since real-world market conditions and limitations on resource additions are not reflected in the model. The following summarizes key decisions for the resource plan.

Conservation (DSR)

The resource plan incorporates cost-effective DSR from the Mid Scenario – the same as in the Low and High Scenarios. Natural gas prices appear to have little impact on DSR, regardless of the load growth forecast. The primary variable that affects the resource decision is the assumption for SCGHG adders. The SCGHG adders are derived from requirements stated in HB1257, which became law during the 2019 legislative session and require the SCGHG adders to be incorporated in the planning analysis as part of capacity expansion decisions. The results show that cost-effective conservation in the Mid Scenario is likely to be a safe decision, since the same level of conservation is cost effective regardless of whether the demand forecast is as low as the 10th percentile in the Low Scenario or as high as the 90th percentile in the High Scenario.

The level of cost-effective DSR found in the deterministic Mid, Low, and High Scenarios is a robust result. The stochastic analysis found this level of DSR was the preferred resource in over 80 percent of the 250 stochastic runs in which demand and natural gas prices were varied randomly. Cost-effective DSR reduced both cost and risk in the natural gas portfolio according to the stochastic analysis. Therefore, the risk of over-building or under-building DSR appears to be low.

Supply-side Resources

The supply-side resources – Plymouth LNG peaker contract, Swarr, and pipeline expansions – represent the High Scenario resource additions. No supply-side resources are needed in the Mid and Low Scenarios. Even in the High Scenario, the only resource needed in the near term is the Plymouth LNG peaker contract. The lead time to acquire this resource contract is short, so no decisions are needed until at least 2022. Swarr and NWP plus Westcoast pipeline additions are needed only in the High Scenario in the back half of the study period, thus no decision will be required in the near term. There will be opportunities to review these resources in future IRP cycles before any decisions are necessary.

4. TECHNICAL MODELING ACTION PLAN

Since the 2017 IRP, PSE has made significant advancements in the analytical tools and methods used, and these advancements have been applied to the 2021 IRP. The improvements are documented throughout this IRP. PSE has also identified several improvements for future IRPs. These are described below.

ELECTRIC RESOURCE PLANNING

1. Adopt winter and summer resource adequacy analyses, and develop a winter and summer peak capacity credit to understand how different resources can contribute to both needs.
2. Evaluate the benefits and impacts of the regional resource adequacy program and integrate into PSE's resource planning if appropriate.
3. Integrate the electric and natural gas portfolio modeling to better evaluate future impacts associated with a rapid replacement of natural gas end uses with electricity.
4. Evaluate technology solutions to reduce model run times for the electric portfolio and stochastic models.
5. Continue to refine energy storage modeling.
6. Explore transmission planning optimization tools to help understand the impacts of transmission in electric supply portfolio modeling.

NATURAL GAS RESOURCE PLANNING

1. Evaluate available natural gas portfolio models for long-term resource planning and implement new model for the 2023 IRP.
2. Integrate the electric and natural gas portfolio modeling to better evaluate future impacts associated with a rapid replacement of natural gas end uses with electricity.
3. Evaluate the ongoing use of the existing natural gas peak day planning standard and study the impacts of changing the planning standard.

4 Planning Environment

This chapter reviews the conditions that defined the planning context for the 2021 IRP.

Contents

1. CLEAN ENERGY TRANSFORMATION ACT RULEMAKINGS

Since the passage of the Clean Energy Transformation Act (CETA) in 2019, several state agencies have been engaged in rulemakings to implement key provisions of the statute. These include the following.

1. The Washington Utilities and Transportation Commission (WUTC) – multiple topics, including the IRP, Clean Energy Implementation Plan (CEIP), and Purchase of Electricity rulemakings
2. The Department of Commerce (Commerce) – CETA rulemaking primarily for consumer-owned utilities
3. The Department of Health (DOH) – cumulative impact analysis
4. The Department of Ecology (Ecology) – unspecified emissions rate and energy transformation projects.

Each of these rulemaking efforts is summarized below. At the time of this writing, some topics remain unresolved in rulemaking and await further discussion and development in 2021.

WUTC CETA Rulemakings

The WUTC completed three rulemakings at the end of 2020 to implement CETA: the Energy Independence Act (EIA) Rulemaking, the IRP/CEIP Rulemaking, and the Purchase of Electricity Rulemaking.

EIA RULEMAKING*.* The EIA rulemaking revises certain provisions of existing EIA rules to align with CETA and defines key terms related to the low-income provisions of CETA in RCW 19.405.120, including “low income,” “energy assistance need” and “energy burden.”

IRP/CEIP RULEMAKING. The IRP/CEIP Rulemaking outlines the timing and processes associated with filing an IRP, a Clean Energy Action Plan (CEAP) and a Clean Energy Implementation Plan (CEIP). Among many other new requirements, utilities are directed to establish equity advisory groups to advise utilities on equity issues, including vulnerable population designation, equity customer benefit indicator development and recommended approaches for compliance with RCW 19.405.040(8) as codified in the rule.

PURCHASE OF ELECTRICITY RULEMAKING. The Purchase of Electricity Rulemaking outlines the timing and expectations for utilities when acquiring resources that are identified as a resource need in the IRP.

In addition, the WUTC anticipates further discussions and policy development in 2021 regarding the following issues through a subsequent Markets Work Group rulemaking as required in RCW 19.405.130 or other rulemakings or policy statements.

- Non-energy benefits and the cost-effectiveness test
- No-coal attestation under CETA
- Natural gas IRP rulemaking per HB 1257
- Policy guidance for implementing Section 12 low-income provisions of CETA
- Interpreting a utility's "use" of electricity to serve customers
- Incorporating DOH's Cumulative Impact Analysis (CIA) into utility planning processes

Department of Commerce CETA Rulemaking

The Department of Commerce (Commerce) is charged with developing rules for implementation of CETA for consumer-owned utilities. Additionally, Commerce is responsible for developing reporting procedures for all utilities, investor-owned and consumer-owned. Commerce published the final rules at the end of 2020.

Department of Commerce CETA Low-income Draft Guidelines and WUTC Low-income Policy Development

In early 2020, the Department of Commerce released draft guidelines to support the low-income reporting requirements that utilities must meet under RCW 19.405.120 (Section 12 of CETA). Utilities provided data related to energy assistance to Commerce pursuant to the guidelines issued on November 13, 2020.

Beginning July 31, 2021, utilities must provide to Commerce a biennial assessment of the following.

- Programs and mechanisms to reduce energy burden, including the effectiveness of those programs and mechanisms for both short-term and sustained energy burden reduction.
- Outreach strategies used to encourage participation of eligible households.
- A cumulative assessment of previous funding levels for energy assistance compared to funding levels needed to meet 60 percent of the current energy assistance need or increasing energy assistance by 15 percent over the amount provided in 2018, whichever is greater, by 2030; and 90 percent of the current energy assistance need by 2050.

This assessment also must include a plan to improve the effectiveness of the assessment mechanisms and strategies towards meeting the energy assistance need.

PSE anticipates that this biennial low-income energy assistance report to Commerce will be used to inform any energy assistance potential assessment that may be required in future IRP cycles.[1]

Department of Health Cumulative Impact Analysis

CETA directs DOH to develop a CIA of the impacts of both climate change and fossil fuels on population health, in order to designate highly impacted communities. The results of the CIA will be used to inform power utilities' planning in the transition towards cleaner energy. While DOH set out to carry out this work collaboratively with robust input from stakeholders through work group meetings and subcommittees, DOH's plans for stakeholder engagement were scaled back in 2020 after the onset of the COVID-19 pandemic. DOH released a final CIA tool in February 2021.

Under CETA, the CIA is an important tool for informing a utility's equity-related assessment in its IRP, as well as informing its Clean Energy Implementation Plans.

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1 / See Draft WAC 480-100-620(3)(b)(iii), included as part of the UTC's IRP/CEIP Final Proposed Draft Rules published on December 4, 2020.

Department of Ecology Rulemaking

The Department of Ecology is responsible for adopting rules that provide methods for assigning greenhouse gas emission factors for electricity and establishing a process for determining what types of projects may be eligible as “energy transformation projects” under CETA.

Ecology adopted a new rule on January 6, 2021 that establishes: 1) the default unspecified emissions factor in CETA; 2) a general process for determining eligible energy transformation projects; and 3) a process and requirements for developing standards, methodologies and procedures to evaluate energy transformation projects.

2. TECHNOLOGY CHANGES

Convergence of Delivery System Planning and Resource Planning

Traditionally, the focus of an integrated resource planning process has been to determine the lowest reasonable cost mix of demand- and supply-side resources needed to meet the total projected load and peak needs of its customers with an adequate reserve margin. In Washington state, the planning process is prepared under rules or requirements for an IRP and reviewed by state utility commissions.

The IRP process includes the cost of transmission and distribution infrastructure needed to connect and transmit the power from potential new generation sources; however, planning for the transmission and distribution delivery systems that ensure power can be delivered to end-use customers has traditionally been separate from the IRP process.

A variety of economic, technological and societal factors are changing the electric utility planning process and blurring the historical division between delivery system planning (DSP) and integrated resource planning. These include the increasing affordability of solar generation (including rooftop solar), the maturing of battery storage technology, electric vehicle adoption, advancements in customer management and information about electricity use, and advancements in the management and data systems used to integrate and control distributed energy technologies.

In the future, continued growth of customer solar generation and other distributed energy resources will contribute to meeting the overall resource need but will also lead to power being pushed back to a distribution feeder that was not designed for two-way power flows. This will require PSE to plan and build a grid that is different than today to capture the resource benefit effectively. The grid of the future needs to be safe, reliable, resilient, smart, clean and flexible.

Washington State's Clean Energy Transformation Act is also driving change. It recognizes that transforming the state's energy supply requires the modernization of its electricity system and that clean energy action planning must include any need to develop new, or expand or upgrade existing, bulk transmission and distribution facilities. Additionally RCW 19.280.100, resulting from House Bill 1126, furthers this connection as energy supply needs are met through distributed energy resources (DERs). It established a policy that guides how distributed energy resource planning processes are to occur in order to illuminate the interdependencies among customer-sited energy and capacity resources.

With this backdrop, PSE is in the process of increasing the coordination of delivery system planning with resource planning, as it provides benefits by bringing together solutions to address delivery system challenges while meeting resource needs.
With the increasing maturity and feasibility of DERs, delivery system needs may be solved using these non-traditional solutions at local points or in certain areas of the delivery system. If these non-traditional resources decrease load (such as demand response programs) or provide a generation source (such as rooftop solar), they may also provide benefit to the overall energy supply resource portfolio. This creates a natural connection between DSP and energy supply resource planning.

Historically, the two planning processes have occurred on separate timelines. However, DERs installed in sufficient quantity to solve delivery system needs may change the results in the resource planning process, so coordinating the two benefits both processes and analyses.

A coordinated process must accommodate:

- customer-owned resources and electric vehicles
- programs such as distribution automation and demand response
- distributed energy resources
- energy storage
- energy efficiency strategies

In addition to incorporating the cost of transmission and distribution infrastructure, the IRP and DSP processes use some of the same core information in different ways. Data flows from one process to the other at different steps as shown in Figures 4-1 and 4-2.

The confluence of technology, customer adoption, grid integration capability and solution effectiveness will drive the pace of interconnecting the DSP and IRP processes.

Figure 4-1: Data Flows between Delivery System Planning and Integrated Resource Planning

Figure 4-2: Data Flows between Delivery System Planning and Integrated Resource Planning (Table)

IRP Outputs in the DSP	Conservation Potential Assessment	Decreases county-level system capacity needs
	Load and Demand Forecast	Decreases county-level system capacity needs
	Distribution Efficiency (CVR)	Decreases capacity needs where implementable and may be a solution alternative
	DER and Resource Supply Cost Curve	Cost supply curve including different types of DER resources which could be used as non-wire solution alternatives if located appropriately
	Final Resource Plan (including DER's)	Insight for participation in resource acquisition process for DERs to enhance locational value opportunities and informs enabling grid modernization requirements
DSP Outputs in the IRP	Non-wire Solutions (DER & Energy Storage Forecast)	Decreases overall resource need by identifying must-take DER resources to meet specific transmission and distribution delivery needs
	Electric T&D Deferral Value	Provides a quantitative value of past T&D investments to use in the conservation potential assessment
	Gas Deferral Value	Provides a quantitative value of past investments to use in the conservation potential assessment
	Hosting Capacity (future)	Future input for economic opportunities
	Long-term System Delivery Plan	Future input for opportunities and constraints that should be considered

New Fuel Technologies

Renewable Natural Gas

Renewable natural gas (RNG) is pipeline quality biogas that can be used as a substitute for conventional natural gas streams. Renewable natural gas is gas captured from sources like dairy waste, wastewater treatment facilities and landfills. The American Biogas Council ranks Washington 22nd in the nation for methane production potential from biogas sources, with the potential to develop 128 new biogas projects within the state. RNG is significantly higher cost than conventional natural gas; however, it provides greenhouse gas benefits in two ways: 1) by reducing CO_2e emissions that might otherwise occur if the methane and/or CO_2 is not captured and brought to market, and 2) by avoiding the upstream emissions related to the production of the conventional natural gas that it replaces.

RNG is not yet produced at utility-scale in this region and will require developing both supply sources and an infrastructure to deliver that supply to utilities. RNG will most likely be directed toward natural gas utilities before being used as a generation fuel. The electric sector has access to a more mature set of renewable options than the natural gas sector; these include hydro, wind, solar, geothermal and energy storage systems that can capture surplus energy. Natural gas utilities have very few options to decarbonize, so as natural gas utilities begin decarbonizing their systems in earnest, markets will probably pull RNG to natural gas utilities before it is used broadly as generation fuel. Costs remain high to upgrade RNG to gas pipeline specifications and bring it to market. Another obstacle is that RNG currently generated in the U.S. is mostly used as a transportation fuel because of federal and state programs such as the EPA's Renewable Fuel Standard (RFS) and California's Low Carbon Fuel Standard (LCFS), which provide more value through generating credits than when it is used for end-use consumption or to generate electricity. However, the existing natural gas distribution network can be used to deliver renewable fuel.

HB 1257 became effective in July, 2019, and PSE is working with the WUTC and other stakeholders to develop guidelines to implement its requirements. However, recognizing the competitive nature of the existing RNG market, PSE concluded that there would be an advantage to be a first-mover. To that end, PSE conducted a RFP to determine availability and pricing of RNG supplies. After analysis and negotiation, PSE acquired a long-term supply of RNG from a recently completed and operational landfill project in Washington at a competitive price. PSE is in final design of Tariff provisions and IT enhancements to facilitate availability of a voluntary RNG program for PSE customers to take effect in the first half of 2021. RNG supply not utilized in

PSE's voluntary RNG program(s) will be incorporated into PSE's supply portfolio, displacing natural gas purchases as provided for in HB 1257.

In addition, PSE has a current offering called Carbon Balance which provides residential natural gas customers the choice to purchase blocks of carbon offsets for a fixed price. The program provides customers with a way to reduce their carbon footprint through the purchase of third-party verified carbon offsets from local projects that work to reduce or capture greenhouse gases.

This IRP does not analyze hypothetical RNG projects that would connect to NWP or to PSE's system and displace conventional natural gas that would otherwise flow on NWP pipeline capacity. Because of RNG's significantly higher cost, the very limited availability of sources, and the unique nature of each individual project, RNG is not suitable for generic analysis. The benefits of RNG are measured primarily in terms of CO_2e reduction, which are unique to each project. The incremental costs of new pipeline infrastructure to connect the RNG projects to the NWP or PSE system are also unique to each project. Avoided pipeline charges realized by connection of acquired RNG directly to the PSE system will be considered, but are not significant, relative to the cost of the RNG commodity. Contract RNG purchases present known costs, however, many projects may not materialize absent a capital investment by PSE. Due to the very competitive RNG development market, including competition from the California compliance markets, PSE is not prepared to discuss specific potential RNG projects in a public environment. Individual projects will be analyzed and documented as PSE pursues additional supplies.

The aforementioned contract acquisition of landfill RNG will, within a few years, provide RNG equal to approximately 2 percent of PSE's current supply portfolio and as much as a 1.5 percent reduction in the carbon footprint of PSE's gas system, annually. PSE is planning significant further investments in cost-effective RNG supplies and continues to believe there is value in being a proactive RNG buyer and/or producer in the region. PSE is confident that it can acquire sufficient RNG volumes to meet the needs of its future Voluntary RNG Program participants and even exceed the 5 percent cost limitation related to the RNG incorporated into the supply portfolio. In order to meet the expectations within the WUTC RNG Policy Statement, PSE will utilize staggered RNG supply contracts and project development timelines, resales in compliance markets and other techniques to manage RNG costs while maximizing the availability of RNG in its portfolio and achieving meaningful carbon reductions.

Biodiesel

Biodiesel is defined as a renewable resource under section 2 (34) of CETA. To be considered renewable, biodiesel must not be derived from crops raised on land cleared from old growth or first-growth forests. Biodiesel is chemically similar to petroleum diesel but is derived from waste cooking oil or from dedicated crops. According to the U.S. Energy Information Administration, there are two facilities in Washington state that make biodiesel, which together can manufacture upwards of 100 million gallons of biodiesel a year.[2] Biodiesel may become crucial in the future as a fuel supply for combustion turbines. These units would be the same basic generator as a natural gas combustion turbine, but instead of burning natural gas with petroleum diesel as a backup fuel, the generator would burn renewable natural gas with biodiesel as the backup fuel. Biodiesel may also serve as a primary fuel for combustion turbines intended for strictly peak need events. At full capacity, a 237 MW frame peaker would require approximately 25,000 gallons of biodiesel per hour. At this fuel feed rate, a facility would require about 1.2 million gallons of biodiesel storage to continuously fire for a 48-hour peak event. Existing Washington state biodiesel production could plausibly supply several combustion turbines intended to supply reliable capacity during critical hours. This technology may be crucial to maintaining a reliable, renewable electric system during low hydro conditions.

Biodiesel use in simple-cycle combustion turbines is explored in this IRP. An analysis of the amount of fuel needed is in Chapter 7, Resource Adequacy Analysis, and the results of the portfolio optimization are in Chapter 8, Electric Analysis.

Hydrogen

Renewable hydrogen, also known as power-to-gas, is a process by which excess renewable electricity can be transformed (by splitting hydrogen from water) into hydrogen, or, if combined with carbon, synthetic natural gas. These fuels can then be stored utilizing existing natural gas pipeline infrastructure to more cost effectively shift seasonal supply when mismatched with demand.

PSE is a founding member of the Renewable Hydrogen Alliance (RHA). The RHA promotes using renewable electricity to produce climate-neutral hydrogen and other energy-intensive products to supplant fossil fuel consumption. This group is instrumental in keeping PSE up to date on industry developments.

Hydrogen or its derivatives can be used to reduce the GHG content of gas for gas utilities. Renewable hydrogen can be injected into the existing pipeline infrastructure. The amount of hydrogen that can be blended into the pipeline system with natural gas is limited, because hydrogen is less energy dense than current standards for pipeline quality gas. That means a cubic foot of hydrogen has less energy than a cubic foot of natural gas. Pipeline systems are required to maintain heat content within predetermined ranges for safety reasons. Natural gas-consuming equipment and appliances are designed to use a certain amount of gas per unit of

2 / *https://www.eia.gov/biofuels/biodiesel/capacity/*

time, so the gas feeding that equipment needs to maintain these standards. Currently, it appears the ratio of hydrogen that could be injected into the system is about 20 percent.

Hydrogen can also be used as a fuel in gas combustion turbines – both simple-cycle and combined-cycle plants. The hydrogen can be blended into the upstream natural gas supply and delivered on existing infrastructure, based on the physical safety limits described above for gas utilities. Hydrogen can also be injected directly into combustion turbines or blended in higher ratios than 20 percent, if the hydrogen manufacturing, storage and delivery infrastructure is built.

A significant challenge for hydrogen is cost. Today, gray hydrogen (hydrogen manufactured with fossil fuel energy) sells for about $2 per kilogram delivered to a few key chemical market hubs, which translates to about $17.6 per MMBtu for natural gas.[3] While green hydrogen may use surplus renewable electricity that may cost less on a dollars per MWh basis, the output of a hydrogen manufacturing facility using only surplus renewable energy will be less, which will drive up the average cost per unit.

For this IRP, PSE explored hydrogen as an alternative fuel source for the combustion turbines. Though manufacturers have done extensive development for a hydrogen-fueled combustion turbine, it was difficult to get a price forecast for the fuel. Also, the modeling techniques are not available to model hydrogen as both a storage for renewable energy and a fuel for the combustion turbines. PSE will continue to explore hydrogen as a fuel source for combustion turbines and new modeling techniques for future IRPs.

3 / See S&P Global at: https://www.spglobal.com/ratings/en/research/articles/201119-how-hydrogen-can-fuel-the-energy-transition-11740867#:~:text=S%26P%20Global%20Ratings%20believes%20hydrogen,and%20massive%20growth%20of%20renewables.&text=A%20Hydrogen%20Council%20report%20suggests,primary%20energy%20supply%20by%202050

3. WHOLESALE MARKET CHANGES

Prices, Volatility and Liquidity / August 2020 Supply Event

Wholesale electricity prices in the Pacific Northwest remain, on average, relatively low. In recent years, however, these relatively low prices have been punctuated by periods of high volatility and limited market liquidity.

On August 17, 2020, in the middle of a heat wave affecting the western U.S., the region's reliability coordinator declared an Energy Emergency Alert for PSE and four other grid operators in the WECC, indicating these entities risked not having sufficient energy supply to meet their load and reliability obligations. Wholesale market dynamics and reliance on energy transfers from neighboring entities were key factors in how this event developed in the Northwest. In the day-ahead market, power prices at the Mid C hub spiked to more than five times what they were just days earlier. Offers to sell power at Mid C disappeared as available supply flowed to even higher priced delivery points in California and the desert southwest. By Monday August 17, 2020, forecasted load had increased with higher temperatures, but additional supply in the Mid C real-time market was extremely scarce. For the highest load hours of the day PSE was unable to procure power at any price. In California, the situation was even more severe, and in the days leading up to August 17, 2020, CAISO implemented rolling black-outs in order to maintain grid stability.

In its report on the August 2020 event, CAISO identifies extreme heat resulting from climate change and the evolving mix of generation resources as primary factors leading to insufficient supply conditions. As extreme temperatures become more common and traditional thermal resources continue to be replaced with variable renewable resources, high price volatility and the risk of unavailable supply are likely to be more prevalent in western U.S. wholesale power markets.

Market Developments / CAISO EDAM

In late 2018, CAISO engaged stakeholders to examine the feasibility of extending participation in its day-ahead market to entities already participating in the energy imbalance market (EIM). Potential benefits of an extended day-ahead market (EDAM) include production cost savings through more efficient use of available transmission, more efficient day-ahead unit commitment, and the creation of day-ahead base schedules at hourly granularity; diversity of imbalance reserves; and environmental benefits including reduced curtailment of renewable resources. EDAM would operate in a framework similar to EIM's approach to the real-time market, which does not require full integration into the California ISO balancing area. Participating entities and their regulatory authorities would remain responsible for transmission planning, resource adequacy and balancing area control performance.

A feasibility assessment completed near the end of 2019 identified significant benefits associated with the EDAM proposal, and stakeholder entities have since started work on more specific market design criteria. Evaluation of topics including governance, resource sufficiency requirements and the distribution of market benefits has been ongoing throughout 2020, and a final market design proposal is expected in late 2021.

4. REGIONAL RESOURCE ADEQUACY

Utilities across the Northwest have partnered to explore a potential regional resource adequacy program. Resource planning in the Northwest is currently done on a utility-by-utility basis, typically through integrated resource planning processes. This utility-by-utility planning framework has worked well for the region during times when the region was surplus capacity. As large amounts of firm generators retire and several regional studies point to a capacity deficit in the next decade, utilities have growing concerns about whether the new capacity needed to maintain regional reliability can be procured in a timely manner. A Northwest resource adequacy program would offer two key benefits: reliability and cost savings. First, a regional resource adequacy program would ensure that sufficient generation is available to reliably serve demand during periods of grid stress. Resource adequacy programs do this by establishing transparent processes to assess, allocate and procure a region's resource needs. Second, a regional resource adequacy program would enable cost savings. By planning for the peak demand of the entire region (the coincident peak demand) instead of each utility's individual (non-coincident) peak demand, a regional approach would produce an overall lower capacity need and therefore a reduced level of investment. Furthermore, larger systems tend to require lower reserve margins because they are less vulnerable to single contingencies and variation in supply and demand.

Resource adequacy programs deliver these benefits by establishing transparent, coordinated calculations of required capacity and offering mechanisms for sharing resources among participants. A resource adequacy program in the Northwest would help the region navigate reliability and cost challenges given its evolving resource mix.

In late 2019, NWPP members initiated a resource adequacy program design development process. In mid-2020, the NWPP Resource Adequacy Program Conceptual Design was completed and Southwest Power Pool (SPP) was hired to lead the detailed design in partnership with the NWPP members. At the time of this writing, the detailed design is underway, and the process is expected to conclude in mid-2021. The timeline for the overall resource adequacy program implementation is estimated to be in 2024. PSE is actively involved in the design development process and looks to leverage program benefits. Future IRPs will need to incorporate the RA program into its resource adequacy analysis and overall planning process.

5. FUTURE DEMAND UNCERTAINTY FACTORS

Electric Vehicles

Electric vehicles (EVs) are rapidly gaining a presence in PSE's service territory and taking hold in every vehicle market. These EVs include light-duty vehicles, medium-duty vehicles, and heavy-duty vehicles, both cars and trucks, and they are operated by individuals and as members of fleets. EVs create new electric load, and the pace and scale of EV adoption is key to the magnitude of these impacts on utility demand. PSE contracted for an EV sales and load forecast, which was then incorporated into the 2021 IRP Demand Forecast. This forecast revealed new opportunities to manage EV load and improve customer experience, which PSE is investigating through a suite of EV pilot programs.

The 2021 IRP Base Demand Forecast incorporates GuideHouse's incremental EV energy forecast by excluding demand from existing vehicles. See Chapter 6, Demand Forecasts, for a discussion of base energy demand and peak impacts.

Demand Impacts

The Electric Vehicle Charger Incentive (EVCI) Pilot Program, which went into effect on May 1, 2014, allowed PSE to offer a $500 rebate to customers who purchase their own Level 2 electric vehicle charger.[4] Using data gathered through this pilot, PSE created an "Electric Vehicle Household and Charger Load Profiling" study with a study period set for 12 months ending June 2017. At the time, there were an estimated 13,140 EVs registered in PSE's electric service territory, of which 9,480 were 100 percent battery-operated (BEV) and 3,660 were plug-in hybrid vehicles (PHEV).[5]

The key findings of the study were as follows:

- On a typical weekday, hourly load per Level 2 EV charger varied between 0.1 kW and 0.9 kW while hourly load per Level 1 charger ranged between 0.06 kW and 0.6 kW.[6]
- On a typical weekend day, hourly load per Level 2 charger ranged between 0.08 kW and 0.6 kW while the range of hourly load per Level 1 charger was 0.04 kW to 0.5 kW.

4 / Docket UE-131585
5 / A list of EV's registered through the end of June 2017 was provided by Washington State Department of Licensing.
6 / The average hourly load per EV charger should not be interpreted as the hourly energy use by a typical EV charger. For example, a typical Level 2 charger uses between 1.1 kW and 2.6 kW while in use and close to zero while not in use. An individual L2 charger load shape would be characterized by a flat load at nearly zero kW for most of the day interrupted by one or more charging events which last a few hours or so per event.

- Daily peak of EV charger load occurred mostly in the early evening hours of 6:00 PM to 8:00 PM, as does monthly system peak demand.
- Monthly load factor and system coincidence factor of EV charger loads are fairly low for most months. During the study period, all of the monthly load factors were below 0.29 while 8 of 12 monthly system coincidence factors were lower than 0.40. However, the system coincidence factor will become very high if monthly system peak and EV charger peak loads occur on the same day, as happened in March 2017 when the system coincidence factor was 0.91.

Although at the time of this study EVs represented a very small portion of the residential class load, PSE predicts that by 2032 there will be more than 250,000 Light Duty EVs in PSE's service territory.

To study the implications of this growing load that can be added anywhere and potentially coincident with peak, PSE's Up & Go Electric programs are actively working to develop load shapes for additional charging use cases that are specific to PSE's electric service territory. This suite of pilot programs is expanding to include workplace charging, multi-unit dwellings, public charging, many unique low-income use cases, a more refined load profile for single-unit dwelling charging, and to capture a broader audience for each of these use cases. The programs will also develop load profiles for prominent medium and heavy duty vehicle charging use cases.

In addition to developing load shapes, a key goal of PSE's Up & Go Electric program is to investigate the most effective and efficient ways of encouraging and enabling EV customers to shift charging to off-peak hours in a way that minimizes demand-side impacts. These programs are ongoing and final results are not yet available, but PSE has already applied some of the early lessons learned to the design of future programs to ensure that customer load is managed not only to reduce coincidence with system peak, but also to minimize the coincidence of charging between EV chargers.

Energy Efficiency Technology, Codes and Standards and Electrification

Changing codes and standards and energy efficiency technology are impacting both customer choices and energy efficiency programs.

In terms of energy efficiency programs for example, when federal minimum lighting performance standards included screw-in LED lighting, this removed LEDs from energy efficiency program offerings; while LEDs continue to achieve savings, they could no longer be included in incentive programs.

The two energy codes that impact PSE customers, the Washington State Energy Code (WSEC) and the Seattle Energy Code, are transitioning to include a focus on carbon emissions in addition to energy efficiency, and these changes emphasize electrification of systems formerly fueled by natural gas. Since 2018, the WSEC no longer gives builders efficiency credits for new single family homes that install natural gas space heating or water heating, instead giving them credits for installing heat pumps for space and water. In 2021, the Seattle Energy Code put significant barriers on using natural gas for space and water heating in new commercial and multi-family buildings. With few exceptions, new buildings will be using various types of heat pump technology to attempt to meet the loads of these systems.

While technology continues to provide innovation in how loads are met in customer homes and buildings, it takes time for these changes to gain significant market penetration. Heat pump water heaters, for example, have been on the market for nearly a decade, but they are largely limited to the new home market rather than the much larger existing home market. When code changes move quickly, adoption issues arise and may include: the lack of robust examples/applications that have validated particular approaches (such as the sole use of heat pumps to serve both space and water heating in large-demand applications, essentially new building electrification); the complexity of the design, operation and maintenance of systems that have been largely hands-off traditionally; and the installer community not being fully prepared to transition to installing and maintaining these systems. Time is required to work out design flaws, build trust in the installer/trades community, and drive down costs so that consumers will pay reasonable costs to make these changes.

Despite how quickly changes are taking place in the areas of technology and codes and standards, PSE remains committed to ensuring its customers are made aware of the opportunities to reduce energy use and carbon footprints, advocating for smart changes to codes and standards and working with our trade allies to understand and mitigate barriers to new technology adoption.

Distributed Energy Resources

DER-based generation, such as rooftop solar panels, has seen price declines and increases in customer adoption. The technology and its rate of adoption are still evolving, and therefore future demand can be significantly impacted by policy, including incentives, and technological advances, including further price declines.

While PSE customer adoption of DER is low when compared to states like California and Hawaii, PSE residential solar is increasing by about 2,000 customers annually. Additionally, the average capacity of residential solar is increasing. In 2009, the average residential capacity was 4.7 kW, while the current average system generating capacity is 10 kW. As of the end of 2020, PSE's system hosted 85 MW of net metered solar, with over 10,100, or about 1 percent, of customers participating. In comparison, solar represents about 25 percent of Hawaii's generation capacity and over 10 percent of its residential customers have solar generation.

Adding increasing volumes of DERs to the distribution system, whether they are generating technologies such as solar, storage technologies such as batteries, or load management tools, requires rethinking how the distribution system operates and what standards and controls are needed to maintain the safety and reliability of the system. Demand will be impacted by when and how these technologies operate, whether dependably and reliably decreasing load or intentionally increasing load if charging is allowed during peak hours.

Additionally, most customers pursing DER solutions today do not consume all of the energy they generate on-site in real time, making demand and power flow more variable on the local distribution system and resource management overall. Storage and control systems promise improvement in managing DERs' benefits and impacts on demand, and over 4 percent of PSE's net metered solar installations include battery storage today. These emerging capabilities are maturing, and as monitoring, control, communications, delivery infrastructure and energy storage systems are modernized, opportunities to understand real demand impacts will increase.

For this IRP, PSE explored and modeled numerous future DER options; these are documented in Chapters 5 and 8.

6. NATURAL GAS SUPPLY AND PIPELINE TRANSPORTATION

Risks to Natural Gas Supply

Natural gas is imported to the Pacific Northwest, primarily from British Columbia and the Rocky Mountain region. Disruptions to natural gas transportation infrastructure, therefore, present a risk to reliable gas supply in the region.

In October 2018 the Westcoast Pipeline, a major pipeline that brings natural gas from British Columbia south to the U.S. border, ruptured, severely limiting the supply of natural gas to the Pacific Northwest. Through a combination of immediate conservation efforts, the shutdown of natural gas fired power plants, and curtailment of service to select industrial customers, the region only narrowly avoided destabilization of the natural gas transportation system and curtailment of service to large swaths of natural gas customers.

Capacity restrictions on the Westcoast Pipeline continued well into 2019 causing a dramatic increase to wholesale natural gas prices in the region. By late 2019, the pipeline had been restored to normal full capacity, and while average gas prices have generally returned to pre-event levels, prices remain significantly more volatile compared to recent historical periods.

The lessons learned from the October 2018 event were applied in the restructured Northwest Mutual Assistance Agreement (NWMAA). The Agreement is made among entities that utilize, operate and control natural gas transportation and/or storage facilities in the Pacific Northwest (British Columbia, Alberta, Washington, Oregon, Nevada and Idaho). The Agreement[7] is intended to define the terms and conditions for cooperation and/or assistance between the parties in an emergency if such aid is volunteered. Another objective is to maintain and improve communication linkages between the members as they pertain to emergency planning and incident response.

7 / https://www.westernenergy.org/nwmaa/

7. PURCHASING VERSUS OWNING ELECTRIC RESOURCES

The IRP determines the supply-side capacity, renewable energy and energy need which set the supply-side targets for future detailed planning in the Clean Energy Implementation Plan, as well as the acquisition process. The formal Request for Proposal (RFP) processes for demand-side and supply-side resources are just one source of information for making acquisition decisions. Market opportunities outside the RFP and resource build decisions should also be considered when making prudent resource acquisition decisions.

In Build versus Buy, “Build” refers to resource acquisitions that involve PSE ownership of an asset. Ownership could occur anywhere along the development life cycle of a project. PSE could complete development activities from the beginning or buy the asset anywhere from early stage development to Commercial Operation Date (COD) or after. “Buy” refers to purchase of the output of a project through a Power Purchase Agreement (PPA).

In general, quantitative and qualitative evaluations for Build and Buy proposals are conducted similarly in an RFP, consistent with WAC 480-107, solving for the lowest cost options for customers. Qualitative project risks are evaluated in the same way for both kinds of acquisitions. Quantitative evaluations for Build options include costs of ownership such as operating expenses and depreciation. These are typically embedded in the MWh price for PPAs. Build proposals include the allowable rate of return on capital assets as a cost to customers, while Buy proposals include a return on the PPA costs as allowed by the Clean Energy Transformation Act. Project designs also need to be more carefully scrutinized for projects that PSE would own and operate. Equipment selection and design specifications must meet PSE standards for ownership.

In the 2018 RFP, PSE received a large number of ownership proposals. These proposals included offers for PSE to take ownership of projects before COD, at COD and after COD. Primarily because of the fact that PSE cannot monetize federal tax incentives for renewable projects, these proposals were not competitive relative to PPAs.

5 Key Analytical Assumptions

This chapter describes the forecasts, estimates and assumptions that PSE developed for this IRP analysis; the scenarios created to test how different sets of economic conditions affect portfolio costs and risks; and the sensitivities used to explore how different resources or environmental regulations impact the portfolio.

Contents

1. OVERVIEW

This chapter describes the forecasts, estimates and assumptions that PSE developed for the electric and natural gas IRP analysis. The details of the electric and natural gas analyses can be found in Chapters 8 and 9, respectively, and further details are available in various appendices.

Section 2, Electric Analysis, presents the electric scenarios created to test how different sets of economic conditions affect portfolio costs and risks, followed by the inputs used to create those scenarios. Scenario inputs include the IRP demand forecast; price assumptions for natural gas and CO_2 costs; assumptions about cost and characteristics for existing and generic resources; and transmission considerations.

Electric portfolio sensitivities are described next. Sensitivities start with the optimized, least cost Mid Scenario portfolio produced in the scenario analysis and change a resource, environmental regulation or other condition to examine the effect of that change on the portfolio. PSE analyzed 27 sensitivities for the electric analysis.

Section 3, Natural Gas Analysis, is organized similarly. The natural gas scenarios are described first, followed by the inputs used to create the scenarios, then the sensitivities used to examine the effects of changes on the Mid Scenario portfolio. PSE analyzed six sensitivities for the natural gas analysis.

Each section also describes the delivery system planning assumptions for its respective energy delivery system.

Time horizon: The time horizon for the 2021 IRP is 2022 – 2041. The natural gas analysis analyzes the time frame 2022 – 2041, but the electric analysis has been expanded to analyze the time frame 2022 – 2045 to better understand the implications of CETA.

2. ELECTRIC ANALYSIS

Electric Price Forecast Scenarios

PSE created three scenarios for the electric analysis to test how different combinations of two fundamental economic conditions – customer demand and natural gas prices – impact the least-cost mix of resources. PSE also added two scenarios to test how different carbon pricing can impact electric prices. The five electric price scenarios are outlined in Figure 5-1 and summarized below. A description of the economic inputs to the scenarios follows.

Figure 5-1: 2021 IRP Electric Price Forecast Scenarios

	Scenario Name	Demand	Natural Gas Price	CO_2 Price/Regulation	RPS/Clean Energy Regulation
1	Mid	Mid[1]	Mid	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC
2	Low	Low	Low	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC
3	High	High	High	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC
4	SCGHG as Dispatch Cost	Mid	Mid	Social cost of greenhouse gasses modeled as federal CO_2 price across the WECC	Washington CETA, plus all regional RPS regulations in the WECC
5	CO_2 tax	Mid	Mid	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: $15/ton in 2022 increasing at $10/year across the WECC	Washington CETA, plus all regional RPS regulations in the WECC

NOTE
1. Mid demand refers to the 2021 IRP Base Demand Forecast.

Scenario 1: Mid

The Mid Scenario is a set of assumptions that is used as a reference point against which other sets of assumptions can be compared.

DEMAND

- The 2021 IRP Base (Mid) Demand Forecast is applied for PSE.
- For electric power price modeling, the Northwest Power and Conservation Council (NPCC) 2019 Policy Update to the 2018 Wholesale Electricity Forecast[1] is applied.
- The regional mid demand forecast is applied to the WECC region.

NATURAL GAS PRICES

- Mid natural gas prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.

CO_2 PRICE AND REGULATIONS

- The social cost of greenhouse gases is expressed as a cost adder for resources in Washington or delivered to Washington.
- For natural gas generation fuel, upstream CO_2 emissions are added to the emission rate of natural gas plants in PSE's portfolio model.
- CO_2 prices for California are included.

CLEAN ENERGY AND RPS REGULATIONS

- For Washington state, at least 80 percent of electric sales (delivered load) are met with non-emitting/renewable resources by 2030 (per CETA) and 100 percent by 2045; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC[2] are applied. See further discussion on methodology in Appendix G, Electric Analysis Models.

1 / https://www.nwcouncil.org/sites/default/files/2019_0611_p4_forecast.pdf
2 / WECC, the Western Electricity Coordinating Council, is the regional forum for promoting electric service reliability in the western United States.

Scenario 2: Low

This scenario models weaker long-term economic growth than the Mid Scenario. Customer demand is lower in the region and in PSE's service territory.

DEMAND

- The 2021 IRP Low Demand Forecast is applied for PSE.
- Electric power price modeling: To extrapolate a low demand forecast for the WECC, the difference between the low and medium demand forecast in the Pacific Northwest from the NPCC 2019 Policy Update to the 2018 Wholesale Electricity forecast is applied to the WECC region medium forecast.

NATURAL GAS PRICES

- Natural gas prices are lower due to lower energy demand; the Wood Mackenzie long-term low forecast is applied to natural gas prices.

CO_2 PRICE AND REGULATIONS

- The social cost of greenhouse gases is expressed as a cost adder for resources in Washington or delivered to Washington.
- For natural gas generation fuel, upstream CO_2 emissions are added to the emission rate of natural gas plants in PSE's portfolio model.
- CO_2 prices for California are included.

CLEAN ENERGY AND RPS REGULATIONS

- For Washington state, at least 80 percent of electric sales (delivered load) are met with non-emitting/renewable resources by 2030 (per CETA) and 100 percent by 2045; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC are applied. See further discussion on methodology in Appendix G, Electric Analysis Models.

Scenario 3: High

This scenario models more robust long-term economic growth than the Mid Scenario, which produces higher customer demand in the region and in PSE's service territory.

DEMAND

- The 2021 IRP High Demand Forecast is applied for PSE.
- Electric power price modeling: To extrapolate a high demand forecast for the WECC, the difference between the high and medium demand forecast in the Pacific Northwest from NPCC 2019 Policy Update to the 2018 Wholesale Electricity forecast is applied to the WECC region medium forecast.

NATURAL GAS PRICES

- Natural gas prices are higher as a result of increased demand; the Wood Mackenzie long-term high forecast is applied to natural gas prices.

CO_2 PRICE AND REGULATIONS

- The social cost of greenhouse gases is expressed as a cost adder for resources in Washington or delivered to Washington.
- For natural gas generation fuel, upstream CO_2 emissions are added to the emission rate of natural gas plants in PSE's portfolio model.
- CO_2 prices for California are included.

CLEAN ENERGY AND RPS REGULATIONS

- For Washington state, at least 80 percent of electric sales (delivered load) are met with non-emitting/renewable resources by 2030 (per CETA) and 100 percent by 2045; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC are applied. See further discussion on methodology in Appendix G, Electric Analysis Models.

Scenario 4: SCGHG as Dispatch Cost

The social cost of greenhouse gases (SCGHG) as Dispatch Cost Scenario models a federal CO_2 tax that effects all WECC states. This electric price forecast will be used for portfolio sensitivity J, SCGHG as a Dispatch Cost in Electric Prices and Portfolio.

DEMAND

- The 2021 IRP Base (Mid) Demand Forecast is applied for PSE.
- For electric power price modeling, the Northwest Power and Conservation Council (NPCC) 2019 Policy Update to the 2018 Wholesale Electricity Forecast[3] is applied.
- The regional mid demand forecast is applied to the WECC region.

NATURAL GAS PRICES

- Mid natural gas prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.

CO_2 PRICE AND REGULATIONS

- The social cost of greenhouse gases is expressed as a CO_2 price across all WECC states.
- For natural gas generation fuel, upstream CO_2 emissions are added to the emission rate of natural gas plants in PSE's portfolio model.

CLEAN ENERGY AND RPS REGULATIONS

- For Washington state, at least 80 percent of electric sales (delivered load) are met with non-emitting/renewable resources by 2030 (per CETA) and 100 percent by 2045; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC[4] are applied. See further discussion on methodology in Appendix G, Electric Analysis Models.

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3 / https://www.nwcouncil.org/sites/default/files/2019_0611_p4_forecast.pdf

4 / WECC, the Western Electricity Coordinating Council, is the regional forum for promoting electric service reliability in the western United States.

Scenario 5: CO_2 Tax

The CO_2 tax scenario models a federal CO_2 tax plus the SCGHG adder for Washington. This electric price forecast will be used for portfolio sensitivity L, SCGHG as a Fixed Cost Plus a Federal CO_2 Tax

DEMAND

- The 2021 IRP Base (Mid) Demand Forecast is applied for PSE.
- For electric power price modeling, the Northwest Power and Conservation Council (NPCC) 2019 Policy Update to the 2018 Wholesale Electricity Forecast[5] is applied.
- The regional mid demand forecast is applied to the WECC region.

NATURAL GAS PRICES

- Mid natural gas prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.

CO_2 PRICE AND REGULATIONS

- The social cost of greenhouse gases is expressed as a cost adder for resources in Washington or delivered to Washington.
- For natural gas generation fuel, upstream CO_2 emissions are added to the emission rate of natural gas plants in PSE's portfolio model.
- CO_2 prices applied to all WECC states.

CLEAN ENERGY AND RPS REGULATIONS

- For Washington state, at least 80 percent of electric sales (delivered load) are met with non-emitting/renewable resources by 2030 (per CETA) and 100 percent by 2045; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC[6] are applied. See further discussion on methodology in Appendix G, Electric Analysis Models.

5 / https://www.nwcouncil.org/sites/default/files/2019_0611_p4_forecast.pdf

6 / WECC, the Western Electricity Coordinating Council, is the regional forum for promoting electric service reliability in the western United States.

Comparison Electric Price Scenario for CETA Rate Impact Cost Control

The rate impact cost controls in the Clean Energy Transformation Act (CETA) are calculated based on incremental costs associated with CETA compliance. Because a comparison to the base assumptions without CETA is required to estimate these incremental costs, PSE also developed a version of the Mid Scenario that does not include CETA. This electric price scenario will be used for the two cost comparison sensitivities without CETA described in Figure 5-26.

Figure 5-2: Comparison Electric Price Scenario for CETA Rate Impact Cost Control

COMPARISON SCENARIO FOR CETA RATE IMPACT COST CONTROL					
	Scenario Name	Demand	Gas Price	CO_2 Price	RPS/Clean Energy Regulations
	Mid + No CETA	Mid[1]	Mid	CA AB32 CO_2 policy	RCW 19.285, plus all regional RPS regulations in the WECC

NOTE
1. Mid demand refers to the 2021 IRP Base Demand Forecast.

Mid + No CETA

This scenario is for comparison purposes only; it is not part of the resource plan.

DEMAND

- The 2021 IRP Base (Mid) Demand Forecast is applied for PSE.
- For electric power price modeling, the Northwest Power and Conservation Council (NPCC) 2019 Policy Update to the 2018 Wholesale Electricity Forecast[7] is applied.
- The regional mid demand forecast is applied to the WECC region.

NATURAL GAS PRICES

- Mid natural gas prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.

CO_2 PRICE

- CO_2 prices for California are included.

CLEAN ENERGY/RPS REGULATIONS

- Per RCW 19.285, 15 percent of Washington state energy is supplied by renewable resources by 2020; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC are applied.

7 / *https://www.nwcouncil.org/sites/default/files/2019_0611_p4_forecast.pdf*

Electric Scenario Inputs

PSE Customer Demand

The 2021 IRP Base, Low and High Demand Forecasts used in this analysis represent estimates of energy sales, customer counts and peak demand over a 20-year period.[8] Significant inputs include the following.

- information about regional and national economic growth
- demographic changes
- weather
- prices
- seasonality and other customer usage and behavior factors
- known large load additions or deletions

Figure 5-3 and Figure 5-4 below show the electric peak demand and annual energy demand forecasts without including the effects of conservation. The forecasts include sales (delivered load) plus system losses. The electric peak demand forecast is for a one-hour temperature of 23° Fahrenheit at Sea-Tac airport.

Why don't demand forecasts in rate cases and acquisition discussions match the IRP forecast?

The IRP analysis takes 12 to 18 months to complete. Demand forecasts are so central to the analysis that they are one of the first inputs to be developed. By the time the IRP is completed, PSE may have updated its demand forecast. The range of possibilities in the IRP forecast is sufficient for long-term planning purposes, but we will always present the most current forecast for rate cases or when making acquisition decisions.

> > > See Chapter 6, Demand Forecasts, *for detailed discussion of the demand forecasts, and* ***Appendix F, Demand Forecasting Models,*** *for the analytical models used to develop them.*

8 / For long-range planning, customer demand is expressed as if it were evenly distributed throughout PSE's service territory, but in reality, demand grows faster in some parts of the service territory than others.

Figure 5-3: 2021 IRP Electric Peak Demand Forecast – Low, Base (Mid), High

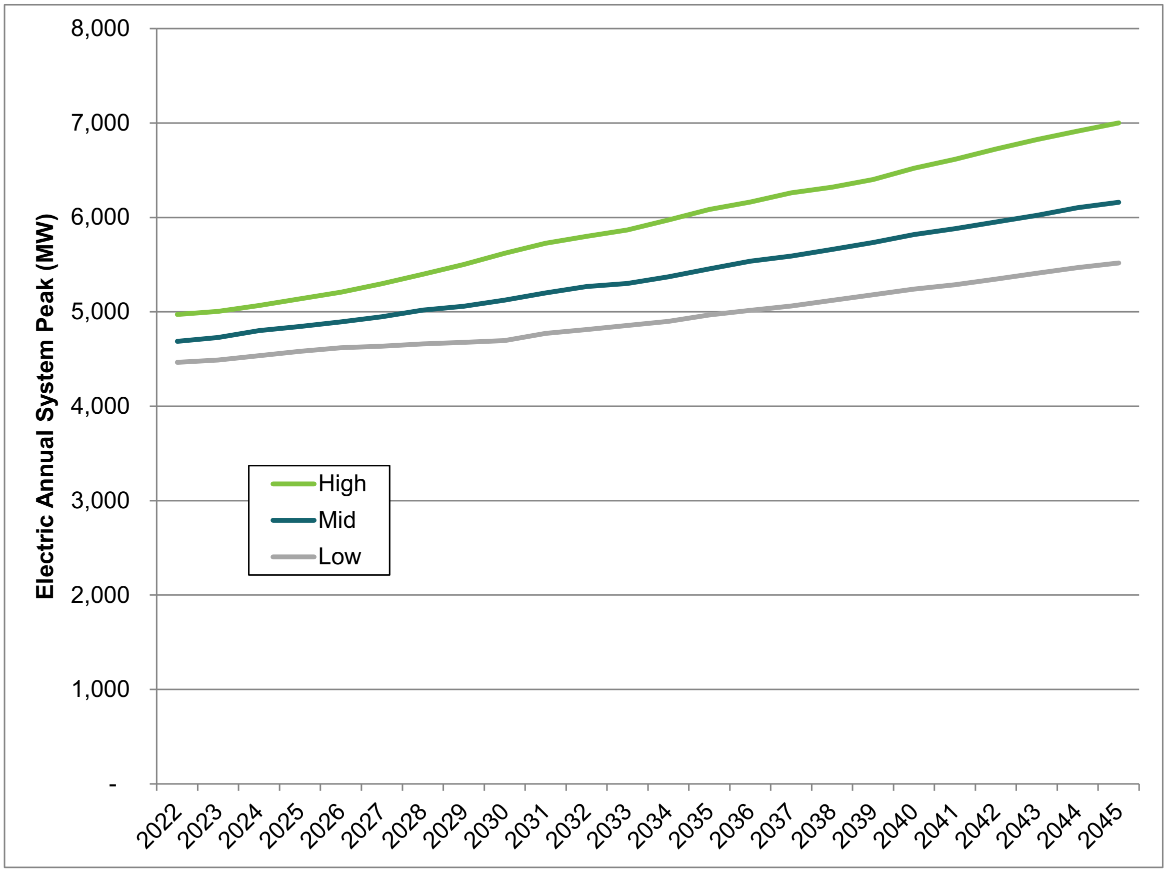
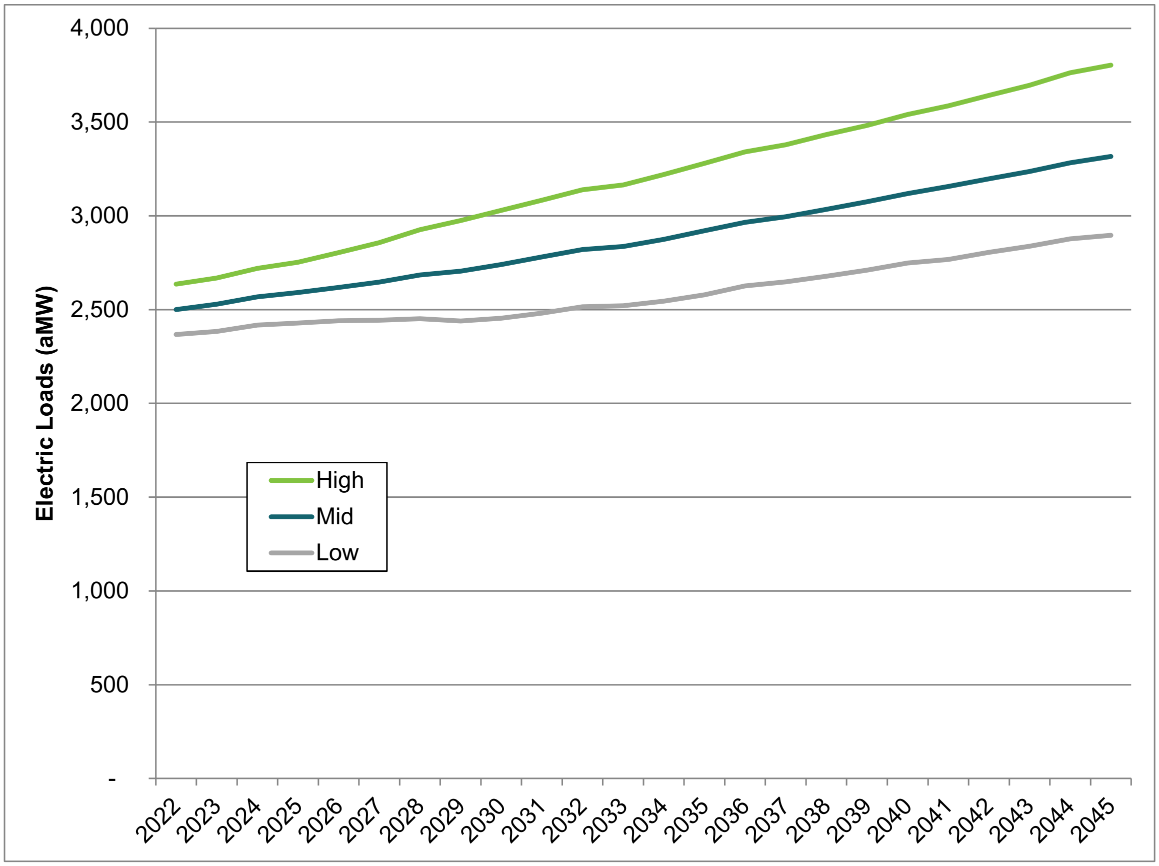


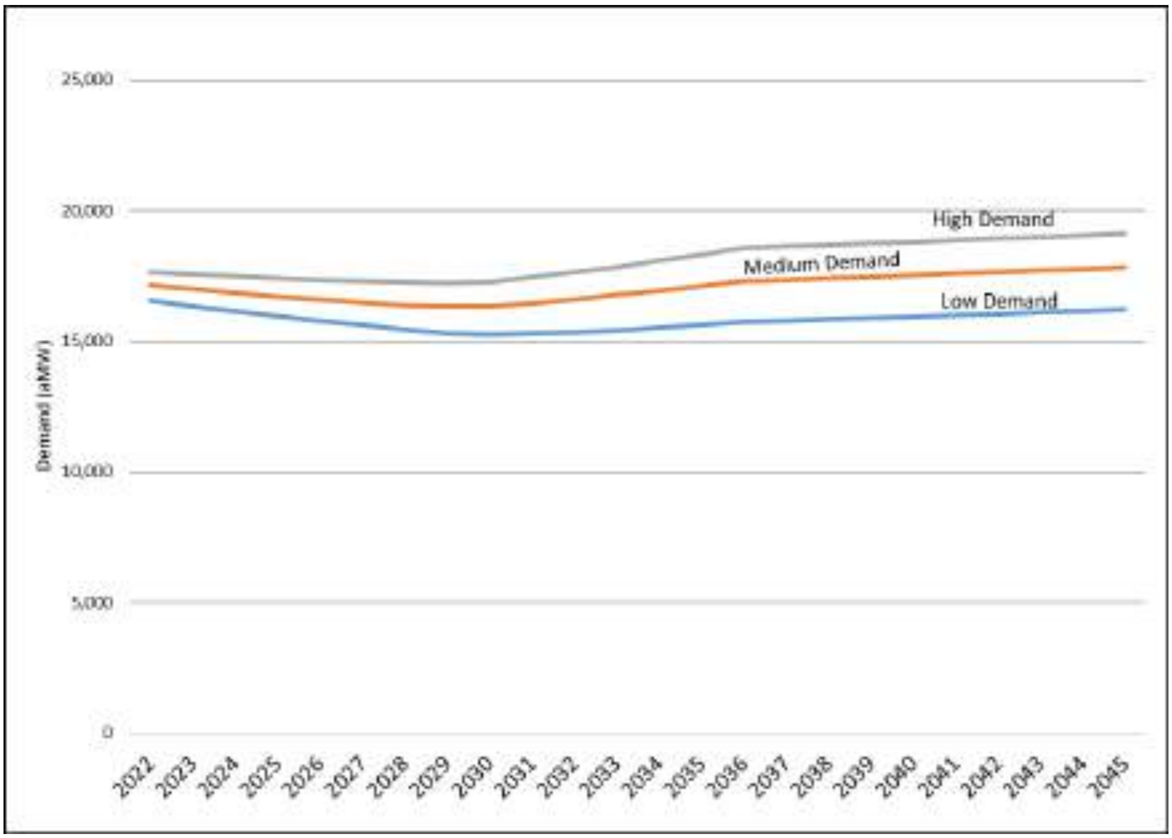
Figure 5-4: 2021 IRP Annual Electric Energy Demand Forecast - Low, Base (Mid) High



Regional Electric Demand

Regional demand must be taken into consideration because it significantly affects power prices. This IRP uses the regional demand developed by the NPCC[9] 2019 Policy Update to the 2018 Wholesale Electricity forecast, the most recent forecast available at the time of this analysis. Updated 2020 loads and COVID-19 impacts were not available from the NPCC until February 2021. Regional demand is used only in the WECC-wide portion of the AURORA analysis that develops wholesale power prices for the scenarios.

Figure 5-5: NPCC Regional Demand Forecast for the Pacific Northwest – Average, not Peak



9 / The NPCC has developed some of the most comprehensive views of the region's energy conditions and challenges. Authorized by the Northwest Power Act, the Council works with regional partners and the public to evaluate energy resources and their costs, electricity demand and new technologies to determine a resource strategy for the region.

Natural Gas Price Inputs

For natural gas price assumptions, PSE uses a combination of forward market prices and fundamental forecasts acquired in Spring 2020[10] from Wood Mackenzie.[11]

- From 2022-2026, this IRP uses the three-month average of forward market prices from June 30, 2020. Forward market prices reflect the price of natural gas being purchased at a given point in time for future delivery.
- Beyond 2029, this IRP uses the one of the Wood Mackenzie long-run natural gas price forecasts published in July 2020.

For the years 2027 and 2028, a combination of forward market prices from 2026 and selected Wood Mackenzie prices from 2029 are used to minimize abrupt shifts when transitioning from one dataset to another.

- In 2027, the monthly price is the sum of two-thirds of the forward market price for that month in 2026 plus one-third of the 2029 Wood Mackenzie price forecast for that month.
- In 2028, the monthly price is the sum of one-third of the forward market price for that month in 2026 plus two-thirds of the 2029 Wood Mackenzie price forecast for that month.

Three natural gas price forecasts are used in the scenario analyses.

MID NATURAL GAS PRICES. The mid natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and the Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020.

LOW NATURAL GAS PRICES. The low natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and an adjusted Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020. To adjust the Wood Mackenzie forecast, PSE used the data trends from the Spring 2018 Wood Mackenzie low price forecast and applied them to the most recent fundamentals forecast. The underlying factors that influence the high and low reports have not changed significantly between the Spring 2018 and Spring 2020 forecasts.

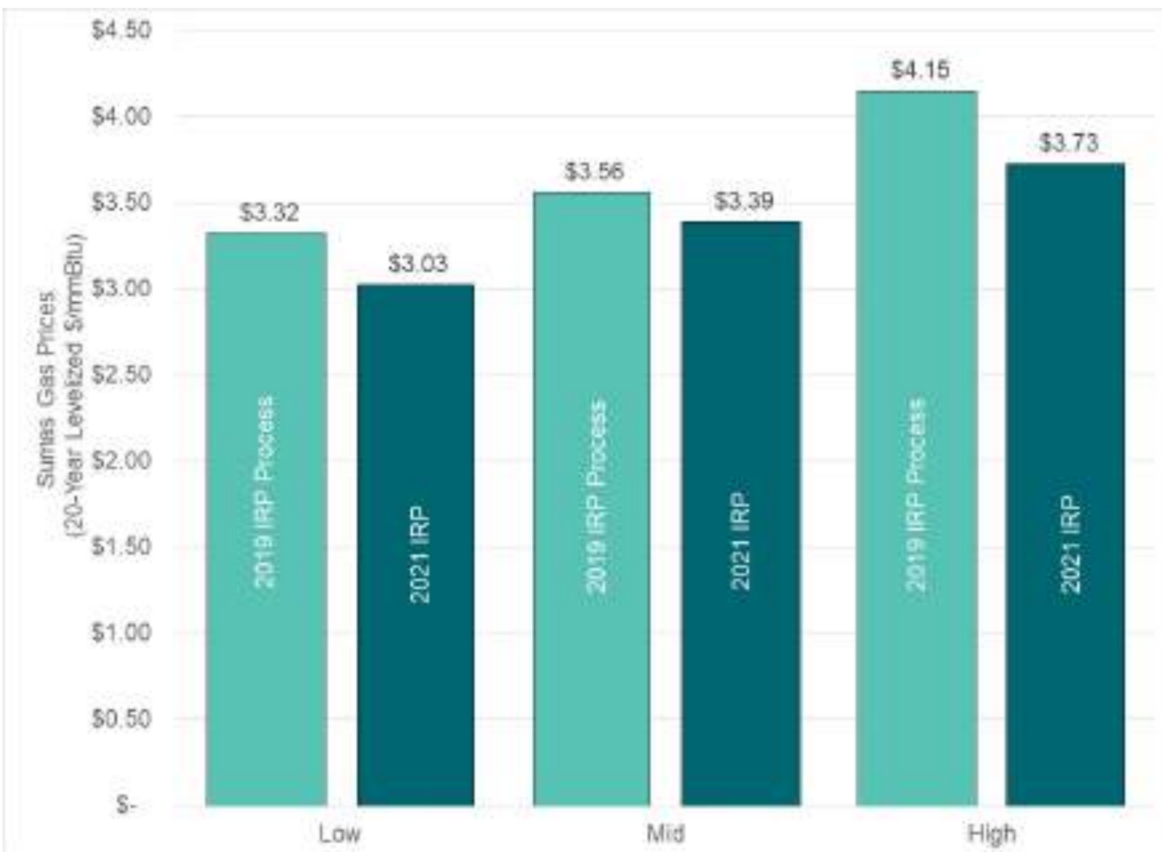
10 / *The Spring 2020 forecast from Wood Mackenzie is updated to account for economic and demographic changes stemming from the COVID-19 pandemic.*

11 / *Wood Mackenzie is a well-known macroeconomic and energy forecasting consultancy whose gas market analysis includes regional, North American and international factors, as well as Canadian markets and liquefied natural gas exports.*

HIGH NATURAL GAS PRICES. The high natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and an adjusted Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020. To adjust the Wood Mackenzie forecast, PSE used the data trends from the Spring 2018 Wood Mackenzie high price forecast and applied them to the most recent fundamentals forecast. The underlying factors that influence the high and low reports have not changed significantly between the Spring 2018 and Spring 2020 forecasts.

Figure 5-6 below illustrates the range of 20-year levelized natural gas prices used in this IRP analysis compared to the 20-year levelized natural gas prices used in the 2019 IRP Process.

Figure 5-6: Levelized Natural Gas Prices Used in Scenarios, 2021 IRP vs. 2019 IRP Process
(Sumas Hub, 20-year levelized 2022-2041, nominal $)



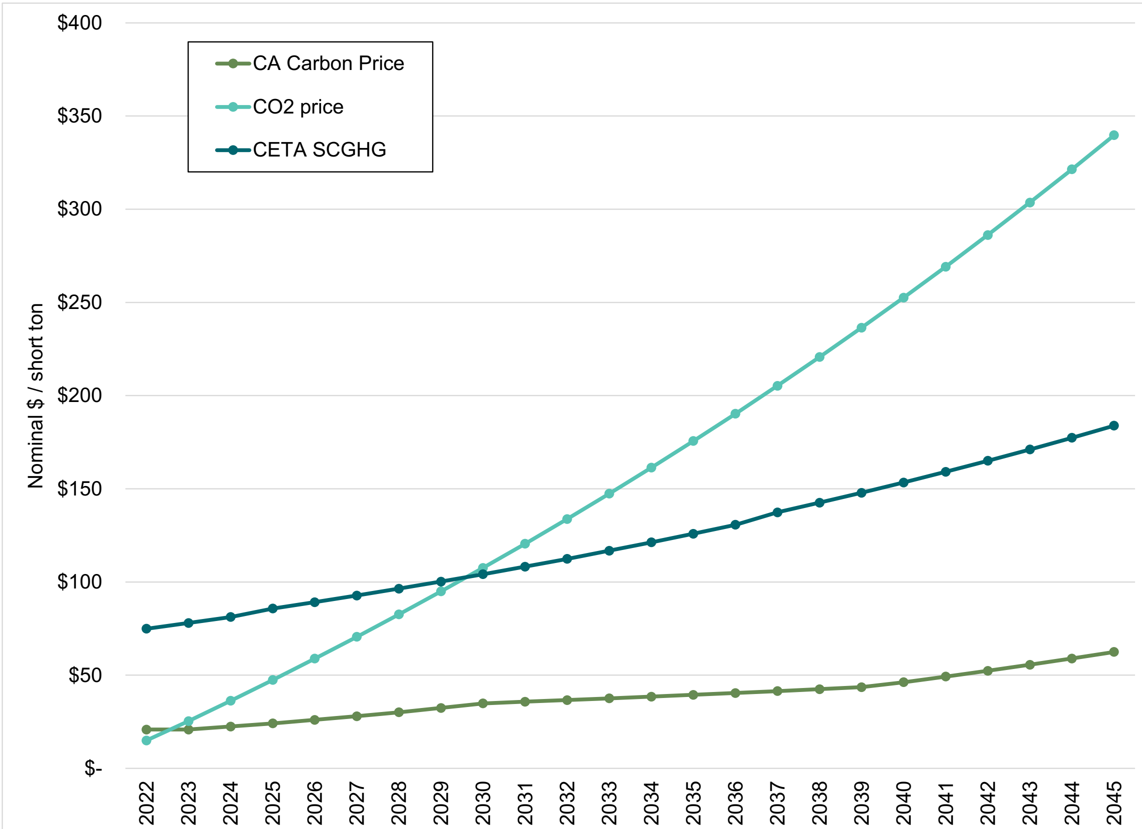
CO_2 Price Inputs

The electric analysis modeled the social cost of greenhouse gases (SCGHG) cited in the Washington Clean Energy Transformation Act (CETA) as a cost adder to thermal resources in Washington state. In addition to the SCGHG mandated by CETA, the analyses modeled the costs imposed by existing CO_2 regulations in California and British Columbia.

SOCIAL COST OF GREENHOUSE GASES (SCGHG). The SCGHG cited in CETA comes from the Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document, August 2016 update. It projects a 2.5 percent discount rate, starting with $62 per metric ton (in 2007 dollars) in 2020. The document lists the *CO_2* prices in real dollars and metric tons. PSE has adjusted the prices for inflation (nominal dollars) and converted to U.S. tons (short tons). This cost ranges from **$69 per ton in 2020 to $189 per ton in 2045,** as shown in Figure 5-7.

CO_2 tax. The CO_2 tax modeled in this IRP is based on HR763 Energy Innovation and Carbon Dividend Act of 2019. The cost starts at $15 per ton and increases at $10 per year, as shown in Figure 5-7.

Figure 5-7: Social Cost of Greenhouse Gases Used in the 2021 IRP



UPSTREAM CO_2 EMISSIONS FOR NATURAL GAS. The upstream emission rate represents the carbon dioxide, methane and nitrous oxide releases associated with the extraction, processing and transport of natural gas along the supply chain. These gases were converted to carbon dioxide equivalents (CO_2e) using the Intergovernmental Panel on Climate Change Fourth Assessment (AR4) 100-year global warming potentials (GWP) protocols.[12]

For the cost of upstream CO_2 emissions, PSE used emission rates published by the Puget Sound Clean Air Agency[13] (PSCAA). PSCAA used two models to determine these rates, GHGenius[14] and GREET.[15] Emission rates developed in the GHGenius model apply to natural gas produced and delivered from British Columbia and Alberta, Canada. The GREET model uses U.S.-based emission attributes and applies to natural gas produced and delivered from the Rockies basin.

Figure 5-8: Upstream Natural Gas Emissions Rates

	Upstream Segment	End-use Segment (Combustion)	Emission Rate Total	Upstream Segment CO2e (%)
GHGenius	10,803 g/MMBtu	+ 54,400 g/MMbtu	= 65,203 g/MMBtu	19.9%
GREET	12,121 g/MMBtu	+ 54,400 g/MMbtu	= 66,521 g/MMBtu	22.3%

NOTE: End-use Combustion Emission Factor: EPA Subpart NN

The upstream segment of 10,803 g/MMBtu is converted to 23 lb/mmBtu and then applied to the emission rate of natural gas plants.

12 / Both the EPA and the Washington Department of Ecology direct reporting entities to use the AR4 100-year GWPs in their annual compliance reports, as specified in table A-1 at 40 CFR 98 and WAC 173-441-040.
13 / Proposed Tacoma Liquefied Natural Gas Project, Final Supplemental Environmental Impact Statement, Ecology and Environment, Inc., March 29, 2019
14 / GHGenius. (2016). GHGenius Model v4.03. Retrieved from http://www.ghgenius.ca/
15 / GREET. (2018). Greenhouse gases, Regulated Emissions and Energy use in Transportation; Argonne National Laboratory.

Renewable Portfolio Standards (RPS) and Clean Energy Standards

Renewable portfolio standards and clean energy standards currently exist in 29 states and the District of Columbia, including most of the states in the WECC and British Columbia. They affect PSE because they increase competition for development of renewable resources. Each state and territory defines renewable energy sources differently, sets different timetables for implementation, and establishes different requirements for the percentage of load that must be supplied by renewable resources.

To model these varying laws, PSE identifies the applicable load for each state in the model and the renewable benchmarks of each state's RPS (e.g., 3 percent in 2012, 9 percent in 2016, then 15 percent in 2020 for Washington State RCW 19.285). Each state's requirements are applied to the state's load. No retirement of existing WECC renewable resources is assumed, which may underestimate the number of new resources that need to be constructed. After existing renewable resources are accounted for, they are subtracted from the total WECC RPS need, and the net RPS need is added to AURORA as a constraint. We then run the long-term capacity expansion with the RPS constraint, and AURORA adds renewable resources to meet RPS need. Technologies modeled included wind and solar.

WASHINGTON CLEAN ENERGY TRANSFORMATION ACT (CETA). CETA requires that at least 80 percent of electric sales (delivered load) in Washington state must be met by non-emitting/renewable resources by 2030 and 100 percent by 2045. For the 2021 IRP, PSE reviewed the Washington Department of Commerce fuel mix report. For utilities that are currently more than 80 percent hydro, it was assumed that they will reach 100 percent by 2030 and for utilities that are less than 80 percent hydro, it was assumed they will reach 80 percent by 2030. This broke down to 52 percent of sales in Washington met by utilities that will reach 100 percent by 2030 and 48 percent of sales in Washington from utilities that will reach 80 percent by 2030. This averaged to the assumption that 90 percent of sales in Washington will be met by renewable resources by 2030.

Figure 5-9: RPS Assumptions Modeled for Each State in the 2021 IRP

State	State Legislation	RPS/Clean Energy Standards modeled in 2021 IRP
Arizona	Ariz. Admin. Code §14-2-1801 et seq.	15% by 2025
California	SB 100	2024: 44% of retail sales must be renewable or carbon-free electricity 2027: 52% of retail sales must be renewable or carbon-free electricity 2030: 60% of retail sales must be renewable or carbon-free electricity 2045: 100% of retail sales must be renewable or carbon-free electricity
Colorado	SB 263	2020: 30% of its retail electricity sales must be clean energy resources. 2050: for utilities serving 500,000 or more customers, 100% clean energy sources by 2050, so long as it is technically and economically feasible and in the public interest.
Idaho	None	N/A
Montana	SB 164	15% by 2015
Nevada	SB 358	22% for calendar year 2020 24% for calendar year 2021 29% for calendar years 2022 and 2023 34% for calendar years 2024 – 2026 42% for calendar years 2027 – 2029 50% for calendar year 2030 and every year thereafter (must generate, acquire or save electricity from renewable energy systems) GOAL (not an RPS standard): 100% zero carbon dioxide emission resources by 2050.
New Mexico	SB 489	40% renewable resources by Jan 1, 2025 50% renewable resources by Jan 1, 2030 80% renewable resources by Jan 1, 2040 100% zero carbon resources by Jan 1 2045
Oregon	SB 1547	Large investor-owned utilities: 50% by 2040 Large consumer-owned utilities: 25% by 2025 Small utilities: 10% by 2025 Smallest utilities: 5% by 2025
Utah	SB 202	20% by 2025 (GOAL)
Washington	SB 5116	100% of sales to be greenhouse neutral by 2030 – 80% must be met by non-emitting/renewable resources State Policy: 100% of sales met by non-emitting/renewable resources by 2045
Wyoming	None	N/A

The electric portfolio model assumes that PSE will meet the requirement of 80 percent of sales by 2030 and 100 percent of sales by 2045. Starting with PSE's 40 percent in 2020, the model assumes a linear trajectory to 80 percent by 2030 and then another linear incline to 100 percent by 2045.

Power Price Inputs

To complete the scenarios and prepare them for portfolio modeling, PSE must create wholesale power prices for each scenario, because the different sets of economic assumptions create different future power market conditions. In this context, "power price" does not mean the rate charged to customers, it means the price to PSE of purchasing (or selling) one megawatt (MW) of power on the wholesale market, given the economic conditions that prevail in that scenario. This is an important input to the analysis, since market purchases make up a substantial portion of PSE's existing electric resource portfolio.

Creating wholesale power price assumptions requires performing two WECC-wide AURORA model runs for each of the four scenarios. (AURORA is an hourly chronological price forecasting model based on market fundamentals.) The AURORA database starts with inputs and assumptions from the Energy Exemplar 2018 v1 database. PSE then includes updates such as regional demand, natural gas prices, gas pipeline adders, variable operations and maintenance, CO_2 prices, RPS need, and resource retirements and builds. Figure 5-10 shows the four power prices produced by the four scenario conditions.

> > > See Appendix G, Electric Analysis Models, *for a detailed description of the methodology used to develop wholesale power prices.*

>>> See Appendix H, Electric Analysis Inputs and Results, *for the results of the AURORA capacity expansion run.*

Figure 5-10: Input Power Prices by Scenario,
Annual Average Flat Mid-C Power Price (nominal $/MWh)

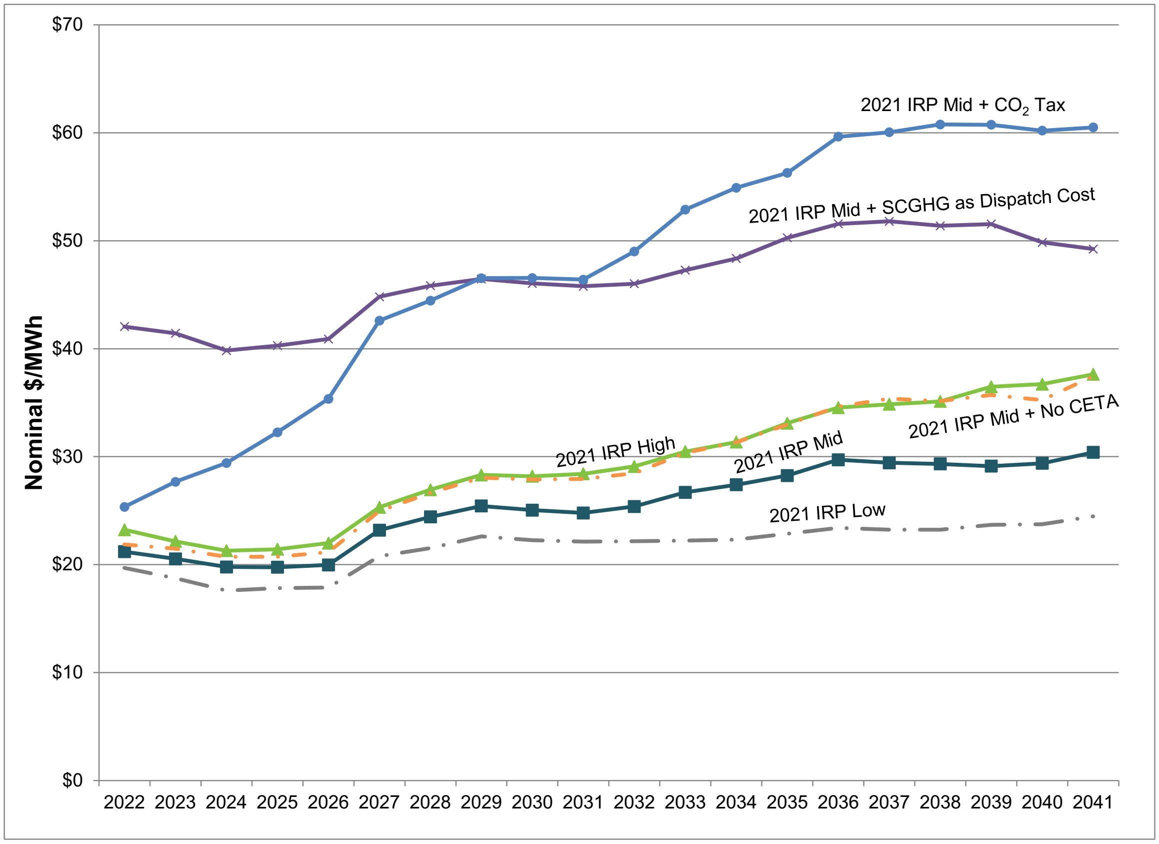
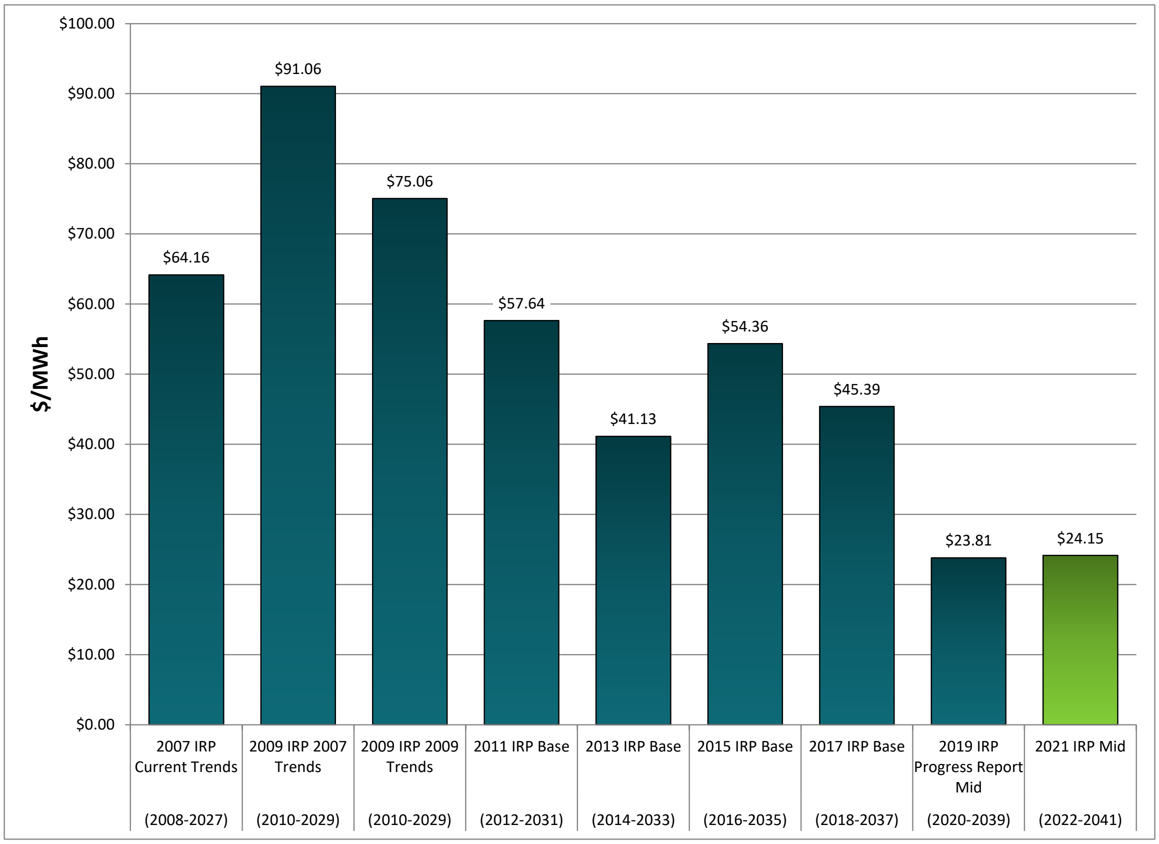


Figure 5-11 below compares the 2021 Mid Scenario power prices to past IRP power prices. In previous IRPs, the downward revisions in forecast power prices corresponded to the downward revisions in natural gas prices. In the 2021 IRP, the large increase in renewable resources in the region required by new clean energy regulations is driving much of the downward revision in forecasted power prices. The 2015 and 2017 IRP Base Scenarios included CO_2 as a tax, whereas the 2021 IRP includes the social cost of greenhouse gases as an adder to resource decisions.

Figure 5-11: 2021 Levelized Power Prices Compared to Past IRPs ($/MWh)



Electric Portfolio Modeling Assumptions

For portfolio modeling, the following assumptions are applied to all scenarios.

Electric Resource Assumptions

PSE modeled the following generic resources as potential portfolio additions in this IRP analysis.

*> > > **See Appendix D, Electric Resources and Alternatives,** for detailed descriptions of the supply-side resources listed here.*
*> > > **See Appendix E, Conservation Potential Assessment and Demand Response Assessment,** for detailed information on demand-side resource potentials.*

Demand-side resources included the following.

ENERGY EFFICIENCY MEASURES. These are a wide variety of measures that result in a lower level of energy being used to accomplish a given amount of work. They include three categories: retrofit programs that have shorter lives, such as efficient light bulbs; lost opportunity measures that have longer lives, such as high-efficiency furnaces; and codes and standards that drive down energy consumption through government regulation. (Codes and standards impact the demand forecast but have no direct cost to utilities.) Energy efficiency also includes some small-scale electric distributed generation such as combined heat and power.

GENERATION EFFICIENCY. Energy efficiency improvements at PSE generating plant facilities.

DISTRIBUTION EFFICIENCY. Voltage reduction and phase balancing. Voltage reduction is the practice of reducing the voltage on distribution circuits to reduce energy consumption. Phase balancing can reduce energy loss by eliminating total current flow losses.

Distributed energy resources included the following.

DEMAND RESPONSE. Demand response resources are like energy efficiency in that they reduce customer peak load, but unlike energy efficiency, they are also dispatchable. These programs involve customers curtailing load when needed. The terms and conditions of demand response programs vary widely.

DISTRIBUTED SOLAR GENERATION. Distributed solar generation refers to small-scale rooftop or ground-mounted solar panels located close to the source of the customer's load. Distributed solar was modeled as a residential-scale resource in western Washington. A summary of the capacity factors for solar resources modeled is provided in Figure 5-12. Solar data was obtained from the National Solar Radiation Database[16] and processed with the NREL System Advisory Model.[17]

Figure 5-12: Distributed Solar Capacity Factors

Solar Resource	Configuration	Capacity Factor (annual average, %)
Western Washington Residential - rooftop	residential-scale, fixed-tilt, rooftop	15.7
Western Washington Residential - ground	residential-scale, fixed-tilt, ground	16.0

BATTERY ENERGY STORAGE. Two battery storage technology systems were analyzed: lithium-ion and flow technology. These systems are modular and made up of individual units that are generally small. Batteries provide both peak capacity and sub-hourly flexibility value. In addition, since they are small enough to be installed at substations, they can potentially defer local transmission or distribution system investments. PSE analyzed 2-hour and 4-hour lithium-ion batteries, as well as, 4-hour and 6-hour flow battery systems.

NON-WIRES ALTERNATIVES. The role of distributed energy resources (DER) in meeting system needs is changing and the planning process is evolving to reflect that change. Non-wires alternatives are being considered when developing solutions to specific, long-term needs identified on the transmission and distribution systems. The resources under study have the benefit of being able to address system deficiencies while simultaneously supporting resource needs and can be deployed across both the transmission and distribution systems, providing some flexibility with how system deficiencies are addressed. The non-wires alternatives considered during the planning process include energy storage systems and solar generation.

16 / https://nsrdb.nrel.gov/
17 / https://sam.nrel.gov/

Supply-side resources included the following.

WIND. Wind was modeled in seven locations throughout the northwest United States including: eastern Washington, central Montana, eastern Montana, Idaho, eastern Wyoming, western Wyoming and offshore Washington. A summary of capacity factors for each wind resources are provided below in Figure 5-13. Wind speed data was obtained from the National Renewable Energy Laboratory's (NREL) Wind Toolkit Database[18] and processed using an in-house, heuristic wind production model.

Figure 5-13: Wind Capacity Factors

Wind Resource	Capacity Factor (annual average, %)
Eastern Washington	36.7
Central Montana	39.8
Eastern Montana	44.3
Idaho	33.0
Eastern Wyoming	47.9
Western Wyoming	39.2
Offshore Washington	34.8

SOLAR. Solar was modeled as a centralized, utility-scale resource at several locations throughout the northwest United States and as a distributed, residential-scale resource in western Washington. A summary of the capacity factors for solar resources modeled is provided in Figure 5-14. Solar data was obtained from the National Solar Radiation Database[19] and processed with the NREL System Advisory Model.[20]

18 / *https://www.nrel.gov/grid/wind-toolkit.html*
19 / *https://nsrdb.nrel.gov/*
20 / *https://sam.nrel.gov/*

Figure 5-14: Solar Capacity Factors

Solar Resource	Configuration	Capacity Factor (annual average, %)
Eastern Washington	utility-scale, single-axis tracker	24.2
Western Washington	utility-scale, single-axis tracker	16.0
Idaho	utility-scale, single-axis tracker	26.4
Eastern Wyoming	utility-scale, single-axis tracker	27.3
Western Wyoming	utility-scale, single-axis tracker	28.0

PUMPED HYDRO ENERGY STORAGE. Pumped hydro resources are generally large, on the order of 250 to 3,000 MW. This analysis assumes PSE would split the output of a pumped hydro storage project with other interested parties. Pumped hydro resources can provide sub-hourly flexibility values similar to batteries at utility scale. Because they are located remote from substations, they cannot contribute the transmission and distribution benefits that smaller battery systems can provide at the local system level. Pumped hydro can provide some benefits to the bulk transmission system, however, such as frequency response and black start capability. PSE analyzed an 8-hour pumped hydro resource.

HYBRID RESOURCES. In addition to stand-alone generation and energy storage resources PSE modeled hybrid resources which combine two or more resources together at the same location to take advantage of synergies between the resources. PSE model three types of hybrid resource including: eastern Washington solar + 2-hour Lithium-ion battery, eastern Washington wind + 2-hour Lithium-ion battery, and Montana wind + pumped hydro.

BASELOAD THERMAL PLANTS (COMBINED-CYCLE COMBUSTION TURBINES OR CCCTs). F-type, 1x1 engines with wet cooling towers are assumed to generate 348 MW plus 19 MW of duct firing, and to be located in PSE's service territory. These resources are designed and intended to operate at base load, defined as running more than 60 percent of the hours in a year.

FRAME PEAKERS (SIMPLE-CYCLE COMBUSTION TURBINES OR SCCTs). F-type, wet-cooled turbines are assumed to generate 237 MW and to be located in PSE's service territory. These resources are modeled with either natural gas or an alternative fuel as the fuel source.

Baseload and peakers
"Baseload" *generators are designed to operate economically and efficiently over long periods of time, which is defined as more than 60 percent of the hours in a year.*

"Peaker" *is a term used to describe generators that can ramp up and down quickly in order to meet spikes in need. Unlike baseload resources, they are not intended to operate economically for long periods of time.*

RECIP PEAKERS (RECIPROCATING ENGINES). This 12-engine design with wet cooling (18.2 MW each) is assumed to generate a total of 219 MW and to be located in PSE's service territory.

Electric Resource Cost Assumptions

Generic resource cost assumptions were generated through review of numerous data sources related to generating resources costs and collaboration with the IRP stakeholder group. The generic resource cost assumption methodology was inspired and informed by the NPCC Generating Resource Advisory Committee's (GRAC) cost assumption process.[21]

In brief, the methodology begins with accumulation of generic resource cost estimations from various organizations and regional IRP estimates. Since cost estimations were acquired from different sources, each cost estimate may include a different set of base assumptions, such as inclusion or exclusion of owner's or interconnection costs. Cost estimates were adjusted to align these assumptions as closely as possible. Cost estimates were then arranged by technology vintage year and summary statistics including average, median, minimum and maximum cost were calculated for each vintage year. All cost estimations and statistics were presented to the IRP stakeholder group with the recommendation that PSE use the average cost for modeling purposes. Stakeholder feedback, such as inclusion of new data sources and removal of specific data sources, was incorporated into final generic resource cost assumptions. The spreadsheet used for calculation of generic resource cost assumptions is

21 / *https://www.nwcouncil.org/energy/energy-advisory-committees/generating-resources-advisory-committee*

available for review on the PSE IRP website.[22] This spreadsheet includes a full list of the data sources used for cost estimate purposes and a breakdown of cost estimations by generic resource type.

*> > > **See Appendix D, Electric Resources and Alternatives**, for a more detailed description of resource cost assumptions, including transmission and natural gas transport assumptions.*

Resource costs are generally expected to decline in the future, as technology advances push costs down. The declining cost curves applied to different resource alternatives come from the National Renewable Energy Laboratory (NREL) 2019 Annual Technology Baseline (ATB).[23] The 2020 ATB was delayed due to the pandemic and was not available till after the generic resource costs for this IRP were finalized. The NREL ATB provides three cost curves for each resource, labeled as: Low, Mid and Constant Technology Cost Scenarios. PSE has selected the Mid Technology Cost Scenario for the IRP cost curves as it represents the "most-likely" future cost projection.

In general, cost assumptions represent the "all-in" cost to deliver a resource to customers; this includes engineering, procurement and construction, owner's costs, and interconnection costs. Interconnection costs include, as needed, natural gas pipelines and 5 miles of transmission from the substation to the main line. The costs calculated using the methodology described above resulted in "overnight capital costs" which typically exclude allowance for funds used during construction (AFUDC) and interconnection costs. PSE has assumed AFUDC costs at 10 percent of the overnight capital cost. PSE derived interconnection costs from a 2018 study on Generic Resource Costs for Integrated Resource Planning[24] prepared by consultant HDR for PSE. PSE believes the estimates used here are appropriate and reasonable.

- Figure 5-15 summarizes generic resource assumptions.
- Figure 5-16 summarizes annual capital cost by vintage year (the year the plant was built) for supply-side resources and energy storage.

22 / https://oohpseirp.blob.core.windows.net/media/Default/documents/Generic_Resource_Cost_Summary_PSE%202021%20IRP_post-feedback_v5.xlsx
23 / https://atb.nrel.gov/electricity/2019/index.html?t=lw
24 / https://oohpseirp.blob.core.windows.net/media/Default/PDFs/HDR_Report_10111615-0ZR-P0001_PSE%20IRP_Rev4%20-%2020190123).pdf

Figure 5-15: New Resource Generic Cost Assumptions

IRP Modeling Assumptions (2020 $)	Nameplate (MW)	First year available	Fixed O&M ($/kw-yr)	Variable O&M[1] ($/MWh)	Capital Costs, Vintage 2021 ($/kw)			
					Overnight Capital Cost	AFUDC[2]	Intercon-nection[3]	Total
CCCT	348	2025	12.87	3.32	1041	104	100	1246
Frame Peaker	237	2025	7.68	7.86	733	73	148	954
Recip Peaker	219	2025	6.40	7.05	1387	139	158	1683
WA Solar - Utility Scale	100	2024	22.23	0.00	1395	139	110	1644
Idaho/Wyoming Solar – Utility Scale	400	2026	22.23	0.00	1395	139	110	1644
WA Solar - Residential Scale	300	2024	0.00	0.00	3264	326	0	3590
Washington Wind	100	2024	40.60	0.00	1569	157	52	1778
Montana Wind	200	2024	40.60	0.00	1569	157	49	1774
Idaho/Wyoming Wind	400	2026	40.60	0.00	1569	157	49	1774
Offshore Wind	100	2030	110.08	0.00	4831	483	71	5385
Pumped Storage	25	2028	16.00	0.00	2367	237	52	2656
Battery 2hr Li-Ion	25	2023	23.49	0.00	937	94	63	1093
Battery 4hr Li-Ion	25	2023	31.93	0.00	1702	170	63	1934
Battery 4hr Flow	25	2023	21.76	0.00	2264	226	63	2553
Battery 6hr Flow	25	2023	37.97	0.00	3157	316	63	3535
Solar + battery	100 solar + 25 battery	2024	45.72	0.00	2099	210	155	2464
Wind + battery	100 wind + 25 battery	2024	64.09	0.00	2255	225	103	2584
Wind + pumped hydro	200 wind + 100 PHES	2028	56.60	0.00	3542	354	91	3988
Biomass	15	2024	207.00	6.20	5791	579	670	7040

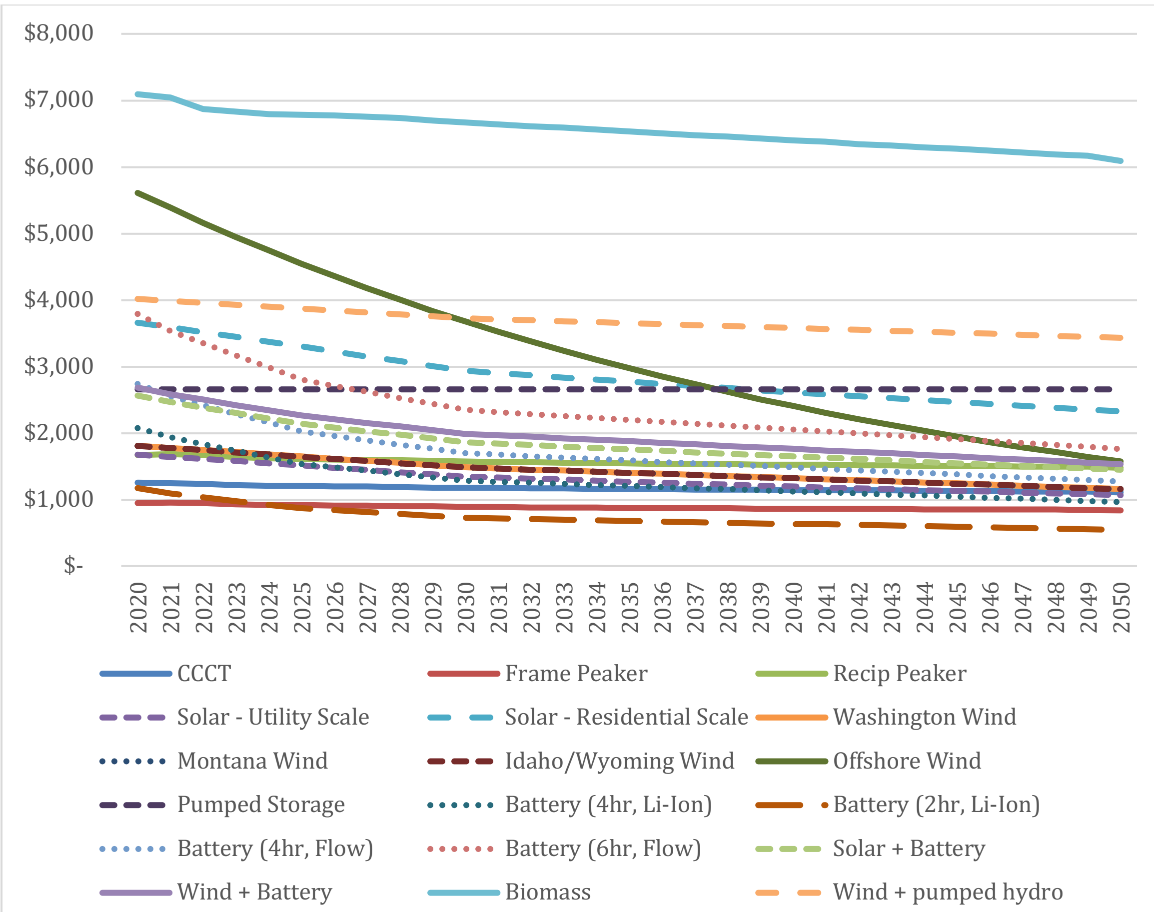
NOTES

1. *Variable O&M costs do not include the cost of fuel for thermal resources*
2. *AFUDC (Allowance for funds used during construction) is assumed at 10 percent of overnight capital*
3. *Interconnection costs includes the transmission, substation and natural gas pipeline infrastructure. Interconnection cost of offshore wind only includes onshore interconnection and does not include the cost of the marine cable to shore.*

The change in capital cost by vintage year is based on the NREL 2019 ATB Mid Technology Cost Scenario. These costs are decreasing on a real basis, but we add a 2.5 percent annual inflation rate for nominal costs. Figure 5-16 shows the annual capital cost of the resources modeled in this IRP by year built in 2020 real dollars.

> > > See Appendix D, Electric Resources and Alternatives, for cost curve charts broken out by resource type (renewable, energy storage and thermal).

Figure 5-16: Annual Capital Costs by Vintage Year (2020 real dollars)



Flexibility Considerations

This analysis focuses on the cost of balancing changes when different resources are added to PSE's portfolio.

The flexibility analysis focused on reflecting the financial impacts of the sub-hourly flexibility analysis in the portfolio analysis. Different resources have different sub-hourly operational capabilities. Even if the portfolio has adequate flexibility, different resources can impact costs and how the entire portfolio operates. For example, batteries could avoid dispatch of thermal plants for some ramping up and down.

For the sub-hourly flexibility analysis, PSE used a model called PLEXOS. First a Current Portfolio Case based on PSE's existing resources was created. The Current Portfolio Case begins by creating a simulation that reflects a complete picture of PSE as a BA and PSE's connection to the market. This includes representation of PSE's BAA load and generation on a day-ahead and real time, 15-minute basis. Opportunities to make purchases and sales at the Mid-C trading hub in hourly increments and the EIM market in 15-minute increments are also included. For this analysis, PSE simulated the year 2025 for both day-ahead and real time, and then took the difference in total portfolio cost between the two simulations.

PSE tested the impact of a range of potential new resources, each of which is individually added to the current portfolio. If the dispatch cost of the portfolio with the new addition is lower than the Current Portfolio Case cost, the cost reduction is identified as a benefit of adding the new resource.

Figure 5-17 below is the cost savings associated with each resource. For example, a CCCT has a cost savings of $5.27/kw-yr. This cost savings is applied back to the fixed O&M of the generic resource as a reduction to the cost.

Figure 5-17: Sub-hourly System Flexibility Cost Savings

Resource	Flexibility Cost Savings ($/kw-yr)
CCCT	$5.27
Frame Peaker	$23.45
Recip Peaker	$25.39
Lithium-ion battery 2hr	$20.45
Lithium-ion battery 4hr	$18.45
Flow battery 4hr	$23.03
Flow battery 6hr	$23.24
Pumped Storage Hydro 8hr	$18.41
Demand Response	$35.24

> > > See Appendix G, Electric Analysis Models, *for a detailed description of the methodology used to develop flexibility benefit.*

> > > See Appendix H, Electric Analysis Inputs and Results, *for further discussion of heat rate improvements, federal subsidies, financial assumptions such as discount rate and inflation, build constraints, and planned builds and retirements in the WECC.*

Regional Transmission Constraints

Transmission constraints are a set of limits imposed on the IRP portfolio model which seek to model real-world transmission limitations within the WECC. These constraints include capacity limitations, transmission losses and transmission costs.

- Transmission capacity constraints limit the quantity of generation development available to specific geographic regions.
- Transmission losses represent energy lost to heat as power is carried from location to another.
- Transmission costs model the cost of transmission to transmit power from a generating resource to PSE's service territory.

Transmission losses and costs have been a key component of the IRP portfolio model for many IRP cycles. Capacity constraints are a new addition to the modeling process for the 2021 IRP.

Transmission Capacity Constraints

Transmission capacity constraints have become an important modeling consideration as PSE transitions away from thermal resources and toward clean, renewable resources to meet the goals of CETA. In contrast to thermal resources such as CCCTs and frame peakers, which can generally be sited in locations convenient to transmission, produce power at a controllable rate, and be dispatched as needed to meet shifting demand, renewable resources are site-specific and have variable generation patterns dependent upon local wind or solar conditions, therefore they cannot track load. The limiting factors of renewable resources have two significant impacts on the power system: 1) a much greater quantity of renewable resources must be acquired to meet the same peak demand as thermal resources, and 2) the best renewable resources to meet PSE's loads may not be located near PSE's service territory because a wind farm in one location will produce a different amount of power from the same wind farm located in another location. This makes it important to consider whether there is enough transmission capacity available to carry power from remote renewable resources to PSE's service territory.

ASSUMPTIONS. To model transmission capacity constraints, PSE created seven resource group regions and set limits on the generation capacity which may be built in each of those regions. Resource group regions were determined based on geographic relationships of the generic resources modeled in the 2021 IRP. Figure 5-18 summarizes the resource group regions and the generic resources available in each group.

Figure 5-18: Resource Group Regions and Generic Resources Available in Each Region

Generic Resource	Resource Group Region						
	PSE Territory (a)	Eastern Washington	Central Washington	Western Washington	Southern Washington / Gorge	Montana	Idaho / Wyoming
CCCT	X						
Frame Peaker	X						
Recip Peaker	X						
WA Solar East - Utility Scale		X	X		X		
WA Solar West - Utility Scale	X						
Idaho Solar – Utility Scale							X
WY Solar East – Utility Scale							X
WY Solar West – Utility Scale							X
DER WA Solar - Rooftop	X						
DER WA Solar – Ground	X						
WA Wind		X	X		X		
MT Wind – East						X	
MT Wind - Central						X	
ID Wind							X
WY Wind East							X
WY Wind West							X
Offshore Wind				X			
Pumped Storage		X	X		X		
Battery 2hr Li-Ion	X						
Battery 4hr Li-Ion	X						
Battery 4hr Flow	X						
Battery 6hr Flow	X						
Solar + battery		X			X		
Wind + battery		X			X		
Wind + pumped storage						X	
Biomass	X			X			

NOTE
(a) Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed

Capacity limits were developed based upon PSE's experience with available transmission capability (ATC) on BPA's system, the results of BPA transmission service requests (TSRs), recent BPA TSR Study and Expansion Process (TSEP) Cluster Studies, regional transmission studies by Northern Grid, and dialogue with regional power sector organizations. Transmission planning, building and acquisition are complex processes with a variety of possible outcomes, therefore a range of plausible transmission limits and timelines were developed for each region. To provide some structure to these ranges, PSE organized the transmission limits into tiers; uncertainty increases from tier to tier based on the ability of PSE to acquire that quantity of transmission. The tiers include:

- **Tier 1:** Transmission capacity that could likely be acquired in the 2022-2025 timeframe. This transmission capacity draws largely from repurposing PSE's existing BPA transmission portfolio.
- **Tier 2:** Transmission capacity that could be acquired in the 2025-2030 timeframe, but is less certain that than Tier 1 transmission projects. This transmission capacity adds new transmission resources to PSE's portfolio. Tier 2 includes all Tier 1 transmission.
- **Tier 3:** Transmission capacity that could be acquired beyond 2030. Acquisition of Tier 3 transmission is less certain than Tiers 1 and 2. Capacity added in Tier 3 would likely come from the addition of long lead-time, new transmission resources to PSE's portfolio. Tier 3 includes all Tier 1 and 2 transmission.
- **Tier 0:** Tier 0 represents a generally unconstrained transmission system, with the exception of very long distance resources. Tier 0 is used as the baseline transmission case for most of the modeling in the 2021 IRP as these assumptions most closely align with previous IRP cycles. Tiers 1, 2 and 3 are analyzed as sensitivities to gain an understanding of how transmission constraints could impact resource build decisions.

Figure 5-19 summarizes the transmission limits by tier for each resource group region.

Figure 5-19: Transmission Capacity Limitations by Resource Group Region

Resource Group Region	Added Transmission (MW)			
	Tier 0	Tier 1	Tier 2	Tier 3
PSE territory (a)	(b)	(b)	(b)	(b)
Eastern Washington	Unconstrained	300	675	1,330
Central Washington	Unconstrained	250	625	875
Western Washington	Unconstrained	0	100	635
Southern Washington/Gorge	Unconstrained	150	705	1,015
Montana	750	350	565	750
Idaho / Wyoming	600	0	400	600
TOTAL	**generally unconstrained**	**1,050**	**3,070**	**5,205**

NOTES
(a) Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed.
(b) Not constrained in resource model, assumes adequate PSE transmission capacity to serve future load.

Rationale for each of the transmission capacity limitations by resource group region is provided below.

Eastern Washington: PSE may obtain 150, 300 or 640 MW, for Tiers 1, 2 and 3 respectively, of transmission to the Lower Snake River region through BPA Cluster Study requests. An additional 150, 375 or 690 MW, for Tiers 1, 2 and 3 respectively, of third-party transmission may be acquired from developer submittals and resource retirements.

Central Washington: PSE may obtain 250, 500 or 750 MW, for Tiers 1, 2 and 3 respectively, of transmission by dual-purposing the existing 1,500 MW of Mid-C transmission currently used for market purchases. An additional 125 MW of transmission may be available in Tiers 2 and 3 for delivery of Kittitas area solar via Grant County PUD system.

Western Washington: Assumes no additional transmission available in Tier 1. Tier 2 may add 100 MW of BPA transmission following expiration of the TransAlta PPA in 2025. Tier 3 may add 335 MW of dual-purpose transmission to prioritize renewable generation from the Mint Farm CCCT region. Tier 3 may also add 200 MW of third-party transmission rights from developer submittals and resource retirements.

Southern Washington / Gorge: PSE may obtain 150, 375 or 685 MW, for Tiers 1, 2 and 3 respectively, of third-party transmission rights from developer submittals or resource retirements. Tier 2 may also add 330 MW of dual-purpose transmission to prioritize renewable generation from the Goldendale CCCT region.

Montana: PSE may obtain 350, 565 or 750 MW, for Tiers 1, 2 and 3 respectively, of transmission from repurposing transmission freed up by the removal of Colstrip Units 3 & 4 from the PSE portfolio.

Wyoming / Idaho: PSE may invest in new transmission projects including the Boardman-to-Hemingway (B2H) and Gateway West projects, adding 400 or 600 MW of transmission for Tiers 2 and 3, respectively.

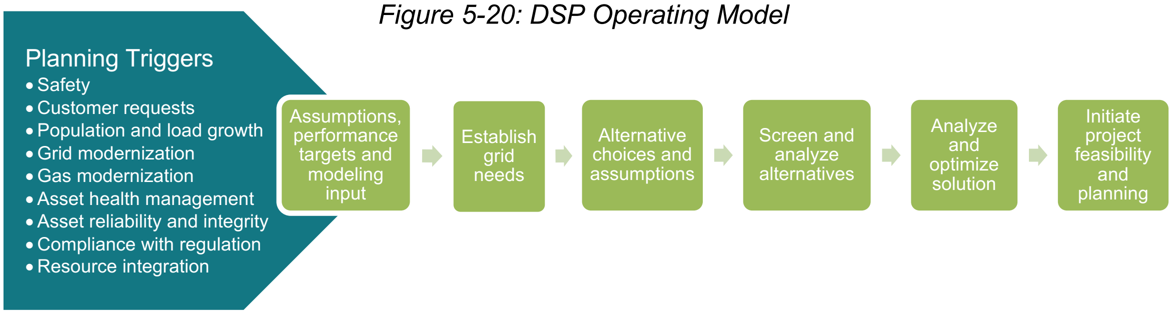
PSE Territory: The assumption for the 2021 IRP is that the PSE system in western Washington is unconstrained, this does not include PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed. This assumption holds because of a robust delivery system planning approach and the resulting long-range delivery system infrastructure plan that includes transmission and distribution system upgrades.

See Appendix M, Delivery System 10-year Plan, for detailed descriptions of transmission and distribution projects planned to ensure unconstrained delivery of resources.

Electric Delivery System Planning Assumptions

PSE follows a structured approach to developing infrastructure plans that support various customer needs, including effective integration of DERs. The approach and associated planning assumptions are shown in Figure 5-20 below.

Figure 5-20: DSP Operating Model



Assumptions	Description
Demand and Peak Demand Growth	Uses county demand forecast applied based on historic load patterns of substation circuits with known point loads adjusted for
Energy Efficiency	Highly optimistic 75% and 100% targets included (PSE benchmarking with peers in 2021)
Resource Interconnections	Known interconnection requests included
Aging Infrastructure	Known concerns included in analysis
Interruptible / Behavior-based Rates	Known opportunities to curtail during peak included
Distributed Energy Resources	Known controllable devices are included (most current solar and battery systems are not controllable to manage peak reliably to date)
System Configurations	As designed
Compliance and Safety Obligations	Meet all regulatory requirements including NESC, NERC and WECC along with addressing voltage regulation, rapid voltage change, thermal limit violations and protection limits

DSP Non-wire Alternatives Forecast

A distributed energy resources forecast is included in the 2021 IRP that evaluates where DERs have been identified as a potential non-wires solution for meeting delivery system needs; the forecast is then extrapolated based on load growth assumptions. As needs arrive in the planning horizon, further analysis relative to specific values and potential will test these assumptions. The non-wires alternatives considered during the delivery system planning process include demand response, targeted energy efficiency, energy storage systems and solar generation, among others, and these resources are considered alone and as part of hybrid resource combinations with traditional infrastructure improvements to optimize the solution. Initial analyses suggest that cost-effective solutions tend to align with needs that are primarily driven by capacity or resiliency. As DER continues to be integrated into system solutions, key questions will need to be answered related to the operational flexibility afforded by DER, as well as related cyber-security considerations. The following assumptions were used to develop a DER forecast for solving identified system needs over the 0 to 10 year time frame.

- Due to practical sizing of DER solutions, projects with needs larger than 20MW were not considered.
- Average historical percentages were applied for determining energy efficiency, demand response and energy storage potential.
- 3 to 4 MW was determined to be a reasonable size for utility-scale PV based on industry knowledge and consultant input for summer needs.

For needs identified in the 10 to 20-year timeframe, the same assumptions were used but the values were extrapolated based on the load forecast (i.e., years with lower forecasted load growth would require fewer, smaller-scale projects to meet system needs versus years with larger forecasted load growth). Additional considerations were made to account for the planning process. Needs identified prior to 2023 are assumed to take 2 to 3 years to complete based on implementation of a new planning process and the learning curve associated with implementing new technologies. As the planning process matures and more experience is gained in siting DER, needs identified after 2023 are assumed to be built by the year that the need first materializes on the system.

Figure 5-21: Forecasted DER Installation by Year and Type

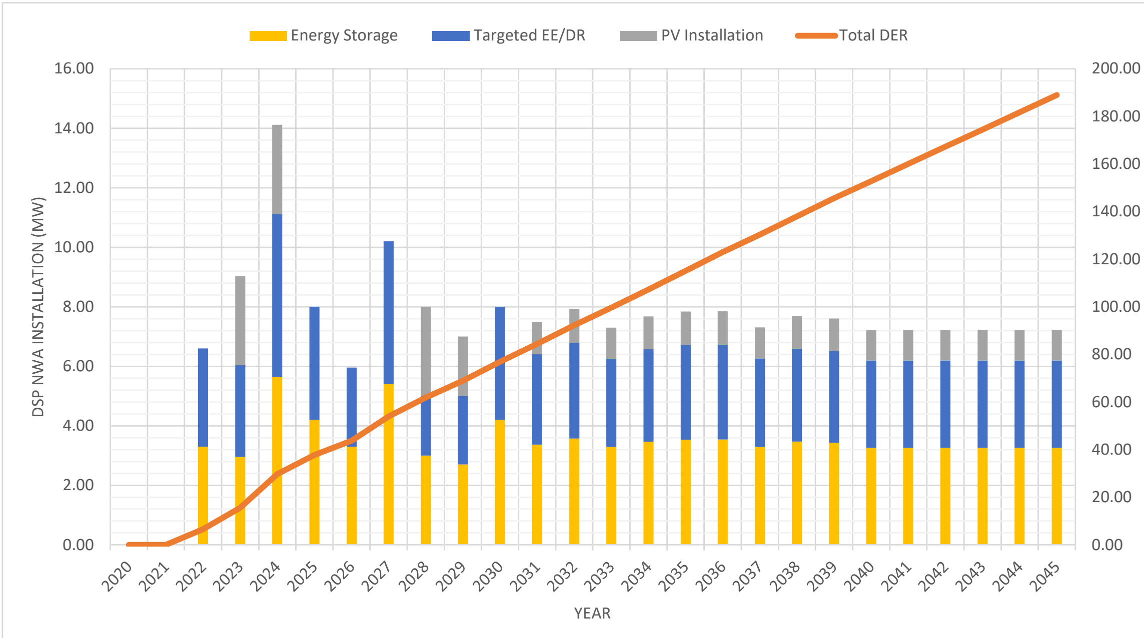


Figure 5-22: Projected T&D Deferral by Project Type by 2040

	Energy Storage (MW)	Targeted EE/DR (MW)	PV Installation (MW)	Total DER (MW)
Planned Transmission System Projects*	6.6	6.0	0.0	12.6
Planned Substation Capacity Projects	18.1	17.2	6.0	41.3
Future Potential System Needs	60.4	53.7	21.0	135.1
Total	**85.1**	**76.9**	**27.0**	**189.0**

** As identified in the PSE Plan for Attachment K*

Only the energy storage and solar PV forecast was modeled in the IRP as part of the DSP non-wires alternatives. The targeted energy efficiency/demand response forecast is included as part of the cost-effective energy efficiency and demand response evaluation in the IRP.

Transmission Loss Constraints

Transmission loss constraints model energy lost to heat as power flows through the transmission line. Many factors, including distance, line material and voltage impact the magnitude of transmission line losses. BPA assumes a flat 1.9 percent line loss across its entire transmission network. A line loss study conducted between PSE and the Colstrip substation found the line loss to be approximately 4.6 percent. Lacking a similar study for transmission to Wyoming and Idaho, PSE has assumed a similar loss given the similar distance. Figure 5-23 provides a summary of the transmission lines losses assumed by resource group region.

Figure 5-23: Average Transmission Line Losses by Resource Group Region

Resource Group Region	Line Loss (%)
Eastern Washington	1.9
Central Washington	1.9
Western Washington	1.9
Southern Washington/Gorge	1.9
Montana	4.6
Idaho / Wyoming	4.6

Transmission Cost Constraints

Transmission cost is another factor used in the PSE Portfolio Model to constrain resource build decisions. Transmission costs include a fixed component measured in dollars per kilowatt per year ($/kW-yr) and a variable component measured in dollars per megawatt-hour ($/MWh). Fixed transmission costs include wheeling tariffs and balancing service tariffs, among others. Wheeling tariffs will vary by region depending on the number of wheels required to return power to PSE's service territory. Variable transmission costs are largely composed of spinning and supply reserve requirement tariffs and may include other penalties or imbalance tariffs. Figure 5-24 provides a summary of fixed and variable transmission costs by generic resource type.

Figure 5-24: Transmission Costs by Generic Resource Type (in 2020 $)

Generic Resource	Fixed Transmission Cost ($/kW-yr)	Variable Transmission Cost ($/MWh)
CCCT	0.00[a]	0.00
Frame Peaker	0.00[a]	0.00
Recip Peaker	0.00[a]	0.00
WA Solar East - Utility Scale	30.48	9.53
WA Solar West - Utility Scale	8.28	9.53
Idaho Solar – Utility Scale	154.78	9.53
WY Solar East – Utility Scale	227.90	9.53
WY Solar West – Utility Scale	207.80	9.53
DER WA Solar - Rooftop	0.00[a]	0.00
DER WA Solar – Ground-mount	0.00[a]	0.00
WA Wind	33.36	9.53
MT Wind – East	49.65	9.53
MT Wind - Central	49.65	9.53
ID Wind	157.66	9.53
WY Wind East	230.78	9.53
WY Wind West	210.68	9.53
Offshore Wind	33.36	9.53
Pumped Storage	22.20	0.00
Battery 2hr Li-Ion	0.00[a]	0.00
Battery 4hr Li-Ion	0.00[a]	0.00
Battery 4hr Flow	0.00[a]	0.00
Battery 6hr Flow	0.00[a]	0.00
Solar + Battery	30.48	9.53
Wind + Battery	33.36	9.53
Wind + Pumped Storage	49.65	9.53
Biomass	22.20	0.00

NOTE
a. Fixed transmission cost is not applied, because the resource is assumed to be built within PSE service territory.

Electric Generation Retirements

For the 2021 IRP, PSE is modeling the economic retirement of existing thermal resources. Colstrip is assumed to be removed from PSE's portfolio by December 31, 2025, but the model is allowed to retire Colstrip earlier based on economics. The other thermal plants are assumed to run through the planning horizon, but they are also allowed to retire early based on economics.

When determining retirement of a generating plant, the model looks at the economics of the power plant for meeting loads and peaks. The valuation process for the generating plants considers the cost of emissions, variable costs (including fuel and operations and maintenance), fixed costs (including ongoing capital for upkeep and maintenance), and decommissioning costs.

Electric Portfolio Sensitivities

Starting with the optimized, least cost Mid Scenario portfolio, sensitivities change a resource, environmental regulation or condition in order to examine the effect of that change on the portfolio.

The portfolio modeling process is complex, with no shortage of potential sensitivities to investigate. During the 2021 IRP process, the Resource Planning team identified over 50 potential modeling sensitivities. As part of the 2021 IRP public participation process, the planning team asked stakeholders for assistance in prioritizing which sensitivity analyses to perform. Appendix A, Public Participation, describes the sensitivity prioritization process. Figure 5-25 summarizes the sensitivities modeled in this IRP.

Figure 5-25: 2021 IRP Electric Portfolio Sensitivities

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Sensitivities	**Alternatives Analyzed**
FUTURE MARKET AVAILABILITY		
A	Renewable Overgeneration Test	The portfolio model is not allowed to sell excess energy to the Mid-C market.
B	Reduced Firm Market Access at Peak	The portfolio model has a reduced access to the Mid-C market for both sales and purchases.
TRANSMISSION CONSTRAINTS AND BUILD LIMITATIONS		
C	"Distributed" Transmission/Build Constraints - Tier 2	The portfolio model is performed with Tier 2 transmission availability.
D	Transmission/Build Constraints – Time-delayed (Option 2)	The portfolio model is performed with gradually increasing transmission limits.

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Sensitivities	**Alternatives Analyzed**
E	Firm Transmission as a Percentage of Resource Nameplate	New resources are acquired with firm transmission equal to a percentage of their nameplate capacity instead of their full nameplate capacity.
CONSERVATION ALTERNATIVES		
F	6-Year Conservation Ramp Rate	Energy efficiency measures ramp in over 6 years instead of 10.
G	Non-energy Impacts	Increased energy savings are assumed from energy efficiency not captured in the original dataset.
H	Social Discount Rate for DSR	The discount rate for demand-side resource measures is decreased from 6.8% to 2.5%.
SOCIAL COST OF GREENHOUSE GASES (SCGHG) AND CO_2 REGULATION		
I	SCGHG as an Externality Cost in the Portfolio Model	The SCGHG is used as an externality cost in the portfolio expansion model.
J	SCGHG as a Dispatch Cost in Electric Prices and Portfolio	The SCGHG is used as a dispatch cost (tax) in both the electric price forecast and portfolio model.
K	AR5 Upstream Emissions	The AR5 model is used to model upstream emissions instead of AR4.
L	SCGHG as a Fixed Cost Plus a Federal CO_2 Tax	Federal tax on CO_2 is included in addition to using the SCGHG as a fixed cost adder.
EMISSION REDUCTION		
M	Alternative Fuel for Peakers	Peaker plants use biodiesel as an alternative fuel.
N	100% Renewable by 2030	The CETA 2045 target of 100% renewables is moved up to 2030, with no new natural gas generation.
O	100% Renewable by 2045	All existing natural gas plants are retired in 2045.
P	No New Thermal Resources before 2030	1. This portfolio limits peaker builds before 2030 so that the model must meet peak capacity with alternative resources. 2. Build pumped hydro storage instead of battery energy storage to meet peak capacity before 2030. 3. Build 4-hour lithium-ion battery energy storage to meet peak capacity before 2030.
DEMAND FORECAST ADJUSTMENTS		
Q	Fuel Switching, Gas to Electric	Gas-to-electric conversion is accelerated in the PSE service territory.
R	Temperature Sensitivity	Temperature data used for economic forecasts is composed of more recent weather data as a way to represent changes in climate.

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Sensitivities	**Alternatives Analyzed**
CETA COSTS		
S	SCGHG Included, No CETA	The SCGHG is included in the portfolio model without the CETA renewable requirement.
T	No CETA	The portfolio model does not have CETA renewable requirement or the SCGHG adder.
U	2% Cost Threshold	CETA is considered satisfied once the 2% cost threshold is reached.
BALANCED PORTFOLIO		
V	Balanced Portfolio	1. The portfolio model must take distributed energy resources ramped in over time and more customer programs. 2. The portfolio model must take distributed energy resources ramped in over time, more customer programs, and early addition of a MT wind + pumped hydro storage resource. 3. The portfolio model must take distributed energy resources ramped in over time, more customer programs, and conservation measures are ramped in over 6 years, instead of 10.
W	Balanced Portfolio with Alternative Fuel for Peakers	The portfolio model must take distributed energy resources ramped in over time and more customer programs, plus carbon free combustion turbines using biodiesel as the fuel.
X	Balanced Portfolio with Reduced Firm Market Access at Peak	The portfolio model must take distributed energy resources ramped in over time and more customer programs, plus a reduced access to the Mid-C market for sales and purchases.
WX	Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak	The portfolio model implements the changes from portfolios W and X simultaneously.
Y	Maximum Customer Benefit	RCW 19.405.040(8) In complying with this section, an electric utility must, consistent with the requirements of RCW 19.280.030 and 19.405.140, ensure that all customers are benefiting from the transition to clean energy: Through the equitable distribution of energy and nonenergy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits and reduction of costs and risks; and energy security and resiliency.
OTHER		
Z	No DSR	This portfolio includes no new demand-side resources (energy efficiency, distribution efficiency and demand response).
AA	Montana Wind + Pumped Hydro Storage	This portfolio adds the hybrid resource of MT wind + pumped hydro storage instead of only the MT wind resource in 2026.

A. Renewable Overgeneration Test

In the portfolio model, excess renewable energy that is produced and sold to the Mid-C market is counted towards PSE's CETA renewable goals. In practice, because this energy would not serve PSE loads, it would not count toward meeting CETA goals. By eliminating market sales of excess renewable energy in this sensitivity, PSE can quantify the importance of market sales with respect to renewable overgeneration.

BASELINE ASSUMPTION: PSE can sell excess renewable production to the Mid-C Market.
SENSITIVITY > PSE is not able to sell excess renewable production to the Mid-C Market.

B. Reduced Firm Market Access at Peak Hours

PSE currently uses market purchases of energy in order to meet demand at peak demand hours. As regional emitting resources are retired in response to decarbonization policies and the regional generation supply mix transforms, Mid-C market purchases may not be available to meet peak capacity. This sensitivity reduces the amount of market purchases and sales that can be made, allowing PSE to examine an optimized portfolio that does not rely heavily on market. Determining the behavior of the model under different market circumstances can inform PSE how to navigate a market with reduced peak availability.

BASELINE ASSUMPTION: PSE can purchase and sell up to the Mid-C transmission limit, typically 1500 MW.
SENSITIVITY > The available market at peak is reduced by 200 MW per year down to 500 MW by 2027. The available purchases during the winter months (January, February, November, and December) and the summer months (June, July, and August) are also reduced by 200 MW per year down to 500 MW by 2027.

C. "Distributed" Transmission/Build Constraints - Tier 2

This sensitivity examines increased transmission constraints on PSE's resources. The PSE Energy Delivery team has defined "Tier 2" transmission availability as projects that are available by 2030, with a moderate degree of confidence in their feasibility. Available projects in this category total 3,070 MW of available transmission.

BASELINE ASSUMPTION: PSE's system only has transmission constraints between the PSE system and the Mid-C market.
SENSITIVITY > PSE's system experiences transmission constraints, and the projects available to increase transmission include Tier 1 and Tier 2 transmission projects.

D. Transmission/Build Constraints – Time-delayed (Option 2)

This sensitivity examines a transmission constraint on the PSE system that is relaxed over time. Transmission will be limited to Tier 1 constraints until 2025, Tier 2 constraints until 2030, Tier 3 constraints until 2035, and unconstrained after 2035. PSE's transmission connection to the Mid-C market remains unchanged in this sensitivity from the Mid Scenario.

BASELINE ASSUMPTION: PSE's system only has transmission constraints between the PSE system and the Mid-C market.
SENSITIVITY > PSE experiences Tier 1 transmission constraints until 2025, Tier 2 constraints until 2030, Tier 3 constraints until 2035, and unconstrained after 2035.

E. Firm Transmission as a Percentage of Resource Nameplate

This sensitivity explores the acquisition of firm transmission for new resources being less than the total nameplate capacity of the resource. For renewable resources, this may provide a monetary benefit for building less transmission for resources that do not always reach maximum output.

BASELINE ASSUMPTION: New resources are acquired with transmission capable of carrying the full output of the resource.
SENSITIVITY > New resources are obtained with firm transmission that is less than their nameplate capacity.

F. 6-Year Conservation Ramp Rate

This sensitivity changes the ramp rate for conservation measures from 10 years to 6 years, allowing PSE to model the effects of faster adoption rates for conservation.

BASELINE ASSUMPTION: Conservation and demand response measures ramp up to full implementation over 10 years.
SENSITIVITY > Conservation measures ramp up to full implementation over 6 years.

G. Non-energy Impacts

This sensitivity adds additional non-energy impacts to the adoption of measures. This increases the amount of energy savings from conservation, assuming there are additional benefits and changes not captured in the data.

BASELINE ASSUMPTION: Conservation measures have the expected load reduction.
SENSITIVITY > Additional conservation measures are cost effective as non-energy impacts reduces the cost of more expensive conservation measures.

H. Social Discount Rate for DSR

This sensitivity changes the discount rate for DSR projects from the current discount rate of 6.8 percent to 2.5 percent. By decreasing the discount rate, the present value of future DSR savings is increased, making DSR more favorable in the modeling process. DSR is then included as a resource option with the new financing outlook.

BASELINE ASSUMPTION: The discount rate for DSR measures is 6.8 percent.
SENSITIVITY > The discount rate for DSR measures is 2.5 percent.

I. SCGHG as an "Externality Cost" (Dispatch Cost) in the Portfolio Model

This sensitivity includes the SCGHG as an externality cost expressed as a variable dispatch cost in the long-term capacity expansion (LTCE) model (only) instead of as a fixed planning adder in order to compare the dispatch methodology to the planning adder methodology. This sensitivity uses the mid electric price forecast with the SCGHG as a separate planning adder to market purchases in the LTCE.

BASELINE ASSUMPTION: The SCGHG is included as a fixed cost of resources in the LTCE Model.
SENSITIVITY > The SCGHG is included as a variable cost of resources in the LTCE model.

J. SCGHG as A Dispatch Cost in Electric Prices and Portfolio Model

This sensitivity includes the SCGHG as a dispatch cost in the LTCE modeling process and in the hourly dispatch and electric price forecast, to compare the dispatch cost methodology with the planning adder methodology. This sensitivity uses a different electric price forecast than in the Mid Scenario portfolio. The SCGHG is added to the electric model as a dispatch cost (tax), so it's included in the electric price forecast. This differs from Sensitivity I in that the electric price with SCGHG is then used in the LTCE instead of the mid electric price plus a planning adder.

BASELINE ASSUMPTION: The SCGHG is included as a fixed cost of resources in the LTCE model only.
SENSITIVITY > The SCGHG is included as a variable cost of resources in the LTCE model and the hourly dispatch model.

K. AR5 Upstream Emissions

This sensitivity uses the AR5 methodology for calculating the upstream natural gas emissions rate instead of the AR4 methodology.

BASELINE ASSUMPTION: PSE will use the AR4 Upstream Emissions calculation methodology which adds 10,803 g/MMBtu (23 lbs/MMBtu) to the emission rate of natural gas plants.
SENSITIVITY > PSE will use the AR5 Upstream Emissions calculation methodology which adds 11,564 g/MMBtu (25 lbs/MMBtu) to the emission rate of natural gas plants.

L. SCGHG as a Fixed Cost Plus a Federal CO_2 Cost

This sensitivity includes a Federal CO_2 tax modeled as $15 per short ton with inflation to provide insight into portfolio impacts in the event of a Federal CO_2 tax.

BASELINE ASSUMPTION: The SCGHG is modeled as a planning adder in the LTCE model only.
SENSITIVITY > The SCGHG is modeled as a planning adder in the LTCE model, as well as a $15 per short ton CO_2 tax that is indexed to inflation.

M. Alternative Fuel for Peakers

This sensitivity will model biodiesel as an available fuel option for peaker plants. Results will provide insight into the costs associated with converting the plants to an alternative fuel to meet CETA requirements. Although PSE intended to model hydrogen as an alternative fuel source, PSE did not have sufficient hydrogen pricing at the time of this IRP to perform the analysis.

BASELINE ASSUMPTION: Peaker plants use natural gas as fuel.
SENSITIVITY > Peaker plants use biodiesel as an alternative fuel.

N. 100% Renewable by 2030

This sensitivity forces PSE to adopt 100% renewable resources by 2030, eliminating all natural gas generation to provide context and insight for the push to 100 percent renewable resources by 2045.

BASELINE ASSUMPTION: PSE must reach 100% renewable resources by 2045.
SENSITIVITY > PSE must reach 100% renewable resources by 2030, and all natural gas generation is retired in 2030.

O. 100% Renewable by 2045

This sensitivity forces all natural gas generating plants to be retired by 2045, instead of waiting for economic retirements with CETA penalties. The results will allow PSE to compare the current plans for natural gas plant retirement with CETA penalties.

BASELINE ASSUMPTION: Carbon-emitting resources retire at the end of their economic life.
SENSITIVITY > In 2045, all carbon-emitting resources are retired, regardless of their economic viability.

P. No New Thermal Resources before 2030

This sensitivity does not allow thermal resources to be built before 2030 to allow the model to optimize new energy storage, renewable resources and demand-side resources to meet near-term capacity need. Results from this sensitivity will provide insight into how energy storage provides value to the system that has traditionally been provided by natural gas plants.

BASELINE ASSUMPTION: Resources are acquired when they provide the most value to the portfolio.
SENSITIVITY 1 > No new thermal resources are added in the near-term capacity need. The model optimizes to the next lowest cost resource.
SENSITIVITY 2 > Instead of battery storage as the optimal resource, the model uses pumped hydro storage as the resource to meet capacity needs.
SENSITIVITY 3 > The model uses 4-hour lithium-ion battery storage as the resource to meet capacity needs.

Q. Fuel Switching, Gas to Electric

This sensitivity models an increased adoption of gas-to-electric conversion within the PSE service territory. Results from this sensitivity will illustrate the effects of rapid electrification on the portfolio and demand profile of the PSE service territory.

BASELINE ASSUMPTION: The portfolio uses the standard demand forecast for the Mid Scenario.
SENSITIVITY > The demand forecast is adjusted to include an increased electrification rate of natural gas customers in the PSE service territory.

R. Temperature Sensitivity

This sensitivity models a change in temperature trends, adjusting the underlying temperature data of the demand forecast to emphasize the influence of more recent years. This change attempts to show the effect of rising temperature trends in the Pacific Northwest. Results from this sensitivity will illustrate changes in PSE's load profile.

BASELINE ASSUMPTION: PSE uses the Base Demand Forecast.
SENSITIVITY > PSE uses temperature data from the NPCC. The NPCC is using global climate models that are scaled down to forecast temperatures for many locations within the Pacific Northwest. The NPCC weighs temperatures by population from metropolitan regions throughout the Northwest. However, PSE also received data from the NPCC that is representative of Sea-Tac airport. This data is, therefore, consistent with how PSE plans for its service area, and this data is not mixed with temperatures from Idaho, Oregon or Eastern Washington. The climate model data provided by the Council is hourly data from 2020 through 2049. This data resembles a weather pattern in which temperatures fluctuate over time, but generally trend upward. For the load forecast portion of the temperature sensitivity, PSE has smoothed out the fluctuations in temperature and increased the heating degree days (HDDs) and cooling degree days (CDDs) over time at 0.9 degrees per decade, which is the rate of temperature increase found in the Council's climate model.

S. SCGHG Included, No CETA

This sensitivity will model the SCGHG as a fixed cost adder, but not include the CETA renewable requirement. Results from this sensitivity will help to quantify the effect of the SCGHG as a fixed cost adder on the portfolio. Results will also allow PSE to quantify a baseline of costs without the CETA legislative constraints.

BASELINE ASSUMPTION: All CETA requirements, including the SCGHG, are included as modeling constraints.
SENSITIVITY > The SCGHG is included in the modeling process as it is in the Mid Scenario, but all other CETA renewable requirements are removed. The portfolio will meet the RCW 19.285 15 percent renewable target.

T. No CETA

This sensitivity will model the portfolio with no SCGHG as a fixed cost adder and no CETA renewable requirement. Results from this sensitivity will help to quantify the effect of CETA. Results will also allow PSE to quantify a baseline of costs without the CETA legislative constraints.

BASELINE ASSUMPTION: All CETA requirements, including the SCGHG, are included as modeling constraints.
SENSITIVITY > SCGHG and CETA renewable targets removed. Portfolio will meet RCW 19.285 15% renewable target.

U. 2% Cost Threshold

CETA is considered fulfilled once renewable targets are met or once the investments imposed by CETA constraints reach 2 percent of the annual revenue requirement. This sensitivity is included for information only. The Clean Energy Implementation Plan will reconcile competing CETA requirements.

BASELINE ASSUMPTION: The portfolio model must meet CETA renewable energy targets.
SENSITIVITY > CETA requirements are considered met once the portfolio costs reach 2 percent of the annual revenue requirement.

V. Balanced Portfolio

This sensitivity will be performed in order to compare the Mid Scenario portfolio with a portfolio that gives increased consideration to distributed energy resources. The inputs for the balanced portfolio were developed using insights gained from analyzing the results of other sensitivity analyses and through the Customer Benefit Indicator framework. The regular electric capacity expansion model is set to optimize total portfolio cost, which delays new builds until near the end of the planning period. This delay produces a lower portfolio cost since the cost curve for all the resources declines over time; however, in reality, it is not always possible to wait until the end years to add a lot of resources. In Sensitivity C, Transmission Build Constraints, the model waits until the last 5 to 10 years to add a significant amount of distributed resources. The balanced portfolio takes those distributed resources and ramps them in over time starting in 2025 and adds more customer programs to meet CETA requirements.

BASELINE ASSUMPTION: New resources are acquired when cost effective and needed, conservation and demand response measures are acquired when cost-effective.
SENSITIVITY > Increased distributed energy resources and customer programs are ramped in over time as follows:

- Distributed ground-mounted solar: 50 MW in 2025
- Distributed rooftop solar: 30 MW/year 2025-2045 for a total of 630 MW
- Demand response programs under $300/kw-yr
- Battery energy storage: 25 MW/year 2025-2031 for a total of 175 MW by 2031
- Increased customer-owned rooftop solar
- Green Direct: additional 300 MW by 2030

W. Balanced Portfolio with Alternative Fuel for Peakers

This sensitivity will be performed in order to compare the Mid Scenario portfolio with a portfolio that gives increased consideration to distributed energy resources plus uses biodiesel as a fuel source for new peaking capacity. The inputs for this portfolio were also developed using insights gained from the results of other sensitivity analyses.

BASELINE ASSUMPTION: New resources are acquired when cost effective and needed, conservation and demand response measures are acquired when cost-effective.
SENSITIVITY > Increased distributed energy resources and customer programs are ramped in over time, plus alternative fuel for combustion turbines as follows:

- Distributed ground-mounted solar: 50 MW in 2025
- Distributed rooftop solar: 30 MW/year from the year 2025 to 2045 for a total of 630 MW
- Demand response programs under $300/kw-yr
- Battery energy storage: 25 MW/year 2025-2031 for a total of 175 MW by 2031
- Increased customer-owned rooftop solar
- Green Direct: additional 300 MW by 2030
- Biodisel used as fuel source for peaking combustion turbines

X. Balanced Portfolio with Reduced Firm Market Access at Peak

This sensitivity is performed to compare the Mid Scenario portfolio with a portfolio that gives increased consideration to distributed energy resources plus decreases market reliance to 500 MW by 2027. The inputs for this portfolio were also developed using insights gained from the results of other sensitivity analyses.

BASELINE ASSUMPTION: New resources are acquired when cost effective and needed, conservation and demand response measures are acquired when cost-effective.
**SENSITIVITY > ** Increased distributed energy resources and customer programs are ramped in over time as follows:

- Distributed ground-mounted solar: 50 MW in 2025
- Distributed rooftop solar: 30 MW/year 2025-2045 for a total of 630 MW
- Demand response programs under $300/kw-yr
- Battery energy storage: 25 MW/year 2025-2031 for a total of 175 MW by 2031
- Increased customer-owned rooftop solar
- Green Direct: additional 300 MW by 2030
- The available market at peak is reduced by 200 MW per year down to 500 MW by 2027. The available purchases during the winter months (January, February, November and December) and the summer months (June, July, and Augus)t are also reduced by 200 MW per year down to 500 MW by 2027.

WX. Balanced Portfolio with Alternative Fuel and Reduced Market Reliance

Sensitivity WX applies the three key changes in Sensitivities V, W and X simultaneously.

Baseline: In the Mid Scenario, new resources are acquired when cost effective and needed, and conservation and demand response measures are acquired when cost-effective.
Sensitivity WX > Additional DER and customer programs are added to the portfolio as in Sensitivity V; biodiesel is used as a fuel for newly built frame peaker resources as in Sensitivity W; and the portfolio has reduced access to market purchases during peak demand months as in Sensitivity X.

Y. Maximum Customer Benefit

RCW 19.405.040(8) In complying with this section, an electric utility must, consistent with the requirements of RCW 19.280.030 and 19.405.140, ensure that all customers are benefiting from the transition to clean energy: Through the equitable distribution of energy and nonenergy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits and reduction of costs and risks; and energy security and resiliency.

BASELINE ASSUMPTION: New resources are acquired when cost effective and needed, conservation and DR measures are acquired when cost-effective.
**SENSITIVITY > ** Create a portfolio around maximizing different customer benefit indicators.

Z. No DSR

This portfolio looks at the costs and benefits associated with demand-side resources

BASELINE ASSUMPTION: New resources are acquired when cost effective and needed, conservation and demand response measures are acquired when cost-effective.
SENSITIVITY > No new energy efficiency and demand response is allowed in the portfolio and all future needs will be met by supply-side resources.

AA. Montana Wind Plus Pumped Hydro Storage

This portfolio evaluates the hybrid resource of wind plus pumped storage hydro.

BASELINE ASSUMPTION: New resources are acquired when cost effective and needed, conservation and demand response measures are acquired when cost-effective.
SENSITIVITY > Instead of adding only Montana wind to the portfolio, the hybrid resource of Montana wind plus pumped hydro storage is added.

3. NATURAL GAS ANALYSIS

Natural Gas Scenarios

Three scenarios were created for the natural gas portfolio analysis to test how different combinations of two fundamental economic conditions – customer demand and natural gas prices – impact the least-cost mix of resources.

Figure 5-26: 2021 IRP Natural Gas Analysis Scenarios

2021 IRP NATURAL GAS ANALYSIS SCENARIOS				
	Scenario Name	Demand	Natural Gas Price	CO_2 Price/Regulation
1	Mid	Mid[1]	Mid	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions
2	Low	Low	Low	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions
3	High	High	High	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions

NOTE: 1. Mid demand refers to the 2021 IRP Base Demand Forecast

Scenario 1: Mid

The Mid Scenario is a set of assumptions that is used as a reference point against which other sets of assumptions can be compared.

DEMAND

- The 2021 IRP Base (Mid) Demand Forecast is applied for PSE.

NATURAL GAS PRICES

- Mid natural gas prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.

CO_2 PRICE

- The social cost of greenhouse gases is reflected as a price adder to the natural gas price.
- The costs of upstream CO_2 emissions are reflected as a price adder to the natural gas price.

Scenario 2: Low

This scenario models weaker long-term economic growth than the Mid Scenario. Customer demand is lower in PSE's service territory.

DEMAND

- The 2021 IRP Low Demand Forecast is applied for PSE.

NATURAL GAS PRICES

- Natural gas prices are lower due to lower energy demand; the Wood Mackenzie long-term low forecast is applied to natural gas prices.

CO_2 PRICE

- The social cost of greenhouse gases is reflected as a price adder to the natural gas price.
- The costs of upstream CO_2 emissions are reflected as a price adder to the natural gas price.

Scenario 3: High

This scenario models more robust long-term economic growth, which produces higher customer demand.

DEMAND

- The 2021 IRP High Demand Forecast is applied for PSE.

NATURAL GAS PRICES

- Natural gas prices are higher as a result of increased demand; the Wood Mackenzie long-term high forecast is applied to natural gas prices.

CO_2 PRICE

- The social cost of greenhouse gases is reflected as a price adder to the natural gas price.
- The costs of upstream CO_2 emissions are reflected as a price adder to the natural gas price.

Natural Gas Scenario Inputs

PSE Customer Demand

The graphs below show the peak demand and annual energy demand forecasts for natural gas service without including the effects of demand side resources (DSR). The forecasts include sales (delivered load) plus system losses. The natural gas peak demand forecast is for a one-day temperature of 13° Fahrenheit at SeaTac airport.

Figure 5-27: 2021 IRP Natural Gas Sales Peak Day Demand Forecast – Low, Mid, High

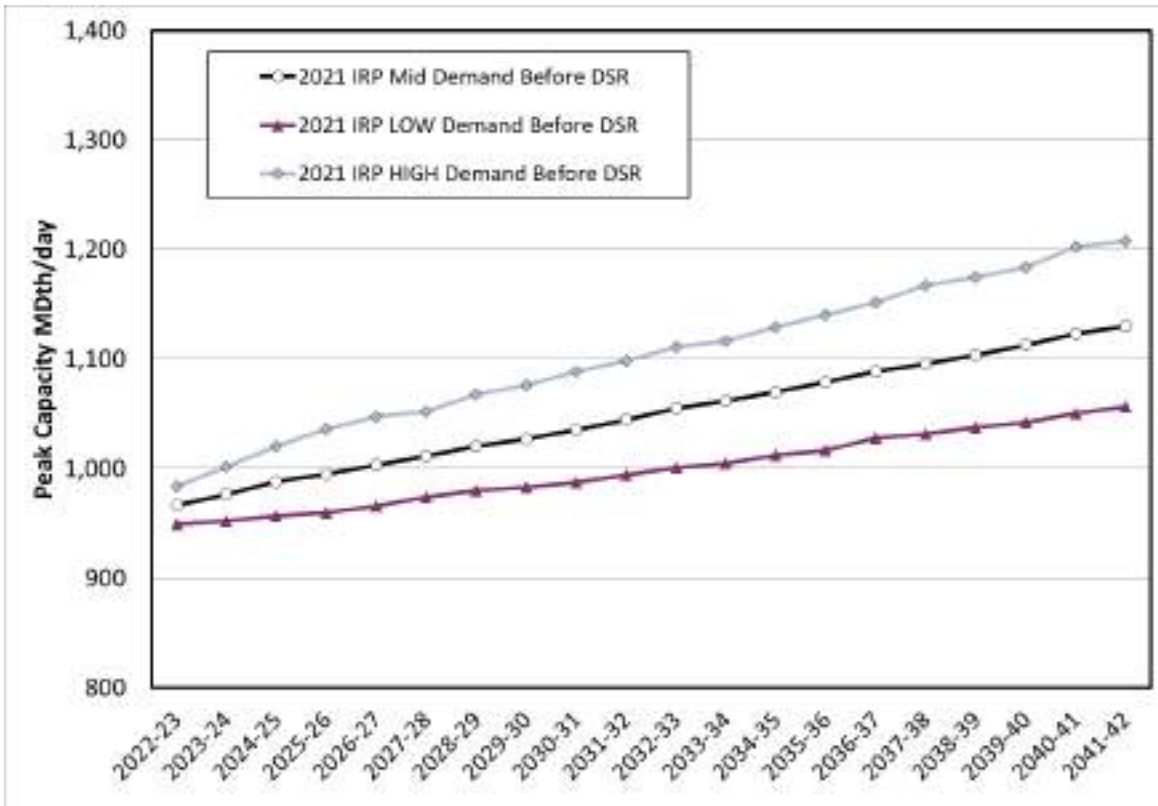
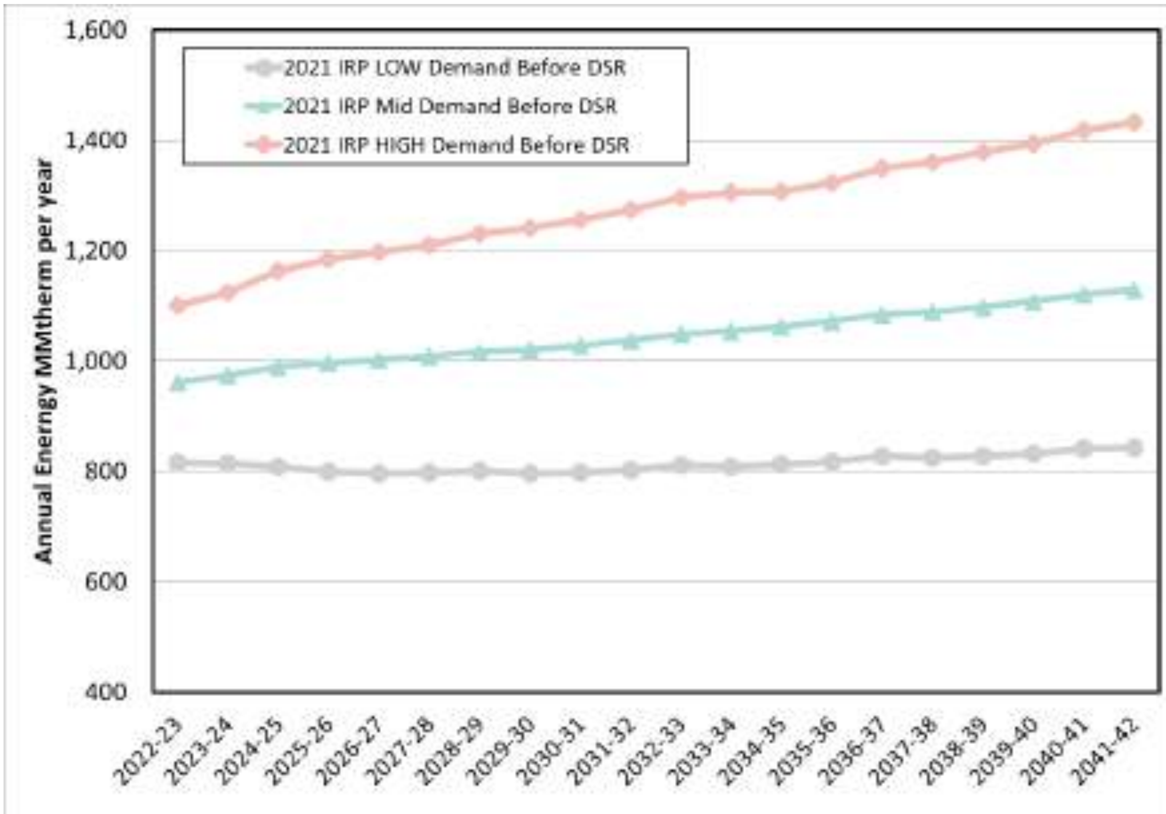


Figure 5-28: 2021 IRP Annual Natural Gas Sales Demand Forecast – Low, Base (Mid), High



Natural Gas Price Inputs

For natural gas price assumptions, PSE uses a combination of forward market prices and fundamental forecasts acquired in Spring 2020[25] from Wood Mackenzie.[26]

- From 2022-2026, this IRP uses the three-month average of forward market prices from June 30, 2020. Forward market prices reflect the price of natural gas being purchased at a given point in time for future delivery.
- Beyond 2029, this IRP uses the Wood Mackenzie long-run natural gas price forecast published in July 2020.

25 / The Spring 2020 forecast from Wood Mackenzie is updated to account for economic and demographic changes stemming from the COVID-19 pandemic.

26 / Wood Mackenzie is a well-known macroeconomic and energy forecasting consultancy whose gas market analysis includes regional, North American and international factors, as well as Canadian markets and liquefied natural gas exports.

For the years 2027 and 2028, a combination of forward market prices from 2026 and selected Wood Mackenzie prices from 2029 are used to minimize abrupt shifts when transitioning from one dataset to another.

- In 2027, the monthly price is the sum of two-thirds of the forward market price for that month in 2026 plus one-third of the 2029 Wood Mackenzie price forecast for that month.
- In 2028, the monthly price is the sum of one-third of the forward market price for that month in 2026 plus two-thirds of the 2029 Wood Mackenzie price forecast for that month.

Three natural gas price forecasts are used in the scenario analyses.

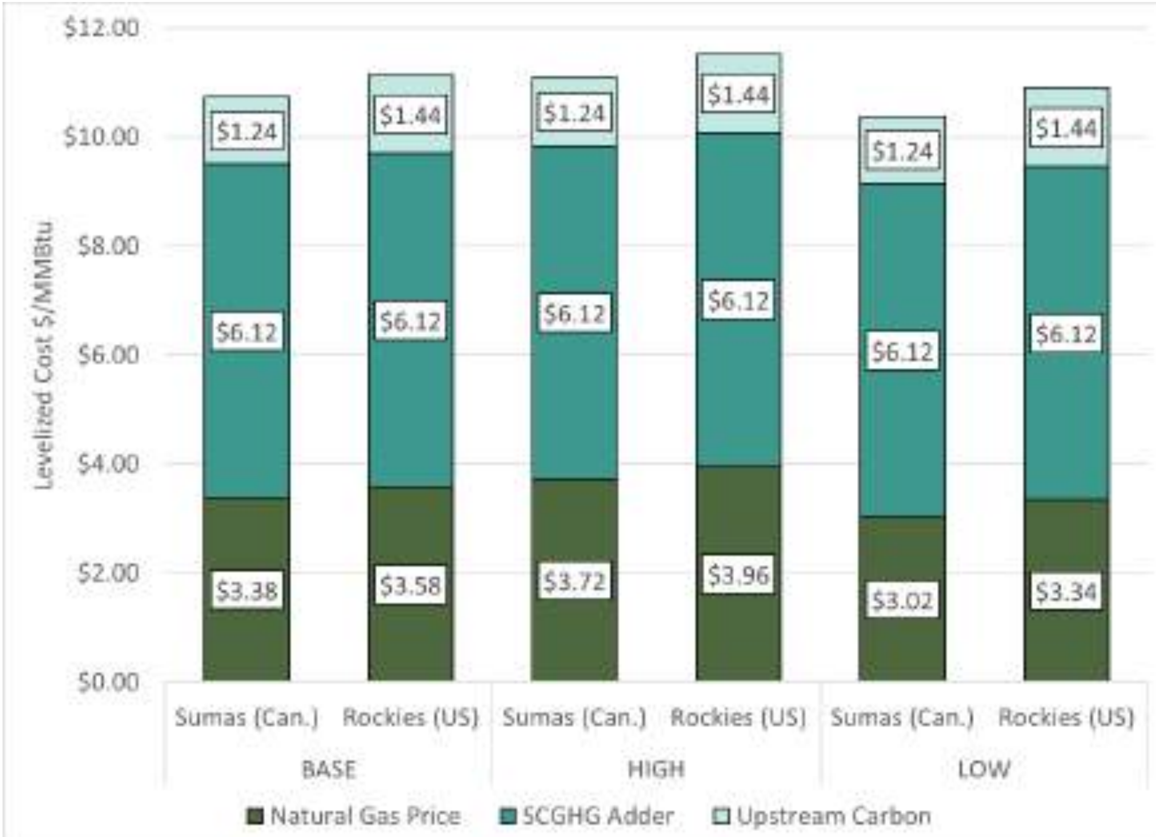
MID NATURAL GAS PRICES. The mid natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and the Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020.

LOW NATURAL GAS PRICES. The low natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and an adjusted Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020. To adjust the Wood Mackenzie forecast, PSE used the data trends from the Spring 2018 Wood Mackenzie low price forecast and applied them to the most recent fundamentals forecast. The underlying factors that influence the high and low reports have not changed significantly between the Spring 2018 and Spring 2020 forecasts.

HIGH NATURAL GAS PRICES. The high natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and an adjusted Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020. To adjust the Wood Mackenzie forecast, PSE used the data trends from the Spring 2018 Wood Mackenzie high price forecast and applied them to the most recent fundamentals forecast. The underlying factors that influence the high and low reports have not changed significantly between the Spring 2018 and Spring 2020 forecasts.

Figure 5-29 below illustrates the range of 20-year levelized natural gas prices used in the 2021 IRP analysis, along with the carbon adders used to develop the total natural gas cost.

Figure 5-29: Levelized Natural Gas Prices and Carbon Adders Used in Scenarios, 2021 IRP

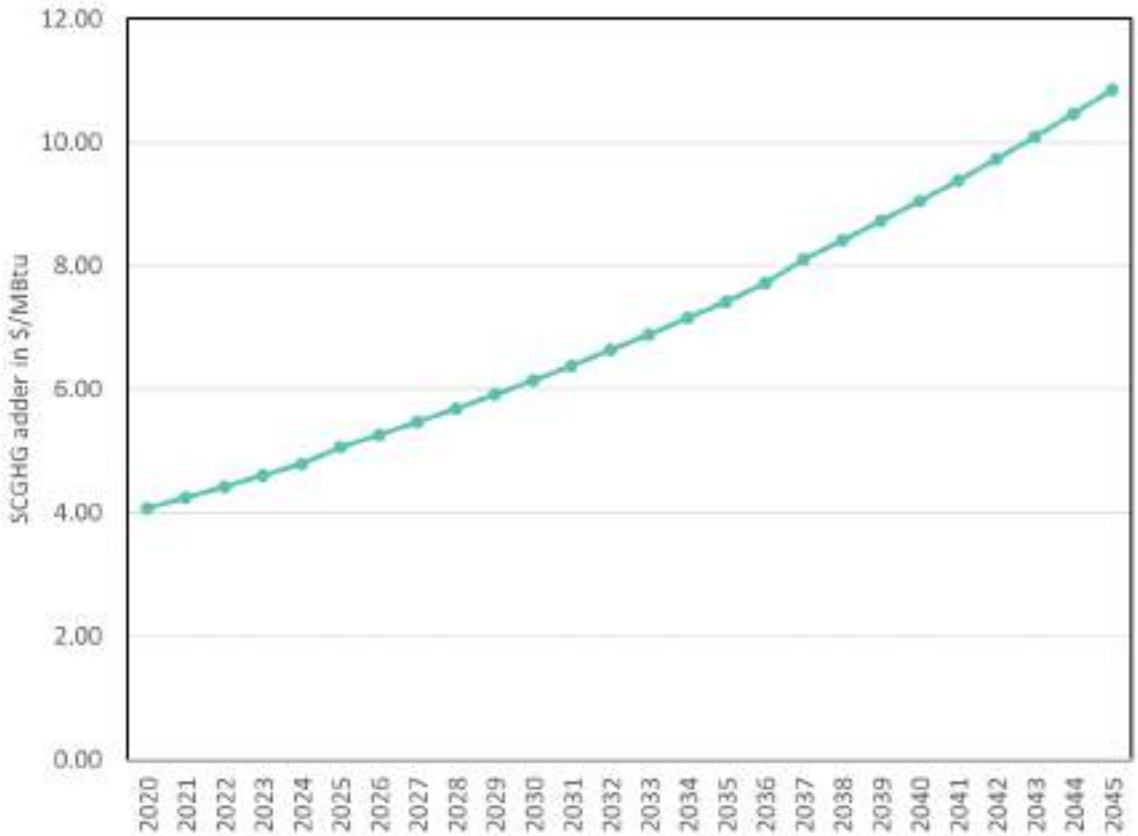


CO_2 Price Inputs

RCW 80.28.380 requires that the natural gas analysis include the cost of greenhouse gases when evaluating the cost-effectiveness of natural gas conservation targets. To implement this requirement, the SCGHG is added to the natural gas commodity price.

SOCIAL COST OF GREENHOUSE GASES. Per RCW 80.28.395, the social cost of greenhouse gases is based on the cost from the Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document, August 2016 update. It projects a 2.5 percent discount rate, starting with $62 per metric ton (in 2007 dollars) in 2020. The document lists the *CO_2* prices in real dollars and metric tons. PSE has adjusted the prices for inflation (nominal dollars) and converted to U.S. tons (short tons). This cost ranges from **$69 per ton in 2020 to $238 per ton in 2052.** This was then converted to a dollars per MMBtu value resulting in Figure 5-31.

Figure 5-30: Social Cost of Greenhouse Gases Used in the 2021 IRP ($/MMBtu)



UPSTREAM CO_2 EMISSIONS FOR NATURAL GAS. The upstream emission rate represents the carbon dioxide, methane and nitrous oxide releases associated with the extraction, processing and transport of natural gas along the supply chain. These gases were converted to carbon dioxide equivalents (CO_2e) using the Intergovernmental Panel on Climate Change Fourth Assessment (AR4) 100-year global warming potentials (GWP) protocols.[27]

27 / Both the EPA and the Washington Department of Ecology direct reporting entities to use the AR4 100-year GWPs in their annual compliance reports, as specified in table A-1 at 40 CFR 98 and WAC 173-441-040.

For the cost of upstream CO_2 emissions, PSE used emission rates published by the Puget Sound Clean Air Agency[28] (PSCAA). PSCAA used two models to determine these rates, GHGenius[29] and GREET.[30] Emission rates developed in the GHGenius model apply to natural gas produced and delivered from British Columbia and Alberta, Canada. The GREET model uses U.S.-based emission attributes and applies to natural gas produced and delivered from the Rockies basin.

Figure 5-31: Upstream Natural Gas Emissions Rates

	Upstream Segment	End-use Segment (Combustion)	Emission Rate Total	Upstream Segment CO2e (%)
GHGenius	10,803 g/MMBtu	+ 54,400 g/MMbtu	= 65,203 g/MMBtu	19.9%
GREET	12,121 g/MMBtu	+ 54,400 g/MMbtu	= 66,521 g/MMBtu	22.3%

NOTE: End-use Combustion Emission Factor: EPA Subpart NN

Delivery of Natural Gas within the PSE System

The assumption for the 2021 IRP is that the PSE natural gas delivery system in western Washington is unconstrained. This assumption holds because of a robust delivery system planning approach and the resulting long-range delivery system infrastructure plan that includes transmission and distribution system upgrades. See Appendix M, Delivery System 10-year Plan, for more detailed descriptions of each project.

28 / *Proposed Tacoma Liquefied Natural Gas Project, Final Supplemental Environmental Impact Statement, Ecology and Environment, Inc., March 29, 2019*

29 / *GHGenius. (2016). GHGenius Model v4.03. Retrieved from http://www.ghgenius.ca/*

30 / *GREET. (2018). Greenhouse gases, Regulated Emissions and Energy use in Transportation; Argonne National Laboratory.*

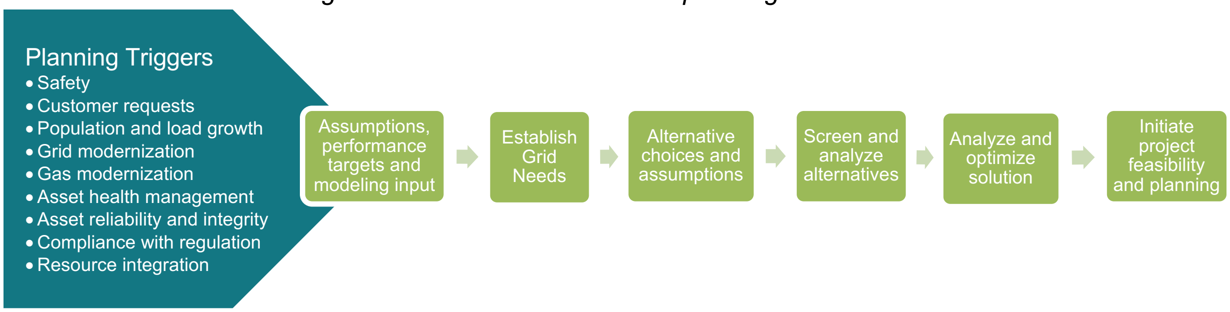
Figure 5-32: Natural Gas Distribution System Planned Work

Transmission and Distribution Summary – Planned work to ensure delivery of resources unconstrained	Description (to be completed for the final IRP)	Project Phase & Estimated In-service date	Potential DER Location
New Intermediate Pressure Main	36 miles	Ongoing	
Gate or Limit Station Upgrades	5	Ongoing	
District Regulation	26	Ongoing	
Gas Main Replaced	200-300 miles	Ongoing	
Bonney Lake Reinforcement (Phase 1)	The project has provided additional capacity and reliability to serve the growth in Bonney Lake area. Phase 1 of the project involved constructing 1.7 miles of 16-inch high pressure main.	36 miles	
Bonney Lake Reinforcement (Phase 2, 3 and 4)	Project driver is to ensure reliability and adequate capacity	5	X
North Lacey Reinforcement	Project driver is to ensure reliability and adequate capacity	26	
Sno-King Reinforcement Projects	Project driver is to ensure reliability and adequate capacity	200-300 miles	
Tolt Pipeline	Project driver is to ensure reliability and adequate capacity	Initiation needed by 2023	

Natural Gas Delivery System Planning Assumptions

PSE follows a structured approach to developing infrastructure plans that support various customer needs including effective integration of DERs.

Figure 5-33: DSP Natural Gas Operating Model



Assumptions	Description
Peak Hour Demand Growth	Uses county demand forecast applied based on historic load patterns of zip codes with known point loads adjusted for
Energy Efficiency	Highly optimistic 75% and 100% targets included (PSE benchmarking with peers in 2021)
Resource Interconnections	Known interconnection requests included
Pipeline Safety and Aging Infrastructure	Known risk-based concerns included in analysis
Interruptible / Behavior-based Rates	Known opportunities to curtail during peak included
Distributed Energy Resources / Manual intervention	Known controllable devices are included where possible such as compressed natural gas injection at low pressure areas or bypassing valves
System Configurations	As designed
Compliance and Safety Obligations	Meet all regulatory requirements including Federal PHMSA and pipeline safety WAC codes, such as addressing low pressure concerns or over-pressure events

Natural Gas Alternatives Modeled

Energy efficiency, transportation and storage are key resources for natural gas utilities. PSE modeled the following generic resources as potential portfolio additions in this IRP analysis.

> > > *See* ***Chapter 9, Gas Analysis****, for detailed descriptions of the resources listed here.*
> > > *See* ***Appendix E, Conservation Potential Assessment and Demand Response Assessment****, for detailed information on demand-side resource potentials.*

Demand-side resources included the following.

ENERGY EFFICIENCY MEASURES. These are a wide variety of measures that result in a lower level of energy being used to accomplish a given amount of work. They include three categories: retrofit programs that have shorter lives; lost opportunity measures that have longer lives, such as high-efficiency furnaces; and codes and standards that drive down energy consumption through government regulation. (Codes and standards impact the demand forecast but have no direct cost to utilities.)

Supply-side resources included the following.

Transport pipelines that bring natural gas from production areas or market hubs to PSE's service area generally require assembling a number of specific segments and/or natural gas storage alternatives. Purchases from specific market hubs are joined with various upstream and direct-connect pipeline alternatives and storage options to create combinations that have different costs and benefits. Seven alternatives were analyzed in this IRP.

Combination # 1 & 1a – NWP Additions + Westcoast

After November 2025, this option expands access to northern British Columbia natural gas at the Station 2 hub, with expanded transport capacity on Westcoast pipeline to Sumas and then on expanded Northwest Pipeline (NWP) to PSE's service area. Natural gas supplies are also presumed available at the Sumas market hub. In order to ensure reliable access to supply and achieve diversity of pricing, PSE believes it will be prudent and necessary to acquire Westcoast capacity equivalent to 100 percent of any new NWP firm take-away capacity from Sumas.

COMBINATION #1A – SUMAS DELIVERED NATURAL GAS SUPPLY. This short-term delivered supply alternative utilizes capacity on the existing NWP system from Sumas to PSE that could be contracted to meet PSE needs from November 2019 to October 2024 in the form of annual winter contracts. This alternative is intended to provide a short-term bridge to long-term resources. Pricing would reflect Sumas daily pricing and a full recovery of pipeline charges. PSE believes that the vast majority – if not all – of the under-utilized firm pipeline capacity in the I-5 corridor that could be used to provide a delivered supply has been or will be absorbed by other new loads by Fall 2025. After that, other long-term resources would need to be added to serve PSE demand.

Combination # 2 – FortisBC/Westcoast (KORP)

This combination includes the Kingsvale-Oliver Reinforcement Project (KORP) pipeline proposal, which is in the development stages and sponsored by FortisBC and Westcoast. Availability is estimated to begin no earlier than November 2025. Essentially, the KORP project expands and adds flexibility to the existing Southern Crossing pipeline. This option would allow delivery of Alberta (AECO hub) natural gas to PSE via existing or expanded capacity on the TC-NGTL and TC-Foothills pipelines, the KORP pipeline across southern British Columbia to Sumas, and then on expanded NWP capacity to PSE. As a major greenfield project, this resource option is dependent on significant additional volume being contracted by other parties.

Combination # 3 – Cross Cascades – NWP from AECO

This option provides for deliveries to PSE via a prospective upgrade of NWP's system from Stanfield, Oregon to contracted points on NWP in the I-5 corridor. Availability is estimated no earlier than November 2025. The increased natural gas supply would come from Alberta (AECO hub) via new upstream pipeline capacity on the TC-NGTL, TC-Foothills and TC-GTN pipelines to Stanfield, Oregon. Final delivery from Stanfield to PSE would be via the upgraded NWP facilities across the Columbia gorge and then northbound to PSE gate stations. Since the majority of this expansion route uses existing pipeline right-of-way, permitting this project would likely be less complicated than for a greenfield project such as the option presented in Combination #2. Also, since smaller increments of capacity are economically feasible with this alternative, PSE is more likely to be able to dictate the timing of the project.

Combination # 4 – Mist Storage and Redelivery

This option involves PSE leasing storage capacity from NW Natural after an expansion of the Mist storage facility. Pipeline capacity from Mist, located in the Portland area, would be required for delivery of natural gas to PSE's service territory, and the expansion of NWP capacity from Mist to PSE will be dependent on an expansion on NWP from Sumas to Portland with significant additional volume contracted by other parties. Mist expansion and a NWP southbound expansion – which would facilitate a lower-cost northbound storage redelivery contract – are not expected to be available until at least November 2025.

Combination # 5 – Plymouth LNG with Firm Delivery

This option includes 70.5 MDth per day firm Plymouth LNG service and 15 MDth per day of firm NWP pipeline capacity from the Plymouth LNG plant to PSE. Currently, PSE's electric power generation portfolio holds this resource, which may be available for renewal for periods beyond April 2023. While this a valuable resource for the power generation portfolio, it may be a better fit in the natural gas sales portfolio.

Combination # 6 – LNG-related Distribution Upgrade

This combination assumes commissioning of the LNG peak-shaving facility, providing 69 MDth per day of capacity. This option considers the timing of the contemplated upgrade to the Tacoma area distribution system, which would allow an additional 16 MDth per day of vaporized LNG to reach more customers. In effect, this would increase overall delivered supply to PSE customers, since natural gas otherwise destined for the Tacoma system would be displaced by vaporized LNG and therefore available for delivery to other parts of the system. The incremental volume resulting from the distribution upgrade can be implemented on three years' notice starting as early as winter 2024/25.

Combination # 7 – Swarr LP-Air Upgrade

This is an upgrade to the existing Swarr LP-Air facility discussed above. The upgrade would increase the peak day planning capability from 10 MDth per day to 30 MDth per day. This plant is located within PSE's distribution network, and could be available on three years' notice as early as winter 2024/25.

Natural Gas Resource Build Constraints

Natural gas expansions are done in multi-year blocks to reflect the reality of the acquisition process. There is inherent "lumpiness" in natural gas pipeline expansion, since expanding pipelines in small increments every year is not practical. Pipeline companies need minimum capacity commitments to make an expansion economically viable. Thus the model is constrained to evaluate pipeline expansions in four-year blocks: 2025 – 2028 and 2033 – 2037. Similarly, some resources have more flexibility. The Swarr LP gas peaking facility's upgrade and the LNG distribution system upgrade were made available in two year increments since these resources are PSE assets.

Natural Gas Portfolio Sensitivities

Figure 5-34: 2021 IRP Natural Gas Portfolio Sensitivities

2019 IRP NATURAL GAS ANALYSIS SENSITIVITIES		
A	AR5 Upstream Emissions	The AR5 model is used to model upstream emissions instead of AR4.
B	6-Year Conservation Ramp Rate	Energy efficiency measures ramp up over 6 years instead of 10.
C	Social Discount Rate for DSR	The discount rate for demand-side resource measures is decreased from 6.8% to 2.5%.
D	Fuel Switching, Gas to Electric	Gas-to-electric conversion is accelerated in the PSE service territory.
E	Temperature Sensitivity on Load	Temperature data used for economic forecasts is composed of more recent weather data as a way to represent changes in climate.
F	No DSR	This portfolio will not include any new demand-side resources energy efficiency, distribution efficiency and demand response

A. AR5 Upstream Emissions

This sensitivity uses the AR5 methodology for calculating the upstream natural gas emissions rate instead of the AR4 methodology.

BASELINE ASSUMPTION: PSE uses the AR4 Upstream Emissions calculation methodology which adds 10,803 g/MMBtu to Canadian supply emissions and 12,121 g/MMBtu to US supply emissions.
SENSITIVITY > PSE will use the AR5 Upstream Emissions calculation methodology which adds 11,564 g/MMBtu to Canadian supply emissions and 13,180 g/MMBtu to US supply emissions.

B. 6-Year Conservation Ramp Rate

This sensitivity changes the ramp rate for conservation measures from 10 years to 6 years, allowing PSE to model the effect of faster adoption rates.

BASELINE ASSUMPTION: Conservation and demand response measures ramp up to full implementation over 10 years.
SENSITIVITY > Conservation measures ramp up to full implementation over 6 years.

C. Social Discount Rate for DSR

This sensitivity changes the discount rate for DSR projects from the current discount rate of 6.8 percent to 2.5 percent. By decreasing the discount rate, the present value of future DSR savings is increased, making DSR more favorable in the modeling process. DSR is then included as a resource option with the new financing outlook.

BASELINE ASSUMPTION: The discount rate for DSR measures is 6.8 percent.
SENSITIVITY > The discount rate for DSR measures is 2.5 percent.

D. Fuel Switching, Gas to Electric

This sensitivity models an increased adoption of gas-to-electric conversion within the PSE service territory. Results from this sensitivity will illustrate the effects of rapid electrification on the portfolio and the demand profile of the PSE service territory.

BASELINE ASSUMPTION: The portfolio uses the standard demand forecast for the Mid Scenario.
SENSITIVITY > The demand forecast is adjusted to include an increased electrification rate of natural gas customers in the PSE service territory resulting in a lower natural gas demand forecast.

E. Temperature Sensitivity

This sensitivity models a change in temperature trends, adjusting the underlying temperature data of the demand forecast to emphasize the influence of more recent years. This change attempts to show the effect of rising temperature trends in the Pacific Northwest. Results from this sensitivity will illustrate changes in PSE's load profile.

BASELINE ASSUMPTION: PSE uses the base demand forecast.

SENSITIVITY > PSE uses temperature data from the NPCC. The NPCC is using global climate models that are scaled down to forecast temperatures for many locations within the Pacific Northwest. The NPCC weighs temperatures by population from metropolitan regions throughout the Northwest. However, PSE also received data from the NPCC that is representative of SeaTac airport. This data is, therefore, consistent with how PSE plans for its service area and this data is not mixed with temperatures from Idaho, Oregon or Eastern Washington. The climate model data provided by the Council is hourly data from 2020 through 2049. This data resembles a weather pattern in which the temperatures fluctuate over time, but generally trend upward. For the load forecast portion of the temperature sensitivity, PSE has smoothed out the fluctuations in temperature and increased the heating degree days (HDDs) and cooling degree days (CDDs) over time at 0.9 degrees per decade, which is the rate of temperature increase found in the Council’s climate model.

F. No DSR

This portfolio looks at the benefits associated with demand-side resources

BASELINE ASSUMPTION: New energy efficiency resources are acquired when cost effective and needed.

SENSITIVITY > No new energy efficiency is allowed in the portfolio and all future needs will be met by supply-side resources.

6 Demand Forecasts

The system-level demand forecast that PSE develops for the IRP is an estimate of energy sales, customer counts and peak demand over a 20-year period. These forecasts are designed for use in long-term resource planning and in Delivery System Planning (DSP) needs assessments.

Contents

1. OVERVIEW

The demand forecasts developed for the IRP estimate the amount of electricity or natural gas that will be required to meet the needs of customers over the 20+ year study period. These forecasts focus on two dimensions of demand: energy demand and peak demand.

- Energy demand refers to the total amount of electricity or natural gas needed to meet customer needs in a given year.
- Peak demand refers to the amount of electricity or natural gas needed to serve customer need on the coldest day of the year, since PSE is a winter-peaking utility.

NOTE: The terms “demand” and “load” are often used interchangeably, but they actually refer to different concepts. “Demand” refers to the amount of energy needed to meet the needs of customers during a calendar year, including losses. “Load” refers to demand plus the planning margin and operating reserves needed to ensure reliable and safe operation of the electric and natural gas systems.

Overall, electric energy demand before additional conservation in the 2021 IRP Base Demand Forecast is expected to grow at an average annual rate of 1.2 percent during the study period from 2022 to 2045, resulting in an increase from 2,500 aMW in 2022 to 3,316 aMW in 2045. This is slower than the 1.4 average annual energy growth rate forecast during the 2019 IRP Process. Electric peak demand before additional conservation is expected to increase at a 1.2 percent annual growth rate, resulting in an increase from 4,687 MW in 2022 to 6,159 MW in 2045. This is also slower than the 1.3 percent average annual growth rate forecast during the 2019 IRP Process and results in lower total peak demand at the end of the study period. System growth is driven by customer additions. Demand from customers using electric vehicles drives up residential and commercial use per customer in the second half of the study period.

The 2021 IRP Natural Gas Base Demand Forecast before additional conservation for both energy and peak demand is also lower than forecast during the 2019 IRP Process. However, for energy, the average annual growth rate (0.8 percent) is higher compared to the 2019 IRP Process (0.7 percent). For peak demand, the average annual growth rate in the 2021 IRP forecast is the same as that in the 2019 IRP Process (0.8 percent). Lower residential customer counts, lower residential use per customer, lingering COVID-19 effects, and the inclusion of recent data on cold weather days in calculating weather sensitivity reduced demand.

In this IRP, the Base Demand Forecast is based on “normal” weather, defined as the average monthly weather recorded at NOAA’s Sea-Tac Airport station over the 30 years ending in 2019. For the 2021 IRP, the natural gas and electric analysis included a temperature sensitivity on demand. PSE proposed three alternative temperature assumptions to stakeholders, and stakeholders selected the temperature assumption with the greatest warming trend. This sensitivity has temperatures warming over time following the trend of one model that the Northwest Power and Conservation Council is using in its climate analyses. More information on this sensitivity can be found in Chapter 5, Key Analytical Assumptions, and the related demand forecast is discussed later in this chapter.

To model a range of potential economic conditions, weather conditions and potential modeling errors in the IRP analysis, PSE also prepares Low and High forecasts in addition to the Base Forecast. The Low Forecast models reduced population and economic growth compared to the Base Forecast; the High Forecast models higher population and economic growth compared to the Base Forecast. For the High and Low Demand Forecasts, historic monthly temperature observations are used to project a distribution of possible future temperature-sensitive demand, thereby modeling a wider range of warmer and colder conditions than the Base Demand Forecast.

CONSERVATION IMPACTS. Demand is reduced significantly when forward projections of additional conservation savings are applied, as shown in Figure 6-1. However, it is necessary to start with forecasts that do not already include forward projections of conservation savings in order to identify the most cost-effective amount of conservation to include in the resource plan.

NOTE: Throughout this chapter, charts labeled "before additional DSR" include only demand-side resource (DSR) measures implemented before the study period begins in 2022. Charts labeled "after applying DSR" include the cost-effective amount of DSR identified in the 2021 IRP.

Figure 6-1: Effect of Conservation Impacts on Demand Forecasts

2021 IRP Base Forecast at End of Forecast Period	Before Additional DSR	After Applying DSR
Electric Energy Demand (aMW) (2045)	3,316	2,604
Electric Peak Demand (MW) (2045)	6,159	4,966
Natural Gas Energy Demand (Mdth) (2041)	112,918	100,678
Natural Gas Peak Demand (Mdth) (2041)	1,130	1,019

2. ELECTRIC DEMAND FORECAST

Highlights of the IRP Base, High and Low Demand Forecasts developed for the electric service area are presented below in Figures 6-2 through 6-5. The population and employment assumptions for all three forecasts are summarized in the section titled “Details of Electric Forecast” and explained in detail in Appendix F, Demand Forecasting Models.

Only DSR measures implemented through December 2021 are included, since the demand forecast itself helps to determine the most cost-effective amount of conservation to include in the portfolio.

Electric Energy Demand

In the 2021 IRP Base Demand Forecast, energy demand before additional DSR is expected to grow at an average rate of 1.2 percent annually from 2022 to 2045, increasing energy demand from 2,500 aMW in 2022 to 3,316 aMW in 2045.

Residential and commercial demand are driving the growth in total energy. Excluding losses, these customer classes are projected to represent 50 percent and 38 percent of demand in 2022, respectively. On the residential side, use per customer is expected to be relatively flat for the short term but to grow over time, mainly due to the adoption of electric vehicles. This, plus population growth, is driving residential energy demand. On the commercial side, use per customer is relatively flat as well, with a small amount of growth in the later part of the forecast due to electric vehicle growth. Rising customer counts therefore drive much of the growth.

The 2021 IRP High Demand Forecast projects an average annual growth rate (AARG) of 1.6 percent; the Low Demand Forecast projects 0.9 percent.

Figure 6-2: Electric Energy Demand Forecast before Additional DSR

Base, High and Low Scenarios (aMW)

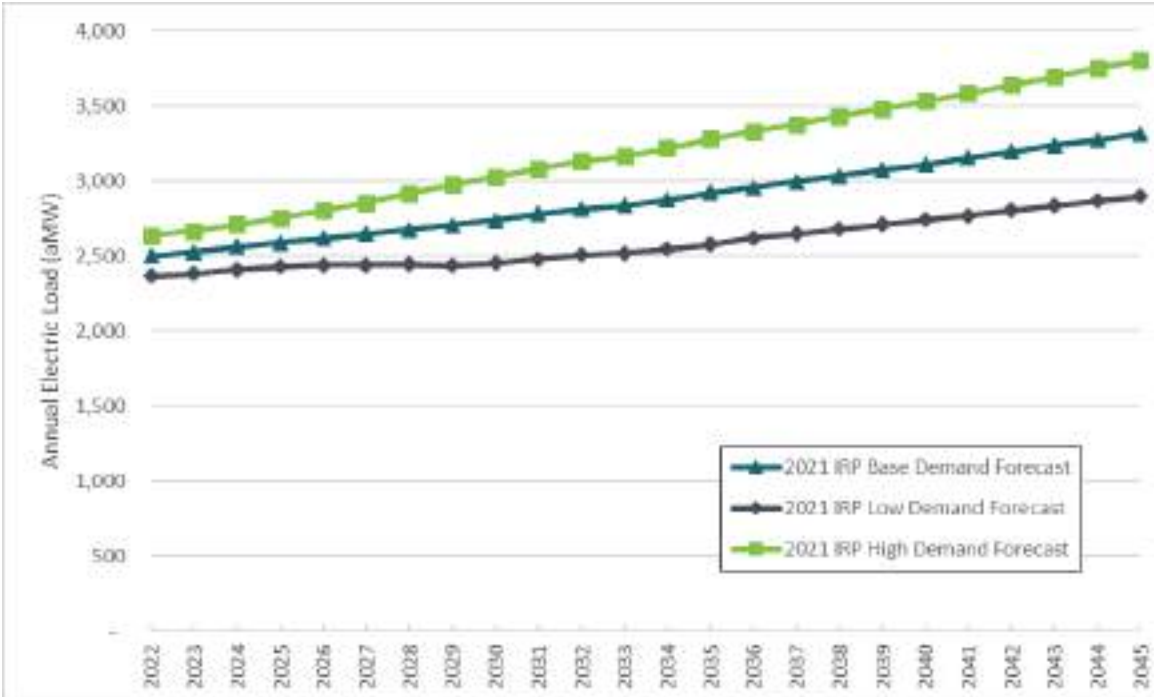


Figure 6-3: Electric Energy Demand Forecast before Additional DSR (Table)
Base, High and Low Scenarios

2021 IRP ELECTRIC ENERGY DEMAND FORECAST SCENARIOS (aMW)							
Scenario	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**	**AARG 2022-2045**
2021 IRP Base Demand Forecast	2,500	2,592	2,740	2,921	3,110	3,316	1.2%
2021 IRP High Demand Forecast	2,636	2,753	3,029	3,281	3,531	3,803	1.6%
2021 IRP Low Demand Forecast	2,367	2,429	2,454	2,580	2,742	2,897	0.9%

Electric Peak Demand

PSE is a winter peaking utility, meaning that the one hour during the year with the highest demand occurs during the winter. The capacity expansion model analyzes winter peaks. However, summer peaks are growing with warming summer temperatures and increased saturation of air conditioning in the region. Different types of supply-side or demand-side resources may better meet a summer or a winter peak. Therefore, PSE considers demand during all hours of the year in the resource adequacy modeling to help determine the best resources to meet load from our customers. This section describes the winter and summer electric peaks.

Winter Electric Peak Demand

The normal electric winter peak hour demand is modeled using 23 degrees Fahrenheit as the design temperature. Since PSE is a winter peaking utility, this peak has historically occurred in December but is occurring in other winter months as well. The 2021 IRP Base Demand Forecast shows a 1.2 percent average annual growth rate for peak demand; this would increase peak demand from 4,687 MW in 2022 to 6,159 MW in 2045.

The 2021 IRP High Demand Forecast shows an average annual peak demand growth rate of 1.5 percent, and the Low Demand Forecast shows a 0.9 percent average annual growth rate.

Figure 6-4: Winter Electric Peak Demand Forecast before Additional DSR Base, High and Low Scenarios, Hourly Annual Peak (MW)

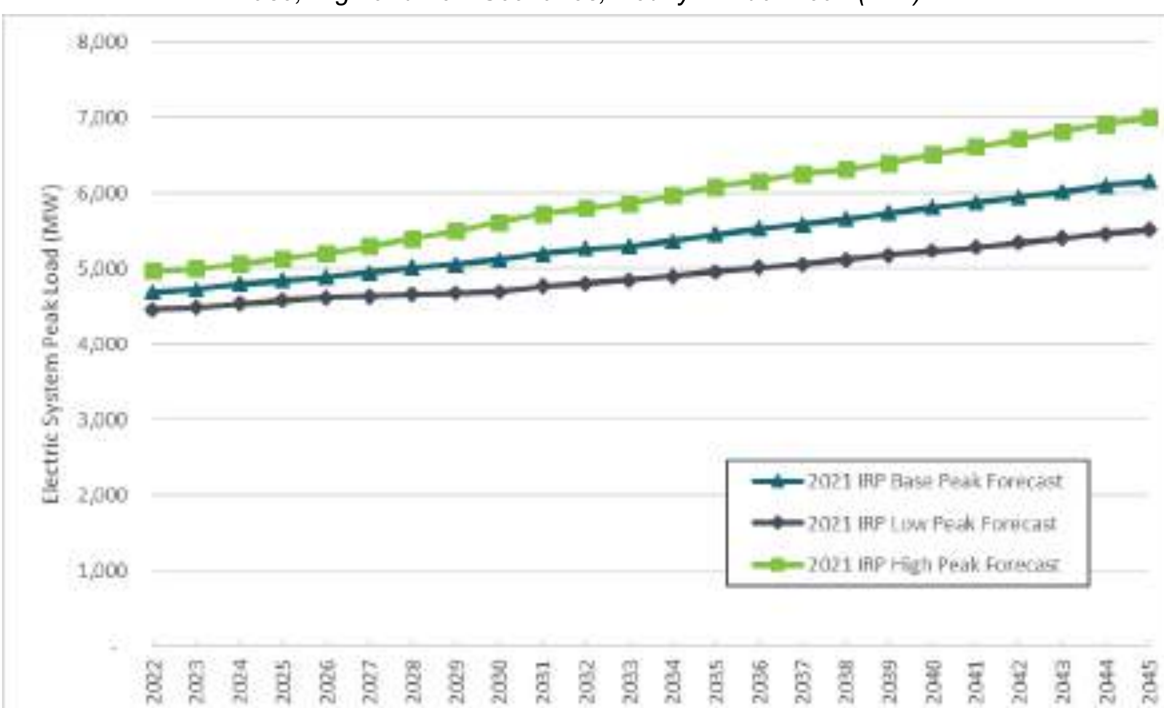
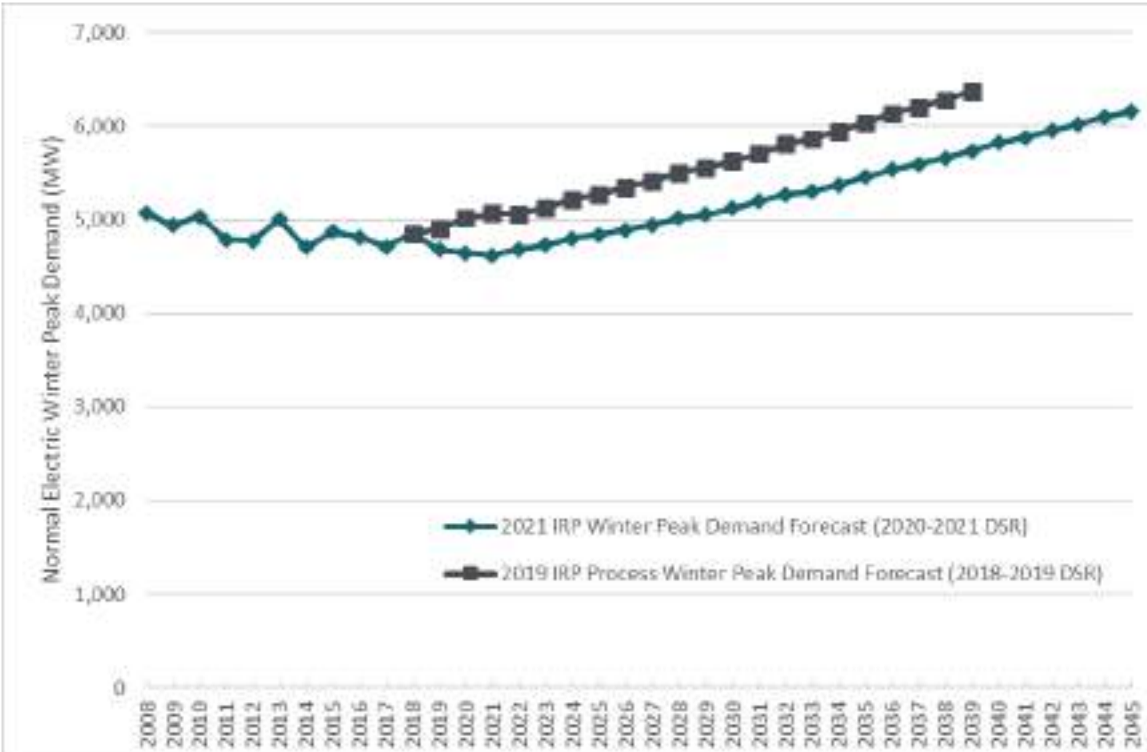


Figure 6-5: Winter Electric Peak Demand Forecast before Additional DSR (Table)
Base, High and Low Scenarios, Hourly Annual Peak (MW)

2021 IRP WINTER ELECTRIC PEAK DEMAND FORECAST SCENARIOS (MW)							
Scenario	2022	2025	2030	2035	2040	2045	AARG 2022-2045
2021 IRP Base Demand Forecast	4,687	4,844	5,123	5,455	5,819	6,159	1.2%
2021 IRP High Demand Forecast	4,972	5,138	5,622	6,085	6,521	7,001	1.5%
2021 IRP Low Demand Forecast	4,466	4,581	4,697	4,966	5,240	5,519	0.9%

Peak demand in the 2021 IRP Base Demand Forecast is lower at the end of the study period (6,159 MW in 2040) compared to the 2019 IRP Process (6,370 MW in 2039). Additionally, the 2021 IRP Peak Demand Forecast has a slower average annual growth rate (1.2 percent) compared to the 2019 IRP Process (1.3 percent). The 2021 IRP Peak Demand Forecast projects slower growth than the 2019 IRP Process Peak Demand Forecast because the 2021 IRP Demand Forecast grows at a slower rate than the 2019 IRP Process due to slower anticipated customer growth (particularly commercial) and lower projected use per customer in all non-residential classes. Observed actual residential customers and sales growth in 2018 and 2019 offset the non-residential trends; however, the downward growth drivers related to lower commercial usage and COVID-19 result in a lower long-term growth rate.

Figure 6-6: Winter Electric Peak Demand Forecast before Additional DSR
2021 IRP Base Scenario versus 2019 IRP Process Base Scenario
Hourly Annual Peak (23 Degrees, MW)



Summer Electric Peak Demand

The normal electric summer peak hour demand is modeled using 93 degrees Fahrenheit as the design temperature. Summer peaks typically occur in July or August. Figure 6-7 shows the 2021 IRP Base Peak Demand Forecast for the winter and the summer. The 2021 IRP Base summer peak demand forecast has an average annual growth rate of 1.7 percent. This increases the summer peak demand from 3,515 MW in 2022 to 5,183 MW in 2045. Because the summer peak forecast does not exceed the winter peak forecast in the timeframe shown, it is assumed that PSE will continue to be a winter peaking utility for the planning period of this IRP.

Figure 6-7: Winter and Summer Electric Peak Demand Forecasts before Additional DSR Base Scenario, Hourly Annual Peak (MW)

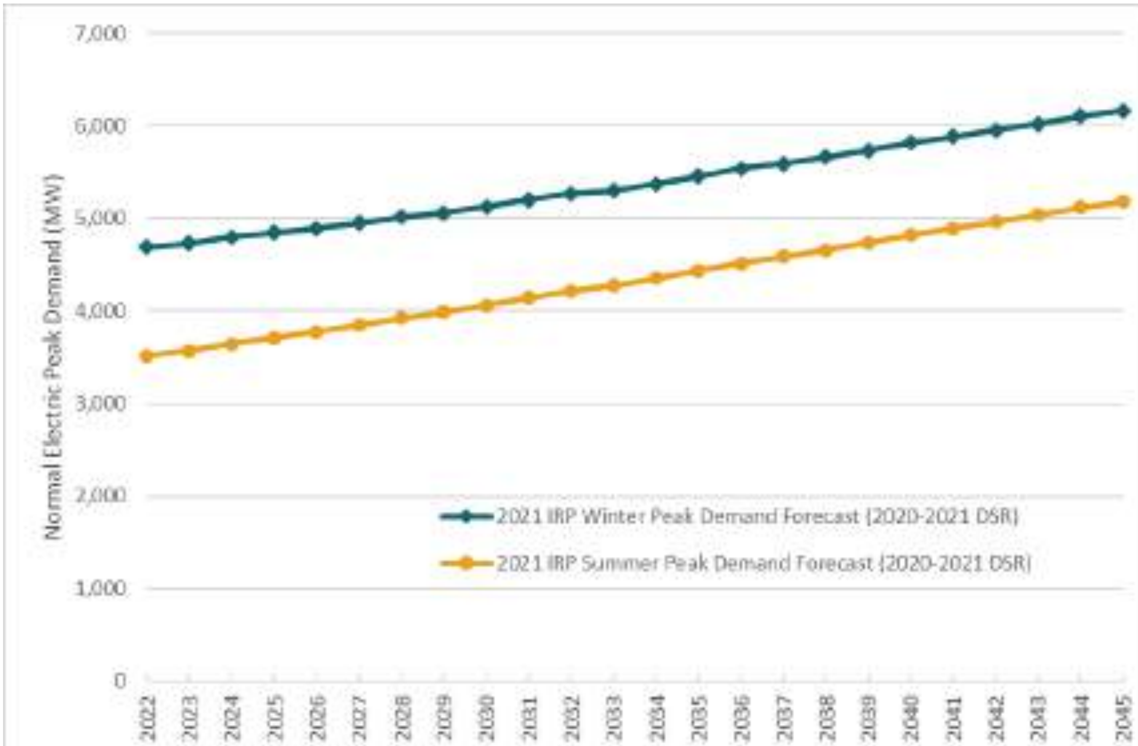


Illustration of Conservation Impacts

The system-level demand forecasts shown above apply only the energy efficiency measures targeted for 2020 and 2021, because those forecasts serve as the starting point for identifying the most cost-effective amount of demand-side resources for the portfolio from 2022 to 2045.

However, PSE also examines the effects of conservation on the energy and peak demand over the full planning horizon. Forecasts with conservation are used internally at PSE for financial and system planning decisions. To illustrate conservation impacts, the cost-effective demand-side resources identified in this IRP[1] are applied to the Base Scenario energy and peak demand forecasts for 2022 to 2045. To account for the 2013 general rate case Global Settlement, an additional 5 percent of conservation is also applied for that period. The results are illustrated in Figures 6-8 and 6-9, below.

[1] / *For demand-side resource analysis, see Chapter 8, Electric Analysis, and Appendix E, Conservation Potential Assessment and Demand Response Assessment.*

DSR IMPACT ON ENERGY DEMAND. When the DSR bundles chosen in the 2021 IRP portfolio analysis are applied to the energy demand forecast:

- Electric energy demand in 2045 is reduced 21 percent to 2,604 aMW.
- Electric energy demand after DSR grows at an average annual rate of 0.23 percent from 2022 to 2045.

DSR IMPACT ON PEAK DEMAND. When the DSR bundles chosen in the 2021 portfolio analysis are applied to the peak demand forecast:

- Electric system peak demand in 2045 is reduced 19 percent to 4,966 MW.
- Electric system peak demand after DSR grows at an average annual rate of 0.3 percent from 2022 to 2045.

Figure 6-8: Electric Energy Demand Forecast (aMW), before Additional DSR and after Applying DSR

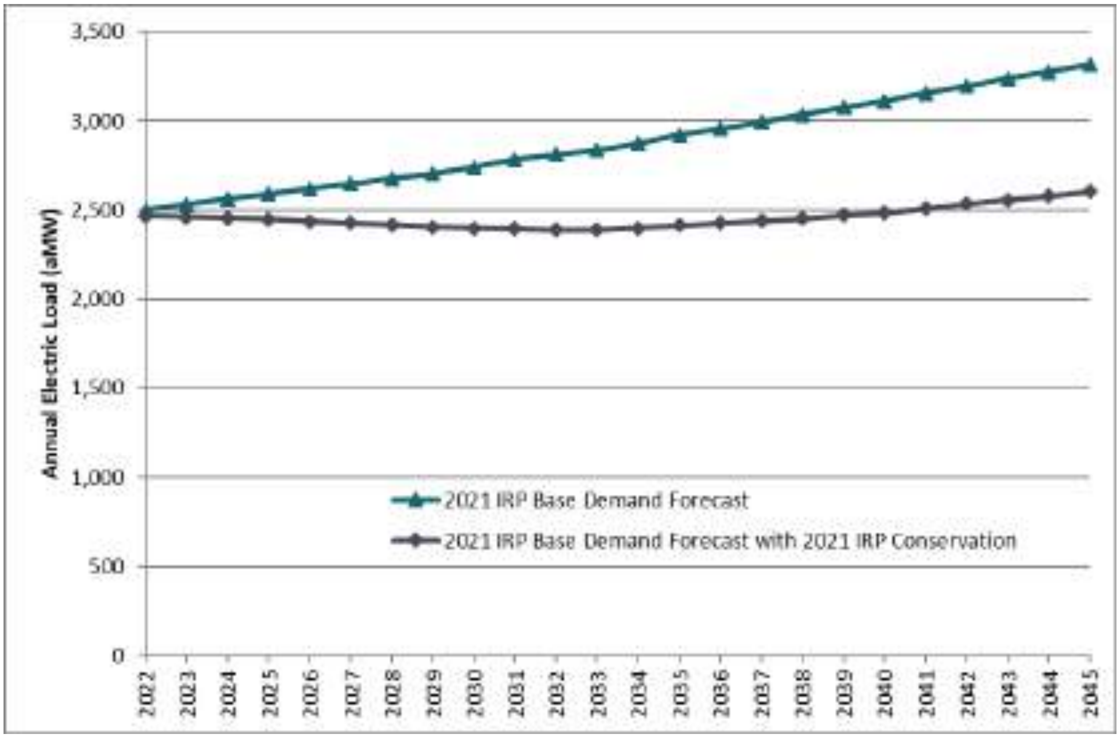
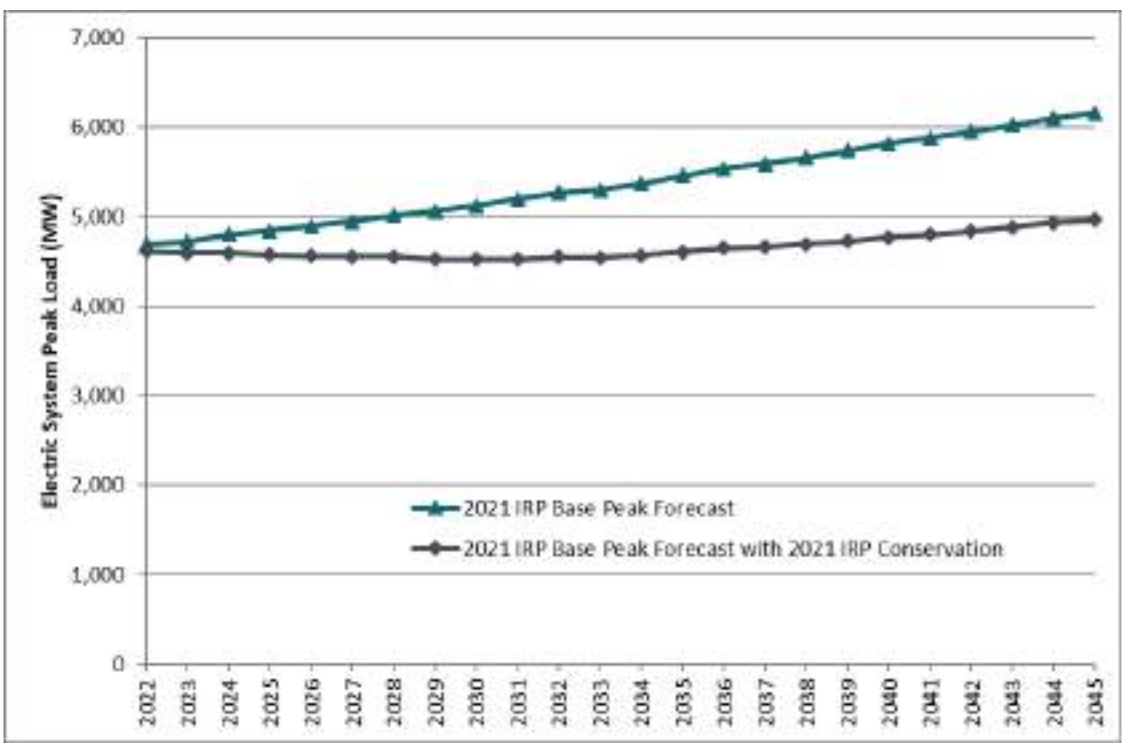


Figure 6-9: Electric Peak Demand Forecast (MW), before Additional DSR and after Applying DSR



Details of Electric Forecast

Electric Customer Counts

System-level customer counts are expected to grow by 1.0 percent per year on average, from 1.21 million customers in 2022 to 1.53 million customers in 2045. This is slower than the average annual growth rate of 1.2 percent projected in the 2019 IRP Process Base Demand Forecast.

Residential customers are driving the overall customer count increase, since they are projected to represent 88 percent of PSE's electric customers in 2022. Residential customer counts are expected to grow at an average annual rate of 1.0 percent from 2023 to 2045. The next largest group, commercial customers, is expected to grow at an average annual rate of 0.9 percent. Industrial customer counts are expected to decline, following a historical trend. These trends are expected to continue as the economy in PSE's service area shifts toward more commercial and less industrial industries.

Figure 6-10: December Electric Customer Counts by Class, 2021 IRP Base Demand Forecast

2021 IRP DECEMBER ELECTRIC CUSTOMER COUNTS BY CLASS, BASE DEMAND FORECAST							
Class	2022	2025	2030	2035	2040	2045	AARG 2022-2045
Total	1,210,701	1,253,182	1,324,465	1,395,434	1,463,388	1,529,051	1.0%
Residential	1,066,293	1,103,799	1,167,538	1,230,936	1,291,536	1,349,980	1.0%
Commercial	133,023	137,547	144,357	151,236	157,975	164,647	0.9%
Industrial	3,249	3,193	3,106	3,023	2,948	2,882	-0.5%
Other	8,130	8,643	9,464	10,239	10,929	11,542	1.5%

Electric Demand by Class

Over the next 20 years, the residential and commercial classes are both expected to have positive demand growth, with the residential class growing faster than the commercial class, before conservation. Residential class demand growth is driven by new additional customers and projected adoption of electric vehicles. Commercial class demand growth is driven by growth in the region's technology sector, which also increases the need for support services such as health care, retail, education and other public services.

Figure 6-11: Electric Energy Demand by Class, 2021 IRP Base Demand Forecast before Additional DSR

ELECTRIC DEMAND BY CLASS, 2021 IRP BASE DEMAND FORECAST (aMW)							
Class	2022	2025	2030	2035	2040	2045	AARG 2022-2045
Total	2,500	2,592	2,740	2,921	3,110	3,316	1.2%
Residential	1,248	1,300	1,392	1,497	1,609	1,722	1.4%
Commercial	954	987	1,036	1,100	1,167	1,249	1.2%
Industrial	120	121	119	117	115	114	-0.2%
Other	8	8	8	8	7	7	-0.7%
Losses	170	176	186	199	211	226	-

Electric Use per Customer

Residential use per customer[2] before conservation is expected to decline in the short term but is forecast to grow over the long term. Near-term efficiency gains and multifamily housing growth will continue to reduce electric use per customer, but the forecast projects that the increasing adoption of electric vehicles will outweigh this and create slightly positive growth, especially in the later part of the forecast. Commercial use per customer is expected to decline in the short term, due to efficiency gains as well as lingering effects from the pandemic on the commercial sector. Commercial use per customer has some positive growth in the long term due to increasing electric vehicle growth.

Figure 6-12: Electric Use per Customer, 2021 IRP Base Demand Forecast before Additional DSR

2021 IRP ELECTRIC USE PER CUSTOMER, BASE DEMAND FORECAST (MWh/CUSTOMER)							
Type	2022	2025	2030	2035	2040	2045	AARG 2022-2045
Residential	10.3	10.4	10.5	10.7	11.0	11.2	0.4%
Commercial	63.1	63.1	63.0	63.9	65.1	66.6	0.2%
Industrial	321.9	330.5	333.6	337.3	341.4	344.7	0.3%

2 / Use per customer is defined as billed energy sales per customer, that is, the amount of energy consumed at the meter.

Electric Customer Count and Energy Demand Share by Class

Customer counts as a percent of PSE's total electric customers are shown in Figure 6-13. Demand share by class is shown in Figure 6-14. The residential class is expected to increase as a percent of both total customers and total demand, and the commercial class is expected to decline as a percent of both.

Figure 6-13: December Electric Customer Count Share by Class, 2021 IRP Base Demand Forecast

ELECTRIC CUSTOMER COUNT SHARES BY CLASS, 2021 IRP BASE DEMAND FORECAST		
Class	Share in 2022	Share in 2045
Residential	88.1%	88.3%
Commercial	11.0%	10.8%
Industrial	0.3%	0.2%
Other	0.7%	0.8%

Figure 6-14: Electric Demand Share by Class, 2021 IRP Base Demand Forecast before Additional DSR

ELECTRIC DEMAND SHARES BY CLASS, 2021 IRP BASE DEMAND FORECAST		
Class	Share in 2022	Share in 2045
Residential	49.9%	51.9%
Commercial	38.1%	37.6%
Industrial	4.8%	3.4%
Other	0.3%	0.2%
Losses	6.8%	6.8%

3. NATURAL GAS DEMAND FORECAST

Highlights of the base, high and low demand forecasts developed for PSE's natural gas sales service are presented below. The population and employment assumptions for all three forecasts are summarized in the section titled "Details of the Natural Gas Forecast" and explained in detail in Appendix F, Demand Forecasting Models.

Only demand-side resources implemented through December 2021 are included, since the demand forecast itself helps to determine the most cost-effective level of DSR to include in the portfolio.

Natural Gas Energy Demand

The 2021 IRP Natural Gas Base Demand Forecast is a forecast of both firm and interruptible demand, because this is the volume of natural gas that PSE is responsible for securing and delivering to customers. For delivery system planning, however, transport demand must be included in total demand; transport customers purchase their own natural gas, but contract with PSE for delivery.

In the 2021 IRP Base Demand Forecast, natural gas energy demand before additional DSR is projected to grow 0.8 percent per year on average from 2022 to 2041; this would increase demand from 96,156 MDth in 2022 to 112,918 MDth in 2041. This is slightly higher than the annual growth rate of 0.7 percent in the 2019 IRP Process Base Demand Forecast. While the growth rate is higher, the levels of demand are lower in the 2021 IRP Base Demand Forecast than in the 2019 IRP Process Demand Forecast because lower residential customer additions, lower residential usage in the first half of the forecast and lingering COVID-19 pandemic effects lower demand in the first part of the forecast, compared to the 2019 IRP Process Forecast.

Before additional DSR, the 2021 IRP High Natural Gas Demand Forecast projects an average annual growth rate of 1.4 percent; the Low Natural Gas Demand Forecast projects a growth rate of 0.2 percent per year.

Figure 6-15: Natural Gas Energy Demand Forecast before Additional DSR Base, High and Low Scenarios, without Transport Load (MDth)

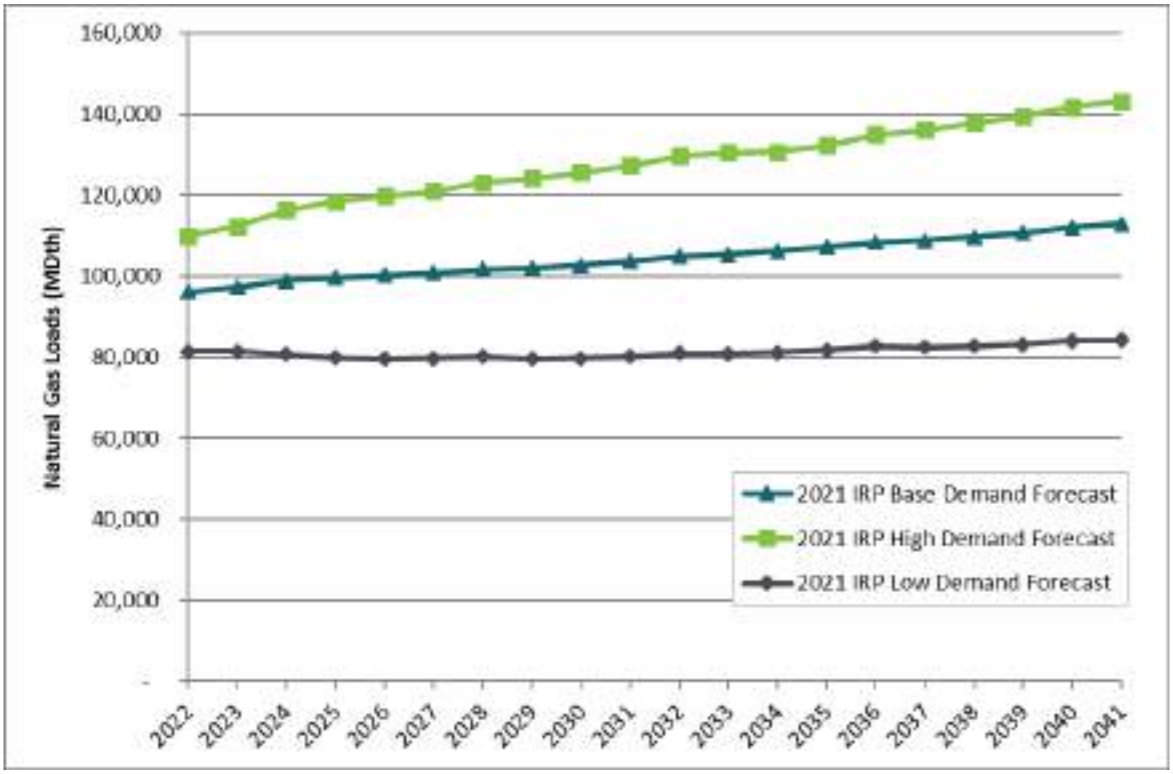


Figure 6-16: Natural Gas Energy Demand Forecast before Additional DSR (Table) Base, High and Low Scenarios without Transport (MDth)

2021 IRP NATURAL GAS ENERGY DEMAND FORECAST SCENARIOS (MDth), WITHOUT TRANSPORT						
Scenario	2022	2025	2030	2035	2041	AARG 2022-2041
2021 IRP Base Demand Forecast	96,156	99,653	102,769	107,195	112,918	0.8%
2021 IRP High Demand Forecast	110,024	118,424	125,542	132,321	143,261	1.4%
2021 IRP Low Demand Forecast	81,498	79,852	79,680	81,707	84,266	0.2%

Natural Gas Peak Demand

The natural gas design peak day is modeled at 13 degrees Fahrenheit average temperature for the day. Only firm sales customers are included when forecasting peak natural gas demand; transportation and interruptible customers are not included.

For peak natural gas demand, the 2021 IRP Base Demand Forecast projects an average increase of 0.8 percent per year from 2022 to 2041; peak demand would rise from 967 MDth in 2022 to 1,130 MDth in 2041. The High Demand Forecast projects a 1.1 percent annual growth rate, and the Low Demand Forecast projects 0.6 percent.

Figure 6-17: Natural Gas Peak Day Demand Forecast before Additional DSR Base, High and Low Scenarios (13 Degrees, MDth)

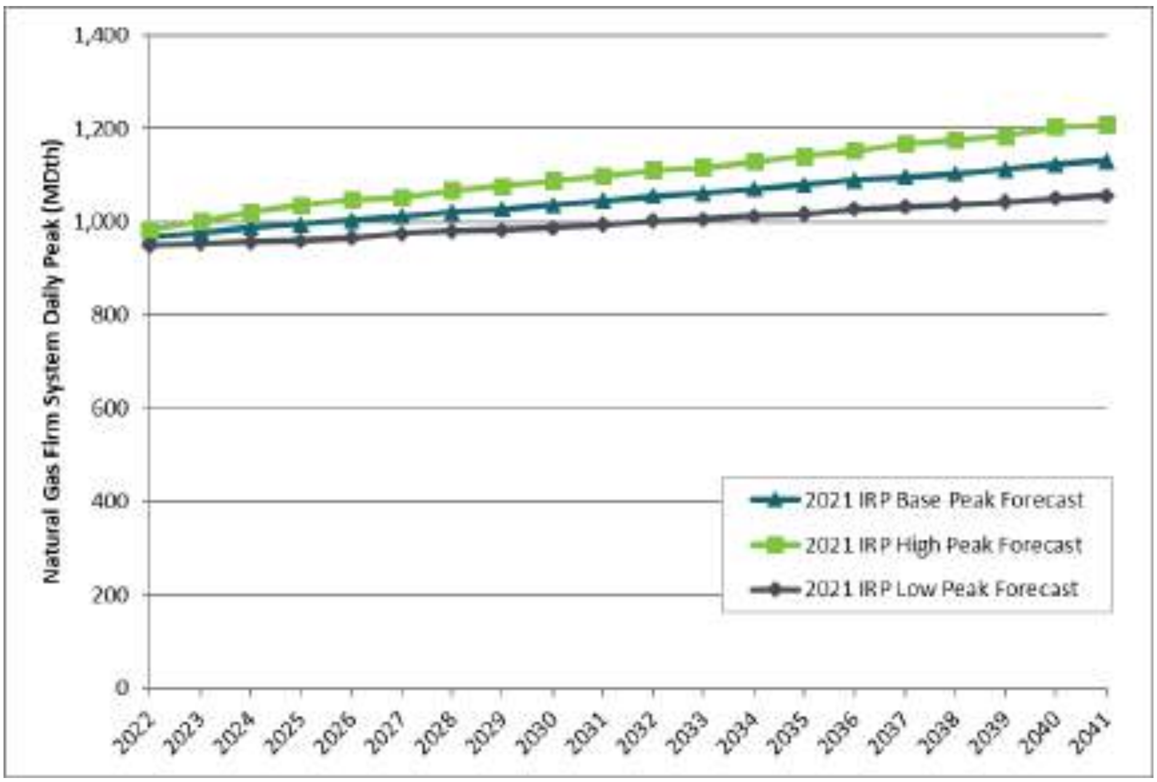


Figure 6-18: Natural Gas Peak Day Demand Forecast before Additional DSR (Table)
Base, High and Low Scenarios (13 Degrees, MDth)

2021 IRP FIRM NATURAL GAS PEAK DAY FORECAST SCENARIOS (MDth)						
Scenario	2022	2025	2030	2035	2041	AARG 2022-2041
2021 IRP Base Demand Forecast	967	995	1,036	1,079	1,130	0.8%
2021 IRP High Demand Forecast	984	1,036	1,088	1,141	1,208	1.1%
2021 IRP Low Demand Forecast	950	960	988	1,017	1,056	0.6%

The peak demand growth rate in the 2021 Base Demand Forecast is the same as the growth rate in the 2019 IRP Process (0.8 percent), but the highest levels of peak are lower in the 2021 IRP. This is partially due to the lower customer forecast, especially in the latter years of the forecast period, and the lingering effects of the COVID-19 pandemic in the first few years of the forecast period. Also, cold winter weather in 2018 and 2019 allowed the 2021 IRP natural gas peak forecast model to better capture the sensitivity of customers to cold weather.

Figure 6-19: Firm Natural Gas Peak Day Forecast before Additional DSR
2021 IRP Base Scenario versus 2019 IRP Process Base Scenario
Daily Annual Peak (13 Degrees, MDth)

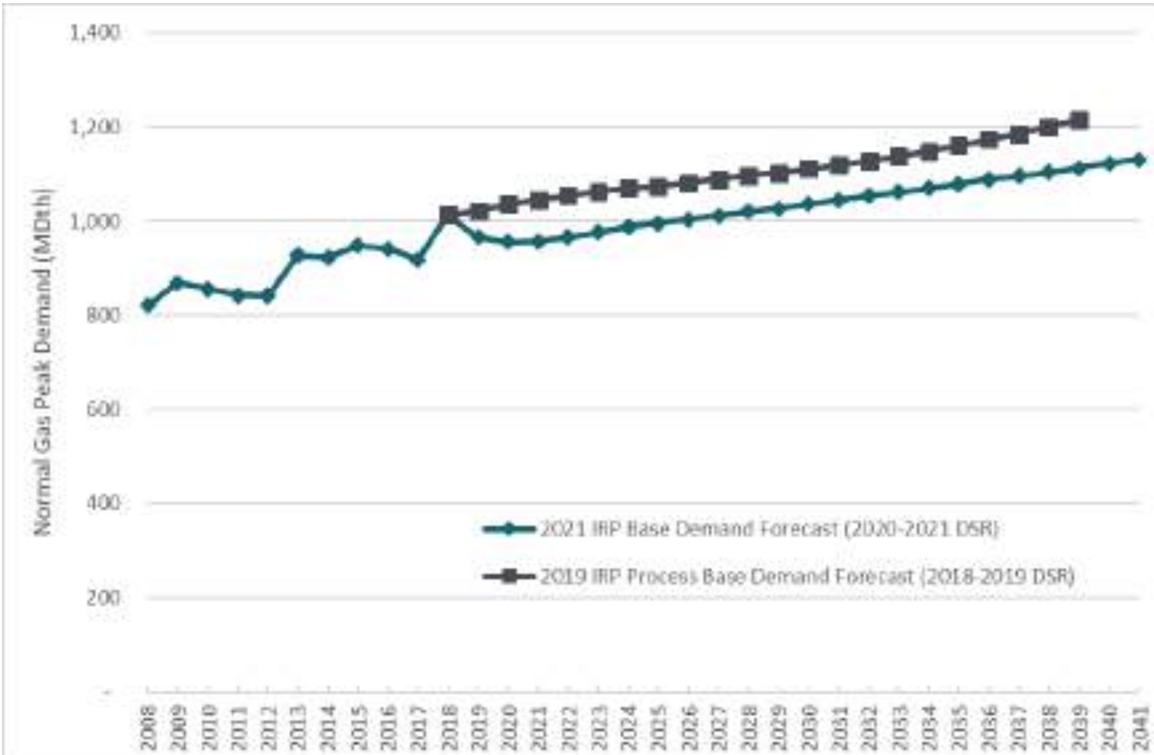


Illustration of Conservation Impacts

As explained at the beginning of the chapter, the natural gas demand forecasts include only demand-side resources implemented through December 2021, since the demand forecast itself helps to determine the most cost-effective level of DSR to include in the portfolio. To examine the effects of conservation on the energy and peak forecasts, the cost-effective amount of DSR determined in this IRP[3] is applied to the energy demand (without transport) and peak demand forecast for 2022 to 2041. To account for the 2017 General Rate Case, an additional 5 percent of conservation is also applied for that period. Forecasts with conservation are used internally at PSE for financial and system planning decisions. The results are illustrated in Figures 6-20 and 6-21, below.

DSR IMPACT ON ENERGY DEMAND. When the DSR bundles chosen in the 2021 IRP portfolio analysis are applied:

- Natural gas energy demand in 2041 is reduced 10.8 percent to 100,678 Mdth.
- Natural gas energy demand grows at an average annual rate of 0.26 percent from 2022 to 2041.

DSR IMPACT ON PEAK DEMAND. When the DSR bundles chosen in the 2021 IRP portfolio analysis are applied:

- Natural gas system peak demand in 2041 is reduced 9.8 percent to 1,019 Mdth.
- Natural gas system peak demand grows at an average annual rate of 0.3 percent from 2022 to 2041.

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3 / For demand-side resource analysis, see Chapter 9, Natural Gas Analysis, and Appendix E, Conservation Potential Assessment.

Figure 6-20: Natural Gas Base Demand Forecast for Energy, before Additional DSR and after Applying DSR

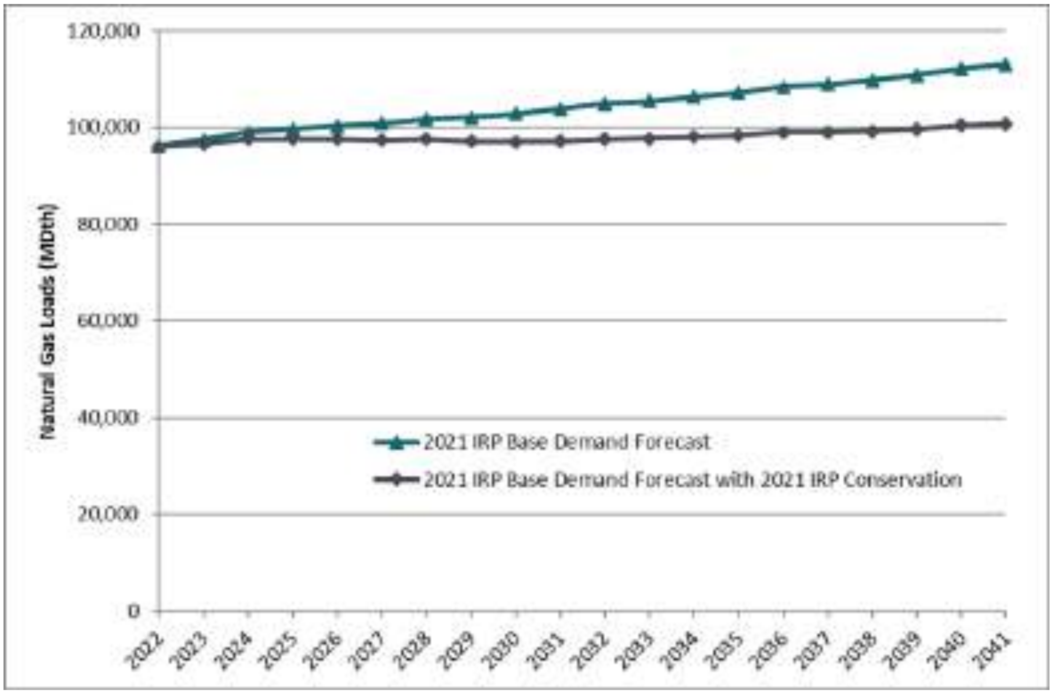
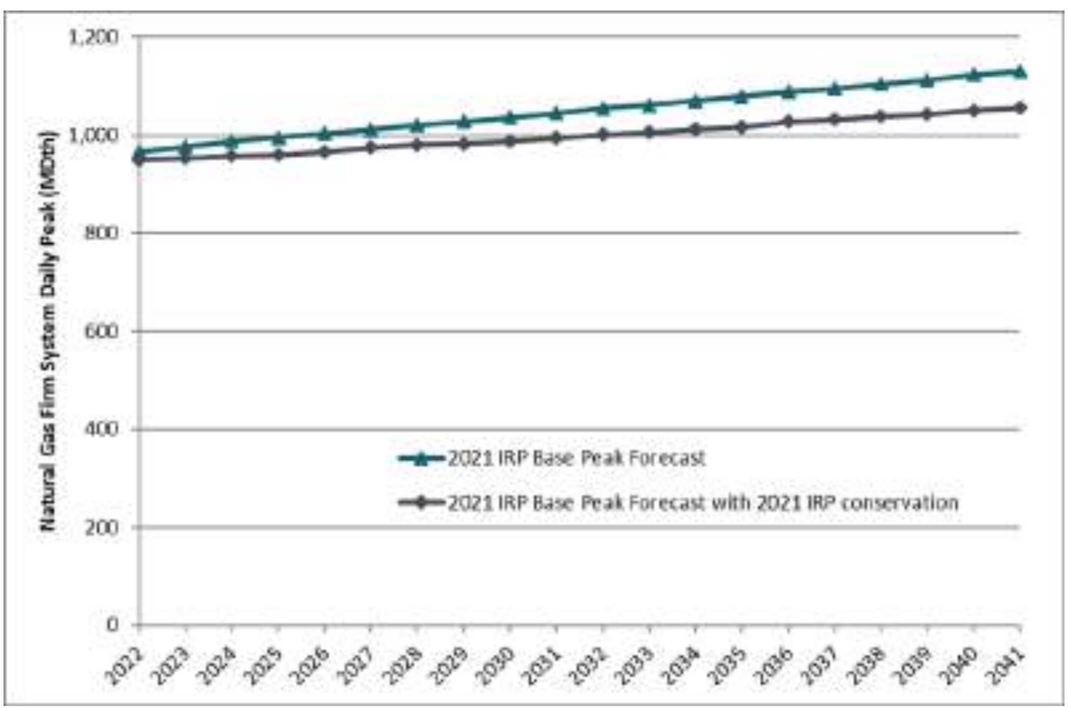


Figure 6-21: Natural Gas Peak Day Base Demand Forecast, before Additional DSR and after Applying DSR



Details of Natural Gas Forecast

Natural Gas Customer Counts

The Base Demand Forecast projects the number of natural gas customers will increase at a rate of 1.0 percent per year on average between 2022 and 2041, reaching 1.059 million customers by the end of the forecast period for the system as a whole. Overall, customer growth is slower than the 1.3 percent average annual growth rate projected in the 2019 IRP Process for 2020 to 2039.

Residential customer counts drive the growth in total customers, since this class makes up 93 percent of PSE's natural gas sales customers. Residential customer counts are expected to grow at an average annual rate of 1.0 percent from 2022 to 2041. The next largest group, commercial customers, is expected to grow at an average annual rate of 0.6 percent from 2022 to 2041. Industrial and interruptible customer classes are expected to continue to shrink, consistent with historical trends.

Figure 6-22: December Natural Gas Customer Counts by Class, 2021 IRP Base Demand Forecast

DECEMBER NATURAL GAS CUSTOMER COUNTS BY CLASS 2021 IRP BASE DEMAND FORECAST						
Customer Type	2022	2025	2030	2035	2041	AARG 2022-2041
Residential	817,317	845,918	892,765	939,222	993,155	1.0%
Commercial	57,264	58,444	60,095	61,734	63,666	0.6%
Industrial	2,244	2,191	2,103	2,016	1,910	-0.8%
Total Firm	876,825	906,553	954,963	1,002,972	1,058,731	1.0%
Interruptible	145	129	102	74	41	-6.4%
Total Firm & Interruptible	876,970	906,682	955,065	1,003,046	1,058,772	1.0%
Transport	225	225	225	225	225	0.0%
System Total	877,195	906,907	955,290	1,003,271	1,058,997	1.0%

Natural Gas Use per Customer

Table 6-23 below shows all firm use per customer at the meter.[4] Residential use per customer before conservation is slowly declining, showing a -0.1 percent average annual growth for the forecast period. Commercial use per customer is expected to rise 0.6 percent annually over the forecast horizon. Industrial use per customer has been declining in recent years and is expected to stay relatively flat. Note the commercial and industrial classes do not include interruptible or transport class usage. These classes can have very different sized customers and therefore the use per customer value can be skewed by very large customers.

Figure 6-23: Natural Gas Use per Customer before Additional DSR
2021 IRP Gas Base Demand Forecast

NATURAL GAS USE PER CUSTOMER (THERMS/CUSTOMER) 2021 IRP BASE DEMAND FORECAST						
Customer	2022	2025	2030	2035	2041	AARG 2022-2041
Residential	784	783	766	763	765	-0.1%
Commercial	4,960	5,122	5,234	5,376	5,553	0.6%
Industrial	10,685	10,691	10,692	10,692	10,694	0.0%

4 / *Use per customer is defined as billed energy sales per customer, that is, the amount of energy consumed at the meter.*

Natural Gas Demand by Class

Total energy demand, including transport, is expected to increase at an average rate of 0.7 percent annually between 2022 and 2041. Residential demand, which is forecast to represent 53 percent of demand in 2022, is expected to increase on average by 0.9 percent annually during the forecast period. Commercial demand, which is forecast to represent 24 percent of demand in 2022, is expected to increase 1.2 percent on average annually.

Population growth is driving residential demand growth. Commercial demand growth is driven by increases in both customer counts and use per customer. Demand in the industrial and interruptible sectors is expected to decline as manufacturing employment in the Puget Sound area continues to slow. Demand from the transport class is expected to grow slowly over time.

Figure 6-24: Natural Gas Energy Demand by Class (MDth), 2021 IRP Base Demand Forecast before Additional DSR

NATURAL GAS DEMAND (MDth) BY CLASS 2021 IRP BASE DEMAND FORECAST						
Class	2022	2025	2030	2035	2041	AARG 2022-2041
Residential	62,949	65,092	67,228	70,454	74,690	0.9%
Commercial	28,039	29,645	31,133	32,857	34,991	1.2%
Industrial	2,390	2,335	2,242	2,149	2,038	-0.8%
Total Firm	93,379	97,072	100,604	105,460	111,719	0.9%
Interruptible	2,585	2,382	1,960	1,520	974	-5.0%
Total Firm and Interruptible	95,964	99,454	102,564	106,981	112,692	0.8%
Transport	22,169	22,445	22,414	22,574	22,948	0.2%
System Total before Losses	118,133	121,899	124,978	129,555	135,641	0.7%
Losses	237	244	250	260	272	-
System Total	118,370	122,143	125,228	129,815	135,912	0.7%

Natural Gas Customer Count and Energy Demand Share by Class

Customer counts as a percent of PSE's total natural gas customers are shown in Figure 6-25. Demand share by class is shown in Figure 6-26.

Figure 6-25: Natural Gas Customer Count Share by Class 2021 IRP Base Demand Forecast

NATURAL GAS CUSTOMER COUNT SHARE BY CLASS, 2021 IRP BASE DEMAND FORECAST		
Class	**Share in 2022**	**Share in 2041**
Residential	93.2%	93.8%
Commercial	6.5%	6.0%
Industrial	0.3%	0.2%
Interruptible	0.02%	0.004%
Transport	0.03%	0.02%

Figure 6-26: Natural Gas Demand Share by Class, 2021 IRP Base Demand Forecast before Additional DSR

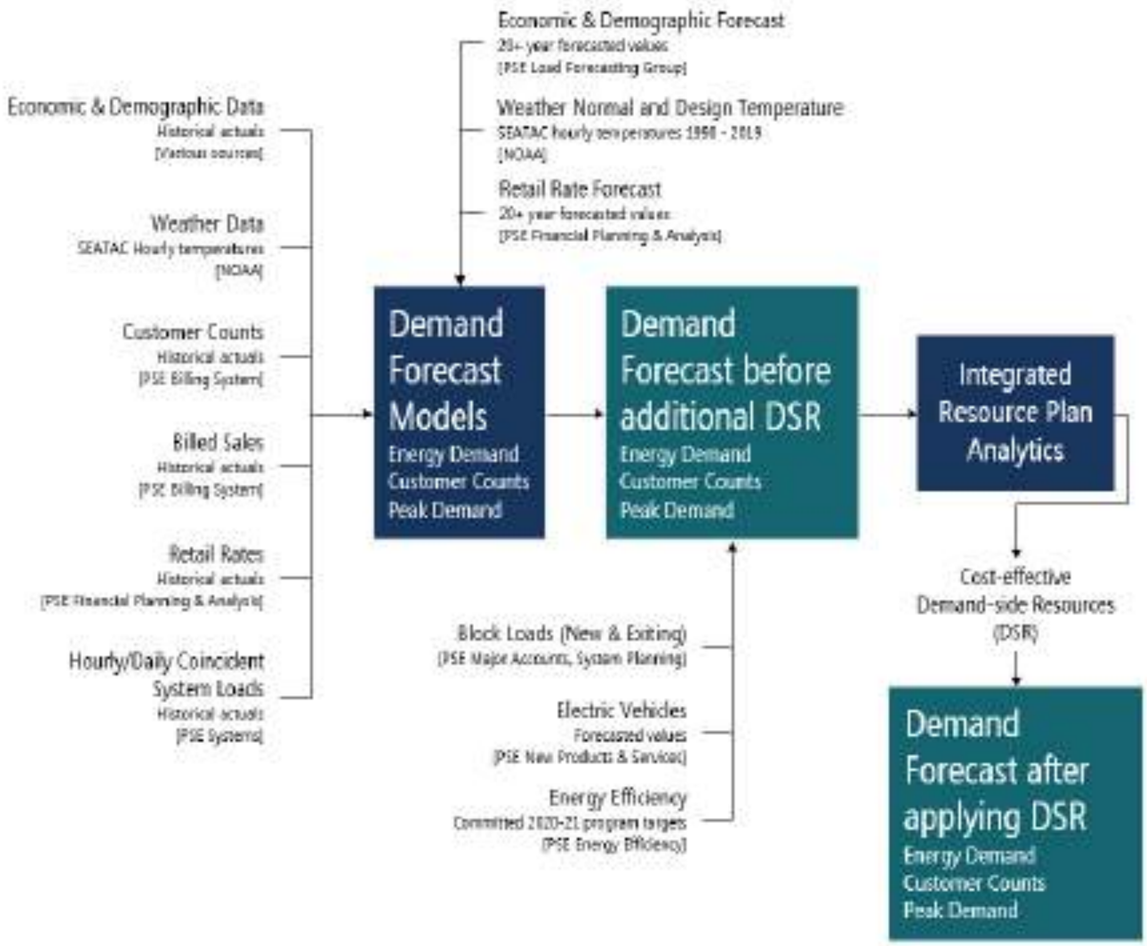
NATURAL GAS DEMAND SHARE BY CLASS, 2021 IRP BASE DEMAND FORECAST		
Class	**Share in 2022**	**Share in 2041**
Residential	53.2%	55.0%
Commercial	23.7%	25.7%
Industrial	2.0%	1.5%
Interruptible	2.2%	0.7%
Transport	18.7%	16.9%
Losses	0.2%	0.2%

4. METHODOLOGY

Forecasting Process

PSE's regional economic and demographic model uses both national and regional data to produce a forecast of total employment, types of employment, unemployment, personal income, households and consumer price index (CPI) for both the PSE electric and natural gas service territories. The regional economic and demographic data used in the model are built up from county level or metropolitan statistical area (MSA) level information from various sources. This economic and demographic information is combined with other PSE internal information to produce energy and peak demand forecasts for the service area. The demand forecasting process is illustrated in Figure 6-27, and the sources for economic and demographic input data are listed in Figure 6-28.

Figure 6-27: PSE Demand Forecasting Process



To forecast energy sales and customer counts, customers are divided into classes and service levels that use energy for similar purposes and at comparable retail rates. The different classes and/or service levels are modeled separately using variables specific to their usage patterns.

- Electric customer classes include residential, commercial, industrial, streetlights, resale and transport (customers purchasing their power not from PSE but from third-party suppliers).

- Natural gas customer classes include firm (residential, commercial, industrial, commercial large volume and industrial large volume), interruptible (commercial and industrial), and transport (commercial firm, commercial interruptible, industrial firm and industrial interruptible).

Transport Customers
"Transport" in the electric and natural gas industries has historically referred to customers that acquire their own electricity or natural gas from third-party suppliers and rely on the utility for distribution service. It does not refer to natural gas fueled vehicles or electric vehicles.

Multivariate time series econometric regression equations are used to derive historical relationships between trends and drivers, which are then employed to forecast the number of customers and use per customer by class or service level. These are multiplied together to arrive at the billed sales forecast. The main drivers of these equations include population, unemployment rates, retail rates, personal income, weather, total employment, manufacturing employment, consumer price index (CPI) and U.S. Gross Domestic Product (GDP). Demand, which is presented in this chapter, is calculated from sales and includes transmission and distribution losses in addition to sales. Weather inputs are based on temperature readings from Sea-Tac Airport. Peak system demand is also projected by examining the historical relationship between actual peaks, temperature at peaks, and the economic and demographic impacts on system demand.

> > > See Appendix F, Demand Forecasting Models*, for detailed descriptions of the econometric methodologies used to forecast billed energy sales, customer counts and peak loads for electricity and natural gas; hourly distribution of electric demand; and forecast uncertainty.*

Figure 6-28: Sources for U.S. and Regional Economic and Demographic Data

DATA USED IN ECONOMIC AND DEMOGRAPHIC MODEL	
County-level Data	**Source**
Labor force, employment, unemployment rate	U.S. Bureau of Labor Statistics (BLS) www.bls.gov
Total non-farm employment, and breakdowns by type of employment	WA State Employment Security Department (WA ESD), using data from Quarterly Census of Employment and Wages esd.wa.gov/labormarketinfo
Personal income	U.S. Bureau of Economic Analysis (BEA) www.bea.gov
Wages and salaries	
Population	WA State Employment Security Department (WA ESD) esd.wa.gov/labormarketinfo/report-library
Households, single- and multi-family	U.S. Census www.census.gov
Household size, single- and multi-family	
Housing permits, single- and multi-family	U.S. Census / Puget Sound Regional Council (PSRC) / City Websites / Building Industry Association of Washington (BIAW) www.biaw.com
Aerospace employment	Puget Sound Economic Forecaster www.economicforecaster.com
U.S.-level Data	**Source**
GDP	Moody's Analytics www.economy.com
Industrial Production Index	
Employment	
Unemployment rate	
Personal income	
Wages and salary disbursements	
Consumer Price Index (CPI)	
Housing starts	
Population	
Conventional mortgage rate	
T-bill rate, 3 months	

High and Low Scenarios

PSE also develops high and low growth scenarios by performing stochastic simulations with stochastic outputs from PSE's economic and demographic model, using historic weather to predict future weather.

- The natural gas high and low scenarios were modelled using 250 stochastic simulations.
- The electric high and low scenarios were created with an additional 60 simulations (for a total of 310), in order to capture variation in electric vehicle loads. The electric modeling also varied the seasonal design peak temperature.

The stochastic simulations reflect variations in key regional economic and demographic variables such as population, employment and income. They also vary the equation coefficients around the standard error of the coefficient to include potential model coefficient errors. In the electric scenarios, EV assumptions were held constant in 250 of the scenarios; a high EV forecast was applied to 30 scenarios; and a low EV forecast was applied to 30 scenarios. The high and low EV forecasts were derived using assumptions from the high and low EV scenarios in the July 2020 Pacific Northwest National Lab report, *Electric Vehicles at Scale – Phase I; Analysis: High EV Adoption Impacts on the Western U.S. Power Grid*. (The base EV forecast is described in more detail in Section 5 of this chapter, Chapter 5, Key Analytical Assumptions, and Chapter 4, Planning Environment.)

High and low growth scenarios also use historic weather scenarios that can reflect higher or lower temperature conditions. Historic weather scenarios use one year of weather data randomly drawn between 1990 and 2019 in each of the simulations. In contrast, the "normal" weather used for the base scenario is defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2019. The low and high scenarios represent the 10th and 90th percentile of the simulations, respectively.

The high and low scenarios are run in the AURORA model to examine how a portfolio would change with high and low growth. The 310 electric stochastic scenarios are run in the AURORA portfolio model to test the robustness of the portfolio under various conditions. The 250 natural gas stochastic scenarios are run in SENDOUT. Detailed descriptions of the stochastics are available in Chapter 8, Electric Analysis, and Chapter 9, Natural Gas Analysis.

*> > > **See Appendix F, Demand Forecasting Models**, for a detailed discussion of the stochastic simulations.*

Resource Adequacy Model Inputs

In addition to the stochastics used to create the high and the low scenarios, PSE also develops 88 electric demand draws for the resource adequacy (RA) model. These demand draws are created with stochastic outputs from PSE's economic and demographic model and two consecutive historic weather years to predict future weather. Each historic weather year from 1929 to 2017 is represented in the 88 demand draws. Since the RA model examines a hydro year from October through September, drawing two consecutive years preserves the characteristics of each historic heating season. RA demand draws were created for the hydro years of 2027 to 2028 and 2031 to 2032.

Additionally, the RA model examines adequacy in each hour of a given future year; therefore, the RA model inputs are scaled to hourly demand using the hourly demand model, described in detail in Chapter 7, Resource Adequacy Analysis. To account for growth in electric vehicles, each of the 88 hourly demand forecasts was first created without electric vehicle demand. Then the hourly forecast of electric vehicle demand was added to each demand forecast, to create the final 88 hourly demand forecasts.

> > > See Chapter 7, Resource Adequacy Analysis *and* ***Appendix F, Demand Forecasting Models****, for detailed discussions of the hourly model.*

Temperature Sensitivity

PSE committed to run a future temperature sensitivity as part of the IRP. To that end, in addition to the definition of normal temperature used for the base energy demand model, PSE offered three alternative average temperature assumptions to the IRP stakeholders and asked them to select one of the options for further analysis. The three options used different future temperature assumptions, representing a wide range of future outcomes. PSE then ran a sensitivity based on the option chosen.

The three temperature sensitivities presented as options were:

1. **15-year normal temperature:** PSE currently uses a 30-year normal for the base demand forecast. That is, the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2019. This normal weather is held constant into the future. The 15-year normal would instead use the most recent 15 years of weather data to create average monthly weather, and that weather would be held constant into the future. Option 1 results in the least amount of future warming.
2. **Historical trended temperature:** PSE contracted with Itron to examine the historic warming trend in temperatures at Sea-Tac Airport. The warming trend at Sea-Tac was determined to be linear over time at 0.4 degrees Fahrenheit warming per decade. This warming trend was then projected linearly into the future. A detailed write-up of this analysis is presented in Appendix L, Temperature Trend Study. Option 2 results in more future warming than Option 1, but less than Option 3.
3. **Council climate model:** A recent project by Bonneville Power Administration, U.S. Army Corps of Engineers, and the Bureau of Reclamation produced downscaled climate models for the Northwest region. The Northwest Power and Conservation Council (NWPCC) has been working with three of these models (CanESM2_BCSD, CCSM4_BCSD and CNRM-CM5_MACA). Each of these models is on the Representative Concentration Pathway of 8.5; some would argue this is a "business as usual" pathway, while others would argue that this is a more extreme climate warming scenario. The three models represent different amounts of warming over time. PSE presented the NWPCC model with the middle amount of warming (CCSM4_BCSD) as an option, which results in 0.9 degrees Fahrenheit of warming per decade. Option 3 represents a more extreme warming trend than Option 2.

Figure 6-29 below further describes the three future temperature options that IRP stakeholders chose from for this sensitivity.

Figure 6-29: Attributes of Temperature Sensitivity Options Compared to the Base Demand Forecast Temperatures Used

	Future Weather in Base Demand Model	Temperature Sensitivity Option 1	Temperature Sensitivity Option 2	Temperature Sensitivity Option 3
Description	30-year normal temperature	15-year normal temperature	Historical temperature trend (developed by Itron)	Council climate model
General Modeling Approach	Industry standard approach of using last 30 years of data to create flat projected temperature	Same methodology as 30-year normal, but using last 15 years of data	Uses historical warming trend to forecast future warming	Global Climate Model down-scaled to Pacific Northwest region
Weather Station Used	Sea-Tac	Sea-Tac	Sea-Tac	Sea-Tac
Historical Sea-Tac Weather Used	Last 30 years	Last 15 years	Data back to 1950 to develop a trend, 30-year normal used to define the starting point for the trend	Uses historic year of 1987 to map forecasted daily min and max temperatures to hourly temperatures
Global Climate Model, down-scaling method, and Representative Climate Pathway (RCP) assumed	NA	NA	NA, results similar to RCP 4.5	CCSM4_BCSD (Community Climate Systems Model v4: Bias Corrected Spatial Disaggregation), RCP 8.5
Energy Demand Modeling Approach	Uses last 30 years of data to create flat projected temperature for future	Uses last 15 years of data to create flat projected temperature for future	Uses historical trend to forecast warming trend in the future. Uses the middle of the last 30 years of weather as a starting point for weather trend.	Draw a trend line through the future temperatures to get warming per year. Uses the middle of the last 30 years of weather as a starting point for weather trend.
Average Warming in the Forecast Period for Energy Demand Modeling	0° F per decade	0° F per decade	0.4° F per decade	0.9° F per decade

To incorporate the future temperature options into the demand forecast, they first had to be converted into heating degree days (HDDs) and cooling degree days (CDDs). Heating and cooling degree days are a measure of how much heating or cooling is expected to be done by electric or natural gas appliances in a given month. Additional information on how to calculate heating and cooling degree days and how they factor into the demand forecast can be found in Appendix F, Demand Forecasting Models.

Figures 6-30 and 6-31 show the resulting heating degree days and cooling degree days from the three temperatures scenarios presented to the stakeholders compared to the current 30-year normal weather approach.

Figure 6-30: Annual Heating Degree Days (Base 65) for the Three Temperature Sensitivity Options Compared to 30-year Normal HDDs Used in the Base Demand Forecast

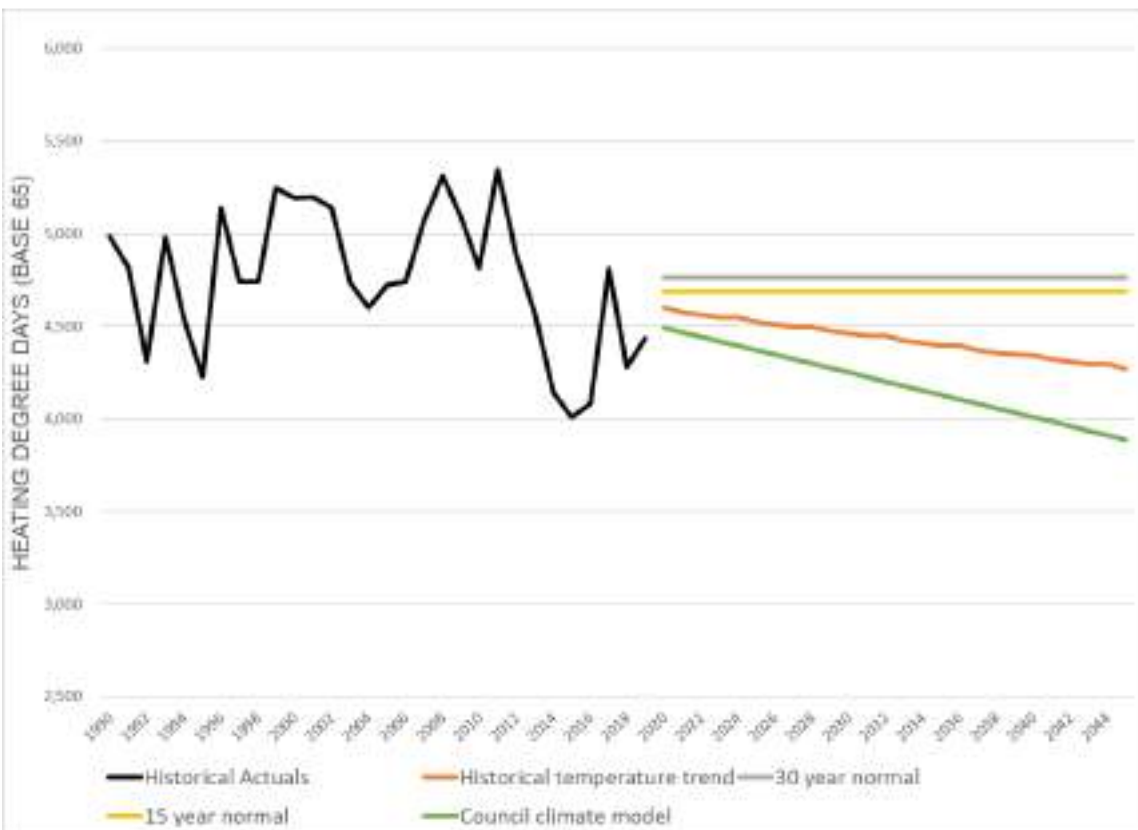
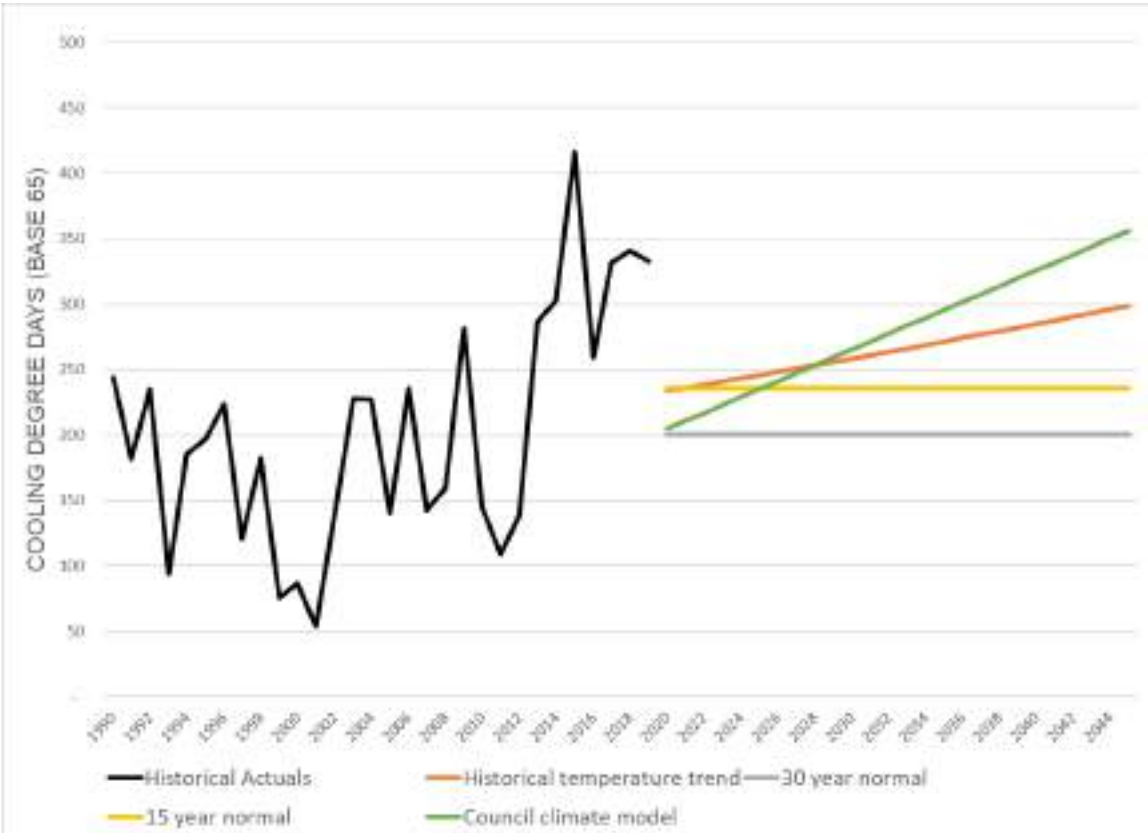


Figure 6-31: Annual Cooling Degree Days (Base 65) for the Three Temperature Sensitivity Options Compared to 30-year Normal HDDs Used in the Base Demand Forecast



Through the sensitivity prioritization process, stakeholders selected temperature sensitivity Option 3, which is based on the Northwest Power and Conservation Council climate model that assumes 0.9 degrees Fahrenheit warming per decade. Figures 6-32 and 6-33 compare the IRP base electric and natural gas energy demand forecasts with the forecasts that result from using this future temperature assumption.

With climate change, average temperatures are increasing over time. However, extreme weather events, both hot and cold, may still occur. Therefore, PSE did not change the peak temperature assumptions for this analysis, and therefore the peak demand did not change with this analysis.

In addition to the electric and gas energy demand forecasts, the electric RA model was run for this temperature sensitivity. The RA model examines a number of possible future conditions, including temperatures. The base RA model uses 88 historic temperature years: to create a wider range of possible future temperatures, PSE used all three of the NWPCC models, which mirrors the range of temperatures in NWPCC's RA analysis.

To create the RA model inputs temperatures from all three NWPCC models were used (CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA). Weather from the future decade in which the RA scenario takes place was used; that is, weather from 2020 through 2029 was used for the 2027 to 2028 RA model run, while weather from 2030 to 2039 was used for the 2031 to 2032 RA model run. The 10 years of weather from the three models was repeated almost three times and coupled with 88 economic and demographic draws to create 88 future hourly loads for the RA model.

Figure 6-32: Base Electric Energy Demand Forecast before Additional DSR Compared to Temperature Sensitivity Demand Forecast (aMW)

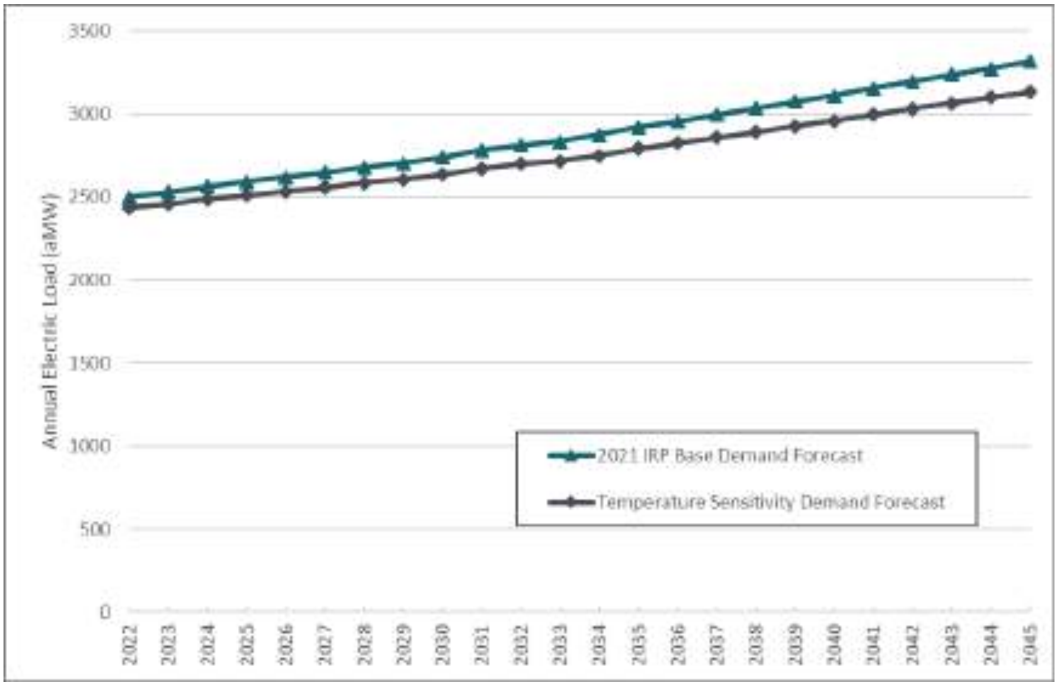
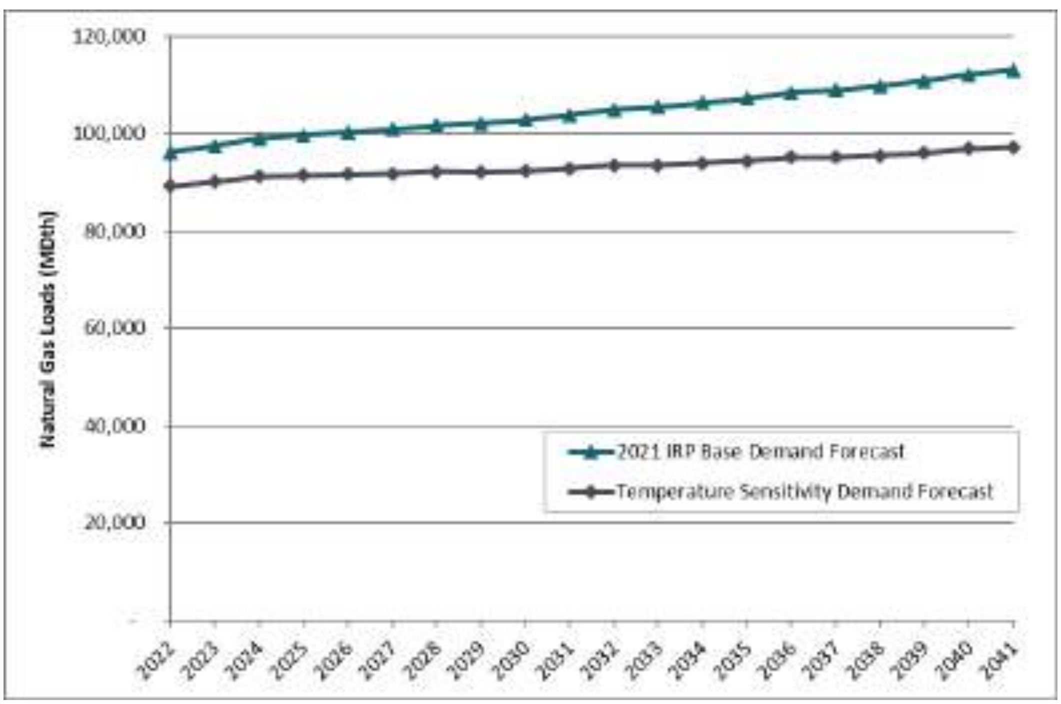


Figure 6-33: Base Natural Gas Energy Demand Forecast before Additional DSR Compared to Temperature Sensitivity Demand Forecast, without Transport Load (MDth)



Updates to Inputs and Equations

Updates to the demand forecast inputs and equations made since the 2019 IRP Process are summarized below.

POPULATION FORECAST. In previous IRPs, PSE has used Moody's forecast of U.S. population along with the economic and demographic model to forecast population in the electric and natural gas service areas. This has been under-forecasting population growth in the Puget Sound Area. In the 2021 IRP, population forecast is built up from county population forecasts that the Washington Employment Security Department (WA ESD) publishes. This better aligns the electric and natural gas forecasts of residential customers with population growth. Therefore, as population growth slows in the later part of the forecast period, the residential customer counts also slow.

ELECTRIC COMMERCIAL AND INDUSTRIAL CUSTOMER CLASSES. To better model the different segments of the electric commercial and industrial classes, the classes were broken out into smaller segments, including small/medium, large, high voltage and commercial lighting. Customer counts and use per customer were modeled for each segment individually, then added up to create the total customer counts and energy demand for each class.

SUMMER PEAK MODELING. The electric peak model was updated to include an index of air conditioning (AC) saturation in lieu of a linear trend as a proxy of past and future AC adoption. The AC index is created by using PSE's historical Residential Characteristics Survey (RCS) data points and calibrating to the U.S. Energy Information Administration (EIA) trend (West Region). The model driver was adopted to better track the non-linear nature of historical and future AC adoption.

MODELING SOFTWARE UPDATE. PSE transferred the demand forecast model from the Eviews application to energy forecasting software developed by Itron. The transition to Itron software enables PSE to manage the forecast input and output data in a database format (rather than separate Excel spreadsheets) and is modular in nature, organizing the forecasting steps in a consistent fashion across models. The modeling approach and methodology has not materially changed with this transition.

5. KEY ASSUMPTIONS

To develop PSE's demand forecasts, assumptions must be made about economic growth, energy prices, weather and loss factors, including certain system-specific conditions. These and other assumptions are described below.

Economic Growth

Economic activity has a significant effect on long-term energy demand. While the energy component of the national GDP has been declining over time, energy is still an essential input into various residential end uses such as space heating/cooling, water heating, lighting, cooking, dishwashing/clothes washing, electric vehicles and various other electric plug loads. The growth in residential building stock therefore directly impacts the demand for energy over time. Commercial and industrial sectors also use energy for space heating and cooling, water heating, lighting and for various plug loads. Energy is also an important input into many industrial production processes. Economic activities in the commercial and industrial sectors are therefore important indicators for the overall trends in energy consumption.

National Economic Outlook

Because the Puget Sound region is a major commercial and manufacturing center with strong links to the national economy, the IRP forecast begins with assumptions about what is happening in the broader U.S. economy. PSE relies on Moody's Analytics U.S. Macroeconomic Forecast, a long-term forecast of the U.S. economy for economic growth rates. The May 2020 Moody's forecast was used for this IRP.

The Moody's forecast calls for:

- A drop in employment and a sharp rise in unemployment in the second quarter of 2020 due to the COVID-19 pandemic. Unemployment stays above 6 percent until the first quarter of 2022, and is above 5 percent until the first quarter of 2023.
- After 2023 Moody's predicts the economy grows modestly as the U.S. population growth rate slows in the long term.
- U.S. GDP to continue to grow over the forecast period with 2.2 percent average annual growth from 2022 to 2045. This growth rate is higher compared to the Moody's forecast used in the 2019 IRP Process, which projected 2.0 percent average annual growth, but some of this growth is from the projected recovery from COVID-19.

- Average annual population growth of 0.4 percent for 2022-2045. This is down from the 0.6 percent growth rate Moody's forecast in the 2019 IRP Process for 2020-2039. However, this IRP did not use Moody's population projections because PSE's regional projections based on Moody's U.S. forecasts were consistently under-forecasting population growth in the electric and natural gas service areas. Instead, PSE used the Washington State Employment Security Department (WA ESD) population projections by county for the electric and natural gas service areas.

Moody's identified possible risks that could affect the accuracy of this forecast:[5]

- The Moody's forecast assumes that COVID-19 infections peak in May 2020 and begin to abate in July 2020. There is a downside risk if additional outbreaks occur, which are possible until a vaccine is widely available.
- Re-imposition of social distancing and forced business closures could derail any recovery that the economy has made.
- Moody's assumes that government and lawmakers provide monetary and fiscal responses to the pandemic to stabilize financial markets. The timing and size of this response is critical for determining the shape of the recovery.
- Changes to the economies of other global powers could affect the U.S. economy, especially as the demand for goods and services changes with the pandemic.
- Retaliations to U.S. tariffs could cause lower U.S. and global growth.

Regional Economic Outlook

PSE prepares regional economic and demographic forecasts using econometric models based on historical economic data for the counties in PSE's service area and the macroeconomic forecasts for the United States.

PSE's service area covers more than 6,000 square miles, stretching from south Puget Sound to the Canadian border, and from central Washington's Kittitas Valley west to the Kitsap Peninsula. PSE serves more than 1.1 million electric customers and more than 840,000 natural gas customers in 10 counties.

Within PSE's service area, demand growth is uneven. Most of the economic growth is driven by growth in the high tech, information technology or retail (including online retail) sectors; supporting industries like leisure and hospitality employment are also growing. Job growth is concentrated in King County, which accounts for half or more of the system's electric and

5 / Moody's Analytics (2020, May) Forecast Risks. Precis U.S. Macro. Volume 25 Number 2.

natural gas sales demand today. Other counties are growing, but typically more slowly, and have added fewer jobs.

Electric Scenario Outlooks: Base, High and Low

BASE SCENARIO OUTLOOK. The following forecast assumptions are used in the 2021 IRP Base Electric Demand Forecast scenario.

- Employment is expected to grow at an average annual rate of 0.6 percent between 2022 and 2045, which is the same as the annual growth rate forecasted in the 2019 IRP Process.
- Local employers are expected to create about 310,000 total jobs between 2022 and 2045, mainly driven by growth in the commercial sector, compared to about 257,000 jobs forecasted in the 2019 IRP Process.
- Manufacturing employment is expected to decline by 0.1 percent annually on average between 2022 and 2045 due to the outsourcing of manufacturing processes to lower wage or less expensive states or countries, and due to the continuing trend of capital investments that create productivity increases.
- An inflow of 975,000 new residents (by birth or migration) is expected to increase the local area population to 5.3 million by 2045, for an average annual growth rate of 0.9 percent. This growth rate is not constant over time, and the population growth rate is expected to be higher in the near term and lower in the long term. However, on average, this growth rate is higher than the 2019 IRP Process forecast, which projected an average annual population growth of 0.6 percent that would have resulted in 4.6 million electric service area residents by 2039. The 2021 forecast has a different growth rate because the population forecast in this IRP is based on the WA ESD forecast of population instead of Moody’s population forecast.

Local economists at Western Washington University have identified possible risks to the regional economy:[6, 5]

- It is unknown when the COVID-19 vaccine will achieve widespread immunity.
- Employers are taking on debt to make ends meet as their customers are spending less.
- Unforeseen layoffs from struggling businesses could slow economic recovery.
- Political and social unrest will have unknown effects on the economy.
- Lingering U.S.-China tension could affect the economy.

HIGH SCENARIO OUTLOOK. For the Electric High Demand Forecast scenario, population grows by 1.1 percent annually from 2022 to 2045, and employment grows by 0.8 percent per year during that period.

LOW SCENARIO OUTLOOK. For the Electric Low Demand Forecast scenario, population grows by 0.7 percent annually from 2022 to 2045. Employment grows 0.3 percent annually from 2022 to 2045.

The Base, High and Low population and employment forecasts for PSE's electric service area are compared in Figures 6-34 and 6-35.

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5 / Western Washington University Center of Economic and Business Research (2020, June) Regional Outlook. Puget Sound Economic Forecaster. Volume 28 Issue 2.

6 / Western Washington University Center of Economic and Business Research (2020, March) Regional Outlook. Puget Sound Economic Forecaster. Volume 28 Issue 1.

Figure 6-34: Population Growth, Electric Service Counties

2021 IRP POPULATION GROWTH, ELECTRIC SERVICE COUNTIES (1,000s)							
Scenario	2022	2025	2030	2035	2040	2045	AARG 2022-2045
2021 IRP Base Demand Forecast	4,334	4,482	4,715	4,936	5,134	5,310	0.9%
2021 IRP High Demand Forecast	4,398	4,609	4,902	5,158	5,398	5,609	1.1%
2021 IRP Low Demand Forecast	4,267	4,363	4,536	4,723	4,869	4,989	0.7%

Figure 6-35: Employment Growth, Electric Service Counties

2021 IRP EMPLOYMENT GROWTH, ELECTRIC SERVICE COUNTIES (1,000s)							
Scenario	2022	2025	2030	2035	2040	2045	AARG 2022-2045
2021 IRP Base Demand Forecast	2,172	2,268	2,327	2,385	2,436	2,482	0.6%
2021 IRP High Demand Forecast	2,365	2,488	2,562	2,669	2,744	2,814	0.8%
2021 IRP Low Demand Forecast	1,996	2,047	2,088	2,103	2,145	2,159	0.3%

Natural Gas Scenario Outlooks: Base, High and Low

BASE SCENARIO OUTLOOK. In the Base Natural Gas Demand Forecast scenario, population grows by 1.0 percent annually from 4.5 million people in 2022 to 5.45 million people by 2041. Employment is expected to grow by 1.2 percent annually from 2022 to 2041.

HIGH SCENARIO OUTLOOK. For the High Natural Gas Demand Forecast scenario, population grows by 1.2 percent annually from 2022 to 2041, and employment grows by 2.1 percent per year during that period.

LOW SCENARIO OUTLOOK. For the Low Natural Gas Demand Forecast scenario, population grows 0.8 percent annually from 2022 to 2041, and employment grows 0.2 percent annually.

The Base, High and Low population and employment forecasts for PSE's natural gas sales service area are compared in Figures 6-36 and 6-37.

Figure 6-36: Population Growth, Natural Gas Service Counties

2021 IRP POPULATION GROWTH, NATURAL GAS SERVICE COUNTIES (1,000s)						
Scenario	2022	2025	2030	2035	2041	AARG 2022-2041
2021 IRP Base Demand Forecast	4,542	4,703	4,953	5,197	5,452	1.0%
2021 IRP High Demand Forecast	4,619	4,842	5,159	5,437	5,766	1.2%
2021 IRP Low Demand Forecast	4,461	4,575	4,769	4,955	5,146	0.8%

Figure 6-37: Employment Growth, Natural Gas Service Counties

2021 IRP EMPLOYMENT GROWTH, NATURAL GAS SERVICE COUNTIES (1,000s)						
Scenario	2022	2025	2030	2035	2041	AARG 2022-2041
2021 IRP Base Demand Forecast	2,225	2,368	2,497	2,628	2,780	1.2%
2021 IRP High Demand Forecast	2,478	2,748	3,043	3,257	3,655	2.1%
2021 IRP Low Demand Forecast	1,975	1,987	1,989	2,022	2,042	0.2%

Other Assumptions

Weather

For the IRP Base Demand scenario, the energy demand forecast is based on normal weather, defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2019. The 2021 IRP forecast methodology, as described in this chapter and Appendix F, Demand Forecasting Models, employs various thresholds of heating and cooling degree days, consistent with industry practices. Employing monthly degree days helps estimate the amount of weather-sensitive demand in the service area. PSE rolls forward the 30-year period employed in each IRP to capture recent climate conditions. To create the High and Low Demand Forecasts historic monthly temperature observations are used to project a distribution of possible future temperature-sensitive demand, thereby modeling a wider range of warmer and colder conditions than the Base Demand Forecast.

In this IRP, PSE is including a temperature sensitivity that explores how changing heating and cooling degree days could affect loads in the future as the climate warms. This sensitivity is described in detail in Chapter 5, Key Analytical Assumptions.

Additionally, PSE is following and participating in the regional efforts of the Northwest Power and Conservation Council to include climate change in its planning process. These efforts include both forecasting future temperatures as well as considering secondary effects of climate change on population and economic growth. Future IRPs will incorporate climate change impacts as regionally accepted information becomes available.

COVID-19 Adjustments

In early March 2020, the COVID-19 pandemic reached the Puget Sound region in earnest. The governor issued a “Stay Home, Stay Healthy” order on March 23 that had immediate impacts on the local economy. To account for the pandemic's effects on the economy, customer counts and demand, PSE incorporated the May 2020 Moody's Analytics economic forecast, the most current Moody's forecast at the time the IRP forecast was developed. Moody's forecast included the following economic and epidemiological assumptions about the severity of the disease and its effects on the economy: that new infections would abate in July 2020 without a second wave of infections; that unemployment would spike in 2Q 2020; and that the recovery from the resulting recession would last through 2023, when unemployment would return to around 5 percent.

The typical relationship between historic economic assumptions and the forecast was not able to capture all of the immediate impacts to the demand forecast for year 2020, so PSE made additional assumptions and adjustments to reflect the impacts of COVID-19 by tracking the observed effects on each customer class. For the commercial class, PSE assessed the potential impacts by building type, since some sectors of the economy were hit harder than others. Adjustments from these additional analyses were then aligned with the epidemiological assumptions made by Moody's May 2020 forecast.

After 2020, no additional adjustments were made above and beyond the effects of the economic forecast that was incorporated into the demand forecast using the macroeconomic variables. The result was a slow recovery over the following few years and a recovered economy by 2024, with lingering effects from the recession persisting thorough out the remainder of the forecast.

PSE performed stochastic simulations that varied the economic forecast around this base forecast. These included simulations with better and worse economic outcomes that were the basis for the high and low forecasts. Since the IRP determines the resource need starting in 2022, the high and low forecasts show alternative ways the pandemic could resolve in the future.

Loss Factors

The electric loss factor is 6.8 percent, compared to 7.1 percent in the 2019 IRP Process. The gas loss factor in this IRP is 0.2 percent, which is the same as the loss factor in the 2019 IRP Process. The loss factors assumed in the demand forecast are system-wide average losses during normal operations for the past 2 to 3 years.

Block Load Additions

Beyond typical economic change, the demand forecast also takes into account known major demand additions and deletions that would not be accounted for though typical load growth in the forecast. The majority of these additions are from major infrastructure projects. These additions to the forecast are called block loads and they use information provided by PSE's system planners. The adjustments to non-transport customers add 91.1 MW of connected demand by 2025 for the electric system as a whole. These block loads are included in the commercial class, and King County has the majority of the additions.

The natural gas forecast includes block loads of 0.1 MDth per day which are included in the industrial class.

Schedule Switching

In addition to block loads, PSE accounts for customers that switch between rate schedules. Customers that purchase their own electricity or natural gas are called transportation customers and they rely on PSE for distribution services. Because PSE is not responsible for acquiring supply resources for electric or natural gas transportation customers, in the IRP they are removed from the forecast before supply-side resource need is determined.

Interruptible Loads

PSE has 152 electric interruptible customers; six of these are commercial and industrial customers and 146 are schools. The school contracts limit the time of day when energy can be curtailed. The other customers represent 14 MW of coincident peak demand. In this IRP, PSE did not count the 14 MW of DR potential, but this will be included in future modeling.

For a number of natural gas customers, all or part of their volume is interruptible volume. The curtailment of interruptible gas volumes was assumed when forecasting peak natural gas demand.

Electric Vehicles

An electric vehicle (EV) forecast was created for PSE by Guidehouse in early 2020. The forecast assumes 60,000 customer-owned light duty EVs on the road in PSE's service area in 2022, increasing to 705,000 EVs in 2045. Annual energy sales from new electric vehicles total 83,000 MWh in 2022 and 1,960,000 MWh in 2045. Initially, 81 percent of this charging is assumed to occur on residential accounts, while the remaining 19 percent is assumed to occur through commercial accounts. During the forecast period this percentage changes as charging at commercial locations becomes more widely available, resulting in 56 percent charging on residential accounts and 44 percent charging on commercial accounts in 2045. Electric vehicles are an emerging technology, thus PSE anticipates this forecast will be revised on an ongoing basis in the future. The additional demand by electric vehicles grows to an 8 percent share of total peak demand by 2045, before including cost-effective DSR identified in the 2021 IRP. Figure 6-38 below shows the December evening peak demand and annual average energy demand from new electric vehicles. Figure 6-39 shows the forecast of electric vehicles as a percent of all vehicles purchased in the PSE service territory.

Figure 6-38: Electric Vehicle Peak Demand and Average Energy Demand from New Vehicles (aMW, MW)

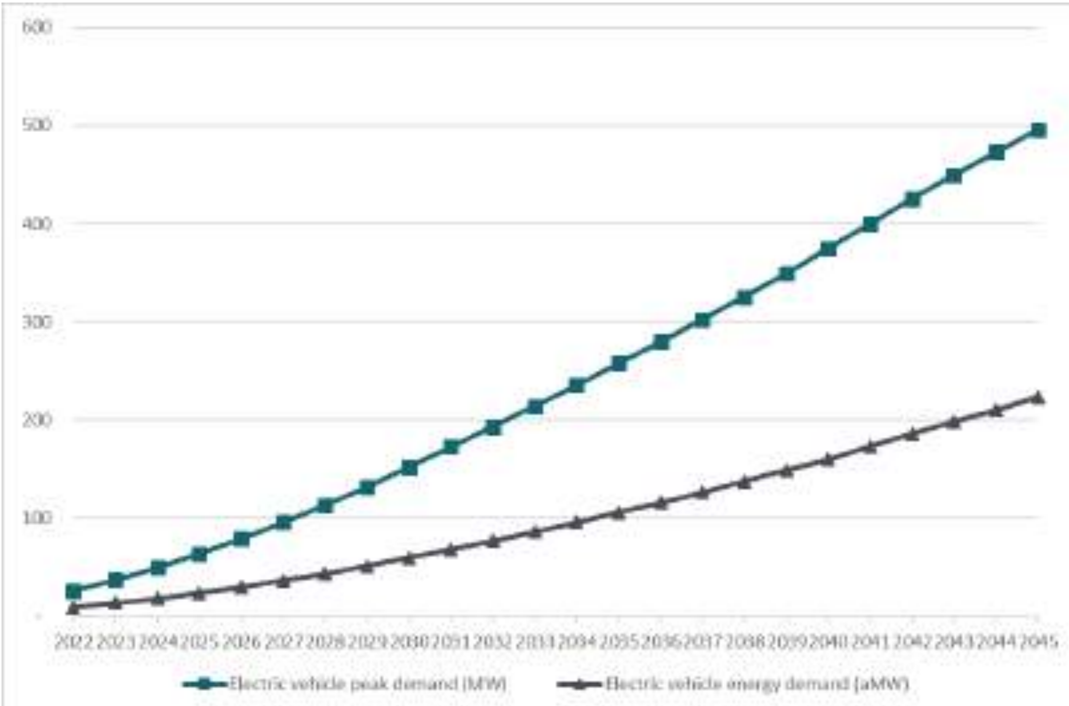
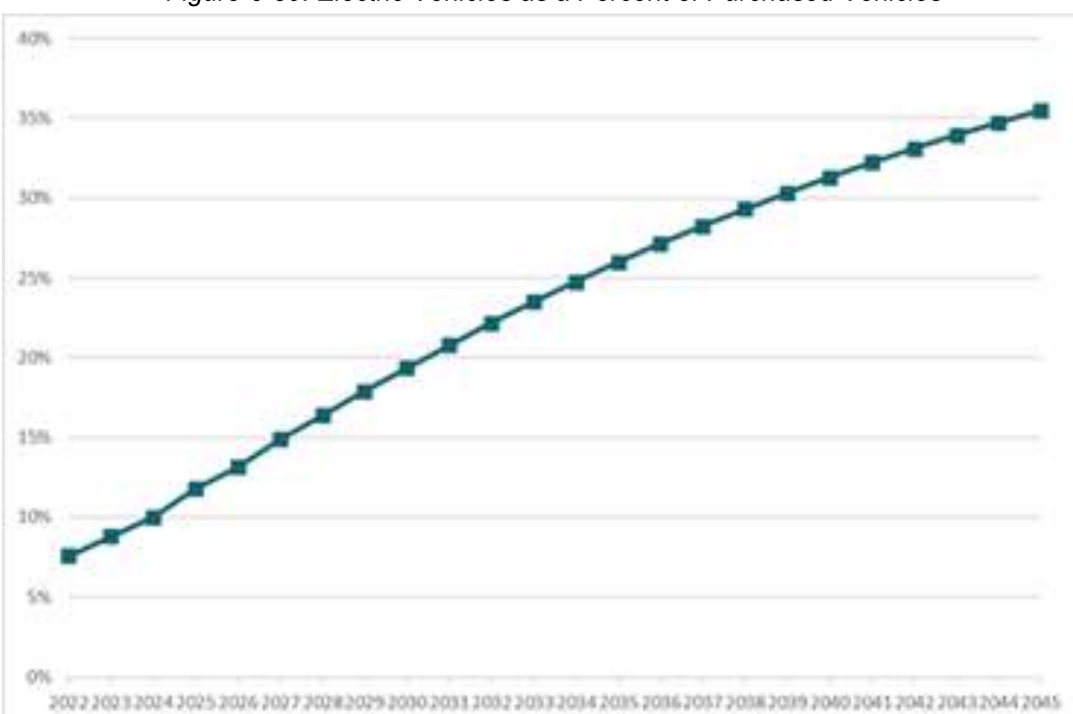


Figure 6-39: Electric Vehicles as a Percent of Purchased Vehicles



Compressed Natural Gas Vehicles

Compressed natural gas (CNG) vehicles were added to the 2021 IRP Natural Gas Base Demand Forecast. CNG vehicles include marine vessels, buses, light-duty vehicles, medium-duty vehicles and heavy-duty vehicles. In 2022, this adds 365 MDth to the forecast. This demand is expected to grow at an average annual rate of 3.5 percent, based on the Annual Energy Outlook 2019 published by the U.S. Department of Energy.

Retail Rates

Retail energy prices – what customers pay for energy – are included as explanatory variables in the demand forecast models, because in the long run, they affect customer choices about the efficiency level of newly acquired appliances, how those appliances are used, and the type of energy source used to power them. The energy price forecasts draw on information obtained from internal and external sources.

Distributed Generation

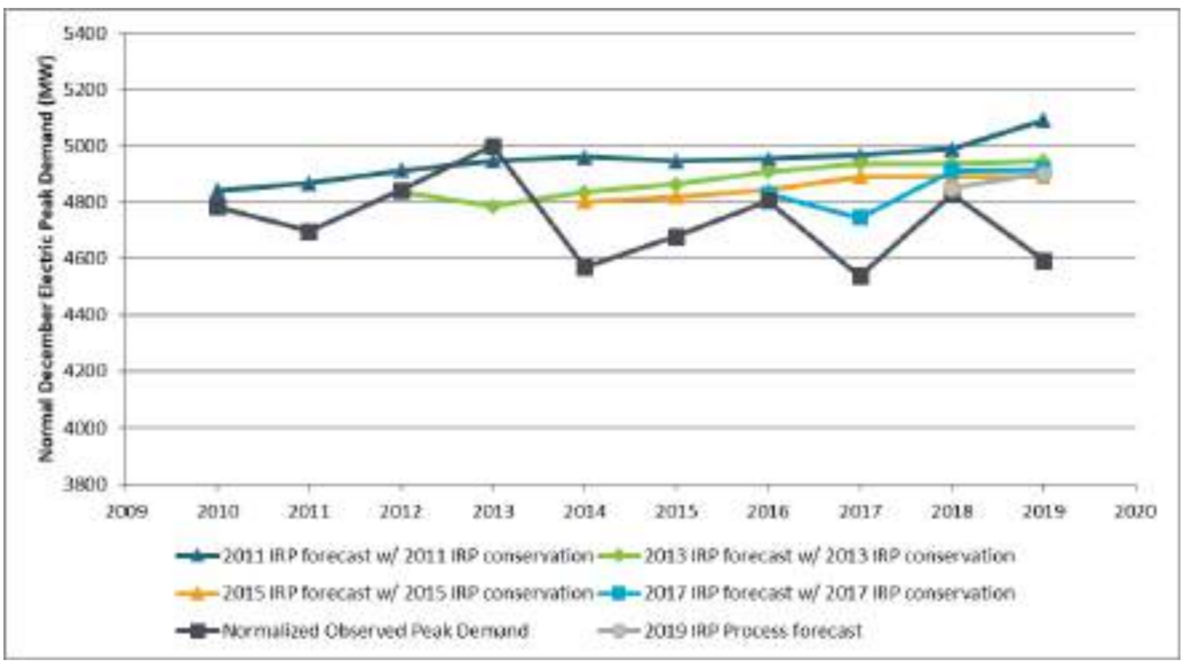
Distributed generation, including customer-level generation via solar panels, was not included in the demand forecast; this energy production is captured in the IRP modeling process as a demand-side resource. A description is included in the Appendix E, Conservation Potential Assessment and Demand Response Assessment.

6. RETROSPECTIVE OF PREVIOUS DEMAND FORECASTS

IRP Peak Demand Forecasts Compared to Actual Peaks

Figure 6-40 compares the 2011, 2013, 2015, 2017 and 2019 IRP Process electric Base Scenario peak demand forecasts after DSR with normalized[7] actual observations. The normalized actual observations account for peak hourly temperature, monthly HDDs, and the day of week and time of day the actual peak was observed. The percent difference of normalized actual values compared to each IRP forecast is presented for each year in Figure 6-41.

Figure 6-40: Observed Normalized Electric December Peak Demand Compared to Previous IRP forecasts



7 / *Given that the forecasts are for peaks at a design temperature, observed actual peaks are adjusted to reflect what would have been the peak if the design peak temperatures had been achieved.*

Figure 6-41: Observed Electric Peak Demand and Difference from Previous IRP Forecasts

ELECTRIC DECEMBER PEAK DEMAND % DIFFERENCE OF IRP FORECAST VERSUS WEATHER NORMALIZED ACTUAL OBSERVATION					
Year	2011 IRP	2013 IRP	2015 IRP	2017 IRP	2019 IRP Process
2010	1.2%				
2011	3.6%				
2012	1.5%	-0.1%			
2013	-1.0%	-4.3%			
2014	8.5%	5.8%	5.1%		
2015	5.7%	4.0%	3.0%		
2016	3.1%	2.1%	0.8%	0.5%	
2017	9.5%	8.8%	7.8%	4.6%	
2018	3.3%	2.3%	1.2%	1.7%	0.5%
2019	10.8%	7.7%	6.5%	7.1%	6.8%

Similarly, weather normalized actual natural gas peak demand is compared to the natural gas peak forecasts after conservation from the 2011, 2013, 2015, 2017 IRPs and the 2019 IRP Process in Figures 6-42 and 6-43.

Figure 6-42: Observed Weather Normalized Natural Gas Peak Demand Compared to Previous IRP Forecasts of Natural Gas Peak Demand

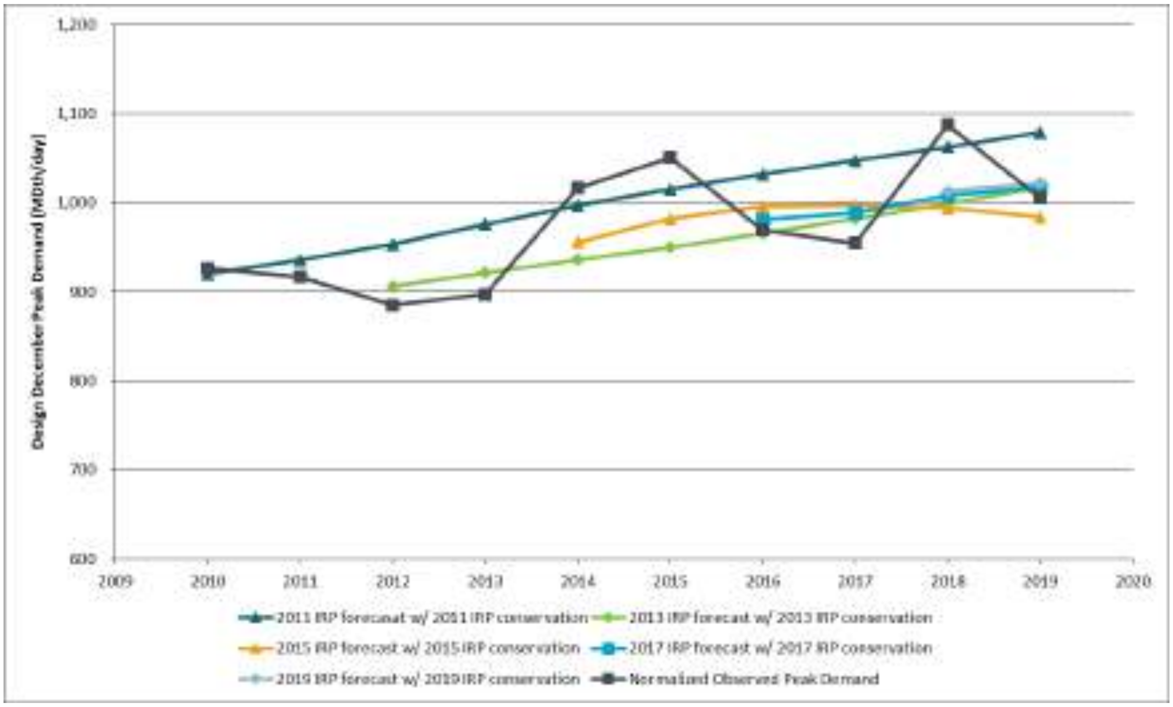


Figure 6-43: Observed Natural Gas Peak Demand and Difference from Previous IRP Forecasts

NATURAL GAS DECEMBER PEAK DEMAND % DIFFERENCE OF IRP FORECAST VERSUS WEATHER NORMALIZED ACTUAL OBSERVATION					
Year	2011 IRP	2013 IRP	2015 IRP	2017 IRP	2019 IRP Process
2010	-0.7%				
2011	2.0%				
2012	7.8%	2.4%			
2013	8.8%	2.7%			
2014	-2.0%	-7.9%	-5.6%		
2015	-3.4%	-9.6%	-6.1%		
2016	6.4%	-0.4%	3.2%	1.2%	
2017	9.7%	2.8%	5.0%	3.6%	
2018	-2.3%	-8.2%	-8.2%	-7.4%	-6.9%
2019	7.3%	1.1%	-1.7%	1.1%	1.6%

Reasons for Forecast Variance

As explained throughout this chapter, the IRP peak demand forecasts are based on forecasts of key demand drivers that include expected economic and demographic behavior, conservation, customer usage and weather. When these forecasts diverge from observed actual behavior, so does the IRP forecast. These differences are explained below.

Economic and Demographic Forecasts

Economic and demographic factors are key drivers for the IRP peak demand forecast. After the 2008 recession hit the U.S. economy, many economists, including Moody's Analytics, assumed that the economy would recover sooner than it did. A full recovery was pushed out with each successive forecast as the U.S. economy failed to bounce back to its previous state year after year. The charts below compare the Moody's forecasts of U.S. housing starts and population growth incorporated in the 2011 IRP through the 2019 IRP Process with actual U.S. housing starts and population growth. Moody's too-optimistic forecasts of housing starts and population growth during the recession led to over-estimated forecasts of customer counts. Since the 2019 IRP Process, forecasts of housing starts are no longer used as a driver in the demand forecast; instead, forecasts of population based on WA ESD data are now used to forecast population in PSE's service territories. The Moody's forecast of housing starts and population from May 2020 are included in the two charts below for comparison

Additionally, while the Moody's forecast used in the 2019 IRP Process did predict a softening of the economy in 2020, it did not forecast the magnitude of the effects from the COVID-19 pandemic. Therefore, Moody's forecasts used prior to the 2021 IRP have likely over-estimated economic growth in 2020 and the following few years. It is likely that the full extent of the pandemic's repercussions on the economy and energy demand will not be known during this IRP cycle.

Figure 6-44: Moody's Forecasts of U.S. Housing Starts Compared to Actual Housing Starts

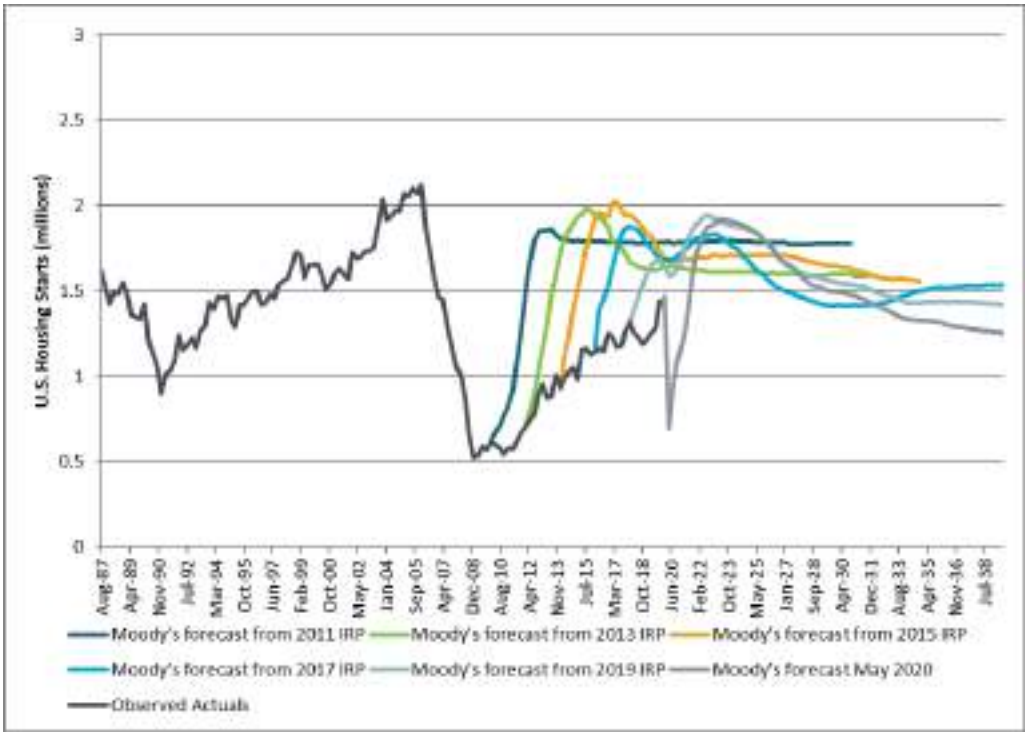
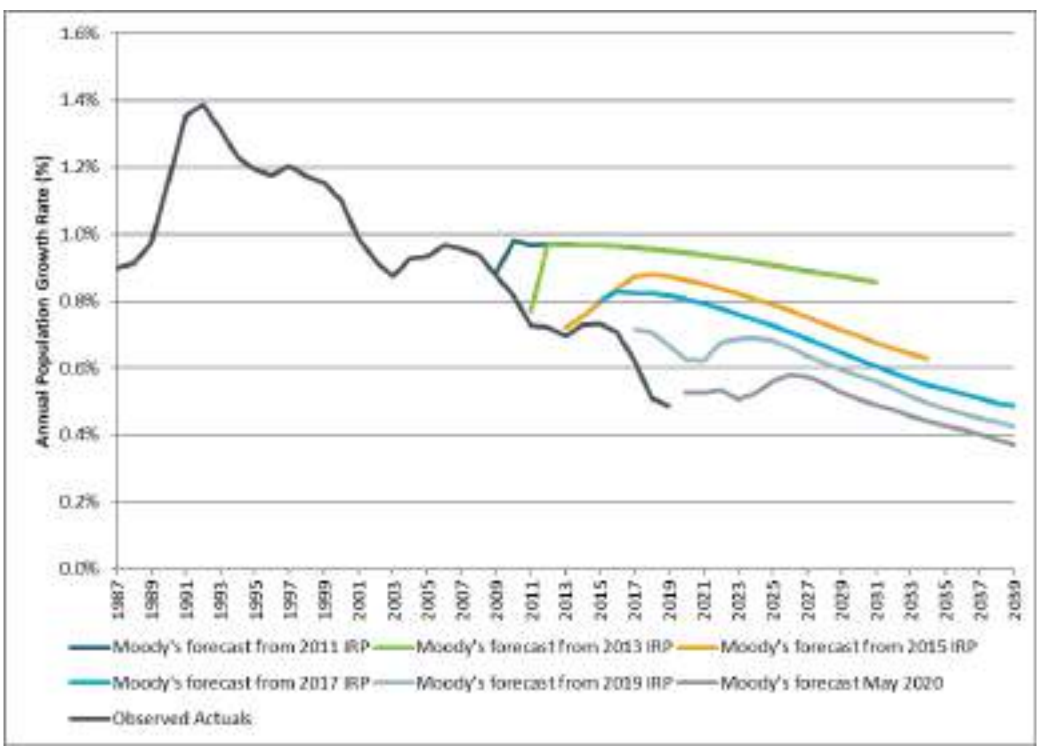


Figure 6-45: Moody's Forecasts of U.S. Population Growth Compared to Actual Population Growth



Conservation and Customer Usage

The comparison in Figures 6-40 and 6-42 of weather normalized peak observations to the IRP peak demand forecasts after conservation assumes that the forecasted conservation will be implemented. However, consumers can adopt energy efficient technologies that are above and beyond what is incentivized by utility-sponsored conservation programs and building codes and standards. This leads to more actual conservation taking place than forecasted. Additionally, conservation programs can change over time. Programs that were not cost effective in the past, and therefore not included in the optimal bundle, can be chosen in a later IRP as cost effective. This can make an older forecast out of date, making the forecast of conservation too low and therefore the load forecast after conservation too high.

Also, due to the Global Settlement from the 2013 General Rate Case (GRC) PSE and the 2017 GRC, PSE decisions accelerate electric and natural gas conservation, respectively, by 5 percent each year. This is additional conservation that is not taken into account in this comparison of IRP forecasts with normalized actuals.

Normal Weather Changes

Normal weather assumptions change from forecast to forecast. For each IRP, the normal weather assumption is updated by rolling off two older years of data and incorporating two new years of weather data into the 30-year average. Over time, normal heating degree days have been declining and normal cooling degree days have been increasing. As temperatures change over time, the forecast of demand with normal weather changes.

Additionally, over time our customers' weather sensitivity has been changing. As energy efficiency measures have been implemented, customers use less energy at a given temperature, including at peak temperatures. More recent forecasts reflect this change in weather sensitivity better than older forecasts.

Non-design Conditions during Observed Peaks

Peak values are weather normalized using the peak forecasting model. This model uses peak values from each month to create a relationship between peak demand, monthly demand and peak temperature. However, some of the observed December peaks shown above occurred on atypical days rather than typical days. For example, natural gas peaks in 2010, 2013, 2016, and 2017 fell on weekends. Natural gas peaks in 2010, 2012, and 2015 fell on New Year's Eve and the 2019 peak fell on Boxing Day (the day after Christmas). Additionally, in 2014, the electric peak fell on the Monday morning after Thanksgiving weekend, in 2015 it fell on New Year's Eve, and in 2019 it fell on the day after Christmas. Usage on these days is likely to be different than usage on a typical non-holiday weekday peak. Therefore, when these dates are weather normalized, they may not line up with the forecasted values since the usage patterns are atypical.

Service Area Changes

In March 2013, Jefferson County left the PSE service area. Jefferson County usage was included in the electric peak demand forecast in the 2011 IRP, therefore, when comparing that forecast to today's actuals, those forecasts would be expected to be higher than the actual peak demand.

This appendix provides an overview of PSE's resource adequacy modeling framework and how it aligns with other regional resource adequacy analyses.

Contents

1. OVERVIEW

The energy supply industry is in a state of transition as major decarbonization policies are implemented in most states. Significant amounts of coal-fired generation is being retired, and new intermittent, renewable generation is being constructed. These changes will cause PSE and other utilities to significantly change how they plan, especially with regard to resource adequacy. To maintain confidence in the wholesale market and ensure that sufficient resources are installed and committed, PSE, along with Northwest Power Pool members, is designing and implementing a regional resource adequacy program. The detailed design phase of the resource adequacy program is under way, with completion expected in mid-2021. As more details are understood, PSE will begin the evaluation of various resource adequacy elements in the resource adequacy analysis included in the 2021 IRP. At this time, the regional resource adequacy program has not been contemplated or included in the analysis described in this chapter.

In the past, relying on short-term wholesale energy markets has been a very cost-effective strategy for customers. This strategy also avoided building significant amounts of new baseload natural gas generation that might have created significant stranded cost concerns under the new policies. Recent experience shows that while wholesale electricity prices remain low, on average, in the Pacific Northwest (PNW), the region is starting to experience periods of high wholesale electricity prices and low short-term market liquidity.

In addition to the resource adequacy analysis, PSE has a completed a market risk assessment which evaluates the availability of short-term market purchases for peak capacity. It is important that PSE continue to closely monitor the region’s projected winter and summer season load/resource balance and any changes in the liquidity of the short-term market, and to update its assessment of the reliability of wholesale market purchases as conditions warrant.

2. 2021 IRP RESOURCE ADEQUACY ANALYSIS

Resource adequacy planning is used to ensure that all of PSE customer's load obligations are reliably met by building sufficient generating capacity, or acquiring sufficient capacity through contracts, to be able to meet customer demand with appropriate planning margins and operating reserves. The planning margin and operating reserves refer to capacity above customer demand that ensure the system has enough flexibility to handle balancing needs and unexpected events with minimal interruption of service. Unexpected events can be variations in temperature, hydro and wind generation, equipment failure, transmission interruption, potential curtailment of wholesale power supplies, or any other sudden departure from forecasts. Reliability requires that the full range of potential demand conditions are met even if the potential of experiencing those conditions is relatively low.

The physical characteristics of the electric grid are very complex, so for planning purposes, a 5 percent loss of load probability (LOLP) reliability metric is used to assess the physical resource adequacy risk. This planning standard requires utilities to have sufficient peaking resources available to fully meet their firm peak load and operating reserve obligations in 95 percent of simulations. Therefore, the likelihood of capacity being lower than load at any time in the year cannot exceed 5 percent. The 5 percent LOLP is consistent with the resource adequacy metric used by the Northwest Power and Conservation Council (NPCC).

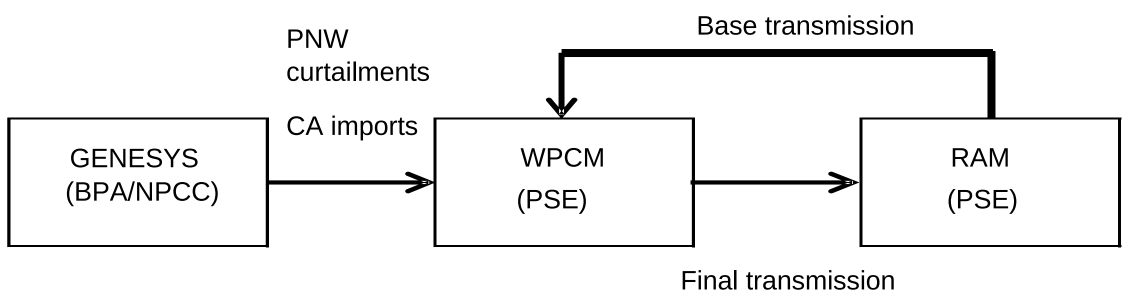
Quantifying the peak capacity contribution of a renewable and energy limited resource (its effective load carrying capacity or ELCC) is an important part of the analysis. The ELCC of a resource represents the peak capacity credit assigned to that resource. It is calculated in the resource adequacy model since this value is highly dependent on the load characteristics and the mix of portfolio resources. The ELCC of a resource is therefore unique to each utility. Since the ELCC is unique to each utility and dependent on load shapes and supply availability, it is hard to compare PSE's ELCC numbers with other entities. Some of the ELCCs are higher and some are lower, depending on PSE's needs, demand shapes and availability of the supply-side resources.

Resource Adequacy Modeling Approach

PSE's Resource Adequacy Model (RAM) is used to analyze load/resource conditions for PSE's power system. Since PSE relies on significant amounts of wholesale power purchases to meet peak need, the analysis must include evaluation of potential curtailments to regional power supplies. To accomplish this, the RAM integrates two other analyses into its results: 1) the GENESYS model developed by the NPCC and BPA, which analyzes regional level load/resource conditions, and 2) the Wholesale Purchase Curtailment Model (WPCM), developed by PSE, which analyzes the specific effects of regional curtailments on PSE's system. This allows us to evaluate PSE's ability to make wholesale market purchases to meet firm peak load and operating reserve obligations.

Figure 7-1 illustrates how the inputs and outputs of these models were linked. The outputs of the GENESYS Model provide inputs for both the WPCM model and the RAM/LOLP model. The RAM/LOLP model and WPCM models are used iteratively, with the final output of the RAM/LOLP model used in the next WPCM modelling run.

Figure 7-1: Market Reliability Analysis Modeling Tools



The GENESYS Model

The GENESYS model was developed by the NPCC and the Bonneville Power Administration (BPA) to perform regional-level load and resource studies. GENESYS is a multi-scenario model that incorporates 80 different years of hydro conditions, and as of the 2023 assessment, 88 years of temperature conditions. For the 2021 IRP, PSE started with the GENESYS model from the NPCC power supply adequacy assessment for 2023. When combined with thermal plant forced outages, the mean expected time to repair those units, variable wind plant generation and available imports of power from outside the region, the model determines the PNW's overall hourly capacity surplus or deficit in 7,040 multi-scenario "simulations." Since the GENESYS model includes all potentially available supplies of energy and capacity that could be utilized to meet PNW firm loads regardless of cost, a regional load-curtailment event will occur on any hour that has a capacity deficit.[1]

1 / Operating reserve obligations (which include unit contingency reserves and intermittent resource balancing reserves) are included in the GENESYS model. A PNW load-curtailment event will occur if the total amount of all available resources (including imports) is less than the sum of firm loads plus operating reserves.

Since the PNW relies heavily upon hydroelectric generating resources to meet its winter peak load needs, GENESYS incorporates sophisticated modeling logic that attempts to minimize potential load curtailments by shaping the region's hydro resources to the maximum extent possible within a defined set of operational constraints. GENESYS also attempts to maximize the region's purchase of energy and capacity from California (subject to transmission import limits of 3,400 MW) utilizing both forward and short-term purchases.

Since the GENESYS model was set for a 2023 assessment, PSE made some updates to capture regional load/resource changes in order to run the model for the years 2027 and 2031. The updates that PSE made to the GENESYS model include:

1. Updated coal plant retirements with retirement years listed in Figure 7-2.

Figure 7-2: Coal Plant Retirements Modeled

Plant	Year Retired in Model
Hardin	2018
Colstrip 1 & 2	2019
Boardman	2020
Centralia 1	2020
N Valmy 1	2021
N Valmy 2	2025
Centralia 2	2025
Jim Bridger 1	2023
Jim Bridger 2	2028
Colstrip 3 & 4	2025

2. Increased the year 2023 demand forecast using the escalation rate of 0.3 percent to the year 2027 and 2031. The escalation rate is from the NPCC demand growth after conservation.
3. Added planned resources from PSE's portfolio: Skookumchuck Wind (131 MW) and Lund Hill solar (150 MW).

PSE did not include any other adjustments to GENESYS for regional build and retirements, other than the updates described above, relying on the assumptions from NPCC already built into the model.

The Wholesale Purchase Curtailment Model (WPCM)

During a PNW-wide load-curtailment event, there is not enough physical power supply available in the region (including available imports from California) for the utilities of the region to fully meet their firm loads plus operating reserve obligations. To mimic how the PNW wholesale markets would likely operate in such a situation, PSE developed the WPCM as part of the 2015 IRP. The WPCM links regional events to their specific impacts on PSE's system and on PSE's ability to make wholesale market purchases to meet firm peak load and operating reserve obligations.

The amount of capacity that other load-serving entities in the region purchase in the wholesale marketplace has a direct impact on the amount of capacity that PSE would be able to purchase. Therefore, the WPCM first assembles load and resource data for both the region as a whole and for many of its individual utilities, especially those that would be expected to purchase relatively large amounts of energy and capacity during winter peaking events. For this analysis, PSE used the capacity data contained in BPA's *2018 Pacific Northwest Loads and Resources Study*, the latest BPA study available at the time this resource adequacy analysis was completed. Due to the pandemic, BPA's 2019 study was delayed and not available for this analysis.

BPA Loads and Resources Study for 2020–2029

BPA published its *2018 Pacific Northwest Loads and Resources Study* in April 2019. This study provided detailed information on BPA's forecasted loads and resources as well as overall loads and resources for the entire region.

The BPA forecast used a 120-hour sustained hydro peaking methodology and assumed that all IPP generation located within the PNW is available to serve PNW peak loads.

- For 2023, the BPA study forecasts an overall regional winter peak load deficiency of 3,056 MW.
- When BPA's 2023 winter capacity forecast is adjusted to include 3,400 MW of potentially available short-term imports, the 3,056 MW capacity deficit noted above would change to a 344 MW surplus.
- Looking forward to 2029 – based upon current information and assuming that all IPP generation will be available to serve PNW peak loads – BPA's forecast shows that the region will transition from a 2020 winter season peak load deficit of approximately 246 MW to a peak load deficit of approximately 4,891 MW in 2029.
- When BPA's 2029 capacity forecasts are adjusted to include 3,400 MW of short-term imports from California – which PSE assumed in its RAM – the region would transition from a 2020 winter capacity surplus of 3,054 MW to a peak load deficit of approximately 1,491 MW by 2029.

Again, the long-term winter capacity trend is perhaps more important than the exact surplus or deficit forecasted for 2023. The BPA forecast indicates, as does the Pacific Northwest Utilities Conference Committee (PNUCC) study, that the PNW may experience larger winter capacity deficits over time.

> > > BPA's *2018 Pacific Northwest Loads and Resources Study* can be found at: https://www.bpa.gov/p/Generation/White-Book/wb/2018-WBK-Loads-and-Resources-Summary-20190403.pdf

In October 2020, BPA published its *2019 Pacific Northwest Loads and Resources Study*. The study was completed after PSE finalized this resource adequacy analysis, so updated 2019 information could not be incorporated. PSE is reviewing the 2019 BPA study to assess its implications for the analysis.

Allocation Methodology

The WPCM then uses a multi-step approach to "allocate" the regional capacity deficiency among the region's individual utilities. These individual capacity shortages are reflected via a reduction in each utility's forecasted level of wholesale market purchases. In essence, on an hourly basis, the WPCM portion of the resource adequacy analysis translates a regional load-curtailment event into a reduction in PSE's wholesale market purchases. In some cases, reductions in PSE's initial desired volume of wholesale market purchases could trigger a load-curtailment event in the LOLP portion of RAM.

It should be noted that in actual operations, no central entity in the PNW is charged with allocating scarce supplies of energy and capacity to individual utilities during regional load-curtailment events.

FORWARD MARKET ALLOCATIONS. The model assumes that each of the five large buyers purchases a portion of their base capacity deficit in the forward wholesale markets. Under most scenarios, each utility is able to purchase their target amount of capacity in these markets. This reduces the amount of remaining capacity available for purchase in the spot markets. If the wholesale market does not have enough capacity to satisfy all of the forward purchase targets, those purchases are reduced on a pro-rata basis based upon each utility's initial target purchase amount.

SPOT MARKET ALLOCATIONS. For spot market capacity allocation, each of the five large utility purchasers is assumed to have equal access to the PNW wholesale spot markets, including available imports from California. The spot market capacity allocation *is not* based on a straight pro-rata allocation, because in actual operations the largest purchaser (which is usually PSE) would not be guaranteed automatic access to a fixed percentage of its capacity need. Instead, all of the large purchasers would be aggressively attempting to locate and purchase scarce capacity from the exact same sources. Under deficit conditions, the largest of the purchasers would tend to experience the biggest MW shortfalls between what they need to buy and what they can actually buy. This situation is particularly true for small to mid-sized regional curtailments where the smaller purchasers may be able to fill 100 percent of their capacity needs but the larger purchasers cannot.

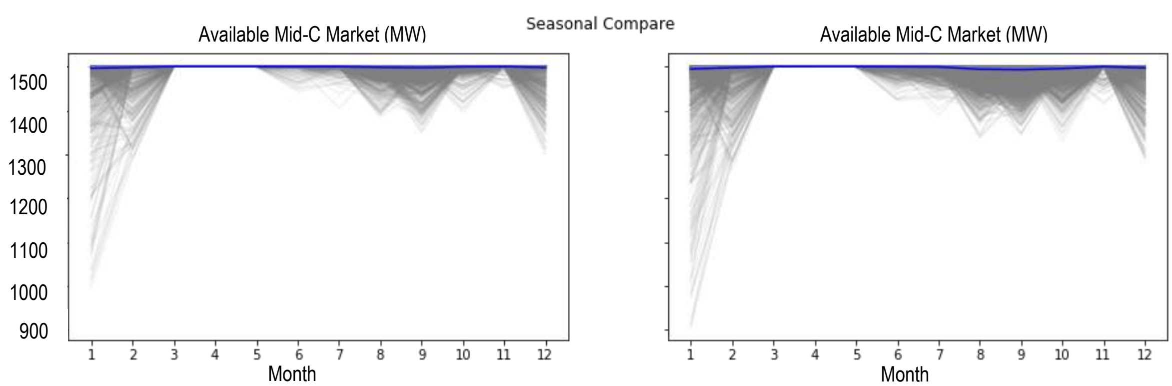
WPCM Outputs

For each simulation and hour in which the NPCC GENESYS model determines there is PNW load-curtailment event, the WPCM model outputs the following PSE-specific information:

- PSE's initial wholesale market purchase amount (in MW), limited only by PSE's overall Mid-Columbia (Mid-C) transmission rights.
- The curtailment to PSE's market purchase amount (in MW) due to the PNW regional capacity shortage.
- PSE's final wholesale market purchase amount (in MW) after incorporating PNW regional capacity shortage conditions.

Figure 7-3 shows the results of the WPCM. The charts illustrate the average of PSE's share of the regional deficiency. The results show the deficiency in each of the 7,040 simulations (gray lines) and the mean of the simulations (blue line). The mean deficiency is close to zero, but in some simulations the market purchases may be limited by 500 MW (in January 2027) and 600 MW (in January 2031). This means that of the 1,500 MW of available Mid-C transmission, PSE was only able to fill 1,000 MW in January 2027.

Figure 7-3: Reduction to Available Mid-C Market



In addition to the WPCM results that are included in PSE's resource adequacy analysis, PSE also conducted a separate market risk assessment. That assessment is described later in this chapter.

The Resource Adequacy Model (RAM)

PSE’s probabilistic Resource Adequacy Model enables PSE to assess the following.

1. To quantify physical supply risks as PSE’s portfolio of loads and resources evolves over time
2. To establish peak load planning standards, which in turn leads to the determination of PSE’s capacity planning margin
3. To quantify the peak capacity contribution of a renewable and energy-limited resource (its effective load carrying capacity, or ELCC)

The RAM allows for the calculation of the following risk metrics.

- **Loss of load probability (LOLP)**, which measures the *likelihood of a load curtailment event occurring* in any given simulation regardless of the frequency, duration and magnitude of the curtailment(s).
- **Expected unserved energy (EUE)**, which measures outage magnitude in MWh and is the *sum of all unserved energy/load curtailments across all hours and simulations divided by the number of simulations.*
- **Loss of load hours (LOLH)**, which measures outage duration and is *the sum of the hours with load curtailments divided by the number of simulations*.
- **Loss of load expectation (LOLE)**, which measures the *average number of days per year with loss of load* due to system load exceeding available generating capacity.
- **Loss of load events (LOLEV)**, which measures the *average number of loss of load events per year*, of any duration or magnitude, due to system load exceeding available generating capacity.

Capacity planning margins and the effective load carrying capability for different resources can be defined using any of these five risk metrics, once a planning standard has been established.

3. CONSISTENCY WITH REGIONAL RESOURCE ADEQUACY ASSESSMENTS

PSE's reliance on market purchases requires that our resource adequacy modeling also reflect regional adequacy conditions, so consistency with the NPCC's regional GENESYS resource adequacy model is needed in order to ensure that the conditions under which the region may experience capacity deficits are properly reflected in PSE's modeling of its own loads, hydro and thermal resource conditions in the RAM.

PSE's RAM operates much like the GENESYS model. Like GENESYS, PSE's RAM is a multi-scenario model that varies a set of input parameters across 7,040 individual simulations; the result of each simulation is PSE's hourly capacity surplus or deficiency. The LOLP, EUE and LOLH for the PSE system are then computed across the 7,040 simulations.

The multi-scenario simulations made in PSE's resource adequacy model are consistent with the 7,040 simulations made in the NPCC's GENESYS model in terms of temperature and hydro conditions.

The existing resources used by PSE included in this analysis are Mid-Columbia purchase contracts and western Washington hydroelectric resources, several natural gas-fired plants (simple-cycle peakers and baseload combined-cycle combustion turbines), long-term firm purchased power contracts, several wind projects, and short-term wholesale (spot) market purchases up to PSE's available firm transmission import capability from the Mid-C. Since Colstrip must be out of PSE's portfolio by 2026, it was assumed to retire on 12/31/2025 and was not included as a resource in either GENESYS or RAM.

The following sources of uncertainty were incorporated into PSE's multi-scenario RAM.

1. **FORCED OUTAGE RATE FOR THERMAL UNITS**. Forced outage refers to a generator failure event, including the time required to complete the repair. The "Frequency Duration" outage method in AURORA is used to model unplanned outages (forced outage) for thermal plants. The Frequency Duration outage method allows units to fail or return to service at any time-step within the simulation, not just at the beginning of a month or a day. The method will employ all or nothing outages for most outages but will use partial outages at the beginning and end of the outage period. The logic considers each unit's forced outage rate and mean repair time. When the unit has a planned maintenance schedule, the model will ignore those hours in the random outage scheduling. In other words, the hours that planned maintenance occurs is not included in the forced outage rate.

2. **HOURLY SYSTEM LOADS**. Hourly system loads are modeled as an econometric function of hourly temperature for the month, using the hourly temperature data for each of the 88 temperature years. These demand draws are created with stochastic outputs from PSE's economic and demographic model and two consecutive historic weather years to predict future weather. Each historic weather year from 1929 to 2016 is represented in the 88 demand draws. Since the resource adequacy model examines a hydro year from October through September, drawing two consecutive years preserves the characteristics of each historic heating season. Additionally, the model examines adequacy in each hour of a given future year; therefore, the model inputs are scaled to hourly demand using the hourly demand model.

3. **MID-COLUMBIA AND BAKER HYDROPOWER.** PSE's RAM uses the same 80 hydro years, simulation for simulation, as the GENESYS model. PSE's Mid-Columbia purchase contracts and PSE's Baker River plants are further adjusted so that: 1) they are shaped to PSE load, and 2) they account for capacity contributions across several different sustained peaking periods (a 1-hour peak up to a 12-hour sustained peak). The 7,040 combinations of hydro and temperature simulations are consistent with the GENESYS model.

4. **WHOLESALE MARKET PURCHASES.** These inputs to the RAM are determined in the Wholesale Purchase Curtailment Model (WPCM) as explained above. Limitations on PSE wholesale capacity purchases resulting from regional load curtailment events (as determined in the WPCM) utilize the same GENESYS model simulations as PSE's RAM. The initial set of hourly wholesale market purchases that PSE imports into its system using its long-term Mid-C transmission rights is computed as the difference between

PSE's maximum import rights less the amount of transmission capability required to import generation from PSE's Wild Horse wind plant and PSE's contracted shares of the Mid-C hydro plants. To reflect regional deficit conditions, this initial set of hourly wholesale market imports was reduced on the hours when a PNW load-curtailment event is identified in the WCPM. The final set of hourly PSE wholesale imports from the WPCM is then used as a data input into the RAM, and PSE's loss of load probability, expected unserved energy, and loss of load expectation are then determined. In this fashion, the LOLP, EUE and LOLH metrics determined in the RAM incorporate PSE's wholesale market reliance risk.

5. **WIND AND SOLAR.** PSE models 250 unique 8,760 hourly profiles, which exhibit the typical wind generation patterns. Since wind and solar are both intermittent resources, one of the goals in developing the generation profile for each wind and solar project considered is to ensure that this intermittency is preserved. The other goals are to ensure that correlations across wind farms and the seasonality of wind and solar generation are reflected. Wind speed data was obtained from the National Renewable Energy Laboratory's (NREL's) Wind Tool Kit database.[2] Wind speed data was collected from numerous sites within a prescribed radius around a region of interest. Wind speed data was processed with a heuristic wind production model to generate hundreds of possible generation profiles. The 250 profiles which aligned most closely with the average seasonal production of the site, as determined by the average of the entire data set, were selected for use in the RAM. The profiles were then correlated by measurement year. Similarly, solar irradiance data for a given region was obtained from the National Solar Radiation Database[3] and processed with the NREL System Advisory Model to generate production profiles. The 250 solar profiles which were most closely aligned with the annual average production, as determined by the annual average of the entire data set, were selected for use in the RAM. The solar profiles were correlated by measurement year.

Construction risk is not directly incorporated in the resource adequacy model. Permitting and construction times are accounted for in the first year that a new resource is available. For example, if a resource takes four years for permitting and construction, and the IRP planning horizon starts in 2022, the new resource would be available in the year 2026. A full discussion of construction and permitting lead times is available in Appendix D.

2 / *https://www.nrel.gov/grid/wind-toolkit.html*
3 / *https://nsrdb.nrel.gov/*

4. OPERATING RESERVES AND PLANNING MARGIN

Operating Reserves

North American Electric Reliability Council (NERC) standards require that utilities maintain "capacity reserves" in excess of end-use demand as a contingency in order to ensure continuous, reliable operation of the regional electric grid. PSE's operating agreements with the Northwest Power Pool (NWPP), therefore, require the company to maintain two kinds of operating reserves: contingency reserves and regulating reserves.

CONTINGENCY RESERVES. In the event of an unplanned outage, NWPP members can call on the contingency reserves of other members to cover the resource loss during the 60 minutes following the outage event. The Federal Energy Regulatory Commission (FERC) approved a rule that affects the amount of contingency reserves PSE must carry – Bal-002-WECC-1 – which took effect on October 1, 2014. The rule requires PSE to carry reserve amounts equal to 3 percent of online generating resources plus 3 percent of load to meet contingency obligations. The terms "load" and "generation" in the rule refer to the total net load and all generation in PSE's Balancing Authority (BA).

In the event of an unplanned outage, NWPP members can call on the contingency reserves held by other members to cover the loss of the resource during the 60 minutes following the outage event. After the first 60 minutes, the member experiencing the outage must return to load-resource balance by either re-dispatching other generating units, purchasing power or curtailing load. The RAM reflects the value of contingency reserves to PSE by ignoring the first hour of a load curtailment, should a forced outage at one of PSE's generating plants cause loads to exceed available resources.

BALANCING AND REGULATING RESERVES. Utilities must also have sufficient reserves available to maintain system reliability within the operating hour; this includes frequency support, managing load and variable resource forecast error, and actual load and generation deviations. Balancing reserves do not provide the same kind of short-term, forced-outage reliability benefit as contingency reserves, which are triggered only when certain criteria are met. Balancing reserves are resources that have the ability to ramp up and down instantaneously as loads and resources fluctuate each hour.

The balancing reserve requirements were assessed by E3 for two study years, using the CAISO flex ramp test. The results depend heavily on the Mean Average Percent Error (MAPE) of the hour-ahead forecasts versus real-time values for load, wind and solar generation. The first study was for the year 2025 and includes PSE's current portfolio plus new renewable resources. The second study is for the year 2030 and includes PSE's current portfolio plus generic wind and solar resources to meet the 80 percent renewable requirement. Figure 7-4 below is a summary of the flex up and flex down requirement given the renewable resources that PSE will balance. By 2030, PSE's balancing reserve requirements will significantly increase with the large increase in intermittent renewable resources. The increase in balancing reserves will increase the need for flexible capacity resources. This analysis was based on the results from the 2019 IRP Process, where PSE estimated that it will balance almost 2,400 MW of wind and 1,400 MW of solar by 2030 to meet CETA goals. These results are in alignment with the 2021 IRP process.

Figure 7-4: Balancing Reserve Requirements

Case	Capacity of PSE-balanced Wind (MW)	Capacity of PSE-balanced solar (MW)	Average Annual Flex up (MW)	Average Annual Flex down (MW)	99th percentile of forecast error (flex up cap)	1st percentile of forecast error (flex down cap)
2025 Case	875	-	141	146	190	196
2030 Case	2,375	1,400	492	503	695	749

This table is a summary of the flexible ramp requirements. RAM uses for the hourly flex up and flex down requirements for each study year.

Planning Margin

The primary objective of PSE's capacity planning standard analysis is to determine the appropriate level of planning margin for the utility. Planning margin is defined as the level of generation resource capacity reserves required to provide a minimum acceptable level of reliable service to customers under peak load conditions. This is one of the key constraints in any capacity expansion planning model, because it is important to maintain a uniform reliability standard throughout the planning period in order to obtain comparable capacity expansion plans. The planning margin (expressed as a percent) is determined as:

Planning Margin = (Generation Capacity – Normal Peak Loads) / Normal Peak Loads,

> Where Generation Capacity (in MW) is the resource capacity that meets the reliability standard established in a probabilistic resource adequacy model. This generation capacity includes existing and incremental capacity required to meet the reliability standard.

The planning margin framework allows for the derivation of multiple reliability/risk metrics such as the likelihood (i.e., LOLP), magnitude (i.e., EUE) and duration (i.e., LOLH) of supply-driven customer outages. Those metrics can then be used to quantify the relative capacity contributions of different resource types towards meeting PSE’s firm peak loads. These include thermal resources, variable-energy resources such as wind, wholesale market purchases, and energy limited resources such as energy storage, demand response and backup fuel capacity.

In this IRP, PSE continues to utilize the LOLP metric to determine its capacity planning margin and establishes the 5 percent LOLP level used by the NPCC as adequate for the region. This value is obtained by running the 7,040 scenarios through RAM, and calculating the LOLP metric for various capacity additions. As the generating capacity is incremented using “perfect” capacity, this results in a higher total capacity and lower LOLP. The process is repeated until the loss of load probability is reduced to the 5 percent LOLP. The incremental capacity plus existing resources is the generation capacity that determines the capacity planning margin.

5. 2021 IRP RAM INPUT UPDATES

The following key updates to the RAM inputs were made since the 2019 IRP Progress Report:

1. The load forecast was updated to reflect the 2021 IRP demand forecast assumptions.
2. The hourly draws of the existing PSE wind fleet and new wind resources were based on NREL wind data set of 250 stochastic simulations.
3. The hourly draws of existing PSE solar resources and new solar resources were based on NREL solar data set of 250 stochastic simulations.
4. Colstrip Units 3 & 4 and Centralia were removed.
5. New resources from the 2018 RFP were added.
6. The balancing reserve requirements were updated to include new results for study years 2025 and 2030.

YEARS MODELED. The 2021 IRP time horizon starts in 2022, so PSE modeled a 5-year and 10-year resource adequacy assessment. The first assessment is the 5-year assessment for the period of October 2027 – September 2028. The second assessment is the 10-year assessment for the period of October 2031 – September 2032. The modeled year follows the hydro year (October – September) and allows the full winter and summer seasons to stay intact for the analysis. This is consistent with the NPCC's GENESYS model. If PSE modeled the calendar year, it would break up the winter season (November – February).

PSE also updated the 2023 forecasts from the 2018 NPCC Resource Adequacy Assessment in the RAM model. Since PSE is modeling the years 2027 and 2031, the GENESYS model was updated from the year 2023 to match the years 2027 and 2031. This was done by updating the demand forecast using the Council's demand escalation, updating plant retirements such as Colstrip and Centralia, and including new resources from PSE's portfolio (Skookumchuck and Lund Hill). The detailed updates were discussed earlier in this chapter.

RAM is an annual model. It is run for all hours of the year studied. All of the loss of load events are then added up for the year and accounted for in the annual modeling process. The model is set up to track annual events to a planning margin that is applied at the system peak. Monthly or seasonal RAM metrics are not available for this IRP but are being considered for the next IRP.

Study Year 2027

The incremental impact of each modeling update on the capacity need for the study year 2027 is documented in Figure 7-5. The starting point is the 2019 IRP Process capacity need with Colstrip Units 3 & 4 removed from the PSE portfolio in 2026.

Figure 7-5: Impact of Key Input Revisions for 2027

	REVISIONS	MW Needed for 5% LOLP Oct 2022 - Sep 2023	MW Needed for 5% LOLP Oct 2027 - Sep 2028
2019 IRP Base	2019 IRP Process resource need	685	
	2019 IRP Process resource need, no Colstrip 1 & 2	1,026	1,867
2021 IRP Updates	Updated contracts to include 2018 RFP contracts	968	
	Updated Wholesale Market Purchase Risk model for years 2027-2028	960	
	Updated balancing reserves for 2025 Case	918	
	Updated transmission assumptions • Add 50 MW BPA contract • Goldendale firm transmission	982	
	GENESYS load growth for 2027 and coal plant retirements Updated outage draws and resource capabilities 2021 IRP Load Forecast for October 2027 – September 2028		1,334
	Updated Wild Horse, Hopkins Ridge, LSR and Skookumchuck shapes to NREL data		1,273
	Updated Lund Hill generation to NREL data		1,291
	Add Golden Hills		1,161
	Add new RFP resource		1,018
	Demand Forecast • Fixed some errors in March • Updated A/C saturation to align with 2021 IRP demand forecast		887
	Fixed generation profile for Lund Hill – discovered error that generation was in DC and updated to AC		881
	Fixed correlations for wind and solar data		907

Figure 7-6 summarizes the resulting metrics when the LOLP meets the 5 percent standard. The Base System represents the current PSE resource portfolio without any new resources. RAM determined that 907 MW of perfect capacity is needed in the year 2027 to meet the 5 percent LOLP.

Figure 7-6: Reliability Metrics at 5% LOLP for 2027

Metric	Base System – no added resources	System at 5% LOLP – add 907 MW
LOLP	68.84%	4.99%
EUE	5,059 MWh	430 MWh
LOLH	11.06 hours/year	0.83 hours/year
LOLE	12.58 days/year	0.12 days/year
LOLEV	2.49 events/year	0.14 events/year

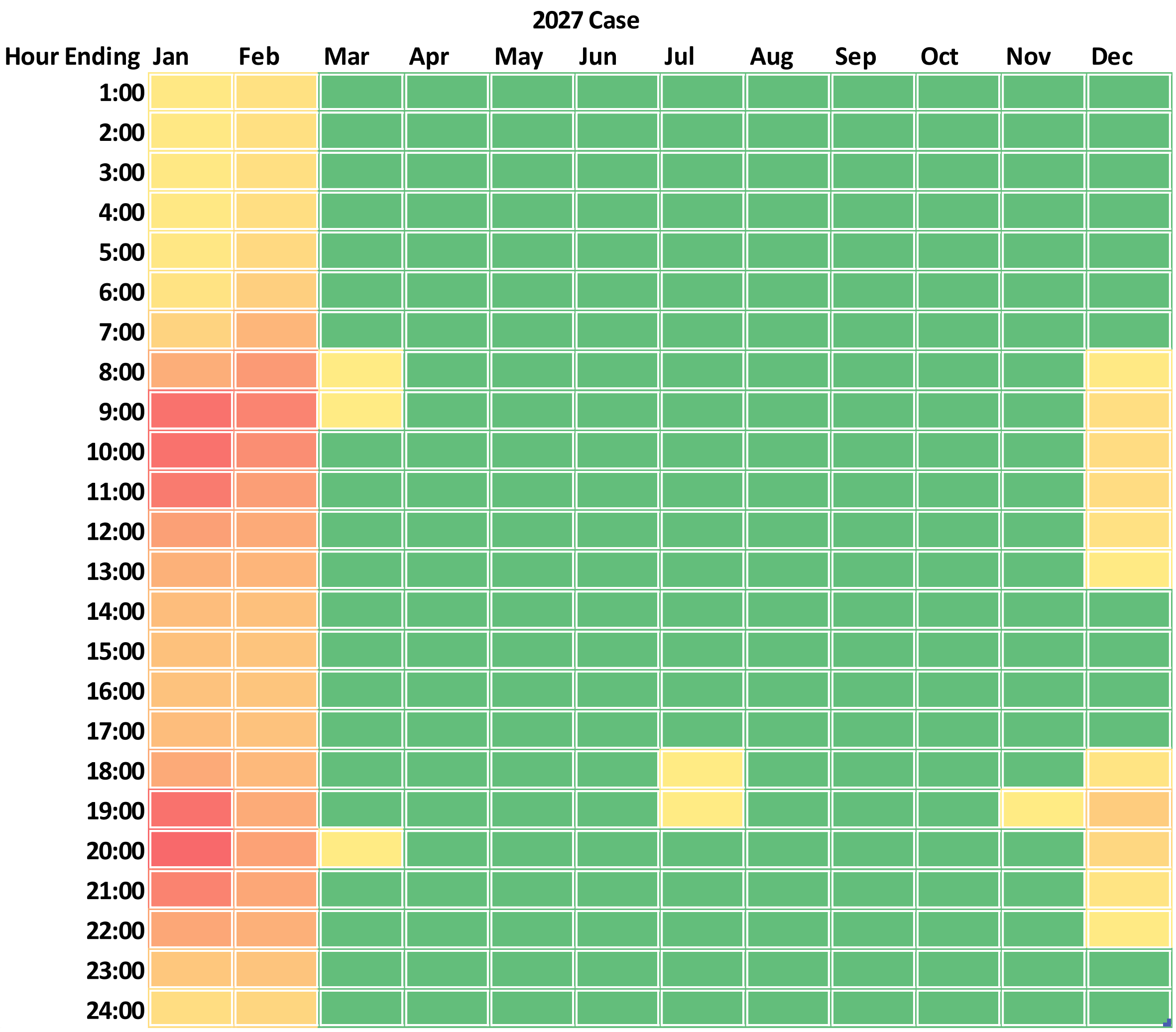
A loss of load event can be caused by many factors, which may include temperature, demand, hydro conditions, plant forced outages and variation in wind and solar generation. All of the factors are modeled as stochastic inputs simulated for 7,040 iterations. Figure 7-7 shows the number of hours over the 7,040 simulations where a loss of load event occurred. The majority of the loss of load events occur in the winter, during the months of January and February. However, this is the first time that we are seeing events occur in the summer, even though they affect few hours (about 0.04 percent of total hours). Given this result, PSE is still strongly winter peaking; we do not see this changing but will continue to monitor the summer events.

Figure 7-7: Hours of Loss of Load across 7,040 Simulations for 2027

Month	Loss of Load (h) Base	Loss of load (h) at 5% LOLP
1	4,846	2,893
2	3,296	2,553
3	10	5
4	-	-
5	-	-
6	10	-
7	3	2
8	-	-
9	-	-
10	-	-
11	5	1
12	474	275

Figure 7-8 is a 12x24 table of the loss of load hours. The plot represents a relative heat map of the number hours of lost load summed by month and hour of day. The majority of the lost load hours still occur in the winter months. From this chart, we can see long duration periods, 24 hours or more, with a loss of load event.

Figure 7-8: Loss of Load Hours for 2027



Study Year 2031

The incremental impact of each modeling update on the capacity need for the study year 2031 is documented in Figure 7-9. The starting point is the 2019 IRP Process capacity need with Colstrip 3 & 4 removed from the PSE portfolio in 2026.

Figure 7-9: Impact of Key Input Revisions for 2031

	REVISIONS	MW Needed for 5% LOLP Oct 2022 - Sep 2023	MW Needed for 5% LOLP Oct 2031 - Sep 2032
2019 IRP Base	2019 IRP Process resource need	685	
	2019 IRP Process resource need, no Colstrip 1 & 2	1,026	2,217
2021 IRP Updates	Updated contracts to include 2018 RFP contracts	968	
	Updated Wholesale Market Purchase Risk model for years 2031-2032	956	
	Updated balancing reserves for 2030 case	1,071	
	Updated transmission assumptions • Add 50 MW BPA contract • Goldendale firm transmission	1,134	
	GENESYS load growth for 2027 and coal plant retirements Updated outage draws and resource capabilities 2021 IRP demand forecast for October 2027 – September 2028		1,635
	Updated Wild Horse, Hopkins Ridge, LSR and Skookumchuck shapes to NREL data		1,581
	Updated Lund Hill generation to NREL data		1,596
	Add Golden Hills		1,469
	Add new RFP resource		1,326
	Demand Forecast • Fixed some errors in March • Updated A/C saturation to align with 2021 IRP demand forecast		1,344
	Fixed generation profile for Lund Hill – discovered error that generation was in DC and updated to AC		1,361
	Fixed correlations for wind and solar data		1,381

Figure 7-10 summarizes the resulting metrics when the LOLP meets the 5 percent standard. The Base System represents the current PSE resource portfolio without any new resources. RAM determined that 1,361 MW of perfect capacity is needed in the year 2031 to meet the 5 percent LOLP.

Figure 7-10: Reliability Metrics at 5% LOLP for 2031

Metric	Base System – no added resources	System at 5% LOLP – add 1361 MW
LOLP	98.45%	5.00%
EUE	19,243 MWh	419 MWh
LOLH	51.90 hours/year	0.86 hours/year
LOLE	11.25 days/year	0.12 days/year
LOLEV	13.80 events/year	0.17 events/year

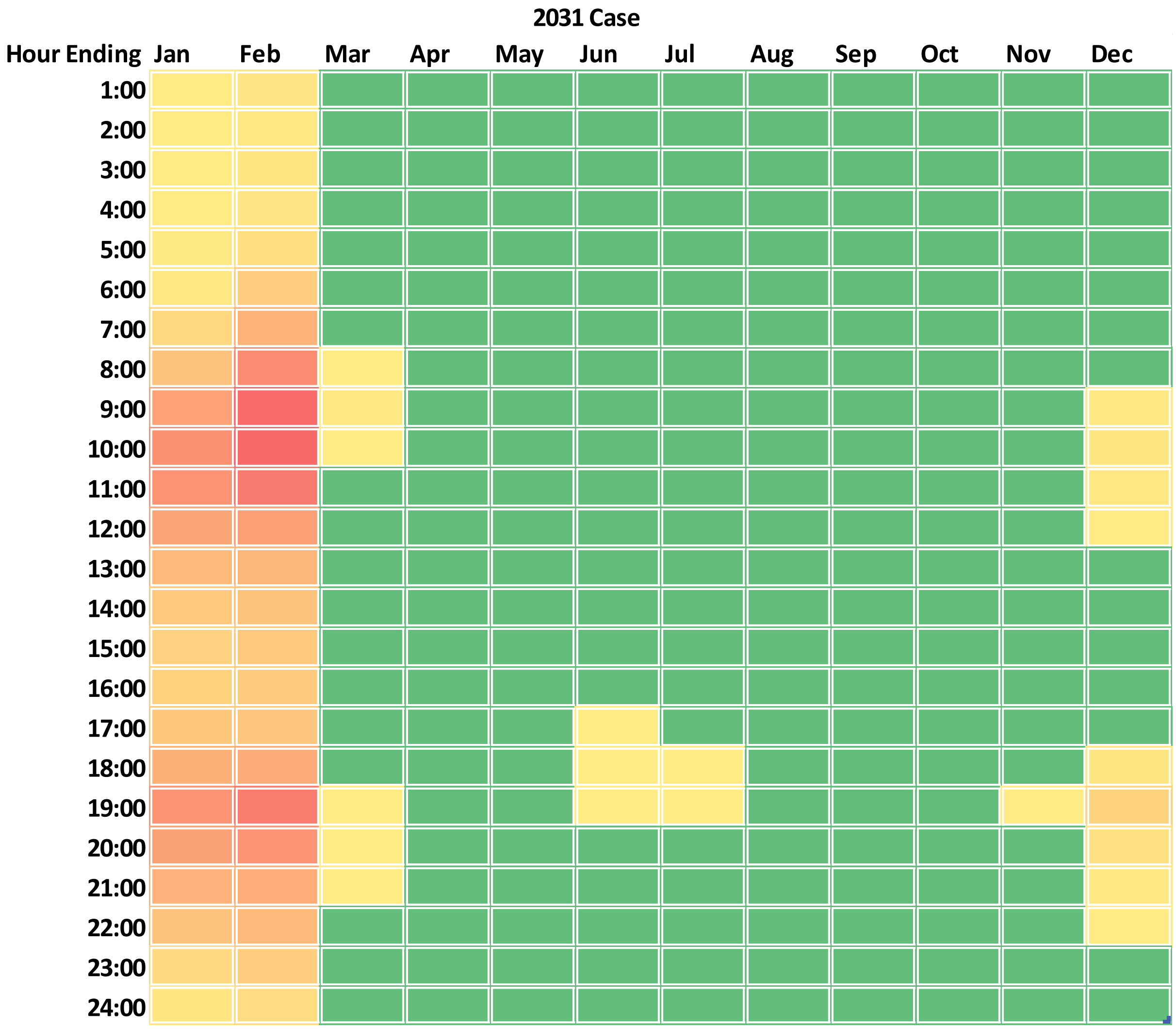
Figure 7-11 shows the number of hours over the 7,040 simulations where a loss of load event occurred. The majority of the loss of load events occur in the winter, during the months of January and February.

Figure 7-11: Hours of Loss of Load across 7,040 Simulations for 2031

Month	Loss of Load (h) Base	Loss of load (h) at 5% LOLP
1	3,860	2,387
2	4,267	3,365
3	40	14
4	-	-
5	-	-
6	12	5
7	4	2
8	4	-
9	-	-
10	-	-
11	9	1
12	325	160

Figure 7-12 is a 12x24 table of the loss of load hours. The plot represents a relative heat map of the number hours of lost load summed by month and hour of day. The majority of the lost load hours still occur in the winter months. From this chart, we can see long duration periods, 24 hours or more, with a loss of load event.

Figure 7-12: Loss of Load Hours for 2031



6. RESOURCE NEED

Planning Margin Calculation

PSE incorporates a planning margin in its description of resource need in order to achieve a 5 percent loss of load probability. Using the LOLP methodology, it was determined that 907 MW of capacity is needed by 2027 and 1,381 MW of capacity by 2031. The planning margin is used as an input into the AURORA portfolio capacity expansion model. It is simply a calculation used as an input into the model to make sure that the expansion model targets 907 MW of new capacity in the year 2027 and 1,381 MW in the year 2031. The planning margin calculation for the 2021 IRP is summarized in Figure 7-13. The Total Resources Peak Capacity Contribution is the combined peak capacity contribution of all the existing resources in PSE's portfolio and is also referred to as the effective load carrying capability (ELCC). The peak capacity contribution of planned future resources is described later in this chapter.

Figure 7-13: 2021 IRP Planning Margin Calculation

	Winter Peak 2027	Winter Peak 2031
Peak Capacity Need to meet 5% LOLP	907 MW	1,381 MW
Total Resources Peak Capacity Contribution	3,591 MW	3,599 MW
Short-term Market Purchases	1,471 MW	1,473 MW
Generation Capacity	5,969 MW	6,453 MW
Normal Peak Load	4,949 MW	5,199 MW
Planning Margin	**20.7%**	**24.2%**

The total peak capacity contribution of existing and new resources has been updated based on the 2021 IRP ELCC calculation.

Peak Capacity Credit of Resources

The effective load carrying capability (ELCC) of a resource represents the peak capacity credit assigned to that resource. It is calculated in RAM since this value is highly dependent on the load characteristics and the mix of portfolio resources. The ELCC of a resource is therefore unique to each utility. In essence, the ELCC approach identifies, for each resource alternative, its capacity relative to that of perfect capacity that would yield the same level of reliability. For resources such as a wind, solar, or other energy-limited resources such as batteries and demand response programs, the ELCC is expressed as a percentage of the equivalent perfect capacity. Since the

ELCC is unique to each utility and dependent on load shapes and supply availability, it is hard to compare PSE's ELCC numbers with other entities. Some of the ELCCs are higher and some are lower, depending on PSE's needs, demand shapes and availability of the supply-side resources.

The ELCC value of any resource, however, is also dependent on the reliability metric being used for evaluating the peak contribution of that resource. This is a function of the characteristics of the resource being evaluated, and more importantly, what each of the reliability metrics is counting. For example, a variable energy resource such as wind or solar with unlimited energy may show different ELCC values depending on which reliability metric is being used – LOLP or EUE. For example, LOLP measures the likelihood of any deficit event for all draws, but it ignores the number of times that the deficit events occurred within each draw, and it ignores the duration and magnitude of the deficit events. EUE sums up all deficit MW hours across events and draws regardless of their duration and frequency, expressed as average over the number of draws. In this study, we utilize LOLP as the reliability metric in estimating the ELCC of wind, solar and market purchases. However, we use EUE to determine the ELCC of energy-limited resources such as batteries and demand response, because LOLP is not able to distinguish the ELCC of batteries and demand response programs with different durations and call frequencies.

HYDRO RESOURCES CAPACITY CREDITS. The estimated peak contribution of hydro resources was modeled in the RAM. We only modeled the ELCC of PSE owned hydro, Baker River Projects and Snoqualmie Falls. The peak capacity contribution of the Mid-C hydro is based on the Pacific Northwest Coordination Agreement (PNCA) final regulation and represents PSE's contractual capacity less losses, encroachment and Canadian Entitlement.

Figure 7-14: Peak Capacity Credit for Hydro Resources
Based on 5% LOLP Relative to Perfect Capacity

Hydro Resources	ELCC Year 2027 (MW)	ELCC Year 2031 (MW)
Upper Baker Units 1 and 2	90	90
Lower Baker Units 3 and 4	82	79
Snoqualmie Falls	38	37

Figure 7-15: Peak Capacity Credit for Mid-C Hydro Resources
Based on Contractual Capacity Less Losses, Encroachment and Canadian Entitlement

Hydro Resources	Peak Capacity Credit Year 2027 (MW)	Peak Capacity Credit Year 2031 (MW)
Priest Rapids	5	5
Rock Island	121.2	121.2
Rocky Reach	313	313
Wanapum	6.1	6.1
Wells	115	115

THERMAL (NATURAL GAS) RESOURCES CAPACITY CREDITS. The peak capacity contribution of natural gas resources is different than other resources. For natural gas plants, the role of ambient temperature change has the greatest effect on capacity. Since PSE's peak need is at 23 degrees Fahrenheit, the capacity of natural gas plants is set to the available capacity of the natural gas turbine at 23 degrees Fahrenheit. The forced outage of natural gas resources is accounted for in the variability of the 7,040 simulations. As mentioned in the "consistency with regional resource adequacy assessments" section above, PSE uses the "Frequency Duration" outage method in AURORA to simulate unplanned outages (forced outage) for thermal plants. The forced outage is already incorporated into the 907 MW capacity need.

Figure 7-16: Peak Capacity Credit for Natural Gas Resources

THERMAL RESOURCES	Peak Capacity Credit based on 23 degrees (MW)
Sumas	137
Encogen	182
Ferndale	266
Goldendale	315
Mint Farm	320
Frederickson CC	134
Whitehorn 2 & 3	168
Frederickson 1 & 2	168
Fredonia 1 & 2	234
Fredonia 3 & 4	126
Generic 1x0 F-Class Dual Fuel Combustion Turbine	237
Generic 1x1 F-Class Combined Cycle	367
Generic 12x0 18 MW Class RICE	219

WIND AND SOLAR CAPACITY CREDITS. In order to implement the ELCC approach for wind and solar in the RAM, the wind and solar projects were added into the RAM incrementally to determine the reduction in the plant's peaking capacity needed to achieve the 5 percent LOLP level. The wind project's peak capacity credit is the ratio of the change in perfect capacity with and without the incremental wind capacity. The order in which the existing and prospective wind projects were added in the model follows the timeline of when these wind projects were acquired or about to be acquired by PSE: 1) Hopkins Ridge Wind, 2) Wild Horse Wind, 3) Klondike Wind, 4) Lower Snake River Wind, 5) Skookumchuck Wind, 6) Lund Hill Solar, 7) Golden Hills Wind, 8) New RFP Resource, and finally 9) a generic wind or solar resource. Figure 7-17 below shows the ELCC of the wind and solar resources modeled in this IRP.

Figure 7-17: Peak Capacity Credit for Wind and Solar Resources Based on 5% LOLP Relative to Perfect Capacity

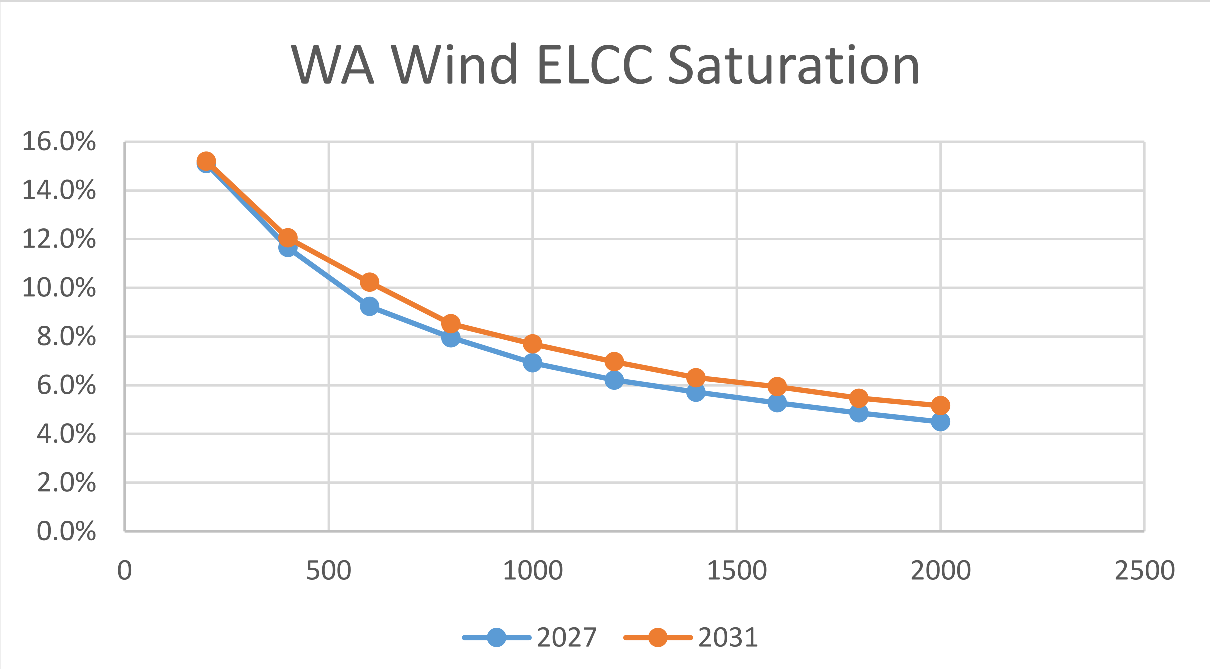
WIND AND SOLAR RESOURCES	Capacity (MW)	ELCC Year 2027	ELCC Year 2031
Existing Wind	823	9.6%	11.2%
Skookumchuck Wind	131	29.9%	32.8%
Lund Hill Solar	150	8.3%	7.5%
Golden Hills Wind	200	60.5%	56.3%
Generic MT East Wind1	350	41.4%	45.8%
Generic MT East Wind2	200	21.8%	23.9%
Generic MT Central Wind	200	30.1%	31.3%
Generic WY East Wind	400	40.0%	41.1%
Generic WY West Wind	400	27.6%	29.4%
Generic ID Wind	400	24.2%	27.4%
Generic Offshore Wind	100	48.4%	46.6%
Generic WA East Wind[1]	100	17.8%	15.4%
Generic WY East Solar	400	6.3%	5.4%
Generic WY West Solar	400	6.0%	5.8%
Generic ID Solar	400	3.4%	4.3%
Generic WA East Solar[1]	100	4.0%	3.6%
Generic WA West Solar – Utility-scale	100	1.2%	1.8%
Generic WA West Solar – DER Roof	100	1.6%	2.4%
Generic WA West Solar – DER Ground	100	1.2%	1.8%

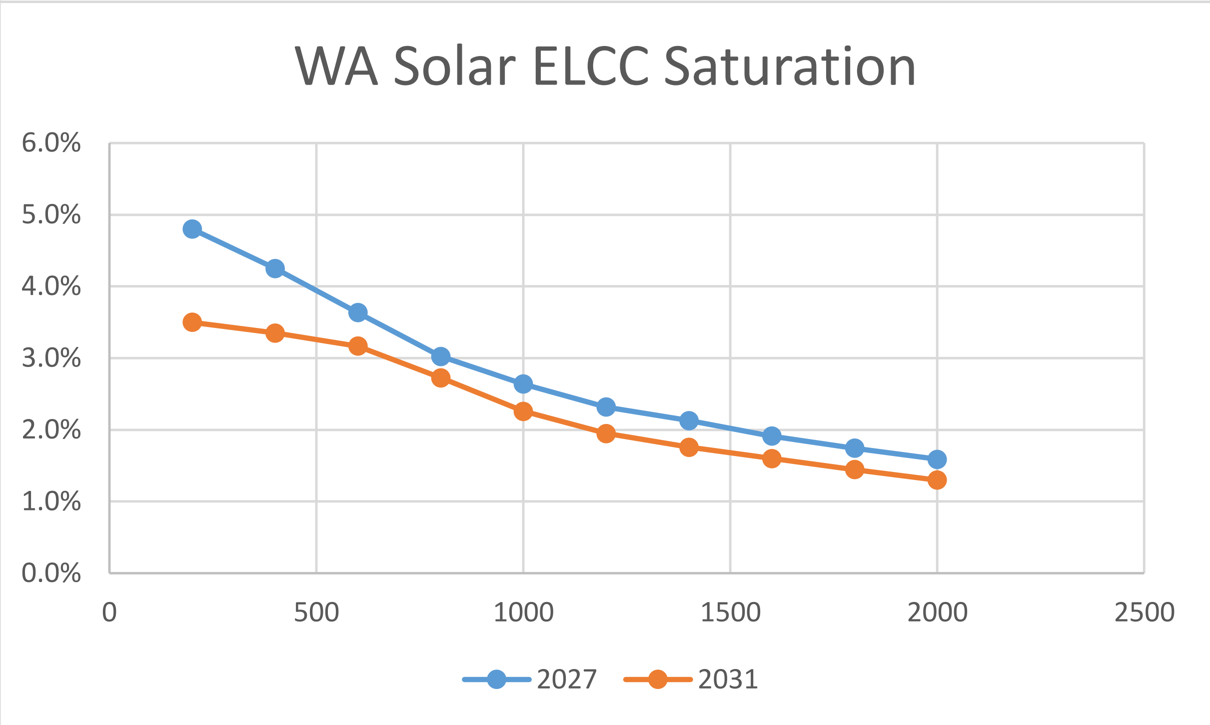
NOTES

1. This ELCC is for the first 100 MW of the resource, the saturation curve for up to 2,000 MW is shown below.

ELCC saturation curves: The peak capacity credit in Figure 7-17 above is for the first 100 MW of installed nameplate capacity for Washington wind and solar. Figure 7-18 below is the ELCC for the next 200 MW and then the next 200 MW after that and so on. The Figure shows a decreasing ELCC as more wind or solar is added to the same region.

Figure 7-18: Saturation Curves for Washington Wind and Solar





STORAGE CAPACITY CREDIT. The estimated peak contribution of two types of batteries were modelled in RAM as well as pumped hydro storage. The lithium-ion and flow batteries modeled can be charged or discharged at a maximum of 100 MW per hour up to two, four or six hours duration when the battery is fully charged. For example, a four-hour duration, 100 MW battery can produce 400 MWh of energy continuously over four hours. Thus, the battery is energy limited. The battery can be charged up to its maximum charge rate per hour only when there are no system outages. The battery can be discharged up to its maximum discharge rate or just the amount of system outage (adjusted for its round-trip [RT] efficiency rating) as long as there is a system outage and the battery is not empty.

As stated previously, the LOLP is not able to distinguish the impacts of storage resources on system outages since it counts only draws with any outage event but not the magnitude, duration and frequency of events within each draw. Because of this, the capacity credit of batteries was estimated using expected unserved energy (EUE). The analysis starts from a portfolio of resources that achieves a 5 percent LOLP, then the EUE from that portfolio is calculated. Each of the storage resources is then added to the portfolio, which leads to lower EUE. The amount of perfect capacity taken out of the portfolio to achieve the EUE at 5 percent LOLP divided by the peak capacity of the storage resource added determines the peak capacity credit of the storage resource. The estimated peak contribution of the storage resources is shown in Figure 7-19.

Since the ELCC is unique to each utility and dependent on load shapes and supply availability, it is hard to compare PSE's peak capacity contributions with other entities. Some of the peak capacity contributions are higher and some lower depending on PSE's needs, demand shapes and availability of the supply-side resources. PSE's winter peak makes it different than the parts of the western interconnect that have a summer peak. Summer peaking events are focused in the late afternoon/evening when the day is the hottest and only last a few hours in the evening, which makes energy storage an ideal solution. However, a winter event can last several days at a time and temperatures can drop low during the night and stay low throughout the day. The low peak capacity contribution for energy storage is because these are short duration resources. As shown in Figures 7-8 and 7-12 above, loss of load events can have extended durations of 24 hours or more. Since energy storage resources have a short discharge period, they have little to contribute during extended duration events.

Figure 7-19: Peak Capacity Credit for Battery Storage Based on EUE at 5% LOLP

BATTERY STORAGE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Lithium-ion, 2-hr, 82% RT efficiency	100	12.4%	15.8%
Lithium-ion, 4-hr, 87% RT efficiency	100	24.8%	29.8%
Flow, 4-hr, 73% RT efficiency	100	22.2%	27.4%
Flow, 6-hr, 73% RT efficiency	100	29.8%	35.6%
Pumped Storage, 8-hr, 80% RT efficiency	100	37.2%	43.8%

HYBRID RESOURCES CAPACITY CREDIT. The capacity contribution of a solar plus battery storage resource is also estimated using EUE. The peak capacity credit of a solar plus battery storage resource is shown in Figure 7-20.

Figure 7-20: Peak Capacity Credit for Hybrid Resource Based on EUE at 5% LOLP

SOLAR + BATTERY RESOURCE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Generic WA Solar, lithium-ion, 25MW/50MWh, 82% RT efficiency	100	14.4%	15.4%
Generic WA Wind, lithium-ion, 25MW/50MWh, 82% RT efficiency	100	23.6%	23.0%
Generic MT East Wind, pumped storage, 8-hr, 80% RT efficiency	200	54.3%	57.7%

DEMAND RESPONSE CAPACITY CREDIT. The capacity contribution of a demand response program is also estimated using EUE, since this resource is also energy limited like storage resources. The same methodology was used as for storage resources. The peak capacity contribution of demand response is shown in Figure 7-21.

Figure 7-21: Peak Capacity Credit for Demand Response

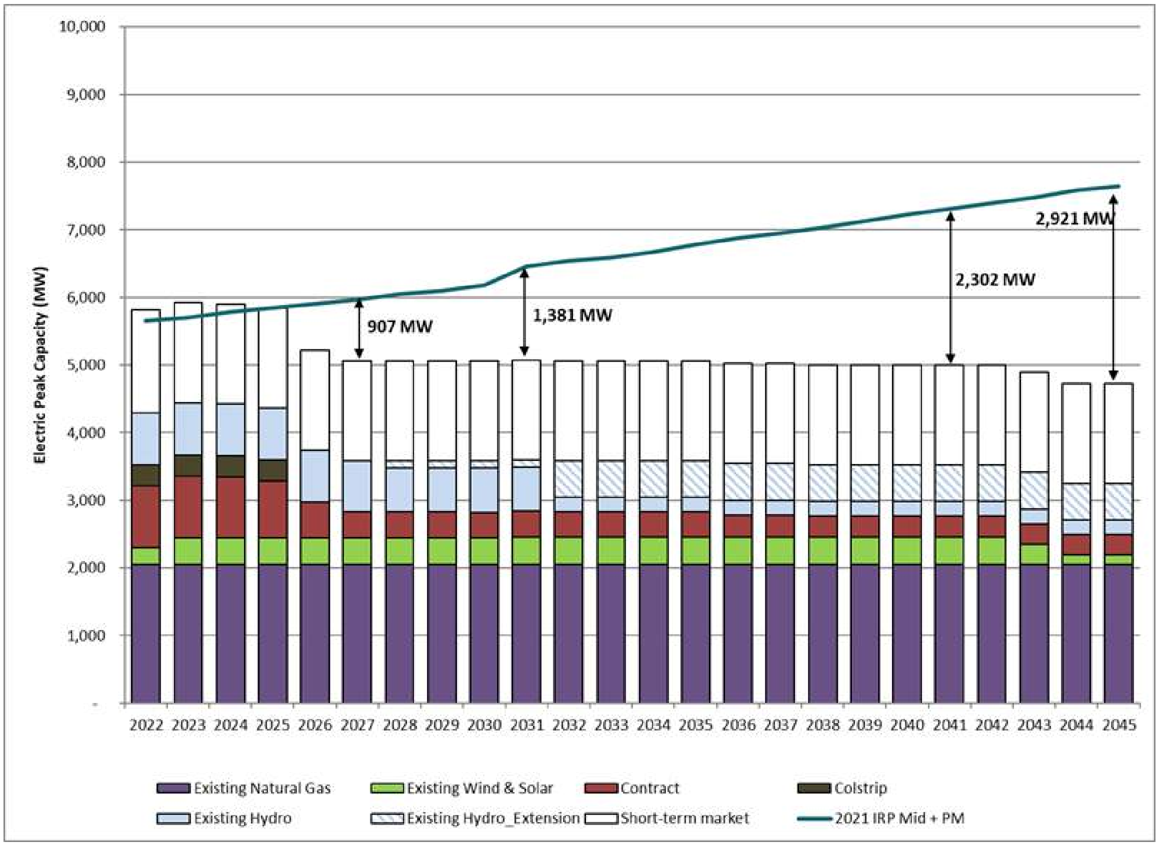
DEMAND RESPONSE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Demand Response, 3-hr duration, 6-hr delay, 10 calls per year	100	26.0%	31.6%
Demand Response, 4-hr duration, 6-hr delay, 10 calls per year	100	32.0%	37.4%

Peak Capacity Need

Figure 7-22 shows the peak capacity need for the mid demand forecast modeled in this IRP. Before any additional demand-side resources, peak capacity need in the mid demand forecast plus planning margin is 907 MW by 2027 and 1,381 MW in 2031 (represented by the teal line in Figure 7-22). This includes a 20.7 percent planning margin (a buffer above a normal peak) to achieve and maintain PSE’s 5 percent LOLP planning standard. The graph shows a noticeable drop in PSE’s resource stack at the end of 2025. The drop is caused by the elimination of Colstrip 3 & 4 from PSE’s energy supply portfolio starting in 2026, which removes approximately 370 MW of capacity, and the expiration of PSE’s 380 MW coal-transition contract with TransAlta when the Centralia coal plant is retired at the end of 2025.

The peak capacity deficit assumes that 1,500 MW of market purchases is available to meet peak capacity need. Further analysis of market risk is described below.

Figure 7-22: Electric Peak Capacity Need
(Physical Reliability Need, Peak Hour Need Compared with Existing Resources)



7. ALTERNATIVE FUEL NEED FOR RESOURCE ADEQUACY

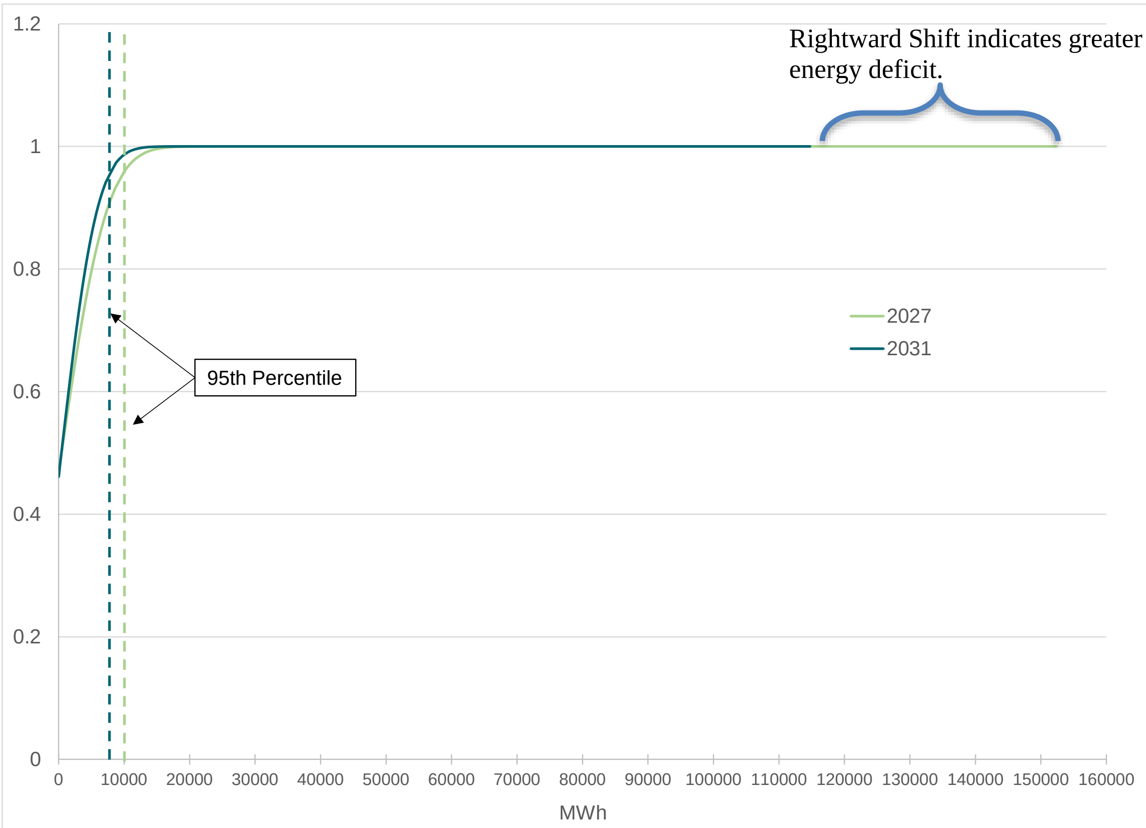
As part of the 2021 IRP, PSE tested CETA-compliant alternative fuels for peakers. When analyzing alternative fuels such as biodiesel, two key issues arise:

1. How many hour many run hours are needed for the year in order to maintain resource adequacy?
2. Is there enough fuel supply?

Incremental outages are examined, using RAM, for loss of load events and hours of outages. Because RAM is a stochastic model performing analysis over 7,040 draws, both the MWh outages and hours of outages are presented as a cumulative distribution.

Figure 7-32 shows the cumulative distribution of generation (MWh) resulting from the incremental outage events for model years 2027 and 2031. This sensitivity was run by removing the peakers form the portfolio and determining how much generation is needed to maintain resource adequacy. The higher the level of capacity that is unable to run due to the lack of peaker generation, the greater the amount of deficit. This is shown by the rightward shift in the cumulative distribution curve. The vertical lines show the 95th percentile of generation that the peakers are needed to maintain resource adequacy.

Figure 7-32: Cumulative Distribution of Incremental Deficit for Loss of Load Events for All Simulations in MWh/yr



In 95 percent of simulations, to maintain resource adequacy, the peakers are needed to run for 10,000 MWh or less, which is around 15 hours of run time, and the maximum dispatch needed is 150,000 MWh, or approximately 205 hours of run time. In a report by the U.S. Energy Information Administration[4] on biofuel production, the total annual production of biodiesel in Washington state is 114 MM gallons per year. To fuel 10,000 MWh of generation, peaking resources would require around 828,000 gallons of biodiesel or about 0.7 percent of Washington State's annual production.

4 / *https://www.eia.gov/biofuels/biodiesel/production/*

8. MARKET RISK ASSESSMENT

PSE has 1,500 MW of firm transmission capacity from the Mid-C market hub to access supply from the regional power market. To date, this transmission capacity has been assumed to provide PSE with access to reliable firm market purchases under the WSPP contract schedule C,[5] where physical energy can be sourced in the day-ahead or the real-time bilateral power markets. PSE has effectively assumed this 1,500 MW of transmission capacity as equivalent to generation capacity available to meet demand. Historically, this assumption has reduced PSE's generation capacity need and ensuing procurement. For this IRP, PSE conducted a market risk assessment to evaluate the 1,500 MW assumption in addition to the evaluation completed with the WPCM.

The market risk assessment results in a proposal to increase firm resource adequacy qualifying capacity contracts while limiting the amount of real-time, day-ahead and term market purchases from 1,500 MW to 500 MW by the year 2027 to satisfy peak capacity needs. Support for such a reduction is based on changing market fundamentals in the Western Electricity Coordinating Council (WECC) that impact PSE's ability to access firm market purchases to meet demand. A reduction from 1,500 MW to 500 MW by 2027 provides a realistic and feasible path towards firm capacity for long-term peak capacity planning. The reduction in market purchases used in IRP planning is supported by the reduced capacity and liquidity in the region, coupled with increased volatility at the Mid-C market hub. The events of August 2020 underscore the need to change the IRP planning assumptions; in that event, PSE and other entities were not able to procure additional supply from the market.

Changing WECC Supply/Demand Fundamentals

Generating Capacity Changes

Power market supply/demand fundamentals have changed significantly in recent years. As customers, corporations and state legislatures across the Western Interconnection prefer or require power from clean energy sources, intermittent energy sources – namely wind and solar – have been built while traditional dispatchable capacity resources have been retired or mothballed. The growing capacity deficit in the region has been well documented in several recent studies.[6] Since 2016, nearly 15,000 MW of clean capacity and 500 MW of batteries have been added to

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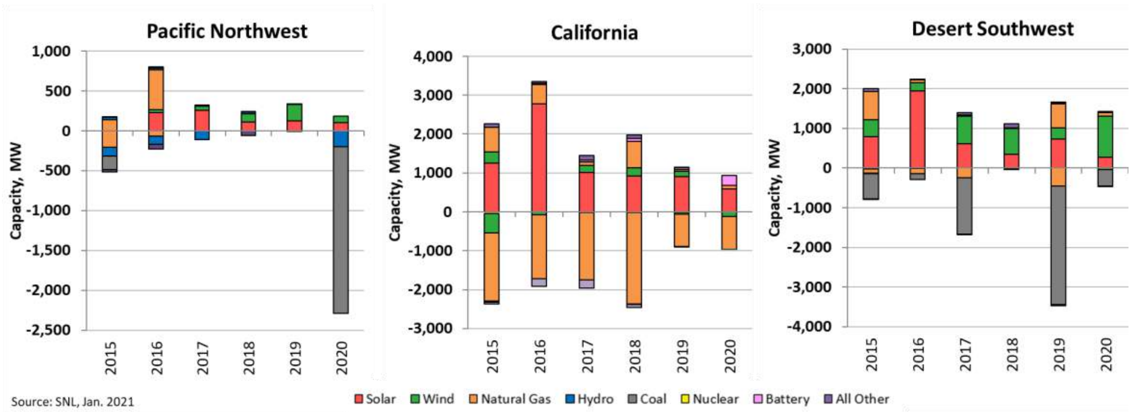
5 / https://www.wspp.org/pages/Agreement.aspx

6 / 2018 Pacific Northwest Loads and Resources Study (White book) (BPA, 2020); Resource Adequacy in the Pacific Northwest (E3, 2019); 2018 Long-Term Reliability Assessment (North American Reliability Corporation and Western Electricity Council, 2018); Pacific Northwest Power Supply Adequacy Assessment for 2023 (Northwest Power and Conservation Council, 2018); Northwest Regional Forecast of Power Loads and Resources: 2020 through 2029 (Pacific Northwest Utilities Conference Committee, 2019); Long Term Assessment of the Load Resource Balance in the Pacific Northwest (Portland Gas and Electric and E3, 2019) the grid while 12,000 MW of coal and natural gas resources have been retired, as illustrated in Figure 7-23.

Figure 7-23: Capacity Additions and Retirements Since 2016

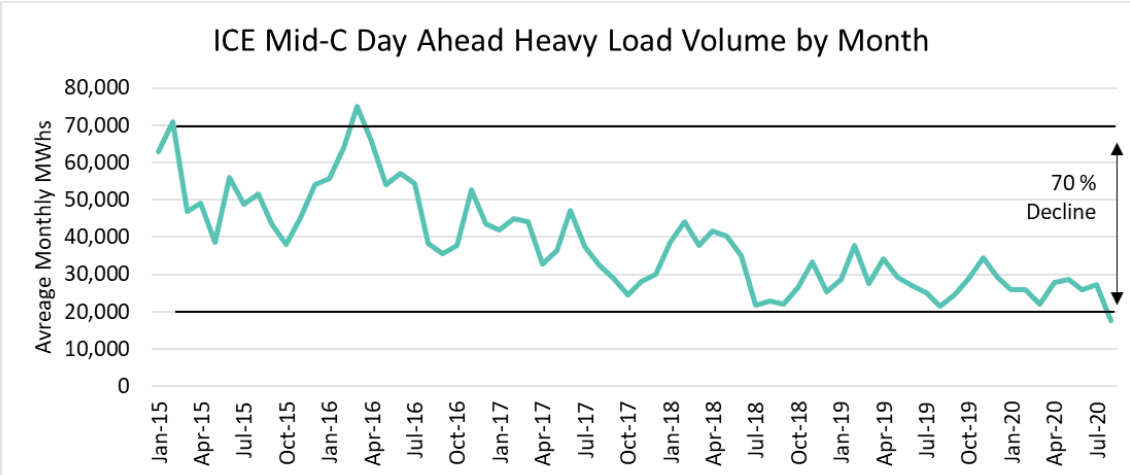


Included in Pacific Northwest thermal retirements are the retirements of Colstrip 1 and 2 in January 2020, which increased PSE's reliance on the short-term market by 300 MW. With less dispatchable generation capacity within the WECC, market supply/demand fundamentals have tightened.

Transaction Volumes and Volatility

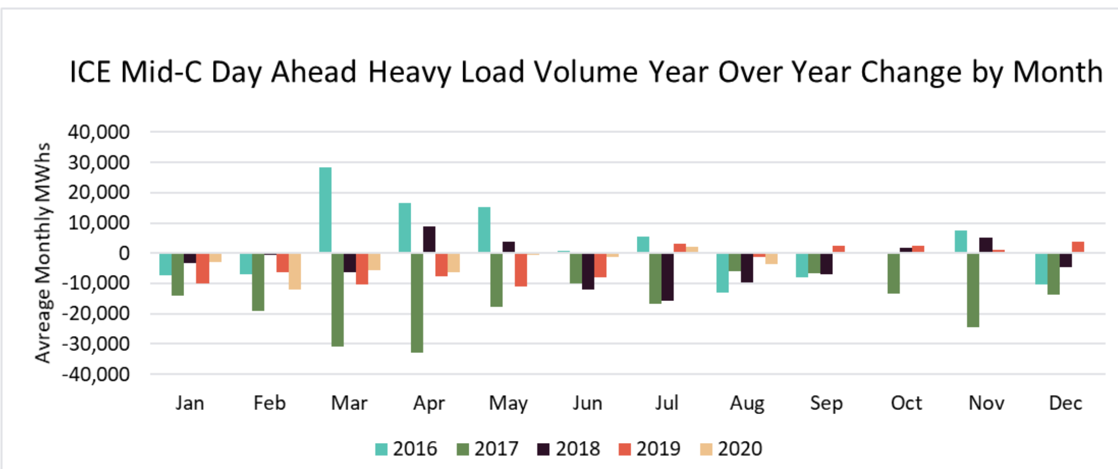
Reductions in traded volume in the day-ahead market also indicate constrained market supply/demand fundamentals; less generation is available, so there is less capacity available which market participants can trade. This also is suggestive of energy being transacted before the month of delivery, so it is not available to be traded in the day-ahead market. Trading volume in the day-ahead market has declined 70 percent since 2015. Figure 7-24 shows the average monthly trading volume between January 2015 and July 2020 on the Intercontinental Exchange.

Figure 7-24: Mid-C Day-ahead Heavy Load Volume Timeline



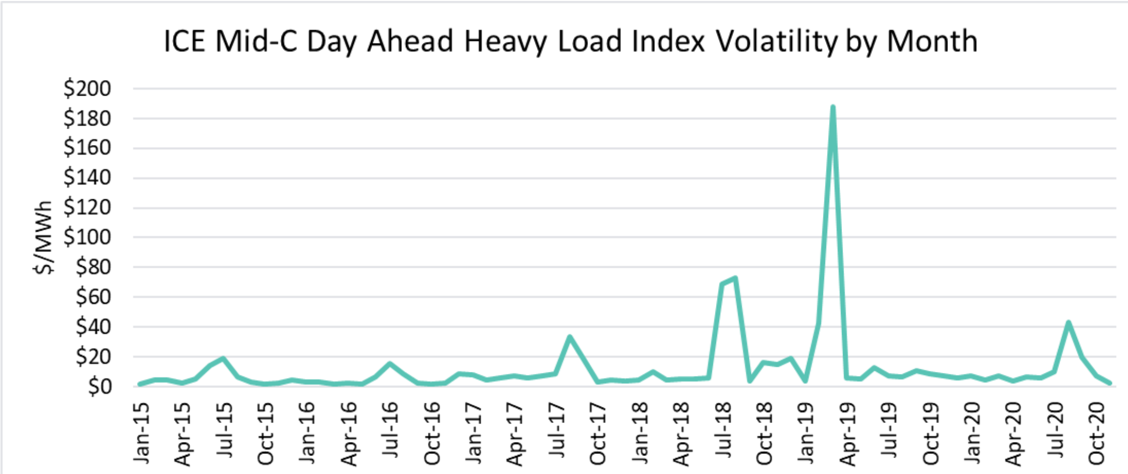
The decline has been consistent in all delivery periods. Figure 7-25 shows the average monthly change in trading volume from one year to the next. Negative bars show a reduction in trading volume while positive bars show an increase in trading volume.

Figure 7-25: Mid-C Day-ahead Heavy Load Volume Monthly Change



Additionally, price volatility has increased since 2015 in response to tighter supply/demand fundamentals, with energy prices spiking precipitously when there is limited supply. Such increases in market volatility were notable in the summer of 2018 when high regional temperatures coincided with forced outages at Colstrip; in March 2019 when regional cold coincided with reduced Westcoast pipeline and Jackson Prairie storage availability; and most recently in August 2020 during a west-wide heat event. The volatility of day-ahead heavy load prices is presented in Figure 7-26.

Figure 7-26: Volatility of Heavy Load Mid-C Day-ahead Prices



Approach of Regional Investor Owned Utilities

Coinciding with the retirement of legacy baseload capacity and the decline of market liquidity, several regional investor owned utilities (IOUs) have reduced their assumptions of available market capacity in their IRPs. A lack of reliance or a reduced reliance on the market for capacity has precedent as shown in Figure 7-27. While it is difficult to get an exact comparison since IOUs have different resource planning assumptions, hedging and procurement practices, it is clear that PSE's market purchases are higher than other IOUs.

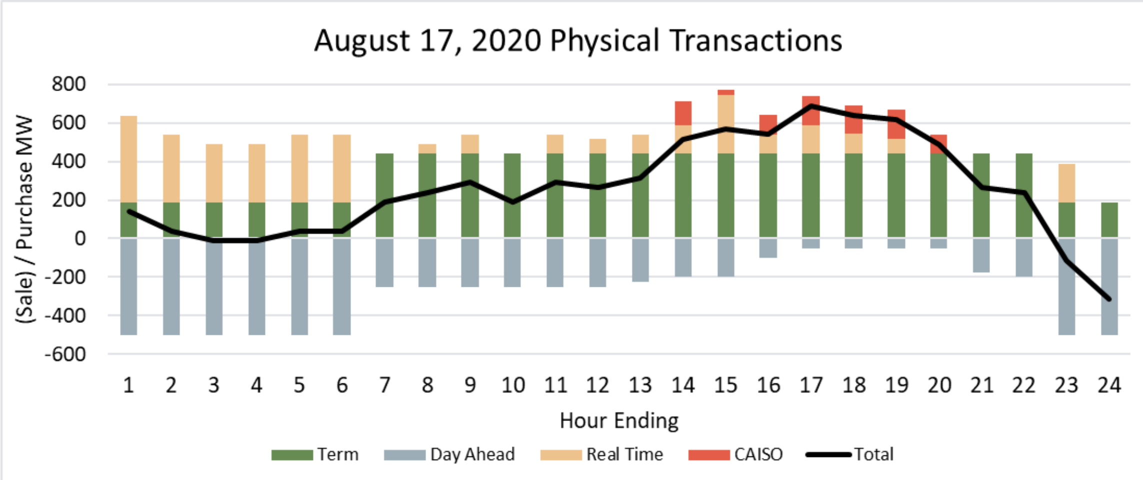
Figure 7-27: Regional IOU Market Reliance

Entity	Planned Summer Market Reliance Limit (MW)	Planned Winter Market Reliance Limit (MW)	Commentary
Avista	330	330	From the draft 2021 IRP. Market purchases are limited to 500 MW during 'unconstrained' hours, and 330 MW during 'constrained' hours
Idaho Power	N/A	N/A	The current IRP (2019) assumes market purchases of 500 MW in the summer and 425 MW in the winter. Specific market purchase limits are not defined in the IRP.
PacifiCorp	500 – Aggregate 150 – Mid-C Seasonal HLH	1000 – Aggregate 0 – Mid-C Seasonal HLH	Proposed Front Office Transaction Limits for the 2021 IRP cycle.
Portland General	50	0	Estimates from *Long Term Assessment of the Load Resource Balance in the Pacific Northwest* (Portland Gas and Electric and E3, 2019)
Puget Sound Energy	1,500	1,500	PSE counts historical energy offers at the Mid-C hub as available capacity to meet peak demand needs in the winter and summer.

Events of August 2020

Amid a west-wide heat wave lasting from August 14, 2020 to August 19, 2020, several balancing authority areas (BAAs) in the Western Interconnect declared various stages of energy emergency. This included the CAISO, which declared a stage 3 emergency and cut firm load on August 14 and 15. PSE's BAA declared a stage 1 emergency on August 17, 2020 as there was concern about the ability to procure capacity to meet load and contingency reserve obligations during hours ending 15 – 18 (3pm – 6pm). PSE's BAA ultimately did not progress further into emergency conditions and all load and contingency reserves were met. PSE ultimately relied on 400-505 MW of market purchases using WSPP-C contracts and 25 to 150 MW of exports from the CAISO, but could not procure additional capacity. This was significantly less than the 1,500 MW of market purchases that has been assumed to be available to meet demand in PSE's IRP. PSE's total market reliance on August 17, 2020 is shown in Figure 7-28. The different color bars show when the energy was procured for each hour on the day of August 17, 2020. Limited amount of imports from California were available.

Figure 7-28: Physical Transactions (MW) on August 17, 2020



Peak Capacity Need

ADJUSTED PEAK CAPACITY NEED. The reduction in market purchases to 500 MW increases the peak capacity deficit in 2027 from 907 MW to 1,853 MW. The planning margin calculation for the adjusted peak capacity need is summarized in Figure 7-29.

Figure 7-29: 2021 IRP Planning Margin Calculation with Declining Market Reliance

	Winter Peak 2027	Winter Peak 2031
Peak Capacity Need to meet 5% LOLP	1,853 MW	2,263 MW
Total Resources Peak Capacity Contribution	3,586 MW	3,599 MW
Short-term Market Purchases	500 MW	500 MW
Generation Capacity	5,940 MW	6,362 MW
Normal Peak Load	4,949 MW	5,199 MW
Planning Margin	**20.0%**	**22.4%**

Figure 7-30 below shows the annual change in peak deficit for the declining market reliance and converting the short-term energy purchases to firm resource adequacy qualifying capacity contracts. The market availability at peak gradually declines over a 5-year period at 200 MW per year through to the year 2027. The gray area is the total available transmission to the Mid-C market. This position is usually left open to the short term market, but based on market availability, the open position will be reduced to 500 MW by 2027 with the remaining available transmission used for firm resource adequacy qualifying capacity purchases.

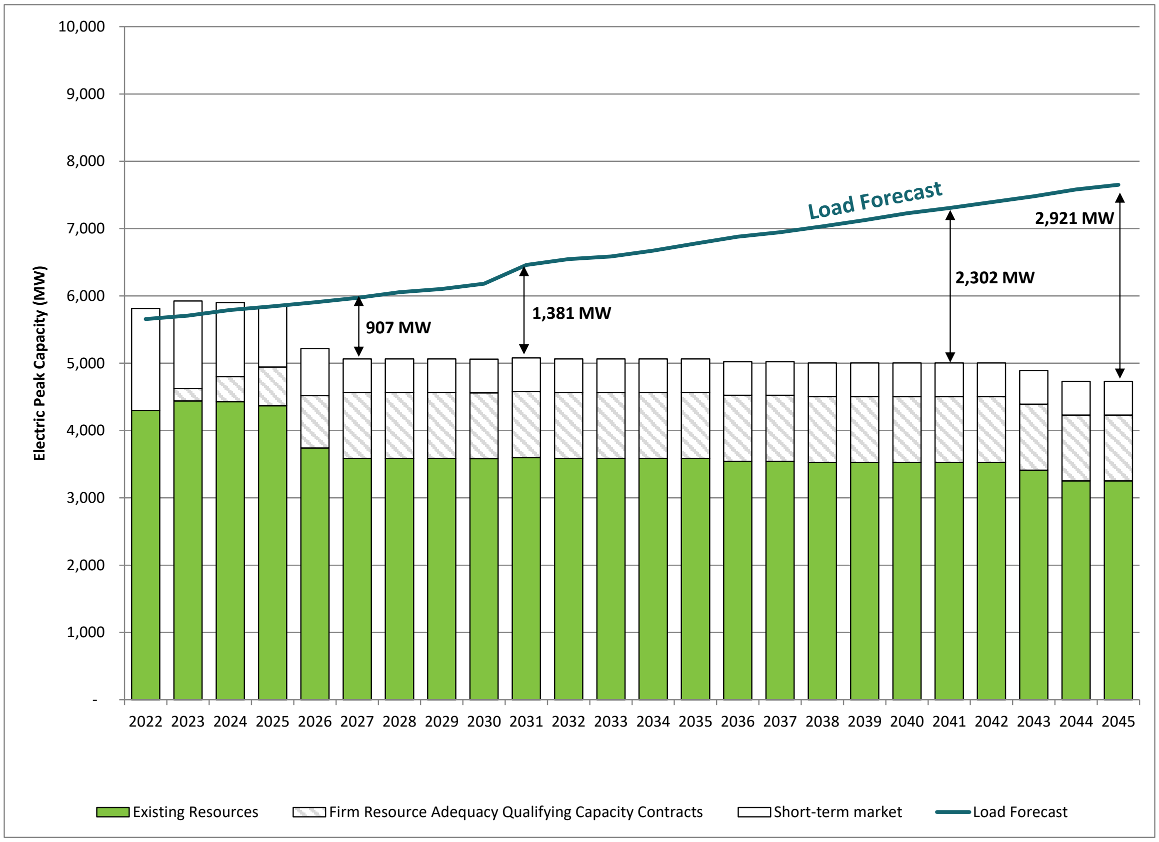
Figure 7-30: Short Term Market Purchases converted to Firm Resource Adequacy Qualifying Capacity Contracts

Year	Available Mid-C transmission (MW)	Short Term Market Purchases (MW)	Firm RA Qualifying Capacity Contracts (MW)
2022	1,518	1,518	-
2023	1,485	1,300	185
2024	1,472	1,100	372
2025	1,474	900	574
2026	1,476	700	776
2027	1,479	500	979
2028	1,479	500	979
2029	1,479	500	979
2030	1,479	500	979
2031	1,479	500	979

After 2031, the short term market stays at 500 MW and the firm resource adequacy qualifying capacity contracts at 979 MW.

Figure 7-31 shows the peak capacity need; the grey dashed bars highlight the reduced market purchases described above. Before any additional demand-side resources, peak capacity needed to meet the demand forecast plus planning margin – after reducing market purchases at peak – is 1,853 MW by the year 2027 and 2,263 MW by the year 2031.

Figure 7-31: Electric Peak Capacity Need
(Physical Reliability Need, Peak Hour Need Compared with Existing Resources)



9. TEMPERATURE SENSITIVITY

PSE committed to run a future temperature sensitivity as a way to begin to evaluate the impacts of climate change. This sensitivity was for the demand forecast only; PSE did not adjust hydro or wind for the adjusted temperature analysis. PSE relies on the Bonneville Power Administration (BPA) to do hydro modeling, and then PSE receives the data through the Pacific Northwest Coordination Agreement Hydro Regulation. This data has long been used by various organizations to estimate hydro variability. PSE will continue to align with BPA hydro modeling and will analyze any new data as it becomes available to better understand the impacts of climate change to the hydro system. There are three components to the temperature sensitivity analysis:

1. An updated energy demand forecast;
2. An alternative resource adequacy analysis; and
3. A portfolio sensitivity using the Aurora Long Term Capacity Expansion portfolio model.

The energy demand forecast is described in Chapter 6. The resource adequacy analysis adjustments made to account for the alternate temperatures is described below and the results of the portfolio sensitivity can be found in Chapter 8.

The base RAM analysis includes 88 historic temperature years. To create a wider range of possible future temperatures, and consistent with the stakeholder-selected energy demand forecast assumptions, PSE used three models that the NPCC has been using in its resource adequacy analyses. These models (CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA) are the product of a recent project by Bonneville Power Administration, U.S. Army Corps of Engineers and the Bureau of Reclamation that down-scaled global climate models to be more specific to the Northwest region. Each of these three models is on the Representative Concentration Pathway of 8.5, which some would argue is a “business as usual” pathway, while others would argue is a more extreme climate warming scenario.

The three models represent different amounts of warming over time. CanESM2_BCSD forecasts 0.9 degree of warming per decade, CCSM4_BCSD forecasts 0.9 degrees of warming per decade, and CNRM-CM5_MACA forecasts 0.5 degrees of warming per decade. While CanESM2_BCSD and CCSM4_BCSD have similar warming trends per decade, the temperatures from the two models are very different from year to year, and CanESM2_BCSD is a full degree warmer than CCSM4_BCSD, on average, over time.

PSE did not change the peak temperature assumptions for this analysis, because while average temperatures may be increasing over time due to climate change, extreme events (both hot and cold) may still occur. Therefore, and as a result, the peak demand forecast did not change.

For each of the three models analyzed, weather from the future decade in which the RA scenario takes place was used; that is, weather from 2020 through 2029 was used for the 2027 to 2028 RAM run, and weather from 2030 to 2039 was used for the 2031 to 2032 RAM run. The 10 years of weather from the three models was repeated almost three times and coupled with 88 economic and demographic draws to create 88 future hourly loads for the RA model. This mirrors the methodology used in the NPCC resource adequacy analysis.

Using the LOLP methodology with the data from this temperature analysis, it was determined that 328 MW of capacity is needed by the year 2027 and 1,019 MW of capacity by the year 2031. The results of this sensitivity are compared with the base RAM results in Figure 7-32.

Figure 7-32: Peak Capacity Need

	Base	Temperature Sensitivity
2027 peak need	907 MW	328 MW
2031 peak need	1,381 MW	1,019 MW

The temperature analysis results showed more loss of load events in the summer caused by inadequate supply while in the base analysis, most loss of load events occurred in the winter season as shown in Figure 7-33. This shift in loss of load events from the winter to summer affects the peak capacity credit of resources. Resources with higher capacities in the summer, such as solar, now have higher peak capacity credit while those with strong winter generation become less effective with a lower peak capacity credit.

Figure 7-33: Frequency of Loss of Load Events by Month and Hour of Day for Model Years 2027 and 2031, Base Scenario and Temperature Sensitivity (red indicates more loss of load events, green indicates zero loss of load events)

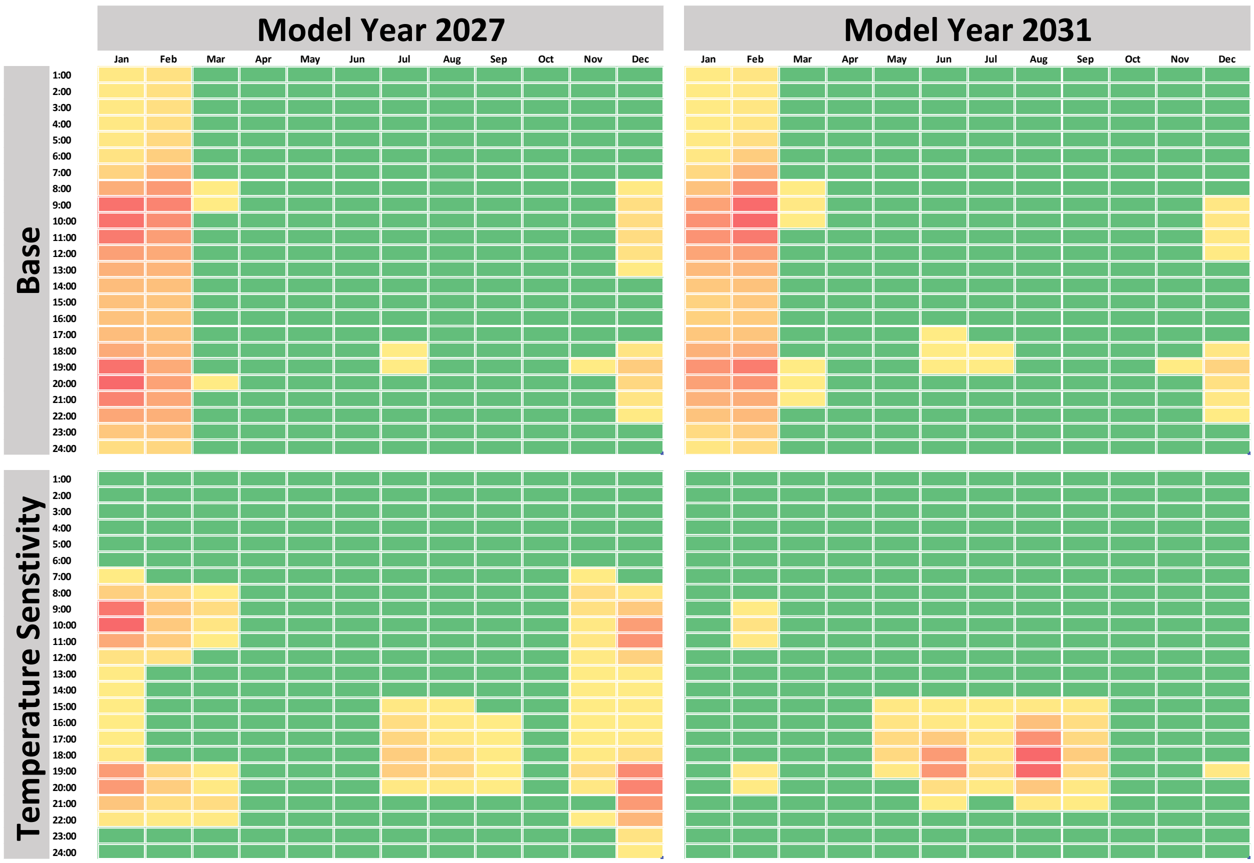


Figure 7-34 presents the effective load carrying capability of the generic resources for the temperature sensitivity as compared to the base scenario. The RAM results presented here were used to develop the inputs for the AURORA portfolio model.

Figure 7-34: Effective Load Carrying Capability for model years 2027 and 2031, Base Scenario and Temperature Sensitivity

WIND AND SOLAR RESOURCES	Capacity (MW)	ELCC Year 2027		ELCC Year 2031	
		Base Scenario	Temp. Sensitivity	Base Scenario	Temp. Sensitivity
Existing Wind	823	9.6%	6.8%	11.2%	6.7%
Skookumchuck Wind	131	29.9%	17.6%	32.8%	9.2%
Lund Hill Solar	150	8.3%	30.3%	7.5%	54.3%
Golden Hills Wind	200	60.5%	49.3%	56.3%	39.3%
Generic MT East Wind1	350	41.4%	28.5%	45.8%	28.1%
Generic MT East Wind2	200	21.8%	13.1%	23.9%	17.7%
Generic MT Central Wind	200	30.1%	23.1%	31.3%	20.9%
Generic WY East Wind	400	40.0%	29.1%	41.1%	32.7%
Generic WY West Wind	400	27.6%	27.2%	29.4%	34.0%
Generic ID Wind	400	24.2%	25.6%	27.4%	28.0%
Generic Offshore Wind	100	48.4%	38.6%	46.6%	27.6%
Generic WA East Wind	100	17.8%	7.8%	15.4%	12.0%
Generic WY East Solar	400	6.3%	13.5%	5.4%	32.5%
Generic WY West Solar	400	6.0%	16.2%	5.8%	36.3%
Generic ID Solar	400	3.4%	16.0%	4.3%	47.3%
Generic WA East Solar	100	4.0%	21.6%	3.6%	45.6%
Generic WA West Solar – Utility-scale	100	1.2%	7.6%	1.8%	20.2%
Generic WA West Solar – DER Roof	100	1.6%	7.6%	2.4%	19.4%
Generic WA West Solar – DER Ground	100	1.2%	7.6%	1.8%	20.2%
BATTERY STORAGE					
Lithium-ion, 2-hr, 82% RT efficiency	100	12.4%	34.2%	15.8%	36.0%
Lithium-ion, 4-hr, 87% RT efficiency	100	24.8%	66.6%	29.8%	68.8%
Flow, 4-hr, 73% RT efficiency	100	22.2%	61.6%	27.4%	63.8%
Flow, 6-hr, 73% RT efficiency	100	29.8%	79.2%	35.6%	84.8%
Pumped Storage, 8-hr, 80% RT efficiency	100	37.2%	89.2%	43.8%	97.8%
SOLAR + BATTERY RESOURCE					
Generic WA Solar, lithium-ion, 25MW/50MWh, 82% RT efficiency	100	14.4%	22.0%	15.4%	56.6%
Generic WA Wind, lithium-ion, 25MW/50MWh, 82% RT efficiency	100	23.6%	26.0%	23.0%	17.8%
Generic MT East Wind, pumped storage, 8-hr, 80% RT efficiency	200	54.3%	73.0%	57.7%	64.0%

DEMAND RESPONSE					
Demand Response, 3-hr duration, 6-hr delay, 10 calls per year	100	26.0%	60.4%	31.6%	61.4%
Demand Response, 4-hr duration, 6-hr delay, 10 calls per year	100	32.0%	69.8%	37.4%	80.8%

It is important to note that this is one model of possible weather changes and provides a preliminary view of the possible impact of warming temperatures. The lessons from this sensitivity are useful as PSE plans for future resource adequacy analyses, but limited conclusions can be made that inform the preferred portfolio in this IRP.

PSE will continue to model weather trends under different scenarios to try to better understand how not only extreme summer events can affect resource adequacy, but also to ensure we are planning for winter extreme events. While average temperatures may be increasing over time due to climate change, extreme events (both hot and cold) may still occur. Further climate change modeling is needed to drive resource planning changes. In the past, there have been three separate regional energy events outside of PSE's control, two in the winter (February 2019 and February 2021), and one in the summer (August 2020). PSE anticipate future changes to the resource adequacy analysis to include both a winter and summer resource adequacy analysis, and will work to develop a winter and summer peak capacity credit to understand how different resources can contribute to both needs.

8 Electric Analysis

This chapter presents the results of the electric analysis.

Contents

1. ANALYSIS OVERVIEW

The electric analysis in the 2021 IRP followed the six-step process outlined below. Steps 1, 3, and 4 are described in detail in this chapter. Other steps are treated in more detail elsewhere in the IRP.

1. Establish Resource Need
Three types of resource need are identified: peak capacity need, energy need and renewable need.

- Chapter 7 presents the resource adequacy analysis.

2. Determine Planning Assumptions and Identify Resource Alternatives

- Chapter 5 discusses the scenarios and sensitivities developed for this analysis.
- Chapter 6 presents the 2021 IRP demand forecasts.
- Appendix D describes existing electric resources and alternatives in detail.

3. Analyze Alternatives and Portfolios Using Deterministic and Stochastic Risk Analysis
Deterministic analysis identifies the least-cost mix of demand-side and supply-side resources that will meet need, given the set of static assumptions defined in the scenario or sensitivity.

- All scenarios and sensitivities were analyzed using deterministic optimization analysis.

Stochastic risk analysis deliberately varies the static inputs to the deterministic analysis to test how the different portfolios developed in the deterministic analysis perform with regard to cost and risk across a wide range of potential future power prices, gas prices, hydro generation, wind generation, loads and plant forced outages.

- Four portfolios were analyzed using stochastic risk analysis.

4. Analyze Results
Results of the quantitative analysis – both deterministic and stochastic – are studied to understand the key findings that lead to decisions for the preferred portfolio.

- Results of the analysis are presented in this chapter and in Appendix H.

5. Develop Resource Plan

Chapter 3 describes the reasoning behind the strategy chosen for this preferred portfolio.

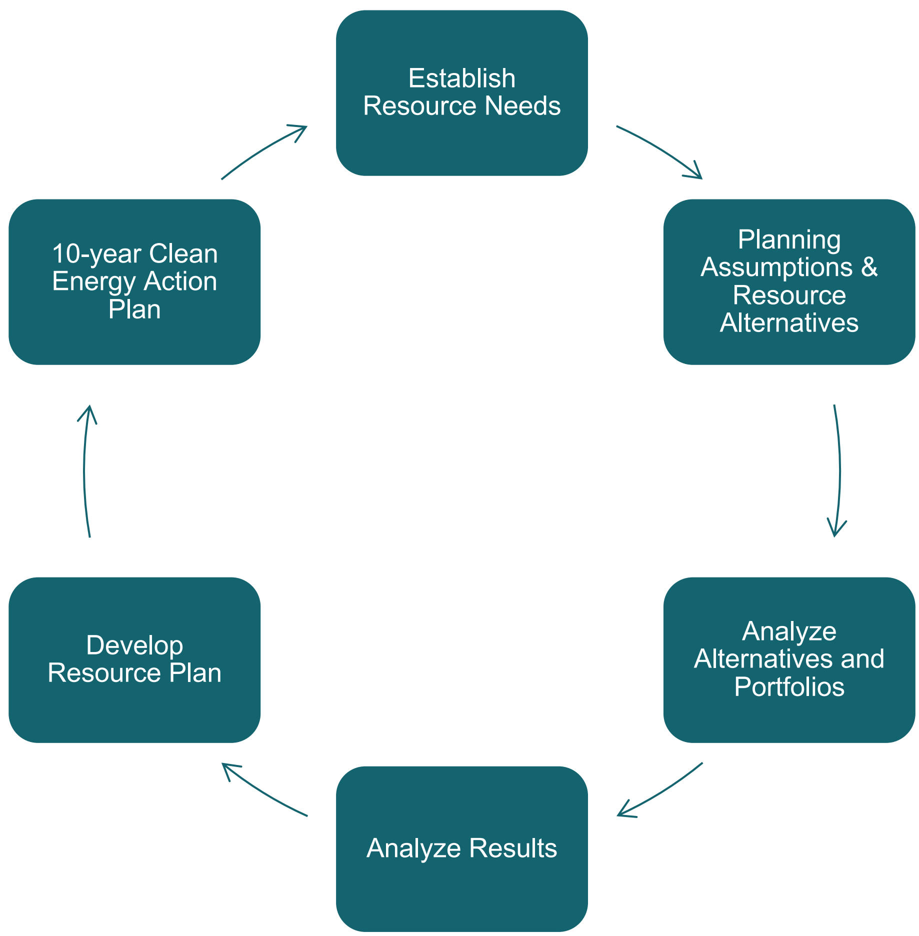
6. Create the 10-year Clean Energy Action Plan

Resource decisions are not made in the IRP. What we learn from the IRP forecasting exercise determines the IRP Action Plan and the 10-year Clean Energy Action Plan.

- The Action Plan is presented in the Executive Summary, Chapter 1.
- The 10-year Clean Energy Action Plan is presented in Chapter 2.

Figure 8-1 illustrates this process.

Figure 8-1: 2021 IRP Process



2. SUMMARY OF SUBSTANTIVE CHANGES

The 2021 IRP marks a major departure from past IRPs due in large part to the passage of the Clean Energy Transformation Act. Changes in technology, updates to datasets and other advances have also contributed to differences in the 2021 IRP. This section provides a summary of the substantive changes from the 2017 IRP to the 2021 IRP.

ELECTRIC POWER PRICES. Several updates were made to the development of the electric price model. AURORA, the power system software used for electric price simulations, was updated to version 13.4 in the 2021 IRP from version 12.3 in the 2017 IRP. In addition, the AURORA Zonal database was updated to the “2018 version 1” release in the 2021 IRP from the “2016 version 3” release used in the 2017 IRP. A detailed account of all updates to the electric price model is provided throughout Chapter 5 and Appendix G.

GENERIC RESOURCE COSTS. In the 2021 IRP, PSE developed a new process for obtaining generic resource costs. In past IRPs, PSE has relied on consultants to estimate generic resource costs. In the 2021 IRP, PSE aggregated publically available generic resource costs from a variety of sources. These data were presented to stakeholders during a public meeting and stakeholder input was used to refine generic resource cost assumptions. This framework mirrors the generic resource cost development process used by the Northwest Power and Conservation Council’s Generic Resource Advisory Group.

LEGISLATION. In 2019, the Clean Energy Transformation Act (CETA) passed into law. CETA set forth aggressive targets for clean and non-emitting resources. Investor-owned utilities are required to obtain 80 percent of energy sales from non-emitting resources by 2030 and 100 percent of energy sales from non-emitting resources by 2045. This dramatically increases the 15 percent renewable portfolio standard established by RCW 19.285. Furthermore, CETA introduced the need to incorporate the social cost of greenhouse gases and the equitable distribution of customer benefits in the resource planning process.

RESOURCE ADEQUACY MODEL. Between the 2017 IRP and the 2021 IRP, PSE completely overhauled its resource adequacy model. This included moving from a SAS based model to a Python based model that incorporates inputs from regional resource adequacy metrics. A full description of the new resource adequacy model is available in Chapter 7.

ELECTRIC PORTFOLIO MODEL. During the three years since the last IRP was filed, PSE has made significant improvements to the portfolio modeling process. For the 2017 IRP, PSE used an Excel-based model called the Portfolio Screening Model (PSM). This annual model relied on AURORA to dispatch the resources, then the data was pulled into PSM where a solver was added to Excel for the linear programming optimization model. By moving the LP optimization model directly into AURORA, PSE is able to evaluate the economic retirement of resources, increase the selection of new generic resources, model energy storage and hybrid resources, and a utilize a more robust solver engine.

STOCHASTIC MODEL. Since the 2017 IRP, PSE has moved stochastic modeling from a simple SAS model to a full dispatch and forecasting model in AURORA. The SAS model used in 2017 looked at historical trends to forecast out a range of monthly electric prices. By moving the electric price model into AURORA, PSE is able to achieve a more forward looking forecast based on the new legislation and changing mix of resources in the region. In the new stochastic model, no historical data is used, only forward looking changes in the region. AURORA then runs a complete dispatch of resources by hour for each draw and produces a forecast of hourly electric prices instead of monthly prices.

CONSERVATION POTENTIAL ASSESSMENT. In the 2017 IRP, the conservation potential assessment (CPA) was conducted by third-party Navigant Consulting. In the 2021 IRP, PSE retained a different consultant, CADMUS, to conduct the CPA. A full description of the CPA is available in Appendix E.

DEMAND FORECAST. The 2017 IRP base demand forecast was based on 2016 macroeconomic conditions such as population growth and employment; the forecast for the 2021 IRP is based on 2020 macroeconomic conditions. The updates to inputs and equations are documented in Chapter 6.

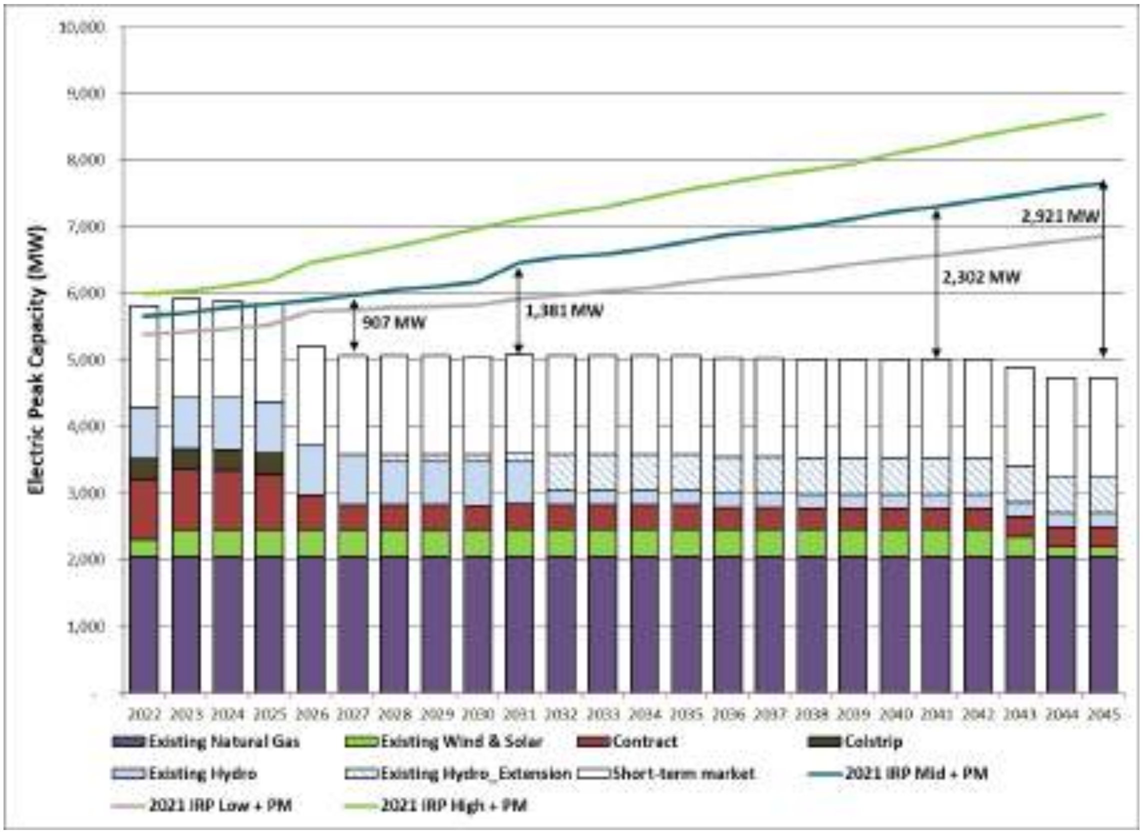
3. RESOURCE NEED

PSE's energy supply portfolio must meet the electric needs of our customers reliably. For resource planning purposes, those physical needs are simplified and expressed in three measurements: 1) peak hour capacity for resource adequacy, i.e., does PSE have the amount of capacity available in each hour to meet customer's electricity needs; 2) hourly energy, i.e., does PSE have enough energy available in every hour to meet customer's electricity needs; and 3) renewable energy, i.e., does PSE have enough renewable and non-emitting resources to meet the clean energy transformation targets.

Peak Capacity Need

Figure 8-2 shows the peak capacity need for the mid demand forecast modeled in this IRP (mid demand refers to the 2021 IRP Base Demand Forecast described in Chapter 6). Using the loss of load probability (LOLP) methodology, it was determined that 907 MW of capacity is needed by 2027 and 1,381 MW of capacity by 2031 before any new conservation. A full discussion of the peak capacity need is presented in Chapter 7, Resource Adequacy Analysis. The physical characteristics of the electric grid are very complex, so for planning purposes PSE simplifies physical resource need into a peak hour capacity metric using PSE's Resource Adequacy Model (RAM).

Figure 8-2: Electric Peak Capacity Need
(physical reliability need, peak hour need compared with existing resources)



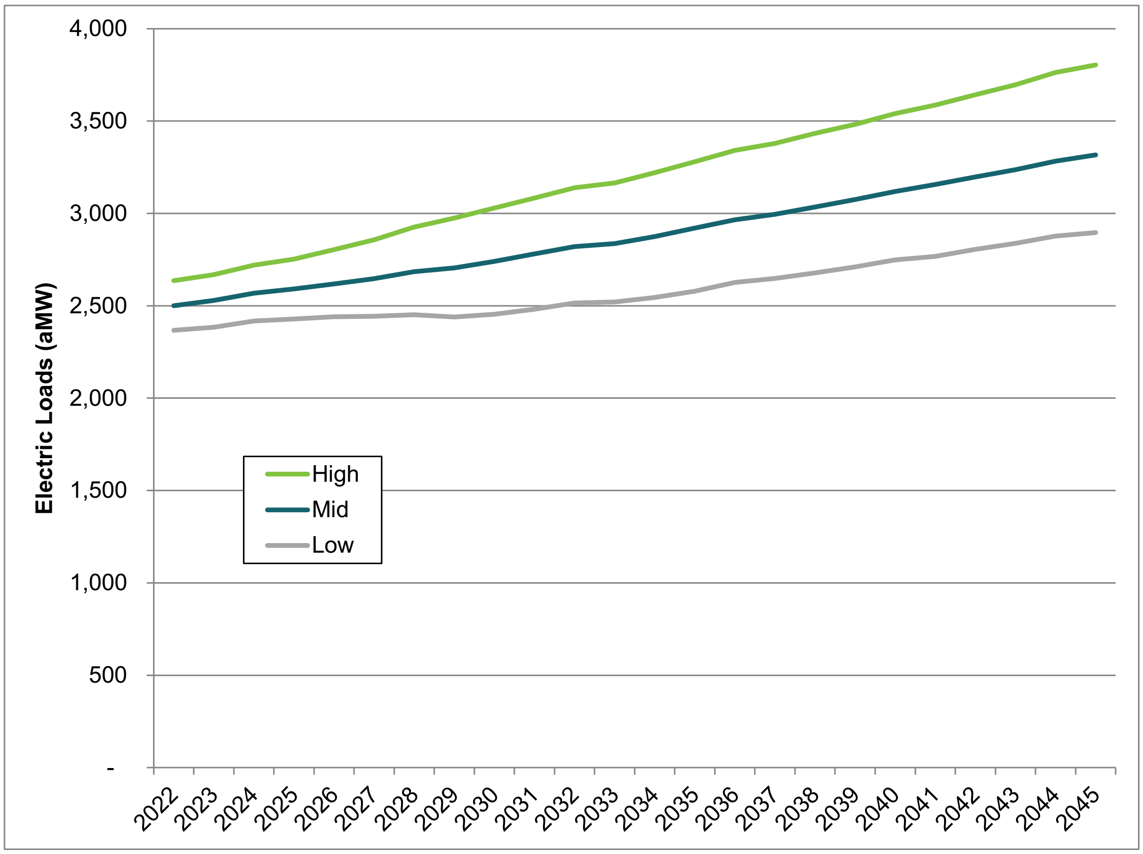
Energy Need

Compared to the physical planning constraints that define peak resource need, meeting customers' "energy need" for PSE is more of a financial concept that involves minimizing costs. Portfolios are required to cover the amount of energy needed in every hour to meet physical loads, but our models also examine how to do this most economically.

Unlike utilities in the region that are heavily dependent on hydro, PSE has thermal resources that can be used to generate electricity if needed. In fact, PSE could generate significantly more energy than needed to meet our load on an average monthly or annual basis, but it is often more cost effective to purchase wholesale market energy than to run our high-variable cost thermal resources. We do not constrain (or force) the model to dispatch resources that are not economical; if it is less expensive to buy power than to dispatch a generator, the model will choose to buy power in the market. Similarly, if a zero (or negative) marginal cost resource like wind is available, PSE's models will displace higher-cost market purchases and use the wind to meet the energy need.

Figure 8-3 illustrates the company's energy demand forecast across the planning horizon, based on the energy demand forecast for the Mid, High and Low Scenarios. The Mid Demand Scenario starts at 2,500 aMW in 2022 and grows to 2,740 aMW by 2030 and 3,316 aMW by 2045.

Figure 8-3: Annual Demand Forecast



Renewable Need

Washington State has two renewable energy requirements. The first is a renewable portfolio standard (RPS) that requires PSE to meet specific percentages of our load with renewable resources or renewable energy credits (RECs) by specific dates. Under the Energy Independence Act (RCW 19.285), PSE must meet 15 percent of retail sales with renewable resources by 2020. PSE has sufficient qualifying renewable resources to meet RPS requirements until 2023, including the ability to bank RECs. Existing hydroelectric resources may not be counted towards RPS goals except under certain circumstances for new run of river plants and efficiency upgrades to existing hydro plants.

The second renewable energy requirement is Washington State's Clean Energy Transformation Act (CETA). CETA requires that at least 80 percent of electric sales (delivered load) in Washington state be met by non-emitting/renewable resources by 2030 and 100 percent by 2045. The difference between CETA and RCW 19.285 is that hydro resources are qualifying renewable resources for compliance with CETA, and other non-emitting resources can be used to meet the requirements.

Washington State's RPS and renewable energy requirements calculate the required amount of renewable resources as a percentage of megawatt hour (MWh) sales; therefore, when MWh sales decrease, so does the amount of renewables needed. Achieving demand-side resource targets has precisely this effect. Demand-side resources decrease sales volumes, which then decreases the amount of renewable resources needed.

Figure 8-4 below shows the calculation for the 80 percent renewable requirement in 2030 to meet CETA. The first line of the table provides the estimated demand forecast in the year 2030 before demand-side resources (conservation) are applied. From this value, energy savings from conservation, line losses to adjust the demand forecast to retail sales, load reducing customer programs and PURPA generation[1] are subtracted to yield the sales net of conservation and customer programs (20.4 million MWh). Eighty-percent of this value represents the raw renewable need for 2030 (16.3 million MWh). From this value, existing renewable generation is subtracted to obtain the need for new renewable and non-emitting resources (7.6 million MWh).

Demand-side resources are optimized within the portfolio model and will provide a further reduction to the need shown in the last line of the table. Under normal hydro conditions and without the addition of new renewable/non-emitting resources, PSE will meet 40 percent of sales with renewable resources in 2022.

1 / The Public Utility Regulatory Policies Act of 1978 (PURPA) created a new class of generating resources known as qualifying facilities. Energy from qualifying facilities is included in this line item.

Figure 8-4: Calculation of 2021 IRP Renewable Need for 2030

	MWh
2030 Estimated Demand Forecast before Conservation[1]	24,004,160
Conservation: Codes & Standards, Solar PV	(774,387)
Line Losses	(1,579,625)
Load Reducing Customer Programs & PURPA	(1,243,449)
Sales Net of Conservation and Customer Programs	20,406,699
80% of Estimated Net Sales	16,325,360
Existing Non-emitting Resources[2]	(8,691,268)
Need for New Renewable/Non-emitting Resources	7,634,092

NOTES
1. 2021 IRP base demand forecast with no new conservation starting in 2022
2. Assumes normal hydro conditions and P50 wind and solar

Figure 8-5 below illustrates the renewable energy need for both RCW 19.285 and CETA based on the mid demand forecast, before any additional demand-side resources are added.

Figure 8-5: Qualifying Energy Need to Meet RCW 19.285 and CETA Requirements (before demand-side resources)

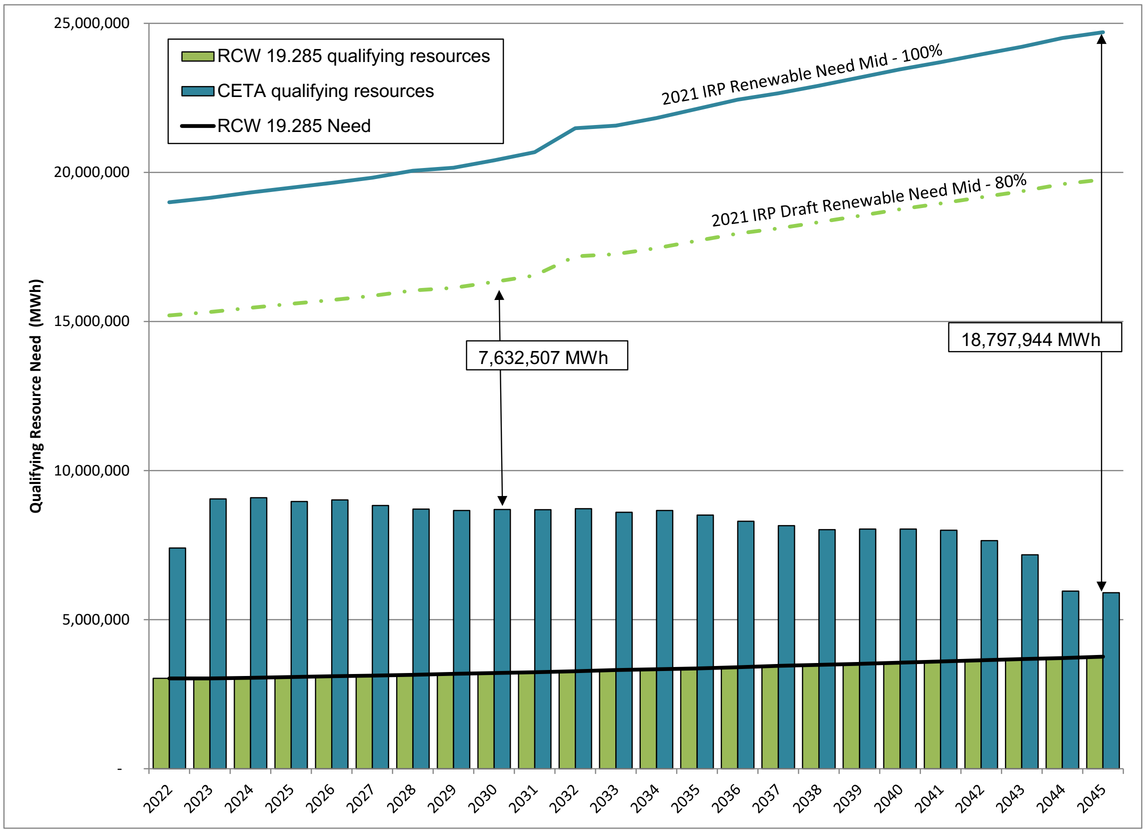
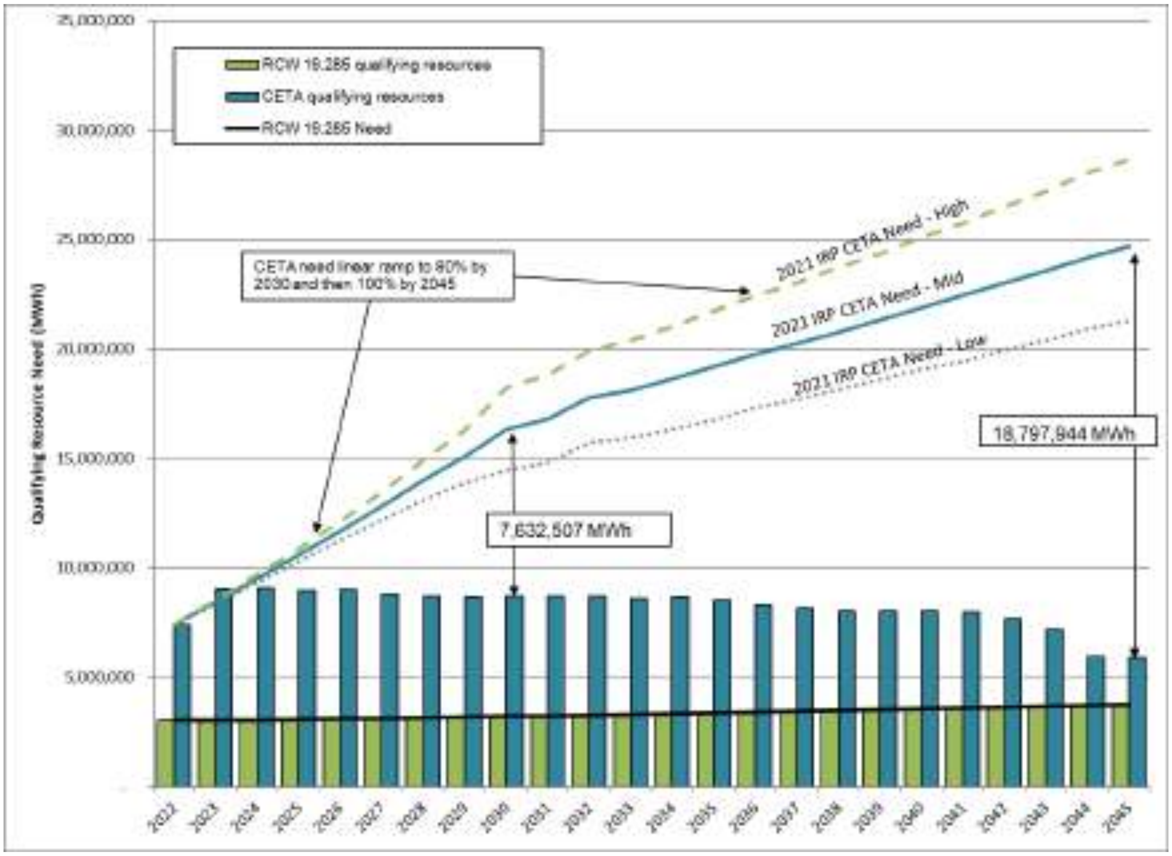


Figure 8-6 below assumes a linear ramp to reach the CETA 80 percent clean energy standard in 2030 and 100 percent clean energy standard in 2045. The linear ramp is needed to ensure that the portfolio model gradually adds resources to meet clean energy standards, rather than waiting until the final year before a goal must be achieved to add them. The linear ramp starts in 2022, as the IRP assumes all new resources are self-builds that will take at least two years before becoming operational. Since the IRP analysis starts in 2022, the earliest a resource can be built is 2024.

Figure 8-6: Renewable Need and Linear Ramp for CETA (before demand-side resources)



4. TYPES OF ANALYSIS

PSE uses deterministic optimization analysis to identify the lowest reasonable cost portfolio for each scenario. We then run a stochastic risk analysis to test different resource strategies.[2] The customer benefit analysis is used to inform the equitable distribution of burdens and benefits in the resource planning process to ensure that all customers are benefiting from the transition to clean energy.

Deterministic Portfolio Optimization Analysis

All scenarios and sensitivities are subjected to deterministic portfolio analysis in the first stage of the resource plan analysis. This identifies the least-cost integrated portfolio – that is, the lowest cost mix of demand-side and supply-side resources that will meet need under the given set of static assumptions defined in the scenario or sensitivity. This stage helps PSE to learn how specific input assumptions, or combinations of assumptions, can impact the least-cost mix of resources.

Deterministic analysis helps to answer the question: How will different resource alternatives dispatch to market given the assumptions that define each of the scenarios and sensitivities? All of PSE's existing resources are modeled, plus all of the generic resource alternatives.

Stochastic Risk Analysis

In this stage of the resource plan analysis, PSE examines how different resource strategies respond to the types of risk that go hand-in-hand with future uncertainty. Inputs that were static in the deterministic analysis are deliberately varied to create simulations called "draws" used to analyze the different portfolios. This allows PSE to learn how different strategies perform with regard to cost and risk across a wide range of power prices, gas prices, hydro generation, wind generation, loads and plant forced outages.

With stochastic risk analysis, PSE tests the robustness of different portfolios; in other words, determine how well the portfolio might perform under a range of different conditions. The goal is to understand the risks of different candidate portfolios in terms of costs and revenue requirements. This involves identifying and characterizing the likelihood of bad events and the likely adverse impacts they may have on a given portfolio.

2 / To screen some resources, we also use simpler, levelized cost analysis to determine if the resource is close enough in cost to justify spending the additional time and computing resources to include it in the two-step portfolio analysis.

For this purpose, PSE takes some of the portfolios (drawn from the deterministic analysis of scenario and sensitivity portfolios) and runs them through 310 draws[3] that model varying power prices, gas prices, hydro generation, wind and solar generation, load forecasts (energy and peak), and plant forced outages. This stochastic analysis enables PSE to evaluate the risk associated with the selected portfolios to inform the preferred portfolio.

Customer Benefits Analysis

The Clean Energy Transformation Act requires utility resource plans to ensure that all customers benefit from the transition to clean energy. The analysis of the equitable distribution of burdens and benefits into the resource planning process is new in the 2021 IRP. PSE is excited to incorporate these new ideas into the resource planning process, but acknowledges that stakeholder input and institutional learning must be allowed to evolve the process. Below is a brief overview of PSE's first attempt to incorporate customer benefits into the IRP process.

Incorporating the equitable distribution of burdens and benefits into the resource planning process requires a multifaceted approach. Therefore, PSE has developed several tools and methods; these include the Economic, Health and Environmental Benefits (EHEB) Assessment, the Equity Advisory Group (EAG) and the Customer Benefits Analysis.

The EHEB Assessment is an analysis outside of the IRP portfolio modeling process that seeks to determine how benefits and burdens are distributed among PSE customers. The EHEB Assessment provides a snapshot of current conditions across PSE's service area that shows where disparities exist and identifies key constituencies (vulnerable populations and highly impacted communities) which are at greater risk according to a range of customer benefit indicators. Customer benefit indicators are measures that speak to the degree to which specific groups are burdened or benefit from public health, environmental, economic and societal impacts. A full description of the methods and results of the EHEB Assessment are provided in Appendix K.

More directly related to the portfolio development process is the Customer Benefit Analysis. Historically, the IRP selected a preferred portfolio based on cost and reliability alone. CETA legislation has added the consideration of customer benefit indicators to these criteria. Since existing portfolio optimization software lacks the ability to incorporate customer benefit indicators, the Customer Benefit Analysis is performed outside of the portfolio and iterated into the overall portfolio development process. The Customer Benefit Analysis ranks portfolios based on a number of customer benefit indicators. Portfolios with high ranks help to inform key components

3 / Each of the 250 simulations is for the 24-year IRP forecasting period, 2022 through 2045.

that should be incorporated into the preferred portfolio. Preferred portfolio candidates are then incorporated into the ranking process to ensure they provide a suitable balance of customer benefit indicators. It is not enough to score well in one or two customer benefit indicator areas, a good portfolio must provide a range of benefits.

Portfolio outputs were mapped to customer benefit indicators using PSE's best judgement. The customer benefit indicators selected for the Customer Benefit Analysis do not necessarily align directly to the customer benefit indicators used in the EHEB Assessment. This is because of data availability constraints of each analysis. In future IRP cycles, PSE aims to better align customer benefit indicators across all analyses through customer input and insights from the Equity Advisory Group. Figure 8-7 provides an overview of the customer benefit indictors used in the Customer Benefit Analysis.

Figure 8-7: Customer Benefit Indicators for Portfolio Analysis

Area	Customer Benefit Indicator	Definition
Air Quality	Particulate Matter Emissions	Total emissions from thermal resources. Measured in tons.
	SO_2 Emissions	Total emissions from thermal resources. Measured in tons.
	NO_x Emissions	Total emissions from thermal resources. Measured in tons.
Environment	Renewable Generation	Energy generated from utility-scale renewable resources. Measured in MWh.
	Customer Programs	Energy generated from Green Direct, Green Power and Qualifying Resources. Measured in MWh.
	Energy Efficiency	Energy savings from energy efficiency, distribution efficiency and codes and standards. Measured in MWh.
	Distributed Generation	Energy generated from distributed solar (rooftop and ground-mounted), non-wires alternatives and net metering. Measured in MWh.
Economic	Portfolio Cost	Levelized cost of the portfolio. Measured in billions of dollars.
Energy Resiliency	Storage	Capacity of distributed storage added to the portfolio. Measured in MW.

Area	Customer Benefit Indicator	Definition
Climate Change	Social Cost of Greenhouse Gases	Levelized social cost of greenhouse gases. Measured in billions of dollars.
	Greenhouse Gas Emissions	CO_2 equivalent emissions. Measured in tons.
Market Position	Market Purchases	Energy purchased from market. Measured in MWh.
Resource Adequacy	Demand Response	Capacity of demand response programs in the portfolio. Measured in MW.

The customer benefit indicators are measured values from each portfolio analyzed. Measurements may be taken over various intervals along the planning horizon to gain an understanding of how customer benefit indicators evolve over time. For example, greenhouse gas emissions may be measured in the year 2031 to understand climate impacts at the 10-year Clean Energy Action Plan planning horizon as well as in the year 2045 to get a view of climate impacts for the entire IRP period.

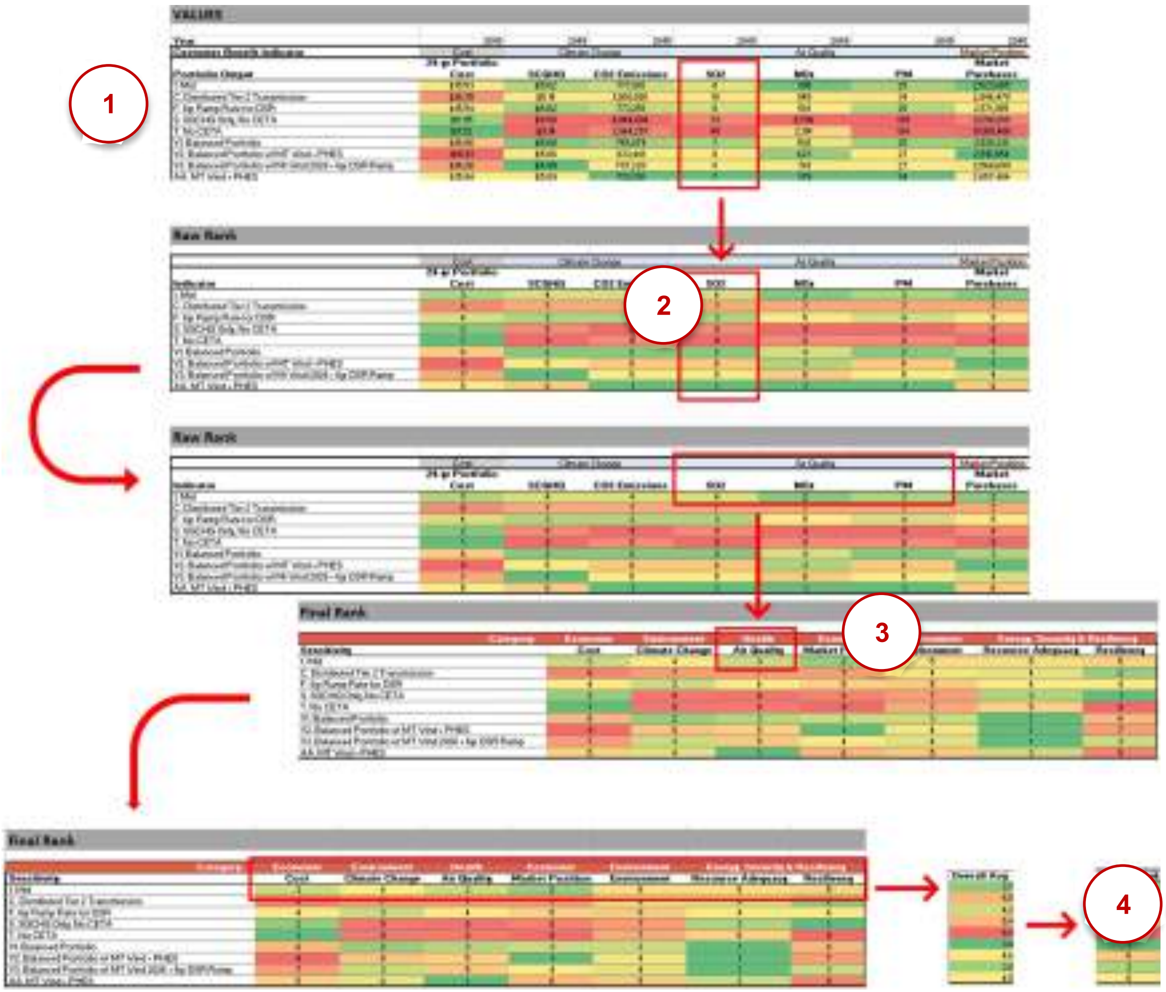
To make meaningful decisions about how different portfolios impact PSE's customers, the relative strengths and weaknesses of the portfolios are compared using the different customer benefit indicators.

The process to compare portfolio tradeoffs is depicted in Figure 8-8:

1. Values for each customer benefit indicator are extracted from the AURORA portfolio model for each portfolio being compared.
2. Values for each customer benefit indicator are ranked; where the most beneficial (or least burdensome) portfolio receives a rank of 1 and the least beneficial (or most burdensome) portfolio receives a rank of ‘n’, where there are n portfolios compared.
3. Individual customer benefit indicators are aggregated into customer benefit areas to more evenly distribute the benefit of each the various areas. For example, the ranks of SO_2, NO_x and PM are averaged together by portfolio to obtain an air quality rank.
4. Finally, for each portfolio, all the customer benefit indicator area ranks are averaged together to produce an overall average which is then converted to an overall rank.

The portfolio with the rank of 1 would provide the best balance of all customer benefit indicators. Furthermore, specific pieces of information may be used throughout the portfolio development process to help derive a more desirable portfolio. For example, the results for Sensitivity C: Distributed, Tier 2 Transmission Constraints, obtain favorable ranks in the Environment customer benefit indicator area, due to the large amount of energy efficiency and distributed resources in the portfolio. These elements may be incorporated into the preferred portfolio to improve its benefit to the environment.

Figure 8-8: Portfolio Ranking Process



NOTE: Data contained within this figure is draft and intended for demonstration purposes only. The results of the Customer Benefit Analysis is provided later in this chapter and a complete set of customer benefit indicator ranks is provided in Appendix H.

PSE recognizes the customer benefit indicators used in the Final IRP are preliminary and will evolve with time. Future IRPs will have the benefit of input from the Equity Advisory Group and the CEIP public participation process. In particular, two areas of consideration that require further stakeholder input have been identified so far:

- **Qualitative measures:** Although most customer benefit indicators are directly tied to quantitative metrics from the portfolio output, PSE recognizes that some customer benefit indicators may also be qualitative in nature. As qualitative measures are developed, this work may evolve the portfolio customer benefit indicator framework to incorporate indicators which are not directly related to specific portfolio model outputs.

- **Weighting factors:** Additionally, PSE understands some indicators may be more important than others to customers, especially for highly impacted communities and vulnerable populations, and thus require additional collaboration with stakeholders to determine the best weighting to apply across indicators and/or portfolios.

5. KEY FINDINGS

This section summarizes the assumptions for the economic scenarios, portfolio sensitivities and customer benefits indicators developed for this IRP; discusses the key findings from these analyses; and summarizes the optimal portfolio costs and builds produced by the scenario, sensitivity and customer benefits analyses. The following tables are included.

- Figure 8-9: 2021 IRP Electric Portfolio Scenarios and Sensitivities
- Figure 8-10: Relative Optimal Portfolio Costs by Sensitivity
- Figure 8-11: Relative Optimal Portfolio Builds by Sensitivity

> > > See Chapter 5, Key Assumptions, for a detailed description of the scenarios and sensitivities and the key assumptions used to create them: customer demand, natural gas prices, possible CO_2 prices, resource costs (demand-side and supply-side) and power prices.

> > > See Appendix D, Electric Resource Alternatives, for a detailed discussion of existing electric resources and resource alternatives.

> > > See Appendix K, Economic, Health and Environmental Benefits Assessment of Current Conditions, for a detailed discussion of the customer indicators developed for the customer benefits analysis.

Summary of Assumptions

Figure 8-9: 2021 IRP Electric Portfolio Sensitivities

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
ECONOMIC SCENARIOS		
1	Mid	Mid gas price, mid demand forecast[a.], mid electric price forecast
2	Low	Low gas price, low demand forecast, low electric price forecast
3	High	High gas price, high demand forecast, high electric price forecast
FUTURE MARKET AVAILABILITY		
A	Renewable Overgeneration Test	The portfolio model is not allowed to sell excess energy to the Mid-C market.
B	Reduced Firm Market Access at Peak	The portfolio model has a reduced access to the Mid-C market for both sales and purchases.
TRANSMISSION CONSTRAINTS AND BUILD LIMITATIONS		
C	"Distributed" Transmission/Build Constraints - Tier 2	The portfolio model is performed with Tier 2 transmission availability.
D	Transmission/Build Constraints – Time-delayed (Option 2)	The portfolio model is performed with gradually increasing transmission limits.
E	Firm Transmission as a Percentage of Resource Nameplate	New resources are acquired with firm transmission equal to a percentage of their nameplate capacity instead of their full nameplate capacity.
CONSERVATION ALTERNATIVES		
F	6-Year Conservation Ramp Rate	Energy efficiency measures ramp up over 6 years instead of 10.
G	Non-energy Impacts	Increased energy savings are assumed from energy efficiency not captured in the original dataset.
H	Social Discount Rate for DSR	The discount rate for demand-side resource measures is decreased from 6.8% to 2.5%.
SOCIAL COST OF GREENHOUSE GASES (SCGHG) AND CO_2 REGULATION		
I	SCGHG as an Externality Cost in the Portfolio Model	The SCGHG is used as an externality cost in the portfolio expansion model.
J	SCGHG as a Dispatch Cost in Electric Prices and Portfolio	The SCGHG is used as a dispatch cost (tax) in both the electric price forecast and portfolio model.
K	AR5 Upstream Emissions	The AR5 model is used to model upstream emissions instead of AR4.
L	SCGHG as a Fixed Cost Plus a Federal CO_2 Tax	Federal tax on CO_2 is included in addition to using the SCGHG as a fixed cost adder.

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
EMISSION REDUCTION		
M	Alternative Fuel for Peakers	Peaker plants use biodiesel as an alternative fuel.
N	100% Renewable by 2030	The CETA 2045 target of 100% renewables is moved up to 2030, with no new natural gas generation.
O	100% Renewable by 2045	All existing natural gas plants are retired in 2045.
P	No New Thermal Resources before 2030	1. This portfolio limits peaker builds before 2030 so that the model must meet peak capacity with alternative resources. 2. Build pumped hydro storage instead of battery energy storage to meet peak capacity before 2030. 3. Build 4-hour lithium-ion battery energy storage to meet peak capacity before 2030.
DEMAND FORECAST ADJUSTMENTS		
Q	Fuel Switching, Gas to Electric	Gas-to-electric conversion is accelerated in the PSE service territory.
R	Temperature Sensitivity	Temperature data used for economic forecasts is composed of more recent weather data as a way to represent changes in climate.
CETA COSTS		
S	SCGHG Included, No CETA	The SCGHG is included in the portfolio model without the CETA renewable requirement.
T	No CETA	The portfolio model does not have CETA renewable requirement or the SCGHG adder.
U	2% Cost Threshold	CETA is considered satisfied once the 2% cost threshold is reached.
BALANCED PORTFOLIO		
V	Balanced Portfolio	1. The portfolio model must take distributed energy resources ramped in over time and more customer programs. 2. The portfolio model must take distributed energy resources ramped in over time, more customer programs, and early addition of a MT wind + pumped hydro storage resource. 3. The portfolio model must take distributed energy resources ramped in over time, more customer programs, and conservation measures are ramped in over 6 years, instead of 10.
W	Balanced Portfolio with Alternative Fuel for Peakers	The portfolio model must take distributed energy resources ramped in over time and more customer programs, plus carbon-free combustion turbines using biodiesel as the fuel.

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
X	Balanced Portfolio with Reduced Firm Market Access at Peak	The portfolio model must take distributed energy resources ramped in over time and more customer programs, plus reduced access to the Mid-C market for both sales and purchases.
WX	Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak	The portfolio model implements the changes from portfolios W and X simultaneously.
Y	Maximum Customer Benefit	RCW 19.405.040 (8) In complying with this section, an electric utility must, consistent with the requirements of RCW 19.280.030 and 19.405.140, ensure that all customers are benefiting from the transition to clean energy: Through the equitable distribution of energy and nonenergy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits and reduction of costs and risks; and energy security and resiliency.
OTHER		
Z	No DSR	This portfolio includes no new demand-side resources. (energy efficiency, distribution efficiency and demand response)
AA	Montana Wind + Pumped Hydro Storage	This portfolio adds the hybrid resource of MT wind + pumped hydro storage instead of only the MT wind resource in 2026.

NOTE
a. Mid demand refers to the 2021 IRP Base Demand Forecast.

Key Findings: Economic Scenarios

The quantitative results produced by extensive analytical and statistical evaluation led to the key findings summarized in the following pages.

Economic Scenarios

Portfolio additions are very similar across all three economic scenarios. The amount of resources added increased or decreased based on high and low load forecasts, respectively. Direct emissions are lower with the retirement of Centralia and the removal of Colstrip 3 & 4 in 2025 as part of CETA compliance, and continue trending down throughout the planning horizon. The renewable requirement to meet CETA drives the renewable builds for each scenario.

Key Findings: Portfolio Sensitivities

Future Market Availability

Renewable overgeneration occurs when renewable resources generate more energy than there is demand. Limiting market access, either sales or purchases, increases the cost of CETA implementation by overbuilding battery storage to store the overgeneration of renewable resources instead of selling it to the market. Reducing the reliance on short-term market during peak increases the peak need for new capacity resources or firm resource adequacy qualifying contracts.

Transmission Constraints and Build Limitations

The majority of new renewable resources included in the 2021 IRP are sited outside of PSE's service area. These resources require transmission to deliver power from the generation site to PSE's customers. Transmission is a relatively scarce asset, and there is uncertainty about PSE's ability to procure transmission for the optimal renewable resource mix. Varying the amount of transmission available to regions around PSE's service area measures the impact of these uncertainties.

There is little impact on portfolio build decisions when transmission constraints are modeled to match transmission procurement expectations and timelines (Sensitivity D). This suggests that the generally unconstrained transmission identified for this IRP is a reasonable assumption for the comparative portfolio sensitivity analysis.

However, portfolio build decisions shift when transmission constraints limit resource build to under 3,070 MW outside of PSE's service area (Sensitivity C). More distributed solar resources located within PSE’s service territory are selected and battery storage is increased to help balance generation and demand.

When contracting firm transmission less than the nameplate capacity of resources, site location and fixed transmission costs are important considerations. Project sites with low transmission costs tend to benefit less than sites with high transmission costs. Wind resources tend to benefit less than solar resources due to the significant portion of time that wind resources spend generating at or near nameplate capacity (i.e., rated power).

Conservation Alternatives

Across the conservation alternatives evaluated for this IRP, cost-effective demand-side resources, portfolio costs and build decisions remain relatively stable. Incremental energy savings by bundle vary depending on the conservation alternative driving the bundle selection. Changes in the assumptions for the conservation alternatives pushed more energy savings into lower bundles. In some results, decreased investment in conservation measures is supplemented by increased demand response measures. By changing the ramp rates and discount rate of the bundles, the portfolio moves into lower bundle levels than the Mid portfolio, but still adds a similar or lower amount of conservation as the Mid portfolio. Overall, the baseline assumptions around demand-side resources included in the mid portfolio optimize to the highest amount DSR added to the portfolio by 2045.

Demand response and conservation are important resource options in PSE’s portfolio, and they are considered load-reducing resources in the calculation of the CETA renewable need. Absent these resources, the portfolio adds more renewable resources, resulting in increased portfolio costs.

Social Cost of Greenhouse Gases (SCGHG) and CO_2 Regulation

Different modeling approaches to incorporating the social cost of greenhouse gases do not have a material impact on the cost-effective amount of conservation, demand response and other resource additions or retirements.

Whether modeling SCGHG as a fixed cost planning adder, a dispatch cost in the resource selection or as a dispatch cost in both the resource selection and hourly portfolio run, CETA requirements for renewable resources are the key driver of portfolio resource additions and costs.

Using the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5) to calculate upstream emissions increased those emissions for natural gas, but did not change resource builds or retirements compared to utilizing the IPCC’s Fourth Assessment Report (AR4).

Applying a Federal CO_2 tax in addition to SCGHG as a fixed-cost planning adder does appear to alter portfolio build decisions, resulting in the addition of fewer thermal resources. Dispatch from thermal plants also declines over time resulting in lower portfolio emissions.

Emissions Reduction

Reducing emissions and even achieving a 100 percent renewable portfolio may be possible with existing technologies, but the cost to do so is high. Large investments in storage to replace thermal resources results in high portfolio costs. Although direct emissions from generating resources are reduced, indirect emissions from market purchases increase because energy purchased from the market is needed to support the storage-heavy portfolios.

Demand Forecast Adjustments

Using alternative temperature data to forecast demand and use in the resource adequacy analysis lowers the demand forecast and the peak capacity need. The lower demand forecast lowers the CETA renewable need. The reduction in peak capacity need results in all future needs being met by new renewable resources and battery energy storage.

On the other hand, fuel switching from gas to electric results in a higher demand forecast and higher CETA renewable need. Resource builds of every resource type increased to support the higher loads.

CETA Costs

CETA requirements drive renewable resource build decisions. Absent CETA requirements, no renewable resources are added to the portfolio except a wind resource towards the end of the planning horizon, which is needed to maintain compliance with RCW 19.285, and more flexible capacity resources are added over time to meet increasing peak capacity need. The cost of the No CETA portfolio is significantly lower than the CETA-compliant portfolios. This is an initial attempt to evaluate the incremental cost of compliance. Portfolio costs stay within the 2 percent annual revenue requirement for the early part of the planning horizon, but increase over time and exceed the 2 percent cost threshold by 2030.

Balanced Portfolio

A forecast of distributed energy resources (DERs) and customer programs ramped in over time helps to spread the revenue requirement throughout the planning horizon. Although DERs have lower peak capacity contributions and increase portfolio costs, there are customer benefits to be gained related to air quality and environment. Significant emission reductions are achieved with the addition of non-emitting resources, the retirement of coal resources and lower dispatch of existing resources. The availability of biodiesel fuel for peaking capacity resources further reduces emissions.

Relative Optimal Portfolio Costs, Builds and Emissions

Figure 8-10: Relative Optimal Portfolio Costs by Sensitivity
(dollars in billions, NPV including end effects)

	24-Yr Levelized Costs ($ Billions)			
Portfolio	**Revenue Requirement**	**SCGHG Adder**	**Total**	**Change from Mid**
1 Mid	$15.53	$5.09	$20.62	$0.00
2 Low	$12.08	$4.53	$16.61	($4.01)
3 High	$21.37	$5.74	$27.11	$6.49
A Renewable Overgeneration	$17.11	$4.45	$21.55	$0.93
B Market Reliance	$16.57	$5.19	$21.76	$1.14
C Distributed Transmission	$16.35	$5.21	$21.56	$0.94
D Transmission/build constraints - time delayed (option 2)	$15.54	$5.11	$20.65	$0.03
F 6-Yr DSR Ramp	$15.54	$5.09	$20.62	$0.00
G NEI DSR	$15.24	$5.12	$20.36	($0.26)
H Social Discount DSR	$15.77	$5.16	$20.94	$0.32
I SCGHG Dispatch Cost - LTCE Model	$15.41	$5.10	$20.51	($0.11)
J SCGHG Dispatch Cost - LTCE and Hourly Models	$18.45	$4.81	$23.26	$2.64
K AR5 Upstream Emissions	$15.56	$5.14	$20.71	$0.09
L SCGHG Federal CO2 Tax as Fixed Cost	$17.77	$4.71	$22.47	$1.86
M Alternative Fuel for Peakers - Biodiesel	$15.53	$4.99	$20.52	($0.10)
N1 100% Renewable by 2030 Batteries	$32.03	$3.76	$35.79	$15.17
N2 100% Renewable by 2030 PSH	$66.64	$2.52	$69.16	$48.54
O1 100% Renewable by 2045 Batteries	$23.35	$4.81	$28.16	$7.54
O2 100% Renewable by 2045 PSH	$46.95	$3.98	$50.94	$30.32
P1 No Thermal Before 2030, 2Hr LiIon	$30.84	$6.38	$37.22	$16.60
P2 No Thermal Before 2030, PHES	$22.85	$4.77	$27.62	$7.00

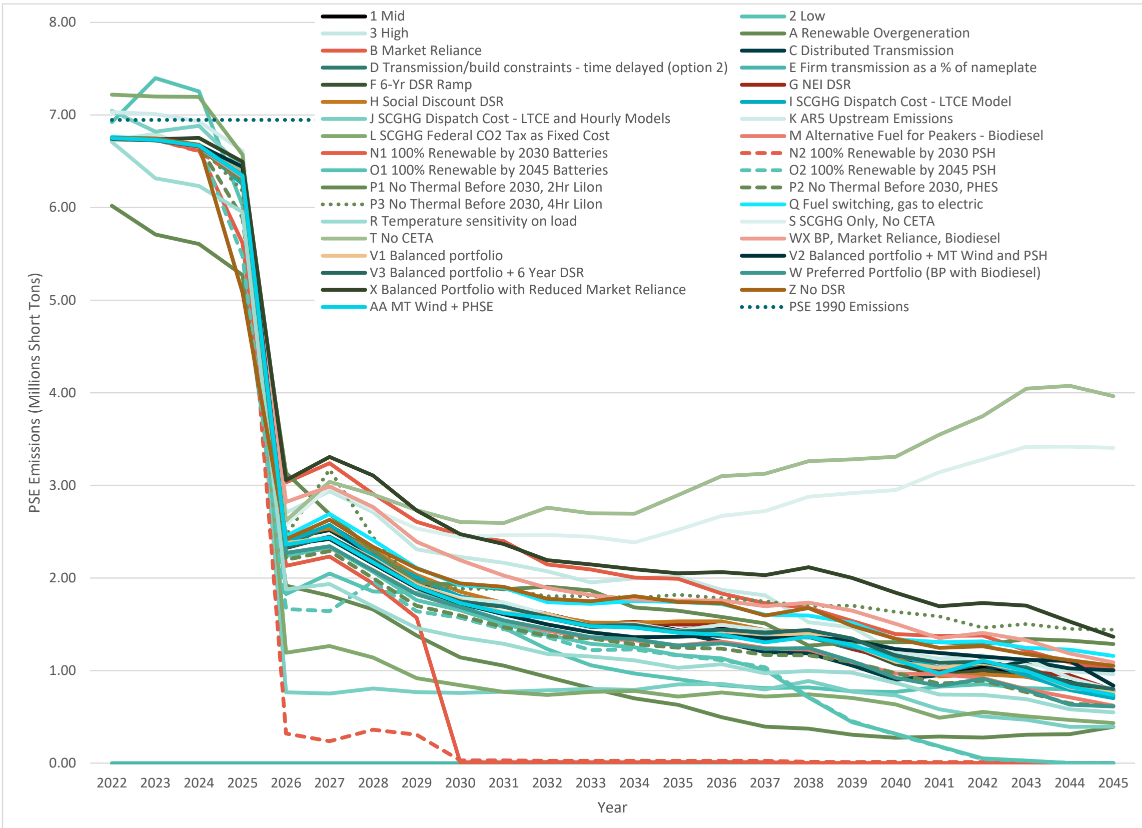
P3 No Thermal Before 2030, 4Hr LiIon	$39.01	$6.69	$45.70	$25.08
Q Fuel switching, gas to electric	$19.56	$5.60	$25.16	$4.54
R Temperature sensitivity on load	$13.53	$4.69	$18.22	($2.40)
S SCGHG Only, No CETA	$9.29	$8.86	$18.16	($2.46)
T No CETA	$9.32	$9.27	$18.59	($2.03)
V1 Balanced portfolio	$16.06	$5.07	$21.14	$0.52
V2 Balanced portfolio + MT Wind and PSH	$16.61	$5.12	$21.73	$1.11
V3 Balanced portfolio + 6 Year DSR	$16.26	$5.06	$21.32	$0.70
W Preferred Portfolio (BP with Biodiesel)	$16.10	$4.96	$21.06	$0.44
X Balanced Portfolio with Reduced Market Reliance	$17.21	$5.36	$22.57	$1.95
WX BP, Market Reliance, Biodiesel	$17.30	$5.06	$22.36	$1.74
Z No DSR	$17.54	$5.56	$23.10	$2.48
AA MT Wind + PHSE	$15.84	$5.16	$20.99	$0.37

Figure 8-11: Relative Optimal Portfolio Builds by Scenario and Sensitivity (cumulative nameplate capacity in MW for each resource addition by 2045)

	Resource Additions by 2045, Nameplate (MW)											
Portfolio	Demand-side Resources	Battery Energy Storage	Solar - Ground and Rooftop	Demand Response	DSP Non-Wire Alternatives	Biomass	Solar	Wind	Renewable + Storage Hybrid	Pump Hydro Storage	Peaking Capacity	Total
1 Mid	1,497	550	0	123	118	90	1,393	3,350	250	0	948	**8,319**
2 Low	1,537	275	0	181	118	30	1,096	2,450	250	0	237	**6,175**
3 High	1,733	900	0	128	118	150	2,292	3,850	0	0	1,659	**10,830**
A Renewable Overgeneration	1,537	1,525	0	192	118	150	2,388	2,250	725	0	474	**9,359**
B Market Reliance	1,497	650	50	173	118	135	995	3,350	375	0	1,732	**9,075**
C Distributed Transmission	1,537	1,050	2,700	178	118	150	500	2,615	125	0	1,003	**9,976**
D Transmission/ build constraints - time delayed (option 2)	1,537	650	0	180	118	135	1,295	3,300	250	0	948	**8,413**
F 6-Yr DSR Ramp	1,372	625	0	175	118	150	1,394	3,150	500	0	966	**8,449**
G NEI DSR	1,304	450	0	188	118	150	1,393	3,450	125	0	1,185	**8,363**
H Social Discount DSR	1,179	675	0	195	118	150	1,391	3,150	625	0	948	**8,431**
I SCGHG Dispatch Cost - LTCE Model	1,497	875	0	188	118	135	1,294	3,150	375	0	766	**8,398**
J SCGHG Dispatch Cost - LTCE and Hourly Models	1,497	850	0	205	118	60	996	3,550	375	0	747	**8,397**
K AR5 Upstream Emissions	1,497	625	0	140	118	150	1,393	3,150	250	0	948	**8,270**
L SCGHG Federal CO2 Tax as Fixed Cost	1,537	525	0	183	118	135	1,395	3,150	250	0	829	**8,122**
M Alternative Fuel for Peakers - Biodiesel	1,537	700	0	185	118	75	1,593	3,150	250	0	948	**8,557**
N1 100% Renewable by 2030 Batteries	1,304	26,200	0	59	118	0	1,994	3,850	0	0	0	**33,523**
N2 100% Renewable by 2030 PSH	1,169	0	0	59	118	75	3,268	3,600	622	21,300	0	**30,211**
O1 100% Renewable by 2045 Batteries	1,304	24,500	0	128	118	0	1,692	3,950	0	0	0	**31,692**

O2 100% Renewable by 2045 PSH	1,537	0	0	204	118	0	99	3,650	1,249	19,600	0	**26,458**
P1 No Thermal Before 2030, 2Hr LiIon	1,372	4,300	0	178	118	15	1,695	3,550	125	0	474	**11,827**
P2 No Thermal Before 2030, PHES	1,304	1,025	0	122	118	15	2,294	3,550	0	2,700	18	**11,146**
P3 No Thermal Before 2030, 4Hr LiIon	1,372	4,425	0	129	118	0	2,292	3,250	0	0	0	**11,586**
Q Fuel switching, gas to electric	1,537	2,000	0	108	118	135	4,880	3,850	825	0	2,961	**16,414**
R Temperature sensitivity on load	1,372	500	0	130	118	150	1,195	3,150	0	0	0	**6,614**
S SCGHG Only, No CETA	1,179	50	0	203	118	0	0	350	0	0	1,896	**3,795**
T No CETA	1,042	0	0	123	118	0	0	350	0	0	2,133	**3,766**
V1 Balanced portfolio	1,784	450	680	217	118	105	696	3,250	375	0	966	**8,641**
V2 Balanced portfolio + MT Wind and PSH	1,784	375	680	217	118	120	895	3,150	425	0	948	**8,711**
V3 Balanced portfolio + 6 Year DSR	1,658	675	680	217	118	120	895	3,450	125	0	1,003	**8,940**
W Preferred Portfolio (BP with Biodiesel)	1,784	450	680	217	118	105	696	3,250	375	0	966	**8,354**
X Balanced Portfolio with Reduced Market Reliance	1,824	775	680	217	118	120	596	3,350	250	0	1,677	**9,321**
WX BP, Market Reliance, Biodiesel	1,824	775	680	217	118	120	596	3,350	250	0	1,677	**9,607**
Z No DSR	690	1,250	0	0	118	150	2,688	3,450	500	0	1,422	**10,268**
AA MT Wind + PHSE	1,497	300	0	182	118	150	1,094	3,350	425	0	948	**8,064**

Figure 8-12: Relative Optimal Portfolio Emissions by Scenario and Sensitivity (annual direct portfolio emissions by year)



6. ECONOMIC SCENARIO ANALYSIS RESULTS

Portfolio Builds

The portfolio builds for all three economic scenarios look very much alike given the generic resource options. The mix of resources is similar and the amount of resources added varied depending on the load forecasts. In the Low economic scenario fewer resources are added due to lower demand, lower peak need and lower renewable need. In the High economic scenario, more resources are added due to higher demand, higher peak need and higher renewable need. Figure 8-13, shows the levelized cost by scenario while Figure 8-14 shows the optimal portfolio builds by scenario.

Figure 8-13: Relative Optimal Portfolio Costs by Scenario
(dollars in billions, NPV including end effects)

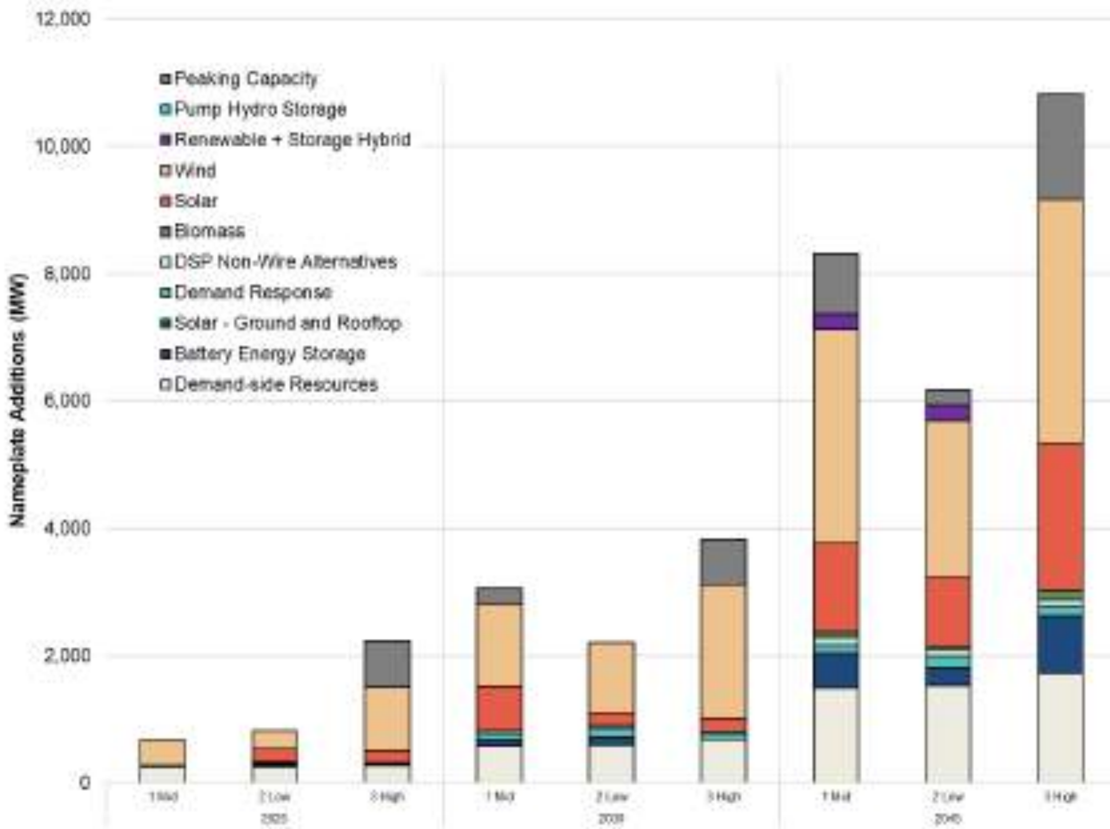
		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
2	Low Scenario	$12.08	$4.53	$16.61	($3.45)
3	High Scenario	$21.37	$5.74	$27.11	$5.84

Figure 8-14: Relative Optimal Portfolio Builds by Scenario
(cumulative nameplate capacity in MW for each resource addition by 2045)

Resource Additions by 2045	1 Mid	2 Low	3 High
Demand-side Resources	1,497 MW	1,537 MW	1,733 MW
Battery Energy Storage	550 MW	275 MW	900 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	181 MW	128 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	3,576 MW	6,292 MW
Biomass	90 MW	30 MW	150 MW
Solar	1,393 MW	1,096 MW	2,292 MW
Wind	3,350 MW	2,450 MW	3,850 MW
Renewable + Storage Hybrid	250 MW	250 MW	0 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	237 MW	1,659 MW

Figure 8-15 below displays the megawatt additions for the deterministic analysis of optimal portfolios for all three scenarios in 2025, 2030 and 2045. No new resources are added until 2024. See Appendix H, Electric Analysis Inputs and Results, for more detailed information.

Figure 8-15: Resource Builds by Scenario, Cumulative Additions by Nameplate (MW)



Portfolio Emissions

Figure 8-16 shows CO_2 emissions for the Mid, Low and High Scenarios. The chart shows the direct emissions from portfolio resources for each scenario and does not account for alternative compliance mechanisms to achieve the carbon neutral standard from 2030 to 2045. Despite varying demand, natural gas price and electric price forecasts, the three scenarios all converge on a similar quantity of direct emissions by 2045, driven by CETA renewable energy targets.

Figure 8-16: CO_2 Emissions for the Mid, Low and High Scenarios
(does not include alternative compliance to meet carbon neutral standard in 2030 and beyond)

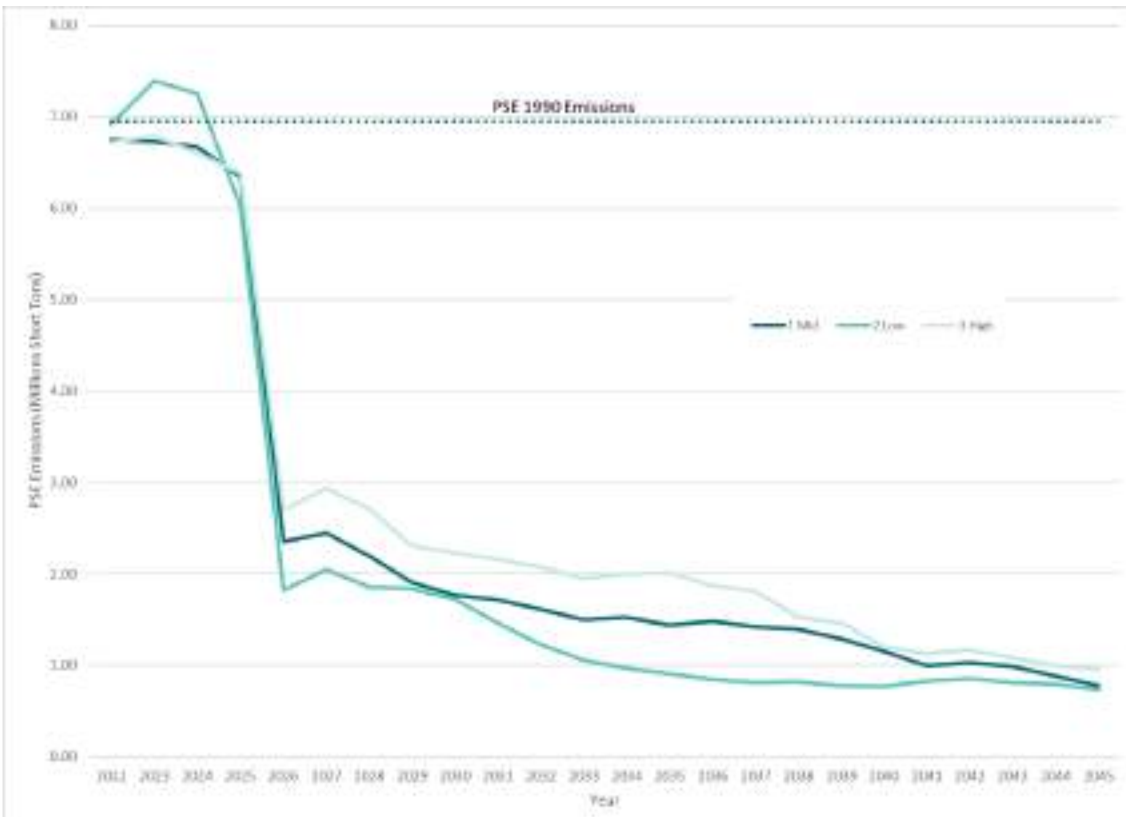
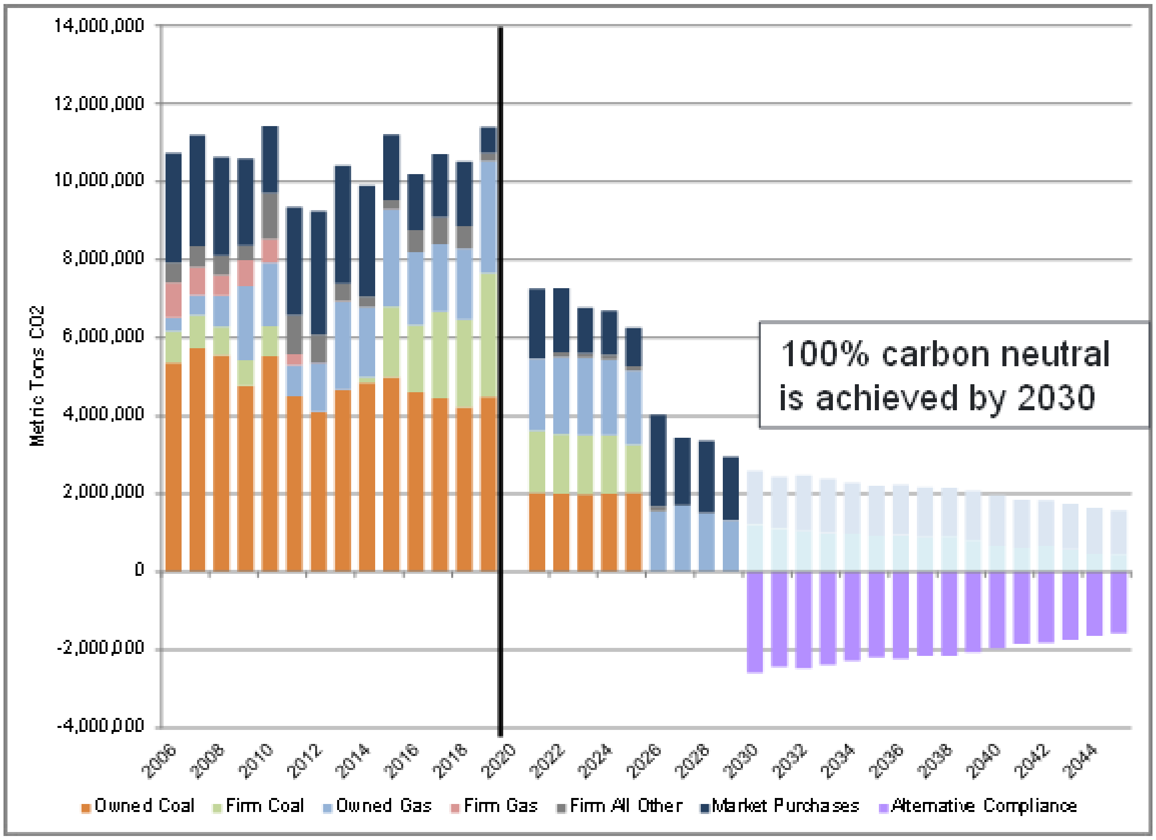


Figure 8-17, below, shows the Mid Scenario portfolio emissions by resource type. There is a direct relationship between emissions and the dispatch of thermal plants. Direct emissions decreased with the retirement of Colstrip 1 & 2 in 2019 and will decrease further with a lower projected economic dispatch of thermal resources as well the exit of Colstrip 3 & 4 and Centralia from the portfolio. With the resource retirements and forecasted drop in dispatch, total portfolio emissions decrease by over 70 percent from 2019 to 2029. Using alternative compliance mechanisms, the portfolio achieves carbon neutrality from 2030 through to 2045.

Figure 8-17: Historical and Projected Annual Total PSE Portfolio CO_2 Emissions for the Mid Scenario Portfolio



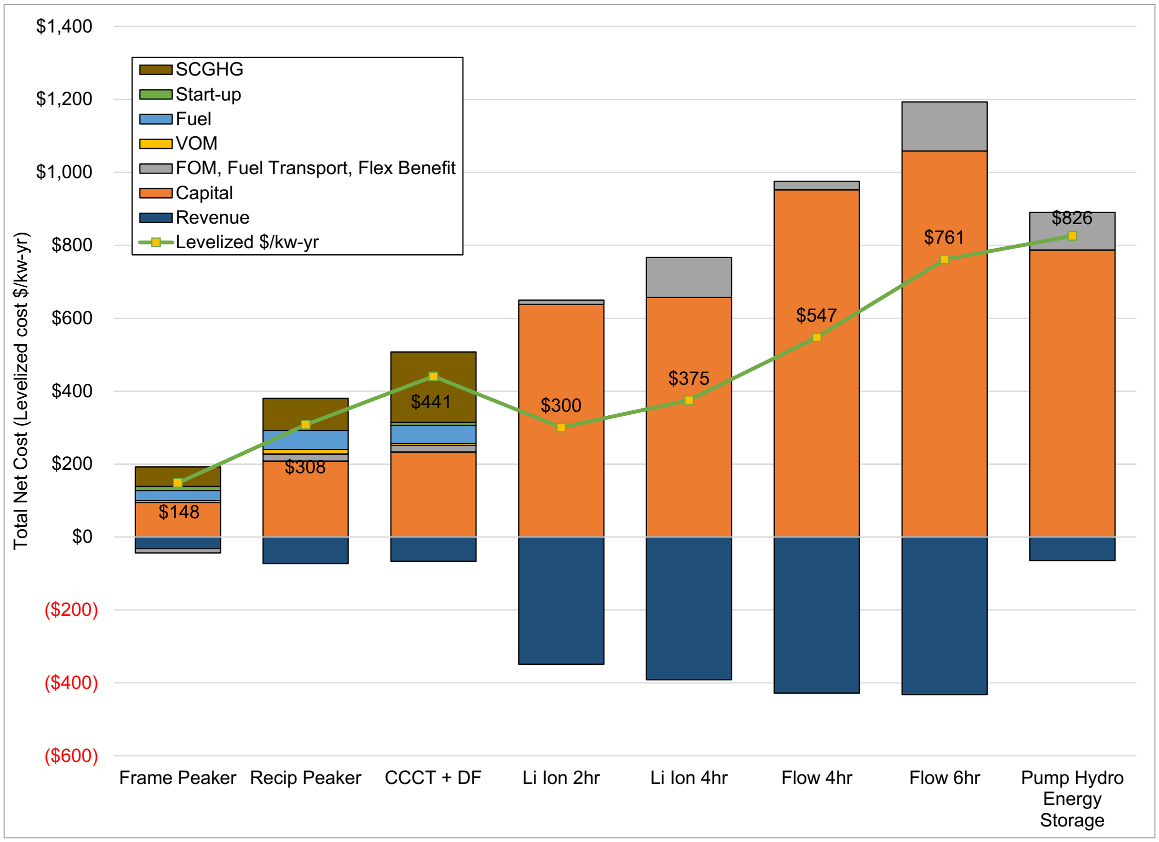
Levelized Cost of Capacity

The levelized costs for peakers, baseload natural gas plants and energy storage resources were evaluated using the Mid Scenario assumptions for electric price, natural gas price and demand to better understand how the resources compare during resource selection. The levelized cost of capacity is based on the peak capacity value of a resource. For example, the nameplate of a 2-hour lithium-ion battery is 25 MW, but it has an ELCC[4] of 12.4 percent, so the peak capacity value is 3.1 MW. (The total cost of the lithium-ion battery is divided by 3.1 MW instead of the 25 MW, which is why it has a high levelized cost of capacity.) When calculating the levelized cost of capacity for new peakers and baseload natural gas plants, the SCGHG is added to the total cost; this increased the levelized cost of capacity for frame peakers from $95 to $148. Figure 8-18

4 / The effective load carrying capacity (ELCC) of a resource represents the peak capacity credit assigned to that resource. More information on ELCC can be found in Chapter 7.

compares the net cost of capacity for peakers, baseload natural gas plants and energy storage resources.

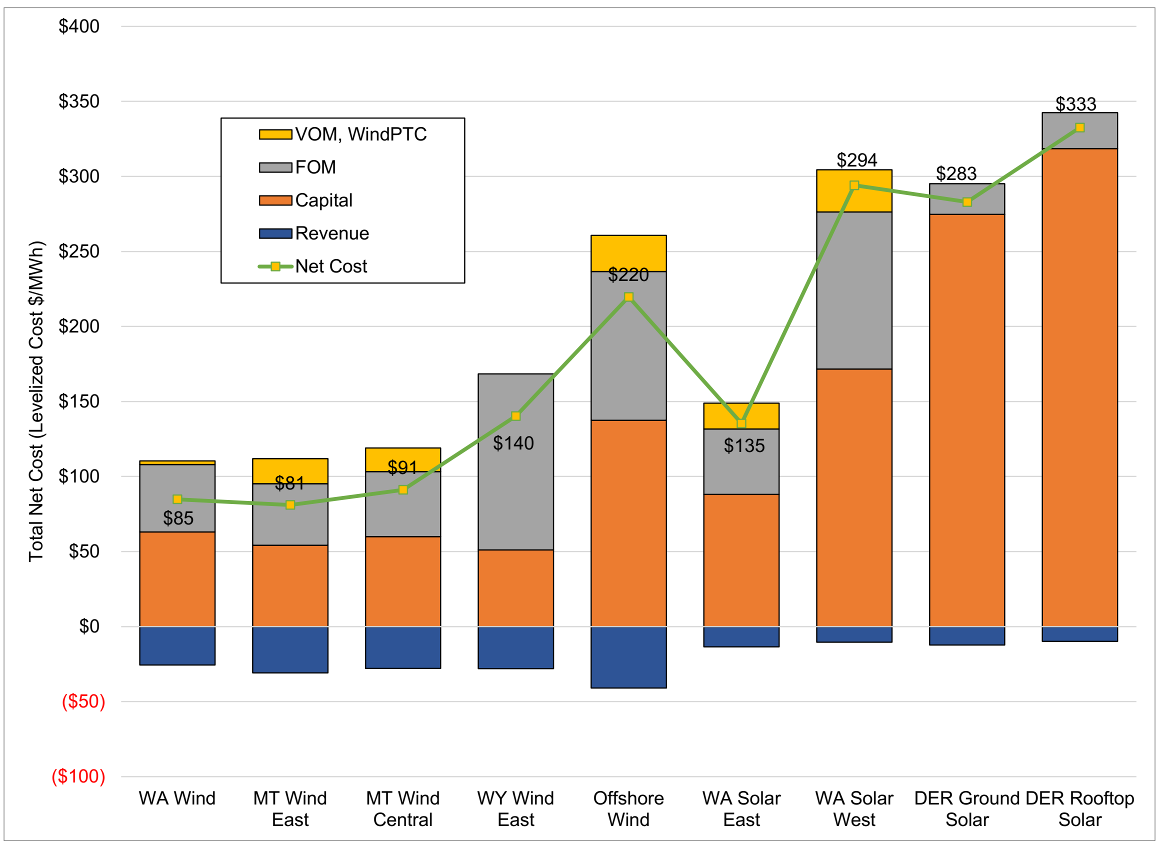
Figure 8-18: Net Cost of Capacity in the Mid Scenario Portfolio Model



Levelized Cost of Energy

The levelized costs of energy for wind and solar resources were also evaluated using the Mid Scenario assumptions to better understand how the resources compare during resource selection. The costs are calculated based on energy and do not account for any peak capacity contribution. Montana wind power is expected to be more cost effective than wind and solar from the Pacific Northwest. Even though Wyoming wind is higher cost because of transmission costs, it has a high peak capacity credit and provides other value to the portfolio. Given transmission constraints, resources outside of the Pacific Northwest region will be limited. After Montana and Wyoming wind, eastern Washington utility-scale solar is the next lowest cost resource. Figure 8-19 illustrates the levelized costs of renewable resource to meet CETA.

Figure 8-19: Wind and Solar Cost Components, Mid Scenario Portfolio



7. SENSITIVITY ANALYSIS RESULTS

Portfolio sensitivity analysis is an important form of risk analysis that helps PSE understand how specific assumptions can change the mix of resources in the portfolio and affect portfolio costs. This section provides the results and detailed analysis for each sensitivity. Additional results, including year-by-year resource timelines, cost breakdowns and emissions data are provided in Appendix H.

Future Market Availability

A. Renewable Overgeneration Test

In the Mid portfolio there were 0.23 percent of load (355 hours) of overgeneration in 2030 and 10 percent of load (4,000 hours) in 2045. This sensitivity tests the costs and portfolio changes to eliminate the overbuild of renewable generation observed in the Mid portfolio. By eliminating market sales of excess renewable energy in this sensitivity, PSE can quantify the importance of market sales to reduce cost of meeting CETA.

Baseline: PSE can sell 1,500 MW of energy to the Mid-C market at any given hour, subject only to transmission availability.
Sensitivity > PSE cannot sell any energy to the Mid-C market.

KEY FINDINGS. Prohibiting sales to the Mid-C market reduces renewable overgeneration by eliminating market sales and increasing battery energy storage so that the generation can be stored instead. Though renewable generation still occurs in Sensitivity A, it is reduced by 10 percent consistent with the 10 percent overbuild of generation in the Mid Scenario. Wind capacity is reduced, and the remaining renewable generation is from increased solar builds. This portfolio costs almost $1.6 billion more than the Mid portfolio by adding more battery energy storage, but only reduced the overgeneration by 3 percent by 2045. Figure 8-20 compares the amount of renewable overgeneration in the Mid Scenario and Sensitivity A portfolios. In the Mid Scenario portfolio, renewable overgeneration can provide value through sales. In Sensitivity A, without the ability to sell excess energy, the model can only curtail that production or use it to charge battery resources; once the battery resources are at capacity, there is no option left but to curtail the energy. The market is an effective way to reducing cost.

Figure 8-20: Renewable Overgeneration – Mid Scenario and Sensitivity A

	2030			2045		
Portfolio	Hours of Over-generation	MWh of Over-generation	% of total load with conservation	Hours of Over-generation	MWh of Over-generation	% of total load with conservation
Mid Scenario	355	53,946	0.23%	4,330	3,021,777	10.6%
Sensitivity A	29	1,495	0.01%	3,396	2,063,604	7.21%

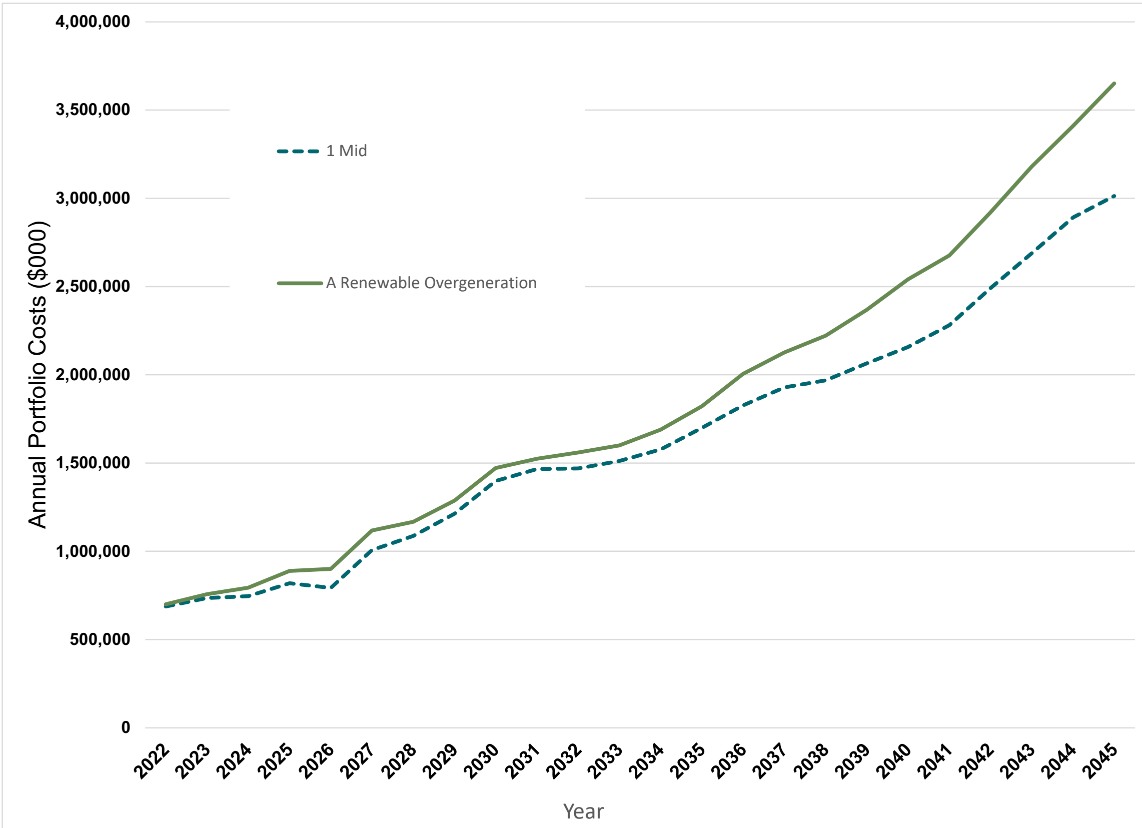
ASSUMPTIONS. This portfolio keeps all underlying assumptions from the Mid portfolio. The only difference between Sensitivity A and the Mid Scenario is PSE's ability to sell energy to the Mid-C market, which is removed in Sensitivity A.

ANNUAL PORTFOLIO COSTS. Figures 8-21 and 8-22 illustrate the breakdown of costs between the Mid Scenario and Sensitivity A portfolios. Sensitivity A is higher cost overall than the Mid portfolio, and costs begin to diverge at a greater pace as sensitivity A invests heavily in the energy storage necessary to store the renewable generation that cannot be sold to the market. .

Figure 8-21: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity A

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
A	Renewable Overgeneration test	$17.11	$4.45	$21.55	$0.93

Figure 8-22: Annual Portfolio Costs – Mid Scenario and Sensitivity A



RESOURCE ADDITIONS. Figure 8-23 compares the nameplate capacity additions of the Sensitivity A and Mid Scenario portfolios. Sensitivity A builds more nameplate capacity than the Mid Scenario, and the distribution of resources shifts some capacity from wind generation to solar and storage. No pumped hydro storage is built, but investment in hybrid resources and standalone battery resources increases. Conservation reaches Bundle 11 in this sensitivity. No PSE resources, new or existing, are retired in this sensitivity.

Figure 8-23: Portfolio Additions– Mid Scenario and Sensitivity A, Renewable Overgeneration

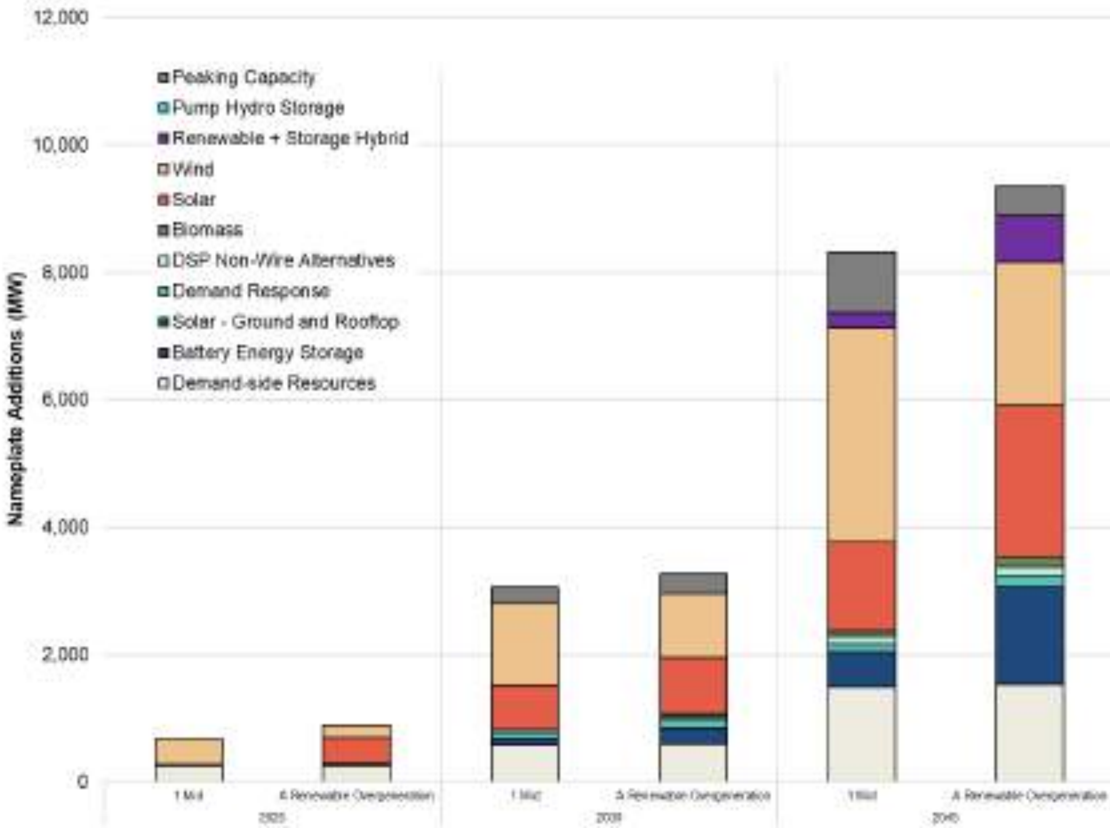


Figure 8-24: Portfolio Additions by 2045 – Mid Scenario and Sensitivity A, Renewable Overgeneration

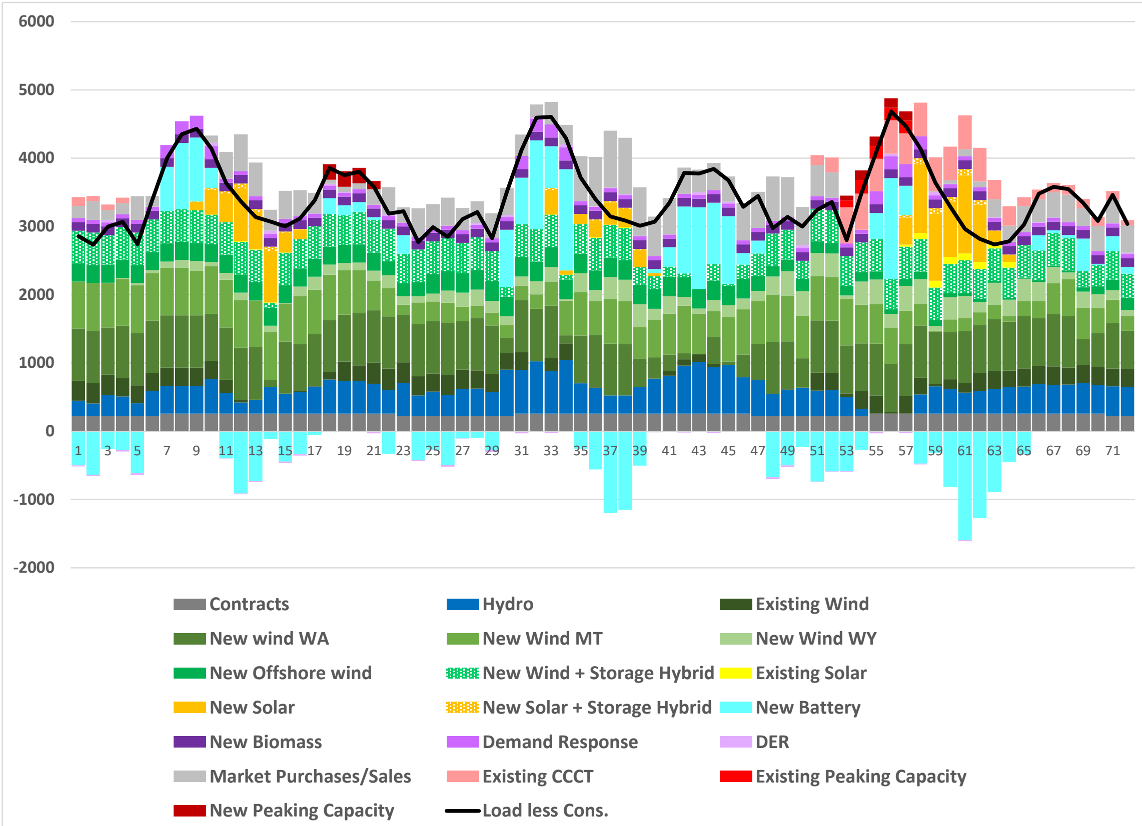
Resource Additions by 2045	1 Mid	A Renewable Overgeneration
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	1,525 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	192 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,788 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	2,388 MW
Wind	3,350 MW	2,250 MW
Renewable + Storage Hybrid	250 MW	725 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	474 MW[1]

NOTE
1. Includes 237 MW of recip peakers and 237 MW of frame peakers

PEAK NEED. In 2045, the peak capacity behavior of the new resources changes in this sensitivity. Figure 8-25 shows the hourly dispatch of resources in Sensitivity A during peak demand for 2045. Resources generating above the black line are producing power in excess of load from mostly market purchases (gray bars) and some new and existing natural gas generation (maroon and pink bars) mostly to charge batteries (blue bars below zero).

During periods of peak demand, there is not enough generation to both meet customer demand and charge batteries. In order for the battery to meet energy need during peaks, the batteries must be charged. Without market for charging the batteries as in this sensitivity, the model uses natural gas generation to charge the batteries.

Figure 8-25: 2045 Peak Demand Period of Sensitivity A, December 28-30, 2045



The relationship between market purchases and battery activity can be seen by examining the times at which the market purchases are occurring. For Sensitivity A, Figure 8-26 shows the percentage of hours each month where market purchases are being made by PSE in the year 2045. Market purchases are made consistently throughout the winter to assist the generating resources. During off-peak hours, market purchases provide energy for the batteries to charge; during peak hours when the batteries are discharging, market purchases help to meet demand.

Figure 8-26: Percentage of Each Month Where Market Purchases are Being Made in Each Hour for Sensitivity A, 2045

All Purchase Hours

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0:00	81%	83%	87%	27%	0%	0%	13%	48%	83%	71%	67%	100%
1:00	81%	83%	84%	27%	0%	0%	13%	48%	90%	71%	67%	100%
2:00	81%	86%	84%	27%	0%	0%	13%	48%	83%	71%	67%	100%
3:00	81%	83%	81%	23%	0%	0%	13%	42%	83%	71%	67%	100%
4:00	81%	86%	77%	17%	0%	0%	10%	48%	83%	74%	63%	87%
5:00	84%	76%	77%	20%	0%	0%	6%	42%	87%	71%	63%	87%
6:00	84%	62%	61%	17%	0%	0%	3%	52%	83%	71%	67%	81%
7:00	81%	69%	65%	3%	0%	0%	10%	48%	73%	68%	60%	77%
8:00	84%	79%	58%	10%	0%	0%	6%	61%	70%	71%	60%	87%
9:00	84%	76%	68%	10%	0%	0%	6%	65%	70%	68%	57%	94%
10:00	81%	79%	71%	10%	0%	0%	13%	61%	67%	68%	57%	97%
11:00	77%	79%	68%	10%	0%	0%	19%	61%	70%	68%	60%	97%
12:00	77%	79%	65%	17%	0%	0%	19%	65%	70%	68%	60%	97%
13:00	77%	79%	71%	13%	3%	0%	23%	58%	70%	68%	60%	97%
14:00	81%	79%	71%	7%	3%	0%	10%	58%	70%	65%	63%	97%
15:00	81%	79%	71%	10%	3%	3%	13%	52%	70%	68%	67%	97%
16:00	84%	79%	61%	3%	0%	0%	0%	48%	70%	71%	73%	97%
17:00	84%	76%	68%	10%	3%	0%	3%	23%	63%	71%	70%	97%
18:00	84%	76%	68%	17%	3%	3%	19%	39%	60%	74%	73%	94%
19:00	84%	83%	68%	17%	6%	3%	26%	32%	63%	74%	70%	94%
20:00	87%	76%	71%	17%	6%	3%	23%	39%	73%	81%	67%	97%
21:00	84%	79%	77%	17%	6%	7%	26%	52%	90%	77%	73%	97%
22:00	81%	83%	77%	17%	6%	7%	19%	45%	93%	74%	73%	97%
23:00	81%	83%	77%	17%	6%	3%	19%	45%	90%	77%	73%	97%

B. Reduced Market Reliance

PSE has 1,500 MW of firm transmission capacity from the Mid-C market hub to access supply from the regional power market. To date, this transmission capacity has been assumed to provide PSE with access to reliable firm market purchases where physical energy can be sourced in the day-ahead or real-time bilateral power markets. PSE has effectively assumed this 1,500 MW of transmission capacity as equivalent to generation capacity available to meet demand. Historically, this assumption has reduced PSE's generation capacity need and the ensuing procurement costs. Given the market events of the past three years, PSE conducted a market risk assessment to evaluate this assumption in addition to the evaluation completed with the resource adequacy model. Sensitivity B provides insight into navigating a market with reduced availability of market purchases by examining how to optimize a portfolio that is limited by these conditions.

Baseline: PSE can make market purchases at the hourly power price, subject to the transmission limits to the Mid-C Market. PSE currently uses these purchases to meet demand at peak demand hours.

Sensitivity B > PSE's transmission access to the Mid-C Market is reduced to 1,300 MW in 2023, 1,100 MW in 2024, 900 MW in 2025, 700 MW in 2026, and 500 MW in 2027 and thereafter during November-February and June-August. Transmission access remains the same for the months March-May and September-October, as well as the year 2022.

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KEY FINDINGS. To compensate for reduced market purchases, sensitivity B overbuilds renewable resources to charge batteries and builds 1,495 of peaking capacity by 2031, nearly double the amount in the Mid Scenario. This sensitivity builds the same amount of Washington wind as the Mid Scenario, but on an accelerated timeline. By 2045, increased storage builds play a larger role in meeting peak demand. Peaking capacity and CCCT thermal generation continue to assist in meeting peak demand, but renewable overgeneration is the primary energy source for batteries.

ASSUMPTIONS. This portfolio keeps all underlying assumptions from the Mid Scenario portfolio, except for changes to Mid-C market access. The amount of Mid-C Market transmission access in Sensitivity B, which defines the amount of market purchases PSE can make, is seen in Figure 8-27.

Figure 8-27: Transmission Limits to the Mid-C Market in Sensitivity B in MW

MW	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2022	1544	1529	1516	1483	1442	1463	1472	1487	1569	1588	1558	1518
2023	1300	1300	1507	1466	1432	1300	1300	1300	1519	1519	1300	1300
2024	1100	1100	1536	1471	1418	1100	1100	1100	1546	1521	1100	1100
2025	900	900	1518	1455	1402	900	900	900	1529	1523	900	900
2026	700	700	1521	1457	1405	700	700	700	1530	1525	700	700
2027	500	500	1523	1460	1408	500	500	500	1532	1526	500	500
2028	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2029	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2030	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2031	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2032	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2033	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2034	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2035	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2036	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2037	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2038	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2039	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2040	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2041	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2042	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2043	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2044	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2045	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2046	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2047	500	500	1525	1462	1411	500	500	500	1533	1526	500	500

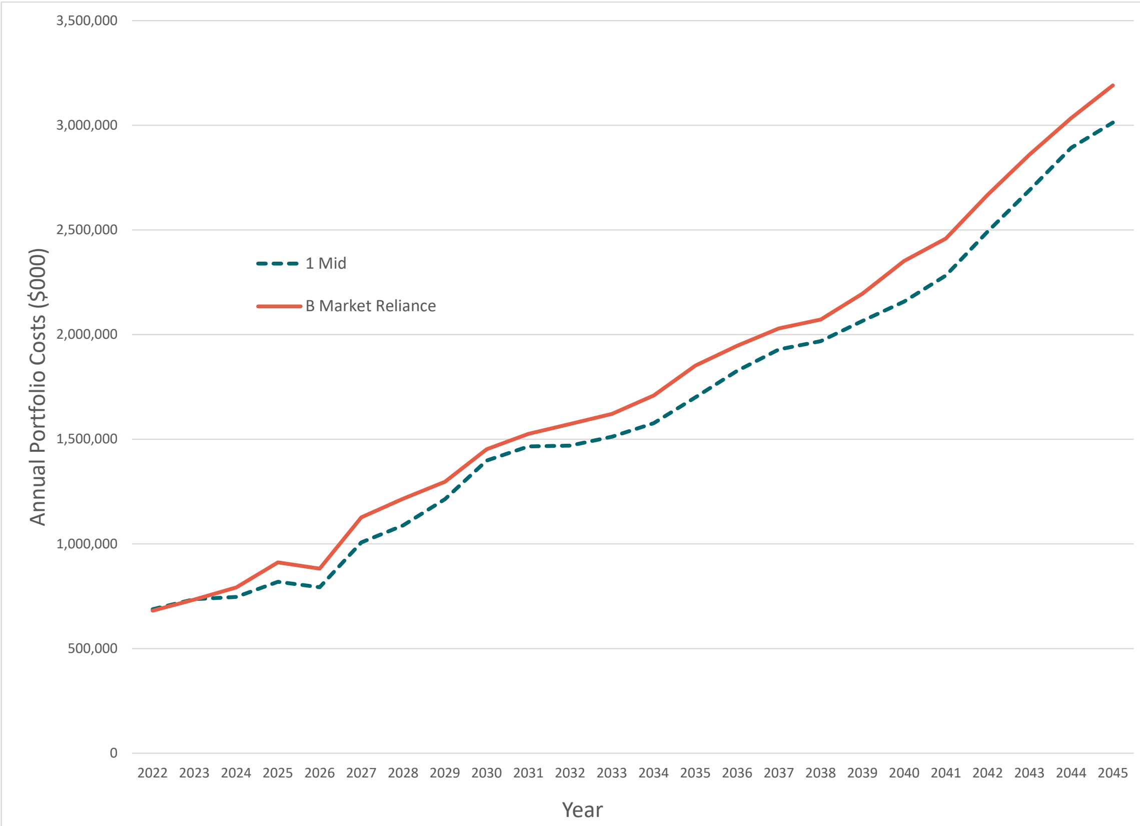
ANNUAL PORTFOLIO COSTS. Figures 8-28 and 8-29 illustrate the breakdown of costs between the Mid Scenario and Sensitivities B. As expected, increasing restrictions to market purchases increases portfolio costs. This sensitivity builds more resources in the early years of the simulation so the annual portfolio costs start diverging as early as 2023.

The final builds of the Sensitivity B and the Mid Scenario portfolios are similar, with more peaking capacity and an accelerated installation of Washington wind in Sensitivity B. As a result, the annual costs of Sensitivity B track with the costs of the Mid Scenario, with the earlier installation timeline and increased peaking capacity raising the overall price.

Figure 8-28: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity B

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
B	Reduced Market Reliance	$16.57	$5.19	$21.76	$1.35

Figure 8-29: Annual Portfolio Costs – Mid Scenario and Sensitivity B



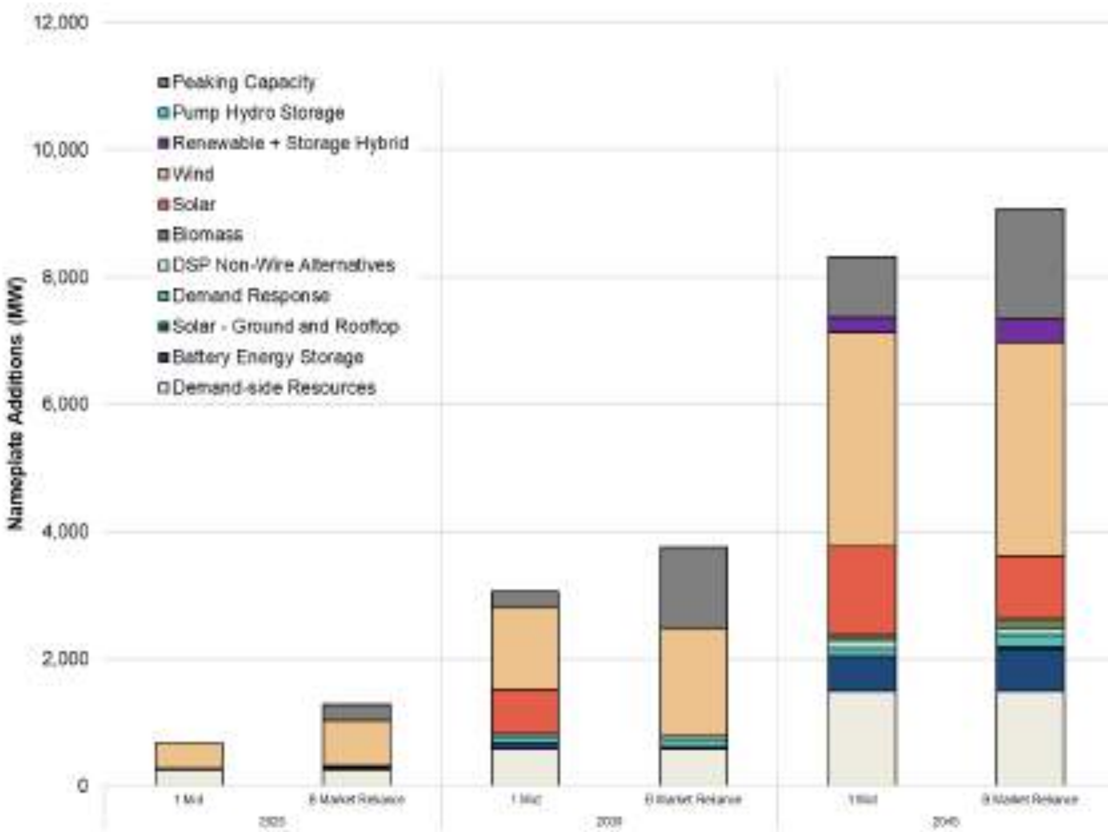
RESOURCE ADDITIONS. Figure 8-30 compares the nameplate capacity additions of the Mid Scenario and Sensitivity B.

Sensitivity B invests in the same amount of demand-side resources as the Mid Scenario (Bundle 10). With limited access to the market, this sensitivity invests heavily in peaking capacity and accelerates the construction of Washington wind resources compared to the Mid Scenario. In the later years of the simulation, storage resources are still needed, but they are delayed due to the high capacity of thermal resources being installed in the early years. Without market purchases to bridge the gap between renewable generation and demand, the portfolio leans heavily on increased peaking capacity builds. Increased peaking capacity is the most prominent difference between the Mid Scenario and Sensitivity B, indicating that the model selects thermal generation as the least cost resource to replace the market purchases. One of the modeling limitations in this IRP, is that new contracts are not modeled. Resources are modeled since they have a set procurement cost and build schedule, but future costs of contractual arrangements are more difficult to predict.

Figure 8-30: Portfolio Additions – Mid Scenario and Sensitivity B, Reduced Market Reliance

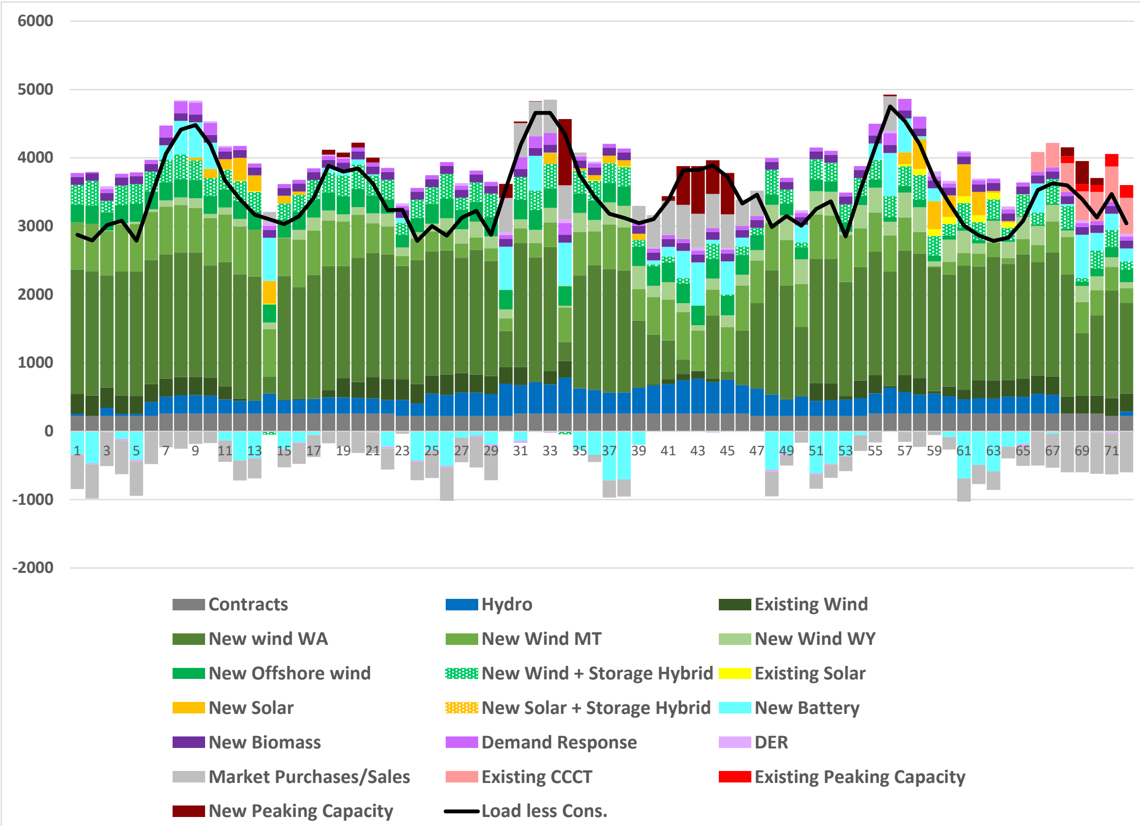
Resource Additions by 2045	1 Mid	B Reduced Market Reliance
Demand-side Resources	1,497 MW	1,497 MW
Battery Energy Storage	550 MW	650 MW
Solar – Ground and Rooftop	0 MW	50 MW
Demand Response	123 MW	173 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,480 MW
Biomass	90 MW	135 MW
Solar	1,393 MW	995 MW
Wind	3,350 MW	3,350 MW
Renewable + Storage Hybrid	250 MW	375 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	1,732 MW

Figure 8-31: Portfolio Additions by 2045 – Mid Scenario and Sensitivity B, Reduced Market Reliance



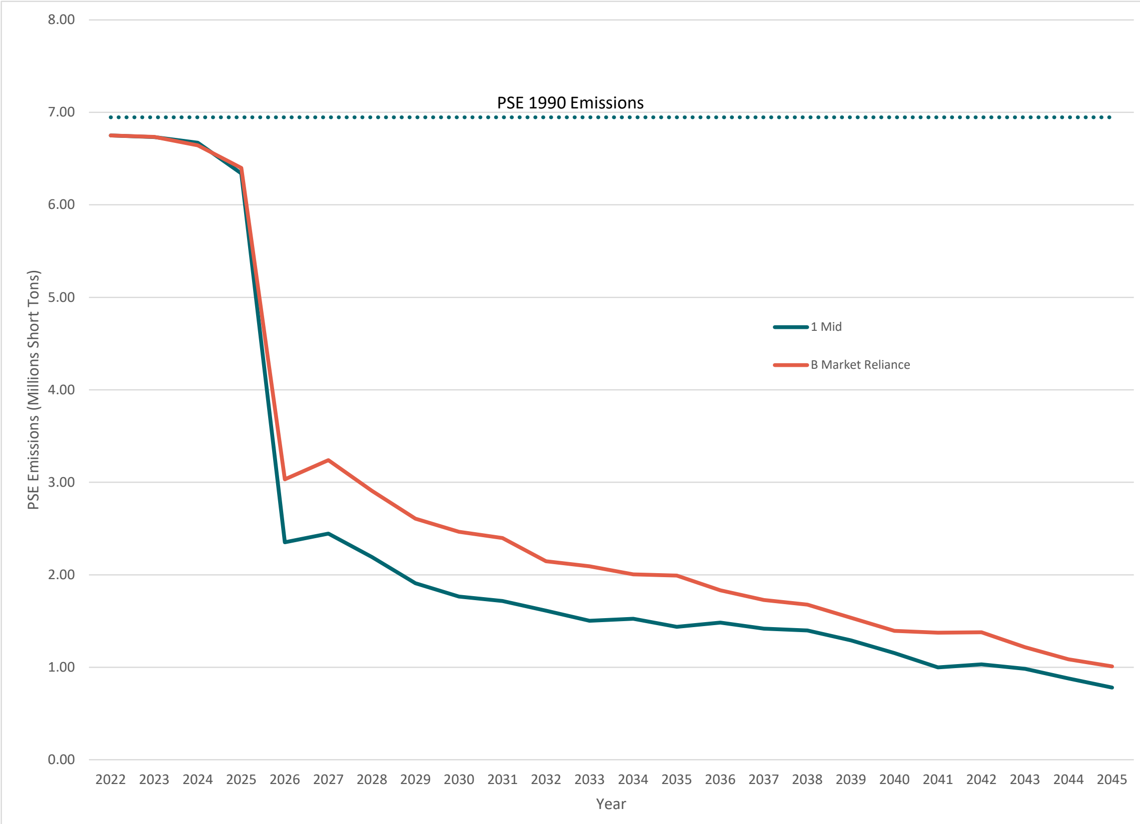
PEAK NEED AND EMISSIONS. The peak demand period of Sensitivity B is shown in Figure 8-32. Portfolio B uses renewable overbuilds as the main method of charging the batteries (blue bars). The excess energy, generation above the black lines, provides value through market sales (gray bars below zero) and the charging of batteries (blue bars below zero) during off-peak hours. Market purchases are still available in a limited capacity, and are still used to assist in meeting demand when renewable generation is not sufficient. Thermal generation also continues to play a role in meeting peak demand. In Figure 8-32, thermal generation is still needed when there is not enough energy from renewable resources, batteries, or demand response to meet demand as can be seen in the hours 30, 34, 40-45, and 68-72.

Figure 8-32: 2045 Peak Demand Period of Sensitivity B, December 28-30, 2045



EMISSIONS. Use of thermal generation to compensate for the reduction of market purchases increases the emissions of PSE resources in sensitivity B. Figure 8-33 compares the yearly emissions of PSE resources (without market purchases) to the Mid Scenario.

Figure 8-33: Annual Emissions of PSE Resources – Mid Scenario and Sensitivity B (market purchases are not included)



Transmission Constraints and Build Limitations

C. "Distributed" Transmission/Build Constraints - Tier 2

This sensitivity examines increased transmission constraints on PSE's resources. The PSE Energy Delivery team has defined "Tier 2" transmission availability as projects that are available by 2030, with a moderate degree of confidence in their feasibility. Available projects in this category total 3,070 MW of available transmission.

Baseline: The Mid Scenario assumes the transmission constraints described by Tier 0. PSE's system is subject to relatively few transmission constraints, including a maximum of 1,500 MW of Mid-C market access and build limitations for Montana, Idaho and Wyoming based resources.
Sensitivity > Sensitivity C assumes the more restrictive transmission constraints described by Tier 2, which includes those described in the baseline plus build limitations for eastern, southern and western Washington resources.

KEY FINDINGS. Tier 2 transmission constraints have relatively minimal impacts on portfolio build decisions for the first 15 years of the modeling horizon compared to the Mid Scenario portfolio. During this period, there is ample transmission to acquire solar and wind resources in eastern, southern and central Washington. However, once this transmission capacity is exhausted, Sensitivity C selects distributed solar resources located within PSE's service territory. Sensitivity C pairs the distributed solar resources with battery storage projects to better serve load when solar generation is not available. These more expensive resources drive up portfolio cost in the later years of the modeling horizon.

ASSUMPTIONS. Sensitivity C assumes transmission capacity outside of PSE's service territory will be limited to 3,070 MW. Figure 8-34 summarizes the Tier 2 transmission capacity assumptions for each resource group region. (A complete description of the four transmission tiers and resource group regions is provided in Chapter 5.)

Figure 8-34: Sensitivity C Transmission Constraints – Tier 2

Resource Group Region	Tier 2
PSE territory	unconstrained
Eastern Washington	675
Central Washington	625
Western Washington	100
Southern Washington/Gorge	705
Montana	565
Idaho / Wyoming	400
TOTAL	**3,070**

Several additional constraints were incorporated into the optimization to encourage realistic resource selections. The forecast of customer-owned, residential solar projects was adjusted to reflect increased adoption of residential solar and matches the Conservation Potential Assessment Low-cost, Business-as-Usual residential solar adoption rate, available in Appendix E. This assumption aligns with a portfolio focused on distributed energy resources.

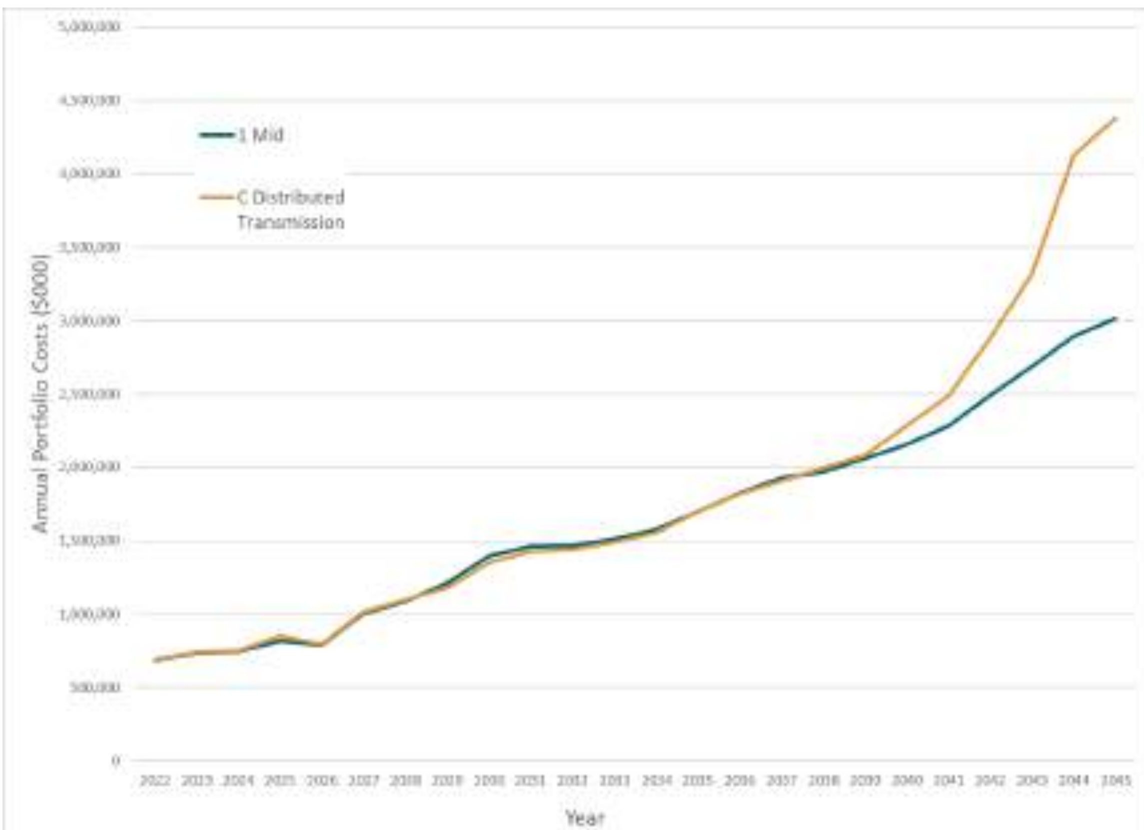
PORTFOLIO COSTS. Compared to the Mid Scenario portfolio, the Sensitivity C portfolio is more expensive over the modeling time horizon as shown in Figure 8-35. Distributed solar resources cost substantially more to install than utility-scale solar resources, resulting in increased generic resource revenue requirements. These increased generic resource revenue requirements are the major driver of the increased portfolio cost.

Figure 8-35: Portfolio Cost Comparison – Mid Scenario and Sensitivity C

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
C	Distributed – Transmission/Build Constraints Tier 2	$16.35	$5.21	$21.56	$0.94

Until year 2039, the Mid Scenario and Sensitivity C portfolios project similar annual revenue requirements as shown in Figure 8-36. After year 2039, Sensitivity C exhausts all available transmission outside of PSE's service territory and is forced to select more costly distributed solar resources, resulting in a sharp increase in annual revenue requirement in the later years.

Figure 8-36: Annual Portfolio Costs – Mid Scenario and Sensitivity C



RESOURCE ADDITIONS. Sensitivity C is marked by a transition from utility-scale wind and solar resources in central, eastern and southern Washington to distributed solar resources within the PSE service territory. Given that the effective load carrying capability of distributed solar resources is low, battery storage resources are added to the portfolio to meet load during peak hours. Biomass resources within the PSE service territory are also added to help accommodate base loads and meet CETA energy targets. New peaking capacity resource additions remain unchanged from the Mid Scenario.

Sensitivity C selects conservation Bundle 11 which is more conservation than selected in the Mid Scenario (Bundle 10). The increased conservation is due to the increased resource costs of distributed solar resources.

These resource build decisions are summarized in Figures 8-37 and 8-38.

Figure 8-37: Portfolio Additions – Mid Scenario and Sensitivity C, Distributed Transmission Tier 2

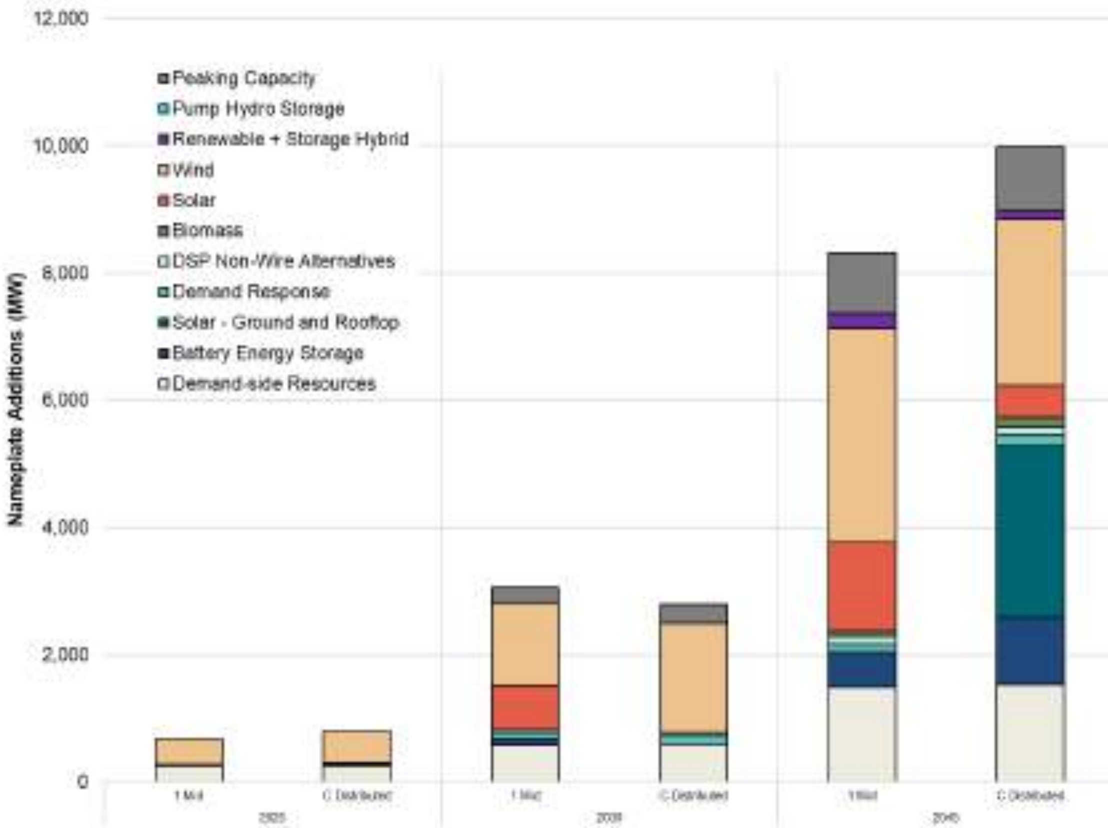


Figure 8-38: Portfolio Additions by 2045 – Mid Scenario and Sensitivity C, Distributed Transmission Tier 2

Resource Additions by 2045	1 Mid	C Distributed Transmission Tier 2
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	1,050 MW
Solar - Ground and Rooftop	0 MW	2,700 MW
Demand Response	123 MW	178 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	3,265 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	500 MW
Wind	3,350 MW	2,615 MW
Renewable + Storage Hybrid	250 MW	125 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	1,003 MW

OTHER FINDINGS. Distributed solar, ground mount and rooftop, is capable of meeting a significant portion of load. As shown in Figure 8-39, distributed solar contributes approximately 13 percent of total energy load in 2045. However, distributed solar is a poor resource for meeting peak capacity need, because it has an effective load carrying capability of less than 2 percent. This means that other resources are needed to provide capacity during peak need events. Sensitivity C selected peaking capacity resources to meet this need, so slightly more peaking resource capacity was added to Sensitivity C compared to the Mid Scenario portfolio. Furthermore, those peaking capacity resources were dispatched more often, resulting in increased emissions for Sensitivity C in the later years of the modeling horizon. In 2045, the Mid Scenario generated 0.78 million tons of greenhouse gases (GHGs), while Sensitivity C generated 1.00 million tons of GHGs. Figure 8-40 compares the emissions from the Mid Scenario and Sensitivity C portfolios in millions short tons.

Figure 8-39: Annual Energy Production by Resource Type (aggregated) – Sensitivity C

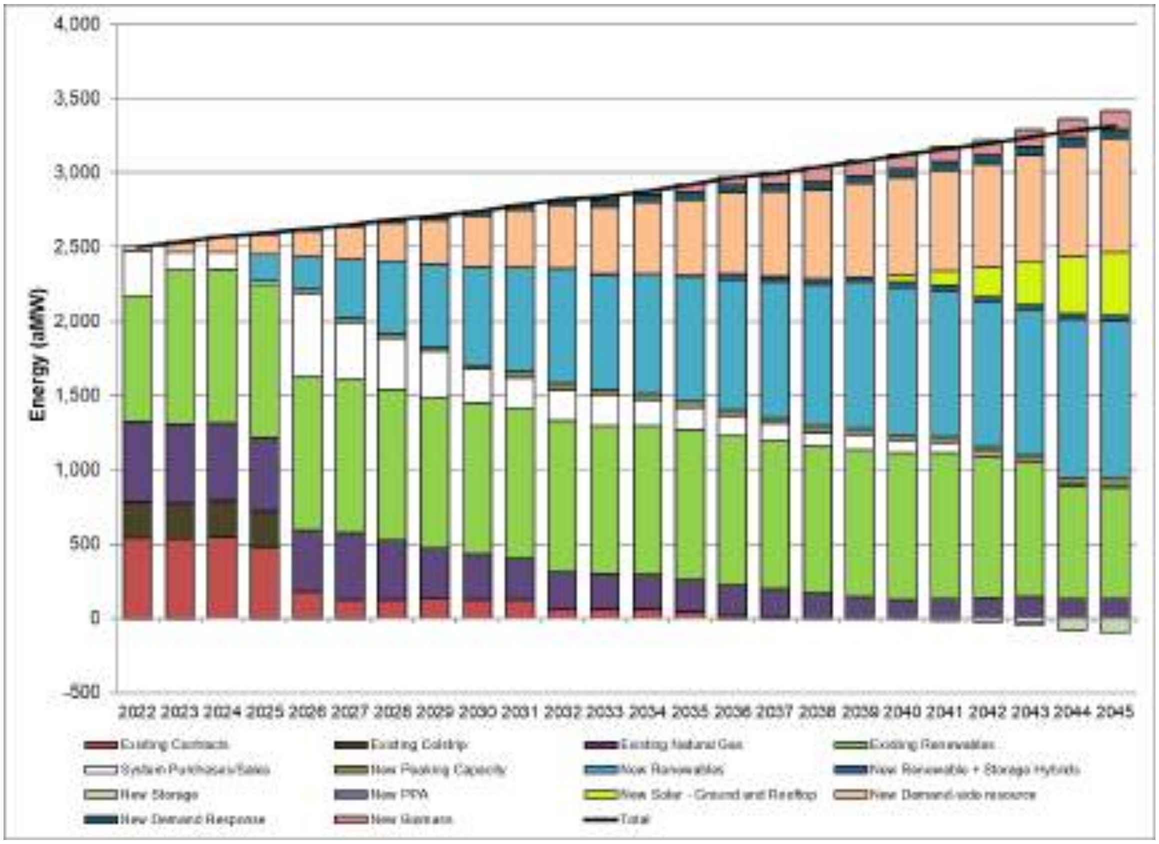
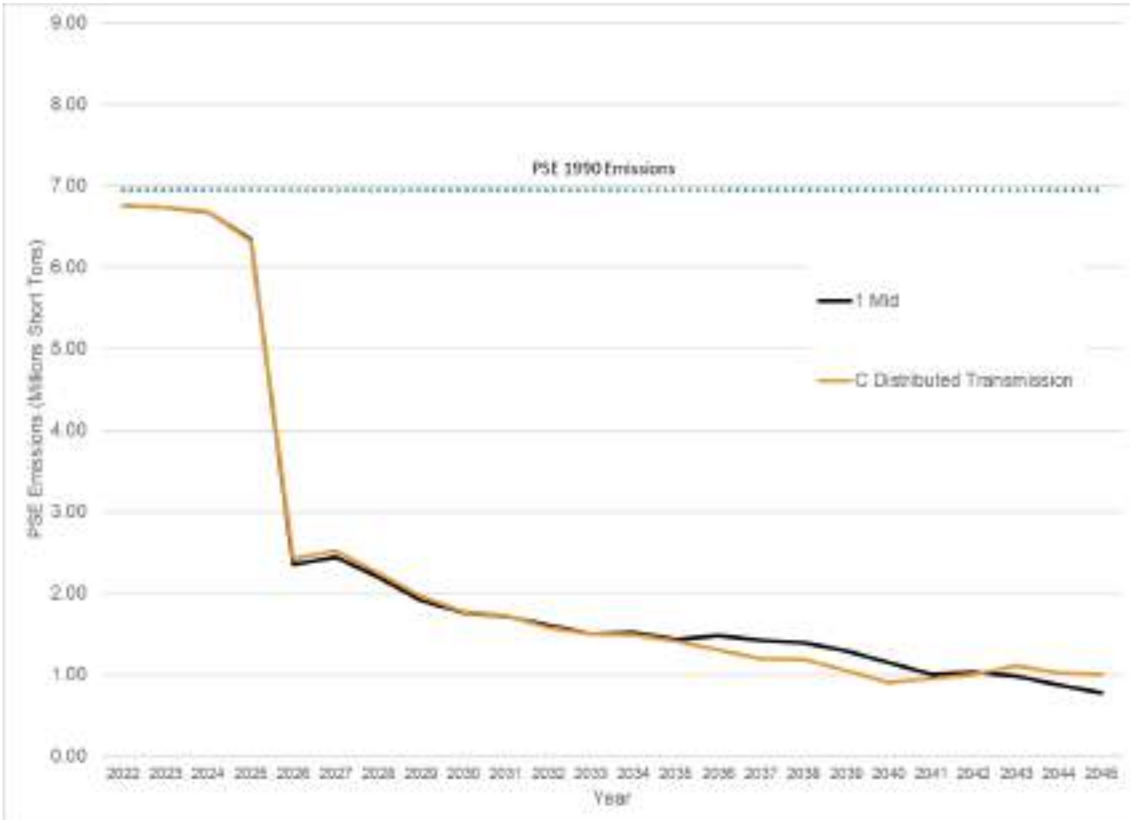


Figure 8-40: Direct Portfolio Emissions – Mid Scenario and Sensitivity C



D. Transmission/Build Constraints – Time-delayed (Option 2)

This sensitivity examines increased transmission constraints on PSE's resources. The PSE Energy Delivery team has defined four "Tiers" of transmission availability, which increase transmission capacity over time. This sensitivity ramps in transmission availability over the modeling horizon.

Baseline: The baseline assumes the transmission constraints described by Tier 0. PSE's system is subject to relatively few transmission constraints, including a limit of 1,500 MW of purchases from the Mid-C market and build limitations for Montana, Idaho and Wyoming based resources.
Sensitivity > Sensitivity D assumes that transmission constraints increase over time, modeling Tier 1 constraints through 2025, Tier 2 through 2030, Tier 3 through 2035 and Tier 0 (generally unconstrained) after 2035. PSE's system is subject to more restrictive transmission constraints, including those described in the baseline, plus build limitations for eastern, southern and western Washington resources.

KEY FINDINGS. The Tiered transmission constraints modeled in Sensitivity D had relatively little impact on the portfolio composition compared to the Mid Scenario. Early in the modeling horizon, Sensitivity D tends to select wind more often than solar compared to Mid Scenario. By the end of the modeling horizon, most resource builds are near those in the Mid Scenario. Costs and GHG emissions are also in line with those in the Mid Scenario. This suggests that transmission constraints (until the year 2035) have little influence on resource acquisition decisions. A similar result was observed in Sensitivity C.

ASSUMPTIONS. Sensitivity D assumes that transmission capacity availability outside of PSE's service territory ramps in over time. Figure 8-41 summarizes the transmission capacity assumptions for each Tier and associated timeframe. (See Chapter 5 for a complete description of the four transmission tiers and resource group regions.)

Figure 8-41: Sensitivity D Transmission Constraints

	Added Transmission (MW)			
Resource Group Region	Tier 0	Tier 1	Tier 2	Tier 3
PSE territory (a)	(b)	(b)	(b)	(b)
Eastern Washington	Unconstrained	300	675	1,330
Central Washington	Unconstrained	250	625	875
Western Washington	Unconstrained	0	100	635
Southern Washington/Gorge	Unconstrained	150	705	1,015
Montana	750	350	565	750
Idaho / Wyoming	600	0	400	600
TOTAL	**generally unconstrained**	**1,050**	**3,070**	**5,205**
Modeling Timeframe	**2035-2045**	**2022-2025**	**2025-2030**	**2030-2035**

NOTES
(a) Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed.
(b) Not constrained in resource model, assumes adequate PSE transmission capacity to serve future load.

PORTFOLIO COSTS. The Sensitivity D portfolio is slightly more expensive over the modeling time horizon compared to the Mid Scenario portfolio, as shown in Figure 8-42. However, the 24-year levelized cost difference is less than $30 million, which suggests that transmission limitations do not strongly constrain resource builds over the 2022 to 2035 time horizon.

Figure 8-42: Portfolio Cost Comparison – Mid Scenario and Sensitivity D

		24-year Levelized Costs (Billion $)			
	Portfolio	**Revenue Requirement**	**SCGHG**	**Total**	**Change from Mid**
1	**Mid Scenario**	$15.53	$5.09	$20.62	--
D	**Transmission/Build Constraints – Time-delayed (Option 2)**	$15.54	$5.11	$20.65	$0.03

RESOURCE ADDITIONS. Resource additions for Sensitivity D are very similar to the Mid Scenario. This similarity suggests that transmission constraints (until the year 2035) do not have a significant impact on resources build decisions. Sensitivity D shifts away from eastern Washington solar and toward Washington wind due to wind's higher capacity factor, which results in more energy production early in the planning horizon. Sensitivity D also builds slightly more and longer-duration storage than the Mid Scenario. However, the increased storage builds in Sensitivity D occur after 2035, once transmission constraints have been lifted, which suggests the storage decisions were a result of the early focus on wind instead of solar. By 2024, wind and solar builds in Sensitivity D are nearly equal the Mid Scenario.

Sensitivity D selects conservation Bundle 11, which is more conservation than selected in the Mid Scenario (Bundle 10).

These resource build decisions are summarized in Figures 8-43 and 8-44.

Figure 8-43: Portfolio Additions – Mid Scenario and Sensitivity D, Transmission Build Constraints – Time Delayed (Option 2)

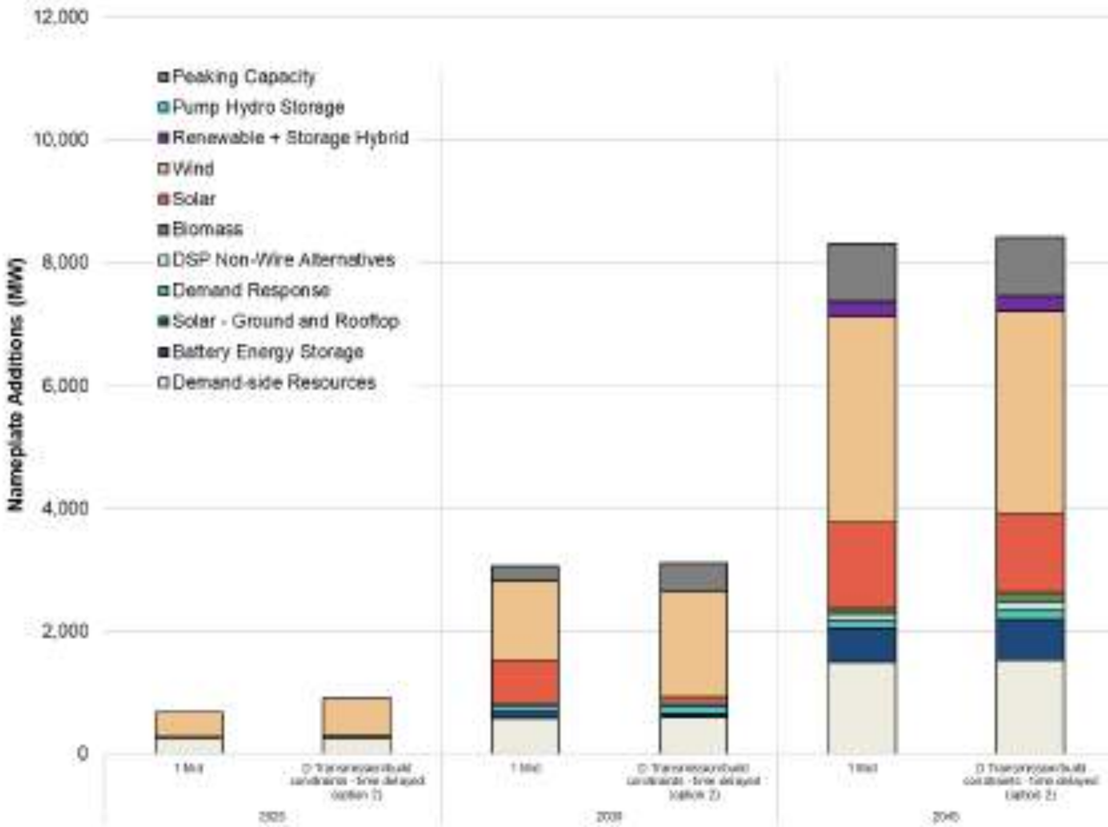


Figure 8-44: Portfolio Additions by 2045, Sensitivity D – Transmission Build Constraints – Time delayed (Option 2)

Resource Additions by 2045	1 Mid	D Transmission Build Constraints – Time delayed (Option 2)
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	650 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	180 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,730 MW
Biomass	90 MW	135 MW
Solar	1,393 MW	1,295 MW
Wind	3,350 MW	3,300 MW
Renewable + Storage Hybrid	250 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	948 MW

E. Firm Transmission as a Percentage of Resource Nameplate

This sensitivity examines the impact on portfolio costs when the capacity of firm transmission purchased with new resources is less than the nameplate capacity of the generating resource.

Baseline: New resources are acquired with transmission capacity equal to their nameplate capacity.

Sensitivity > New resources are acquired with less transmission capacity than nameplate capacity.

KEY FINDINGS. The benefit from contracting firm transmission less than the nameplate capacity of a renewable resource is highly site specific. Project sites with low transmission costs tend to benefit less than sites with high transmission costs. Wind resources tend to benefit less than solar resources due the significant portion of time that wind resources spend at or near nameplate capacity (i.e., rated power).

ASSUMPTIONS. This sensitivity examines the trade-off between investing in the cost of firm transmission versus the cost of having to replace power lost to transmission curtailment because transmission less than nameplate capacity was acquired. This trade-off was calculated for the following generic resource alternatives: Washington wind, Montana wind east, Montana wind central, Wyoming wind east, Wyoming wind west, Idaho wind, utility-scale Washington solar east, utility-scale Wyoming solar east, utility-scale Wyoming solar west and utility-scale Idaho solar.

The annual transmission cost for each resource was calculated using the fixed transmission cost of the resource (provided in Figure 5-25 in Chapter 5) times the nameplate capacity of the resource. The transmission-curtailed energy was calculated as the sum of all hours where the resource production exceeded the transmission limit. For example, a 100 MW wind farm operating at rated power with 10 percent reduced transmission will curtail 10 MWh for a one-hour period (100 MW x 1 h – 100 MW x (1-0.10) x 1 h = 10 MWh).

The replacement cost of transmission-curtailed energy was assumed to be equal to the levelized cost of power for the given resource. PSE acknowledges that these assumptions present a “worst-case scenario” analysis, where it is assumed that all power produced can be used (i.e., production equals demand) and that no short-term transmission may be purchased to supplement long-term firm transmission. While not a comprehensive analysis, this assessment provides a reasonable estimate of potential costs and benefits attributable to reduced transmission sensitivities.

WIND RESULTS. Figure 8-45 shows the trade-off for 200 MW of generic wind resources modeled in the 2021 IRP at various degrees of transmission under-build. Points greater than zero on this plot indicate reduced transmission scenarios that provide a benefit to the project, while negative values indicate a cost. All transmission reduction scenarios are presented relative to firm transmission capacity equal to resource nameplate capacity (100 percent), therefore at 100 percent, there is no benefit or cost.

The results show that resources with high transmission costs (Wyoming and Idaho wind resources) return the greatest savings. All wind resources indicate at least some benefit in the range of transmission capacity reductions from around 99 percent to 96 percent of nameplate capacity. This is because wind farms typically produce 0 to 3 percent less power than nameplate due to internal electrical line losses. After this point, the trade-off quickly drops below zero for resources with low fixed transmission costs because wind resources often produce close to their rated power. Figure 8-46 shows a typical histogram for a generic wind resource, where the plurality of the generation time is at or above 95 percent net capacity factor. Most often, therefore, when the wind farm is generating power, it is likely to be using all available transmission.

Fixed transmission costs for Idaho and Wyoming resources are more than four times higher than for eastern Washington wind resources. These premium fixed transmission costs are why Idaho and Wyoming wind resources have such a large potential benefit compared to other wind resources.

Figure 8-45: Trade-off as a Function of Transmission Under-build Degree for 200 MW Wind Resources

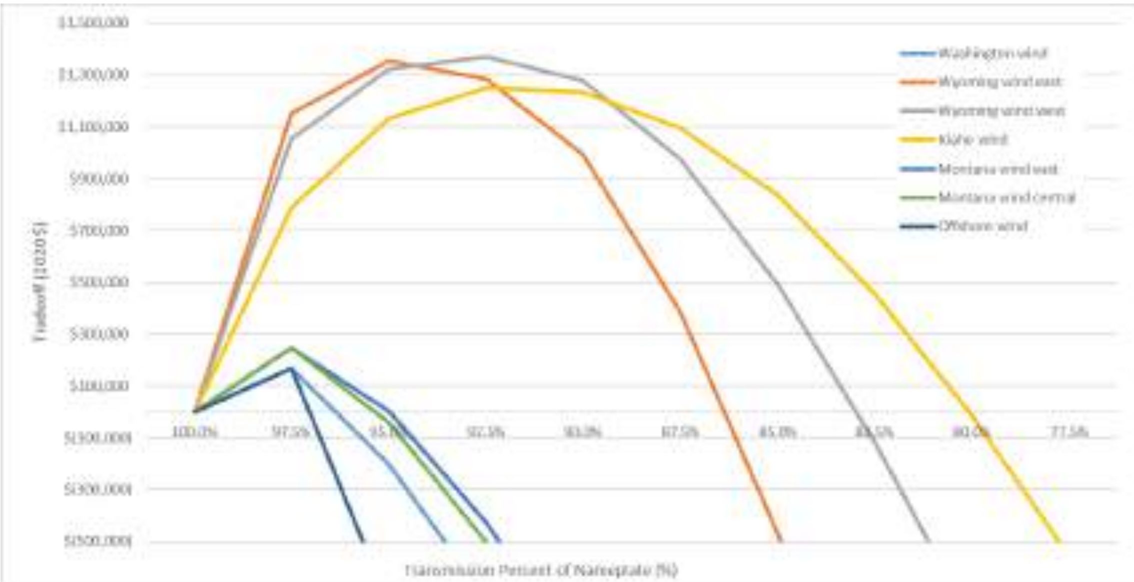
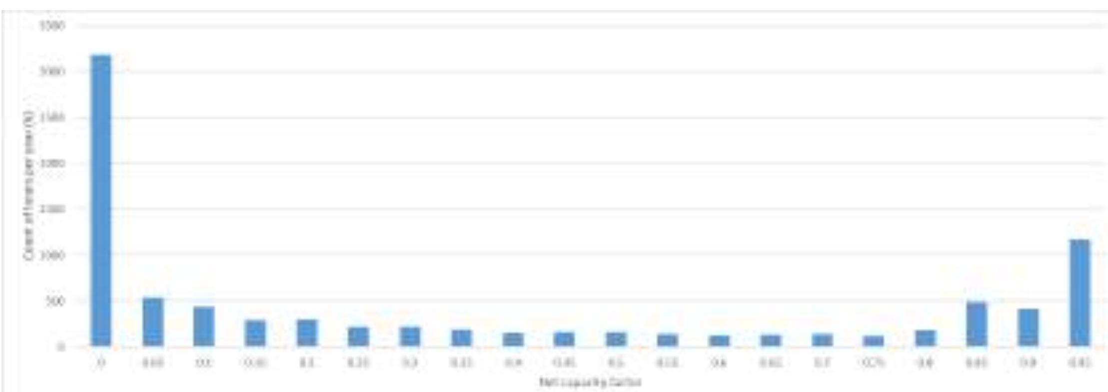


Figure 8-46: Net Capacity Factor Distribution of a Typical Wind Resource



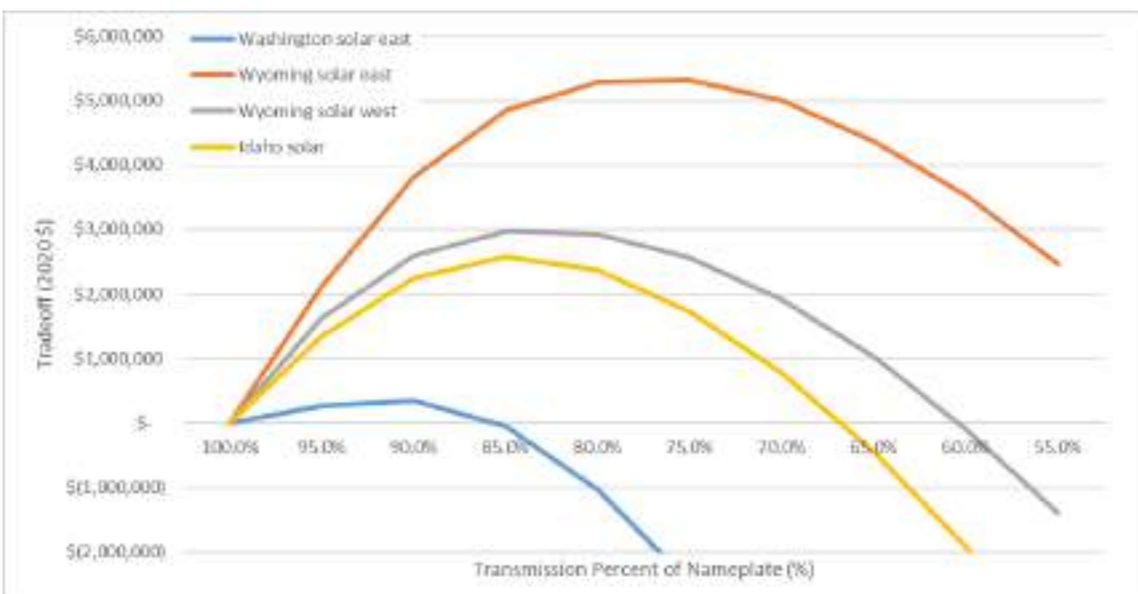
The results of this investigation came as a surprise to PSE. Initial investigations in the 2021 Draft IRP showed very little benefit for all wind resources. However, re-evaluation of the transmission costs for Idaho and Wyoming resources resulted in a very different conclusion. The new results show that firm transmission less than nameplate capacity can be an effective means to reduce portfolio cost; however, the results are highly site specific.

PSE will continue to investigate the potential benefits and risks of contracting less firm transmission than the nameplate capacity of resources. There are numerous modeling obstacles to overcome, such as assessing impacts on the effective load carrying capability of resources, long-term capacity expansion frameworks, and others. PSE looks forward to learning more about the benefits of reducing firm transmission contracts in future IRP cycles.

SOLAR RESULTS. Figure 8-47 shows the trade-off for 200 MW of generic solar resources modeled in the 2021 IRP at various degrees of transmission reduction. Points greater than zero on this plot indicate transmission reduction scenarios which provide a benefit to the project, while negative values indicate a cost. All transmission reduction scenarios are presented relative to firm transmission capacity that equals resource nameplate capacity (100 percent), therefore at 100 percent there is no benefit or cost.

Similar to the wind resources discussed above, the benefit of under-built transmission capacity is highly site specific and strongly correlated to fixed transmission cost. Regions with high fixed transmission costs (Idaho and Wyoming) have significantly more benefit than regions with low fixed transmission costs (eastern Washington).

Figure 8-47: Trade-off as a Function of Transmission Under-build Degree for 200 MW Solar Resources



Similar to the wind results above, the results of the solar investigation came as a surprise to PSE. Initial investigations for the 2021 draft IRP showed very little benefit for all solar resources. However, re-evaluation of the transmission costs for Idaho and Wyoming resources resulted in a very different conclusion. The new results show that firm transmission less than nameplate capacity can be an effective means to reduce portfolio cost; however, the circumstances are highly site specific.

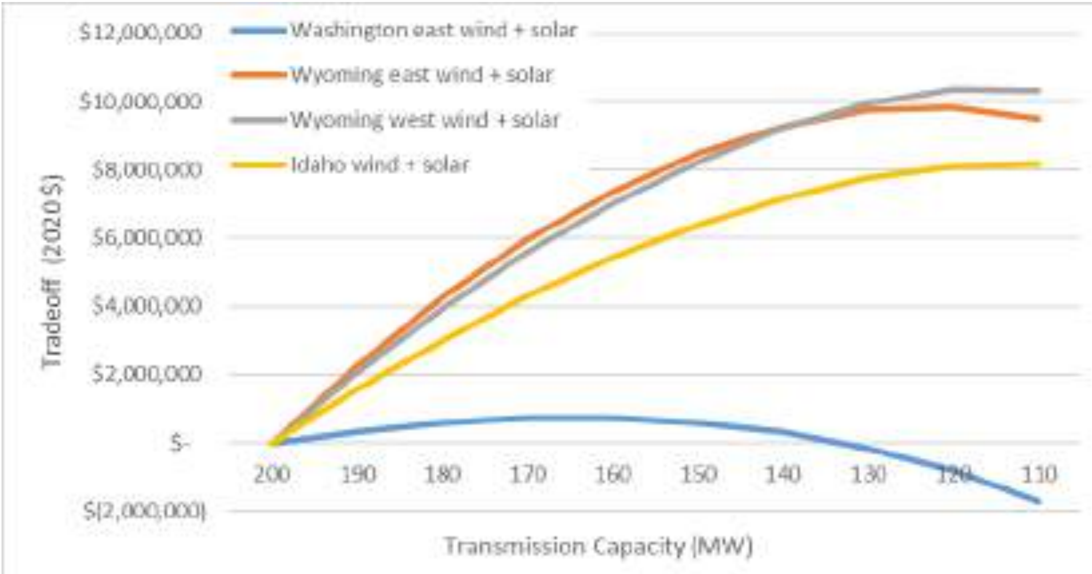
PSE will continue to investigate potential benefits and risks of contracting less firm transmission than the nameplate capacity of resources. There are numerous modeling obstacles to overcome, such as assessing impacts on the effective load carrying capability, long-term capacity expansion frameworks, and others. PSE looks forward to learning more about the benefits of reducing firm transmission contracts in future IRP cycles.

NEXT STEPS. In addition to the transmission sensitivities described above, PSE also looked at co-locating a wind and solar resource with shared, limited transmission capacity. A complementary relationship appears to exist between the resource pairs assessed. First, wind resources with higher winter production may benefit from co-location with solar resources that have higher summer production. Second, wind resources with higher overnight production may benefit from co-location with solar resources that, by nature, only produce power during the day. Optimizing the amount of transmission to better match the average seasonal and diurnal production of the co-located resources may realize cost savings, as opposed to securing firm transmission for both resources individually.

Figure 8-48 shows the possible benefits of co-locating a 100 MW wind farm with a 100 MW solar farm at various locations. Cost benefits from reducing firm transmission contracts are strongly correlated to fixed transmission cost, as seen in the analysis of individual wind and solar resources. Interestingly, on a dollar-per-megawatt nameplate capacity basis, the benefit of the co-location is even greater than for individual wind or solar resources, which shows a synergistic relationship between co-located wind and solar resources that share transmission capacity.

PSE looks forward to continuing to learn more about benefits of co-located resources in future IRP cycles.

Figure 8-48: Trade-off as a Function of Transmission Capacity for Co-located 100 MW Wind and 100 MW Solar Resources



Conservation Alternatives

F. 6-year Ramp Rate for Conservation
G. Non-energy Impacts
H. Social Discount Rate

These sensitivities were performed to assess changes in the implementation rate, financial structure, and overall effectiveness of conservation measures.

Baseline: Conservation resources are implemented over 10 years using PSE's baseline assumptions on costs and energy savings.
Sensitivity F > Conservation measures are implemented over 6 years instead of 10 years, and associated costs and energy savings are updated.
Sensitivity G > Conservation measures include additional non-energy impacts. Assuming there are additional benefits not captured in the original dataset, this increases the amount of energy savings from conservation and demand response.
Sensitivity H > The discount rate of DSR projects is changed from 6.8 percent to 2.5 percent. When the discount rate is decreased, the present value of future DSR savings is increased.

KEY FINDINGS. Costs and resource builds remain relatively stable across changes to the conservation inputs. Sensitivity F (6-year Ramp) selected Bundle 9, Sensitivity G (Non-energy

Impacts) selected bundle 8 and Sensitivity G (Social Discount Rate) selected bundle 6, compared to bundle 10 in the Mid Scenario. Though lower conservation bundles were selected, additional demand response measures were added. Changes to the conservation assumptions push more energy savings measures into lower bundles so the portfolio selects similar or lower amounts of conservation for lower costs. Overall, the baseline assumptions around demand-side resources included in the mid portfolio optimize to the highest amount DSR added to the portfolio by 2045, compared to making adjustments around ramp rates and discount rates.

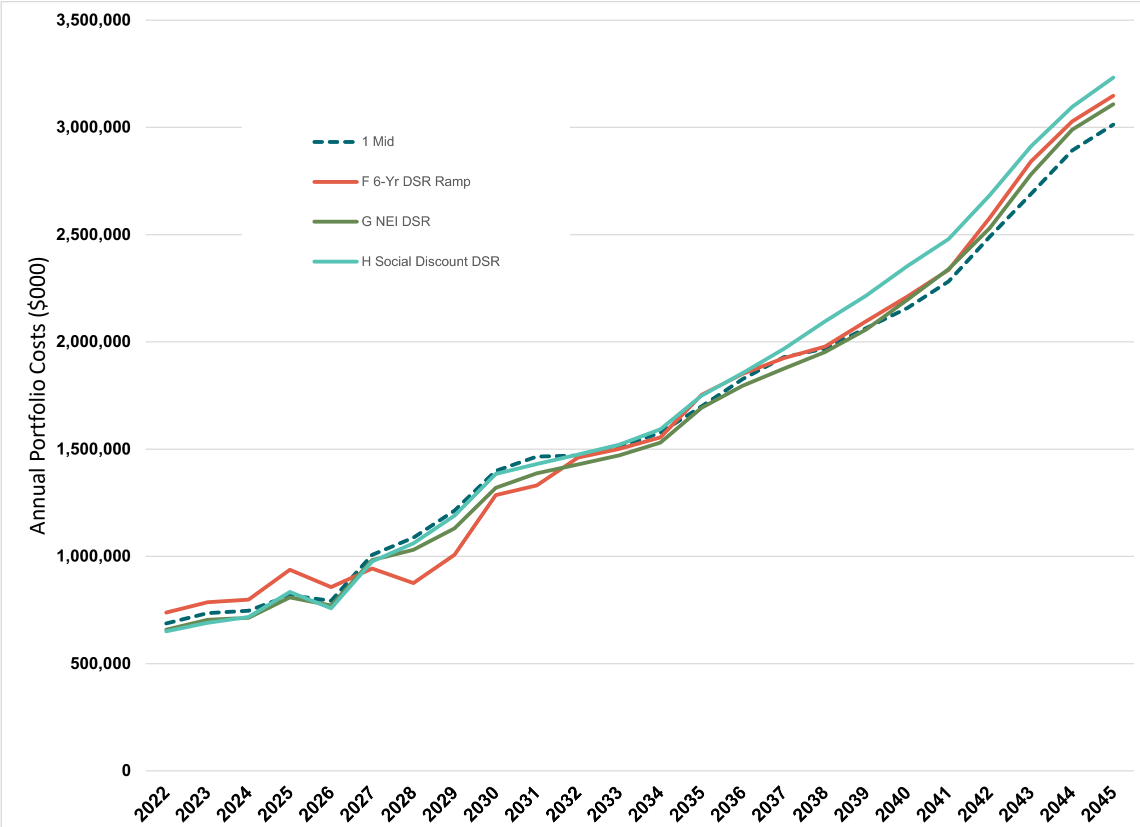
ASSUMPTIONS. These portfolios keep all underlying assumptions from the Mid Scenario portfolio, then change the costs and energy savings of the conservation measures available as resources. All DSR inputs in the Mid Scenario and Sensitivities F, G and H, can be found in Appendix H.

ANNUAL PORTFOLIO COSTS. Across all three sensitivities, changes to the overall costs of the portfolio are minor. In Sensitivity F, there is virtually no difference in overall portfolio cost compared to the Mid Scenario, although different timelines for the additions of Washington wind, Wyoming wind and Washington east solar lead to differences in annual costs in the earlier years of the simulation. Sensitivity G shows a small decrease in costs, achieving the same energy savings benefits as Sensitivity F at a lower cost conservation bundle. Sensitivity G also adds a frame peaker by 2045 compared to the Mid Scenario and Portfolio F, resulting in fewer battery builds. Frame peaker builds are a less expensive way to increase capacity and peak capacity, but the overall changes to the portfolio costs are small. Sensitivity H shows a minor increase in costs as a result of increased battery and renewable hybrid builds in the later years of the simulation. Otherwise, the portfolio costs of Sensitivity H follow the annual cost trends of the Mid Scenario.

Figure 8-49: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivities F, G and H

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
F	6-Year Conservation Ramp Rate	$15.54	$5.09	$20.63	$0.01
G	Non-energy Impacts for DSR	$15.24	$5.12	$20.36	($0.26)
H	Social Discount Rate for DSR	$15.77	$5.16	$20.94	$0.32

Figure 8-50: Annual Portfolio Costs – Mid Scenario and Sensitivities F, G and H



RESOURCE ADDITIONS. Figures 8-51 and 8-52 compare the nameplate capacity additions of the Mid Scenario to Sensitivities F, G and H. Resource builds do not change significantly across the portfolios. Minor differences are seen in the timing of renewable resource construction and total nameplate capacity built. Any reductions in standalone renewable capacity are offset by increased hybrid resources or battery storage resources. Sensitivity H shows the largest increase in overall capacity, adding 100 MW of wind, 250 MW of hybrid resources and 100 MW of battery storage by 2045. Sensitivity F builds an additional 250 MW of hybrid resources and 75 MW of battery resources, but reduces standalone wind resources by 200 MW. Sensitivity G increases battery storage and standalone wind resources by 200 MW each, but reduces hybrid resource builds by 250 MW by 2045. These differences from the Mid Scenario are minor and affect the later years of the simulation.

Figure 8-51: Portfolio Additions – Mid Scenario and Sensitivities F, G and H

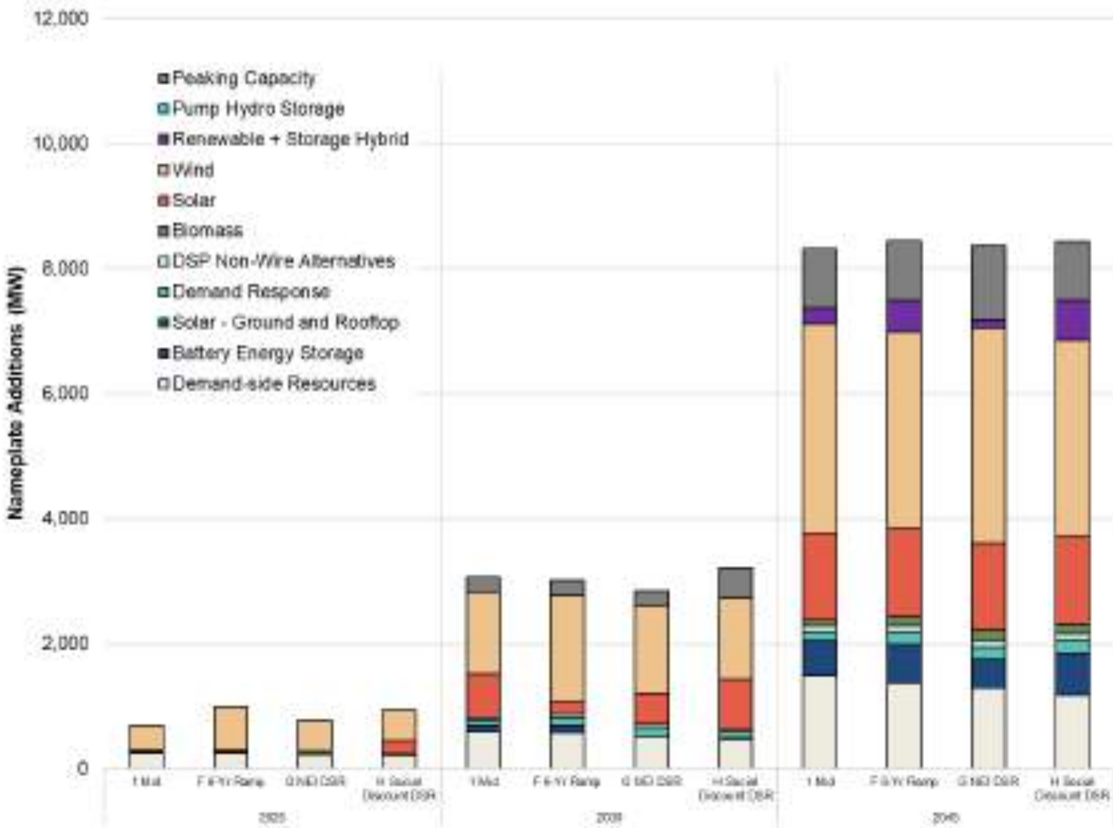


Figure 8-52: Portfolio Additions – Mid Scenario and Sensitivities F, G and H

Resource Additions by 2045	1. Mid	F. 6-Yr DSR Ramp	G. NEI DSR	H. Social Discount DSR
Demand-side Resources	1,497 MW	1,372 MW	1,304 MW	1,179 MW
Battery Energy Storage	550 MW	625 MW	450 MW	675 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW	0 MW
Demand Response	123 MW	175 MW	188 MW	195 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	4,694 MW	4,993 MW	4,691 MW
Biomass	90 MW	150 MW	150 MW	150 MW
Solar	1,393 MW	1,394 MW	1,393 MW	1,391 MW
Wind	3,350 MW	3,150 MW	3,450 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	500 MW	125 MW	625 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	966 MW	1,185 MW	948 MW

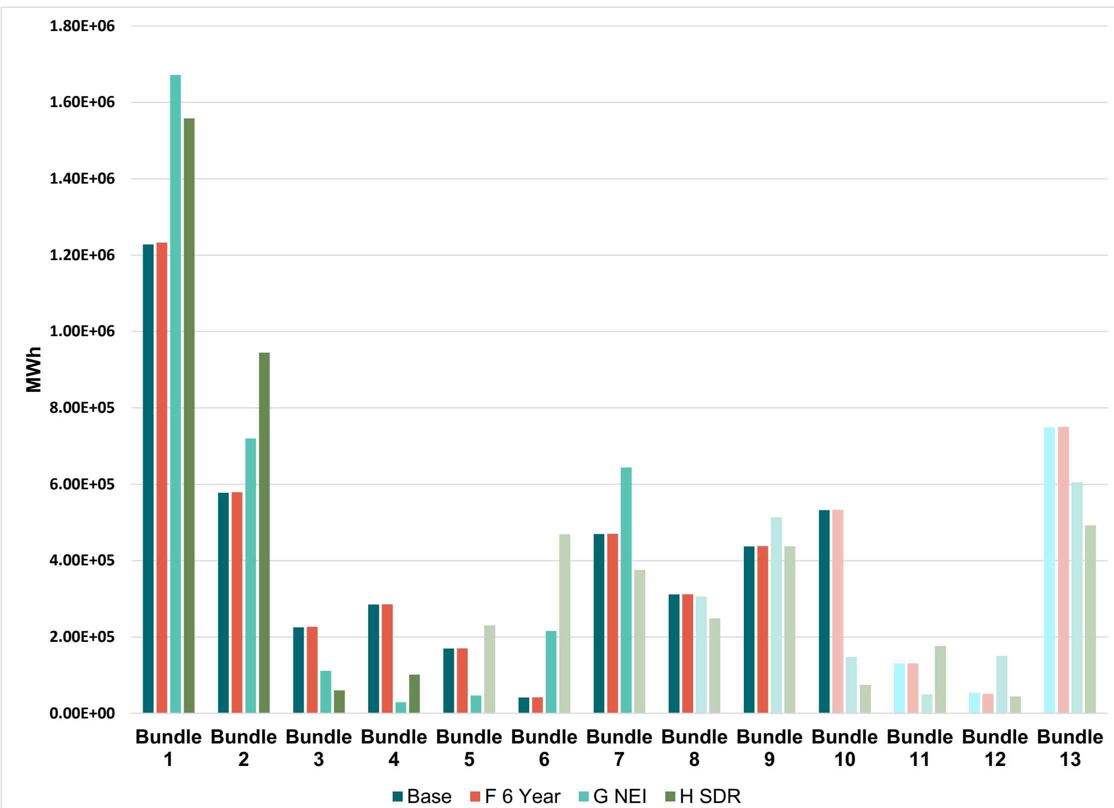
CHANGES IN CONSERVATION AND DEMAND RESPONSE. The primary focus of these sensitivities was to assess the implementation of changes to the available conservation measures. Figure 8-53 shows the final conservation selections in each sensitivity.

Figure 8-53: Conservation Measures Selected – Mid Scenario and Sensitivities F, G and H

Sensitivity	Conservation Bundle	Average Annual Energy Savings from Conservation	Number of Demand Response Measures	Capacity of Demand Response Measures Added
Mid Scenario	Bundle 10	718 aMW	3	123 MW
F - 6-Year Ramp	Bundle 9	659 aMW	5	175 MW
G - Non-Energy Impacts	Bundle 7	624 aMW	8	188 MW
H - Social Discount Rate	Bundle 4	538 aMW	9	195 MW

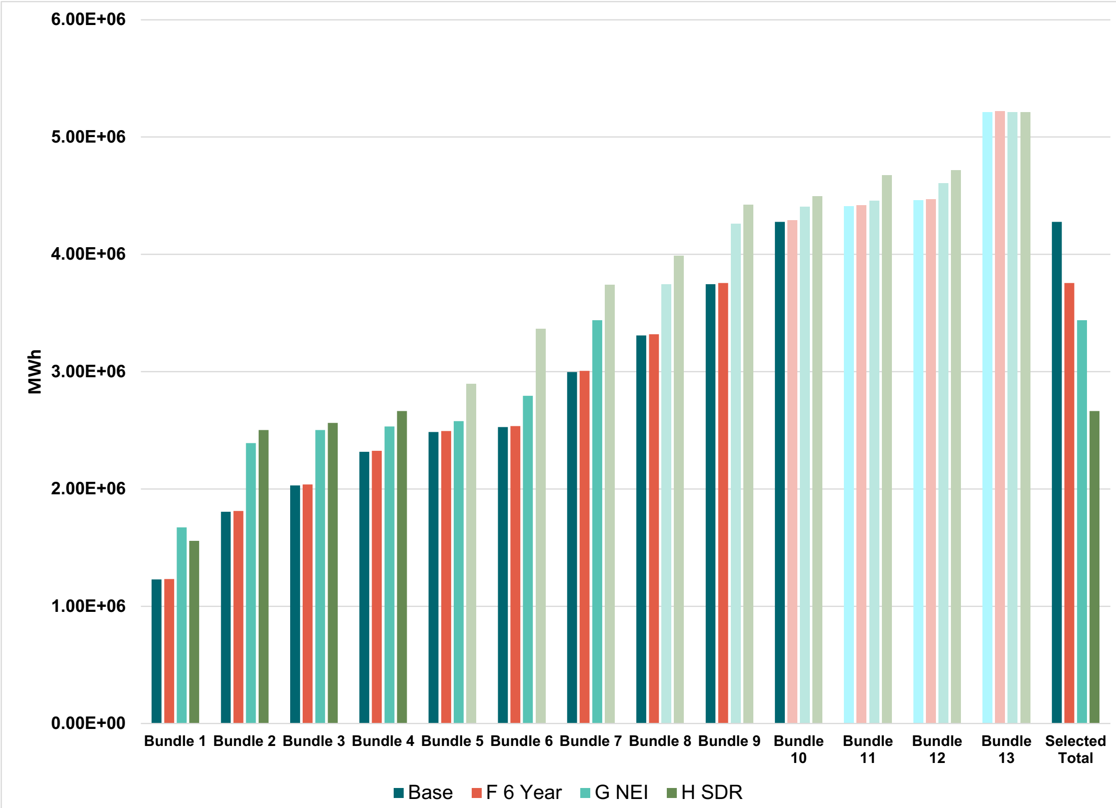
Updates to the DSR inputs changed the energy and cost values associated with each conservation measure. Since each conservation bundle is a collection of individual conservation programs within a price range, the assessment of individual measures within a bundle is not possible. However, the aggregate attributes of each bundle can be seen. Figure 8-39 shows the incremental energy savings provided by each bundle by 2045. In order to add a bundle in the AURORA model, the previous bundle must also be added (excluding Bundle 1), each bundle is dependent on adding the previous bundle. Figure 8-54 shows the cumulative energy savings provided by a selected bundle and all preceding bundles.

Figure 8-54: Incremental Energy Savings Provided by Each Bundle by the Year 2045 (darkened bars indicate that the bundle was selected in the portfolio)



Across the DSR sensitivities, adjustments to the underlying DSR attributes push more energy savings into lower bundles. In the long-term capacity expansion model, AURORA responds to these changes by adding less conservation while increasing investment in demand response measures. This trend is shown in Figure 8-55 where the cumulative energy savings within each bundle is greater for Sensitivities F, G and H than the Mid Scenario (Base).

Figure 8-55: Cumulative savings Achieved by Each Incremental Bundle by the Year 2045 (darkened bars indicate that the bundle was selected in the portfolio)



Social Cost of Greenhouse Gases and CO_2 Regulation

I. SCGHG as an Externality Cost in the Portfolio Model Only
J. SCGHG as an Externality Cost in the Portfolio Model and Dispatch Model

The goal of these sensitivities is to compare methodologies for applying the social cost of greenhouse gases to portfolios.

Baseline: The SCGHG is included as a planning adder to emitting resources in the long-term capacity expansion (LTCE) model. The planning adder is a fixed cost.
Sensitivity I > The SCGHG is included as an externality cost to emitting resources in the LTCE model. This externality cost is a variable cost of dispatch, in contrast to the fixed cost of the planning adder.

Sensitivity J > As in Sensitivity I, the SCGHG is included as an externality cost to emitting resources in the LTCE model. In addition, the SCGHG is included as a dispatch cost in the hourly dispatch model as a carbon tax.

KEY FINDINGS. Including the SCGHG in the LTCE and hourly dispatch models produces portfolios similar to the Mid Scenario. This is expected, as the CETA renewable requirement is the main driver of reduced emissions and thermal resources. In Portfolio I, costs and emissions are nearly identical to the Mid Scenario. In Portfolio J, which also includes the SCGHG as a carbon tax, the overall revenue requirement increases over the course of the planning horizon, but the largest increase occurs while Colstrip is operating from 2022 to 2025. Portfolio J also increases the use of market purchases to meet demand and shows a small decrease in overall emissions compared to the Mid Scenario.

ASSUMPTIONS. In both Sensitivity I and J, the SCGHG defined by CETA is simply applied as a variable cost on the dispatch of emitting resources. Figure 8-56 shows the value of the SCGHG as defined by CETA and the conversion used in AURORA.

In Sensitivity J, the SCGHG is also applied as a carbon tax in the hourly dispatch model. This requires an updated power price dataset since a carbon tax would impact the operations of all utilities in Washington.

Figure 8-56: CETA Definition of SCGHG and the Converted Values Used in AURORA

Year	2019$ / metric ton CO2	AURORA Input 2012$ / short ton CO2
2022	77.73	59.33
2023	78.95	60.25
2024	80.16	61.18
2025	82.59	63.03
2026	83.81	63.96
2027	85.02	64.89
2028	86.24	65.81
2029	87.45	66.74
2030	88.67	67.67
2031	89.88	68.60
2032	91.09	69.52
2033	92.31	70.45
2034	93.52	71.38
2035	94.74	72.30
2036	95.95	73.23
2037	98.38	75.08
2038	99.60	76.01
2039	100.81	76.94
2040	102.03	77.86
2041	103.24	78.79
2042	104.46	79.72
2043	105.67	80.65
2044	106.88	81.57
2045	108.10	82.50

ANNUAL PORTFOLIO COSTS. Figures 8-57 and 8-58 illustrate the breakdown of costs between the Mid Scenario and Sensitivities I and J.

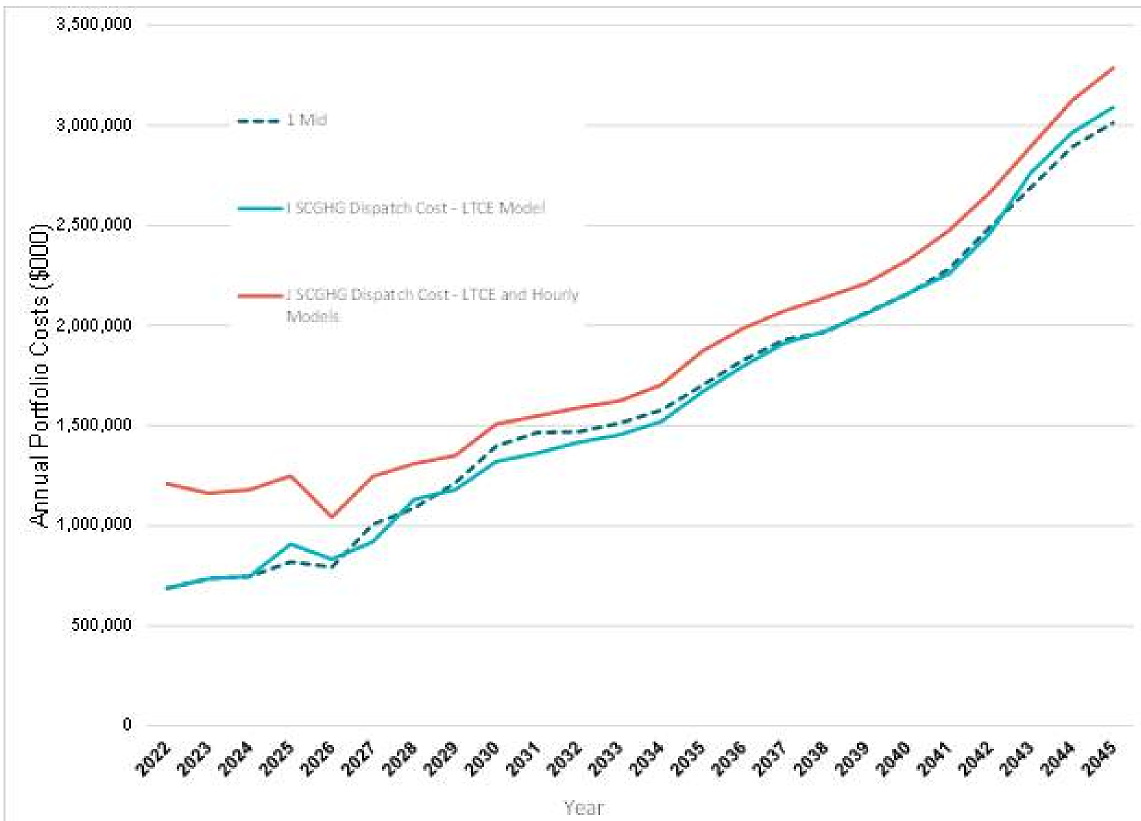
The final builds of the portfolios are similar, though Portfolio J greatly increases the emission costs of the portfolio in earlier years since the emissions of Colstrip and other thermal resources are now also taxed in the hourly dispatch model. After the retirement of Colstrip, as the carbon tax delays the construction of more flexible capacity resources, Portfolio J emissions do decrease compared to the portfolios in the Mid Scenario and Sensitivity I. Despite these differences, the cost trends of the portfolios remain the same after 2036. Sensitivity J has a higher overall cost since the SCGHG is now included as a dispatch cost and in the electric price forecast. This makes it difficult to divide out the revenue requirement from SCGHG. Even though sensitivity J has a lower SCGHG cost, it only reflects the cost of generating resources; the cost of market is in the revenue requirement, so it is hard to compare this portfolio against the Mid scenarios.

Figure 8-57: 24-year Levelized Portfolio Costs – Mid Scenario, Sensitivities I and J

		24-year Levelized Costs (Billion $)			
	Portfolio	**Revenue Requirement**	**SCGHG**	**Total**	**Change from Mid**
1	**Mid Scenario**	$15.53	$5.09	$20.62	--
I	**SCGHG Externality Cost – LTCE Model Only**	$15.41	$5.10	$20.51	($0.11)
J	**SCGHG Externality Cost – LTCE Model and Hourly Dispatch***	$18.45	$4.81	$23.26	$2.64

** Sensitivity J uses a different electric price forecast than the Mid Scenario.*

Figure 8-58: Annual Portfolio Costs – Mid Scenario, Sensitivity I and Sensitivity J



RESOURCE ADDITIONS. Figures 8-59 and 8-60 compare the nameplate capacity additions of the Mid Scenario to Sensitivities I and J. Both sensitivities select Bundle 10 for conservation and reach 2045 with a similar builds of batteries and renewables. Timing of resources builds is different for each sensitivity, but both result in similar portfolios to the Mid Scenario.

Sensitivity I builds one less frame peaker than the Mid Scenario, but adds 55 MW of reciprocating peakers. It also builds 200 MW less of Washington wind and 100 MW less of Washington solar than the Mid Scenario, but adds 125 MW of hybrid resources to the portfolio. Overall, Sensitivity I adds 325 MW more battery resources than the Mid Scenario. There is also a shift in the type of battery resources selected with 575 MW of 4-hour lithium-ion batteries built compared to the Mid Scenario's 50 MW.

Sensitivity J builds two fewer frame peakers than the Mid Scenario, but adds 273 MW of reciprocating peakers. Washington wind capacity increases by 200 MW by 2045, and Washington solar capacity decreases by 400 MW, netting the same overall intermittent renewable nameplate capacity as Portfolio I. Portfolio J also adds 125 MW of hybrid resources. Overall, Sensitivity J adds an additional 300 MW more of battery resources than the Mid Scenario. There is also a shift in the type of battery resources selected with 400 MW of 6-hour flow batteries built compared to no 6-hour flow batteries the Mid Scenario.

Figure 8-59: Portfolio Additions – Mid Scenario and Sensitivities I and J

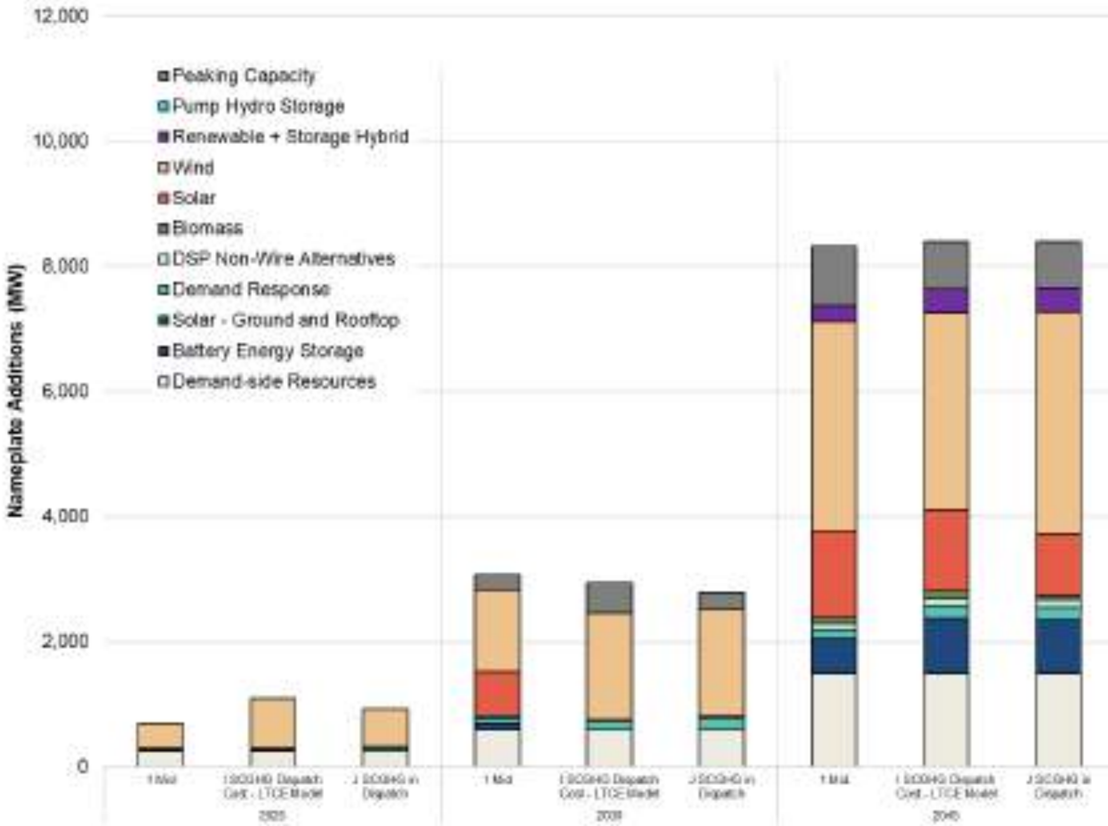


Figure 8-69: Portfolio Additions – Mid Scenario and Sensitivities I and J

Resource Additions by 2045	1 Mid	I SCGHG Dispatch Cost - LTCE Model	J SCGHG Dispatch Cost - LTCE and Hourly Models
Demand-side Resources	1,497 MW	1,497 MW	1,497 MW
Battery Energy Storage	550 MW	875 MW	850 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	188 MW	205 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	4,579 MW	4,606 MW
Biomass	90 MW	135 MW	60 MW
Solar	1,393 MW	1,294 MW	996 MW
Wind	3,350 MW	3,150 MW	3,550 MW
Renewable + Storage Hybrid	250 MW	375 MW	375 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	766 MW	747 MW

EMISSIONS. Emissions are the largest difference between Sensitivity I and J. Figure 8-61 compares the direct emissions of the Mid Scenario, Sensitivity I and Sensitivity J. Portfolio J builds a similar amount of peaking capacity as Portfolio I, but relies much more heavily on market purchases to meet demand. Including the market purchase emission rate assumed in CETA brings Portfolio J in line with Sensitivity I, showing a modest decrease in emissions as shown in Figure 8-62. This is expected, as the CETA renewable requirement is the main driver of emissions reductions, not the SCGHG.

Figure 8-61: Direct Portfolio Emissions – Mid Scenario and Sensitivities I and J (market purchases not included)

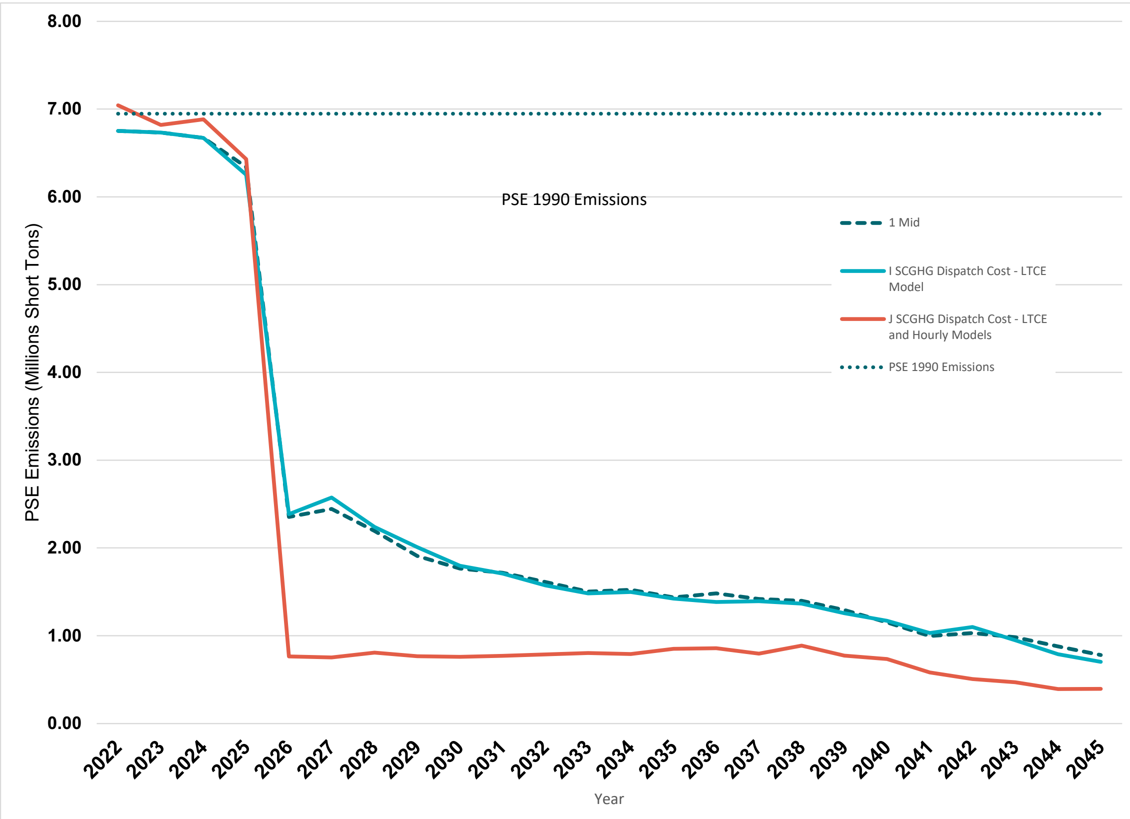
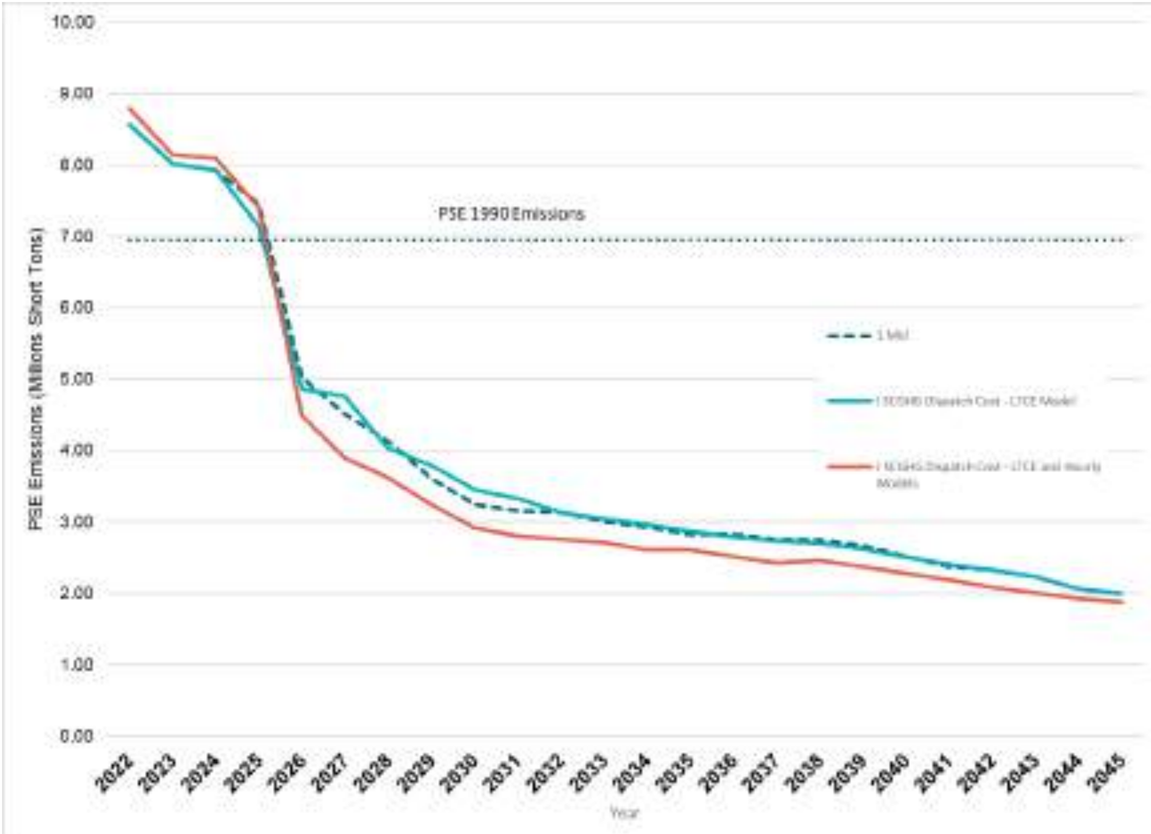


Figure 8-62: Indirect Portfolio Emissions – Mid Scenario and Sensitivities I and J (market purchases included)



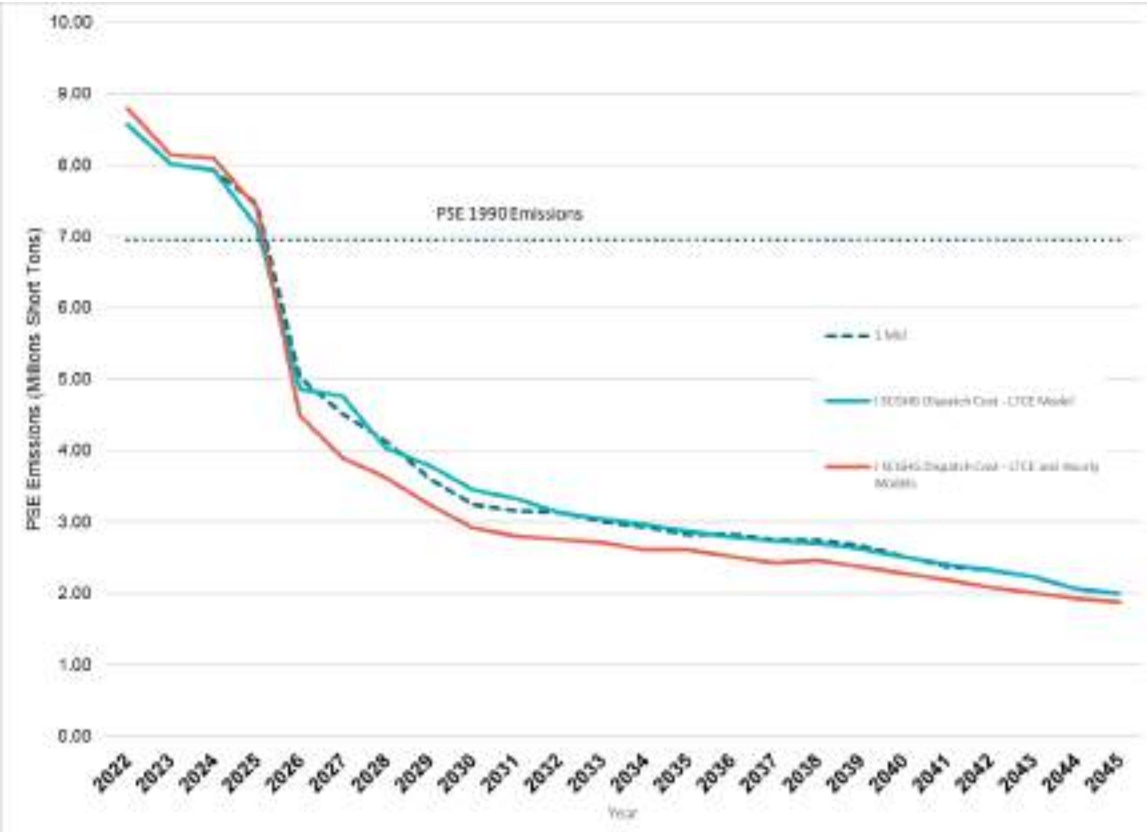
K. AR5 Upstream Emissions

This sensitivity examines how using different methodologies to calculate upstream emissions affects portfolios.

Baseline: The IPCC's Fourth Assessment Report (AR4) is used to calculate the rate of upstream emissions for PSE thermal generating plants.
Sensitivity K > The IPCC's Fifth Assessment Report (AR5) is used to calculate the rate of upstream emissions for PSE thermal generating plants.

KEY FINDINGS. Updating the upstream emission rate from AR4 to AR5 methodology does not produce broad changes to the Mid Scenario portfolio. When thermal resources are assumed to have a higher rate of emissions, emissions and costs increase slightly.

Figure 8-62: Indirect Portfolio Emissions – Mid Scenario and Sensitivities I and J (market purchases included)



K. AR5 Upstream Emissions

This sensitivity examines how using different methodologies to calculate upstream emissions affects portfolios.

Baseline: The IPCC's Fourth Assessment Report (AR4) is used to calculate the rate of upstream emissions for PSE thermal generating plants.
Sensitivity K > The IPCC's Fifth Assessment Report (AR5) is used to calculate the rate of upstream emissions for PSE thermal generating plants.

KEY FINDINGS. Updating the upstream emission rate from AR4 to AR5 methodology does not produce broad changes to the Mid Scenario portfolio. When thermal resources are assumed to have a higher rate of emissions, emissions and costs increase slightly.

ASSUMPTIONS. The sensitivity is updated to include the AR5 methodology of calculating upstream emissions. Figure 8-63 compares the emission rates of resources in the Mid Scenario and Sensitivity K. All other underlying assumptions from the Mid Scenario portfolio are kept the same.

Figure 8-63: Upstream Emission Rates – Mid Scenario (AR4) and Sensitivity K (AR5)

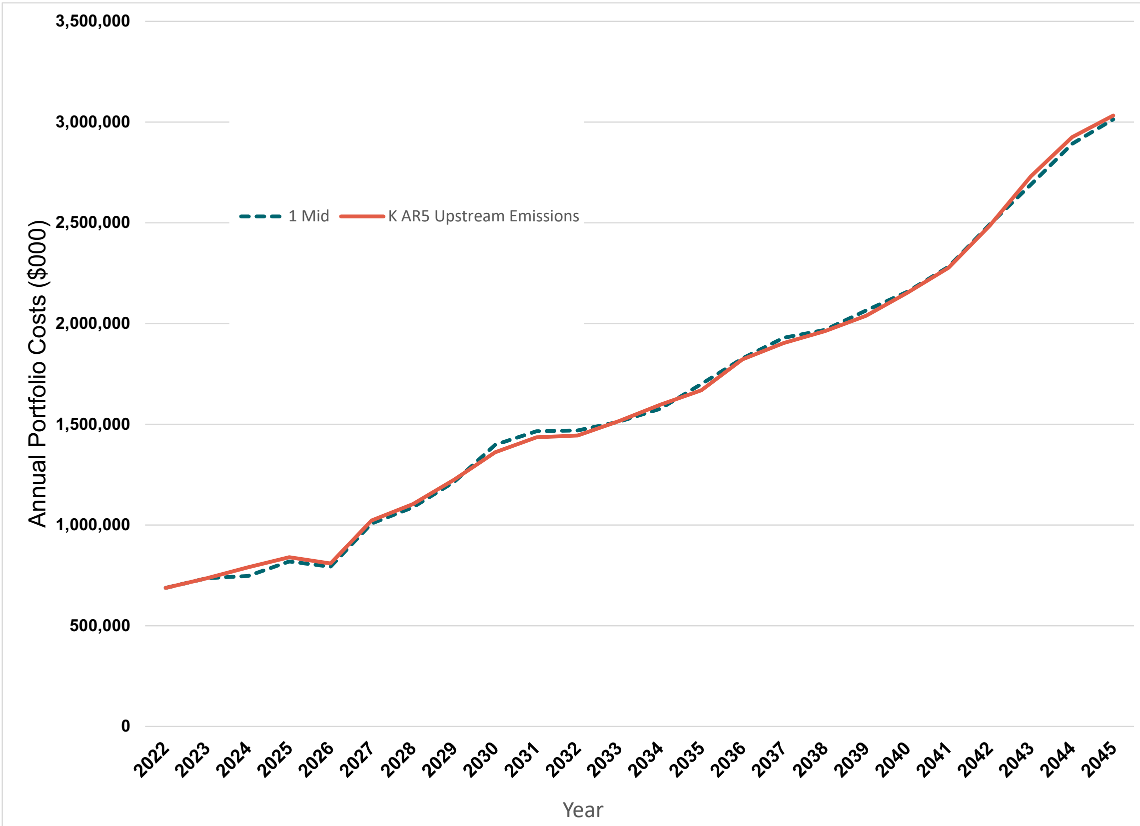
Resource	Mid Scenario AR4 Upstream Emission Rates (lb/mmBtu)	Sensitivity K AR5 Upstream Emission Rates (lb/mmBtu)
New Frame Peaker	23	24
New Recip Peaker	23	24

ANNUAL PORTFOLIO COSTS. The costs of the Sensitivity K and Mid Scenario portfolios are nearly identical. There are no significant changes in portfolio builds that would lead to changes in costs. The increased emissions costs are expected, as thermal plants are associated with slightly higher emissions.

Figure 8-64: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity K

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	**Mid Scenario**	$15.53	$5.09	$20.62	--
K	**AR5 Emissions**	$15.56	$5.14	$20.71	$0.09

Figure 8-65: Annual Portfolio Costs – Mid Scenario and Sensitivity K



RESOURCE ADDITIONS. Figures 8-66 and 8-67 compare the nameplate capacity additions in the portfolios of the Mid Scenario and Sensitivity K. Both select Bundle 10 for conservation, and Sensitivity K selects four additional demand response resources for a total of seven. Minor differences are seen in the timing of wind and solar resources. Nearly the same amount of peaking capacity, solar and hybrid capacity is built by 2045 in both portfolios. However, 200 MW less of wind and an additional 75 MW of battery storage are built by 2045 in the Sensitivity K portfolio.

Figure 8-66: Portfolio Additions – Mid Scenario and Sensitivity K

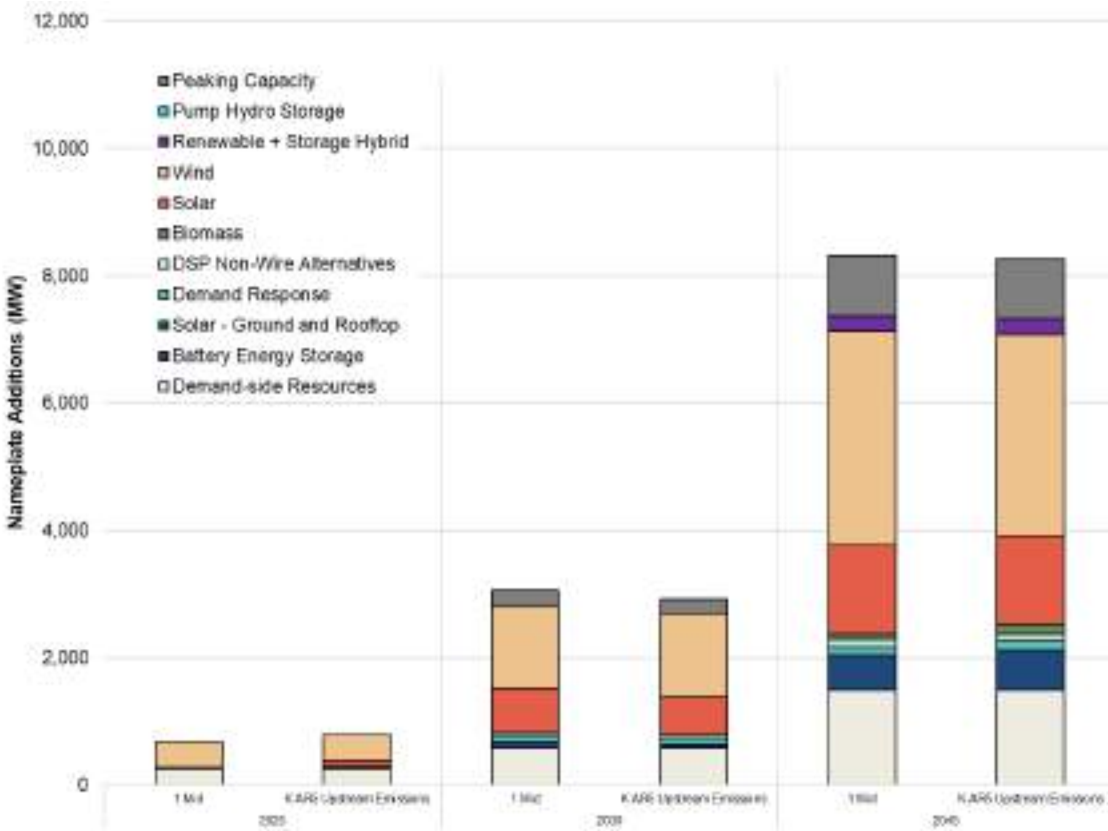
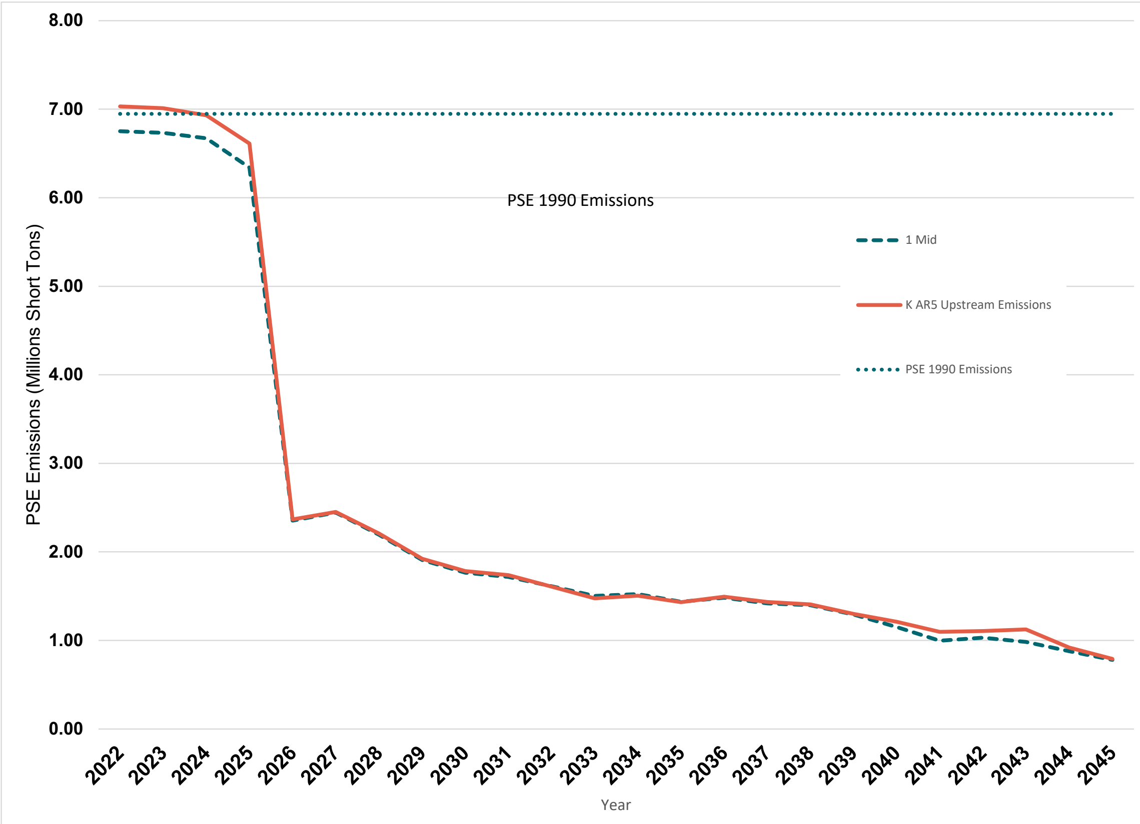


Figure 8-67: Portfolio Additions – Mid Scenario and Sensitivity K

Resource Additions by 2045	1 Mid	K AR5 Upstream Emissions
Demand-side Resources	1,497 MW	1,497 MW
Battery Energy Storage	550 MW	625 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	140 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,693 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	1,393 MW
Wind	3,350 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	948 MW

EMISSIONS. Changing to the AR5 methodology does not significantly change the emissions of Portfolio K. Figure 8-68 compares the emissions of the Mid Scenario and Portfolio K. The change to the AR5 methodology makes the most difference in the earlier years when dispatch of the natural gas resources are higher. Over time, the dispatch of the natural gas resources drops significantly enough that there is negligible change in emissions between the two portfolios.

Figure 8-68: Annual Emissions – Mid Scenario and Portfolio K



L. SCGHG as a Fixed Cost Plus a Federal CO_2 Tax

This sensitivity examines the impact of adding a Federal CO_2 tax in addition to SCGHG as a fixed cost adder for thermal plants during the resource selection process.

Baseline: The SCGHG is included as a planning adder (fixed cost) to thermal resources during the LTCE modeling process.

Sensitivity L > In addition to SCGHG as a planning adder (fixed cost) to thermal resources during the LTCE modeling process, a Federal CO_2 tax is applied to emissions from thermal resources during both the LTCE modeling process and the hourly dispatch model. This Federal CO_2 tax is applied to the power prices of the portfolio as well, which affects all WECC resources.

KEY FINDINGS. There is relatively little change to the renewable resource additions in Sensitivity L since the CETA requirement drives renewable portfolio additions rather than the SCGHG or a Federal CO_2 tax. However, adding a Federal CO_2 alters the dispatch of thermal resources. The capacity factor of all thermal plants declines overtime as the Federal CO_2 tax increases during the planning horizon.

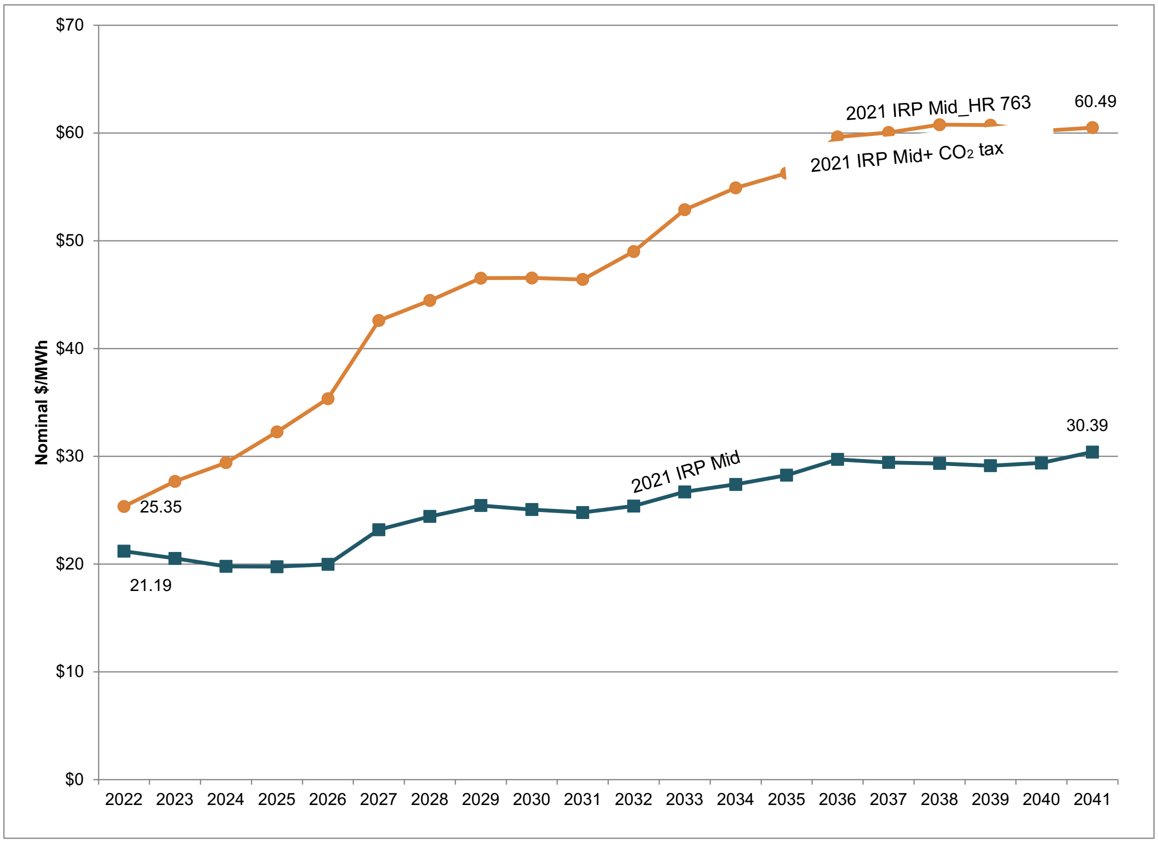
ASSUMPTIONS. For this sensitivity, PSE modeled the Energy Innovation and Carbon Dividend Act of 2019 (H.R. 763) that was introduced in Congress on January 2019, as the assumed federal CO_2 tax. The bill imposes a fee on the carbon content of fuels, including crude oil, natural gas, coal or any other product derived from those fuels. The fee is imposed on the producers or importers of the fuels and is equal to the greenhouse gas content of the fuel multiplied by the carbon fee rate. The rate begins at $15 in 2019, increases by $10 each year, and is subject to further adjustments based on progress in meeting specified emissions reduction targets. Figure 8-69 shows the value of the Federal CO_2 tax included in AURORA and the SCGHG used for this sensitivity.

Figure 8-69: SCGHG under CETA and the Federal CO_2 Tax under H.R. 763 (in 2012 dollars per short ton)

Year	SCGHG 2012$ / short ton CO_2	Federal CO_2 Tax 2012$ / short ton CO_2
2022	59.33	12.33
2023	60.25	20.35
2024	61.18	28.37
2025	63.03	36.20
2026	63.96	43.83
2027	64.89	51.28
2028	65.81	58.55
2029	66.74	65.64
2030	67.67	72.56
2031	68.60	79.31
2032	69.52	85.90
2033	70.45	92.32
2034	71.38	98.59
2035	72.30	104.70
2036	73.23	110.67
2037	75.08	116.49
2038	76.01	122.17
2039	76.94	127.71
2040	77.86	133.11
2041	78.79	138.38
2042	79.72	143.53
2043	80.65	148.55
2044	81.57	153.44
2045	82.50	158.22

Using the Federal CO_2 tax requires an updated power price forecast since the Federal tax would impact the operations of all thermal plants in the WECC. Figure 8-70 compares the addition of a Federal CO_2 tax to Mid-C power prices with the Mid Scenario power price forecast. The 20-year levelized Mid-C power price is $43.11 per MWh, an increase of almost $19 per MWh over the Mid Scenario power prices.

Figure 8-70: Mid-C Power Prices – Mid Scenario and Sensitivity L (in 2012 dollars per short ton)

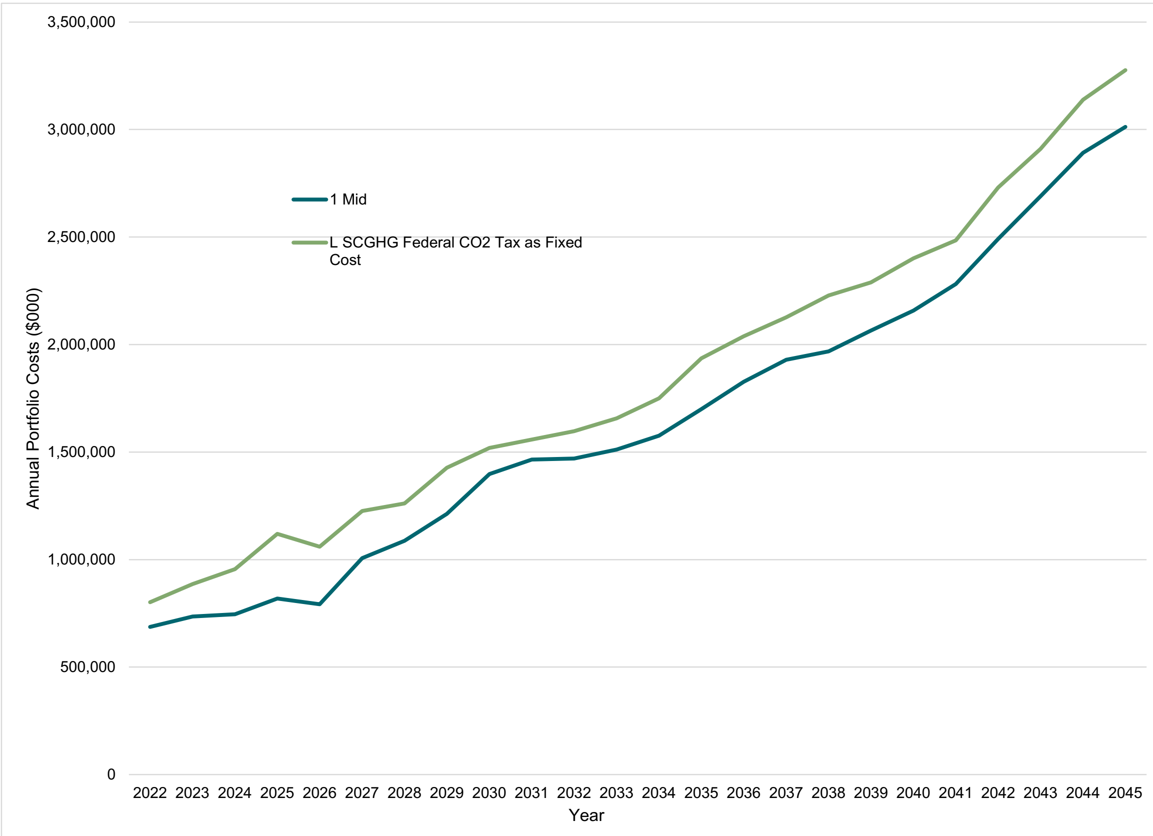


ANNUAL PORTFOLIO COSTS. The Sensitivity L portfolio costs are $2.24 billion higher than Mid Scenario costs. The higher costs can be attributed to the increase in market purchases and the selection of conservation Bundle 11 in Sensitivity L instead of conservation Bundle 10 in the Mid Scenario portfolio. Emissions costs in Sensitivity L are lower since thermal plants are dispatching less and generating lower emissions.

Figure 8-71: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity L

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
L	SCGHG as a Fixed Cost Plus a Federal CO_2 Tax	$17.77	$4.71	$22.47	$2.24

Figure 8-72: Annual Portfolio Costs – Mid Scenario and Sensitivity L



RESOURCE ADDITIONS. Figure 8-73 compares the nameplate capacity additions in the Mid Scenario and Sensitivity L portfolios. Adding the Federal CO_2 tax not only reduced the amount of flexible capacity resources added, but it also changed the mix of those flexible capacity resources. Sensitivity L adds a combined-cycle turbine in 2026, while the Mid Scenario adds a frame peaker in 2026. Sensitivity L also selects a higher conservation bundle (Bundle 11 compared to Bundle 10 in the Mid Scenario) and two additional demand response resources for a total of five. Minor differences are seen in the portfolio builds for solar, wind and hybrid capacity built by 2045.

Figure 8-73: Portfolio Additions – Sensitivity L and Mid Scenario

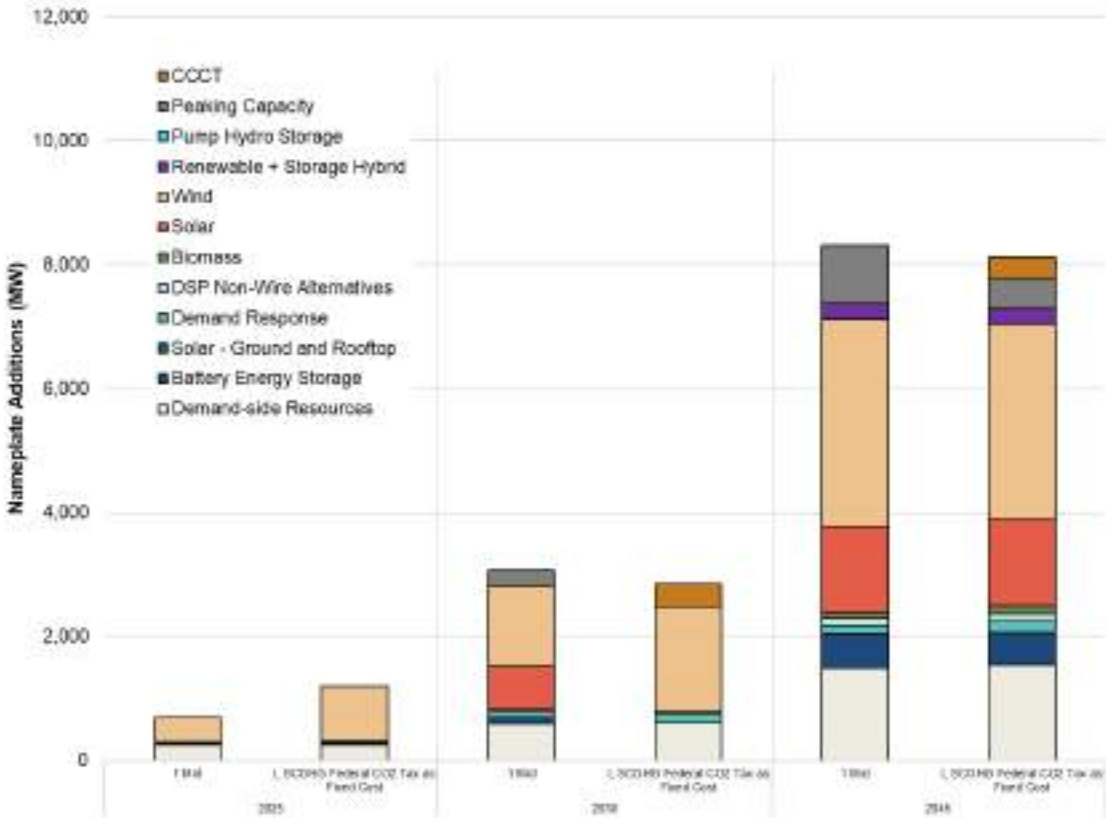


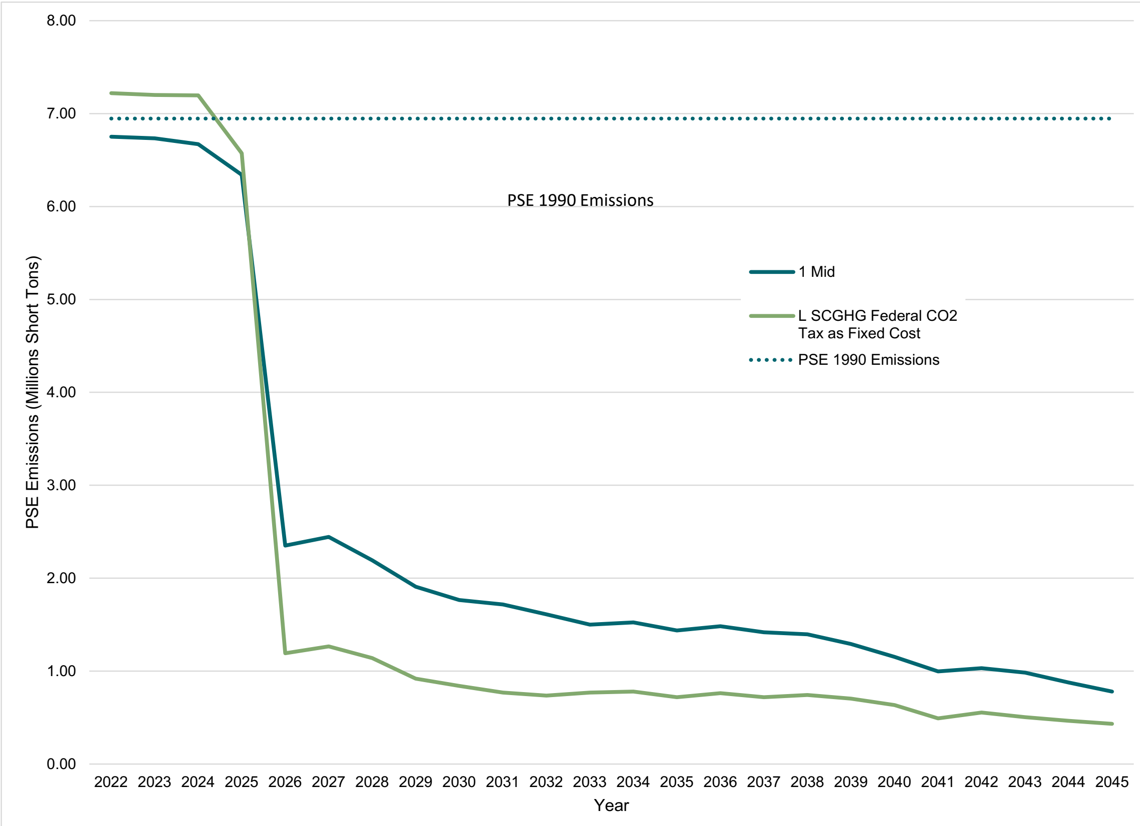
Figure 8-74 compares the nameplate capacity additions of the Mid Scenario and Sensitivity L portfolios by 2045.

Figure 8-74: Portfolio Additions – Mid Scenario and Sensitivity L

Resource Additions by 2045	1 Mid	L Federal CO_2 Tax SCGHG as Fixed Cost
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	525 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	183 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,680 MW
Biomass	90 MW	135 MW
Solar	1,393 MW	1,395 MW
Wind	3,350 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	474 MW
CCCT	0 MW	355 MW

EMISSIONS. Inclusion of a Federal CO_2 tax changed the emissions of Portfolio L significantly. In Portfolio L, after a large decline in emissions following the retirement of Centralia and Colstrip in 2026, existing and new thermal plants dispatch less and generate lower emissions due to the cost hurdle imposed by the Federal CO_2 tax. As a result, market purchases increased in Sensitivity L to make up for the decline in energy from thermal plants. Figure 8-75 compares the emissions of the Mid Scenario and Sensitivity L portfolios.

Figure 8-75: Annual Emissions – Mid Scenario and Portfolio L



Emissions Reduction

M. Alternative Fuel for Peakers

This sensitivity examines the effects of replacing the fuel supply for new frame peaker resources with a renewable fuel source, specifically biodiesel.

Baseline: New frame peaker resources are supplied with natural gas as their primary fuel source.
Sensitivity > New frame peaker resources are supplied with biodiesel as their primary fuel source.

KEY FINDINGS. In Sensitivity M, substituting biodiesel for natural gas in new frame peakers has only subtle impacts on the resulting portfolio. The 24-year levelized portfolio costs remain relatively unchanged, and resource additions are very similar to the Mid Scenario. GHG emissions are reduced slightly over the course of the modeling horizon. Biodiesel may be a feasible, cost-effective option for fueling peaking capacity resources while attaining CETA's zero emission goals and maintaining grid reliability.

ASSUMPTIONS. In Sensitivity M, new frame peaker resources are supplied with biodiesel as their primary fuel source. It is assumed that there are negligible differences between natural gas and biodiesel-fueled frame peakers in plant capital costs and fixed and variable operations and maintenance costs. Biodiesel is only available to frame peakers; new reciprocating peakers, new combined-cycle plants. Existing thermal resources are fueled with natural gas.

The market price for biodiesel was estimated from PSE experience and informed by the U.S. Department of Energy Clean Cities Alternative Fuel Price Report, October 2020. PSE has assumed a fixed biodiesel price of $37.20 per million British Thermal Units (MM BTU) (2020 dollars, adjusted for inflation annually) over the entire study period.

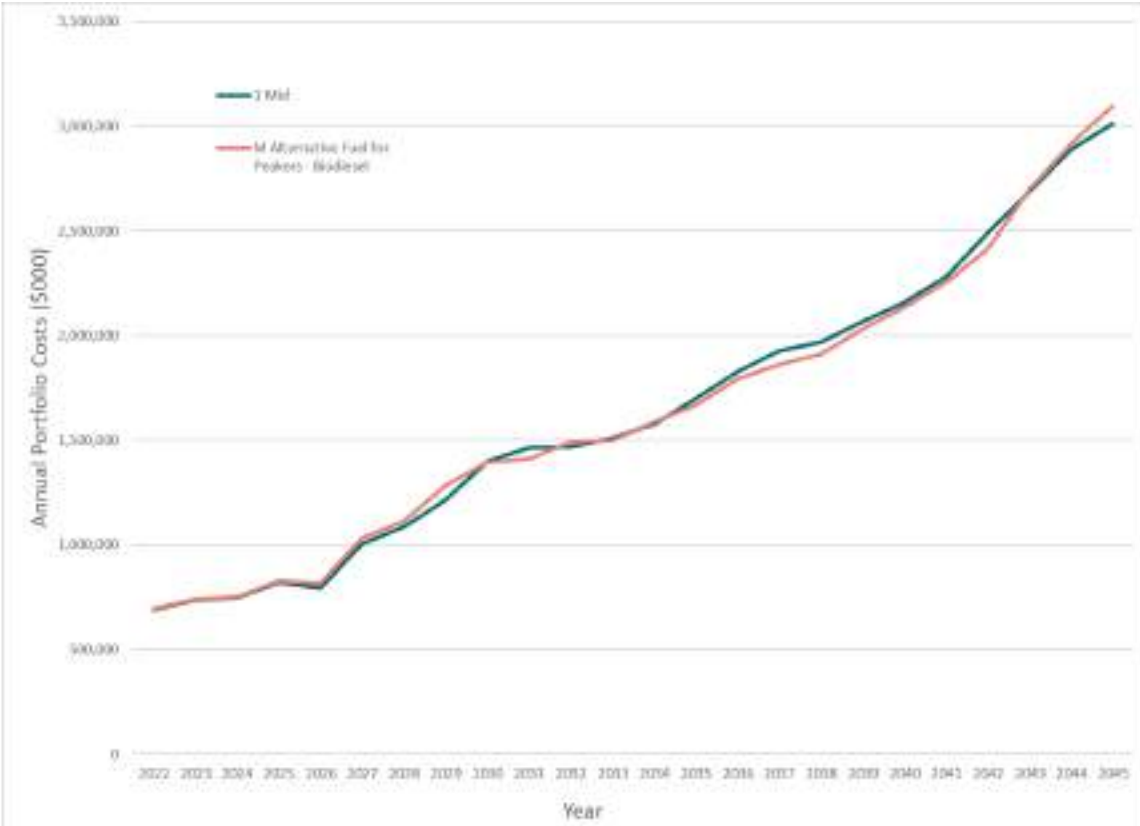
Given the anticipated constraints on biodiesel fuel supply, the flexibility benefit of frame peakers was removed ($0/kW-yr) in Sensitivity M as compared to the flexibility benefit of $23.45/kW-yr for frame peakers in the Mid Scenario.

PORTFOLIO COSTS. Figures 8-76 and 8-77 compare the breakdown of costs between the Mid Scenario and Sensitivity M portfolios. The 24-year levelized cost of Sensitivity M is nearly equal to the cost of Mid Scenario. However, the social cost of greenhouse gases is $100 million less in Sensitivity M compared to the Mid Scenario due to the use of a carbon neutral fuel for new frame peakers.

Figure 8-76: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity M

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
M	Alternative Fuel for Peakers	$15.53	$4.99	$20.52	($0.10)

Figure 8-77: Annual Portfolio Costs – Mid Scenario and Sensitivity M



RESOURCE ADDITIONS. Figures 8-78 and 8-79 compare the nameplate capacity additions of the Sensitivity M and Mid Scenario portfolios. Resource additions for Sensitivity M are very similar to those in the Mid Scenario. Both add the same quantity of peaking capacity, hybrid resources and similar quantities of renewable resources. Sensitivity M builds slightly more solar and slightly less wind than the Mid Scenario, and Sensitivity M selects conservation Bundle 11, whereas the Mid Scenario selects Bundle 10.

Figure 8-78: Portfolio Additions – Sensitivity M and the Mid Scenario

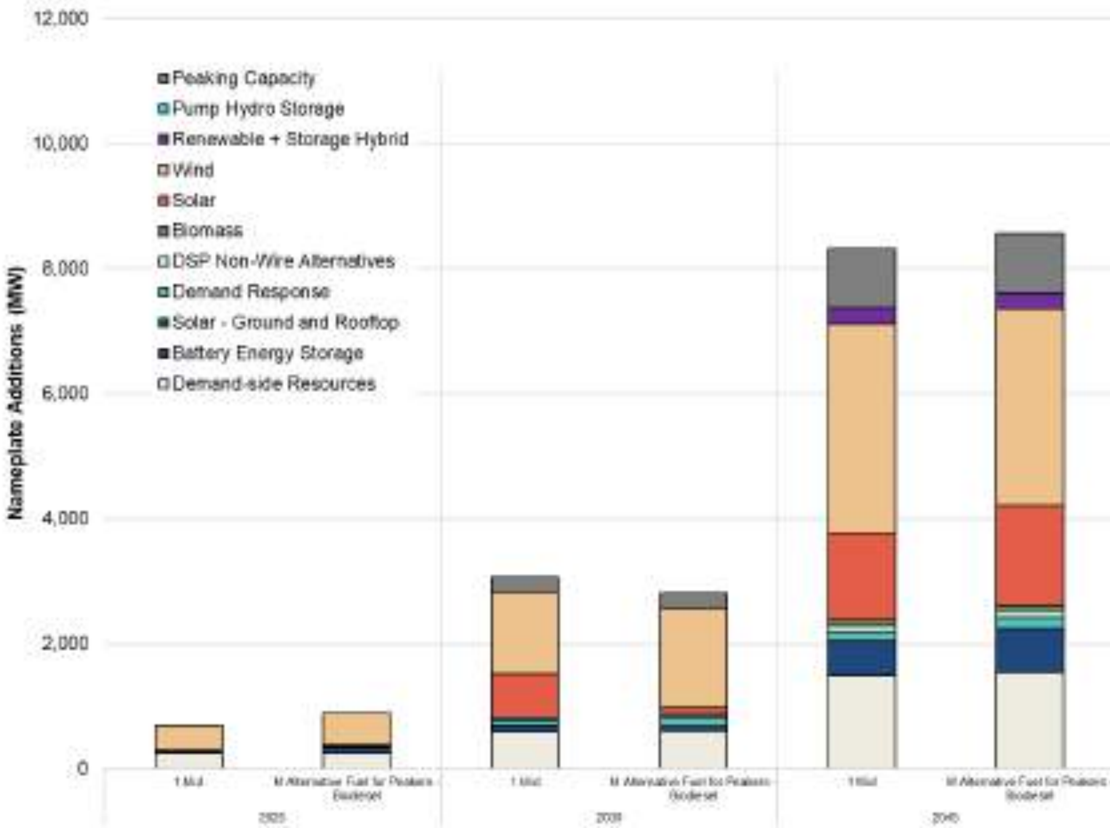
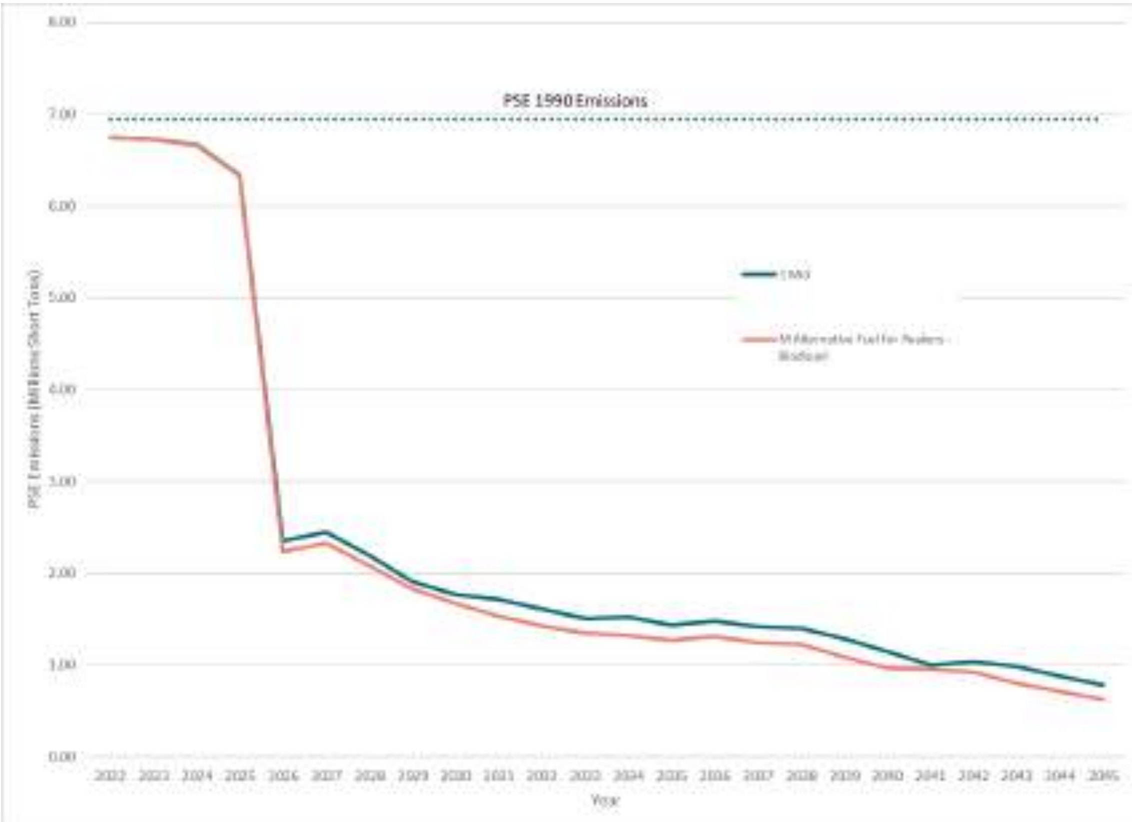


Figure 8-79: Portfolio Additions by 2045 – Mid Scenario and Sensitivity M, Alternative Fuel for Peakers

Resource Additions by 2045	1. Mid	M. Alternative Fuel for Peakers
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	700 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	185 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,818 MW
Biomass	90 MW	75 MW
Solar	1,393 MW	1,593 MW
Wind	3,350 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	948 MW

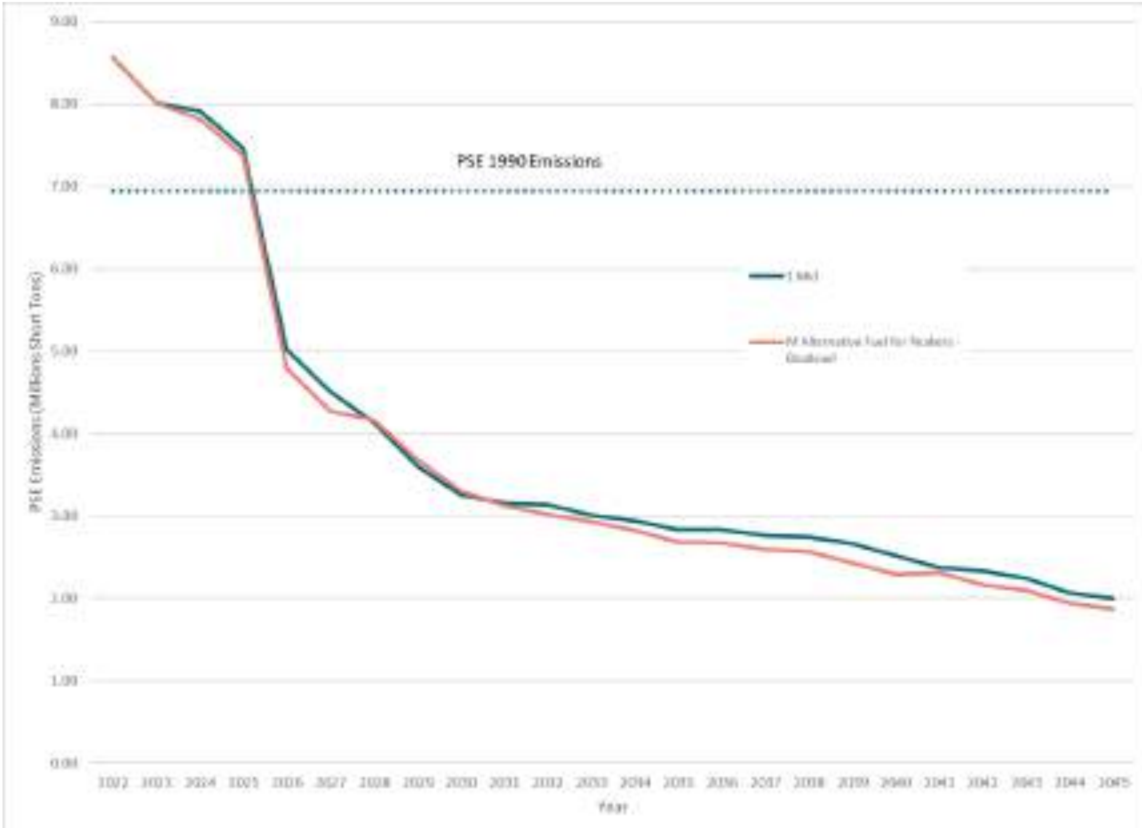
EMISSIONS. Sensitivity M resulted in fewer direct GHG emissions compared to the Mid Scenario due to the use of a carbon neutral fuel for peaking capacity needs. Figure 8-80 compares the GHG emissions from the Mid Scenario and Sensitivity M portfolios. Following acquisition of the first peaking capacity resource in 2026, Sensitivity M has consistently lower GHG emissions over the course of the modeling horizon.

Figure 8-80: Direct GHG Emissions – Mid Scenario and Sensitivity M, Alternative Fuel for Peakers



A similar trend is observed in Figure 8-81 which compares GHG emissions from the Sensitivity M with the Mid Scenario emissions, including both direct and indirect (i.e. market) emissions. Sensitivity M maintains lower emissions, however, the difference in emission reductions between the two portfolios is smaller.

Figure 8-81: Direct and Indirect GHG Emissions– Mid Scenario and Sensitivity M



To put emission reductions into perspective, it is useful to look at them as a function of portfolio cost (or, the cost of emissions reduction). To calculate this metric, divide the difference in the 24-year levelized cost between the sensitivity and the Mid Scenario by the difference in 24-year levelized emissions between the Mid Scenario and the sensitivity:

$$\frac{Sensitivity\ 24yr\ Levelized\ Cost\ - Mid\ Sc\ 24\ yr\ Levelized\ Cost}{Mid\ 24yr\ Levelized\ Emissions -\ Sensitivity\ 24yr\ Levelized\ Emissions}$$

Figure 8-82 shows the results of this calculation for Sensitivity M and provides the preferred portfolio (Sensitivity W) as a comparison. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. Sensitivity M is very efficient a reducing portfolio emissions; this is why biodiesel was added a fuel to the preferred portfolio.

Figure 8-82: Cost of Emissions Reduction – Mid Scenario, Sensitivity M and Sensitivity W (the Preferred Portfolio)

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	53.87	$15.53	--
M Alternative Fuel for Peakers	52.84	$15.53	<0.01
W Preferred Portfolio (BP with Biodiesel)	52.77	$16.10	0.52

CAPACITY FACTOR. Despite the much higher cost of biodiesel ($30.53/MMBtu) as compared to natural gas ($3.56/MMBtu), the overall revenue requirement of Sensitivity M and the Mid Scenario are roughly equal. This is because the high cost of biodiesel drives down the dispatch frequency of the new frame peaking resources. New frame peakers in the Mid Scenario had an annual capacity factor of about 3 percent in the year 2045. In Sensitivity M, the annual capacity factor of new frame peakers dropped to less than 0.1 percent. This suggests that the frame peakers were only dispatched in periods of peak demand to fill a specific role in providing peak capacity to the portfolio.

BIODIESEL AVAILABILITY. When modeling a portfolio like Sensitivity M that relies on a limited commodity such as biodiesel, it is important to consider the availability of that resource. Washington state produced around 114 million gallons of biodiesel in 2019 from two facilities.[5] In Sensitivity M, biodiesel fueled frame peakers supplied, at most, 7,233 MWh of energy over the modeling horizon. This equates to an annual need of approximately 600,000 gallons of biodiesel or about 0.5 percent of Washington State's annual production. This relationship suggests that the Washington biodiesel market could plausibly support the use of biodiesel for peak need electricity generation. PSE also evaluated the fuel needed to maintain resource adequacy which is included in Chapter 7.

5 / https://www.eia.gov/biofuels/biodiesel/production/

N. 100% Renewable by 2030

This sensitivity examines the cost difference between the Mid Scenario portfolio and a portfolio that advances the CETA target of 100 percent renewable energy to 2030.

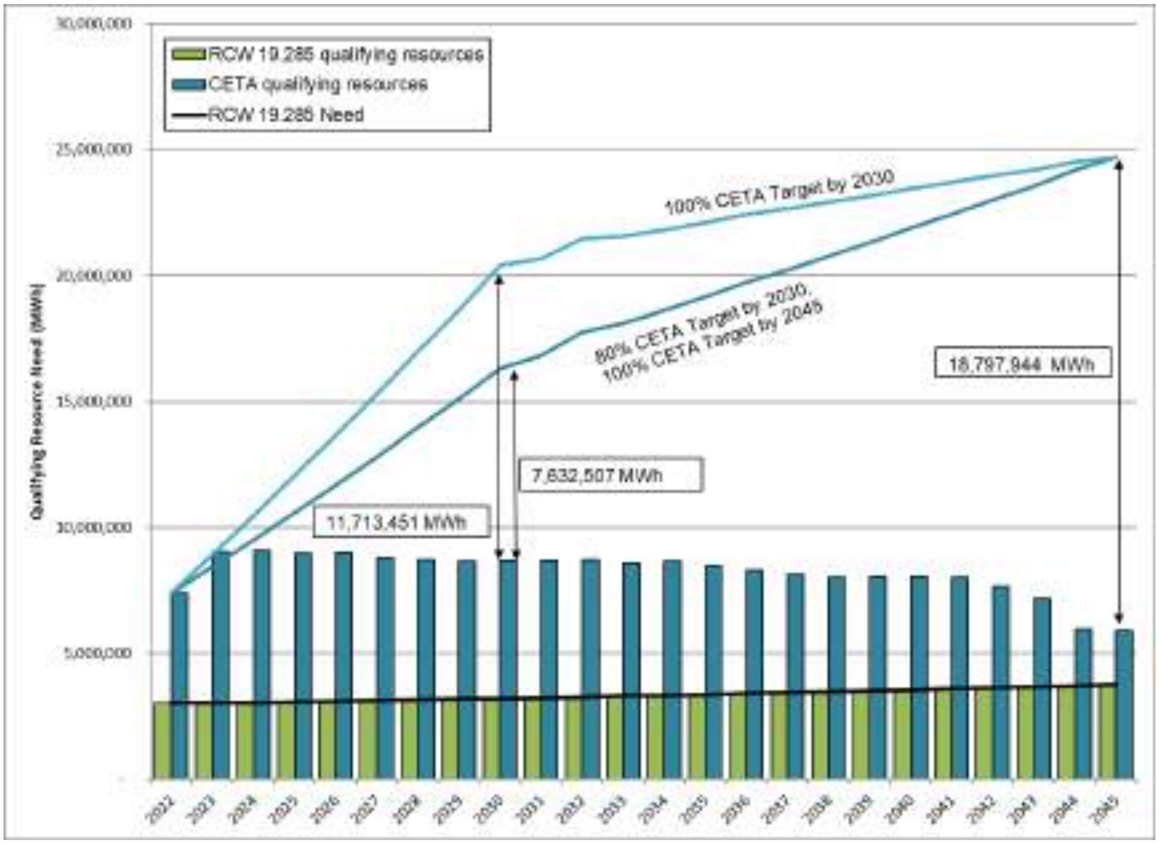
Baseline: 80 percent of sales must be met by non-emitting/renewable resources by 2030; the remaining 20 percent is met through alternative compliance.
Sensitivity > 100 percent of sales must be met by non-emitting/renewable resources by 2030.

KEY FINDINGS. Sensitivity N demonstrates that achieving a 100 percent renewable portfolio is possible with existing technologies, but the cost to do so is unrealistically high. The 24-year levelized portfolio cost of Sensitivity N is $15.17 and $33.37 billion more than the Mid Scenario for variations N1 and N2 respectively. The resource additions responsible for these higher portfolio costs do provide a benefit to overall portfolio emissions, but the efficiency of these emissions reductions per dollar spent are extremely low.

ASSUMPTIONS. In the Mid Scenario portfolio, 80 percent of sales are met by non-emitting/renewable resources by 2030, ramping up to 100 percent by 2045. Existing thermal plants continue to be in operation unless economically retired by the model. New peaking capacity resources remain an option for new resource selection. In order for the Mid Scenario portfolio to be 100 percent greenhouse gas neutral by 2030, an estimate for alternative compliance costs is calculated starting in 2030 through 2044. In Sensitivity N, all existing thermal plants are retired by 2030 regardless of economic viability. New peaking capacity resources are also removed for new resource selection. The CETA target is adjusted to 100 percent renewable by 2030. This means the renewable energy target increases by 4.1 million MWhs, rising from 7.6 million MWhs in 2030 to 11.7 million MWhs as shown in Figure 8-70.

Sensitivity N modeled two slightly different sets of assumptions. The first iteration, Sensitivity N1, used the model constraints provided above. Sensitivity N1 allowed the portfolio model to optimize to the 100 percent CETA target by 2030 by whatever means necessary. The second iteration, Sensitivity N2, removed lithium-ion and flow batteries from the available resources. Sensitivity N2 forced the model to solve using pumped hydro storage as the primary storage technology.

Figure 8-83: Renewable Targets – Mid Scenario and Sensitivity N1 and N2 Portfolios

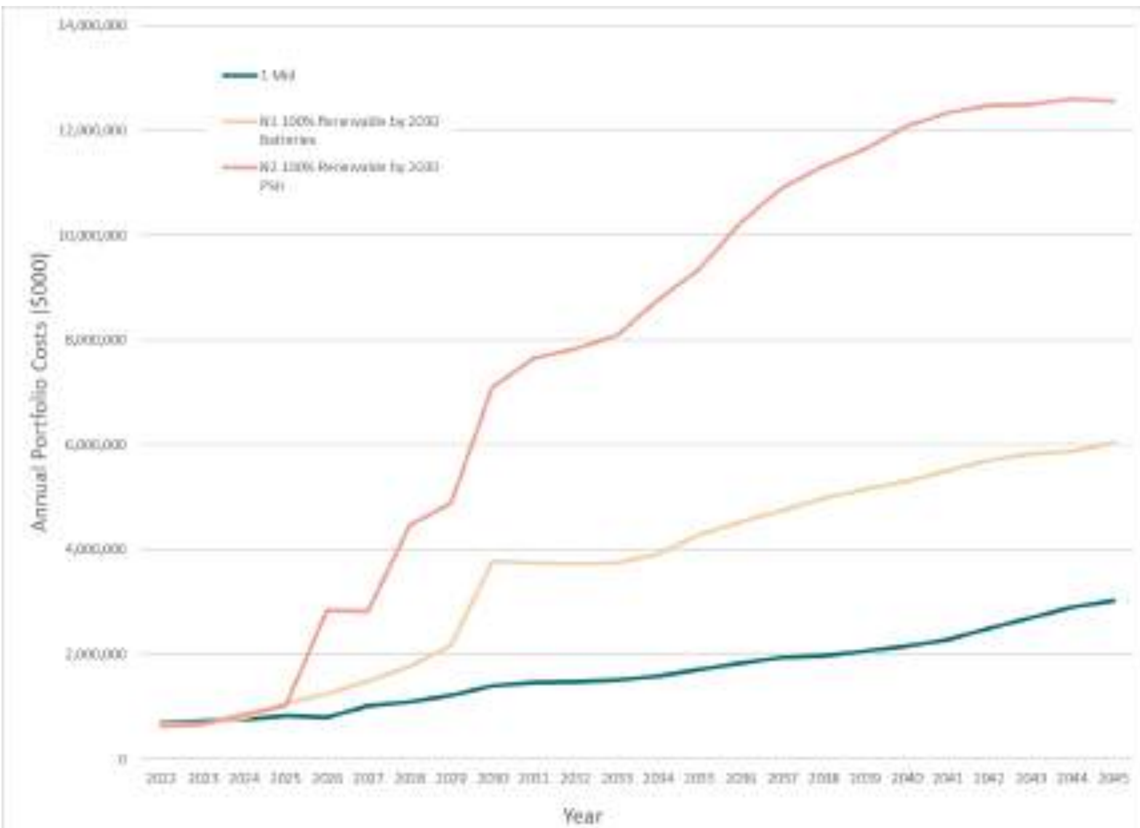


PORTFOLIO COSTS. Sensitivity N demonstrates that aggressively meeting CETA targets ahead of schedule may be possible with existing technologies, but that the cost to do so is high. The increase in costs for Sensitivity N is due to the increase in overall resource builds, particularly for storage resources. Both variations of Sensitivity N have lower SCGHG compared to the Mid Scenario; however, both variations also are among the most expensive portfolios modeled as part in the 2021 IRP. Figures 8-84 and 8-85 compare the breakdown of costs between the Mid Scenario and Sensitivity N portfolios.

Figure 8-84: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity N1 and N2

		24-year Levelized Costs (Billion $)			
	Portfolio	**Revenue Requirement**	**SCGHG**	**Total**	**Change from Mid**
1	**Mid Scenario**	$15.53	$5.09	$20.62	--
N1	**100% Renewable by 2030 (Batteries)**	$32.03	$3.76	$35.79	$15.17
N2	**100% Renewable by 2030 (PHES)**	$66.64	$2.52	$69.16	$33.37

Figure 8-85: Annual Portfolio Costs – Mid Scenario and Sensitivity N1 and N2



RESOURCE ADDITIONS. Figures 8-86 and 8-87 compare the nameplate capacity additions of the Sensitivity N and Mid Scenario portfolios. By 2025, Sensitivity N1 has built a large amount of wind and Sensitivity N2 has built a large amount of solar (both standalone and hybrid) to replace the energy from retirements of Colstrip and Centralia, as well as to meet the high CETA renewable need. Through 2030, Sensitivity N1 selects a portfolio composed largely of 2-hour lithium-ion batteries and wind, whereas Sensitivity N2 selects a more diversified set of resources, adding pumped hydro as a storage resource and a mix of solar and wind projects. At the end of planning period, storage resources compose 78 percent and 71 percent of the resource capacity for Sensitivities N1 and N2 respectively. These massive investments in storage dwarf the resource additions selected in the Mid Scenario, resulting in exorbitant portfolio costs.

Figure 8-86: Portfolio Additions – Mid Scenario and Sensitivity N, 100% Renewable by 2030

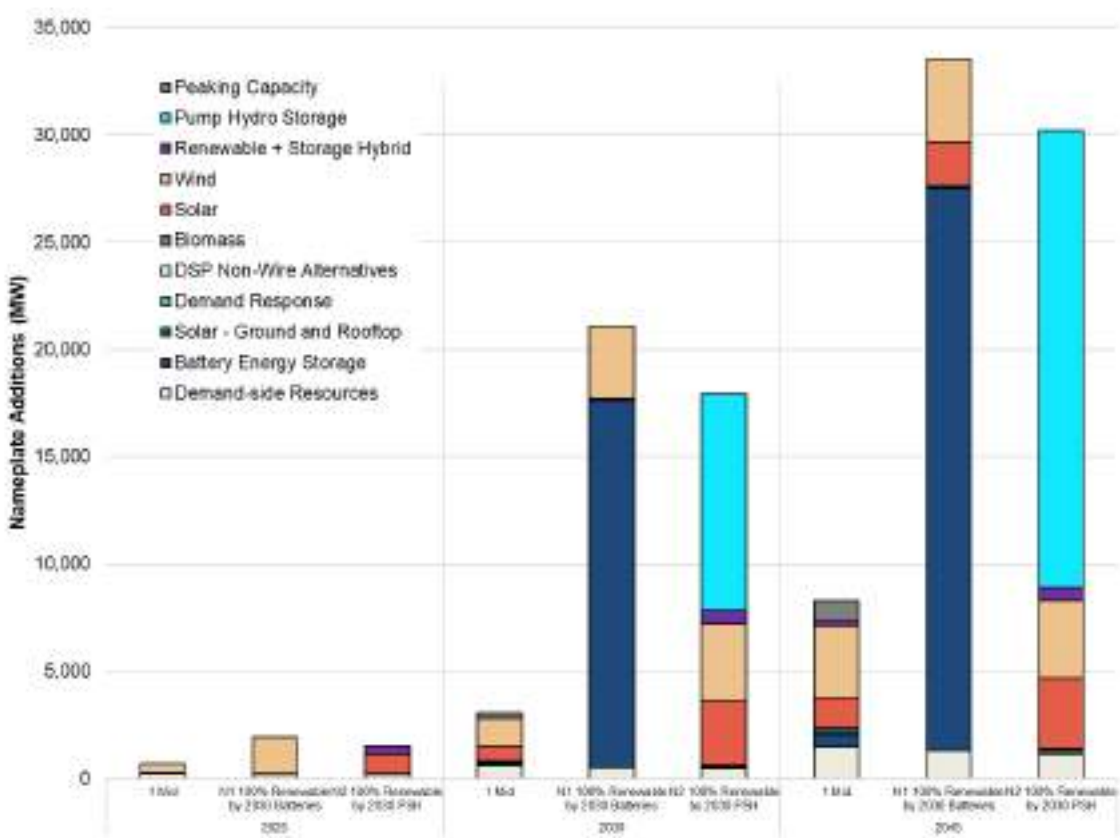


Figure 8-87: Portfolio Additions by 2045 – Sensitivity N, 100% Renewable by 2030

Resource Additions by 2045	1 Mid	N1 100% Renewable by 2030 - Batteries	N12100% Renewable by 2030 - PHES
Demand-side Resources	1,497 MW	1,304 MW	1,169 MW
Battery Energy Storage	550 MW	26,200 MW	0 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	59 MW	59 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	5,844 MW	6,943 MW
Biomass	90 MW	0 MW	75 MW
Solar	1,393 MW	1,994 MW	3,268 MW
Wind	3,350 MW	3,850 MW	3,600 MW
Renewable + Storage Hybrid	250 MW	0 MW	622 MW
Pumped Hydro Storage	0 MW	0 MW	21,300 MW
Peaking Capacity	948 MW	0 MW	0 MW

EMISSIONS. Figure 8-88 compares the direct GHG emissions from the Sensitivity N variations with the Mid Scenario. Direct emissions are defined as emissions linked directly to PSE-owned generating equipment. Since all emitting resources have been retired by 2030, the emissions for Sensitivity N drop to zero at 2030. However, this tells only part of the story. PSE is an active participant in the Mid-C wholesale power market. Storage resources are able to charge from market purchases, and under CETA rules, these market purchases are associated with a specific GHG emission rate.

Figure 8-88: Direct GHG Emissions – Mid Scenario and Sensitivity N, 100% Renewable by 2030

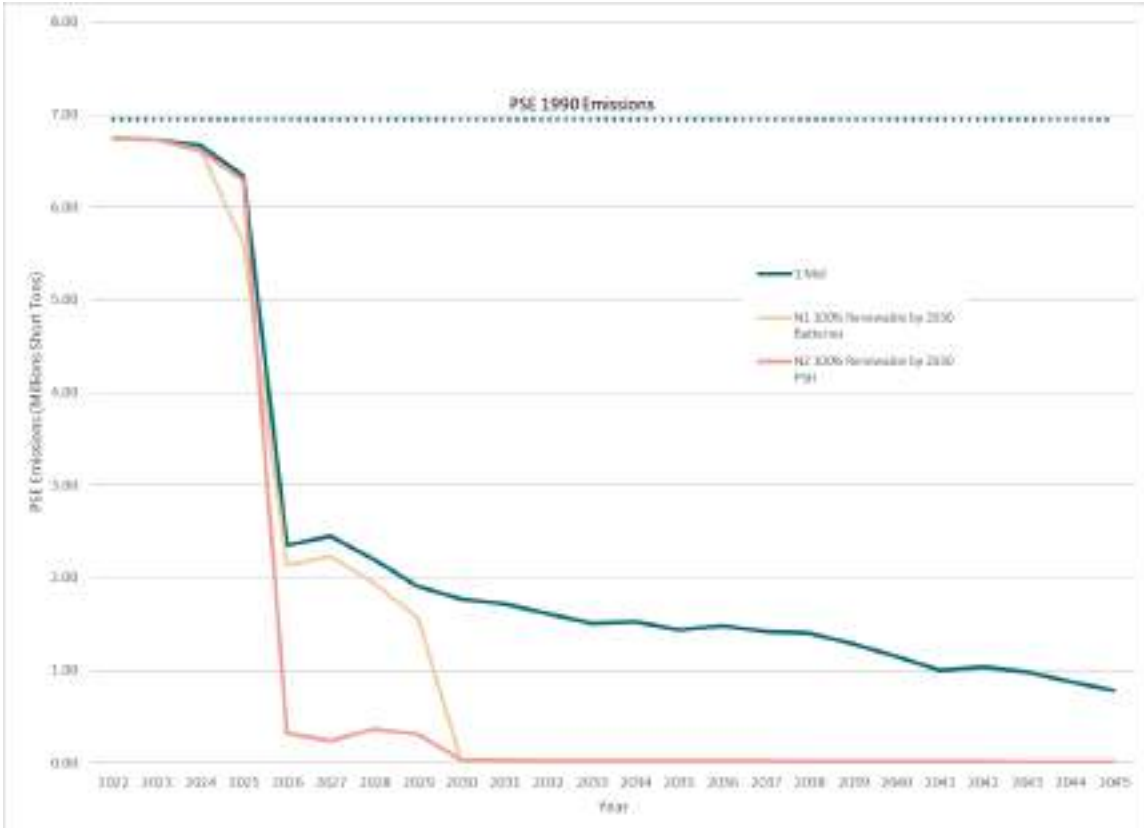
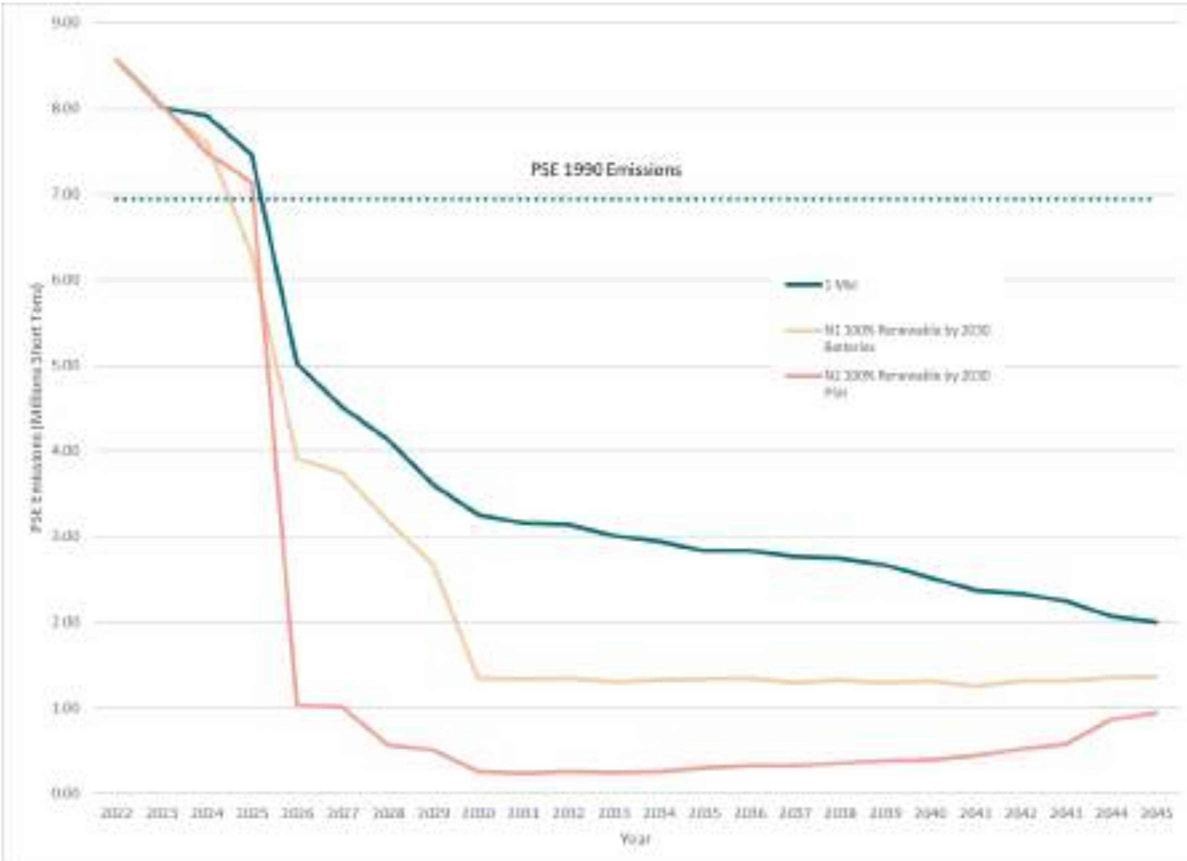


Figure 8-89 compares GHG emissions from the Sensitivity N1 and N2 variations with the Mid Scenario, for both direct and indirect (i.e., market) emissions. Sensitivity N emissions are lower than Mid Scenario emissions throughout the planning horizon, but it is interesting to note that emissions start to increase again for both Sensitivities N1 and N2 in the later years of the planning period due to the increase in energy purchased from market to fill the growing demand from storage resources.

Figure 8-89: Direct and Indirect GHG Emissions – Mid Scenario and Sensitivity N, 100% Renewable by 2030



To put emission reductions in perspective, it is useful to look at them as a function of portfolio cost (or, the cost of emissions reduction). To calculate this metric, divide the difference in the 24-year levelized cost between the sensitivity and the Mid Scenario by the difference in 24-year levelized emissions between the Mid Scenario and the sensitivity:

$$\frac{Sensitivity\ 24yr\ Levelized\ Cost\ - Mid\ Sc\ 24\ yr\ Levelized\ Cost}{Mid\ 24yr\ Levelized\ Emissions - \ Sensitivity\ 24yr\ Levelized\ Emissions}$$

Figure 8-90 shows the results of this calculation for the Sensitivity N variations and provides the preferred portfolio (Sensitivity W) as a comparison. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. The Sensitivity N variations are an order of magnitude higher than the preferred portfolio, which suggests that forcing 100 percent renewable energy by 2030 is not an efficient means to reduce emissions.

Figure 8-90: Cost of Emissions Reduction – Mid Scenario, Sensitivity N and Preferred Portfolio

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	53.87	$15.53	--
N1 100% Renewable by 2030 - Batteries	42.16	$32.03	1.41
N2 100% Renewable by 2030 - PHES	30.65	$66.64	2.20
W Preferred Portfolio (BP with Biodiesel)	52.77	$16.10	0.52

O. 100% Renewable by 2045

This sensitivity examines the cost difference between the Mid Scenario portfolio and a portfolio that has no natural gas-fired generation resources by 2045.

Baseline: No planned retirements of existing gas fired generation resources; however, the model allows for economic retirement.
Sensitivity > All existing natural gas-fired resources, including new peaking capacity resources, must be retired by 2045.

KEY FINDINGS. Sensitivity O shows that it is possible to phase out natural gas generation by the year 2045. However, the capital cost to do so it very high. On the basis of tons of GHG emissions reduced per dollar, there are more efficient ways to achieve comparable emissions reductions. Sensitivity O also shows the importance of market purchases to supporting a storage-heavy portfolio in a cost-effective manner.

ASSUMPTIONS. In the Mid Scenario portfolio, existing natural gas-fired generation resources remain in operation unless economically retired by the model. Generic peaking capacity resources are available as a new resource, but they retire by 2045. In Sensitivity O, all existing natural gas-fired generation resources are retired by 2045, regardless of economic viability. Existing thermal plant retirements are ramped in over time at a rate of approximately 200 MW per year between 2030 and 2045 to create a smoother transition to renewable generation.

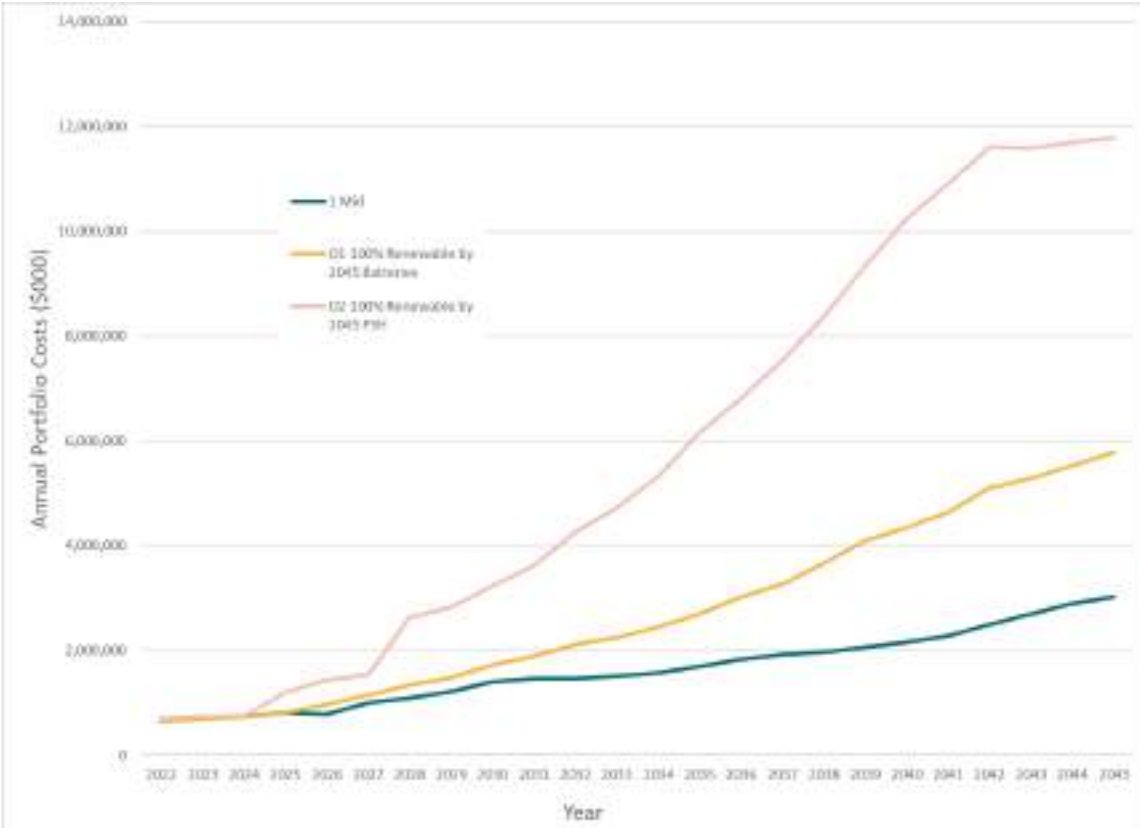
Sensitivity O modeled three slightly different sets of assumptions. The first iteration, Sensitivity O1, used the model constraints provided above and allowed the model to optimize removing natural gas fueled resource by 2045. The second iteration, Sensitivity O2, removed lithium-ion and flow batteries from the list of available resources and forced the model to solve using pumped hydroelectric storage as the primary storage technology.

PORTFOLIO COSTS. Figures 8-91 and 8-92 illustrate the breakdown of costs between the Mid Scenario and Sensitivity O portfolios. The increase in costs for Sensitivity O is attributed to the increase in the overall resource builds.

Figure 8-91: 24-year Levelized Portfolio Costs – Mid Scenario, Sensitivity O1 and Sensitivity O2

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
O1	100% Renewable by 2045 – Batteries	$23.35	$4.81	$28.16	$7.54
O2	100% Renewable by 2045 – PHES	$46.95	$3.98	$50.94	$30.32

Figure 8-92: Annual Portfolio Costs – Mid Scenario and Sensitivity O



RESOURCE ADDITIONS. Figures 8-93 and 8-94 compare the nameplate capacity additions of Sensitivity O and the Mid Scenario portfolios. Neither variation of Sensitivity O selects any flexible capacity resources over the course of the planning period. Both variations focus on building storage resources early and often to keep up with growing capacity need. Sensitivity O1 builds solely standalone 2-hour lithium-ion batteries, whereas Sensitivity O2 builds a mix of pumped hydroelectric storage and hybrid resources. Both variations rely heavily on market purchases to charge storage resources throughout the planning period.

Figure 8-93: Portfolio Additions – Mid Scenario and Sensitivity O

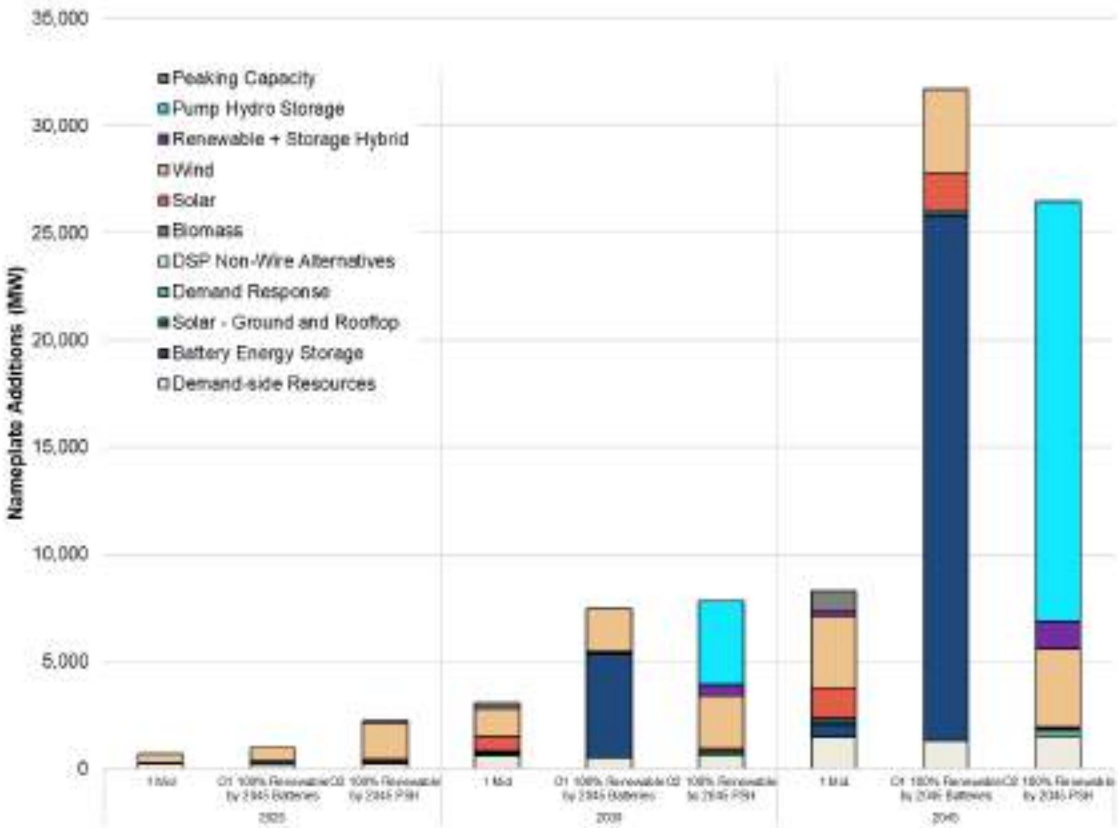


Figure 8-94: Portfolio Additions by 2045 – Mid Scenario and Sensitivity O, – 100% Renewable by 2045

Resource Additions by 2045	1 Mid	O1 100% Renewable by 2045 - Batteries	O2 100% Renewable by 2045 - PHES
Demand-side Resources	1,497 MW	1,304 MW	1,537 MW
Battery Energy Storage	550 MW	24,500 MW	0 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	128 MW	204 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	5,642 MW	3,749 MW
Biomass	90 MW	0 MW	0 MW
Solar	1,393 MW	1,692 MW	99 MW
Wind	3,350 MW	3,950 MW	3,650 MW
Renewable + Storage Hybrid	250 MW	0 MW	1,249 MW
Pumped Hydro Storage	0 MW	0 MW	19,600 MW
Peaking Capacity	948 MW	0 MW	0 MW

PEAK CAPACITY. The results of Sensitivity O are somewhat conflicted. On one hand, Sensitivity O1 just barely exceeds the peak capacity need in the year 2045 as shown in Figure 8-95. On the other hand, Sensitivity O2 was significantly over-built, exceeding peak need by over 5,000 MW in 2045 as shown in Figure 8-83. These two extremes make the results difficult to interpret with confidence. It seems unlikely that many small 2-hour storage resources are the most effective resources to meet peak need without the aid of thermal resources. However, Sensitivity O1 was far less costly than Sensitivity O2, which included seemingly more flexible 8-hr storage resources. Sensitivity O placed extreme demands on the simulation to dispatch over 10,000 MW of storage capacity and to replace over 2,000 MW of existing thermal resources in a single year. More work is required to refine storage logic within the portfolio model.

Figure 8-95: Peak Capacity Contribution – Mid Scenario and Sensitivity O1, 100% Renewable by 2045 – Batteries

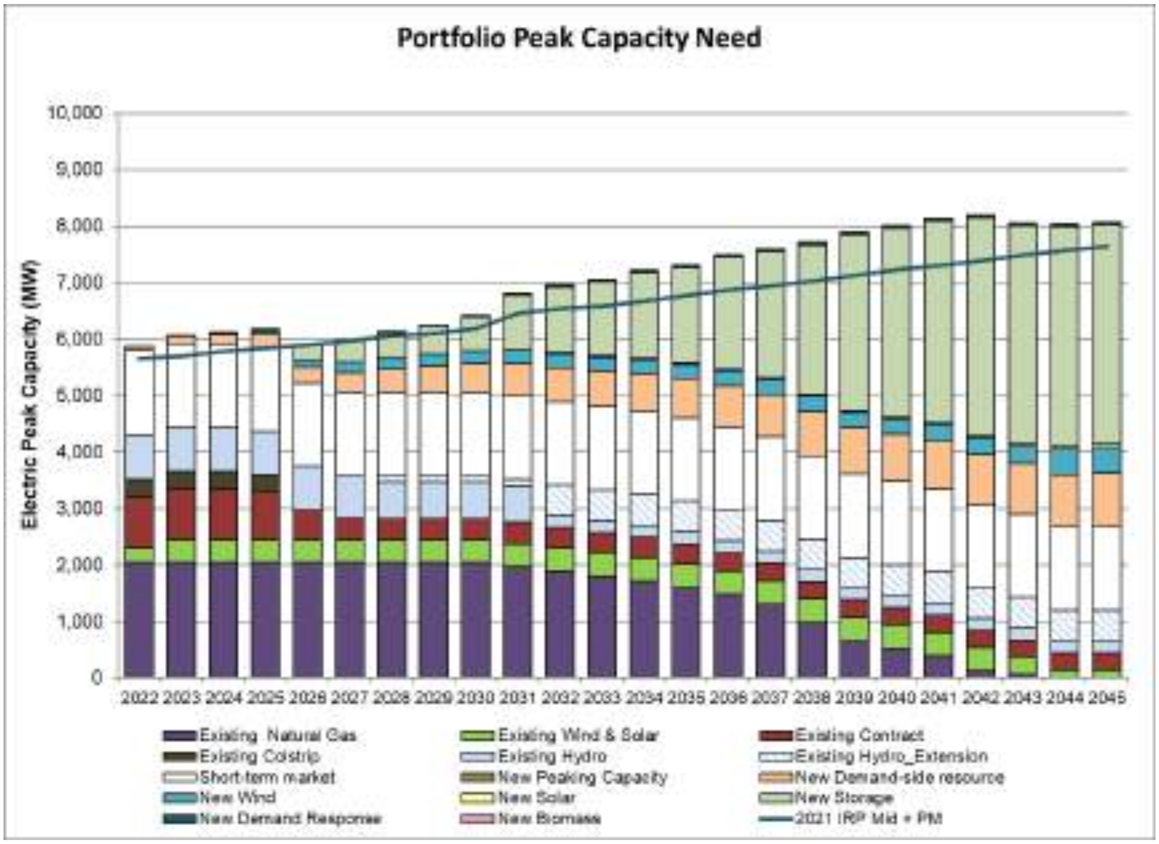
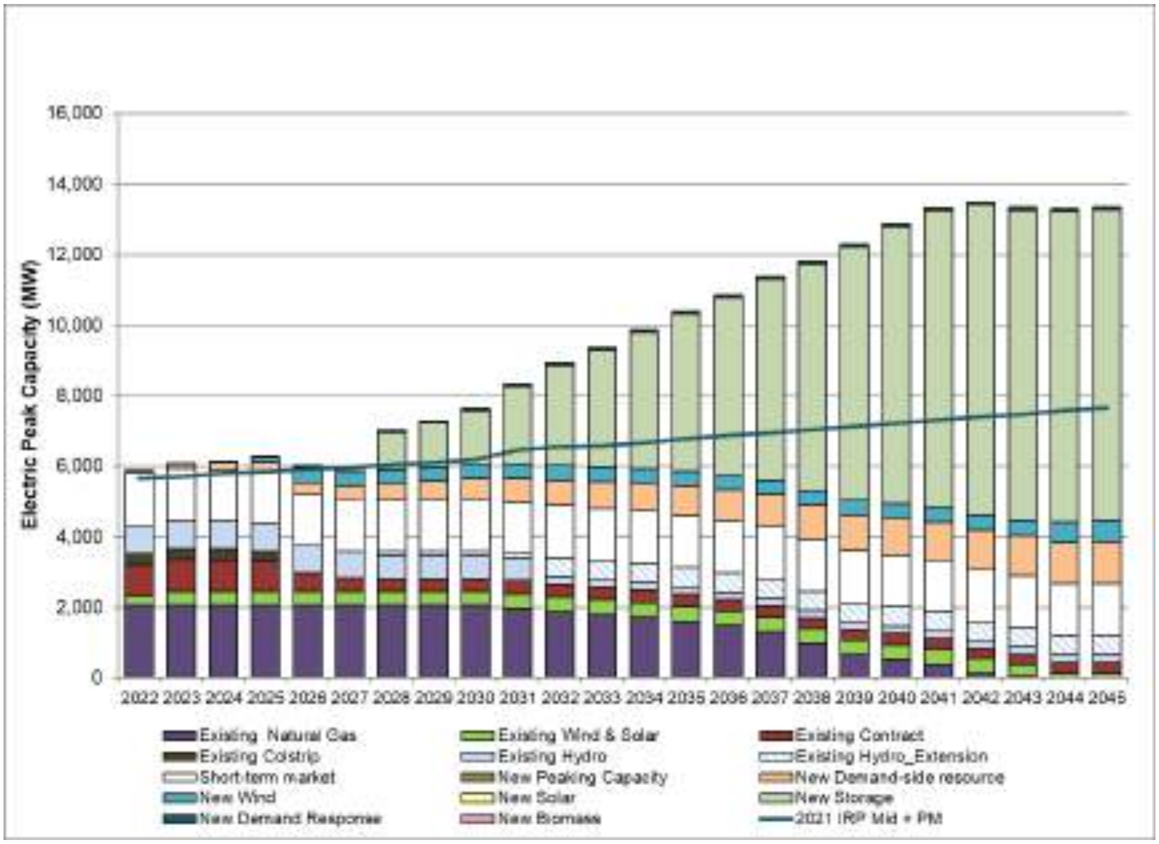


Figure 8-96: Peak Capacity Contribution – Mid Scenario and Sensitivity O2 – 100% Renewable by 2045 – Pumped Hydro Storage



EMISSIONS. Figure 8-97 compares the direct GHG emissions from the Sensitivity O variations with the Mid Scenario. Direct emissions are defined as emissions linked directly to PSE-owned generating equipment. Since all emitting resources have been retired by 2045, the emissions for Sensitivity O drop to zero by 2045. However, this tells only part of the story. PSE is an active participant in the Mid-C wholesale power market. Storage resources are able charge from market purchases, and under CETA rules, these market purchases are associated with a specific GHG emission rate.

Figure 8-97: Direct GHG Emissions – Mid Scenario and Sensitivity O, 100% Renewable by 2045

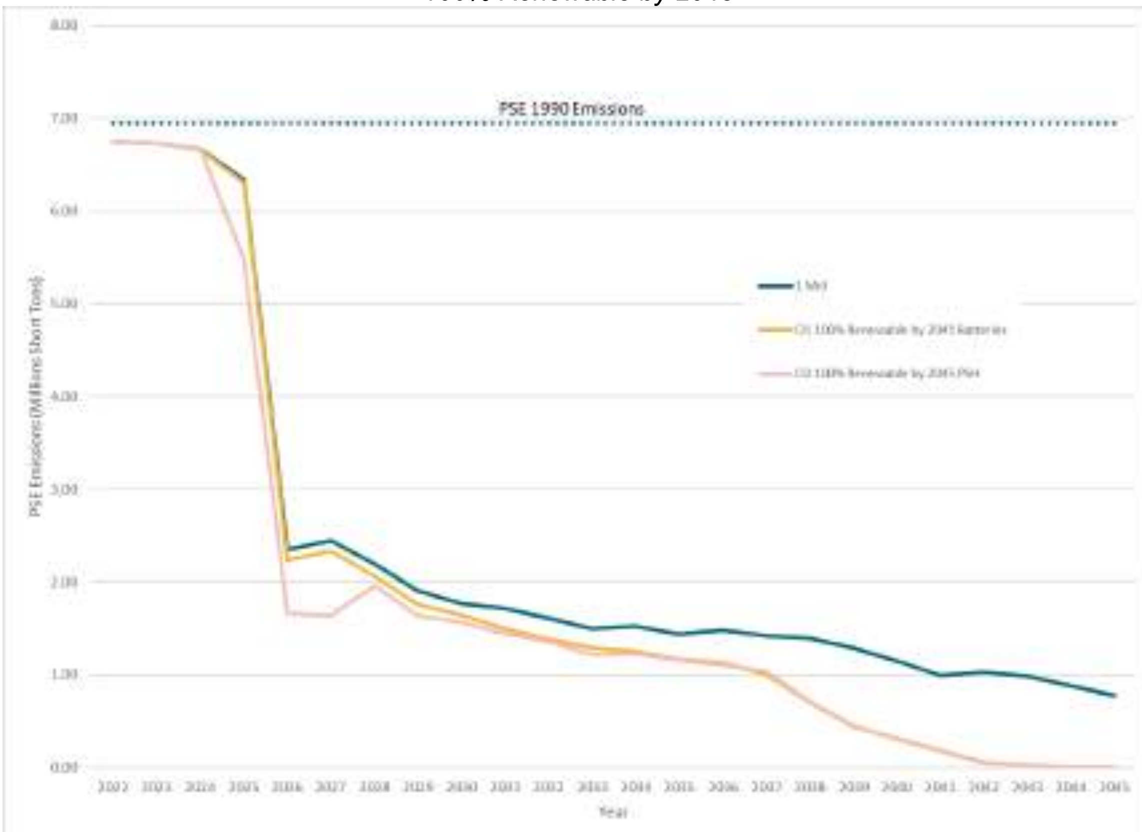
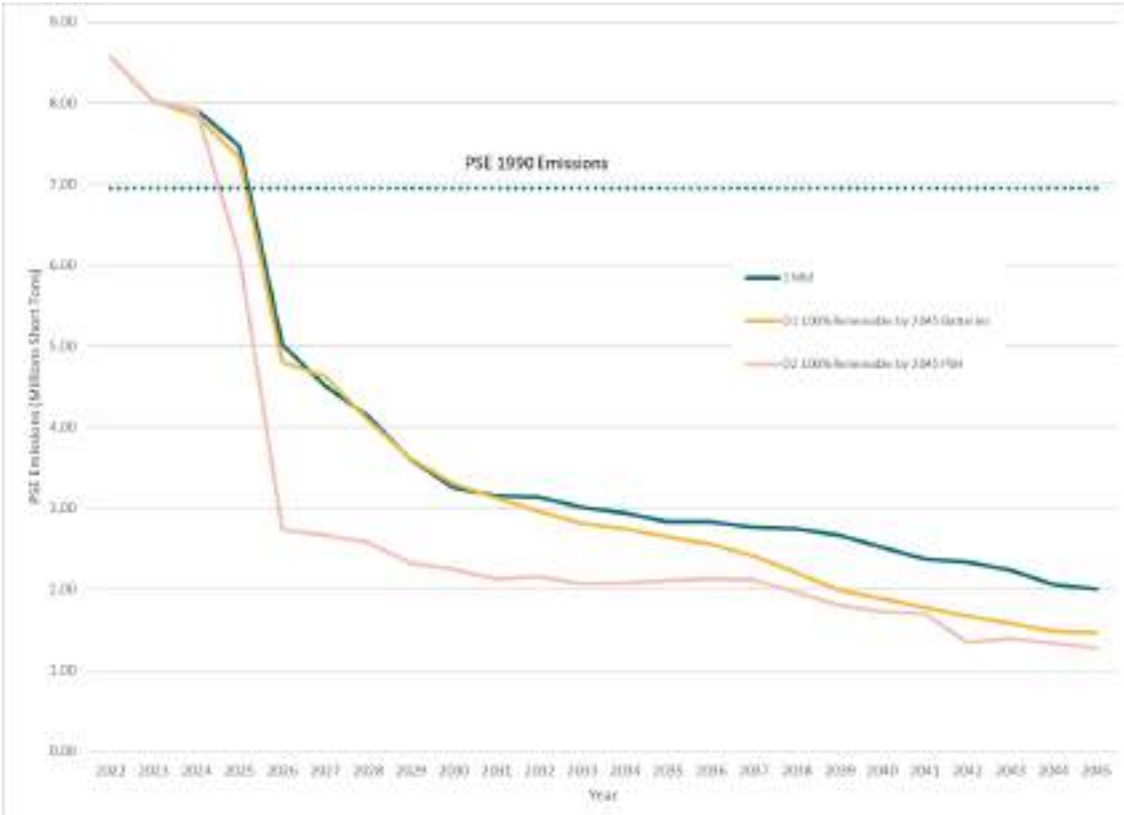


Figure 8-98 provides a view of GHG emissions from the Sensitivity O variations compared to the Mid Scenario, for both direct and indirect (i.e., market) emissions. Sensitivity O emissions are still lower than Mid Scenario emissions throughout the planning horizon.

Figure 8-98: Direct and Indirect GHG Emissions – Mid Scenario and Sensitivity O, 100% Renewable by 2045



To put emission reductions into perspective, it is useful to look at them as a function of portfolio cost (or, the cost of emissions reduction). To calculate this metric, divide the difference in the 24-year levelized cost between the sensitivity and the Mid Scenario by the difference in 24-year levelized emissions between the Mid Scenario and the sensitivity:

$$\frac{Sensitivity\ 24yr\ Levelized\ Cost\ - Mid\ Sc\ 24\ yr\ Levelized\ Cost}{Mid\ 24yr\ Levelized\ Emissions - \ Sensitivity\ 24yr\ Levelized\ Emissions}$$

Figure 8-99 shows the results of this calculation for Sensitivity O and provides the preferred portfolio (Sensitivity W) as a comparison. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. The Sensitivity O variations are an order of magnitude larger than the preferred portfolio, suggesting that forcing out natural gas generation is not an efficient means to reduce emissions.

Figure 8-99: Cost of Emissions Reduction – Mid Scenario, Sensitivity O and Preferred Portfolio

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	53.87	$15.53	--
O1 100% Renewable by 2045 - Batteries	51.83	$23.35	3.83
O2 100% Renewable by 2045 - PHES	43.54	$46.95	3.04
W Preferred Portfolio (BP with Biodiesel)	52.77	$16.10	0.52

P. No New Thermal Resources Before 2030

This sensitivity provides insight into how energy storage provides value to a system that has traditionally been provided by natural gas plants.

Baseline: Thermal peaking capacity resources may be added to the portfolio as early as 2025**.**
Sensitivity P > No thermal peaking capacity may be added to the portfolio until 2030, thereby requiring the model to optimize new energy storage, renewable resources and demand-side resources to meet near-term capacity need.

KEY FINDINGS. In Sensitivity P, delaying the availability of peaking capacity resources resulted in much earlier addition of storage resources and the addition of fewer peaking capacity resources. However, these changes increased portfolio costs by $7 to $25 billion depending on the type of storage resource selected. Furthermore, Sensitivities P1 and P3 showed no reduction in GHG emissions compared to the Mid Scenario. Sensitivity P2 did show a small reduction in GHG emissions, but the emission reduction efficiency was quite low compared to other portfolios such as the preferred portfolio.

ASSUMPTIONS. In the Mid Scenario portfolio, peaking capacity resources are available as early as 2025. In Sensitivity P, peaking capacity resources are available much later, in 2030. This forces the model to optimize its resource selection of energy storage, renewable resources and demand-side resources to keep the portfolio balanced until peaking capacity resources are available.

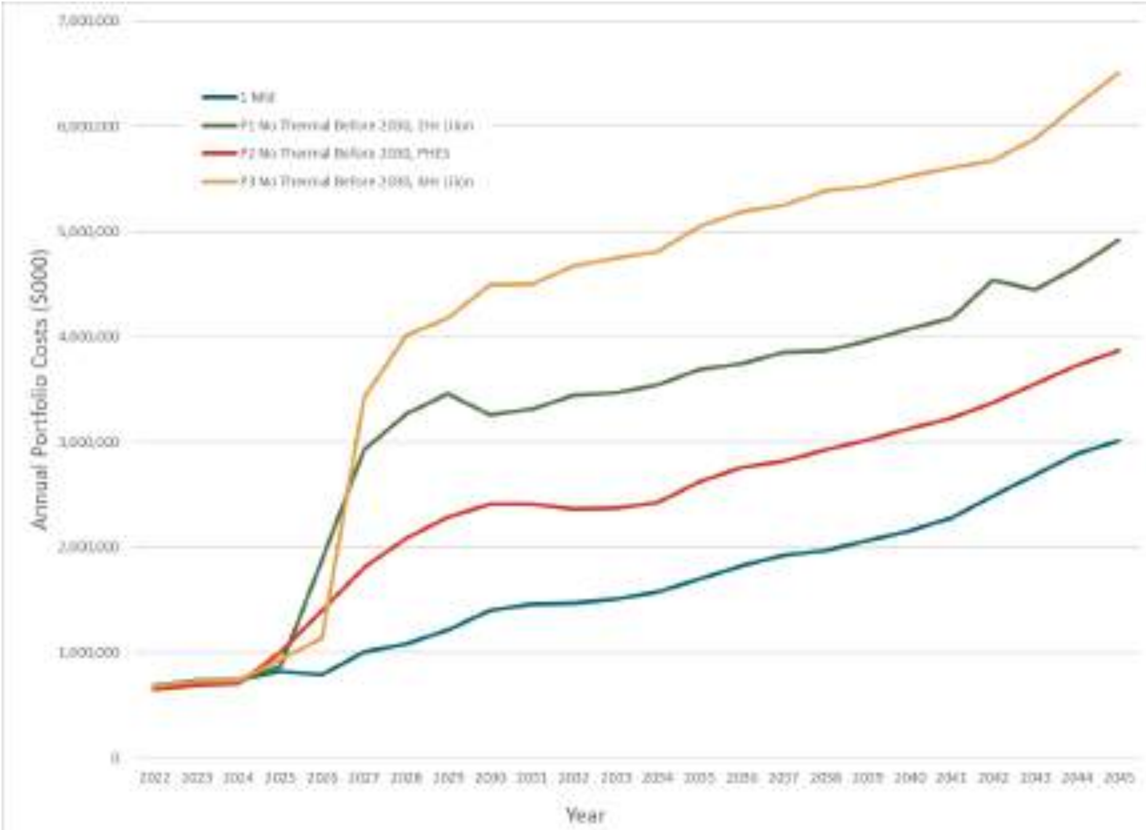
To gain an understanding of how the model reacts to different storage resources, three variations on Sensitivity P were run. Sensitivity P1 used the model constraints described above and allowed the model to select the most cost-effective storage resource in the period 2022 to 2030; the model selected 2-hour lithium-ion batteries. Sensitivity P2 removed lithium-ion and flow batteries from the list of available resources before 2030 and forced the model to solve using pumped hydroelectric storage as the primary storage technology. Sensitivity P3 removed 2-hour lithium-ion batteries from the available resources before 2030, and forced the model to select the next most cost-effective storage resource to meet capacity need before 2030; then the model selected 4-hour lithium-ion batteries.

PORTFOLIO COSTS. Figures 8-100 and 8-101 illustrate the breakdown of costs between the Mid Scenario and Sensitivities P1, P2 and P3. Annual portfolio costs are significantly higher for all variations of Sensitivity P compared to the Mid Scenario. Storage resources and demand response programs are more expensive options than peaking capacity resources. All variations of Sensitivity P added over 2,500 MW more nameplate capacity of new resources compared to the Mid Scenario, resulting in higher portfolio costs. A significant amount of batteries and pumped hydro energy storage was added to both portfolios between 2025 and 2030 causing the spike in annual portfolio costs.

Figure 8-100: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity P

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
P1	No New Thermal Resources – 2-hr Li-Ion	$30.84	$6.38	$37.22	$16.60
P2	No New Thermal Resources – PHES	$22.85	$4.77	$27.62	$7.00
P3	No New Thermal Resources – 4-hr Li-Ion	$39.01	$6.69	$45.70	$25.08

Figure 8-101: Annual Portfolio Costs – Mid Scenario and Sensitivity P



RESOURCE ADDITIONS. Figures 8-102 and 8-103 compare the nameplate capacity additions of the portfolios in Sensitivities P1, P2 and P3 and the Mid Scenario. The Mid Scenario portfolio added 237 MW of peaking capacity resources in 2026 as Colstrip and Centralia were removed. It would take about 3,800 MW nameplate capacity of batteries to equal those new peaking capacity resources since 2-hour lithium-ion batteries have only a 12.4 percent ELCC. Sensitivity P1 selected 3,775 MW of 2-hour lithium-ion batteries to make up for the absence of new peaking capacity resources. Similar resources are added in the other variations of Sensitivity P, the only difference being the addition of alternative storage resources (pumped hydroelectric storage and 4-hour lithium-ion batteries).

All three Sensitivity P portfolios added a significant amount of 2-hour lithium-ion battery resources. Sensitivity P1 selected 2-hour lithium-ion batteries as the most cost-effective resource and built nearly exclusively 2-hour lithium ion batteries, except for 25 MW of 4-hour lithium-ion batteries in the year 2045. Sensitivity P2 was forced to select pumped hydro storage as the initial storage technology; after 2030, no new pumped hydro storage was added, but 1,025 MW of 2-hour lithium-ion batteries were added. Similarly, Sensitivity P3 was forced to select 4-hour lithium-ion batteries as the initial storage technology; after 2030 no new 4-hour batteries were added, but 875 MW of 2-hour lithium-ion batteries were added to the portfolio.

By the end of the planning period, Sensitivity P1 had built 474 MW of peaking capacity, about half of the peaking capacity selected in the Mid Scenario. The large capacity storage resources (PHES and 4-hour lithium-ion batteries) built far less peaking capacity, with Sensitivity P2 building only 18 MW of peaking capacity and Sensitivity P3 building none at all.

Figure 8-102: Portfolio Additions – Mid Scenario and Sensitivity P

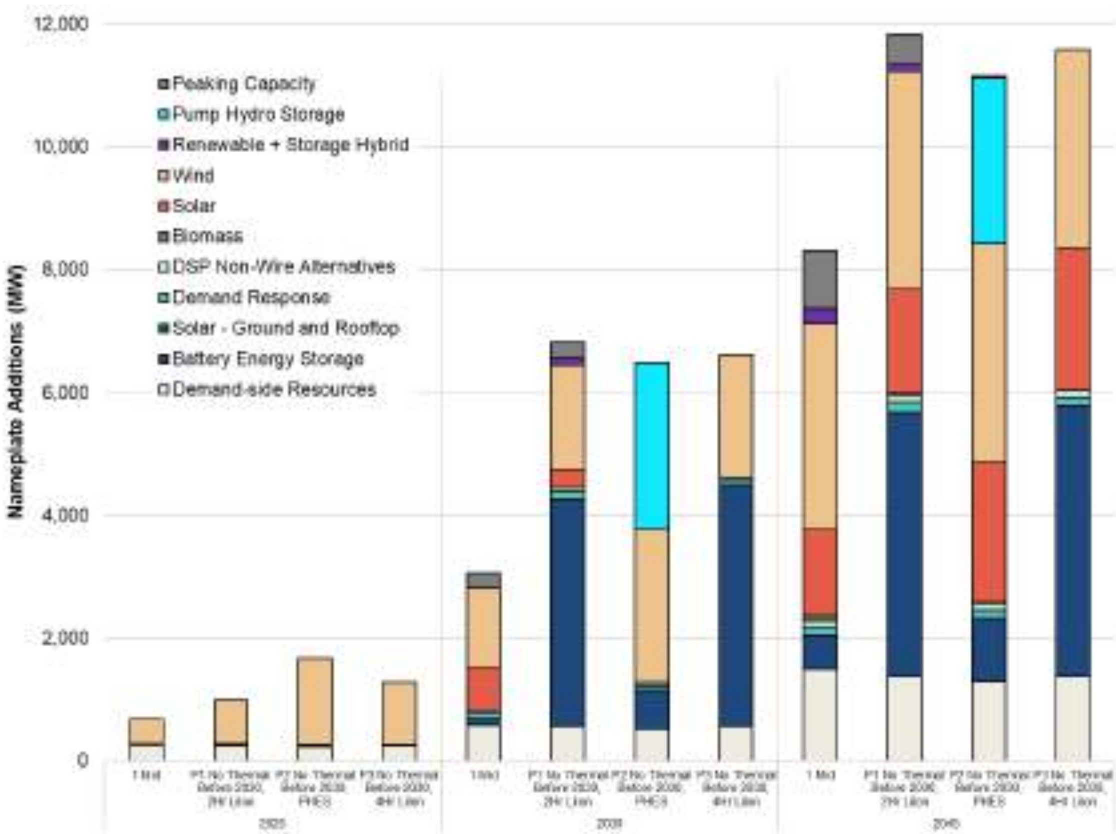
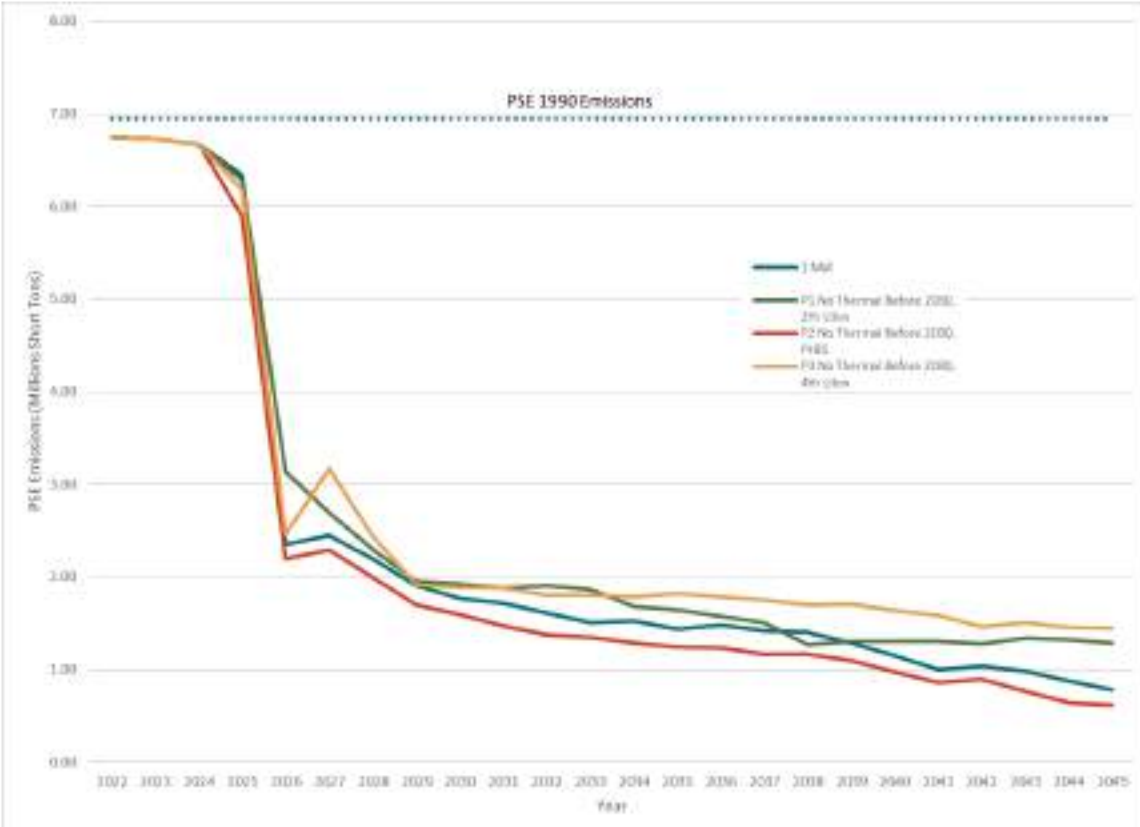


Figure 8-103: Portfolio Additions by 2045 – Mid Scenario and Sensitivity P, No New Thermal Before 2030

Resource Additions by 2045	1 Mid	P1 No New Thermal – 2hr Li-Ion	P2 No New Thermal – PHES	P3 No New Thermal – 4hr Li-Ion
Demand-side Resources	1,497 MW	1,372 MW	1,304 MW	1,372 MW
Battery Energy Storage	550 MW	4,300 MW	1,025 MW	4,425 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW	0 MW
Demand Response	123 MW	178 MW	122 MW	129 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	5,260 MW	5,859 MW	5,542 MW
Biomass	90 MW	15 MW	15 MW	0 MW
Solar	1,393 MW	1,695 MW	2,294 MW	2,292 MW
Wind	3,350 MW	3,550 MW	3,550 MW	3,250 MW
Renewable + Storage Hybrid	250 MW	125 MW	0 MW	0 MW
Pumped Hydro Storage	0 MW	0 MW	2,700 MW	0 MW
Peaking Capacity	948 MW	474 MW	18 MW	0 MW

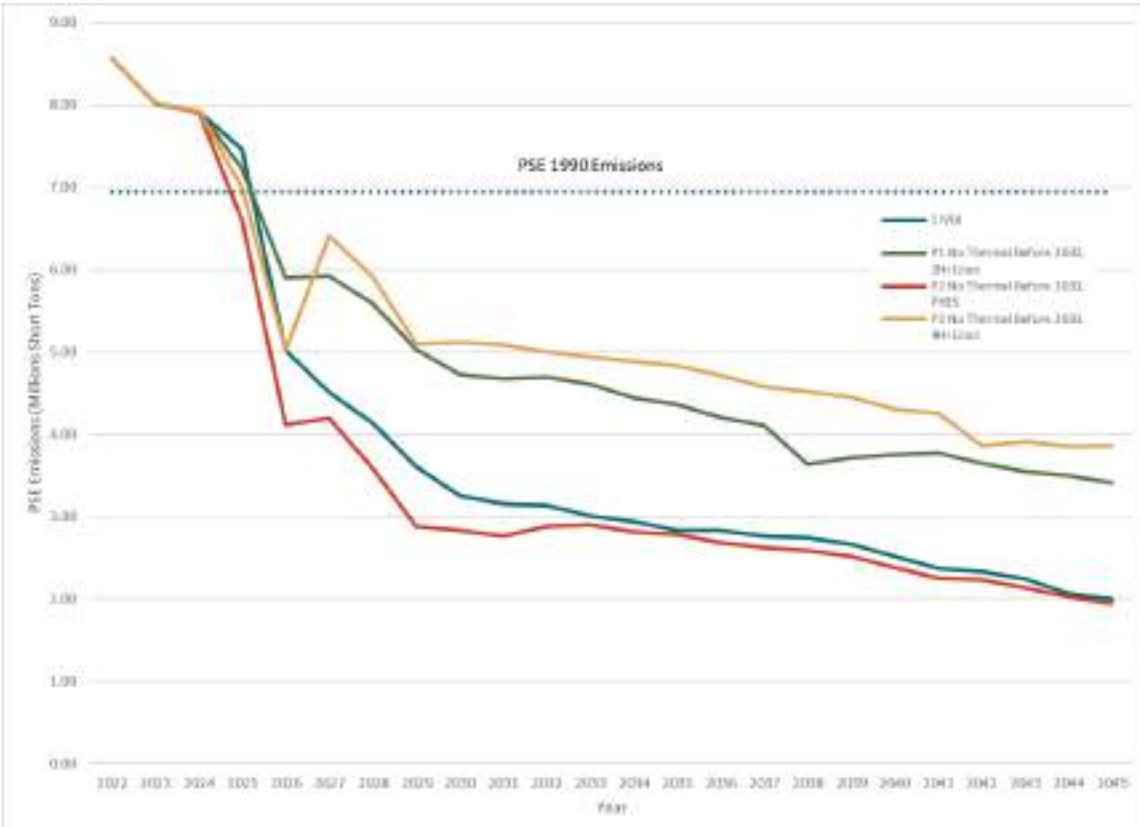
OTHER FINDINGS. Figure 8-104 compares the direct GHG emissions from the Sensitivity P variations with to the Mid Scenario. Direct emissions are defined as emissions linked directly to PSE-owned generating equipment. Despite fewer peaking capacity resources built over the planning period, Sensitivities P1 and P3 have higher direct GHG emissions compared to the Mid Scenario due increased dispatch of existing thermal resources over the planning period. Existing thermal resources are not as efficient as new peaking resources and therefore generate greater emissions.

Figure 8-104: Direct GHG Emissions – Mid Scenario and Sensitivity P, No New Thermal Before 2030



When storage is a major component of a resource portfolio, indirect emissions from market purchases increase. Storage resources may charge from market purchases and these unspecified market purchases are tagged with a GHG emission rate per CETA rules. Figure 8-105 provides a view of GHG emissions from the Sensitivity P variations as compared to the Mid Scenario, for both direct and indirect (i.e., market) emissions. Sensitivities P1 and P3 are now significantly higher emitters than the Mid Scenario, and Sensitivity P3 has nearly the same emission rate as the Mid Scenario. The increase in emissions from portfolios P1 and P3 comes from an increase in dispatch from the existing natural gas resources.

Figure 8-105: Direct and Indirect GHG Emissions – Mid Scenario and Sensitivity P, No New Thermal Before 2030



To put emission reductions into perspective, it is useful to look at the reduction in emissions as a function of portfolio cost (or, the cost of emissions reduction). To calculate this metric, divide the difference in the 24-year levelized cost between the sensitivity and the Mid Scenario by the difference in 24-year levelized emissions between the Mid Scenario and the sensitivity:

$$\frac{Sensitivity\ 24yr\ Levelized\ Cost\ - Mid\ Sc\ 24\ yr\ Levelized\ Cost}{Mid\ 24yr\ Levelized\ Emissions -\ Sensitivity\ 24yr\ Levelized\ Emissions}$$

Figure 8-106 shows the results of this calculation for Sensitivity P and provides the preferred portfolio (Sensitivity W) as a comparison. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. For Sensitivities P1 and P3, both the cost of the portfolio and the levelized quantity emissions were greater than the Mid Scenario, which by definition means they are not feasible plans for reducing emissions. Sensitivity P2 did result in a small reduction in emissions, but the cost of emissions reduction is much higher than in the preferred portfolio, suggesting that replacing the new peaker with storage is not an effective means to reduce emissions.

Figure 8-106: Cost of Emissions Reduction – Mid Scenario, Sensitivity P and Preferred Portfolio

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	53.87	$15.53	--
P1 No New Thermal Before 2030 – 2hr Li-Ion	64.73	$30.84	higher cost & higher emissions
P1 No New Thermal Before 2030 – PHES	50.60	$22.85	2.24
P1 No New Thermal Before 2030 – 4hr Li-Ion	67.00	$39.01	higher cost & higher emissions
W Preferred Portfolio (BP with Biodiesel)	52.77	$16.10	0.52

Demand Forecast Adjustments

Q. Fuel Switching, Gas to Electric

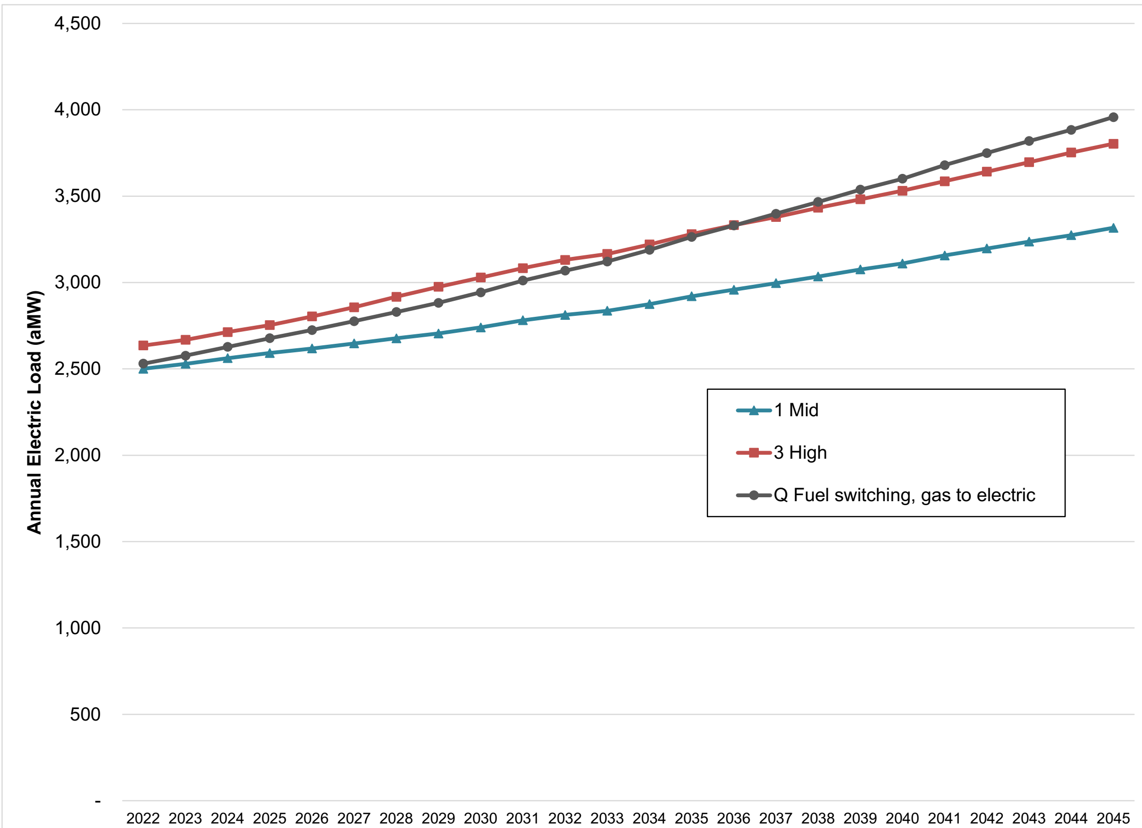
Natural gas is often used for space heating, water heating, cooking, industrial process heat and feedstocks and other uses in residential, commercial and industrial settings. Recent trends in local legislation limit the use of natural gas for these purposes in new construction. Sensitivity Q explores how the energy environment may change if electricity was used as an energy supply in place of the current uses of natural gas.

Baseline: The Mid Scenario assumes the IRP Base Demand Forecast.
Sensitivity R > Sensitivity Q modifies the demand forecast to simulate substitution of electricity for current uses of natural gas in PSE's service area.

KEY FINDINGS. Incorporating a higher penetration of electrification changed the key modeling assumptions for the portfolio and produced a higher electric demand forecast, higher CETA renewable need and a higher peak capacity need compared to the IRP Base Demand Forecast used in the Mid Scenario. As a result, Sensitivity Q selected higher resource builds and had higher portfolio costs compared to the Mid Scenario. More capacity was added in nearly every resource category to meet the increased demand forecast.

ASSUMPTIONS. The demand forecast is adjusted to add a transition from natural gas to electricity for end uses in the PSE service territory resulting in a higher electric demand forecast. PSE hired Cadmus to develop the adjusted electric load which assumes an increase in energy of 203 aMW in 2030 to 641 aMW by 2045 from the Mid Scenario. Figure 8-107 shows the annual electric load (aMW) used for Sensitivity Q compared to the Mid and High Scenarios. In comparison to the electric load in the High Scenario, the electric load for Sensitivity Q is lower through 2036, then higher by 154 aMW by 2045. More information on the load conversion assumptions can be found in Appendix E, Conservation Potential Assessment.

Figure 8-107: Electric Energy Demand Forecast for the Mid and High Scenario Compared to Sensitivity Q (Electrification) Demand Forecast (aMW)

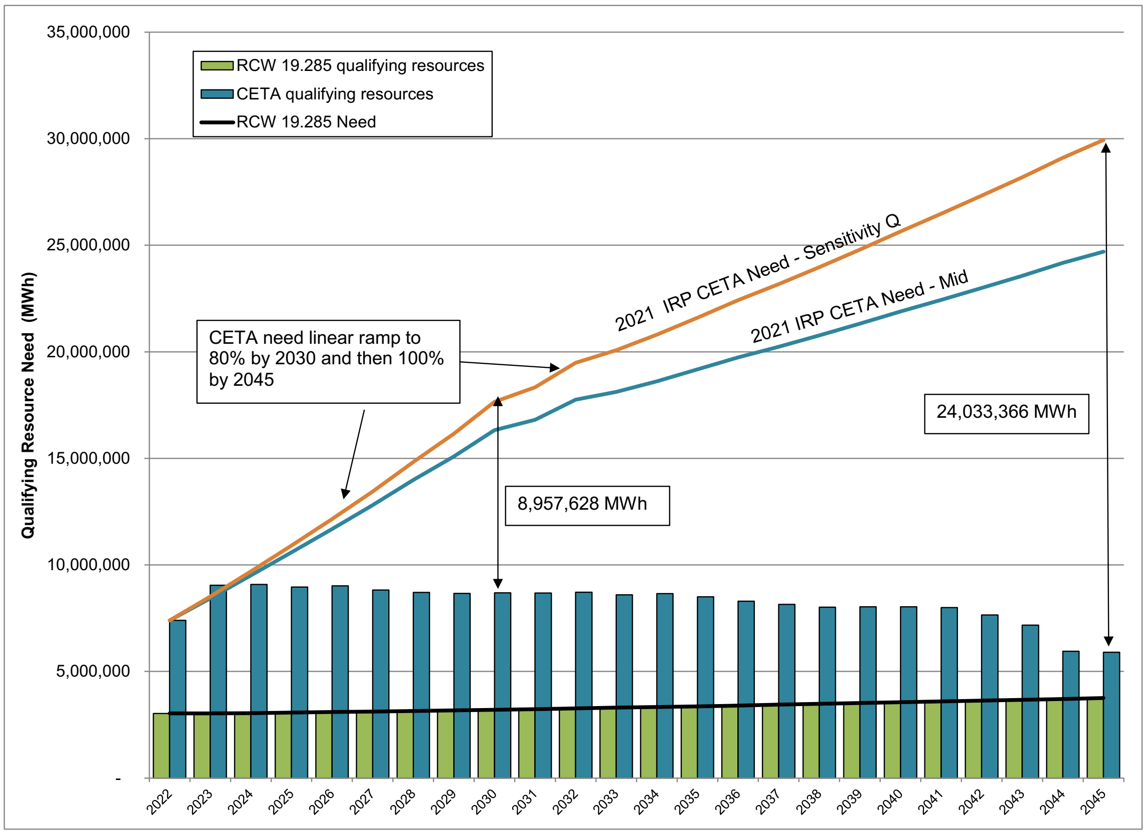


The increased electric demand requires additional CETA-compliant electricity above the Mid Scenario. To reflect this increased electric demand, the CETA renewable need is updated to reflect the change in the electric demand forecast. Figures 8-108 and 8-109 show the CETA renewable need for Sensitivity Q compared to the Mid Scenario. In Sensitivity Q, the CETA renewable need in 2045 is 24 million MWhs, an increase of 5.2 million MWhs from the Mid Scenario.

Figure 8-108: CETA Renewable Need – Mid Scenario and Sensitivity Q by 2030 and 2045

		CETA Renewable Need (MWh)	
	Portfolio	**2030**	**2045**
1	**Mid Scenario**	7,632,507	18,797,944
Q	**Fuel Switching, Gas to Electric**	8,957,628	24,033,366

Figure 8-109: CETA Renewable Need – Mid Scenario and Sensitivity Q

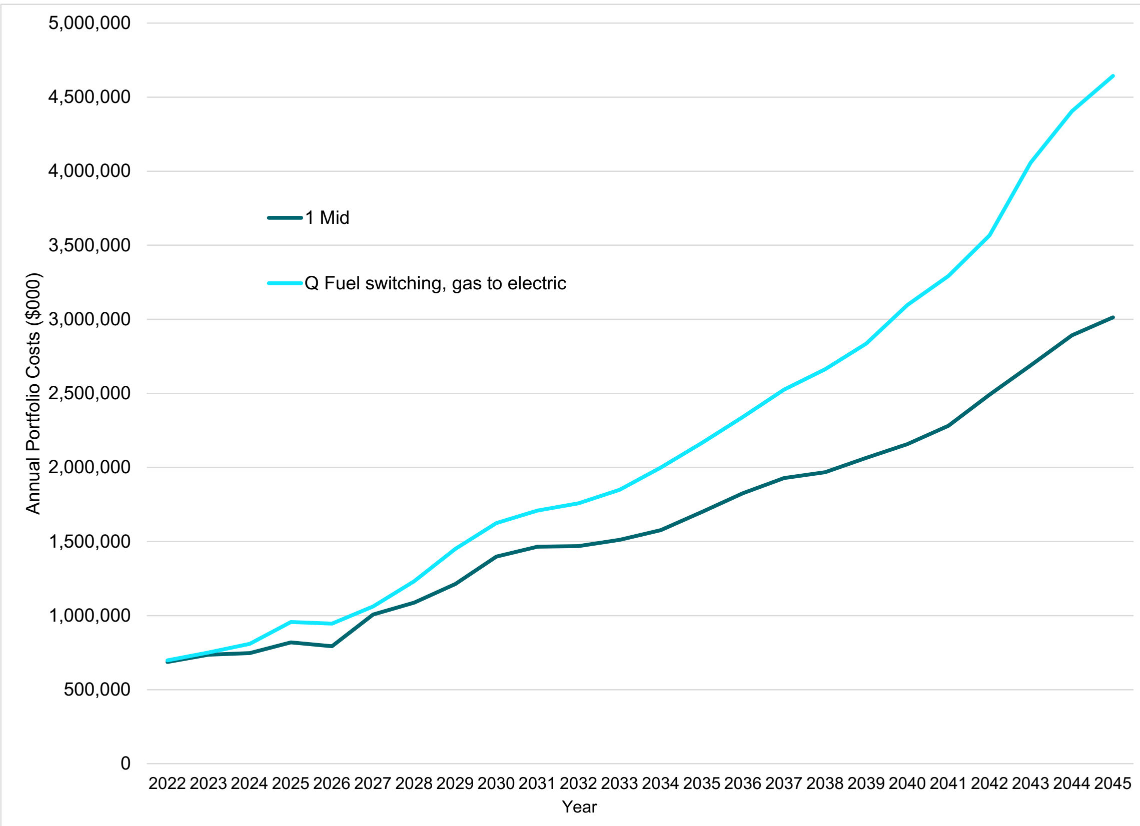


ANNUAL PORTFOLIO COSTS. Figures 8-110 and 8-111 illustrate the breakdown of portfolio costs between the Mid Scenario and Sensitivity Q. Due to the significant increase in electric demand and renewable need, costs for Sensitivity Q are much higher than the Mid Scenario. Additional costs associated with fuel switching (such as appliance or process replacement), changes to the electric and natural gas distribution systems and any incremental transmission needs, are not included in this analysis.

Figure 8-110: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity Q

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
Q	Fuel Switching, Gas to Electric	$19.56	$5.60	$25.16	$4.54

Figure 8-111: Annual Portfolio Costs – Mid Scenario and Sensitivity Q



RESOURCE ADDITIONS. Figures 8-112 and 8-113 compare the nameplate capacity additions of Sensitivity Q and the Mid Scenario portfolios. Sensitivity Q added more capacity in nearly every resource category to meet the increased demand forecast, except for wind which shifted to an increase in Wind + Battery hybrid resource. Sensitivity Q selected conservation Bundle 11, whereas the Mid Scenario selected Bundle 10.

Figure 8-112: Portfolio Additions – Mid Scenario and Sensitivity Q

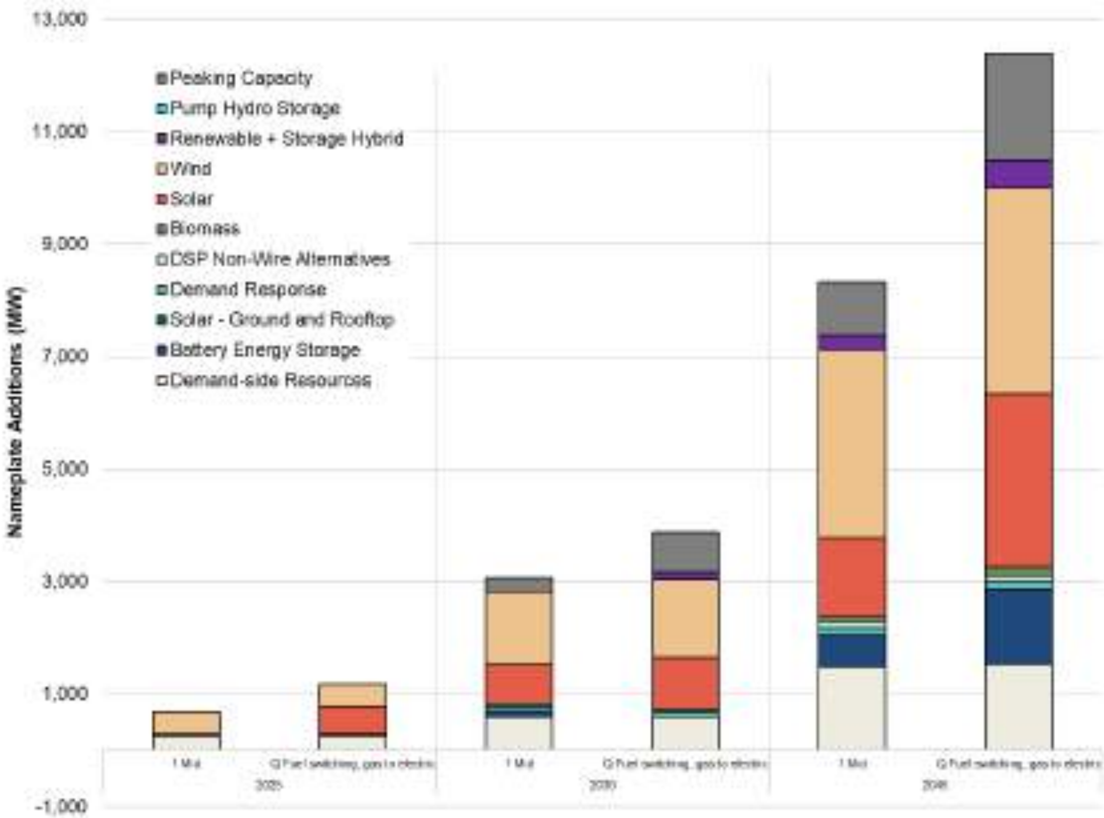
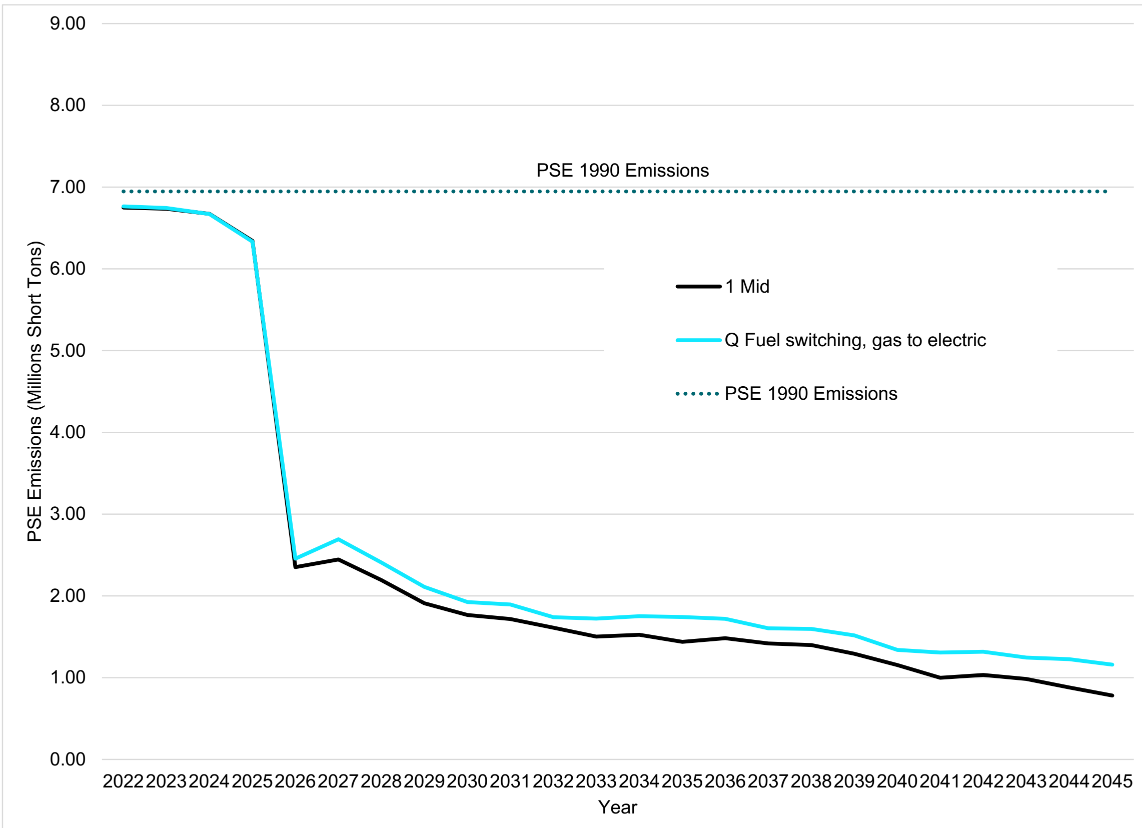


Figure 8-113: Portfolio Additions – Mid Scenario and Sensitivity Q

Resource Additions by 2045	1 Mid	Q Fuel Switching, Gas to Electric
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	1,325 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	129 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	6,888 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	3,088 MW
Wind	3,350 MW	3,650 MW
Renewable + Storage Hybrid	250 MW	500 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	1,896 MW

EMISSIONS. The amount of peaking capacity resources doubled from 948 MW in the Mid Scenario to 1,896 MW in Sensitivity Q as result of the higher energy and peak need, despite increases in demand response and batteries. The higher dispatch from these flexible capacity resources produce a slightly higher overall emissions compared to the Mid Scenario. Figure 8-114 compares the emissions of the Mid Scenario and Sensitivity Q.

Figure 8-114: Direct GHG Emissions – Mid Scenario and Sensitivity Q



R. Temperature Sensitivity

This sensitivity models a change in temperature trends, adjusting the underlying temperature data of the demand forecast to emphasize the influence of more recent years. This change attempts to show the effect of rising temperature trends in the Pacific Northwest. Results from this sensitivity illustrate potential changes in PSE's load profile.

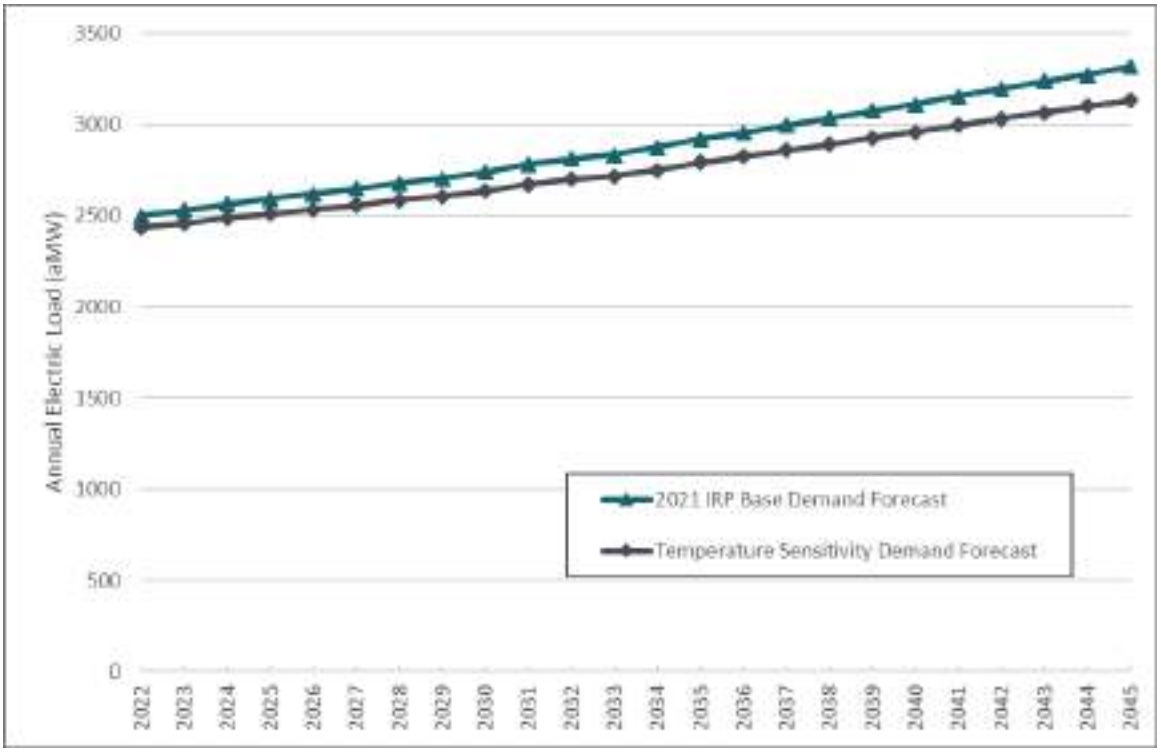
Baseline: The IRP Base Demand Forecast used in the Mid Scenario is based on "normal" weather, defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the past 30 years ending in 2019.

Sensitivity R > PSE used forecast temperature data from the Northwest Power and Conservation Council (the “Council”) to model a new demand forecast. The Council is using global climate models that are scaled down to forecast temperatures for many locations within the Pacific Northwest. The Council weighs temperatures by population from metropolitan regions throughout the Northwest. However, PSE also received data from the Council that is representative of Sea-Tac airport. This data is consistent with how PSE plans for its service area and is not mixed with temperatures from Idaho, Oregon or eastern Washington. The climate model data provided by the Council is hourly data from 2020 through 2049. This data resembles a weather pattern in which temperatures fluctuate over time, but generally trend upward. For the load forecast portion of the temperature sensitivity, PSE smoothed out the fluctuations in temperature and increased the heating degree days (HDDs) and cooling degree days (CDDs) over time at 0.9 degrees per decade, the rate of temperature increase found in the Council’s climate model. PSE also updated the peak capacity need using the resource adequacy analysis. A full description of the temperature sensitivity can be found in Chapter 7.

KEY FINDINGS. Using alternative temperature data for forecasting demand and peak changed the key modeling assumptions for the portfolio and produced a lower demand forecast, lower CETA renewable need and a lower peak capacity need compared to the IRP Base Demand Forecast used in the Mid Scenario. As a result, Sensitivity R selected lower resource builds and had lower portfolio costs compared to the Mid Scenario. Resource additions were driven by the CETA renewable need, and a total of 4,495 MW nameplate capacity of renewable resources was added by 2045 to meet CETA.

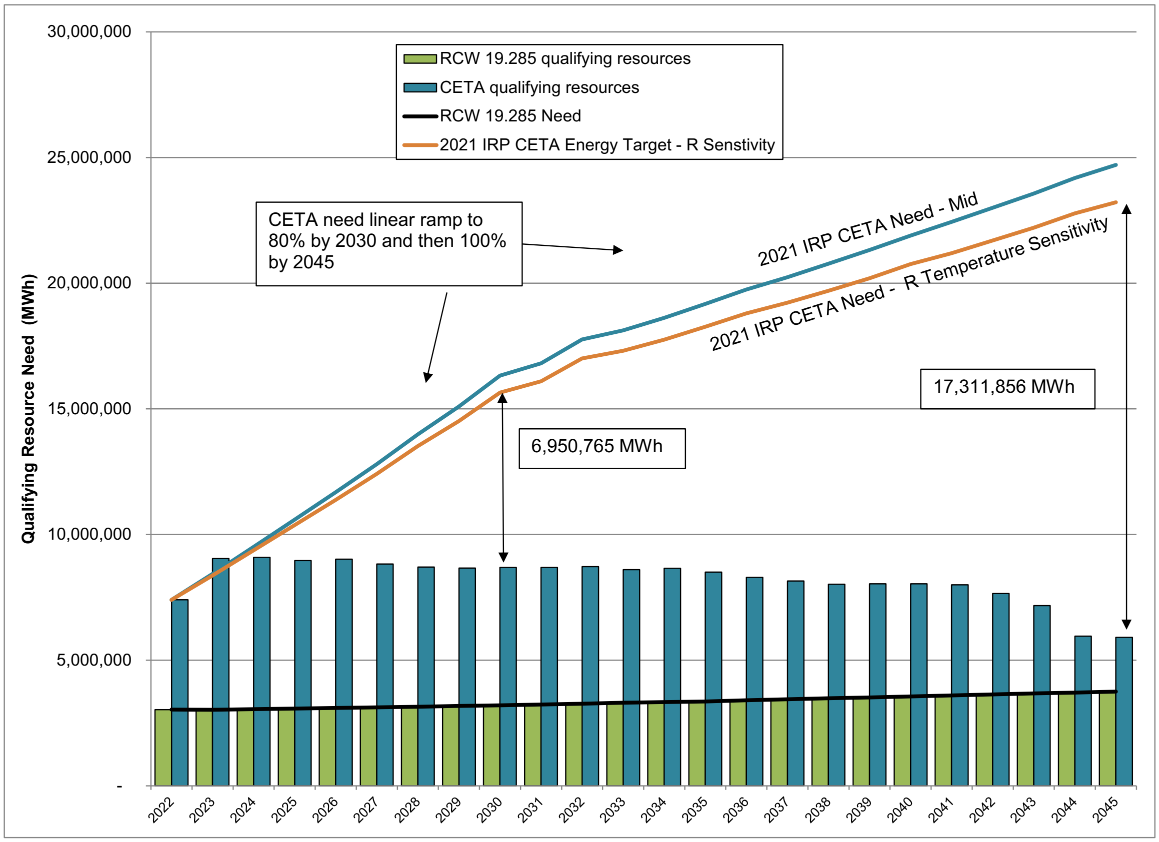
ASSUMPTIONS. In this sensitivity, the demand forecast reflects temperatures warming over time based on the trend of one model that the Council is using in its climate analyses. The related demand forecast is discussed in Chapter 6, Demand Forecasts. Figure 8-115 shows the annual electric load (aMW) used for Sensitivity R compared to the Mid Scenario.

Figure 8-115: Electric Energy Demand Forecast – Mid Scenario Compared to Temperature Sensitivity Demand Forecast (aMW)



The CETA renewable need is updated to reflect the change in the electric demand forecast. Figure 8-116 shows the CETA renewable need for Sensitivity R compared to the Mid Scenario. In Sensitivity R, the CETA renewable need in 2045 is 17.3 million MWhs, a decrease of 1.5 million MWhs from the Mid Scenario.

Figure 8-116: CETA Renewable Need – Mid Scenario and Sensitivity R



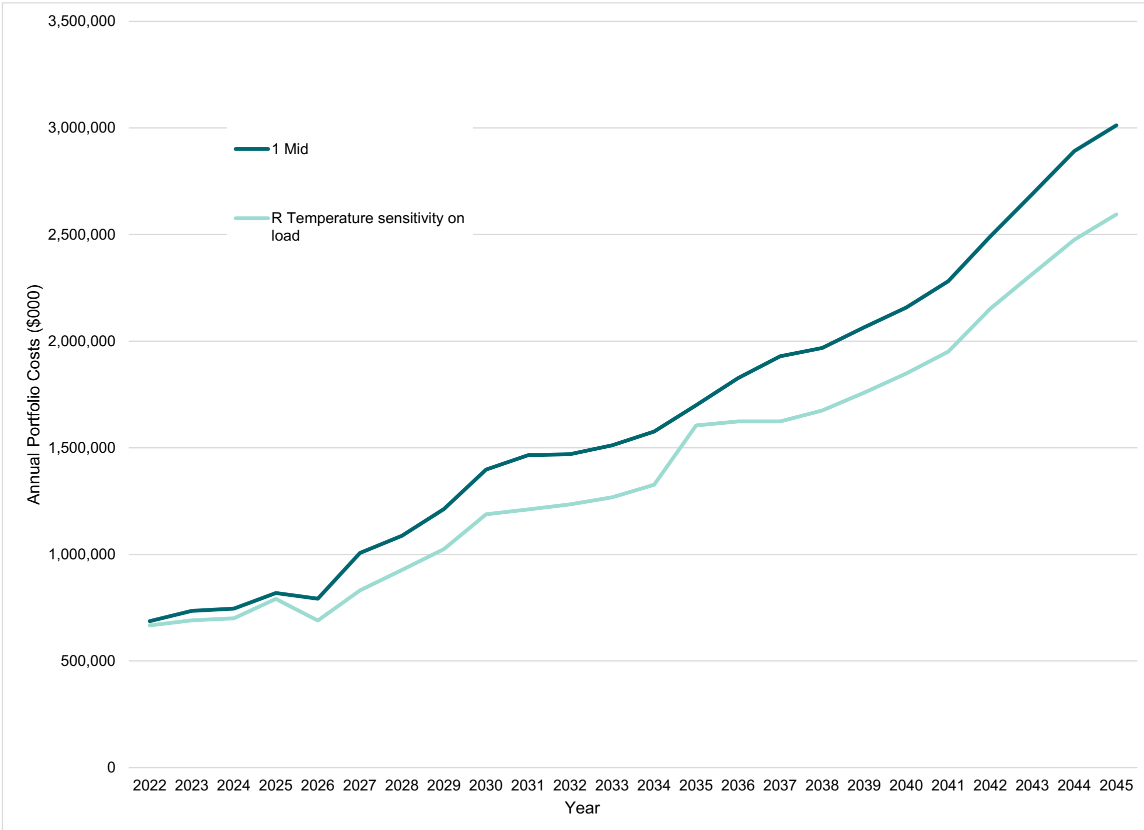
In addition to the change in the electric demand forecast and CETA renewable need, the Resource Adequacy Model was run for this temperature sensitivity reflecting a decrease in peak capacity need from 907 MW to 328 MW in 2027, and from 1,381 MW to 1,019 MW in 2031. More information on this sensitivity can be found in Chapter 7, Resource Adequacy Analysis.

ANNUAL PORTFOLIO COSTS. Figures 8-117 and 8-118 illustrate the breakdown of costs between the Mid Scenario and Sensitivity R. The reduction in costs for Sensitivity R is due to the decrease in the overall resource builds.

Figure 8-117: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity R

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
R	Temperature Sensitivity	$13.53	$4.69	$18.22	($2.40)

Figure 8-118: Annual Portfolio Costs – Mid Scenario and Sensitivity R



RESOURCE ADDITIONS. Figures 8-119 and 8-120 compare the nameplate capacity additions of the Sensitivity R and Mid Scenario portfolios. Peaking capacity resources are not added in Sensitivity R. All other resource options have lower additions except for 2-hour lithium-ion batteries and biomass, both of which showed a minor increase. Sensitivity R selected conservation Bundle 9, which includes 1,372 MW of capacity, whereas the Mid Scenario selected Bundle 10.

Figure 8-119: Portfolio Additions – Mid Scenario and Sensitivity R

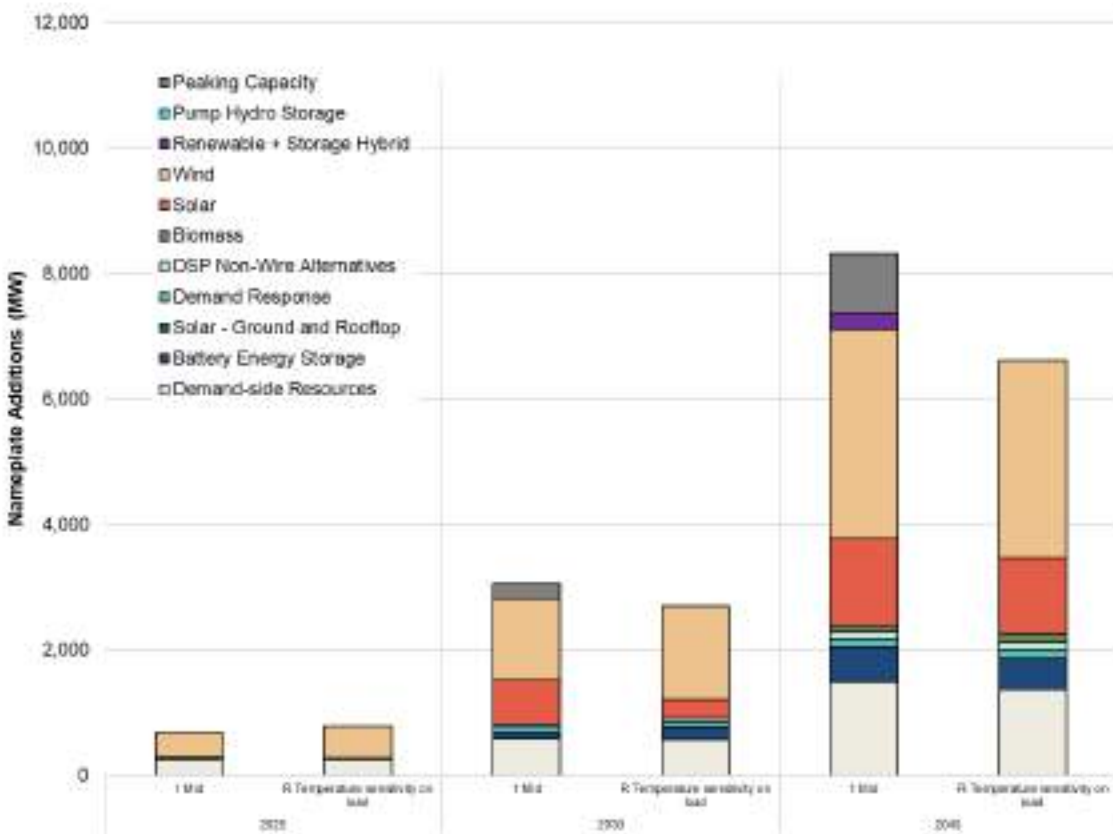
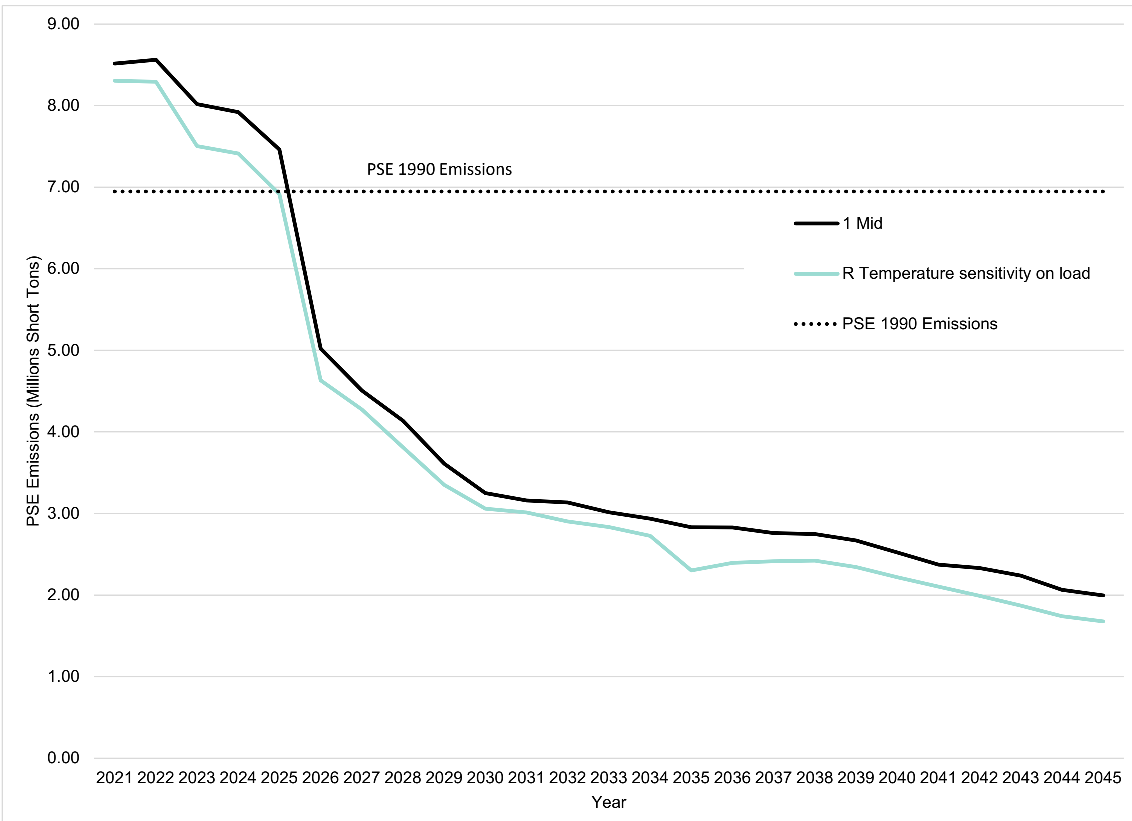


Figure 8-120: Portfolio Additions – Mid Scenario and Sensitivity R

Resource Additions by 2045	1 Mid	R Temperature sensitivity on load
Demand-side Resources	1,497 MW	1,372 MW
Battery Energy Storage	550 MW	500 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	130 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,495 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	1,195 MW
Wind	3,350 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	0 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	0 MW

EMISSIONS AND ECONOMIC RETIREMENTS. Sensitivity R resulted in fewer GHG emissions compared to the Mid Scenario. This is due to the lower dispatch of existing thermal resources and the lack of peaking capacity resource additions. The lower energy demand and peak capacity need also contributed to the economic retirement of existing thermal plants. Two of the natural gas resources were retired by 2023 and replaced by 2-hour lithium-ion batteries. Figure 8-121 compares the GHG emissions from Sensitivity R with the Mid Scenario.

Figure 8-121: Annual Emissions – Mid Scenario and Portfolio R



CETA Costs

S. SCGHG Cost Included, No CETA
T. No CETA

The purpose of this sensitivity is to evaluate the cost of CETA compliance. To assess the effect of CETA and the SCGHG, a baseline must be established. Sensitivity S models PSE without the CETA renewable generation requirement. Sensitivity T models PSE without the CETA renewable requirement or the SCGHG. By analyzing the PSE portfolios without CETA requirements, the impact of CETA can be quantified.

Baseline: The Mid Scenario includes SCGHG for thermal resources as a fixed cost adder and CETA requirements.
Sensitivity S > The model includes SCGHG as a fixed cost adder, but there is no CETA renewable requirement.
Sensitivity T > The model includes no SCGHG and no CETA renewable requirement.

KEY FINDINGS. Without the CETA renewable requirement and SCGHG as a fixed cost adder, the 24-year levelized revenue requirement for Sensitivity T is $9.05 billion dollars, $6.48 billion dollars less than the Mid Scenario portfolio. Compared to Sensitivity S, the 24-year levelized revenue requirement for Sensitivity T is higher by $0.02 billion dollars. The price differences between Sensitivity S and T are negligible, indicating that some conservation and demand response additions can be a revenue requirement-neutral way of cutting emissions. Even so, less conservation is selected in both sensitivities compared to the Mid Scenario.

ASSUMPTIONS. In the Mid Scenario portfolio, 80 percent of sales must be met by non-emitting/renewable resources by 2030; the remaining 20 percent is met through alternative compliance.

In Sensitivity S, the SCGHG is included as a fixed cost adder for thermal resources during resource selection. The CETA renewable generation requirement is not included, but the 15 percent of sales RPS requirement under RCW 19.285 is applied.

In Sensitivity T, there is no CETA renewable requirement and the SCGHG is not included, but the 15 percent of sales RPS requirement under RCW 19.285 is applied.

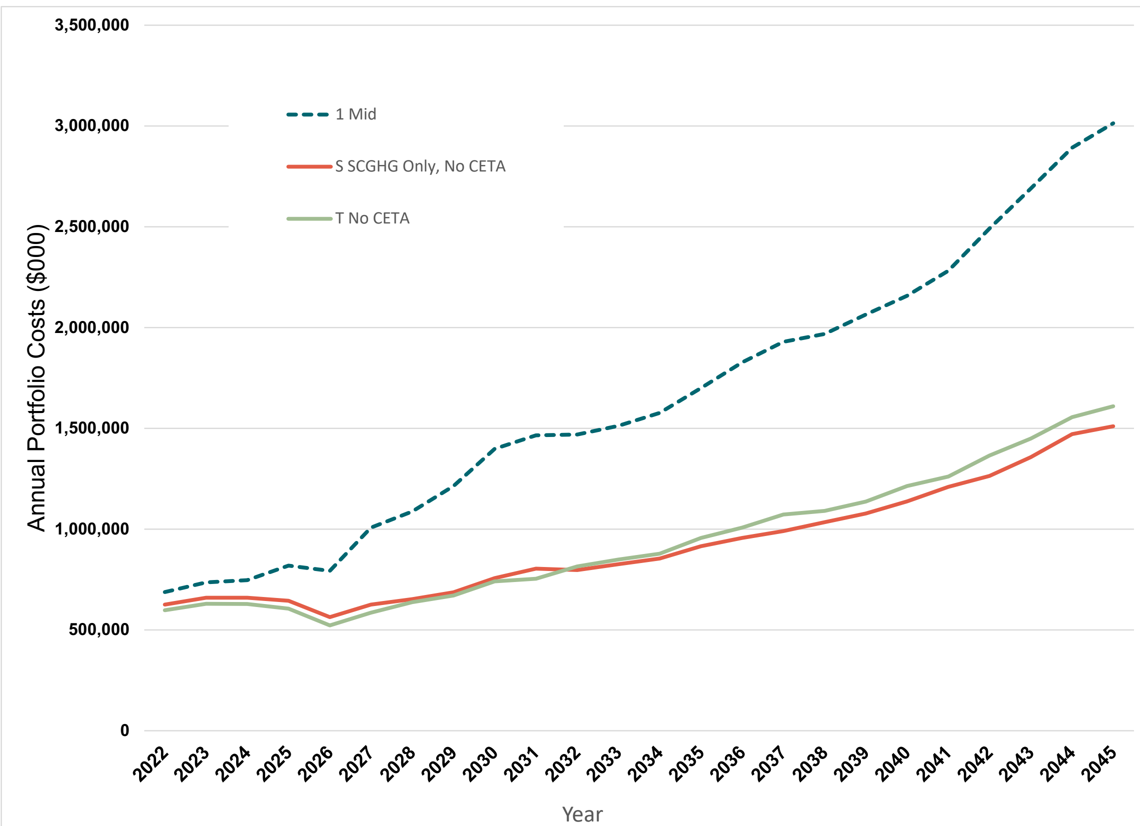
ANNUAL PORTFOLIO COSTS. Figures 8-122 and 8-123 illustrate the breakdown of costs between the Mid Scenario, Sensitivity S and Sensitivity T portfolios. The conservation resources selected in Sensitivity S drive the revenue requirements of the portfolio even lower compared to

Sensitivity T, as they slow the pace of peaker construction and prevent an additional frame peaker from being built by 2045. Since the SCGHG is not included in Sensitivity T, the costs of emissions are not included.

Figure 8-122: 24-year Levelized Portfolio Costs – Mid Scenario, Sensitivity S and Sensitivity T

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
S	SCGHG Only, No CETA	$9.03	$8.86	$17.89	($2.73)
T	No CETA, No SCGHG	$9.05	--	$9.05	($11.57)

Figure 8-123: Annual Portfolio Costs – Mid Scenario, Sensitivities S and Sensitivity T



RESOURCE ADDITIONS. Figure 8-124 compares the nameplate capacity additions of the Mid Scenario to Sensitivities S and T. The build patterns of Sensitivities S and T are similar and simple; both portfolios build frame peakers to keep up with increasing demand. Aside from the Montana wind addition in 2044 to maintain compliance with the RPS requirement, no new renewable resources are built in either portfolio. In Sensitivity T, conservation Bundle 2 is selected, along with 3 demand response measures. In Sensitivity S, conservation Bundle 6 is selected, along with 11 demand response measures. Sensitivity S also builds 50 MW of 2-hour lithium-ion batteries in 2025. The additional demand response, conservation, and storage added in Sensitivity S results in one less frame peaker resource being built by 2045 compared to Sensitivity T.

Figure 8-124: Portfolio Additions – Mid Scenario, Sensitivity S and Sensitivity T

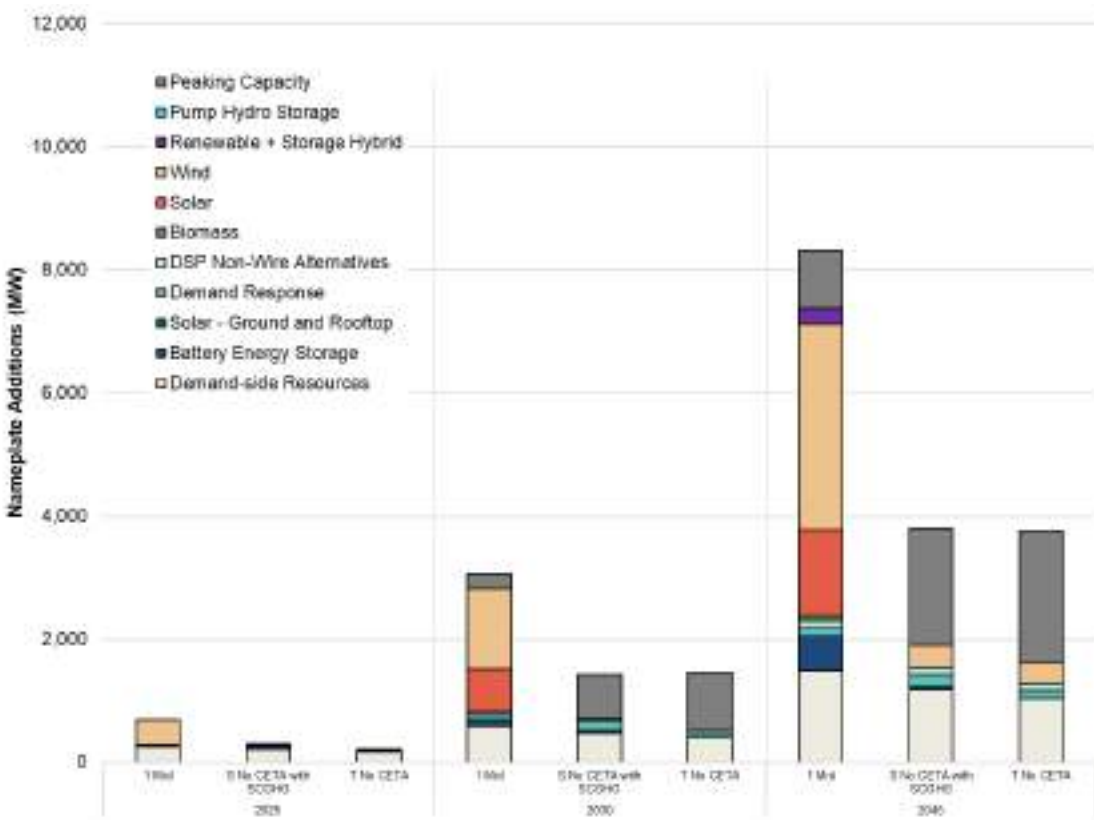
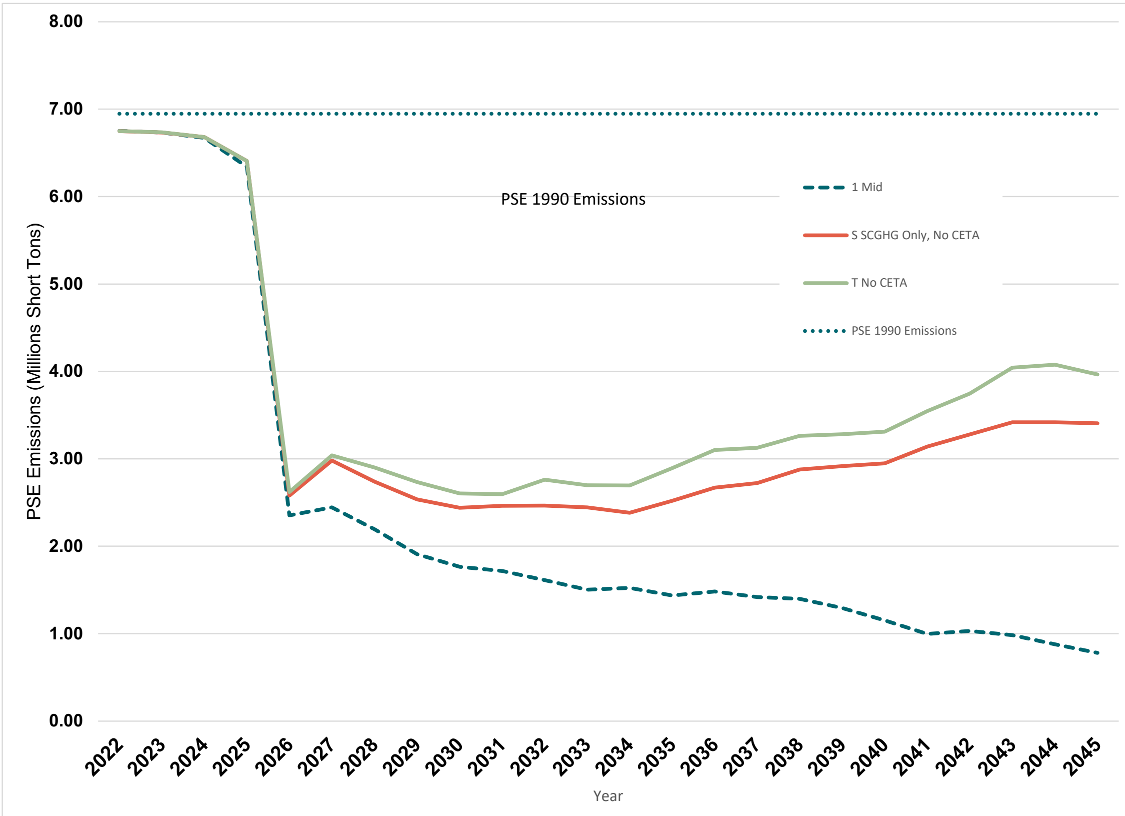


Figure 8-125: Portfolio Additions by 2045 – Mid Scenario, Sensitivity S and Sensitivity T

Resource Additions by 2045	1 Mid	S SCGHG Only, No CETA	T No CETA
Demand-side Resources	1,497 MW	1,179 MW	1,042 MW
Battery Energy Storage	550 MW	50 MW	0 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	203 MW	123 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	350 MW	350 MW
Biomass	90 MW	0 MW	0 MW
Solar	1,393 MW	0 MW	0 MW
Wind	3,350 MW	350 MW	350 MW
Renewable + Storage Hybrid	250 MW	0 MW	0 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	1,896 MW	2,133 MW

EMISSIONS. As expected, the S and T portfolios have a significantly higher rate of emissions than the Mid Scenario. The ultimate goal of CETA is to reduce GHG emissions, and the S and T portfolios demonstrate the need for CETA in curbing emissions from PSE's portfolio. Figure 8-126 shows the annual emissions of the PSE portfolio in Sensitivities S and T.

Figure 8-126: Portfolio Emissions – Mid Scenario, Sensitivity S and Sensitivity T (market purchases are not included)



U. 2% Cost Cap Threshold

The incremental cost of compliance section of CETA states:

> An investor-owned utility must be considered to be in compliance with the standards under RCW 19.405.040(1) and 19.405.050(1) if, over the four-year compliance period, the average annual incremental cost of meeting the standards or the interim targets established under subsection (1) of this section equals a two percent increase of the investor-owned utility's weather-adjusted sales revenue to customers for electric operations above the previous year, as reported by the investor-owned utility in its most recent commission basis report.[6]

6 / RCW 19.405.060 3(a)

PSE calculated the incremental cost as the difference between Portfolio T, No CETA with SCGHG adder, and the preferred portfolio, Portfolio W. The calculation is as follows:

$$Incremental\ Cost = \ Preferred\ Portfolio\ Annual\ Cost - No\ CETA\ with\ SCGHG\ adder\ annual\ Cost$$

The 2 percent cost threshold is calculated based upon the expected annual revenue requirement. Figure 8-127 illustrates how the 2 percent cost threshold is calculated. First, the current revenue requirement is established using PSE's 2019 General Rate Case (GRC) revenue requirement. The GRC revenue requirement is adjusted for inflation at 2.5 percent per year to obtain the estimated 2021 revenue requirement (shown in the top half of the figure). The 2 percent cost threshold for the year 2022 is simply 2 percent of the inflation-adjusted GRC revenue requirement in 2021, approximately $44 million. For subsequent years, 2 percent of the inflation-adjusted GRC revenue requirement is added to the previous 2 percent cost threshold (also adjusted for inflation). This creates the compounding 2 percent cost threshold (shown in the bottom half of the figure).

Figure 8-127: Calculation of the 2 Percent Cost Threshold

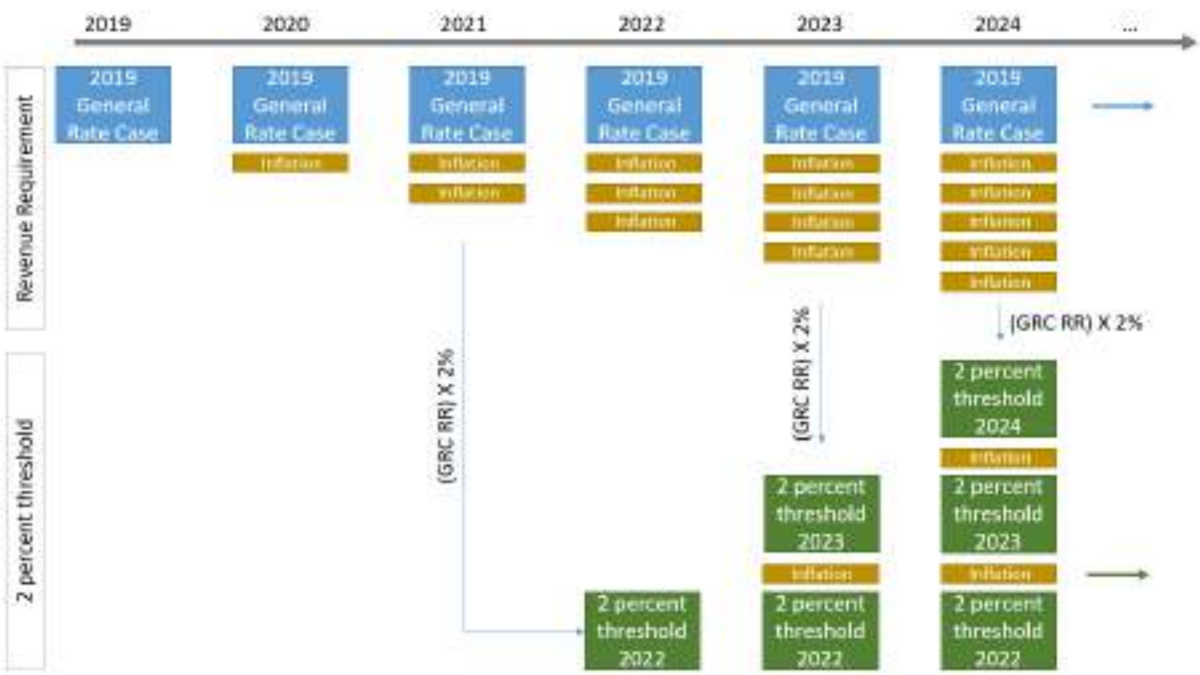
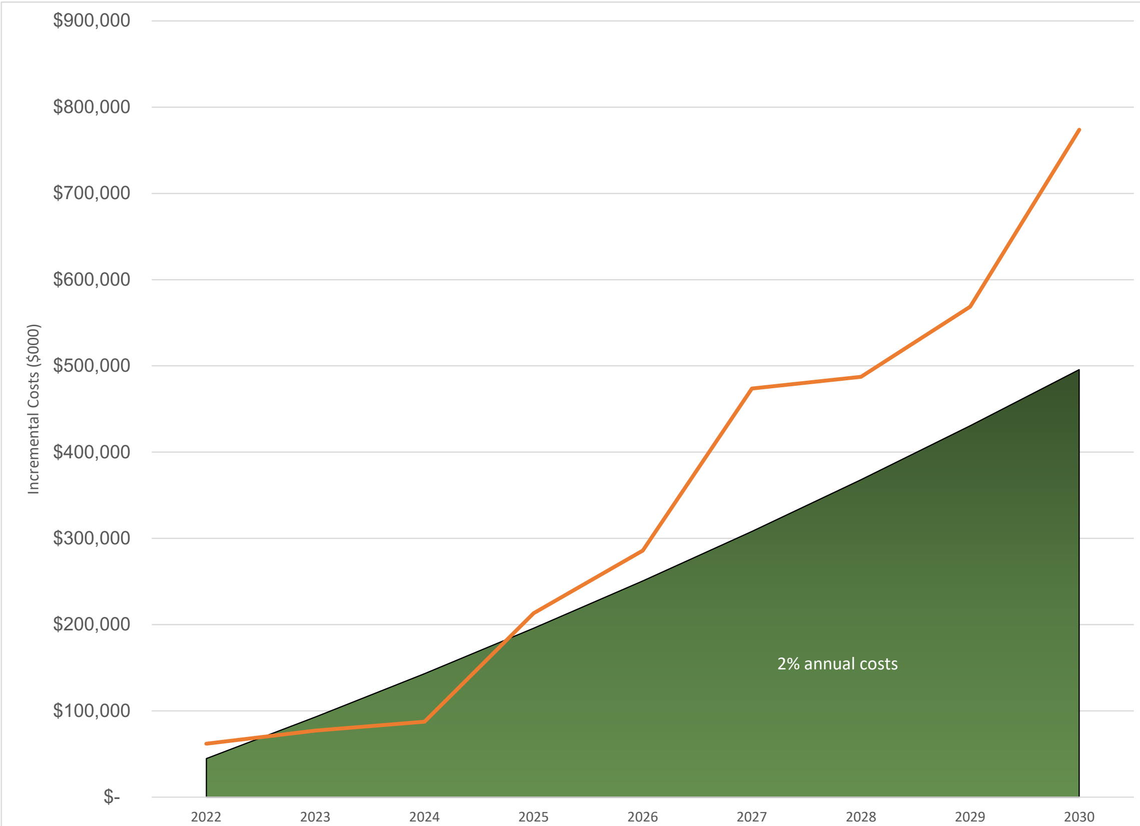


Figure 8-128 compares the 2 percent cost threshold (the green area) with the incremental cost of the preferred portfolio (the orange line). By 2025, the cost of CETA compliance increases to more than the 2 percent cost threshold.

Figure 8-128: Incremental Cost of CETA Compliance



There is some uncertainty associated with this comparison. The annual portfolio costs only include the costs associated with generating resources modeled in the IRP. There may be other costs that are not captured as part of the IRP analysis. Better clarity into this comparison will be obtained through the CEIP. All costs associated with the CETA implementation will be available and included in CEIP. In this IRP, PSE has included the cost of compliance calculation and a comparison with the preferred portfolio for information only.

Balanced Portfolios

V. Balanced Portfolio

Sensitivity V applies insights gained from the analysis of other sensitivities to compare with the results to the Mid Scenario portfolio. Sensitivity V gives increased consideration to distributed energy resources, ramping those and other customer programs in over time starting in 2025. In contrast, the Mid Scenario capacity expansion model is set to optimize total portfolio cost and builds new resources toward the end of the planning period because the cost curve of all resources declines over time. In Sensitivity C, for example, the model waits until the end of the planning period to add a significant amount of distributed resources. However, waiting until the end is not always realistic.

Baseline: New resources are acquired when cost effective and needed, and conservation and demand response measures are acquired when cost-effective.
Sensitivity V1 > Increased distributed energy resources and customer programs are ramped in over time. These include rooftop and ground-mounted solar, demand response programs, battery energy storage, customer-owned rooftop solar and an expanded Green Direct program.
Sensitivity V2 > Same as Sensitivity V1, with the substitution of a Montana wind + pumped hydro storage resource for the first eastern Montana resource constructed in 2028, similar to Sensitivity AA described below.
Sensitivity V3 > Same as Sensitivity V1, except conservation measures ramp in over 6 years instead of 10 years, similar to Sensitivity F described above.

KEY FINDINGS. Ramping in resource additions versus economic resource selection resulted in higher portfolio costs in Sensitivity V variations compared to the Mid Scenario. Distributed solar resources are higher cost than Washington wind and Washington solar east resources, which were found to be the optimal renewable resources after the addition of Montana and Wyoming wind resources in the Mid Scenario portfolio. In Sensitivity V1, the 24-year levelized revenue requirement is $16.06 billion, an increase of $0.47 billion or 3 percent over the Mid Scenario portfolio. Adding MT wind plus pumped hydro storage (V2) or a 6-year DSR ramp increases these costs further.

ASSUMPTIONS. Sensitivity V1 assumes greater investment in distributed energy resources and load-reducing resources like the Green Direct program and conservation measures to create a portfolio with greater balance between large, central power plants and small, distributed resources. Investments in these resources are modeled as must-take resource additions. These must-take resource additions include:

- Addition of 50 MW of distributed, ground-mounted solar in the year 2025.
- Annual addition of 30 MW of distributed, rooftop solar from the year 2025 to 2045 for a total of 630 MW of nameplate capacity.
- Addition of all demand response programs with a cost less than $300/kw-yr.
- Annual addition of 25 MW of 2-hour lithium-ion battery storage from the year 2025 to 2031 for a total of 175 MW of nameplate capacity.
- An adjusted forecast of customer-owned solar projects to reflect increased residential solar adoption. The forecast matches the CPA Low-cost, Business-as-Usual residential solar adoption rate, available in Appendix E.
- Addition of three new Green Direct programs consisting of 100 MW of Washington wind in 2025, 100 MW of eastern Washington solar in 2027 and 100 MW of Washington wind in 2030.

PSE has ramped in resource additions in this sensitivity to spread out the acquisition of new resources. All generic resource options are still available for economic selection by the optimization model.

Sensitivity V2 makes the same assumptions as Sensitivity V1 except a Montana wind + pumped hydro storage resource is forced into the portfolio in the year 2028.

Sensitivity V3 makes the same assumptions as Sensitivity V1 except conservation measures are implemented over 6 years instead of 10 years and associated costs and energy savings are updated.

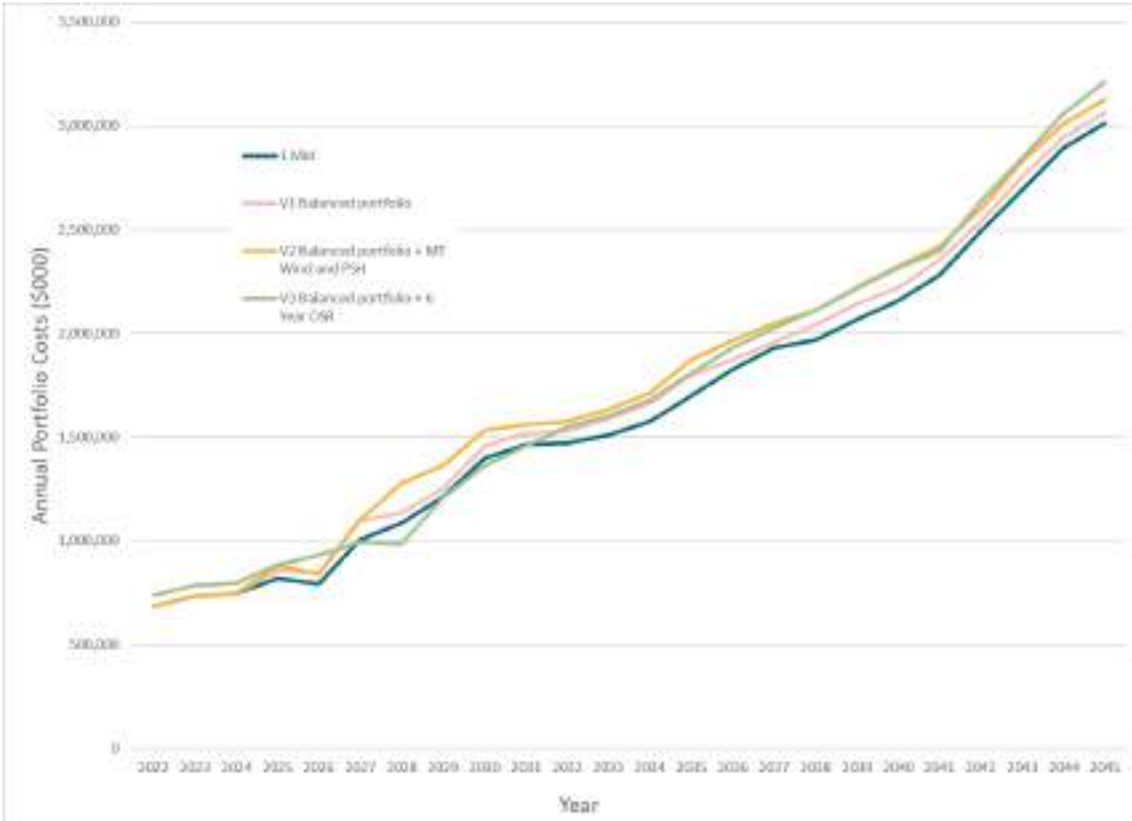
PORTFOLIO COSTS. Figures 8-129 and 8-130 compare the portfolio costs and annual revenue requirements, respectively, of the Sensitivity V variations and the Mid Scenario. Early investments in high-cost resources such as distributed solar and storage result in overall higher portfolio costs for the Sensitivity V variations compared to the Mid Scenario. Sensitivity V1 has a slightly higher revenue requirement from 2024 to the end of the planning period compared to the Mid Scenario. Sensitivity V2 has a significant increase the annual revenue requirement in 2028 from the addition of the expensive Montana wind plus pumped hydro storage resource and never recovers those costs compared to the Mid Scenario. Sensitivity V3 starts as the most expensive portfolio due to the accelerated ramp of conservation measures, and then sees some cost savings in the years 2027 to 2032 compared to the Mid Scenario. However, in 2032 the Mid Scenario conservation measures complete their 10-year ramp-in, equalizing the energy savings between the two portfolios. After 2032, Sensitivity V3 costs increase above the Mid Scenario due to resource acquisitions in the later portion of the planning period.

The SCGHG for the Sensitivity V variations is similar the SCGHG for the Mid Scenario. Sensitivities V1 and V2 achieve slightly lower SCGHG than the Mid Scenario, while Sensitivity V2 has a slightly higher SCGHG overall.

Figure 8-129: Portfolio Cost Comparison – Mid Scenario and Sensitivities V, W and X

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
V1	Balanced Portfolio	$16.06	$5.07	$21.14	$0.54
V2	Balanced Portfolio with MT wind + PHES	$16.61	$5.12	$21.73	$1.11
V3	Balanced Portfolio with 6-year DSR	$16.26	$5.06	$21.32	$0.70

Figure 8-130: Annual Portfolio Costs – Mid Scenario and Sensitivities V1, V2 and V3



RESOURCE ADDITIONS. Figures 8-131 and 8-132 compare the nameplate capacity additions of the Sensitivity V variations and the Mid Scenario portfolio. Resource additions for Sensitivity V1 and the Mid Scenario are similar, except for the quantity of ground-mounted and rooftop solar forced into the portfolio in the early years that displaces utility-scale solar. Resource additions for the Sensitivity V variations are all very similar. Sensitivity V3 delays acquisition of resources until the later years of the planning period, but concludes the planning period with a similar resource mix as Sensitivities V1 and V2.

Figure 8-131: Portfolio Additions – Mid Scenario and Sensitivities V1, V2 and V3

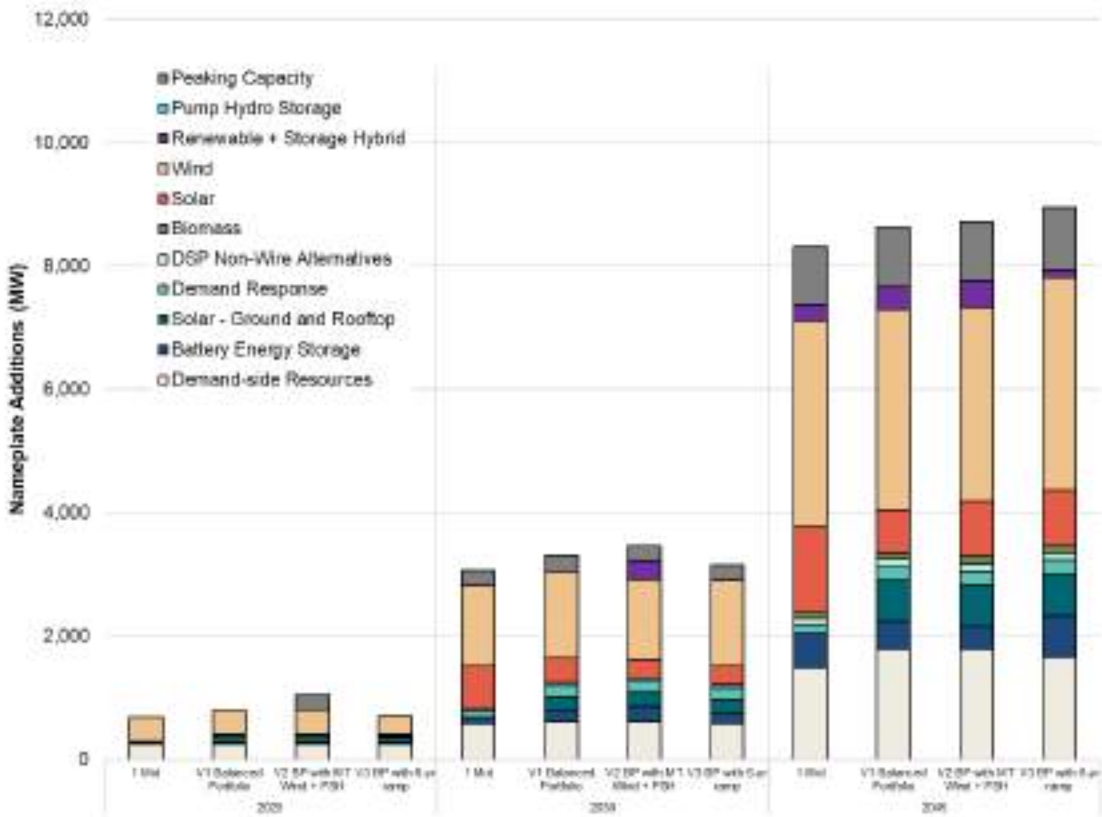
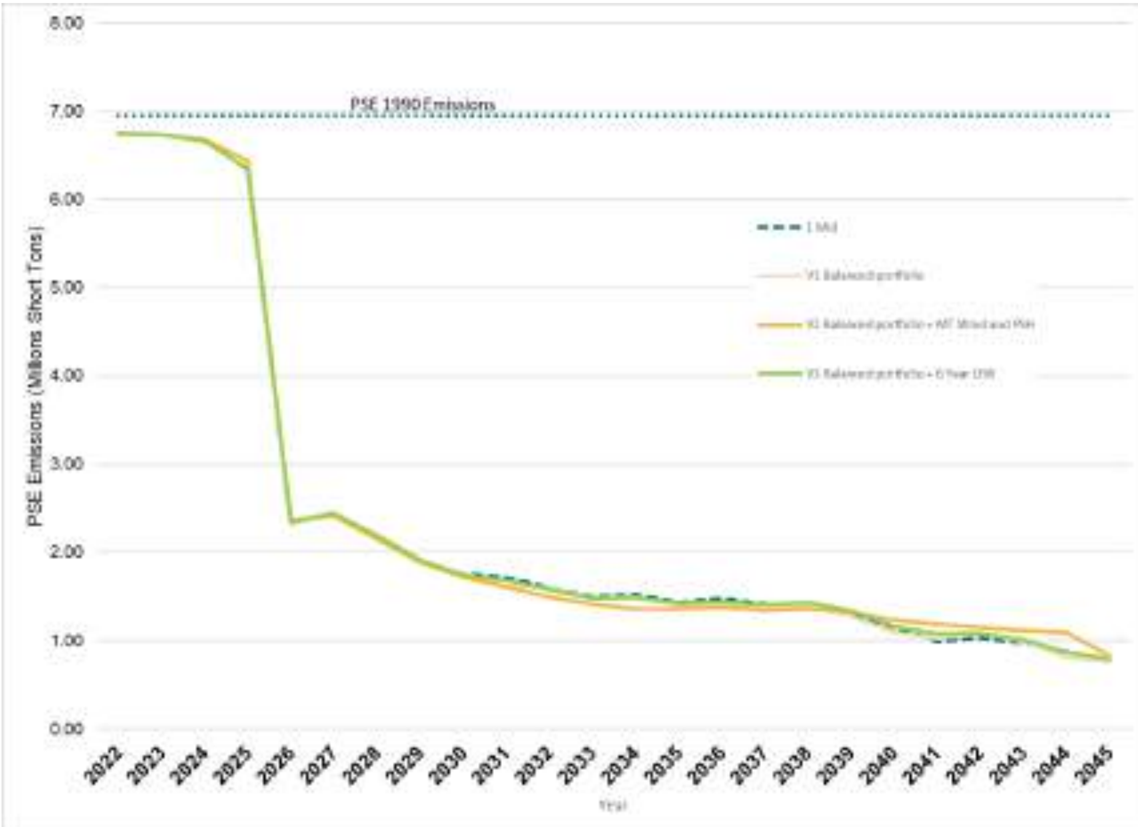


Figure 8-132: Portfolio Additions by 2045 – Sensitivities V1, V2 and V3

Resource Additions by 2045	Mid Scenario Portfolio	Sensitivity V1 - Balanced Portfolio	Balanced Portfolio with MT wind + PHES	Balanced Portfolio with 6-year DSR
Demand-side Resources	1,497 MW	1,784 MW	1,784 MW	1,658 MW
Battery Energy Storage	550 MW	450 MW	375 MW	675 MW
Solar - Ground and Rooftop	0 MW	680 MW	680 MW	680 MW
Demand Response	123 MW	217 MW	217 MW	217 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	4,051 MW	4,165 MW	4,465 MW
Biomass	90 MW	105 MW	120 MW	120 MW
Solar	1,393 MW	696 MW	895 MW	895 MW
Wind	3,350 MW	3,250 MW	3,150 MW	3,450 MW
Renewable + Storage Hybrid	250 MW	375 MW	425 MW	125 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	966 MW	948 MW	1,003 MW

OTHER FINDINGS: GHG Emissions. Figure 8-133 compares the direct GHG emissions from Sensitivities V1, V2 and V3 with the Mid Scenario. Significant emissions reductions are achieved with the addition of non-emitting resources, the retirement of coal resources and lower dispatch of existing resources. All three Sensitivity V variations show similar reductions in emissions by the year 2045.

Figure 8-133: Portfolio GHG Emissions – Sensitivities V1, V2 and V3

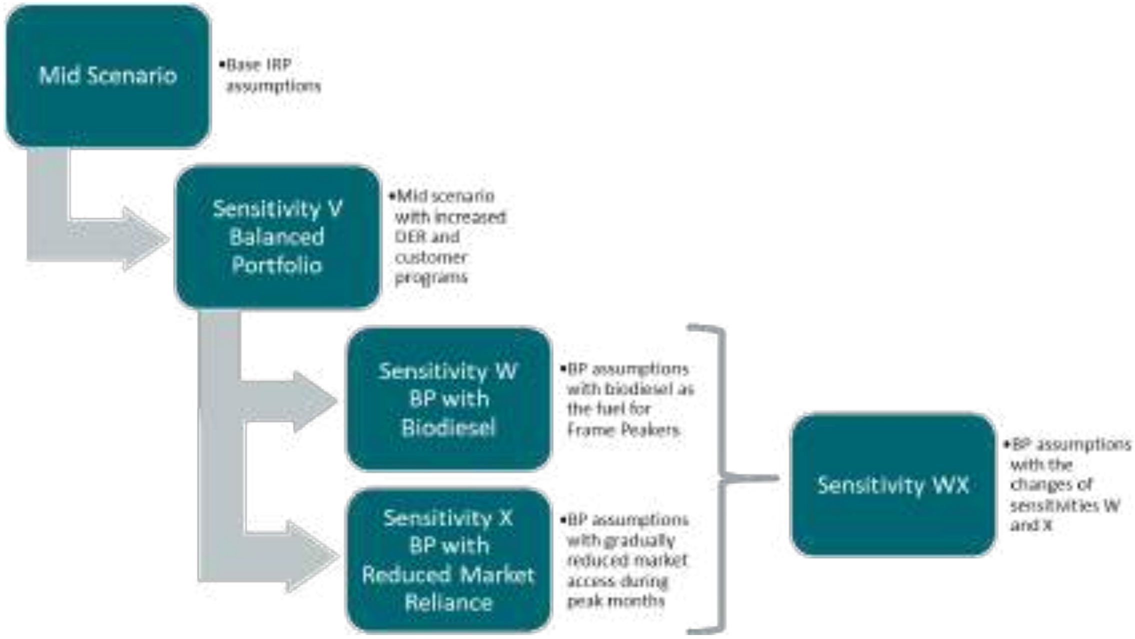


W. Balanced Portfolio with Alternative Fuel
X. Balanced Portfolio with Reduced Market Reliance
WX. Balanced Portfolio with Alternative Fuel and Reduced Market Reliance

Sensitivities W and X incorporate significant changes to Sensitivity V1, the Balanced Portfolio. Sensitivity W substitutes biodiesel for natural gas in new peaking capacity resources and Sensitivity X reduces the market reliance of the portfolio. Sensitivity WX applies the key changes in Sensitivities W and X simultaneously. Figure 8-134 illustrates how these changes are applied.

Figure 8-134: Sensitivities V, W, X and WX, and Their Relation to the Mid Scenario

BP = Balanced Portfolio



Baseline: In the Mid Scenario, new resources are acquired when cost effective and needed, and conservation and demand response measures are acquired when cost-effective.

Sensitivity W > Same as Sensitivity V1, with the addition of biodiesel as the fuel source for new frame peaker resources, similar to Sensitivity M.

Sensitivity X > Same as Sensitivity V1, but market purchases during seasonal peak conditions gradually decline by 200 MW per year down to 500 MW by 2027 in the winter months (January, February, November and December) and the summer months (June, July, and August), similar to sensitivity B.

Sensitivity WX > Additional DER and customer programs are added to the portfolio. Biodiesel is used as a fuel for newly built frame peaker resources. The portfolio has reduced access to market purchases during peak demand months.

KEY FINDINGS: SENSITIVITY W. Extending the assumptions from Sensitivity V1 to include biodiesel as a fuel source for new frame peakers resulted in an increase of $0.57 billion dollars in the 24-year levelized revenue requirement for Sensitivity W compared to the Mid Scenario. The 24-year levelized revenue requirement is $16.10 billion, an increase of less than $0.04 billion from Sensitivity V1. Even with the premium on biodiesel fuel prices compared to natural gas prices, the model selected the same amount of frame peaker resources in Sensitivity W compared to the Mid Scenario portfolio.

KEY FINDINGS: SENSITIVITY X. While ramping in distributed energy resources and customer programs over time helps to achieve increased renewable resources, introducing the reduced market reliance strategy creates tension, since Sensitivity X adds more peaking capacity resources compared to the Mid Scenario and Sensitivity V. The 24-year levelized revenue requirement for Sensitivity X is $17.21 billion, $1.68 billion more than the Mid Scenario and $1.14 billion more than Sensitivity V1.

KEY FINDINGS: SENSTIVITY WX. Portfolio WX is nearly identical to portfolio X. The same resources are selected at the same time. The only difference in builds is an increase in demand-side resources. Portfolio WX emissions decrease compared to portfolio X due to the use of biodiesel, but are higher than portfolio W due to the reduced availability of market purchases during peak hours.

ASSUMPTIONS: Sensitivity V1: Balanced Portfolio
Increased distributed energy resources and customer programs ramp in over time as follows:

- Addition of 50 MW of distributed, ground-mounted solar in 2025.
- Annual addition of 30 MW of distributed, rooftop solar from 2025 to 2045 for a total of 630 MW of nameplate capacity.
- Annual addition of all demand response programs that cost less than $300/kw-yr.
- Annual addition of 25 MW of 2-hour lithium-ion battery storage from 2025 to 2031 for a total of 175 MW of nameplate capacity.
- Adjusted forecast of customer-owned solar projects to reflect increased residential solar adoption. (The forecast matches the CPA Low-cost, Business-as-Usual residential solar adoption rate, available in Appendix E.)
- Addition of three new Green Direct programs: 100 MW of Washington wind in 2025, 100 MW of eastern Washington solar in 2027 and 100 MW of Washington wind in 2030.

ASSUMPTIONS: Sensitivity W. Sensitivity W uses the Sensitivity V1 assumptions, but also includes the use of alternative fuel for some peaking capacity resources. New frame peakers are assumed to be fueled by biodiesel instead of natural gas. Existing thermal resources, new CCCT+DF and new recip peakers continue to be fueled with natural gas throughout the modeling horizon. PSE estimated a biodiesel price of $37.20 per million British Thermal Units (MM BTU) (2020$, adjusted for inflation annually) informed by the U.S. Department of Energy's October 2020 Clean Cities Alternative Fuel Price Report.

ASSUMPTIONS: Sensitivity X. For Sensitivity X, available market purchases were constrained to capture the impact of reduced market reliance on the Balanced Portfolio. Available market purchases during peak conditions are reduced by 200 MW per year down to 500 MW by 2027 in the winter months (January, February, November and December) and the summer months (June, July, and August).

Figure 8-135 shows the Sensitivity X market purchase limits for each year and month.

Figure 8-135: Monthly Market Purchase Access in Portfolio X (MW)

MW	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2022	1544	1529	1516	1483	1442	1463	1472	1487	1569	1588	1558	1518
2023	1300	1300	1507	1466	1432	1300	1300	1300	1519	1519	1300	1300
2024	1100	1100	1536	1471	1418	1100	1100	1100	1546	1521	1100	1100
2025	900	900	1518	1455	1402	900	900	900	1529	1523	900	900
2026	700	700	1521	1457	1405	700	700	700	1530	1525	700	700
2027	500	500	1523	1460	1408	500	500	500	1532	1526	500	500
2028	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2029	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2030	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2031	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2032	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2033	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2034	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2035	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2036	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2037	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2038	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2039	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2040	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2041	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2042	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2043	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2044	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2045	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2046	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2047	500	500	1525	1462	1411	500	500	500	1533	1526	500	500

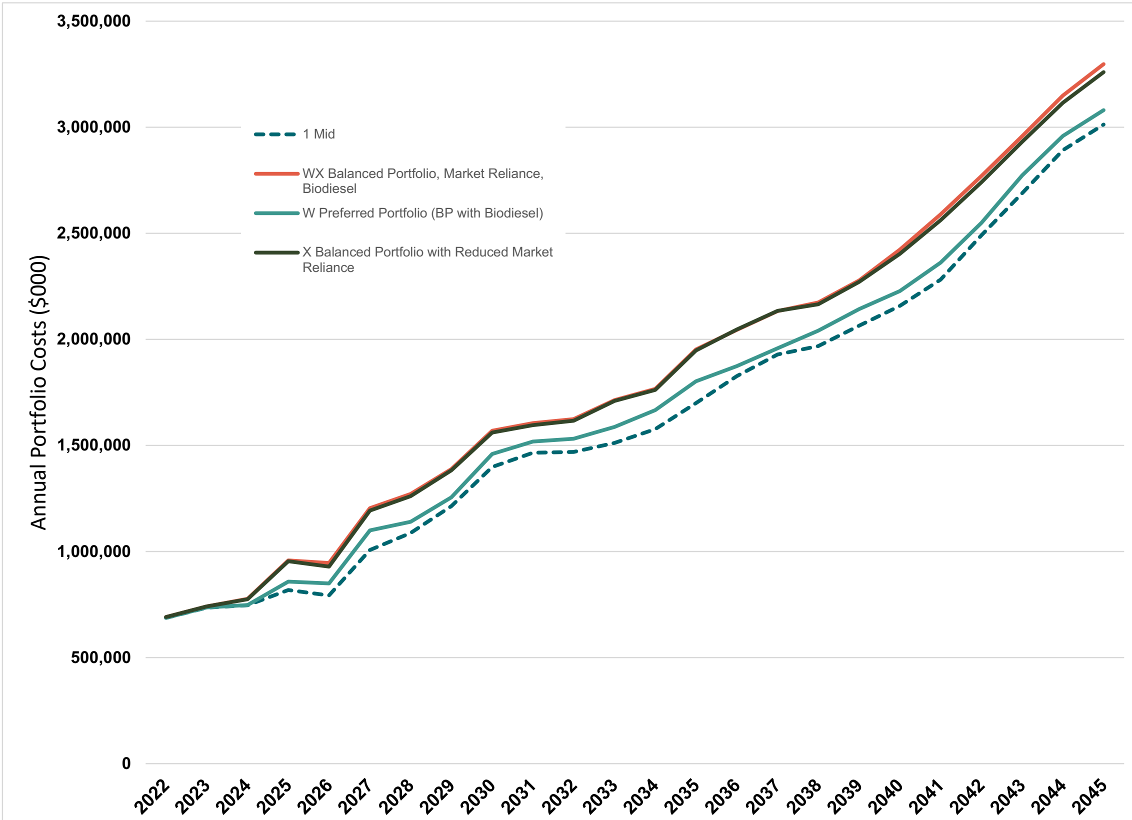
ASSUMPTIONS: Sensitivity WX. Sensitivity WX combines the changes incorporated to Sensitivity W and Sensitivity X. Therefore, biodiesel is available for new frame peakers and the portfolio has reduced market purchase limits.

ANNUAL PORTFOLIO COSTS. Figures 8-136 and 8-137 show the portfolio costs and annual revenue requirements, respectively, of Sensitivities WX, W and X, compared to the Mid Scenario. Early investments in high-cost resources such as distributed solar and storage result in higher portfolio costs for Sensitivities WX, W and X. For Sensitivity W, increased portfolio costs are driven by the increased revenue requirements of the portfolio, as shown in Figure 8-X. Sensitivity W has slightly lower SCGHG due the use of alternative fuel for new peaking resources than the Mid Scenario portfolio. In Sensitivity X, the increased portfolio costs are due to the addition of more flexible capacity resources, which also increases the SCGHG. Portfolio WX significantly increases the revenue requirement over the Mid Scenario portfolio, although less than the combined increases of the W and X portfolios over the Mid Scenario. The portfolio builds are nearly identical to portfolio X, but the use of biodiesel reduces the SCGHG costs and costs overall. The slight increase in portfolio costs compared to portfolio X is due to the use of biodiesel and increased investment in demand-side resources.

Figure 8-136: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivities WX, W and X

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
WX	Balanced Portfolio, Biodiesel, Reduced Market Reliance	$17.30	$5.06	$22.36	$1.74
W	Balanced Portfolio, Biodiesel	$16.10	$4.96	$21.06	$0.44
X	Balanced Portfolio, Reduced Market Reliance	$17.21	$5.36	$22.57	$1.95

Figure 8-137: Annual Portfolio Costs – Mid Scenario and Sensitivities WX, W and X



RESOURCE ADDITIONS. Figures 8-138 and 8-139 compare the nameplate capacity additions of Sensitivities W, X, WX and the Mid Scenario portfolios.

Portfolio builds for Sensitivity W are relatively similar to the wind and peaking capacity resource builds in the Mid Scenario. Wind is a low cost, CETA-eligible resource, so it is to be expected that all four portfolios selected similar amounts of wind capacity. Peaking capacity resources are among the lowest cost methods to meet peak demand hours. Therefore, it is also to be expected that most portfolios will include some peaking capacity. Sensitivity W has an additional 18 MW of reciprocating peaker resources compared to the quantity of peaking capacity resources in the Mid Scenario. In Sensitivity W, new frame peaker resources are fueled with renewable biodiesel instead of natural gas which therefore does not include an SCGHG cost. However, biodiesel is also much more expensive than natural gas. At the current cost projections for biodiesel, it appears that the higher fuel price and lower SCGHG cost are offsetting each other, resulting in similar peaking resource decisions.

The primary differences between the Mid Scenario and Sensitivity W are related to the forced build decisions described in the assumptions section above. Increased distributed solar builds result in less utility-scale solar builds, as these resources fill a similar niche within the portfolio. Increased demand response programs in Sensitivity W may also offset some utility-scale solar builds.

More storage is built in Sensitivity W compared to the Mid Scenario portfolio. Sensitivity W ramps in 2-hour lithium-ion battery storage from 2025 to 2031. This storage is useful, particularly paired with the increased distributed solar builds in both sensitivities. However, the storage in the Mid Scenario portfolio is comprised of 4-hour lithium-ion and 6-hour flow battery storage, which is built after year 2040. Sensitivity W shows similar late year additions of longer duration storage, despite the abundance of 2-hour storage added early in the modeling horizon. This shows that longer-duration storage is an important component of these portfolios.

With the reduced market purchase limit in Sensitivity X, more conservation resources, battery energy storage and peaking capacity resources are added to fill the energy that would have been purchased in the market.

The builds of portfolio WX are nearly identical to portfolio X, the only difference is an increase in demand-side resources. The construction timeline of resources is also the same in WX and X.

Figure 8-138: Portfolio Additions – Mid Scenario and Sensitivities WX, W and X

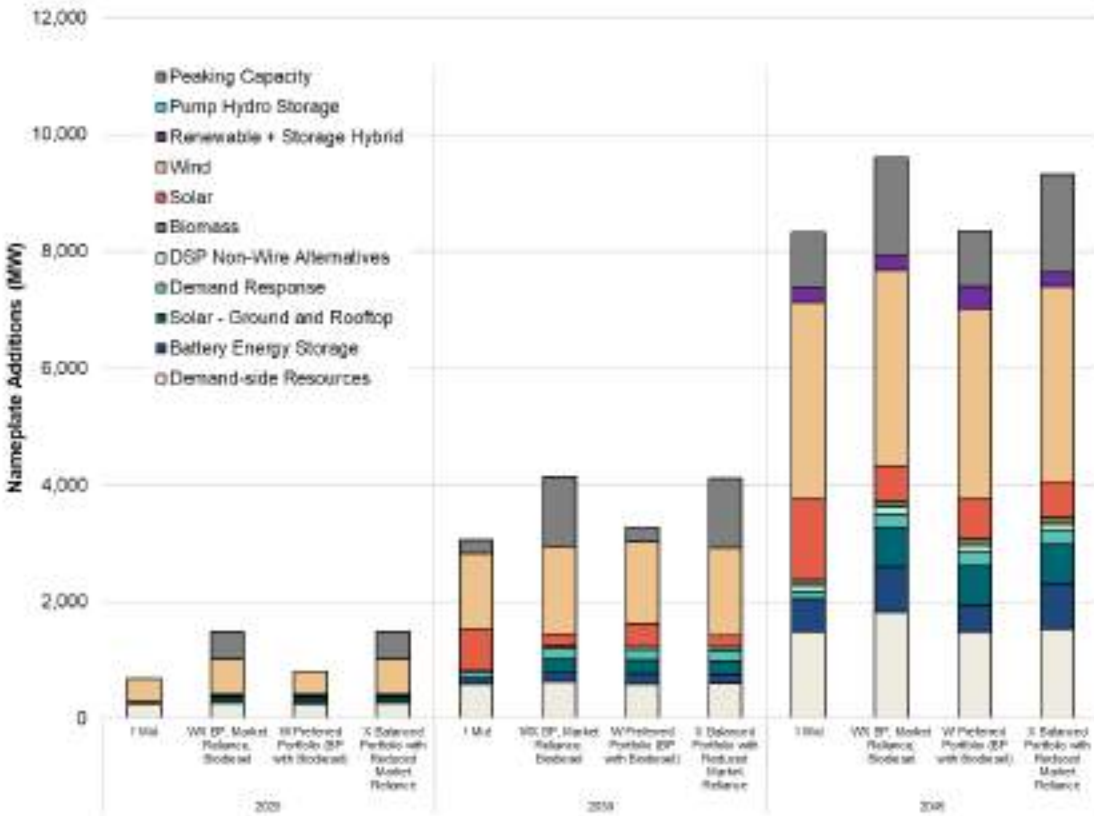
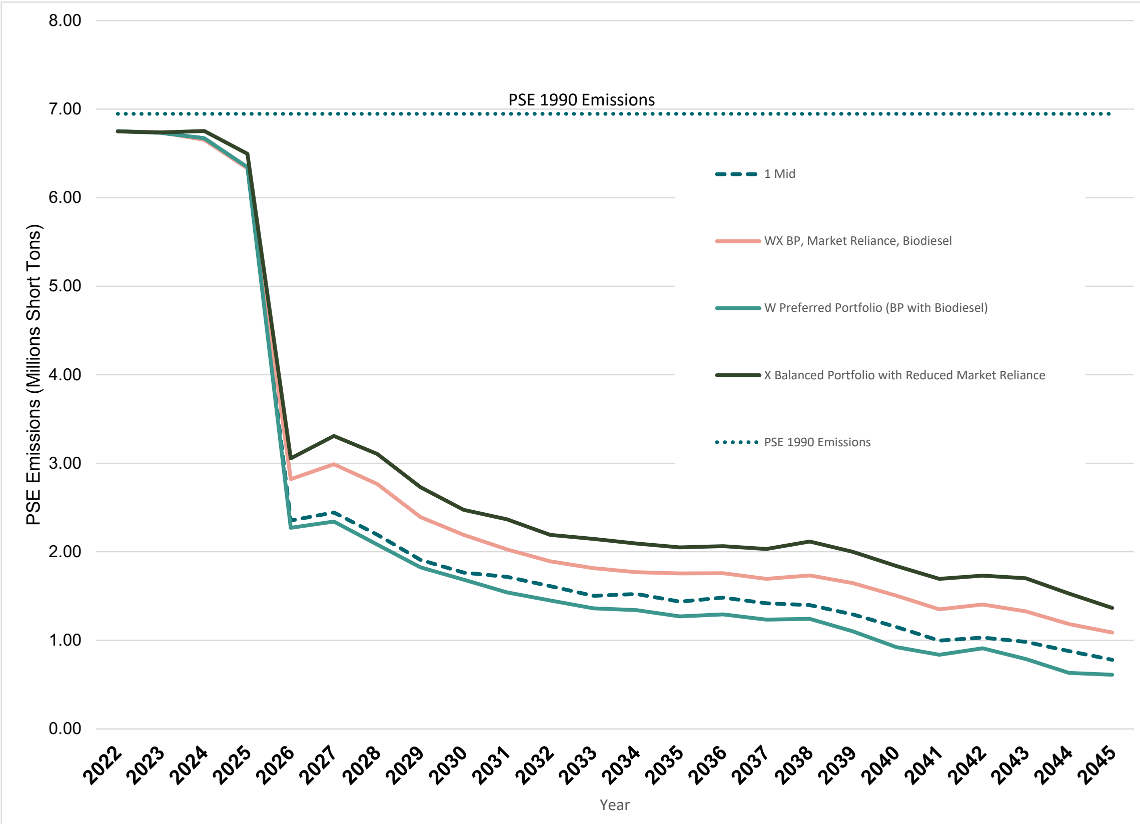


Figure 8-139: Portfolio Additions – Mid Scenario and Sensitivities WX, W and X

Resource Additions by 2045	1 Mid	WX BP, Market Reliance, Biodiesel	W Preferred Portfolio (BP with Biodiesel)	X Balanced Portfolio with Reduced Market Reliance
Demand-side Resources	1,497 MW	1,824 MW	1,784 MW	1,824 MW
Battery Energy Storage	550 MW	775 MW	450 MW	775 MW
Solar - Ground and Rooftop	0 MW	680 MW	680 MW	680 MW
Demand Response	123 MW	217 MW	217 MW	217 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	4,066 MW	4,051 MW	4,066 MW
Biomass	90 MW	120 MW	105 MW	120 MW
Solar	1,393 MW	596 MW	696 MW	596 MW
Wind	3,350 MW	3,350 MW	3,250 MW	3,350 MW
Renewable + Storage Hybrid	250 MW	250 MW	375 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW	0 MW
Flexible Capacity	948 MW	1,677 MW	966 MW	1,677 MW

EMISSIONS. Figure 8-140 compares direct GHG emissions from Sensitivities WX, W and X to the Mid Scenario. For Sensitivity W, emissions decrease compared to the Mid Scenario, through use of biodiesel for peaking capacity resources. For Sensitivity X, emissions increase compared to the Mid Scenario due to increased additions of peaking capacity resources. Consistent with the findings of sensitivities W and X, reducing market purchases and using of biodiesel have opposite effects on overall portfolio emissions. The overall emissions of portfolio WX fall between W and X.

Figure 8-140: Portfolio GHG Emissions – Mid Scenario and Sensitivity WX, W and X



Y. Maximum Customer Benefit

Maximizing customer benefits is a complex task. Numerous customer benefit indicators exist, and often increasing the benefit of one indicator reduces the benefit of another. Therefore, PSE's approach to maximizing customer benefits was to model a wide range of possible portfolios, many of which maximized specific customer benefit indictors. Through isolating and maximizing specific customer benefit indicators, it is possible to see trade-offs in other customer benefits and opportunities to balance those tradeoffs.

The following list highlights portfolios that maximize specific customer benefit indicators:

- Mid Scenario – The Mid Scenario, in addition to providing a basis for comparison to other sensitivities, is designed to be among the lowest cost portfolios. Over the 24-year timeframe, the Mid Scenario is ranked fourth best in terms of portfolio cost. Sensitivities G, I and M rank higher, but have only marginally lower portfolio costs and all include unique inputs which bring their costs down. Portfolio cost is directly related to the energy costs passed on to customers and should be minimized to keep energy burdens low. The AURORA portfolio model is an economic model which seeks to minimize cost; therefore, increasing other customer benefit indicators typically results in increased portfolio costs. In developing a preferred portfolio, PSE must balance portfolio cost with other customer benefit indicators.

- Sensitivity C – The distributed, transmission limited sensitivity maximizes utilization of distributed energy resources. Distributed energy resources provide significant transmission and distribution benefits, offsetting the need for long-distance transmission. In Sensitivity, C thermal resources were necessary to provide capacity during periods of peak demand resulting in higher emissions than most other portfolios. Distributed resources are also expensive compared to utility-scale resources, resulting in higher portfolio costs, but they offset potential transmission risk. Adding more distributed resources helps to optimize the customer benefit areas of environment and resiliency.
- Sensitivity N, the 100 percent renewable by 2030 sensitivity maximizes several customer benefit indicators through transitioning to a clean energy portfolio ahead of CETA targets. Sensitivity N2 (pumped hydro storage) obtains the highest rank for the 24-year timeframe for the customer benefit areas of Climate Change, Air Quality and Market Position. Sensitivity N1 (batteries) ties for the highest rank in Air Quality and achieves the highest rank in Resiliency. Sensitivity N1 uses batteries to provide capacity resulting in a much more resilient portfolio than Sensitivity N2, which relies on centralized pumped hydro storage for capacity. Early adoption of clean energy technologies carries significant benefits. However, these benefits are balanced by extremely high portfolio costs. Furthermore, both Sensitivities N1 and N2 score low in the Resource Adequacy customer benefit indicator area due to the reliance on short-term energy storage for capacity. These short-term energy storage resources are energy limited, exposing PSE's customers to risk in the event of long-duration peak events.

Other portfolios assessed in this IRP provide varying degrees of customer benefits. Results for these portfolios are available earlier in this chapter. Of particular importance, are the Balanced Portfolios (Sensitivities V, W and WX) which do not seek to maximize any single customer benefit, but to provide meaningful contributions to customer benefit indicators to develop a well-rounded, low-risk portfolio.

Z. No DSR

This sensitivity examines the value of conservation and demand response resources to the portfolio.

Baseline: Conservation resources are selected when they are cost-effective.
Sensitivity Z > No conservation or demand response measures are included.

KEY FINDINGS. Without demand response or conservation, the cost of the Mid Scenario portfolio increases by $2.48 billion, building additional solar and storage resources to reach CETA compliance, and building two additional frame peakers to maintain peak capacity.

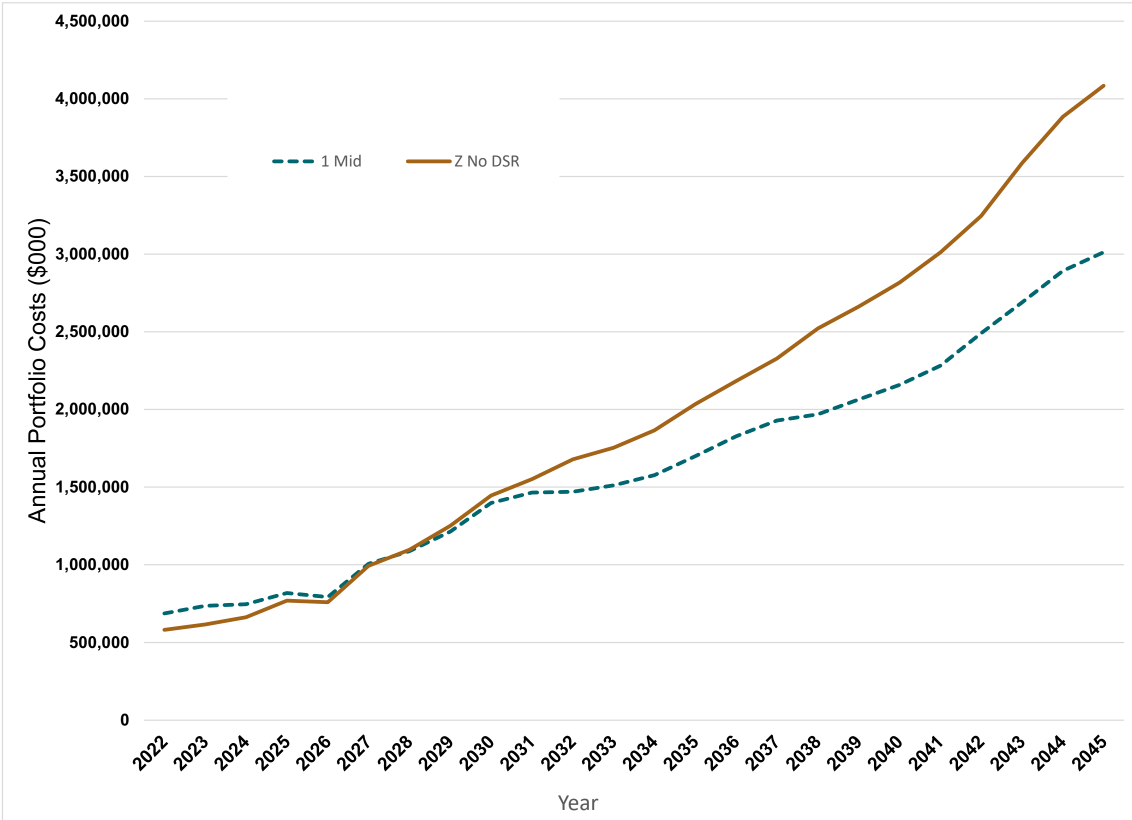
ASSUMPTIONS. Sensitivity Z keeps all the Mid Scenario modeling assumptions, except no conservation or demand response measures are included.

ANNUAL PORTFOLIO COSTS. Overall, the annual portfolio costs of Sensitivity Z and the Mid Portfolio are similar until 2030, when the removal of demand response and conservation from the portfolio reduce the costs of Portfolio Z. After 2030, growing demand that is unchecked by conservation measures combines with CETA renewable need to accelerate resource need and increase costs. Despite the up-front investment, DSR saves the Mid Scenario $2.48 billion by reducing demand and preventing the need for new resources, both renewable and thermal.

Figure 8-141: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity Z

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
Z	No DSR	$17.54	$5.56	$23.10	$2.48

Figure 8-142: Annual Portfolio Costs – Mid Scenario and Sensitivity Z



RESOURCE ADDITIONS. Figures 8-143 and 8-144 compares the nameplate capacity additions of the Mid Scenario and Sensitivity Z portfolios. To meet increased demand, Portfolio Z adds an additional two frame peakers (474 MW), 1,195 MW of eastern Washington solar, 250 MW of hybrid resources and 700 MW of 4- and 6-hour flow batteries by 2045. Solar builds begin to outpace the Mid Scenario as early as 2024, and a second round of builds enters late in the portfolio. For example, in Sensitivity Z, Washington wind capacity reaches 2,000 MW by 2039 with no further additions for the rest of the planning period compared to 1,500 MW of wind added in the Mid Scenario in 2039 which goes on to increase to 1,900 by 2045.

Figure 8-143: Portfolio Additions – Mid Scenario and Sensitivity Z

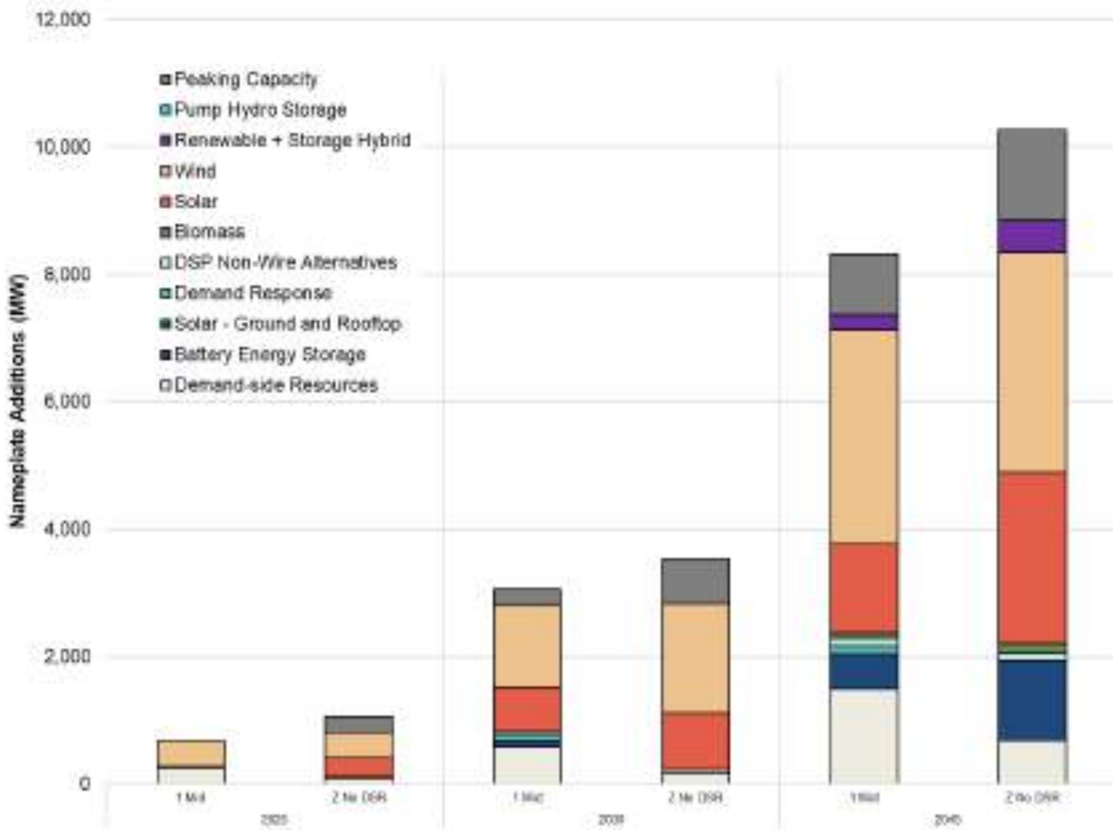


Figure 144: Portfolio Additions – Mid Scenario and Sensitivity Z

Resource Additions by 2045	1 Mid	Z No DSR
Demand-side Resources	1,497 MW	690 MW
Battery Energy Storage	550 MW	1,250 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	0 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	6,288 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	2,688 MW
Wind	3,350 MW	3,450 MW
Renewable + Storage Hybrid	250 MW	500 MW
Pumped Hydro Storage	0 MW	0 MW
Flexible Capacity	948 MW	1,422 MW

Other

AA. Montana Wind + Pumped Storage Hydro

This sensitivity examines the value of adding a hybrid resource early in the planning period.

Baseline: Hybrid resources are selected when they are cost-effective.
Sensitivity AA > A Montana wind plus pumped hydro storage hybrid resource is substituted for the eastern Montana wind resource added to the Mid Scenario in the year 2028.

KEY FINDINGS. Early addition of a hybrid Montana wind plus pumped hydro resource does not add meaningful value the portfolio. Portfolio costs are slightly higher and emissions remain the same or increase slightly. Peaking capacity additions are postponed by one or two years but are still added to the portfolio.

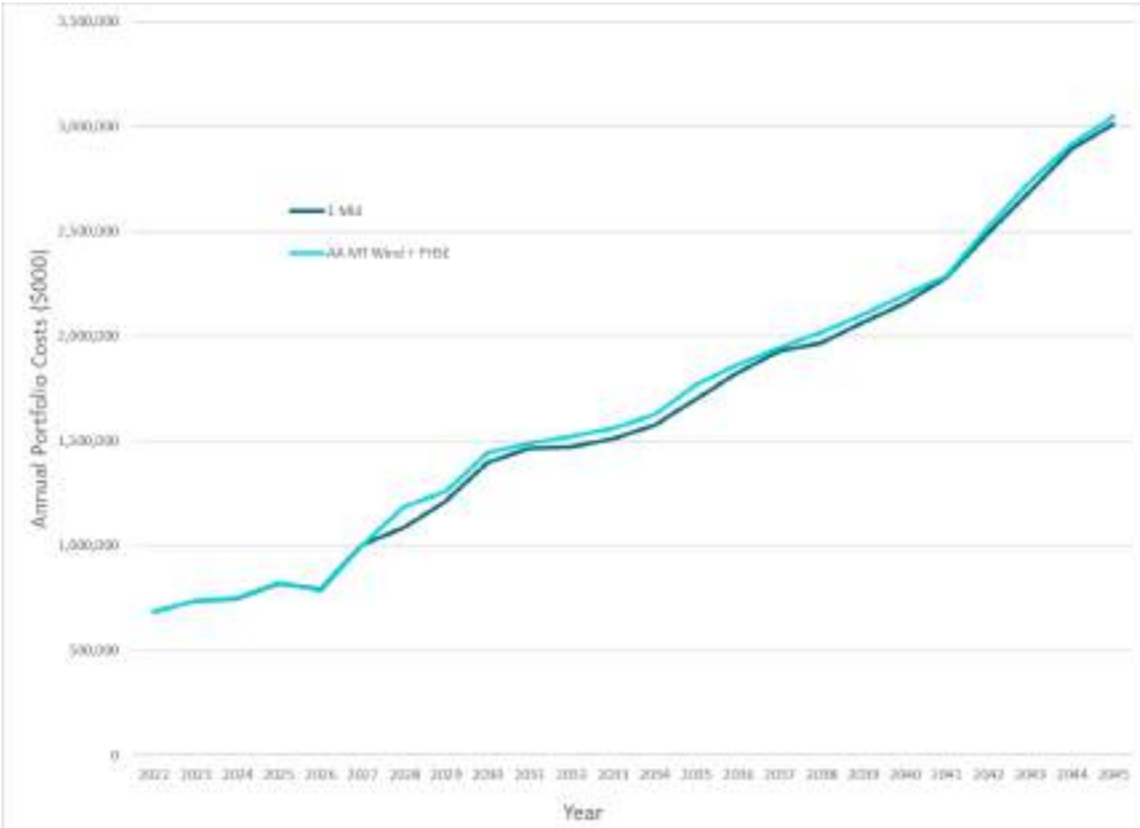
ASSUMPTIONS. Sensitivity AA keeps all the Mid Scenario modeling assumptions, except a Montana wind plus pumped storage hydro resource is forced into the portfolio in the year 2028.

ANNUAL PORTFOLIO COSTS. Overall, the annual portfolio costs of Sensitivity AA and the Mid Portfolio are similar except for the spike in revenue requirement in the year 2028 to purchase the Montana wind plus pumped hydro hybrid instead of the eastern Montana wind resource. The more costly revenue requirement of the hybrid resource is seen for the remainder of the planning period. Otherwise, portfolio costs are nearly identical.

Figure 8-145: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity AA

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
AA	MT wind + PHES	$15.84	$5.16	$20.99	$0.37

Figure 8-146: Annual Portfolio Costs – Mid Scenario and Sensitivity AA



RESOURCE ADDITIONS. Figures 8-147 and 8-148 compare the nameplate capacity additions of the Mid Scenario and Sensitivity AA portfolios. Resource additions are extremely similar between the two portfolios, the only notable differences being that Sensitivity AA adds the forced MT wind plus pumped hydro addition in 2028, 250 MW less independent storage and 300 MW less solar. Sensitivity AA adds peaking capacity on a slightly delayed schedule, but reaches the same amount of peaking capacity by 2045. Both portfolios select conservation Bundle 10.

Figure 8-147: Portfolio Additions – Mid Scenario and Sensitivity AA

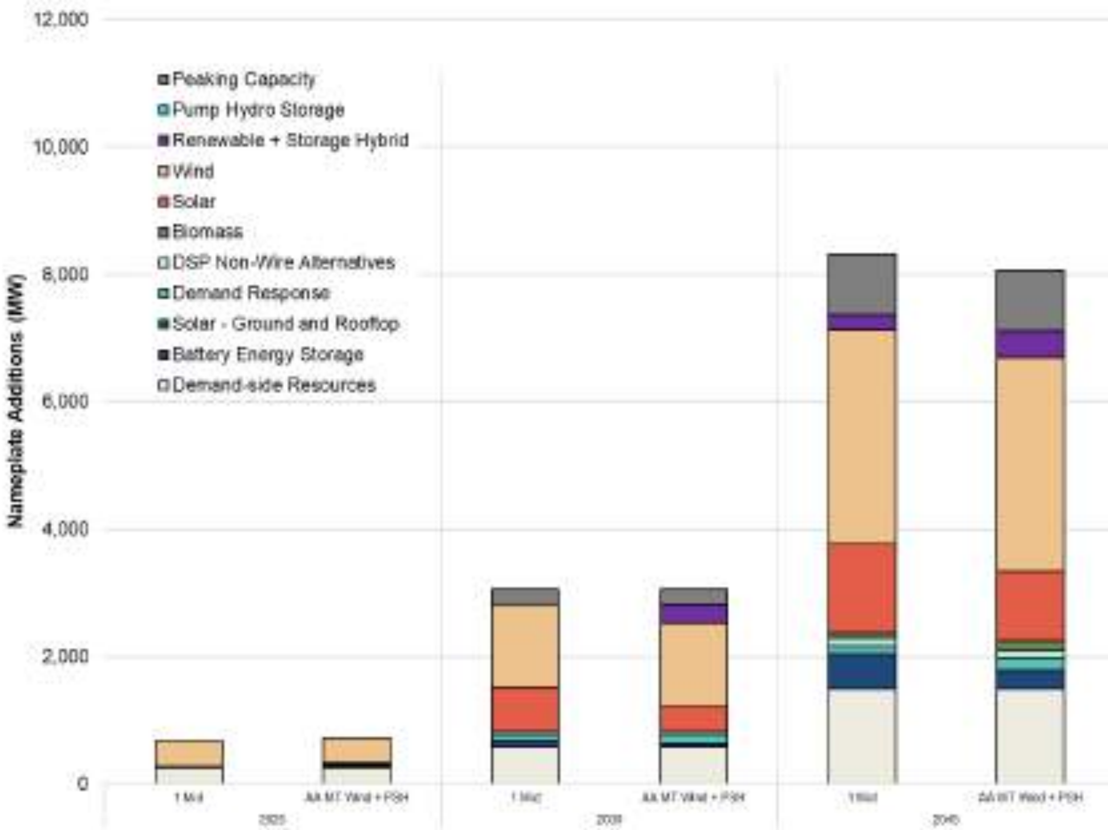
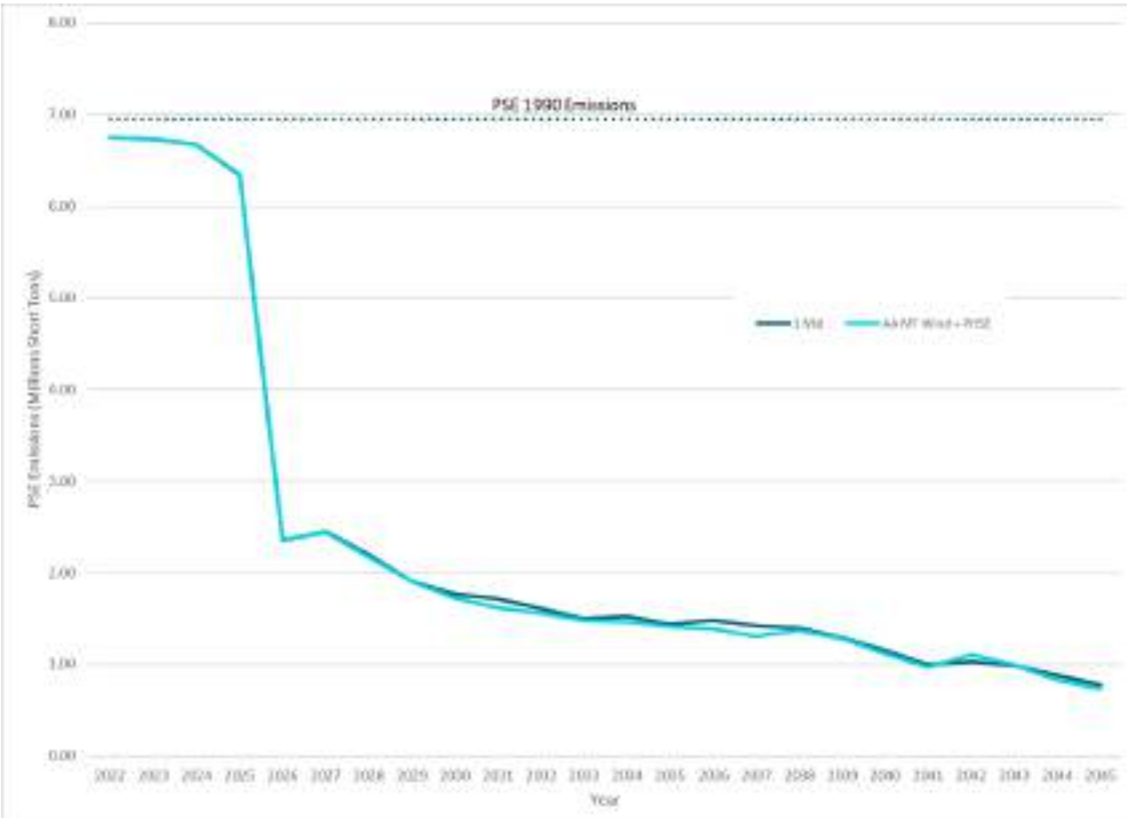


Figure 8-148: Portfolio Additions – Sensitivity AA

Resource Additions by 2045	1 Mid	AA MT Wind + PHES
Demand-side Resources	1,497 MW	1,497 MW
Battery Energy Storage	550 MW	300 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	182 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,594 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	1,094 MW
Wind	3,350 MW	3,350 MW
Renewable + Storage Hybrid	250 MW	425 MW
Pumped Hydro Storage	0 MW	0 MW
Flexible Capacity	948 MW	948 MW

EMISSIONS. Figure 8-149 compares direct GHG emissions from Sensitivity AA to the Mid Scenario. Both portfolios have very similar direct emissions profiles.

Figure 8-149: Direct Emissions – Mid Scenario and Sensitivity AA



8. CUSTOMER BENEFITS ANALYSIS RESULTS

This section presents the results of the Customer Benefit Analysis. Not all portfolios were included in the Customer Benefit Analysis. To be included in the Customer Benefit Analysis, portfolios must meet the following criteria:

- Maintain consistency across demand and electric price forecasts
  - This criteria removed portfolios such as the Low and High Scenarios which varied demand and electric price inputs
- Must meet CETA requirements
  - This criteria removed portfolios such as Sensitivity T No CETA which does not include the CETA clean energy targets as a constraint.
- Represent current carbon regulation
  - This criteria removed portfolios such as Sensitivity L, SCGHG as a Fixed Cost Plus a Federal CO_2 Tax, which models a federal carbon tax which is yet to be enacted.

These criteria limit the analysis to portfolios that are solving for the same fundamental goals and are built from the same fundamental inputs. In other words, it allows for an “apples to apples” comparison between all the selected portfolios. The Customer Benefit Analysis is described earlier in this chapter.

Customer Benefit Analysis results are presented for two timeframes, 2031 and 2045. These timeframes correspond to the 10-year Clean Energy Action Plan and 24-year IRP planning horizons, respectively. There is value in understanding how customer benefits evolve over the planning horizon of a portfolio, and benefits which only manifest themselves in the latest years of the planning horizon may hold less value, as these years hold the most uncertainty.

All Customer Benefit Analysis results and accompanying calculations are also provided in Appendix H.

Figures 8-150 and 8-151 present the portfolio outputs selected to represent customer benefit indicators (CBIs) for the 10-year and 24-year timeframes, respectively. These outputs have been color coded, from red (least benefit) to green (most benefit).

Figure 8-150: 10-year Customer Benefit Analysis – Portfolio Customer Benefit Indicators – Values

Customer Benefit Indicator Area	Cost	Climate Change		Air Quality			Market Position	Environment				Resource Adequacy	Resiliency
Sensitivity / Customer Benefit Indicator	Portfolio Cost ($ Billions, NPV)	SCGHG ($ Billions, NPV)	CO2 Emissions from Generation includes upstream emissions (Short tons)	SO2	NOx	PM	Market Purchases (MWh)	Utility Scale Renewable Generation (MWh)	Energy Efficiency, Distribution Efficiency and Codes and Standards (MWh)	Distributed Solar: DSP NWA, Rooftop, Ground, Customer net metering (MWh)	Customer Programs: Green Direct, Green Power, Qualifying Facilities (MWh)	Demand Response (Nameplate MW)	Distributed energy storage includes DSP NWA (Nameplate MW)
3 Mid	$6.65	$3.43	1,700,538	15.3	695	51.7	2,999,778	12,917,098	3,270,127	42,882	1,251,324	98	338
A Renewable Overgeneration	$7.09	$3.06	1,041,572	8.8	953	38.4	3,405,768	12,388,230	3,299,397	42,882	1,244,115	348	268
C Distributed Transmission	$6.65	$3.47	1,735,375	15.4	1,050	54.1	3,416,781	12,836,902	3,310,807	73,759	1,250,798	317	98
D Transmission/build constraints - time delayed (option 2)	$6.68	$3.45	1,689,008	15.5	692	51.6	3,308,201	12,890,995	3,314,809	42,882	1,251,005	338	88
F 6-Yr DSR Ramp	$6.70	$3.45	1,686,138	15.3	683	51.1	3,226,151	12,913,582	3,240,695	42,882	1,251,092	333	303
G NE DSR	$6.57	$3.48	1,738,991	15.7	704	52.2	3,301,909	12,811,285	3,158,255	42,882	1,251,120	345	98
H Social Discount DSR	$6.57	$3.51	1,739,776	15.7	704	52.2	3,347,718	13,145,408	2,889,283	42,882	1,251,122	309	88
I SCGHG Dispatch Cost - LTCE Model	$6.61	$3.44	1,696,929	15.4	688	51.5	3,367,791	12,722,327	3,270,127	42,882	1,251,025	338	88
K ARS Upstream Emissions	$6.71	$3.48	1,736,261	15.6	702	52.0	3,085,879	12,883,792	3,270,127	42,882	1,251,337	322	88
M Alternative Fuel for Peakers - Biodiesel	$6.67	$3.00	1,517,836	13.1	555	43.9	3,318,583	12,741,689	3,410,803	42,882	1,251,103	337	313
N1 100% Renewable by 2030 Batteries	$10.86	$2.92	-	-	-	-	3,712,665	17,891,571	2,877,410	42,882	1,248,278	45	17,268
N2 100% Renewable by 2030 PSH	$14.92	$2.23	-	-	-	-	427,851	24,758,565	2,376,605	42,386	1,135,805	45	98
O1 100% Renewable by 2045 Batteries	$7.51	$3.46	1,491,992	13.7	497	42.6	3,365,936	13,363,504	2,879,010	42,882	1,251,098	99	6,138
O2 100% Renewable by 2045 PSH	$13.77	$2.96	1,405,497	12.1	457	40.6	1,418,112	16,378,054	3,318,519	42,882	1,250,373	375	98
P1 No Thermal Before 2030, 2Hr Lilon	$13.46	$3.88	1,890,588	20.3	1,358	68.6	5,808,370	12,405,127	3,158,254	42,882	1,243,805	116	3,738
P2 No Thermal Before 2030, PHES	$9.94	$3.19	1,457,354	13.8	479	45.5	2,695,865	14,828,699	2,878,683	42,882	1,250,530	98	663
P3 No Thermal Before 2030, 4Hr Lilon	$15.36	$3.91	1,888,834	20.9	1,490	75.4	6,659,481	11,885,433	3,158,254	42,882	1,240,334	94	3,963
V1 Balanced portfolio	$6.90	$3.42	1,617,638	14.3	862	48.6	2,975,094	11,888,295	3,270,127	428,908	1,088,083	305	238
V2 Balanced portfolio + MT Wind and PSH	$7.13	$3.43	1,596,777	14.1	608	47.1	3,366,282	11,375,806	3,270,127	428,908	2,080,066	305	312
V3 Balanced portfolio + 6 Year DSR	$6.84	$3.39	1,677,083	15.2	675	50.7	3,039,087	11,789,240	3,246,605	428,908	2,080,038	305	212
W Preferred Portfolio (BP with Biodiesel)	$6.91	$3.39	1,531,671	13.2	787	44.9	3,015,301	12,736,388	3,270,127	428,908	1,251,118	305	238
AA MT Wind + PHSE	$6.78	$3.45	1,610,870	14.3	613	47.8	3,207,371	12,633,279	3,270,127	42,882	1,251,134	128	88

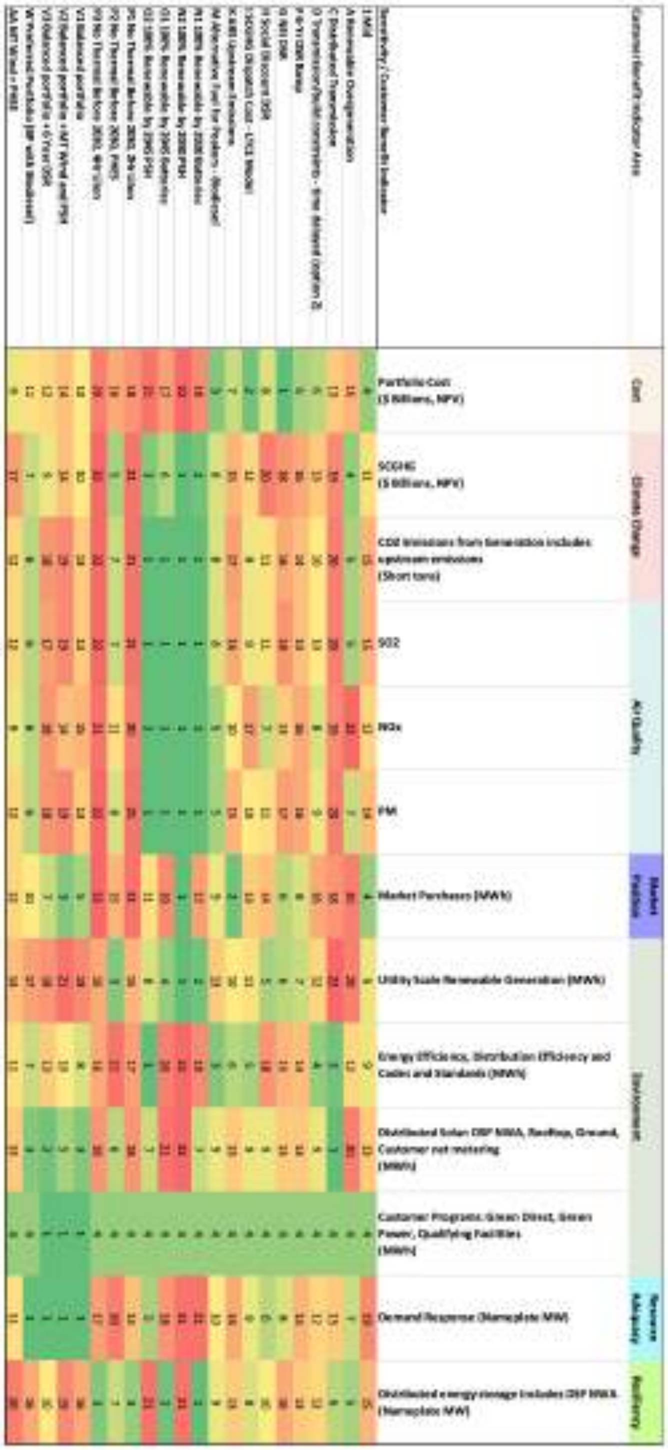
Figure 8-151: 24-year Customer Benefit Analysis – Portfolio Customer Benefit Indicators – Values

Figures 8-152 and 8-153 rank each of the selected portfolios on each of the CBIs for the 10-year and 24-year timeframes, respectively.

Figure 8-152: 10-year Customer Benefit Analysis – Portfolio Customer Benefit Indicators – Ranks

Customer Benefit Indicator Area	Cost	Climate Change		Air Quality			Market Position	Environment				Resource Adequacy	Resiliency
Sensitivity / Customer Benefit Indicator	Portfolio Cost ($ Billions, NPV)	SCGHG ($ Billions, NPV)	CO2 Emissions from Generation includes upstream emissions (Short tons)	SO2	NOx	PM	Market Purchases (MWh)	Utility Scale Renewable Generation (MWh)	Energy Efficiency, Distribution Efficiency and Codes and Standards (MWh)	Distributed Solar: DSP NWA, Rooftop, Ground, Customer net metering (MWh)	Customer Programs: Green Direct, Green Power, Qualifying Facilities (MWh)	Demand Response (Nameplate MW)	Distributed energy storage includes DSP NWA (Nameplate MW)
1 Mid	6	11	16	17	13	16	6	7	6	6	5	19	12
A Renewable Overgeneration	14	4	3	3	19	3	20	17	5	20	19	6	7
C Distributed Transmission	5	17	17	14	21	20	19	10	1	5	15	11	18
D Transmission/build constraints - time delayed (option 2)	8	14	15	16	12	15	14	9	1	6	14	9	14
F 6-Yr DSR Ramp	3	15	13	13	10	13	12	8	13	6	12	14	11
G NO DSR	1	19	18	19	16	18	11	11	15	6	7	7	18
H Social Discount DSR	2	20	19	20	15	19	10	8	21	6	6	15	17
I SCGHG Dispatch Cost - LTCE Model	4	12	14	15	11	14	18	15	6	6	13	10	18
K ARS Upstream Emissions	9	18	20	18	14	17	9	12	6	6	9	18	14
M Alternative Fuel for Peakers - Biodiesel	7	8	7	7	8	7	15	13	1	6	10	11	13
N1 100% Renewable by 2030 Batteries	18	3	1	1	1	1	4	1	20	17	18	21	1
N2 100% Renewable by 2030 PSH	22	1	1	1	1	1	1	1	22	22	22	21	19
O1 100% Renewable by 2045 Batteries	16	16	6	6	5	6	16	5	18	6	11	18	2
O2 100% Renewable by 2045 PSH	19	2	4	4	3	4	2	3	4	17	17	5	18
P1 No Thermal Before 2030, 2Hr Li-Ion	20	21	21	21	20	21	21	18	16	19	20	13	4
P2 No Thermal Before 2030, PHES	17	5	5	5	4	5	3	4	19	6	16	20	5
P3 No Thermal Before 2030, 4Hr Li-Ion	21	22	22	22	22	22	22	20	17	20	21	17	3
V1 Balanced portfolio	12	9	11	10	18	11	5	19	8	1	1	1	8
V2 Balanced portfolio + MT Wind and PSH	15	10	9	9	7	9	17	21	6	1	1	1	6
V3 Balanced portfolio + 6 Year DSR	11	6	12	12	9	12	8	21	13	1	3	1	10
W Preferred Portfolio (BP with Biodiesel)	13	7	8	8	17	8	7	14	6	1	8	1	8
AA MT Wind + PHSE	10	13	10	11	8	10	13	16	6	6	4	8	14

Figure 8-153: 24-year Customer Benefit Analysis – Portfolio Customer Benefit Indicators – Ranks



Figures 8-154 and 8-155 aggregate CBIs into customer benefit indicator areas and determine an overall portfolio rank from the seven CBI areas for the 10-year and 24-year timeframes, respectively.

Figure 8-154: 10-year Customer Benefit Analysis –
Portfolio Customer Benefit Indicator Areas and Overall Portfolio Ranks

Overall Rank	Sensitivity / Customer Benefit Indicator Area	Cost	Climate Change	Air Quality	Market Position	Environment	Resource Adequacy	Resiliency	Overall Avg
12	1 Mid	6	14	15	6	6	19	12	11.1
9	A Renewable Overgeneration	14	4	8	20	15	6	7	10.6
20	C Distributed Transmission	5	17	18	19	8	11	18	13.7
15	D Transmission/build constraints - time delayed (option 2)	8	15	14	14	8	9	14	11.6
11	F 6-Yr DSR Ramp	3	14	12	12	10	14	11	10.8
16	G NEI DSR	1	19	18	11	10	7	18	11.8
18	H Social Discount DSR	2	20	18	10	10	15	17	13.0
17	I SCGHG Dispatch Cost - LTCE Model	4	13	13	18	10	10	18	12.3
19	K ARS Upstream Emissions	9	19	16	9	8	16	14	13.1
8	M Alternative Fuel for Peakers - Biodiesel	7	8	7	15	8	11	13	9.7
5	N1 100% Renewable by 2030 Batteries	18	2	1	4	14	21	1	8.8
14	N2 100% Renewable by 2030 PSH	22	1	1	1	17	21	18	11.5
13	O1 100% Renewable by 2045 Batteries	16	11	6	16	10	18	2	11.2
4	O2 100% Renewable by 2045 PSH	19	3	4	2	10	5	18	8.7
21	P1 No Thermal Before 2030, 2Hr LiIon	20	21	21	21	18	13	4	16.8
7	P2 No Thermal Before 2030, PHES	17	5	5	3	11	20	5	9.4
22	P3 No Thermal Before 2030, 4Hr LiIon	21	22	22	22	20	17	3	18.1
2	V1 Balanced portfolio	12	10	13	5	7	1	8	8.0
6	V2 Balanced portfolio + MT Wind and PSH	15	10	8	17	8	1	6	9.2
3	V3 Balanced portfolio + 6 Year DSR	11	9	11	8	10	1	10	8.5
1	W Preferred Portfolio (BP with Biodiesel)	13	8	11	7	7	1	8	7.8
10	AA MT Wind + PHSE	10	12	10	13	8	8	14	10.6

Figure 8-155: 24-year Customer Benefit Analysis – Portfolio Customer Benefit Indicator Areas and Overall Portfolio Ranks

Overall Rank	Sensitivity / Customer Benefit Indicator Area	Cost	Climate Change	Air Quality	Market Position	Environment	Resource Adequacy	Resiliency	Overall Avg
14	1 Mid	4	13	14	4	9	19	15	11.1
13	A Renewable Overgeneration	15	5	11	20	14	7	5	11.0
20	C Distributed Transmission	13	20	20	18	7	13	6	13.8
11	D Transmission/build constraints - time delayed (option 2)	6	12	9	16	7	12	12	10.5
17	F 6-Yr DSR Ramp	5	15	15	8	10	15	13	11.5
10	G NEI DSR	1	17	16	6	10	8	16	10.5
8	H Social Discount DSR	8	16	10	14	9	6	10	10.3
3	I SCGHG Dispatch Cost - LTCE Model	2	11	12	13	7	9	8	8.8
12	K ARS Upstream Emissions	7	16	14	2	8	16	13	10.8
1	M Alternative Fuel for Peakers - Biodiesel	3	8	6	9	7	10	9	7.5
6	N1 100% Renewable by 2030 Batteries	19	2	1	17	8	21	1	9.8
15	N2 100% Renewable by 2030 PSH	22	1	1	1	12	21	21	11.3
9	O1 100% Renewable by 2045 Batteries	17	4	1	19	12	18	2	10.4
5	O2 100% Renewable by 2045 PSH	21	2	1	11	5	5	21	9.4
21	P1 No Thermal Before 2030, 2Hr LiIon	18	21	21	21	14	14	4	16.0
18	P2 No Thermal Before 2030, PHES	16	6	9	15	9	20	7	11.6
22	P3 No Thermal Before 2030, 4Hr LiIon	20	22	22	22	14	17	3	17.0
4	V1 Balanced portfolio	10	12	14	5	8	1	16	9.3
16	V2 Balanced portfolio + MT Wind and PSH	14	17	17	3	9	1	19	11.4
7	V3 Balanced portfolio + 6 Year DSR	12	14	18	7	9	1	10	10.0
2	W Preferred Portfolio (BP with Biodiesel)	11	7	6	10	8	1	16	8.3
19	AA MT Wind + PHSE	9	15	11	12	11	11	20	12.6

Figure 8-156 summarizes the overall portfolio rank for both the 10-year and 24-year timeframes. Generally, portfolios that ranked well in the 10-year timeframe also ranked well in the 24-year timeframe. However, there are notable exceptions, including Sensitivities I and P2.

Sensitivity I modeled the SCGHG as a dispatch cost in the LTCE model. Sensitivity I has a poorer overall rank in the 10-year timeframe but improves to be among the top-ranked portfolios in the 24-year timeframe. This suggests that Environmental and Resiliency benefits, which this portfolio ultimately scores well in, do not provide meaningful benefits until the end of the modeling horizon, and that other portfolios should be considered to deliver benefits as early as possible.

Sensitivity P2 forced the selection of pumped hydro storage resources before any flexible capacity could be added to the portfolio. Sensitivity P2 is a well-ranked portfolio in the 10-year timeframe but drops to near the bottom of the rankings in the 24-year time horizon. This suggests that too much focus on early adoption of storage resources is a costly endeavor that sets up the portfolio to be reliant on large quantities of market purchases to charge the storage resources.

Figure 8-156: Overall Portfolio Rank by 10-year and 24-year Timeframe

	10-year	24-year
1 Mid	12	14
A Renewable Overgeneration	9	13
C Distributed Transmission	20	20
D Transmission/build constraints - time delayed (option 2)	15	11
F 6-Yr DSR Ramp	11	17
G NEI DSR	16	10
H Social Discount DSR	18	8
I SCGHG Dispatch Cost - LTCE Model	17	3
K AR5 Upstream Emissions	19	12
M Alternative Fuel for Peakers - Biodiesel	8	1
N1 100% Renewable by 2030 Batteries	5	6
N2 100% Renewable by 2030 PSH	14	15
O1 100% Renewable by 2045 Batteries	13	9
O2 100% Renewable by 2045 PSH	4	5
P1 No Thermal Before 2030, 2Hr LiIon	21	21
P2 No Thermal Before 2030, PHES	7	18
P3 No Thermal Before 2030, 4Hr LiIon	22	22
V1 Balanced portfolio	2	4
V2 Balanced portfolio + MT Wind and PSH	6	16
V3 Balanced portfolio + 6 Year DSR	3	7
W Preferred Portfolio (BP with Biodiesel)	1	2
AA MT Wind + PHSE	10	19

As shown in Figure 8-156, the Customer Benefit Analysis suggests Sensitivity M as the portfolio that provides the greatest benefit to PSE customers in the 24-year IRP timeframe. PSE recognizes that this portfolio has many desirable attributes including low cost, low climate change impacts and low impacts on air quality. However, Sensitivity M does not include very many distributed energy resources, which play an important role in balancing utility-scale renewable investments and transmission constraints while also meeting local distribution system needs and improving customer benefits. Therefore, PSE has selected Sensitivity W Balanced Portfolio with Biodiesel as the preferred portfolio. Sensitivity W provides many of the same benefits as Sensitivity M, but also includes greater investment in distributed energy resources. Furthermore, Sensitivity W is shown to provide the greatest benefit in the 10-year CEAP timeframe. This shows that early investment in these distributed resources provides benefits over the entire span of the modeling horizon, whereas Sensitivity M benefits are realized most strongly in the later years.

9. SUMMARY OF STOCHASTIC PORTFOLIO ANALYSIS

With stochastic risk analysis, PSE tests the robustness of different portfolios. In other words, PSE seeks to know how well the portfolio might perform under a range of different conditions. To achieve this purpose, PSE runs select portfolios through 310 simulations, or draws,[7] that vary power prices, gas prices, hydro generation, wind generation, solar generation, load forecasts (energy and peak), and plant forced outages. From this analysis, PSE can quantify the risk of each portfolio. Four different portfolios were tested in the stochastic portfolio analysis. Figure 8-xx describes the four different portfolios.

Figure 8-157: Portfolios Tested for Stochastic Analysis

Portfolios Tested for Stochastic Analysis		
1	Mid Scenario	This is the optimal portfolio for the Base Scenario. It includes frame peakers for capacity and solar for the RPS.
W	Balanced Portfolio with Alternative Fuel for Peakers	This is the optimal portfolio for the Balanced Portfolio with Alternative Fuel for Peakers sensitivity. It includes distributed energy resources ramped in over time and more customer programs plus carbon-free combustion turbines using biodiesel as the fuel.
WX	Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak	This is the optimal portfolio for the Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak sensitivity. It includes distributed energy resources ramped in over time and more customer programs plus carbon-free combustion turbines using biodiesel as the fuel, along with a reduced access to the Mid-C market for both sales and purchases.
Z	No DSR	This portfolio is from the no DSR sensitivity.

7 / Each of the 310 simulations is for the twenty four-year IRP forecasting period, 2022 through 2045.

Risk Measures

The results of the risk simulation allow PSE to calculate portfolio risk. Risk is calculated as the average value of the worst 10 percent of outcomes (called TailVar90). This risk measure is the same as the risk measure used by the Northwest Power and Conservation Council (NPCC) in its power plans.

PSE also looked at annual volatility by calculating the standard deviation of the year-to-year percent changes in revenue requirements. A summary measure of volatility is the average of the standard deviations across the simulations, but this can be described by its own distribution as well. It is important to recognize that this does not reflect actual expected rate volatility. The revenue requirement used for portfolio analysis does not include rate base and fixed-cost recovery for existing assets. The annual volatility data can be found in Appendix H, Electric Analysis Inputs and Results.

Stochastic Results

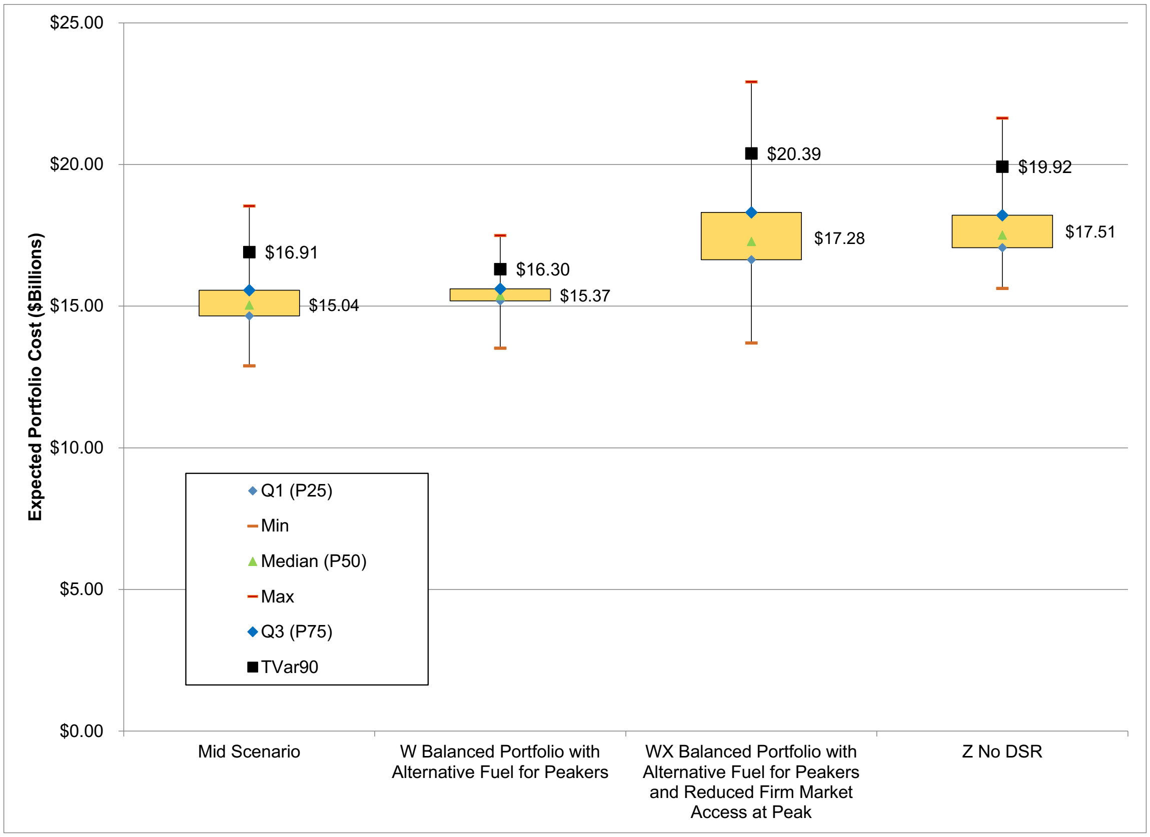
PSE's approach to the electric stochastic analysis holds portfolio resource builds constant across the 310 simulations. In reality, these resource forecasts serve as a guide, and resource acquisitions will be made based on the latest information available through the Request for Proposal and other acquisition processes. Nevertheless, the result of the risk simulation provides an indication of portfolio costs risk range under varying input assumptions. Figure 8-158 shows a comparison of the 24-year levelized costs for the deterministic run, the mean portfolio cost across 310 simulations, and the TailVar90 of portfolio cost for all 4 portfolios examined for the stochastic analysis. The mean portfolio cost of the 310 simulations is lower than the deterministic model run for 3 of the portfolios except for the No DSR portfolio.

Figure 8-158: Portfolio Costs across 310 Simulations

		24-year Levelized Costs (Billion $)					
Revenue Requirement	Portfolio	Deterministic	Difference from Mid	Mean	Difference from Mid	TVar90	Difference from Mid
1	Mid Scenario	$15.53	--	$15.18	--	$16.91	--
W	Balanced Portfolio with Alternative Fuel for Peakers	$16.10	$0.57	$15.42	$0.24	$16.30	($0.60)
WX	Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak	$18.78	$3.25	$17.53	$2.34	$20.39	$3.49
Z	No DSR	$17.54	$2.01	$17.74	$2.56	$19.92	$3.01

Figure 8-159 compares the expected portfolio costs for each portfolio. The vertical axis represents the costs and the horizontal axis represents the portfolio. The green triangle on each of the boxes represents the median for that particular portfolio. The interquartile range box represents the middle 50 percent of the data. The whiskers extending from either side of the box represent the minimum and maximum data values for the portfolio. The black square represents the TailVar90 which is the average value for the highest 10 percent of outcomes.

Figure 8-159: Range of Portfolio Costs across 310 Simulations



Key results of the analysis include:

- The interquartile range for Sensitivity W is comparatively narrow and has the lowest TailVar90 at $16.3 billion, suggesting that the overall expected portfolio costs are the least variable compared to the other portfolios.
- Sensitivity WX has the widest interquartile range and the highest TailVar90 at $20.4 billion, suggesting the highest risk in portfolio costs variability. With the reduction of market access, the risk shifts from Mid-C market price volatility to natural gas price volatility. Thermal resources replace the energy that is no longer available from the market. Portfolio fuel costs may increase or decrease depending on the simulation.
- In Sensitivity Z, the mean of the 310 simulations is $17.7 billion, which is $0.2 billion higher than the deterministic portfolio costs. In comparison to the Mid Scenario, the mean and the deterministic portfolio costs are higher for Sensitivity Z. This suggests that demand-side resources reduce both cost and market risk in portfolios.

Figures 8-160 to 8-161 below show the frequency distribution of portfolio cost for selected portfolios. Portfolio cost results for each simulation are sorted into “bins,” with each bin containing a narrow range of expected portfolio costs.

Figure 8-160 compares the Mid Scenario to Sensitivity W. The shorter right-hand tail and lower TailVar90 value of Sensitivity W indicate there is less risk associated with Sensitivity W than the Mid Scenario, despite the higher average portfolio cost.

Figure 8-160: Frequency Histogram of Expected Portfolio Cost (Billions $) – Mid Scenario vs. Sensitivity W

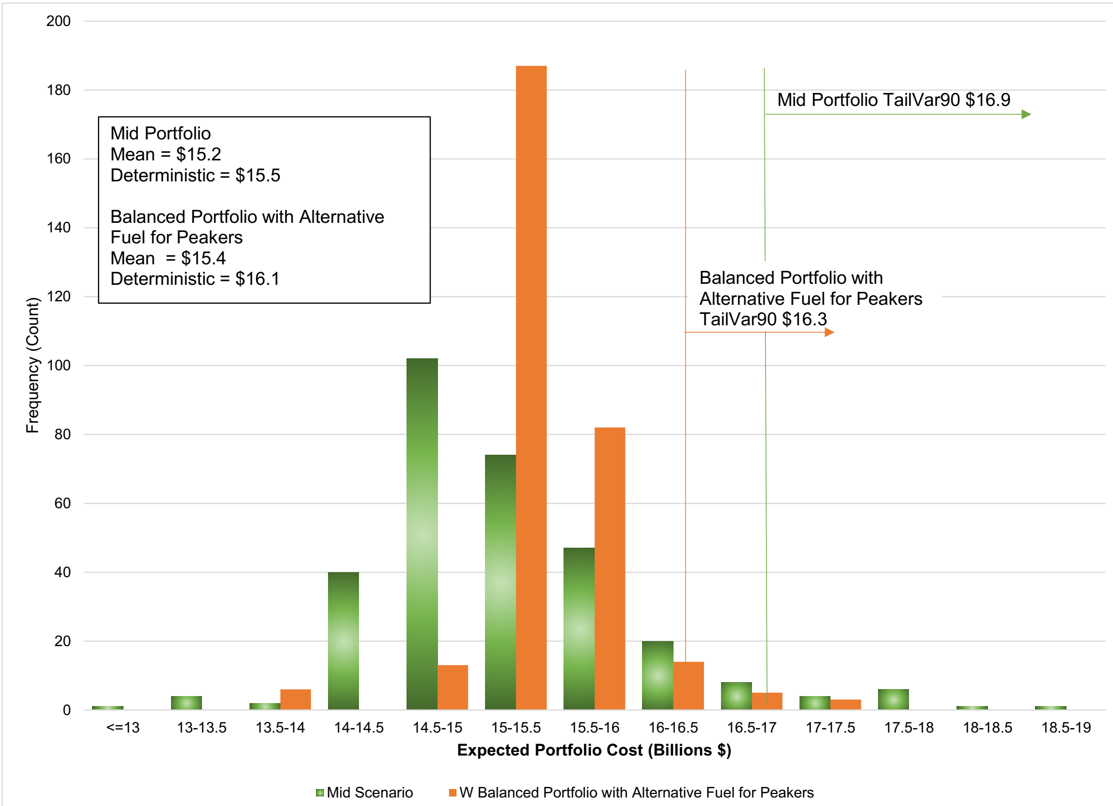


Figure 8-161 compares the Mid Scenario with Sensitivity Z. The longer tail, higher TailVar90 and higher average portfolio cost of Sensitivity Z indicate the demand-side resources are an effective way to reduce both portfolio cost and risk.

Figure 8-161: Frequency Histogram of Expected Portfolio Cost (Billions $) – Mid Scenario vs. Sensitivity Z

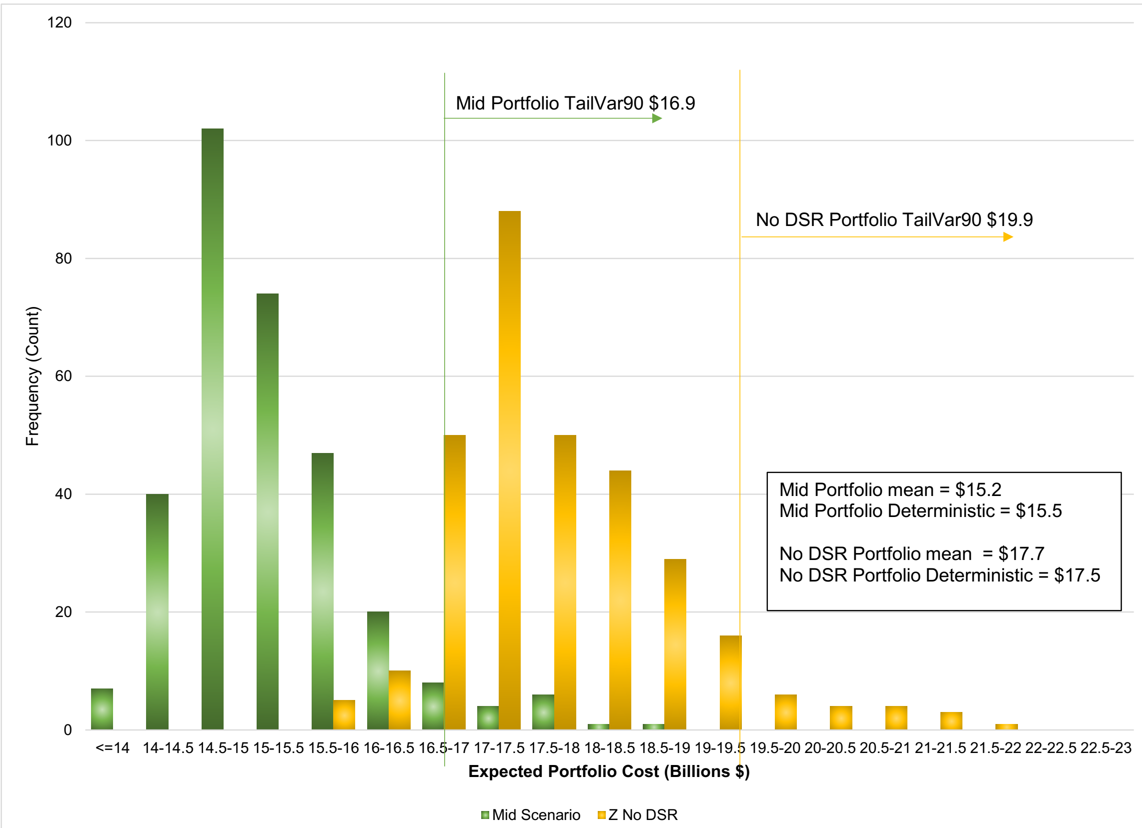
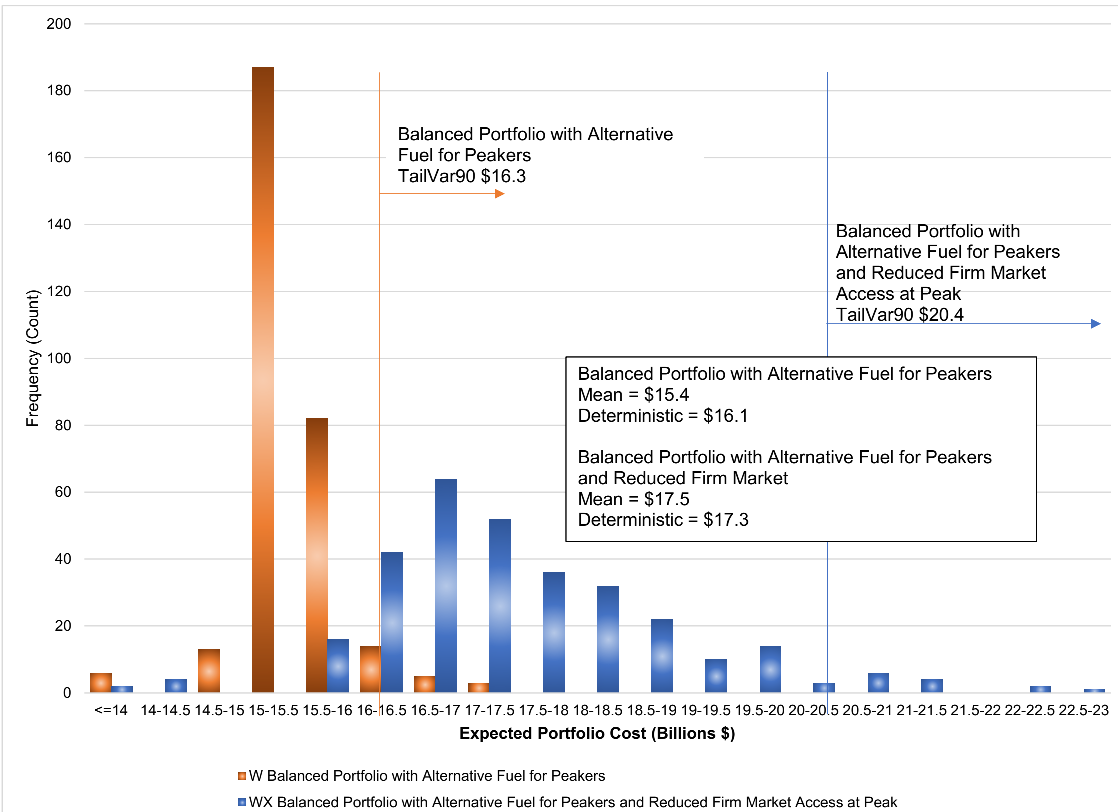


Figure 8-162 compares Sensitivity W with Sensitivity WX. The only difference between Sensitivity W and Sensitivity WX is the reduced access to market purchases during peak demand in Sensitivity WX. The longer tail, higher TailVar90 and higher average portfolio cost of Sensitivity WX show that it is both more costly and riskier than the Sensitivity W. As stated above, this added risk is associated with volatility of natural gas prices to fuel thermal resources used to replace market purchases during peak demand. Further study is needed and PSE will continue to evaluate the impacts of different types of resources.

Figure 8-162: Frequency Histogram of Expected Portfolio Cost (Billions $) – Preferred Portfolio vs. Preferred Portfolio with Market Reduction



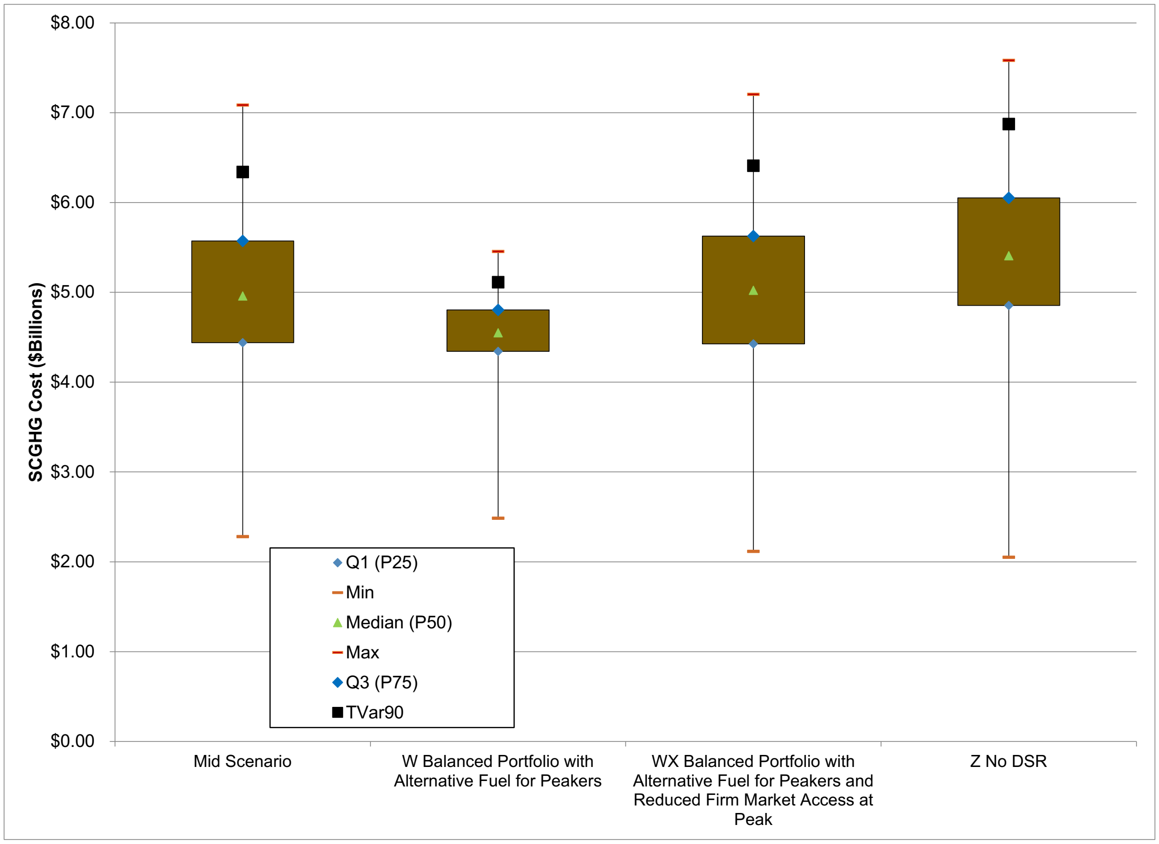
In addition to the expected portfolio costs, PSE also evaluated the expected SCGHG. Figure 8-163 and 8-164 below show a comparison of the 24-year levelized emissions costs for the deterministic run, the mean across 310 simulations, and the TailVar90 of all 4 portfolios.

Results are similar to the portfolio cost results discussed above. Sensitivity W shows the narrowest, and therefore least-risk, range of SCGHG.

Figure 8-163: SCGHG across 310 Simulations

		24-year Levelized Costs (Billion $)					
SCGHG	Portfolio	Emissions	Difference from Mid	Mean	Difference from Mid	TVar90	Difference from Mid
1	Mid Scenario	$5.09	--	$4.98	--	$4.98	--
W	Balanced Portfolio with Alternative Fuel for Peakers	$4.96	($0.13)	$4.54	($0.44)	$4.54	($0.44)
WX	Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak	$4.74	($0.35)	$5.02	$0.47	$6.41	$1.43
Z	No DSR	$5.56	$0.47	$5.42	$0.41	$6.87	$1.90

Figure 8-164: Range of SCGHG across 310 Simulations



10. ELECTRIC DELIVERY SYSTEM ANALYSIS

Overview

PSE's electric delivery system is responsible for delivering electricity safely, reliably and on demand. PSE is also responsible for meeting all regulatory requirements that govern the system. To accomplish this, we must do the following.[8]

- Operate and maintain the system safely and efficiently on an annual, daily and real-time basis.
- Ensure the system meets both peak demands and day-to-day demands at a local level and system level.
- Meet state and federal regulations and complete compliance-driven system work.
- Address reliability performance and system integrity concerns.
- Meet the interconnection needs of independent power generators and customers that choose to connect and provide energy to our system.
- Monitor and improve processes to meet future needs including customer and system trends and customer desires so infrastructure will be in place when the need arrives.

Some of these are regional responsibilities. For instance, all PSE facilities that are part of the Bulk Electric System and the interconnected western system must be planned and designed in accordance with the latest applicable and approved version of the North American Electric Reliability Corporation (NERC) Transmission Planning (TPL) Reliability Standards. These standards set forth performance expectations that affect how the transmission system – 100 kilovolts (kV) and above – is planned, operated and maintained. PSE also must follow Western Electricity Coordinating Council (WECC) reliability criteria; these can be more stringent or more specific than NERC standards at times.

8 | These obligations are defined by various codes and best practices such as Washington Administrative Code (WAC) 296 - 45 Electric Power Generation, Transmission, and Distribution; WAC 480-100 Electric Companies; WAC 480-108 Electric companies - Interconnection with Electric Generators; WAC 480-100-358:398 Part VI Safety and Standard Rules; National Electric Safety Code (NESC) Parts 1, 2 and 3; NERC Reliability Standards; WECC Regional Reliability Standards; Code of Federal Regulations (CFR) Title 18; CFR Title 49; FERC Order 1000; Occupational Safety and Health Administration; Washington Industrial Safety and Health Administration; National Electric Code; and Institute of Electrical and Electronics Engineers.

Ever more important today is to ensure that the system is flexible enough to adapt to coming changes. Smart and flexible equipment, customer distributed resources and demand response programs are some of the effective solutions the industry is moving toward, and PSE's electric delivery system needs to be prepared to integrate them for the benefit of our customers. Figure 8-XX depicts PSE's grid modernization framework for electric system improvements.

Figure 8-165: Grid Modernization Framework

The goal of PSE's planning process is to help us fulfill these responsibilities in the most cost-effective manner possible. Through it, we evaluate system performance and bring issues to the surface; we identify and evaluate possible solutions; and we explore the costs and consequences of potential alternatives. This information helps us make the most effective and cost-effective decisions going forward.

Delivery system planners prepare both 10-year plans required for the IRP and annual implementation plans. This section describes the current process for developing both. Planning begins with assessing needs followed by evaluating solution alternatives and recommendations. Need assessments begin with county- and local-level load forecasts and an evaluation of the system's current performance and future needs based on data analysis and modeling tools. Planning considerations include internal inputs such as reliability indices, company goals and commitments, and the root causes of historic outages. External inputs include service quality indices, regulations, municipalities' infrastructure plans, customer complaints and ongoing service issues. Solution assessment includes identifying alternatives to meet the need and comparing these alternatives against one another. A recommended alternative(s) is identified that will proceed to project planning if approved. PSE identifies the portfolio of projects that will proceed based on optimizing benefit and cost for a given funding level that is supported by approval within the overall company budget. The process is the same for both long-term and short-term planning. Typically, utilities align investment in non-revenue producing infrastructure to customer revenue associated with growth, which further defines a given funding level or constraint for optimization of the portfolio of infrastructure work.

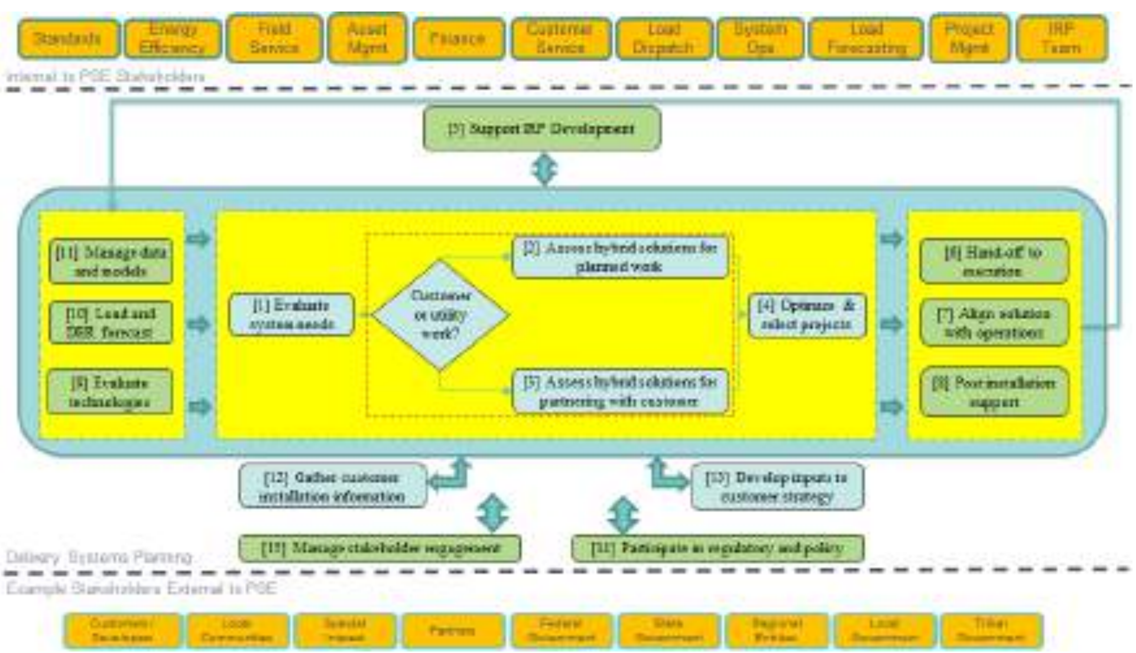
Key Findings

PSE’s 10-year plan is included as Appendix M of this IRP.

Analysis Process and Needs Assessment

PSE follows a structured approach to analyze delivery system needs and potential solutions. The Delivery System Planning (DSP) operating model incorporates inputs from both external stakeholders and groups within PSE; gathers input data for planning studies (represented by the yellow box on the left in Figure 8-166 below); analyzes system needs; develops solutions (which may consider customer-side assets and be a hybrid of traditional and non-traditional alternatives); selects preferred project alternatives (depicted in the central yellow box); and communicates the selected projects for execution of detailed design, construction/implementation, integration with operations and post-installation support (described in the yellow box on the right).

Figure 8-166: PSE Delivery System Planning Operating Model



Electric delivery system needs are driven by a number of different key factors as described below. All of these factors to be considered to identify the right needs across the system.

DELIVERY SYSTEM DEMAND AND PEAK DEMAND GROWTH. Demands on the overall system increase as the population of PSE's service area grows and economic activity increases, despite the increasing role of energy-conserving demand-side resources. Within the service area, however, demand is uneven, with much higher demand growth in the central business districts surrounding the urban centers. Peak loads occur when the weather is most extreme. PSE carefully evaluates system performance during peak load periods each year, updates its system models and compares these models against future demand and growth forecasts. Taking these steps prepares PSE to determine where additional infrastructure investment is required to meet peak firm loads. System investments are sometimes required to serve specific "point loads" that may appear at specific locations in PSE service area. For example, PSE has requests from several data centers, industrial facilities, etc., that plan to connect in the next few years with projected loads between 5 and 15 MW.

Energy efficiency consists of measures and programs that replace existing building energy using components and systems such as lighting, heating, water heating, insulation, appliances, etc., with more energy efficient ones. These replacements can reduce both peak demand and overall energy consumption for residential and commercial customers. Customers who agree to reduce their energy use during periods of system stress, system imbalance or in response to market prices are participating in demand response (DR). Interruptible rates are a subset of demand response. When used to relieve loading at critical times, demand response can offset anticipated loads and reduce the need for traditional delivery infrastructure. Interruptible rates are used in PSE's service area, and there is a high dependence on curtailment of these customers in order to meet demand.

RESOURCE INTEGRATION. FERC and state regulations require PSE to integrate generation resources into our electric system according to processes outlined in federal and state codes. A new generation facility, whether it is owned and operated by PSE or by others, can require significant electric infrastructure investment to integrate and maintain appropriate electrical power flows within our system and across the region. Also, if natural gas is the generation feedstock, large plants will require careful planning to ensure the availability of fuel.

AGING INFRASTRUCTURE. Aging infrastructure refresh is an important element of modernizing the delivery system. Equipment that has reached end of life and is incapable of supporting the digitization of the grid includes substation assets, circuit breakers and remote terminal units. Assets whose age and condition create reliability and resilience issues include direct buried high molecular weight underground distribution cable, poles and cross arms, and substation transformers.

RELIABILITY. Improving areas across the delivery system to minimize both the total number and duration of outages is important to customers today. This will become increasingly important in a modern grid as we anticipate customers will be even more reliant on electrical power as transformation such as transportation conversions continue to occur.

OPERATIONAL FLEXIBILITY. The ability to switch circuits to transfer load is important in responding to unplanned and planned outages, and the ability to perform necessary maintenance on equipment.

DISTRIBUTED ENERGY RESOURCES. At sufficient scale, distributed energy resources such as roof-top solar can reduce demand or provide operational flexibility. If uncontrolled, they can increase demand such as charging batteries during peak times or triggering voltage or power quality concerns if there are too many or they don't operate appropriately.

SAFETY AND REGULATORY REQUIREMENTS. These requirements drive action for mitigation in short order and/or are dictated through contractual agreements and as a result are identified and resolved outside of this long term planning process.

The energy delivery system is reviewed each year to improve the reliability of service to existing customers. Past outage experience, equipment inspection, maintenance records, customer feedback, PSE employee knowledge and analytic tools identify areas where improvements are likely required and where such improvements bring the most customer benefit. PSE collects system performance information from field charts, remote telemetry units, SCADA, employees and customers. Some information is analyzed over multiple years to normalize the effect of variables like weather that can change significantly from year to year. PSE gives additional consideration to system enhancements that will improve resiliency, such as the ability to deliver electricity via a second line, possibly from another substation, to make the grid more self-healing. Programs are also in place to address aging infrastructure by replacing poles and other components that are nearing the end of their useful life.

External inputs such as new regulations, municipal and utility improvement plans, and customer feedback, as well as company objectives such as PSE's asset management strategy and Grid Modernization strategy, are also included in the system evaluation. PSE obtains the annual updates to local jurisdiction six-year Transportation Improvement Plans to gain long-term planning perspective on upcoming public improvement projects. As the transportation projects develop through design, engineering and construction, PSE works with the local jurisdictions to identify and minimize potential utility conflicts and to identify opportunities to address system deficiencies and needs. PSE also collects public input regarding the need for infrastructure improvement through the PSE and WUTC complaint process, as well as through open forums that result from less than satisfactory service. These inputs help us to understand commitments and opportunities to mitigate impact or improve service at least cost.

PSE actively reviews and evaluates new technologies that can support delivery system needs. These technologies are identified, cataloged, and evaluated by an internal, cross-functional group of experts for business alignment, potential value, and feasibility. Cybersecurity continues to be a top consideration when evaluating products that are new in the market. PSE also seeks to leverage existing investments wherever possible when selecting and implementing new technologies. Following a successful evaluation, new technologies can be tested in a lab or piloted *in situ*. Results are documented and reviewed by all impacted teams. As new technologies complete the pilot process, they can be deployed at scale to meet the delivery system needs described above.

PSE relies on several tools to help identify needs or concerns and to weigh the benefits of alternative actions to address them. Figure 8-167 provides a brief summary of these tools, the planning considerations (inputs) that go into each and the results (outputs) that they produce. Each tool is used to provide data independently for use in iDOT,[9] which then creates the full understanding of all the benefits and risks.

[9] / *Investment Decision Optimization Tool which is a software tool called Folio by PwC.*

Figure 8-167: Delivery System Planning Tools

TOOL	USE	INPUTS	OUTPUTS
Synergi®	Gas and Electric network modeling	Gas and electric distribution infrastructure from GIS and load characteristics from CIS; load approvals; load forecast	Predicted system performance
Power World Simulator – Power Flow	Electric network modeling	Electric transmission infrastructure from WECC base case and load/generation characteristics from CIS; load approvals; load forecast	Predicted system performance
Electric Predictive Spreadsheet	Electric outage predictive analysis	Electric outage history from SAP	Predicted outage savings
Estimated Unserved Energy (EUE) Spreadsheet	Electric financial analysis	Estimated project costs; hourly load data from EMS; load growth scenarios from load forecast	Net Present Value; income statement; load growth vs. capacity comparisons; EUE
Asset Management Assessment	Electric maintenance analysis	Electric infrastructure operating or maintenance concerns from various databases	Program funding options to mitigate higher risk facilities
All data collected by the tools above are input into iDOT			
Investment Decision Optimization Tool (iDOT)	Gas and electric project data storage & portfolio optimization	Project scope, budget, justification, alternatives and benefit/risk data collected from above tools and within iDOT; resources/financial constraints	Optimized project portfolio; benefit cost ratio for each project; project scoping document

PSE's electric distribution model is a large integrated model of the entire delivery system using a software application (Synergi® Electric) that is updated to reflect new customer loads and system and operational changes. This modeling tool predicts capacity constraints and system performance on a variety of temperatures and under a variety of load growth scenarios. Results are compared to actual system performance data to assess the model's accuracy.

To simulate the performance of the electric transmission system, PSE primarily uses Power World Simulator. This simulation program uses a transmission system model that encompasses infrastructure across 11 western states, two provinces in western Canada and parts of northern Mexico. The power flow and stability data for these models are collected, coordinated and distributed through regional organizations that have included ColumbiaGrid, NorthernGrid, and WECC (one of eight regional reliability organizations under NERC). These power system study programs support PSE's planning process and facilitate demonstration of compliance with WECC and NERC reliability performance standards. While PSE utilizes a regional model for system evaluation and coordination, the focus is on local concerns and projects. Appendix J, Regional Transmission Resources, describes regional transmission planning and the role of the Regional Planning Organization (RPO). PSE has been a member of the ColumbiaGrid since 2006, succeeded by NorthernGrid in 2020. The RPO has had substantial responsibilities for transmission planning, reliability and other development services in order to improve the operational efficiency, reliability and planned expansion of the Pacific Northwest transmission grid. PSE is one of eight utilities that coordinate regional planning through the RPO, which has provided transparency and encourages broad participation and interaction with stakeholders, including customers, transmission providers, states and tribes.

Modeling is a three-step process. First, a map of the infrastructure and its operational characteristics is built from the GIS and asset management system, or in the case of transmission, provided by WECC. For electric infrastructure, this includes conductor cross-sectional area, impedance, length, construction type, connecting equipment, transformer equipment, voltage settings, and any DER that is controllable on the system. Next, PSE identifies customer loads, either specifically (for large customers) or as block loads for address ranges. Existing customer loads come from PSE's customer information system (CIS) or actual circuit readings. DERs that are not controllable require PSE to consider the load without them operating due to the need for the system to serve as backup. Finally, PSE takes into consideration seasonal variations, types of customers (interruptible vs. firm), time of daily peak usage, the status of components (valves or switches closed or open) and forecast future loads to model scenarios of infrastructure or operational adjustments. The goal is to find the optimal solution to a given issue. Where issues surface, the model can be used to evaluate alternatives and their effectiveness. PSE augments potential alternatives with cost estimates and feasibility analysis to identify the lowest reasonable cost solution for both current and future loads. DERs that are on the system that may not be controllable may serve as solutions if and when control and aggregation technologies are added.

The performance criteria that lie at the heart of PSE's infrastructure improvement planning process are summarized below in Figure 8-168. Evaluation begins with a review of existing operational challenges, load forecasts, demand-side management (DSM), commitments, obligations and opportunities. Planning triggers are specific performance criteria that trigger a need for a delivery system study. There are different triggers or thresholds for transmission and distribution, as well as for capacity and reliability. A "need" is identified when performance criteria is not met.

Figure 8-168: Performance Criteria for Electric Delivery System

Electric delivery system performance criteria are defined by:
Safety and compliance with all regulations and contractual requirements (100 percent compliance)
The temperature at which the system is expected to perform (normal winter peak, extreme winter peak) with expected reliability conservation
The nature of service and level of reliability that each type of customer has contracted for (firm or interruptible)
The minimum voltage that must be maintained in the system (no more than 5 percent below standard voltage)
The maximum voltage acceptable in the system (no more than 5 percent above standard voltage)
Thermal limits of equipment used to deliver power to load centers and transmission customers (per PSE Transmission and Distribution Planning Guidelines)
The interconnectivity with other utility systems and resulting requirements, including compliance with NERC planning standards (100 percent compliance) and all required planning scenarios and sensitivities.
The historical or future reliability performance that may be unacceptable or beyond benchmarks which may be caused by aging infrastructure, vegetation, third party damage, equipment condition, or animal interference.
The ability to remove equipment from service for maintenance and provide flexibility for outage restoration.

PSE expects the planning assumptions, described in Chapter 5, guidelines, and performance criteria to change over time due to the current policies pursing electrification, distributed energy resources dependency at the local circuit level, and deferral of traditional infrastructure network. PSE expects that customers will have higher expectations of reliability and economic impact of outages to be greater, requiring a delivery system with better reliability and resiliency than today. PSE expects delivery system planning margins to increase to account for operating concerns relating to distributed energy resource including behavior based conservation and demand response programs. PSE's delivery system planning assumptions relative to conservation and demand response have historically incorporated outputs generically, but these assumptions while appropriate for resource planning may not be appropriate for circuit level decisions and reliability. Higher cost conservation is likely customer type specific and as a result greater study and specific application of targeted conservation programs is necessary in order for conservation to be reliable. PSE may also need to develop assumptions regarding demand response programs as customer adoption may change as home occupancy changes over time.

PSE meets with jurisdictions in various forums such as quarterly roundtable discussions that include other utilities and agencies and in formal public presentations required through agreement or local regulation in order to gather input about concerns and coordinate solutions. For example, PSE and the City of Bellevue meet annually to exchange plans related to community development and utility system improvements, which provides an opportunity for interested stakeholders to ask questions and raise issues and concerns. Similarly, PSE engages in a multi-year coordination with Bainbridge Island stakeholders to discuss reliability and gather input regarding improvements.

Solutions Assessment and Criteria

The alternatives available to address delivery system needs including capacity, reliability, aging infrastructure, and operational flexibility are listed below. Each has its own costs, benefits, challenges and risks.

Figure 8-169: Alternatives for Addressing Electric Delivery System

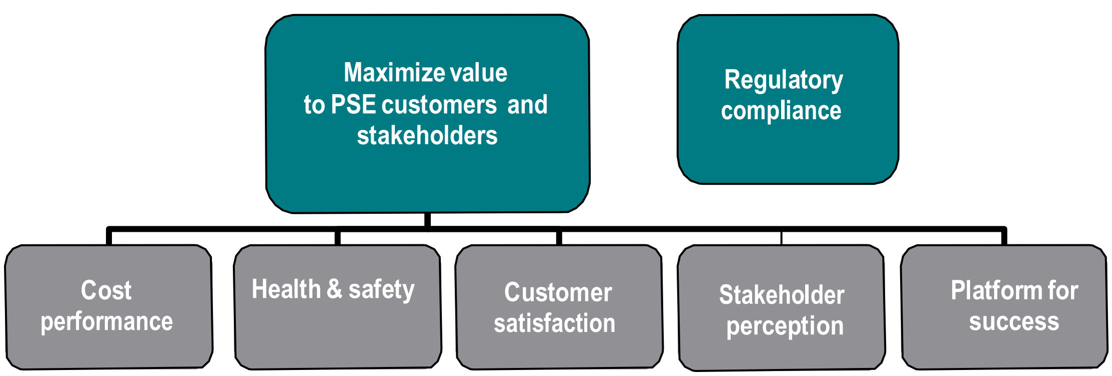
ELECTRIC SYSTEM ALTERNATIVES	
Add energy source	Substation; Distributed energy resource
Strengthen feed to local	New conductor; Replace conductor
Improve existing facility	Substation modification; Expanded right-of-way; Uprate system; Modify automatic switching scheme
Load reduction	Rebalance load; Fuel switching; Battery storage; Natural gas conversion; Conservation/Demand response; Load control equipment; Possible new tariffs

Load reduction alternatives are a focus of improvement in the planning process. Alternatives may depend on customer participation for siting, control or actionable behavior, and PSE continues to gain understanding and confidence in these as deferral and permanent solution alternatives are considered. Energy storage can be incorporated in both large-scale and small-scale projects (such as paired with rooftop solar DERs). Conservation above cost-effective measures and demand response can be incorporated as alternatives as our understanding of their effectiveness and the role of customer participation increases. Additionally, reducing the voltage at an end-user's site by a small percentage can result in energy savings without compromising the operation of customers' equipment. Finally, in sufficient quantities, distributed energy generated close to load (such as rooftop solar) can also defer investments in traditional delivery system infrastructure and potentially defer the need for additional generation.

Technical and non-technical solution criteria are established to ensure PSE implements the right solutions that fully address the needs. Based on the need identified, a Solutions Study is performed in which project alternatives are developed. The Solutions Studies will consider the opportunity to partner with customers, PSE programs or a PSE pilot. The solution alternatives are vetted and evaluated to meet specific solution criteria. Technical solution criteria includes meeting all performance criteria as described in Figure 8-169 as well as consideration of the substation utilization, avoidance of adverse impacts to reliability or operating characteristics, and the requirement of solution longevity delaying the need to retrigger additional investments for an established number of years, considering customer rate burden as investments are recovered. Non-technical solution criteria includes feasible permitting, environmental and community acceptance as facilitated through permitting processes, reasonable project cost, the maturity of technology, and constructability within a reasonable timeframe.

To evaluate alternatives, PSE compares the relative costs and benefits of various solutions (i.e., projects) using the iDOT Tool. iDOT is a project portfolio optimization based on PriceWaterhouseCooper's Folio software that allows us to capture project and program criteria and benefits and score them across thirteen factors associated with 6 categories. These include meeting required compliance with codes and regulations; net present value of the project; improvement to reliability and safety; future possible customer/load additions; deferral or elimination of future costs; customer satisfaction; improved external stakeholder perception; and opportunities for future success gained by increasing system flexibility or learning about new technologies and methods or drivers of specific company objectives. iDOT makes it easier to conduct side-by-side comparisons of projects and programs of different types, thus helping us evaluate infrastructure solutions that will be in service for 30 to 50 years.

Figure 8-170: Benefit Structure to Evaluate Delivery System Projects



Project costs are calculated using a variety of tools, including historical cost analysis and unit pricing models based on estimated internal engineering costs and service provider contracts. Cost estimates are refined as projects move through detailed scoping. Through this process, alternatives are reviewed and recommended solutions are vetted and undergo an internal peer review process. Projects that address routine infrastructure replacement, such as pole or meter replacements, are proposed at a program level and incorporated into a parallel path within the iDOT process. Risk assessment tools are used to prioritize projects within these programs. An example is the cable remediation program which prioritizes based on risks such as number of past failures, number of customers impacted and system configuration that prevents timely restoration.

iDOT builds a hierarchy of the value these benefits bring to customers and stakeholders against the project cost. The benefits are reviewed and reassessed periodically with senior management to ensure proper weight and priority is assigned throughout the evaluation process. Using project-specific information, iDOT optimizes total value across the entire portfolio of non-mandated or discretionary system infrastructure projects (electric and natural gas) which results in a set of capital projects that provide maximum value to PSE customers and stakeholders relative to given financial constraints. Further minor adjustments are made to ensure that the portfolio addresses resource planning and other applicable constraints or issues such as known permitting or environmental process concerns. Periodically, PSE has reviewed this process and the optimization tool along with the resulting portfolio with WUTC staff.

The iDOT tool also helps PSE examine projects in greater detail than a simple benefit/cost measure. iDOT includes factors such as brand value, health and safety improvements, environmental impact, sustainability, customer value and stakeholder perception. As a result, projects that contribute intangible value receive due consideration in iDOT.

PSE recently expanded the capabilities of iDOT to help us evaluate and compare the relative costs and benefits of wire, non-traditional and hybrid alternatives for the Bainbridge, Seabeck, Lynden and Kitsap pilot projects. New non-traditional benefits mapped to existing iDOT categories include generation capacity deferral entered as a cost reduction. Future iDOT enhancements could incorporate benefits such as battery-produced generation capacity deferral and extended asset life, etc., more transparently. PSE recognizes that carbon emissions reduction is an important objective as it builds implementation plans towards meeting CETA compliance, 100% clean electricity by 2045. The IRP captures greenhouse gas benefits relative to electric energy and so in order to prevent double counting of benefits, delivery system projects, may be more appropriately focused capturing these types of benefits as they relate to the manufacturing or transportation of the different types of assets that support different alternatives. As non-wire analysis is pursued, it essentially helps to find the most ideal location for distributed energy resources that are identified through the IRP recommended portfolio, adding value to what has already been captured in that process. Finally, PSE's delivery system planning process will also mature with clarity of the customer benefit assessment process prescribed in CETA, specifically as energy security and resilience is defined and the considerations and applications of energy and non-energy benefits relative to vulnerable populations and highly impacted communities evolves through required advisory group engagements.

Non-Wire Alternative Analysis

PSE's planning process has incorporated non-wire alternative analysis. The planning process may result in a lengthy project initiation phase as the need and alternatives are evaluated with a broader team. PSE's non-wire alternative analysis is a screening process that breaks down of the problem to understand what different pieces may be provided by a distributed energy resource, evaluates the technical distributed energy resource potential, performs an economic analysis, and then results in a recommended solution. The planning process is a comparison of alternatives searching for the least cost solution that maximizes value for customers and stakeholders and as such evaluates a traditional wired solution, a full non-wire solution, and potential hybrids across the problem components.

All types of distributed energy resources are considered. With the problem deconstructed to better understand the timing and costs specific portions of the need, a basis analysis tool helps to identify typical distributed energy resources that could solve the problem and whether more detailed analysis is warranted. Leveraging the structure and conservation potential process and tools of the IRP, the analysis may then map distributed energy resource potential to zip codes and estimate hourly load shapes based on specific customer loads to understand the potential further. The analysis may result in a heuristic-based DER potential and cost analysis graphic to help understand what is possible. Understanding the length of investment benefit or lifecycle is important as well such as lifespan of a battery or even demand response programs as home ownership transitions the benefit may change from initial results. The next step of economic analysis determines the costs of alternatives, using traditional cost estimating tools for traditional alternatives, and leveraging IRP cost assumptions and consultant's expertise to understand current and future costs based on developing maturity. This allows for testing optimistic, high benefit value low cost, and pessimistic, low benefit value high cost, considerations through the process. As discussed previously, iDOT can then be used to help evaluate alternatives for benefit to cost and further consider benefits not traditionally quantified. The result of the process is a recommended solution that meets the technical and non-technical solution criteria that then is documented in the solution assessment and the project moves to the project planning phase.

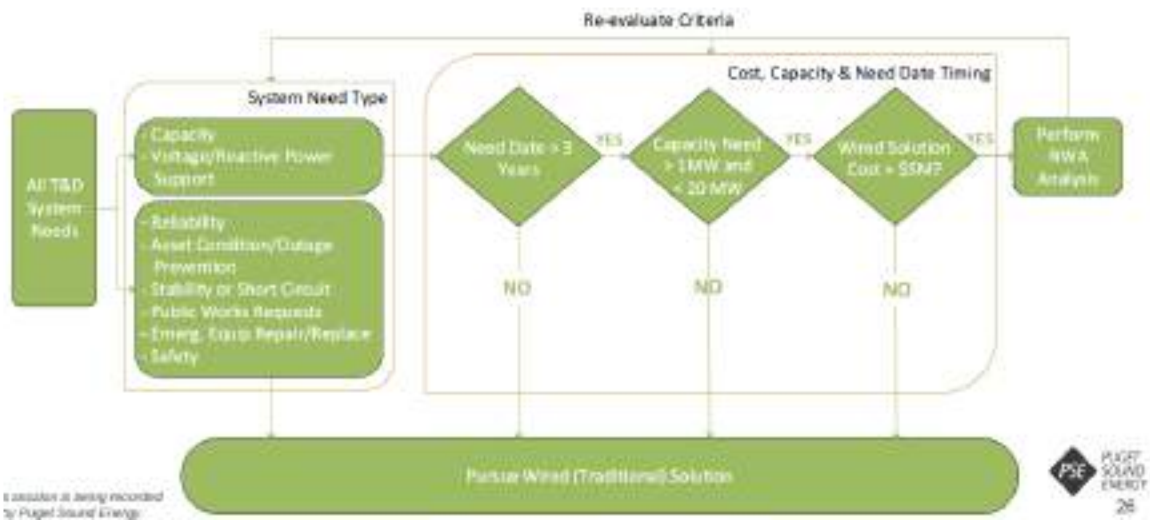
PSE embarked on non-wire analysis in 2018, committing to perform this analysis in four different areas of the system to learn and develop the process. PSE engaged the broad expertise of Navigant and Quanta Technologies to perform and develop its non-wire process and analysis. Non-wire analysis was completed for Bainbridge Island which had a capacity, reliability, aging infrastructure, and operational flexibility need, the entire Kitsap County which had a capacity, aging infrastructure and operational flexibility need, Seabeck which had a smaller circuit capacity and reliability need, and Lynden which had a local capacity, reliability, aging infrastructure, and operational flexibility need. The analysis on these four areas spanned almost 2 years which highlights the complexity of this type of analysis. More detail can be found for each of these area needs in Appendix M.

As a result of this analysis, there are some lessons learned relative to results and where this lengthy complex analysis is most valued. Key findings thus far are that:

- Capacity needs can be effectively met using non-wire alternatives when right sized, maximizing behavior based solutions first. Distributed energy resources that are too large begin to exceed traditional alternatives due to higher cost and long duration of need. Recharging requirements of batteries become as great of a challenge as discharging in some cases.
- Reliability needs are more challenged using non-wire alternatives depending on the length of reliability concern and location of need. Resilience needs, while not discussed much, may be ideal for future distributed energy resource supporting microgrids and locations where critical facilities exist for resilience such as train stations, refueling locations, life support facilities, and commerce.
- Aging infrastructure needs are challenged using non-wire alternatives as they are generally specific locational needs and equipment that if removed cause a wide duration and impact as a result of the connectivity of the grid.
- Non-wires analysis is a time intensive process requiring skilled resources and as a result costs more. Deploying this analysis where the project initiation cost brings value is important to consider in the scheme of the total project costs.
- Non-wire solutions may take time to implement depending on the type of distributed energy resource, PSE's experience, and grid readiness. Solutions such as demand response or behavior based solutions will take time to implement and build reliable confidence to defer traditional solutions. As PSE completes AMI and ADMS implementation and additional grid modernization investments, cost effectiveness of non-wire solutions will increase.

PSE has drafted an initial non-wires screening as a result, Figure 8-171, and through the 2021 IRP began seeking feedback from IRP stakeholders. PSE has performed additional analysis since the initial four areas were identified and these continued studies along with operational experience from previous installations such as PSE's battery in Glacier, Washington as well as on-going pilots will be used to inform this study screening process. This process will be adjusted as technology mature and cost decrease as well.

Figure 8-171: Non-wire Alternative Screening Criteria



Project Planning and Implementation Phase

nce the above process for a particular project and portfolio is completed, reviewed by senior management and approved for funding, the Delivery System Planning initiation phase is complete and the project planning phase begins. The outcome of project initiation is a needs assessment and solutions assessment document. For small projects this may be captured in PSE's SAP system through a notification process or supported from a business case that addresses needs programmatically. The project planning phase involves detailing engineering and technical specifications, pursuing real estate right-of-way needs, planning stakeholder communications and considering potential coordination with other projects in the area. Implementation risks are assessed and mitigation plans are developed as needed. PSE's 10 year plan included in Appendix M reflects projects that are largely in project initiation. Once a project moves to the project planning phase, the need has been established and IRP stakeholder engagement ends while community engagement begins.

Once project need and initiation recommendations are reviewed, annual and two-year work plans are developed for project planning and implementation feasibility. Work plans are coordinated with other internal and external work and resource plans are developed. Final adjustments may be made as the system portfolio is compared with other objectives of the company such as necessary generator or dam work, or customer initiatives. While annual plans are considered final, throughout the year they continue to be adjusted based on changing factors (such as public improvement projects that arise or are deferred; changing forecasts of new customer connections; or project delays in permitting) so that the total portfolio financial forecast remains within established parameters. As plans and projects develop through the design and permitting phases, cost and benefit are routinely evaluated and confirmed before progressing. Alternatives may be reviewed through project lifecycle phase gates and through detailed routing and siting discussions.

Long-range plans are communicated to the public through local jurisdictional tools such as the city and county Comprehensive Plans required by the Washington State Growth Management Act. Often this information serves as the starting point for demonstrating the need for improvements to local jurisdictions, residents and businesses far in advance of a project moving to project planning, design, permitting and construction. Project maps and details are updated on PSE.com as well.

9 Natural Gas Analysis

This analysis enables PSE to develop valuable foresight about how resource decisions to serve our natural gas customers may unfold over the next 20 years in conditions that depict a wide range of futures.

Contents

1. RESOURCE NEED AND DISCUSSION TOPICS

Resource Need

More than 840,000 customers in Washington state depend on PSE for safe, reliable and affordable natural gas services.

PSE's natural gas sales need is driven by peak day demand, which occurs in the winter when temperatures are lowest and heating needs are highest. The current design standard ensures that supply is planned to meet firm loads on a 13-degree design peak day, which corresponds to a 52 Heating Degree Day (HDD).[1] Two primary factors influence demand, peak day demand per customer and the number of customers. The heating season and number of lowest-temperature days in the year remain fairly constant and use per customer is growing slowly, if at all, so the biggest factor in determining load growth at this time is the increase in customer count.[2]

The IRP analysis tested three customer demand forecasts over the 20-year planning horizon: the 2021 IRP Mid (Base) Demand Forecast, the 2021 IRP High Demand Forecast and the 2021 IRP Low Demand Forecast.[3]

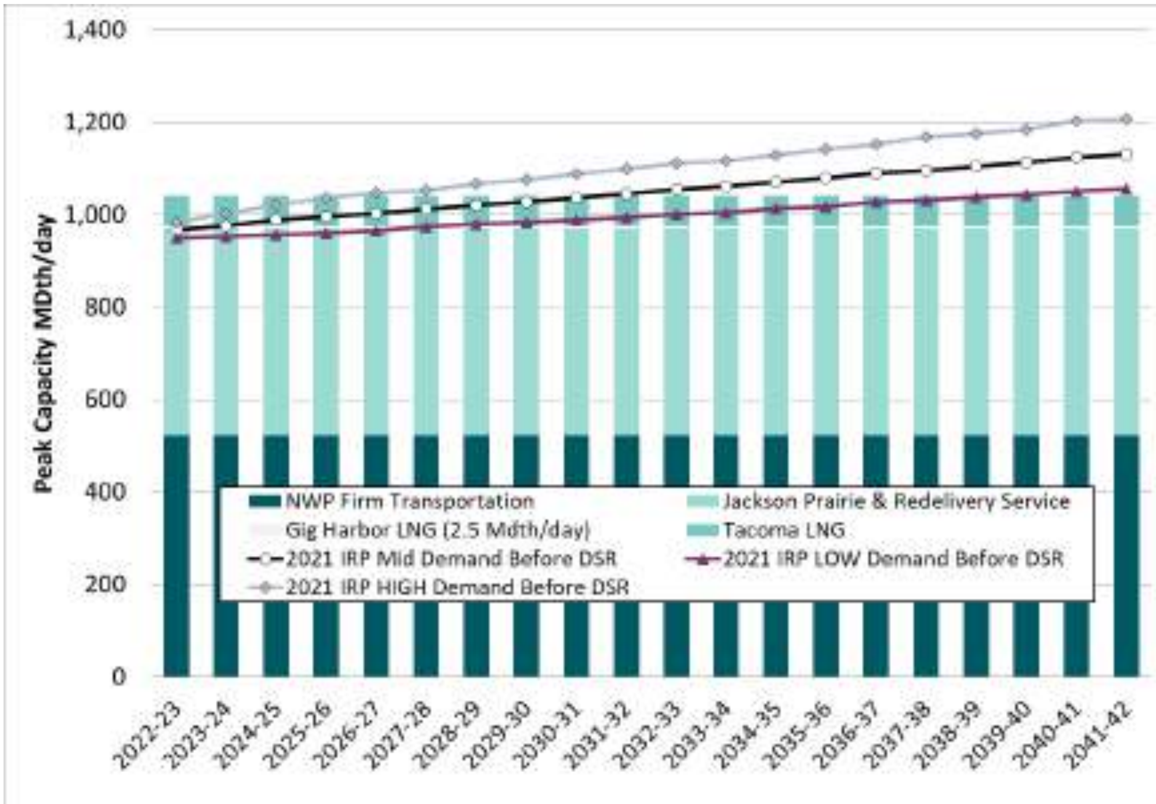
- In the Low Demand Forecast, we have sufficient firm resources to meet peak day need throughout the study period.
- In the Mid Demand Forecast, the first resource need occurs in the winter of 2031-32.
- In the High Demand Forecast, the first resource need occurs immediately.

Figure 9-1 illustrates natural gas sales peak resource need over the 20-year planning horizon for the three demand forecasts modeled in this IRP. Figure 9-2 shows the resource need surplus/deficit for the Mid Demand Forecast.

1 / Heating Degree Days (HDDs) are defined as the number of degrees relative to the base temperature of 65 degrees Fahrenheit. A 52 HDD is calculated as 65° less the 13° temperature for the day.
2 / The 2021 IRP demand forecast projects the addition of approximately 9,000 natural gas sales customers annually on average.
3 / The 2021 IRP demand forecasts are discussed in detail in Chapter 6, Demand Forecasts.

In Figure 9-1, the lines rising toward the right indicate peak day customer demand before additional demand-side resources (DSR),[4] and the bars represent existing resources for delivering natural gas supply to our customers. These resources include contracts for transporting natural gas on interstate pipelines from production fields, storage projects and on-system peaking resources.[5] The gap between demand and existing resources represents the resource need.

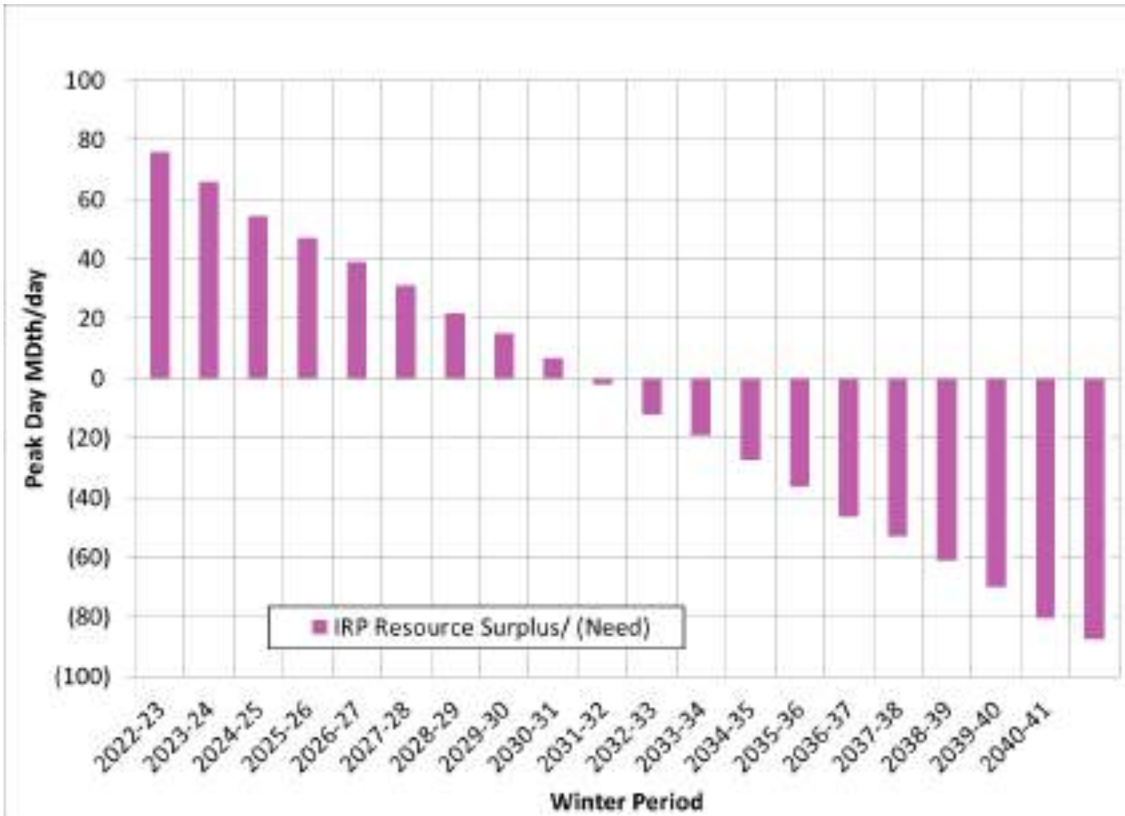
Figure 9-1: Natural Gas Sales Peak Resource Need before DSR, Existing Resources Compared to Peak Day Demand (meeting need on the coldest day of the year)



4 / One of the major tasks of the IRP analysis is to identify the most cost-effective amount of conservation to include in the resource plan. To accomplish this, it is necessary to start with demand forecasts that do not already include forward projections of additional conservation savings. Therefore the IRP Natural Gas Demand Forecasts include only DSR measures implemented ***before*** *the study period begins in 2022. These charts and tables are labeled "before DSR."*

5 / Tacoma LNG is shown as an existing resource, as the facility is currently under construction and anticipated to be in service and available late in the winter of 2021-22.

Figure 9-2: Natural Gas Sales Peak Resource Need Surplus/Deficit in Mid Demand Forecast before DSR



Discussion Topics

Infrastructure Reliability

Natural gas transportation and distribution systems are not designed to include the type of redundant capacity that electric distribution systems have because the majority of gas infrastructure is located underground where it is largely insulated from the effects of wind and storm damage. Equipment failure is rare, but it does occur, and there can be significant repercussions. For this reason, PSE builds flexibility and resiliency into the system in four ways.

- **A conservative planning standard:** Since PSE's peak day design standard is based on the coldest temperature on record for our service territory, and since this extreme temperature is not often reached and even more rarely sustained, there is some excess capacity in the system on most days.
- **Diverse transport resources:** PSE has built a transport portfolio that intentionally sources natural gas equally from north and south of our service territory to preserve flexibility in the event of supply disruptions. (Approximately 50 percent of PSE's natural gas supply is sourced from Station 2 and Sumas to the north, and 50 percent from AECO and the Rockies connected to the south.)
- **Natural gas storage:** Including natural gas storage in the portfolio (via Jackson Prairie, Clay Basin, Gig Harbor LNG, and the soon-to-be-completed Tacoma LNG Project) contributes to flexibility and resiliency in several ways. Storage minimizes the need and costs associated with relying on long haul pipelines to deliver gas on cold days; it allows more natural gas to be purchased in the typically less expensive summer season; and it can furnish natural gas supply in the event of a pipeline disruption.
- **Cooperation with regional entities:** Lessons learned from the October 2018 event discussed on the next page were applied in the restructured Northwest Mutual Assistance Agreement (NWMAA). Members of the agreement utilize, operate or control natural gas transportation and/or storage facilities in the Pacific Northwest, and they pledge to work together to provide and maintain firm service during emergency conditions and to restore normal service to their customers as quickly as possible after such events occur.

Two incidents illustrate how these strategies work in practice.

A 36-inch pipe on the Westcoast pipeline[6] (Westcoast) between Station 2 and Sumas in central British Columbia (B.C.) ruptured in the early evening of October 9, 2018, shutting off the flow of natural gas from production points in northeast B.C to Sumas for over 30 hours. This resulted in the loss of over 800,000 Dth per day of Sumas supply. Coincidentally, the Jackson Prairie Storage Project was shut down for scheduled maintenance at the time. Coordinating efforts through the Northwest Mutual Assistance Agreement, all the of the natural gas pipelines, utilities, power plant operators and major industrial customers affected worked together to add supply or shed load. Fortis BC, a large downstream utility in southern British Columbia, was able to use some natural gas flowing on its pipeline from Alberta (Southern Crossing), and PSE and other utilities and end-users took steps to reduce natural gas consumption or increase supply from their own on-system storage. These combined efforts prevented a significant loss of pressure in the system, and by 2 p.m. on October 11, 2018 portions of the Westcoast pipeline system were back in service and 38 percent of the normal gas volume from B.C. was flowing. Jackson Prairie personnel worked around the clock to complete the storage facility's planned maintenance ahead of schedule, providing important additional supply to ease the regional situation. Thanks to the combined efforts of Northwest Mutual Assistance participants, the incident lasted less than 48 hours, however, the extensive testing and recertifying required to restore the natural gas flow from B.C. to 100 percent of capacity took over a year. Westcoast was allowed to begin operating its system at 100 percent by mid-November 2019.

In February, 2019, while Westcoast pipeline was still operating significantly below normal levels, the Jackson Prairie Gas Storage Project suffered a major compressor failure that reduced natural gas deliverability by approximately 250,000 Dth per day. The compressor was repaired and back online in less than 30 days, and the net effect of the outage was a reduction in total available storage withdrawals of only 750,000 Dth. Customers experienced no service interruption, but to compensate for the unavailable storage supplies, PSE and other entities that draw natural gas from the storage facility had to purchase additional flowing supply from the market at a time when supply was low and demand, and therefore prices, were high.

These incidents, while quite rare, demonstrate the resilience of the natural gas transportation and storage system in the region. Despite two major failures, no firm residential or commercial customer was without natural gas, nor was there a loss of electrical service, which is increasingly dependent on the natural gas infrastructure. With PSE's current modeling capabilities, it is not possible to model random outages; however, these recent "real-world" experiences demonstrate that the steps taken by PSE to prepare for occasional infrastructure failure have proven successful.

6 / *Westcoast Pipeline is operated by Westcoast Energy, a subsidiary of Enbridge, Inc*

Supply Adequacy

As noted above, PSE intentionally sources natural gas from both north and south of our service territory to preserve flexibility in the event of supply disruptions. Fifty percent of PSE's natural gas supply is sourced from Station 2 and Sumas to the north, and 50 percent from AECO and the Rockies connected to the south. At this time, we are monitoring developments on the Westcoast pipeline that serves the Sumas market.

PSE holds firm capacity on Westcoast's system for approximately 50 percent of its needs from British Columbia in order to access natural gas supplies in the production basin in northern British Columbia rather than only at the Sumas market. This strategy provides a level of reliability (physical access to natural gas in the production basin) and an opportunity for pricing diversity, as often there is a significant pricing differential between Station 2 and Sumas that more than offsets the cost of holding the capacity.

When natural gas production in NE B.C. increased substantially due to the shale revolution, a shortage of pipeline capacity leaving the basin developed as producers sought market outlets for the increased production. For the past several years, Westcoast has run at its maximum available capacity nearly year-round (limited by maintenance restrictions); so far, the result has been an adequate supply at Sumas in winter months (when the pipeline is in normal operations) and an excess in summer months.

A 2017 Westcoast capacity offering was fully subscribed, and this will drive construction of facilities to provide an additional 105,000 Dth per day of firm capacity on Westcoast and also 94,000 Dth per day of capacity that was previously held back for maintenance and reliability reasons. The new contracts, totaling 199,000 Dth per day, will bring more firm natural gas to the Sumas hub beginning in November 2021

However, between 2024 and 2027, two new large-volume firm industrial loads totaling over 400,000 Dth per day are expected to come online. Because these two new loads have acquired the firm Westcoast capacity necessary to serve their demand (from both existing and expansion capacity), they will control their own supply and destiny. Much of the firm pipeline capacity that they will use to access their natural gas supply is currently used to provide the adequate and occasionally abundant supplies at the Sumas market hub to other customers. Once the new customers start up their facilities, they will effectively and dramatically reduce the supply available for other customers at Sumas on most days.

PSE is confident that there will be adequate supplies at Sumas at most times of the year with the increased capacity on Westcoast beginning in 2021, and that PSE will still be able to compete (on price) to obtain sufficient supplies in peak periods to fill its existing Northwest Pipeline (NWP) capacity, even when the new industrial concerns begin operations. However, PSE is concerned because the increased demand of 400,000 Dth per day is supported by only 199,000 Dth per day of increased capacity, thus placing price pressure on the remaining supplies.

Because there is currently an equilibrium of firm supply and firm demand in peak winter periods and a surplus in summer periods, PSE believes it is not necessary to secure additional firm Westcoast capacity at this time. However, in the future there is the potential for inadequate capacity to bring sufficient supply to Sumas in peak periods. For this reason, the IRP analysis continues to assume that any new long-term NWP capacity from Sumas used to serve incremental PSE firm loads would need to be coupled with additional firm capacity on Westcoast that begins at the supply source in NE B.C.

PSE will continue to monitor developments in the NE B.C. supply and capacity market and to analyze the implications on an ongoing basis.

2. ANALYTIC METHODOLOGY

Analysis of the natural gas supply portfolio begins with an estimate of resource need that is derived by comparing 20-year demand forecasts with existing long-term resources. Once need has been identified, a variety of planning tools, optimization analyses and input assumptions help PSE identify the lowest-reasonable-cost portfolio of natural gas resources in a variety of scenarios. Renewal or term extension of existing resources are among the alternatives considered.

Analysis Tools

PSE uses a gas portfolio model (GPM) to analyze natural gas resources for long-term planning and long-term natural gas resource acquisition activities. The current GPM is SENDOUT Version 14.3.0 from ABB Ventyx, a widely-used model that employs a linear programming algorithm to help identify the long-term, least-cost combination of integrated supply- and demand-side resources that will meet stated loads. While the deterministic linear programming approach used in this analysis is a helpful analytical tool, it is important to acknowledge this technique provides the model with "perfect foresight" – meaning that its theoretical results may not be achievable. For example, the model knows the exact load and price for every day throughout a winter period, and can therefore minimize cost in a way that is not possible in the real world. Numerous critical factors about the future will always be uncertain; therefore we rely on linear programming analysis to help *inform* decisions, not to *make* them.

> > > See Appendix I, Natural Gas Analysis Results*, for a more complete description of the SENDOUT gas portfolio model.*

Deterministic Optimization Analysis

PSE developed three natural gas scenarios for this IRP analysis, Mid, High and Low, as shown in Figure 9-3.[7] Scenario analysis allows the company to understand how different resources perform across a variety of economic and regulatory conditions that may occur in the future. Scenario analysis also clarifies the robustness of a particular resource strategy. In other words, it helps determine if a particular strategy is reasonable under a wide range of possible circumstances.

Figure 9-3: 2021 IRP Natural Gas Analysis Scenarios

2021 IRP NATURAL GAS ANALYSIS SCENARIOS				
	Scenario Name	Demand	Natural Gas Price	CO_2 Price/Regulation
1	Mid	Mid[1]	Mid	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions
2	Low	Low	Low	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions
3	High	High	High	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions

NOTE 1. Mid demand corresponds to the 2021 IRP Base Demand Forecast

7 / Chapter 5, Key Assumptions, describes the scenario inputs in detail.

PSE also tested five sensitivities in the natural gas sales analysis; these are described below. Sensitivity analysis allows us to isolate the effect of a single resource, regulation or condition on the portfolio.

Figure 9-4 2021 IRP Natural Gas Portfolio Sensitivities

2019 IRP NATURAL GAS ANALYSIS SENSITIVITIES		
A	AR5 Upstream Emissions	The AR5 model is used to model upstream emissions instead of AR4.
B	6-Year Conservation Ramp Rate	Energy efficiency measures ramp up over 6 years instead of 10.
C	Social Discount Rate for DSR	The discount rate for demand-side resource measures is decreased from 6.8% to 2.5%.
D	Fuel Switching, Gas to Electric	Gas-to-electric conversion is accelerated in the PSE service territory.
E	Temperature Sensitivity on Load	Temperature data used for economic forecasts is composed of more recent weather data as a way to represent changes in climate.
F	No DSR	This portfolio will not include any new demand-side resources energy efficiency, distribution efficiency and demand response.

> > > See Appendix I, Natural Gas Analysis Results, *for a detailed presentation of scenario and sensitivity analysis results.*

Natural Gas Peak Day Planning Standard

PSE completed a detailed cost-benefit analysis during the 2005 least cost plan (LCP) that is the basis for the current planning standard. That analysis looked at customers' value of reliability of service with the incremental costs of the resources necessary to provide that reliability at various temperatures. Based on the analysis, PSE determined that it would be appropriate to use the 52 HDD (13ºF) as the peak day planning standard.

PSE has used this planning standard since 2005, including in the 2021 IRP. PSE believes that the planning standard is still appropriate in the current environment for the reasons outlined below.

- The standard is based on reliability and safety. In the natural gas sector when there is an outage, it triggers a safety protocol that requires service technicians to physically shut off the gas at the appliance before gas service is restored and make another visit to turn on pilot gas lights. Due to the work hours involved, the outages can take days to weeks to restore during a time when the weather is at its coldest and space heating is an essential service. The existing standard has prevented outages over the last 15 years, and while during this time we have not seen temperatures that approach the design peak day temperature, there is no certainty that we will not see this temperature in the near future.
- When seen in the context of other regional gas utility planning standards, the PSE natural gas planning standard is in line with industry best practices. PSE's implied temperature criteria derived from its planning standard places it in the 98th percentile for annual peaks from 1950 to 2019 (see Figure 9-5), similar to other PNW utilities (see Figure 9-6).

Figure 9-5: PSE Planning Standard Implied Temperature Criteria

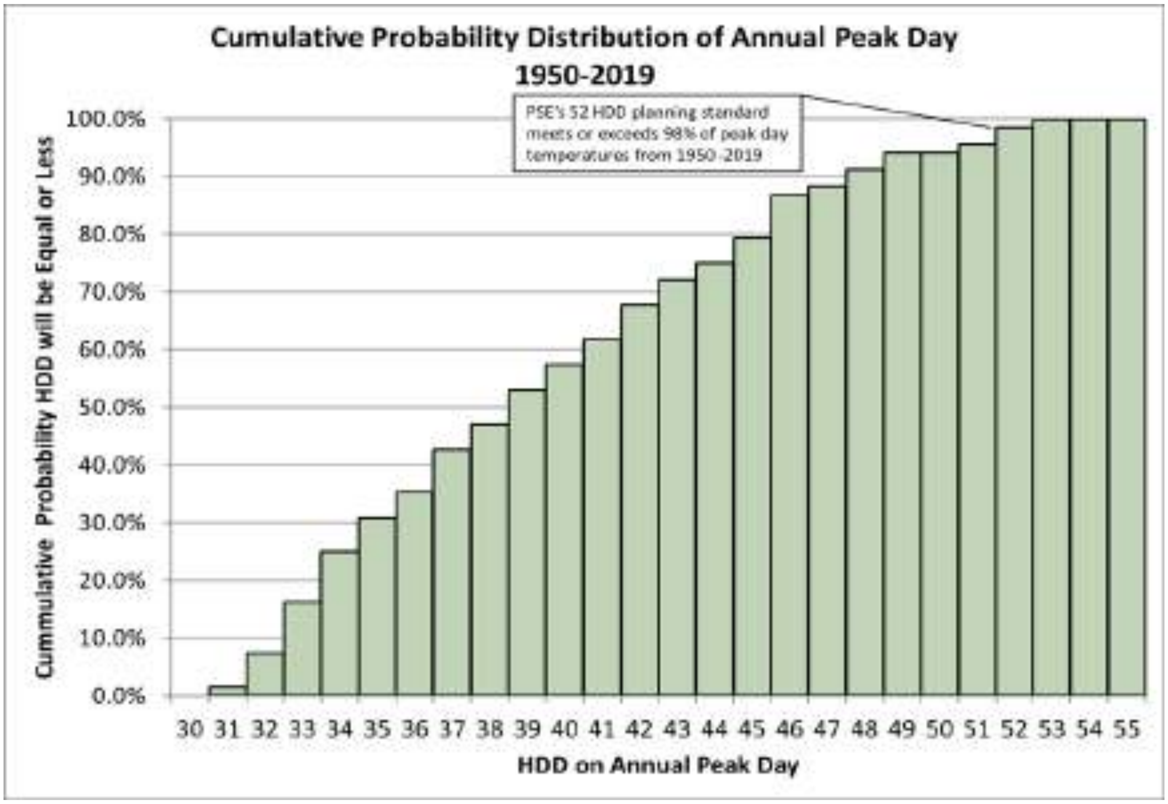


Figure 9-6: Pacific Northwest Natural Gas Utility Planning Standards

PNW Gas Utility	Peak Capacity Design Standard
NW Natural	NW Natural will plan to serve the highest firm sales demand day in any year with 99% certainty: 99th percentile of annual peak days over last 100 years.
Cascade Natural	Coldest day during the past 30 years.
Avista Corp	Adjust the middle day of the five-day cold weather event to the coldest temperature on record for a service territory, as well as adjusting the two days on either side of the coldest day to temperatures slightly warmer than the coldest day.
Fortis NG	1 in 20 years temperature based on annual peak days over last 60 years.
PSE	98th percentile of annual peak days from 1950-2019

Natural gas ignition technology has not changed much in the last 15 years. Penetration of electronic ignition is still very small, so service personnel are still required to relight homes in the event of an outage. The cost of relighting has also increased since the 2005 study due to increased population density and travel times in the region.

The results of the 2021 IRP analysis show that lower demand, which may result from a revised peak day planning standard, will likely not change the resource alternatives needed to serve future loads. Even in the Low Scenario, the natural gas portfolio model selected the same level of cost-effective conservation as the High Scenario. Thus, revising the planning standard would not change the results of the analysis in the 2021 IRP.

Given that the PSE planning standard is in line with peer natural gas utilities, has provided a reliable natural gas system, and will not result in any material change to the resource alternatives chosen in the analysis, PSE believes it is appropriate to use the 52 HDD peak day planning standard in the 2021 IRP. PSE plans to study the impacts of changing the planning standard.

3. EXISTING RESOURCES

Existing natural gas sales resources consist of pipeline capacity, storage capacity, peaking capacity, natural gas supplies and demand-side resources.

Existing Pipeline Capacity

There are two types of pipeline capacity. “Direct-connect” pipelines deliver supplies directly to PSE’s local distribution system from production areas, storage facilities or interconnections with other pipelines. “Upstream” pipelines deliver natural gas to the direct pipeline from remote production areas, market centers and storage facilities.

Direct-connect Pipeline Capacity

All natural gas delivered to our distribution system is handled last by PSE’s only direct-connect pipeline, Northwest Pipeline (NWP). We hold nearly one million dekatherms (Dth) of firm capacity with NWP.

- 542,872 Dth per day of year-round TF-1 (firm) transportation capacity
- 447,057 Dth per day of firm storage redelivery service from Jackson Prairie

Receipt points on the NWP transportation contracts access supplies from four production regions: British Columbia, Canada (B.C.); Alberta, Canada (AECO); the Rocky Mountain Basin (Rockies) and the San Juan Basin. This provides valuable flexibility, including the ability to source natural gas from different regions on a day-to-day basis in some contracts.

Upstream Pipeline Capacity

To transport natural gas supply from production basins or trading hubs to the direct-connect NWP system, PSE holds capacity on several upstream pipelines.

A schematic of the natural gas pipelines for the Pacific Northwest region is provided in Figure 9-7. For the details of PSE's natural gas sales pipeline capacity, see Figure 9-8.

Figure 9-7: Pacific Northwest Regional Natural Gas Pipeline Map

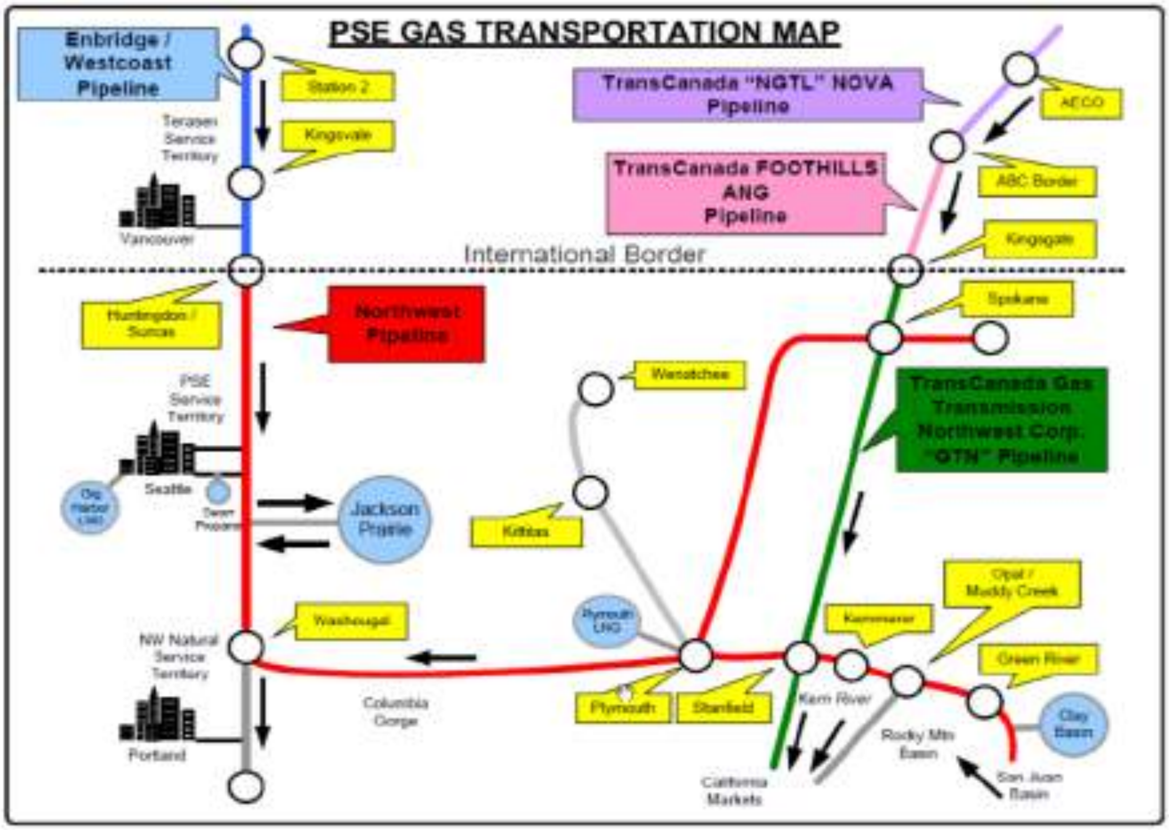


Figure 9-8: Natural Gas Sales - Firm Pipeline Capacity (Dth/day) as of 11/01/2020

Pipeline/Receipt Point			Year of Expiration	
	Note	Total	2023-28	2028+
Direct-connect				
NWP/Westcoast Interconnect (Sumas)	1	287,237	135,146	152091
NWP/TC-GTN Interconnect (Spokane)	1	75,936	-	75,936
NWP/various in US Rockies & San Juan Basin	1	179,699	52,423	127,276
Total TF-1		**542,872**	**187,569**	**355,303**
NWP/Jackson Prairie Storage Redelivery Service	1,2	447,057	444,184	2,873
Storage Redelivery Service		**447,057**	**444,184**	**2,873**
Total Capacity to City Gate		**989,929**	**631,753**	**358,176**

Pipeline/Receipt Point			Year of Expiration	
	Note	Total	2023-28	2028+
Upstream Capacity				
TC-NGTL: from AECO to TC-Foothills Interconnect (A/BC Border)	3	79,744	79,744	-
TC-Foothills: from TC-NGTL to TC-GTN Interconnect (Kingsgate)	3	78,631	78,631	-
TC-GTN: from TC-Foothills Interconnect to NWP Interconnect (Spokane)	4	65,392	65,392	-
TC-GTN: from TC-Foothills Interconnect to NWP Interconnect (Stanfield)	4,5	11,622	11,622	-
Westcoast: from Station 2 to NWP Interconnect (Sumas)	6,7	135,795	135,795	-
Total Upstream Capacity	**8**	**371,184**	**371,184**	**-**

NOTES
1. NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.
2. Storage redelivery service (TF-2 or discounted TF-1) is intended only for delivery of storage volumes during the winter heating season, November through March; these annual costs are significantly lower than year-round TF-1 service.
3. Converted to approximate Dth per day from contract stated in gigajoules per day.
4. TC-GTN contracts have automatic renewal provisions, but can be canceled by PSE upon one year's notice.
5. Capacity can alternatively be used to deliver additional volumes to Spokane.
6. Converted to approximate Dth per day from contract stated in cubic meters per day. Westcoast has adjusted the heat content factor upward to reflect the higher Btu gas now normal on its system. The effect is to allow customers to transport more Btu in the same contractual capacity.
7. The Westcoast contracts contain a right of first refusal upon expiration.
8. Upstream capacity is not necessary for a supply acquired at interconnects in the Rockies and for supplies purchased at Sumas.

Transportation Types

TF-1

TF-1 transportation contracts are "firm" contracts, available every day of the year. PSE pays a fixed demand charge for the right, but not the obligation, to transport natural gas every day.

Storage Redelivery Service

PSE holds TF-2 and winter-only discounted TF-1 capacity under various contracts to provide for firm delivery of Jackson Prairie storage withdrawals. These services are restricted to the winter months of November through March and provide for firm receipt only at Jackson Prairie; therefore, the rates on these contracts are substantially lower than regular TF-1 transportation contracts.

Primary Firm, Alternate Firm and Interruptible Capacity

FIRM TRANSPORTATION CAPACITY carries the right, but generally not the obligation (subject to operational flow orders from a pipeline), to transport up to a maximum daily quantity of natural gas on the pipeline from a specified receipt point to a specified delivery point. Firm transportation requires a fixed payment, whether or not the capacity is used, plus variable costs when physical gas is transported. Primary firm capacity is highly reliable when used in the contracted path from receipt point to delivery point.

ALTERNATE FIRM CAPACITY occurs when firm shippers have the right to temporarily alter the contractual receipt point, the delivery point and even the flow direction – subject to availability of capacity for that day. This "alternate firm capacity" can be very reliable if the contract is used to flow natural gas within the primary path; that is, in the contractual direction to or from the primary delivery or receipt point. Alternate firm is much less reliable or predictable if used to flow natural gas in the opposite direction or "out of path." While "out of path" alternate firm capacity has higher rights than non-firm, interruptible capacity, it is not considered reliable in most circumstances.

INTERRUPTIBLE CAPACITY on a fully contracted pipeline can become available if a firm shipper does not fully utilize its firm rights on a given day. This unused (interruptible) capacity, if requested (nominated) by a shipper and confirmed by the pipeline, becomes firm capacity for that day. The rate for interruptible capacity is negotiable and typically billed as a variable charge. The rights of this type of non-firm capacity are subordinate to the rights of firm pipeline contract owners who request to transport natural gas on an alternate basis, outside of their contracted firm transportation path.

The flexibility to use firm transport in an alternate firm manner “within path” or “out of path,” along with the ability to create “segmented release” capacity, has resulted in very low non-firm, interruptible volumes on the NWP system.

When capacity is not needed to serve natural gas customers on a given day, PSE may use its firm capacity to transport natural gas from a low-priced basin to a higher-priced location and resell the gas to third parties to recoup a portion of demand charges. When PSE has a surplus of firm capacity and market conditions make such transactions favorable for customers, PSE may release capacity into the capacity release market. The company may also access additional firm capacity from the capacity release market on a temporary or permanent basis when it is available and competitive with other alternatives.

Interruptible service plays a limited role in PSE’s resource portfolio because of the flexibility of the company’s firm contracts and because it cannot be relied on to meet peak demand.

Existing Storage Resources

Natural gas storage capacity is a significant component of PSE’s natural gas sales resource portfolio. Storage capacity improves system flexibility and creates significant cost savings for both the system and customers. Benefits include the following.

- Ready access to an immediate and controllable source of firm natural gas supply or storage space enables PSE to handle many imbalances created at the interstate pipeline level without incurring balancing or scheduling penalties.
- Access to storage makes it possible for the company to purchase and store natural gas during the lower-demand summer season, generally at lower prices, for use during the high-demand winter season.
- Combining storage capacity with firm storage redelivery service transportation allows PSE to contract for less of the more expensive year-round pipeline capacity.
- PSE also uses storage to balance city gate gas receipts from natural gas marketers with the actual loads of our natural gas transportation customers.

We have contractual access to two underground storage projects. Each serves a different purpose. Jackson Prairie Gas Storage Project (Jackson Prairie) in Lewis County, Wash. is an aquifer-driven storage field, located in the market area that is designed to deliver large quantities of natural gas over a relatively short period of time. Clay Basin, in northeastern Utah, provides supply-area storage and a winter-long natural gas supply. Figure 9-9 presents details about storage capacity.

Figure 9-9: Natural Gas Sales Storage Resources[1] as of 11/1/2020

	Withdrawal Capacity (Dth/Day)	Injection Capacity (Dth/Day)	Storage Capacity (Dth)	Expiration Date
Jackson Prairie – PSE Owned	398,667	147,333	8,528,000	N/A
Jackson Prairie – PSE Owned [2]	(50,000)	(18,500)	(500,000)	2023
Net JP Owned	**348,667**	**128,833**	**8,028,000**	
Jackson Prairie – NWP SGS-2F [3]	48,390	20,404	1,181,021	2023
Net Jackson Prairie	**397,057** [5]	**149,237**	**9,209,021**	
Clay Basin [4]	107,356	53,678	12,882,750	2023
Net Clay Basin	**107,356**	**53,678**	**12,882,750**	
Total	**504,413** [6]	**202,915**	**22,091,771**	

NOTES
1. Storage, injection and withdrawal capacity quantities reflect PSE's capacity rights rather than the facility's total capacity.
2. Storage capacity made available to PSE's electric generation portfolio (at market-based price) from PSE natural gas sales portfolio. Renewal may be possible, depending on gas sales portfolio needs. Firm withdrawal rights can be recalled to serve natural gas sales customers.
3. NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.
4. PSE expects to renew the Clay Basin storage agreements.
5. Plus 50,000 Dth when Jackson Prairie is recalled from the electric portfolio for a total of 447,057 Dth/day.
6. Plus 50,000 Dth when Jackson Prairie is recalled from the electric portfolio.

Jackson Prairie Storage

As shown in Figure 9-9, PSE, NWP and Avista Utilities each own an undivided one-third interest in the Jackson Prairie Gas Storage Project, which PSE operates under FERC authorization. PSE owns 398,667 Dth per day of firm storage withdrawal rights and associated storage capacity from Jackson Prairie. Some of this capacity has been made available to PSE's electric portfolio at market rates. The firm withdrawal rights – but not the storage capacity – may be recalled to serve natural gas sales customers under extreme conditions. In addition to the PSE-owned portion of Jackson Prairie, PSE has access to 48,390 Dth per day of firm deliverability and associated firm storage capacity through an SGS-2F storage service contract with NWP. In total, PSE holds 447,057 Dth per day of firm withdrawal rights for peak day use. PSE has 447,057 Dth per day of storage redelivery service transportation capacity from Jackson Prairie. The NWP contracts renew automatically each year, but PSE has the unilateral right to terminate the agreement with one year's notice.

PSE uses Jackson Prairie and the associated NWP storage redelivery service transportation capacity primarily to meet the intermediate peaking requirements of core natural gas customers – that is, to meet seasonal load requirements, balance daily load and minimize the need to contract for year-round pipeline capacity to meet winter-only demand.

Clay Basin Storage

Dominion-Questar Pipeline owns and operates the Clay Basin storage facility in Daggett County, Utah. This reservoir stores natural gas during the summer for withdrawal in the winter. PSE has two contracts to store up to 12,882,750 Dth and withdraw up to 107,356 Dth per day under a FERC-regulated service.

PSE uses Clay Basin for certain levels of baseload supply and for backup supply in the case of well freeze-offs or other supply disruptions in the Rocky Mountains during the winter. It provides a reliable source of supply throughout the winter, including peak days; it also provides a partial hedge to price spikes in this region. Natural gas from Clay Basin is delivered to PSE's system (or other markets) using firm NWP TF-1 transportation.

Treatment of Storage Cost

Similar to firm pipeline capacity, firm storage arrangements require a fixed charge whether or not the storage service is used. PSE also pays a variable charge for natural gas injected into and withdrawn from Clay Basin. Charges for Clay Basin service (and the non-PSE-owned portion of Jackson Prairie service) are billed to PSE pursuant to FERC-approved tariffs, and recovered from customers through the Purchased Gas Adjustment (PGA) regulatory mechanism, while costs associated with the PSE-owned portion of Jackson Prairie are recovered from customers through base distribution rates. Some Jackson Prairie costs are recovered from PSE transportation customers through a balancing charge.

Existing Peaking Supply and Capacity Resources

Firm access to other resources provides supplies and capacity for peaking requirements or short-term operational needs. The Gig Harbor liquefied natural gas (LNG) satellite storage and the Swarr vaporized propane-air (LP-Air) facility provide firm natural gas supplies on short notice for relatively short periods of time. Generally a last resort due to their relatively higher variable costs, these resources typically help to meet extreme peak demand during the coldest hours or days. These resources do not offer the flexibility of other supply sources.

Figure 9-10: Natural Gas Sales Peaking Resources

	Withdrawal Capacity (Dth/Day)	Injection Capacity (Dth/Day)	Storage Capacity (Dth)	Transportation Tariff	Availability
Gig Harbor LNG	2,500	2,500	10,500	On-system	current
Swarr LP-Air [1, 2]	30,000	16,680	128,440	On-system	Nov. 2024+
Tacoma LNG [3]	69,300	2,100	538,000	On-system	Mar. 2021
TOTAL	**101,800**	**21,280**	**676,940**		

NOTES
1. Swarr is currently out of service pending upgrades to reliability, safety and compliance systems. It may be considered in resource acquisition analysis for an in-service date of November 2024 or later.
2. Swarr holds 1.24 million gallons. At a refill rate of 111 gallons per minute, it takes 7.7 days to refill, or 16,680 Dth per day.
3. Planned in-service date is Mar. 1, 2021. Withdrawal (vaporization) capacity will rise in the future when the distribution system is upgraded. Such a distribution system upgrade – allowing an increase of 16,000 Dth per day in LNG vaporization – is considered as a potential new resource in this IRP.

Gig Harbor LNG

Located in the Gig Harbor area of the Kitsap Peninsula, this satellite LNG facility ensures sufficient supply during peak weather events for a remote but growing region of PSE's distribution system. The Gig Harbor plant receives, stores and vaporizes LNG that has been liquefied at other LNG facilities. It represents an incremental supply source, and its 2.5 MDth per day capacity is therefore included in the peak day resource stack. Although the facility directly benefits only areas adjacent to the Gig Harbor plant, its operation indirectly benefits other areas in PSE's service territory since it allows natural gas supply from pipeline interconnects or other storage to be diverted elsewhere.

Swarr LP-Air

The Swarr LP-Air facility has a net storage capacity of 128,440 Dth natural gas equivalents and can produce the equivalent of approximately 10,000 Dth per day. Swarr is a propane-air injection facility on PSE’s natural gas distribution system that operates as a needle-peaking facility. Propane and air are combined in a prescribed ratio to ensure the compressed mixture injected into the distribution system maintains the same heat content as natural gas. Preliminary design and engineering work necessary to upgrade the facility’s environmental, safety and reliability systems and increase production capacity to 30,000 Dth per day is under way. The upgrade is evaluated as a resource alternative for this IRP in Combination #7 – Swarr LP-Air Upgrade, and is assumed to be available on three years’ notice as early as the 2023/24 winter season. Since Swarr connects to PSE’s distribution system, it requires no upstream pipeline capacity.

Tacoma LNG

PSE expects the completion of construction and successful start-up of this LNG peak shaving facility to serve the needs of core natural gas customers as well as regional LNG transportation fuel consumers. By serving new LNG fuel markets (primarily large marine consumers) the project will achieve economies of scale that reduce costs for core natural gas customers. This LNG peak-shaving facility is located at the Port of Tacoma and connects to PSE’s existing distribution system. The 2021 IRP assumes the project is put into service late in the 2020-21 heating season, providing 69 MDth per day of capacity – 50 MDth per day of vaporization and 19 MDth per day of recalled natural gas supply. The full 85 MDth per day of capacity will become available when additional upgrades to the natural gas distribution system allow vaporization of an additional 16 MDth per day; this additional capacity is assumed to be available as a new resource on three years’ notice beginning in the 2024/25 heating season.

Existing Natural Gas Supplies

Advances in shale drilling have expanded the economically feasible natural gas resource base and dramatically altered long-term expectations with regard to natural gas supplies. Not only has development of shale beds in British Columbia directly increased the availability of supplies in the West, but the east coast no longer relies so heavily on western supplies now that shale deposits in Pennsylvania and West Virginia are in production.

Within the limits of its transportation and storage network, PSE maintains a policy of sourcing natural gas supplies from a variety of supply basins. Avoiding concentration in one market helps to increase reliability. We can also mitigate price volatility to a certain extent; the company's capacity rights on NWP provide some flexibility to buy from the lowest-cost basin, with certain limitations based on the primary capacity rights from each basin. While PSE is heavily dependent on supplies from northern British Columbia, it also maintains pipeline capacity access to producing regions in the Rockies, the San Juan basin and Alberta. PSE's pipeline capacity on NWP currently provides for 50 percent of our flowing natural gas supplies to be delivered from north of our service territory and the remaining 50 percent from south of our service territory.

Price and delivery terms tend to be very similar across supply basins, though shorter-term prices at individual supply hubs may "separate" due to pipeline capacity shortages, operational challenges or high local demands. This separation cycle can last several years, but is often alleviated when additional pipeline infrastructure is constructed. PSE expects generally comparable pricing across regional supply basins over the 20-year planning horizon, with differentials primarily driven by differences in transportation costs and forecasted demand increases. The long-term supply pricing scenarios used in this analysis were provided by Wood-Mackenzie, whose North American supply/demand model considers the non-synchronized cyclical nature of growth in production, demand and infrastructure development to forecast monthly pricing in the supply basins accessed by PSE pipeline capacity.

PSE has always purchased our supply at market hubs. In the Rockies and San Juan basin, there are various transportation receipt points, including Opal, Clay Basin and Blanco. Alternate points, such as gathering system and upstream pipeline interconnects with NWP, allow some purchases directly from producers as well as marketers. In fact, PSE has a number of supply arrangements with major producers in the Rockies to purchase supply near the point of production. Adding upstream pipeline transportation capacity on Westcoast, TransCanada's Nova (TC-NGTL) pipeline, TransCanada's Foothills pipeline and TransCanada's Gas Transmission NW (TC-GTN) pipeline to the company's portfolio has increased PSE's ability to access supply nearer producing areas in Canada as well.

Natural gas supply contracts tend to have a shorter duration than pipeline transportation contracts, with terms to ensure supplier performance. PSE meets average loads with a mix of long-term (more than two years) and short-term (two years or less) supply contracts. Long-term contracts typically supply baseload needs and are delivered at a constant daily rate over the contract period. PSE also contracts for seasonal baseload firm supply, typically for the winter months November through March. Near-term transactions supplement baseload transactions, particularly for the winter months. PSE estimates average load requirements for upcoming months and enters into month-long or multi-month transactions to balance load. Daily positions are balanced using storage from Jackson Prairie, Clay Basin, day-ahead purchases and off-system sales transactions; intra-day positions are balanced using Jackson Prairie. PSE monitors natural gas markets continuously to identify trends and opportunities to fine-tune our contracting, purchasing and storage strategies.

Existing Demand-side Resources

PSE has provided demand-side resources to our customers since 1993.[8] These energy efficiency programs operate in accordance with requirements established as part of the stipulated settlement of PSE's 2001 General Rate Case.[9] Through 1998, the programs primarily served residential and low-income customers; in 1999, they were expanded to include commercial and industrial customer facilities. The majority of natural gas energy efficiency programs are funded using gas "rider" funds collected from all customers.

Figure 9-11 shows that energy efficiency measures installed through 2019 have saved a cumulative total of over 5.4 million Dth, which represents a reduction in CO_2 emissions of approximately 324,000 metric tons – more than half of this amount has been achieved since 2010. Savings per year have mostly ranged from 3 to 5 million therms, peaking at just over 6.3 million therms in 2013.

Energy savings targets and the programs to achieve those targets are established every two years. The 2018-2019 biennial program period concluded at the end of 2019. The current program cycle runs from January 1, 2020 through December 31, 2021 and has a two-year energy savings target of approximately 8 million therms. This goal was based on extensive analysis of savings potentials and developed in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group and Integrated Resource Plan Advisory Group.

PSE spent over $17.5 million for natural gas conservation programs in 2019 (the most recent complete program year) compared to $3.2 million in 2005. Spending over that period increased more than 35 percent annually. The low cost of natural gas and increasing cost of materials and equipment have put pressure in the cost-effectiveness of savings measures. PSE is collaborating with regional efforts to find creative ways to make delivery and marketing of natural gas efficiency programs more cost-effective, and to find ways to reduce barriers for promising measures that have not yet gained significant market share.

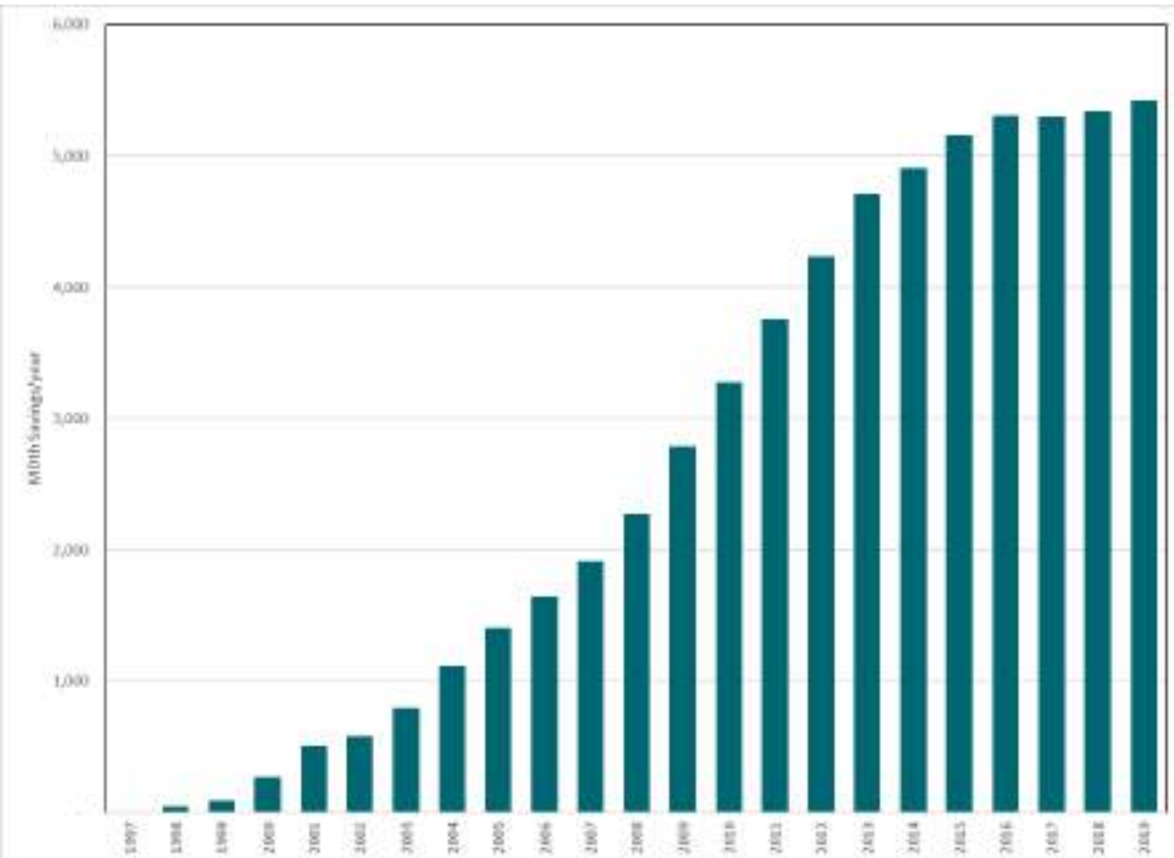
Figure 9-11 summarizes energy savings and costs for 2018 through 2021.

8 / Demand-side resources, also called conservation, contribute to meeting resource need by reducing demand.
9 / PSE's 2001 General Rate Case, WUTC Docket Nos. UG-011571 and UE-011570.

Figure 9-11: Natural Gas Sales Energy Efficiency Program Summary, 2018 – 2021
Total Savings and Costs

Program Year	Actual Savings (MDth)	Actual Cost ($ millions)	Target Savings (MDth)	Budget ($ millions)
2018	377.1	15.8	327	15.3
2019	322.8	17.7	314.7	15.9
2020-21			795.3	34.5

Figure 9-12: Cumulative Natural Gas Sales Energy Savings from DSR, 1997 – 2019



4. RESOURCE ALTERNATIVES

The natural gas sales resource alternatives considered in this IRP address long-term capacity challenges rather than the shorter-term optimization and portfolio management strategies PSE uses in the daily conduct of business to minimize costs.

Combinations Considered

Transporting natural gas from production areas or market hubs to PSE's service area generally entails assembling a number of specific pipeline segments and natural gas storage alternatives. Purchases from specific market hubs are joined with various upstream and direct-connect pipeline alternatives and storage options to create combinations that have different costs and benefits. Within PSE's service territory, demand-side resources are a significant resource.

In this IRP, the alternatives have been gathered into seven broad combinations for analysis purposes. These combinations are discussed below and illustrated in Figure 9-13. Note that demand-side resources is a separate alternative discussed later in this chapter.

The following acronyms are used in the descriptions below.

- AECO: the Alberta Energy Company trading hub, also known as Nova Inventory Transfer (NIT)
- LP-Air: liquid propane-air (liquid propane is mixed with air to achieve the same heating value as natural gas)
- NWP: Williams Northwest Pipeline, LLC pipeline
- TC-Foothills: TransCanada-Foothills BC (Zone 8) pipeline
- TC-GTN: TransCanada-Gas Transmission-Northwest pipeline
- TC-NGTL: TransCanada-NOVA Gas Transmission Ltd. pipeline
- Westcoast pipeline: Westcoast Energy Inc. pipeline

Combination # 1 & 1a – NWP Additions + Westcoast

After November 2023, this option expands access to northern British Columbia natural gas at the Station 2 hub, with expanded transport capacity on Westcoast pipeline to Sumas and then on expanded NWP to PSE's service area. Natural gas supplies are also presumed available at the Sumas market hub. In order to ensure reliable access to supply and achieve diversity of pricing, PSE believes it will be prudent and necessary to acquire Westcoast capacity equivalent to 100 percent of any new NWP firm take-away capacity from Sumas.

COMBINATION #1A – SUMAS DELIVERED NATURAL GAS SUPPLY. This short-term delivered supply alternative utilizes capacity on the existing NWP system from Sumas to PSE that might be available to be contracted to meet PSE needs from November 2022 to October 2025 in the form of annual winter contracts. This alternative is intended to provide a short-term bridge to long-term resources. Pricing would reflect Sumas daily pricing and a full recovery of pipeline charges. PSE believes that the vast majority – if not all – of the under-utilized firm pipeline capacity in the I-5 corridor that could be used to provide a delivered supply has been or will be absorbed by other new loads by Fall 2025. After that, other long-term resources would need to be added to serve PSE demand.

Combination # 2 – FortisBC/Westcoast (KORP)

This combination includes the Kingsvale-Oliver Reinforcement Project (KORP) pipeline proposal, which is in the development stages and sponsored by FortisBC and Westcoast. Availability is estimated to begin no earlier than November 2025. Essentially, the KORP project expands and adds flexibility to the existing Southern Crossing pipeline. This option would allow delivery of Alberta (AECO hub) natural gas to PSE via existing or expanded capacity on the TC-NGTL and TC-Foothills pipelines, the KORP pipeline across southern British Columbia to Sumas, and then on expanded NWP capacity to PSE. As a major greenfield project, this resource option is dependent on significant additional volume being contracted by other parties.

Combination # 3 – Cross Cascades – NWP from AECO

This option provides for deliveries to PSE via a prospective upgrade of NWP's system from Stanfield, Ore. to contracted points on NWP in the I-5 corridor. Availability is estimated no earlier than November 2025. The increased natural gas supply would come from Alberta (AECO hub) via new upstream pipeline capacity on the TC-NGTL, TC-Foothills and TC-GTN pipelines to Stanfield, Ore. Final delivery from Stanfield to PSE would be via the upgraded NWP facilities across the Columbia gorge and then northbound to PSE gate stations. Since the majority of this expansion route uses existing pipeline right-of-way, permitting this project would likely be less complicated. Also, since smaller increments of capacity are economically feasible with this alternative, PSE is more likely to be able to dictate the timing of the project.

Combination # 4 – Mist Storage and Redelivery

This option involves PSE leasing storage capacity from NW Natural Gas after an expansion of the Mist storage facility. Pipeline capacity from Mist, located in the Portland area, would be required for delivery of natural gas to PSE's service territory, and the expansion of NWP pipeline capacity from Mist to PSE will be dependent on an expansion on NWP from Sumas to Portland with significant additional volume contracted by other parties. Mist expansion and a NWP southbound expansion – which would facilitate a lower-cost northbound storage redelivery contract – are not expected to be available until at least November 2025.

Combination # 5 – Plymouth LNG with Firm Delivery

This option includes 70.5 MDth per day firm Plymouth LNG service and 15 MDth per day firm NWP pipeline capacity from the Plymouth LNG plant to PSE. Currently, PSE's electric power generation portfolio holds this resource, which may be available for renewal for periods beyond April 2023. While this is a valuable resource for the power generation portfolio, it may be a better fit in the natural gas sales portfolio.

Combination # 6 – LNG-related Distribution Upgrade

This combination assumes completion of the LNG peak-shaving facility, providing 69 MDth per day of capacity. This option considers the timing of the contemplated upgrade to the Tacoma area distribution system, which would allow an additional 16 MDth per day of vaporized LNG to reach more customers. In effect, this would increase overall delivered supply to PSE customers, since natural gas otherwise destined for the Tacoma system would be displaced by vaporized LNG and therefore available for delivery to other parts of the system. The incremental volume resulting from the distribution upgrade can be implemented on three years' notice starting as early as winter 2024-25.

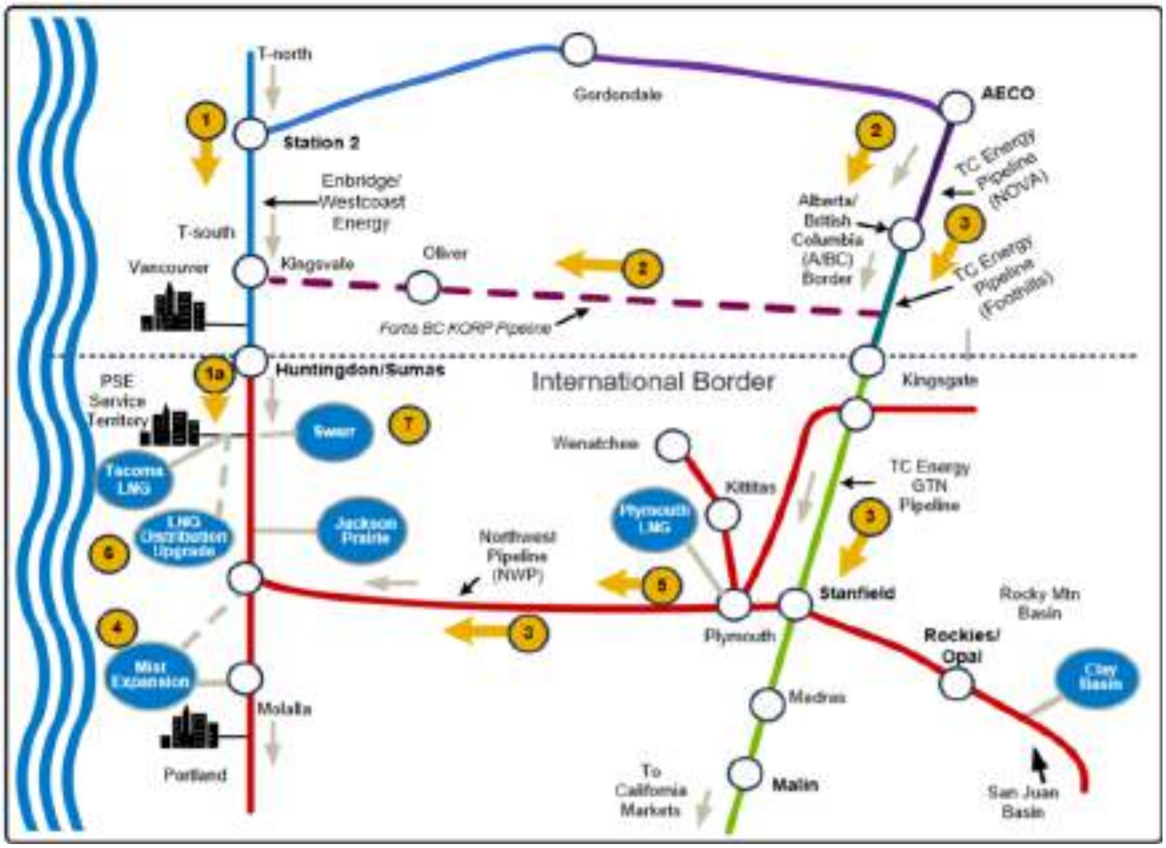
Combination # 7 – Swarr LP-Air Upgrade

This is an upgrade to the existing Swarr LP-Air facility discussed above. The upgrade would increase the peak day planning capability from 10 MDth per day to 30 MDth per day. This plant is located within PSE's distribution network, and could be available on three years' notice as early as winter 2024-25.

NOTE: Combinations 2, and 4 include new greenfield projects and would require significant participation by other customers in order to be economic.

A schematic of the natural gas sales resource alternatives is depicted in Figure 9-13 below.

Figure 9-13: PSE Natural Gas Transportation Map Showing Supply Alternatives



Pipeline Capacity Alternatives

Direct-connect Pipeline Capacity Alternatives

The direct-connect pipeline alternatives considered in this IRP are summarized in Figure 9-14 below.

Figure 9-14: Direct-connect Pipeline Alternatives Analyzed

Direct-connect Pipeline Alternatives	Description
NWP - Sumas to PSE city gate *(from Combinations 1 & 2)*	Expansions considered in conjunction with upstream pipeline/supply expansion alternatives (KORP or additional Westcoast capacity) assumed available November 2025.
NWP – Portland area to PSE city gate *(from Combination 4)*	Expansion considered in conjunction with storage expansion alternatives (Mist storage capacity) assumed available after November 2025.

Upstream Pipeline Capacity Alternatives

In some cases, a tradeoff exists between buying natural gas at one point and buying capacity to enable purchase at an upstream point closer to the supply basin. PSE has faced this tradeoff with supply purchases at the Canadian import points of Sumas and Kingsgate. For example, previous analyses led the company to acquire capacity on Westcoast (Westcoast Energy's B.C. pipeline), which allows PSE to purchase natural gas at Station 2 rather than Sumas and take advantage of greater supply diversity availability at Station 2. Similarly, acquisition of additional upstream pipeline capacity on TransCanada's Canadian and U.S. pipelines would enable PSE to purchase natural gas directly from suppliers at the very liquid AECO/NIT trading hub and transport it to the existing interconnect with NWP and its proposed Cross-Cascades upgrade on a firm basis. FortisBC and Westcoast have proposed the KORP, which in conjunction with additional capacity on TransCanada's Canadian pipelines, would also increase access to AECO/NIT supplies.

Figure 9-15: Upstream Pipeline Alternatives Analyzed

Upstream Pipeline Alternatives	Description
Increase Westcoast Capacity (Station 2 to PSE) *(from Combination 1)*	Acquisition of new Westcoast capacity is considered to increase access to natural gas supply at Station 2 for delivery to PSE on expanded NWP capacity from Sumas.
Increase TransCanada Pipeline Capacity (AECO to Madras or Stanfield) *(from Combination 3)*	Acquisition of new capacity on TransCanada pipelines (NGTL, Foothills and GTN), to increase deliveries of AECO/NIT natural gas to Madras for connection to the TC Cross-Cascades project and a separate northbound upgrade of NWP or to Stanfield for delivery to PSE city gate via the proposed NWP Cross Cascades upgrade. Assumed availability no earlier than November 2025.
Kingsvale-Oliver Reinforcement Project (KORP) *(from Combination 2)*	Expansion of the existing FortisBC Southern Crossing pipeline across southern B.C., enhanced delivery capacity on Westcoast from Kingsvale to Huntingdon/Sumas. This alternative would include a commensurate acquisition of new capacity on the TC-NGTL and TC-Foothills pipelines. Available no earlier than November 2025.

The KORP alternative includes PSE participation in an expansion of the existing FortisBC pipeline across southern British Columbia, which includes a cooperative arrangement with Westcoast for deliveries from Kingsvale to Huntingdon/Sumas. Acquisition of this capacity, as well as additional capacity on the TC-NGTL and TC-Foothills pipelines, would improve access to the AECO/NIT trading hub. While not inexpensive, such an alternative would increase geographic diversity and reduce reliance on British Columbia-sourced supply connected to upstream portions of Westcoast.

Storage and Peaking Capacity Alternatives

As described in the existing resources section, PSE is a one-third owner and operator of the Jackson Prairie Gas Storage Project, and PSE also contracts for capacity at the Clay Basin storage facility located in northeastern Utah. Additional pipeline capacity from Clay Basin is not available and storage expansion is not under consideration. Expanding storage capacity at Jackson Prairie is not analyzed in this IRP although it may prove feasible in the long run. For this IRP, the company considered the following storage alternatives.

Mist Expansion

NW Natural Gas Company, the owner and operator of the Mist underground storage facility near Portland, Ore., would consider a potential expansion project to be completed in 2025. PSE is assessing the cost-effectiveness of leasing storage capacity beginning November 2025, once the Mist upgrade is built. This would also require expansion of NWP's interstate system to PSE's city gate. PSE may be able to acquire discounted winter-only capacity from Mist to PSE's city gate if NWP expands from Sumas to Portland for other shippers, making the use of Mist storage cost-effective. Since this resource is dependent on other parties willingness to contract for an expansion, this resource availability is not in PSE's control.

LNG-related Distribution System Upgrade

This option considers the timing of the contemplated upgrade to the Tacoma area distribution system, allowing an additional 16 MDth per day of vaporized LNG to reach more customers. The effect is to increase overall delivered supply to PSE customers because natural gas otherwise destined for the Tacoma system is displaced by vaporized LNG and therefore available for delivery to other parts of the system. The incremental volume resulting from the distribution upgrade can be implemented on three years' notice starting as early as winter 2024-25.

Swarr

The Swarr LP-Air facility is discussed above under "Existing Peaking Supply and Capacity Resources." This resource alternative is being evaluated while PSE is in the preliminary stages of designing the upgrade to Swarr's environmental, safety and reliability systems and increasing production capacity to 30,000 Dth per day. The facility is assumed to be available on three years' notice for the 2024-25 heating season or beyond.

Figure 9-16: Natural Gas Storage Alternatives Analyzed

Storage Alternatives	Description
Expansion of Mist Storage Facility *(Combination 5)*	Considers the acquisition of expanded Mist storage capacity, based on estimated cost and operational characteristics. Assumes a 20-day supply at full deliverability of up to 100 MDth/day beginning the 2025-26 heating season. (Requires incremental pipeline capacity.)
Distribution upgrade allowing greater utilization of Tacoma LNG *(Combination 7)*	Considers the timing of the planned upgrade to PSE's Tacoma area distribution system allowing an incremental 16 MDth/day of LNG peak-shaving beginning the 2024-25 heating season.
Swarr LP-Air Facility Upgrade *(Combination 8)*	Considers the timing of the planned upgrade for reliability and increased capacity (from 10 MDth/day to 30 MDth/day) beginning the 2024-25 heating season.
Plymouth LNG contract with NWP firm transportation *(Combination 6)*	Considers acquisition of an existing Plymouth LNG contract and associated firm transportation for 15 MDth/day, beginning April 2023.

Natural Gas Supply Alternatives

Conventional Natural Gas

As described earlier, natural gas supply and production are expected to continue to expand in both northern British Columbia and the Rockies production areas as shale and tight gas formations are developed using horizontal drilling and fracturing methods. With the expansion of supplies from shale gas and other unconventional sources at existing market hubs, PSE anticipates that adequate natural gas supplies will be available to support pipeline expansion from northern British Columbia via Westcoast or TC-NGTL,TC-Foothills and TC-GTN or from the Rockies basin via NWP.

Renewable Natural Gas (RNG)

Renewable natural gas is gas captured from sources like dairy waste, wastewater treatment facilities and landfills. RNG is significantly higher cost than conventional natural gas; however, it provides greenhouse gas benefits in two ways: 1) by reducing CO_2e emissions that might otherwise occur if the methane and/or CO_2 is not captured and brought to market, and 2) by avoiding the upstream emissions related to the production of the conventional natural gas that it replaces.

HB 1257 passed the Washington State legislature and became effective in July, 2019; it was also incorporated in the WUTC RNG Policy Statement issued in December 2020. PSE is working with the WUTC and other stakeholders to develop guidelines for implementation, PSE conducted a RFI (Request for Information) to determine the availability and pricing of RNG supplies. After analysis and negotiation, PSE acquired a long-term supply of RNG from a recently completed and operational landfill project in Washington at a competitive price. PSE is in final design of tariff provisions and IT enhancements to facilitate availability of a voluntary RNG program for PSE customers to take effect in 2021. RNG supply not utilized in PSE's voluntary RNG program(s) will be incorporated into PSE's supply portfolio, displacing natural gas purchases as provided for in HB 1257.

This IRP does not analyze hypothetical RNG projects that would connect to NWP or to PSE's system and displace conventional natural gas that would otherwise flow on NWP pipeline capacity. However, because of RNG's significantly higher cost, the very limited availability of sources, and the unique nature of each individual project, RNG is not suitable for generic analysis. The benefits of RNG are measured in terms of CO_2e reduction, which are unique to each project. The incremental costs of new pipeline infrastructure to connect the RNG projects to the NWP or PSE system are also unique to each project. Avoided pipeline charges realized by connecting acquired RNG directly to the PSE system will be considered, but are not significant relative to the cost of the RNG commodity. Contract RNG purchases present known costs, however, many projects may not materialize absent a capital investment by PSE. Due to the very competitive RNG development market, including competition from the California compliance markets, PSE is not prepared to discuss specific potential RNG projects in a public environment. Individual projects will be analyzed and documented as PSE pursues additional supplies.

The aforementioned contract acquisition of landfill RNG will, within a few years, provide RNG equal to approximately 2 percent of PSE's current supply portfolio and as much as a 1.5 percent reduction in the carbon footprint of PSE's natural gas system, annually. PSE is planning significant further investments in cost-effective RNG, and PSE is confident that it can acquire sufficient RNG volumes to meet the needs of its future voluntary RNG program participants and even exceed the 5 percent cost limitation related to the RNG incorporated into the supply portfolio. In order to meet the expectations in the WUTC RNG Policy Statement, PSE will utilize staggered RNG supply contracts and project development timelines, resales in compliance markets and other techniques to manage RNG costs while maximizing the availability of RNG in its portfolio and achieving meaningful carbon reductions.

Demand-side Resource Alternatives

To develop demand-side alternatives for use in the portfolio analysis, PSE first conducts a conservation potential assessment. This study reviews existing and projected building stock and end-use technology saturations to estimate the savings possible through installation of more efficient commercially available technologies. The broadest measure of savings from making these installations (or replacing old technology) is called the technical potential. This represents the total unconstrained savings that could be achieved without considering economic (cost-effectiveness) or market constraints.

The next level of savings is called *achievable* technical potential. This step reduces the unconstrained savings to levels considered achievable when accounting for market barriers. To be consistent with electric measures, the achievability factors for all natural gas retrofit measures was assumed to be 85 percent. Similar to electric measures, all natural gas measures receive a 10 percent conservation credit stemming from the Power Act of 1980. The measures are then organized into a conservation supply curve, from lowest to highest levelized cost.

Next, individual measures on the supply curve are grouped into cost segments called "bundles." For example, all measures that have a levelized cost of between $2.2 per Dth and $3.0 per Dth may be grouped into a bundle and labeled "Bundle 2." The lower cost bundles were further divided into smaller segments to ensure that some measures included in a larger, marginal bundle don't get missed.[10] The Codes and Standards bundle has zero cost associated with it because savings from this bundle accrue due to new codes or standards that have been passed but that take effect at a future date. This bundle is always selected in the portfolio, where it effectively represents a reduction in the load forecast.

Figure 9-17 shows the price bundles and corresponding savings volumes in achievable technical potential that were developed for this IRP. The bundles are shown in dollars per therm and the savings for each bundles shown in 2031 and 2041 are in thousand dekatherms per year

10 / The $4.5 to $5.5 per Dth and the $5.5 to $7.0 per Dth bundles were divided into four bundles: $4.5 to $5.0, $5.0 to $5.5, $5.5 to $6.2 and $6.2 to $7.0. The narrower ranges allow for a more refined selection of conservation on the supply curve.

(MDth/year). These savings were developed using PSE's weighted average cost of capital (WACC) as the discount rate.

PSE currently seeks to acquire as much cost-effective natural gas demand-side resources as quickly as possible. The acquisition rate or "ramp rate" of natural gas sales DSR can be altered by changing the speed with which discretionary DSR measures are acquired. In these bundles, the discretionary measures assume a 10-year ramp rate; in other words, they are acquired during the first 10 years of the study period.

Figure 9-17: Natural Gas DSR Cost Bundles and Savings Volumes (MDth/year)

	DSR Savings Volume (MDth/year)	
	2031	2041
Codes & Standards	725	1,446
Bundle 1: <$0.22	2,393	4,356
Bundle 2: $0.22 to$0.30	2,673	4,672
Bundle 3: $0.30 to $0.45	3,902	7,764
Bundle 4: $0.45 to $0.50	3,932	7,802
Bundle 5: $0.50 to $0.55	3,988	7,898
Bundle 6: $0.55 to $0.62	4,008	7,936
Bundle 7: $0.62 to $0.70	5,112	9,105
Bundle 8: $0.70 to $0.85	5,419	10,093
Bundle 9: $0.85 to $0.95	5,586	10,286
Bundle 10: $0.95 to $1.20	5,812	11,373
Bundle 11: $1.20 to $1.50	7,621	13,341
Bundle 12: >$1.50	10,421	17,051

> > > See Appendix E, Conservation Potential Assessment and Demand Response Assessment*, for more detail on the measures, assumptions and methodology used to develop DSR potentials.*

In the final step, the natural gas portfolio model (GPM) was used to test the optimal level of demand-side resources in each scenario. To format the inputs for the GPM analysis, the cost bundles were further subdivided by market sector and weather/non-weather sensitive measures. Increasingly expensive bundles were added to each scenario until the GPM rejected bundles as not cost effective. The bundle that reduced the portfolio cost the most was deemed the appropriate level of demand-side resources for that scenario. Figure 9-18 illustrates the methodology described above.

Figure 9-18: General Methodology for Assessing Demand-side Resource Potential

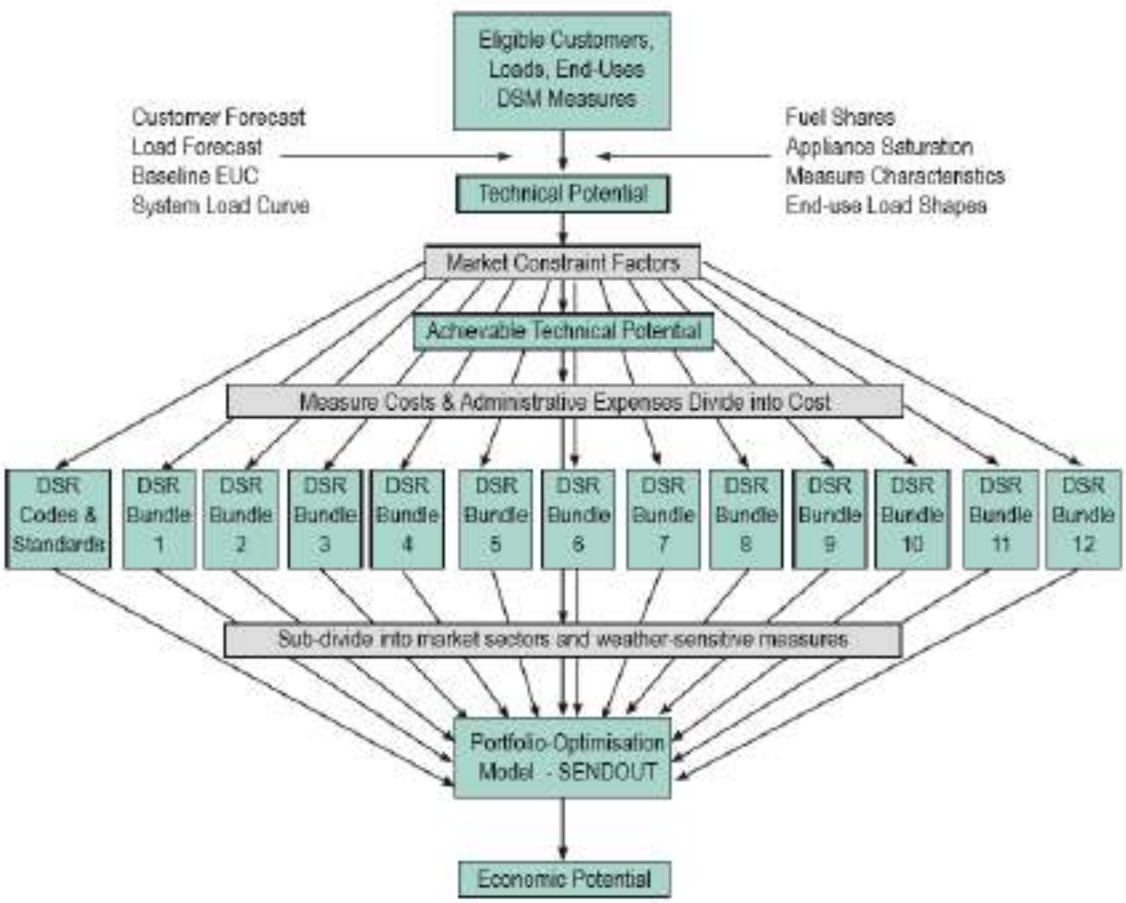


Figure 9-19 shows the range of achievable technical potential among the twelve cost bundles used in the GPM. It selects an optimal combination of each bundle in every customer class to determine the overall optimal level of demand-side natural gas resource for a particular scenario.

Figure 9-19: Demand-side Resources – Achievable Technical Potential Bundles

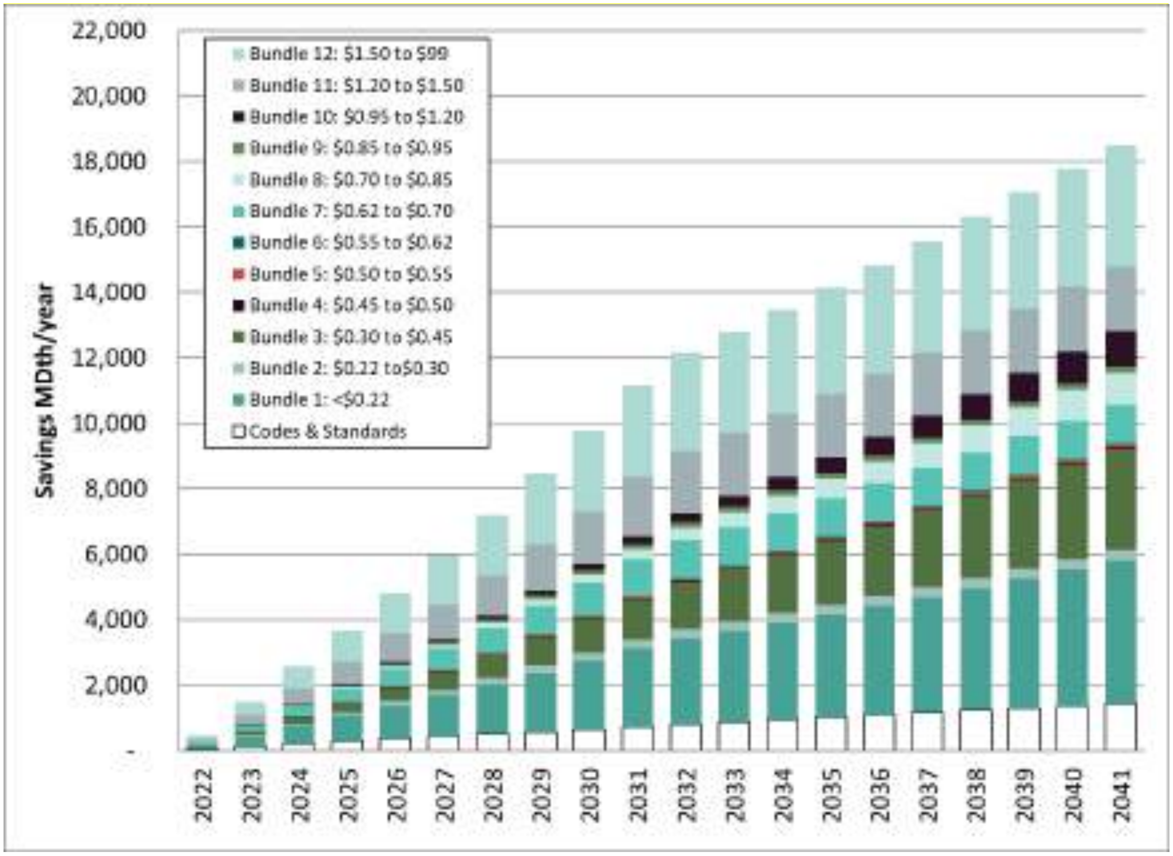
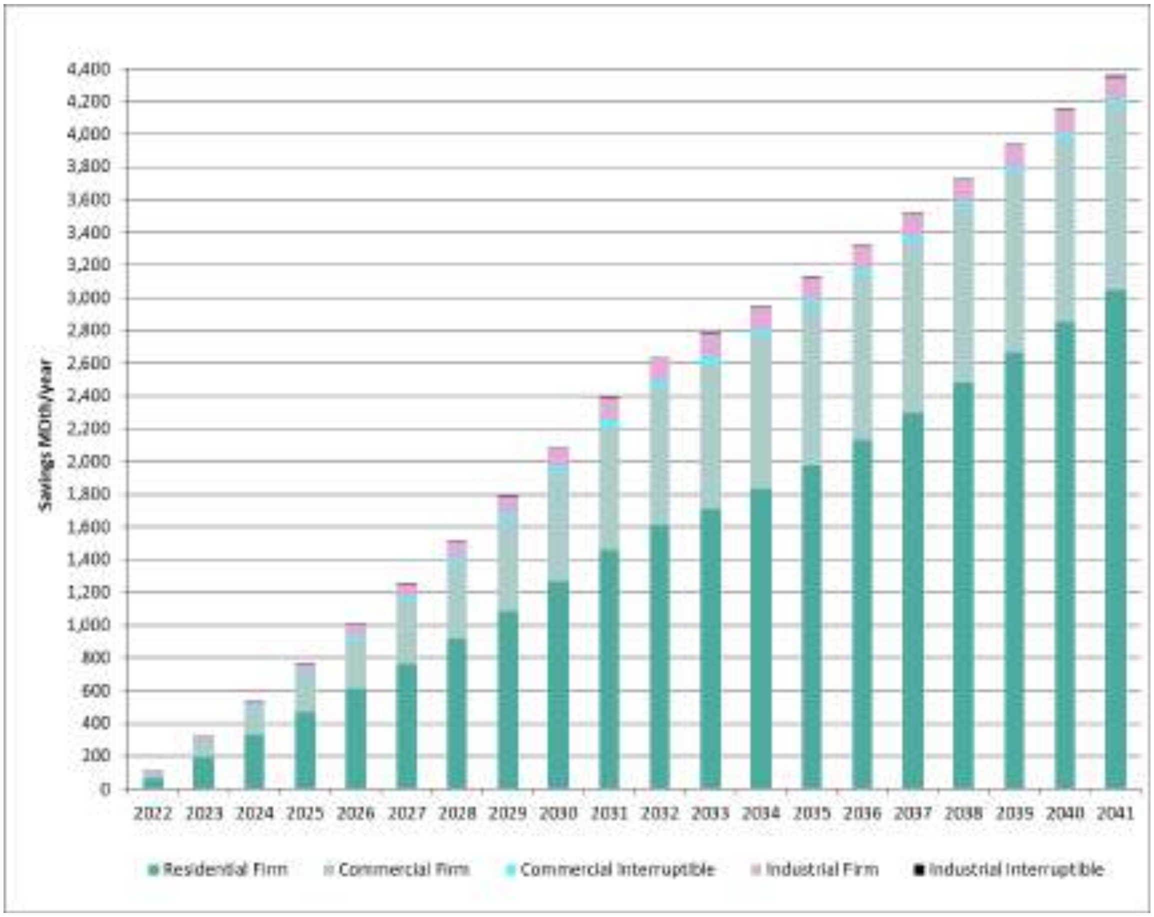


Figure 9-20 shows DSR savings subdivided by customer class. This input format is used in the GPM for all bundles in all the IRP scenarios.

Figure 9-20: Savings Formatted for Portfolio Model Input by Customer Class



5. NATURAL GAS SALES ANALYSIS RESULTS

Key Findings

The key findings from this analytical evaluation will provide guidance for development of PSE's long-term resource strategy, and also provide background information for resource development activities over the next two years.

1. **In the Mid Scenario, the natural gas sales portfolio is short resources beginning in the winter of 2031/32 and each year after that.** The High Scenario also has a deficit starting in 2026/27 and a growing resource shortfall throughout the study, while in the Low Scenario the portfolio is short beginning 2040/41.
2. **Resource needs are primarily met with demand-side resources in the Mid and Low Scenarios.** The gas portfolio model adds the same amount of demand-side resources in both scenarios. In both cases, it added slightly more DSR than is needed to meet the resource need due to the high total natural gas costs resulting from the SCGHG and upstream emissions adders.
3. **The High Scenario has a higher need and is short 165 MDth/day on the peak day in 2041.** The natural gas portfolio model adds the same amount of DSR as in the Mid and Low Scenarios and chooses Plymouth LNG, Swarr and pipeline capacity expansion on Northwest and Westcoast pipelines sourcing natural gas from Station 2 to meet resource need.
4. **Cost-effective DSR is higher in the 2021 IRP.** The cost-effective bundles in all sectors are higher on the supply curve compared to the 2017 IRP. The increase is due to a significant increase in the quantity of new DSR savings in the supply curve and substantially higher natural gas costs. The result is an overall increase in the cost-effective DSR
5. **Cost-effective DSR is the same in all three scenarios.** The total amount of cost-effective DSR chosen in the Mid, Low and High Scenarios did not change. The primary driving factor appears to be the high total natural gas cost, which the DSR helps to offset, thereby reducing portfolio cost.
6. **The Swarr LP-Air upgrade project is cost effective in the High Scenario** and is expected to provide 30 MDth per day of peaking capacity effective November 2037.
7. **The Tacoma area distribution system upgrade project was not needed.** The resource need is low in the 2021 IRP and is mostly filled with cost-effective DSR.

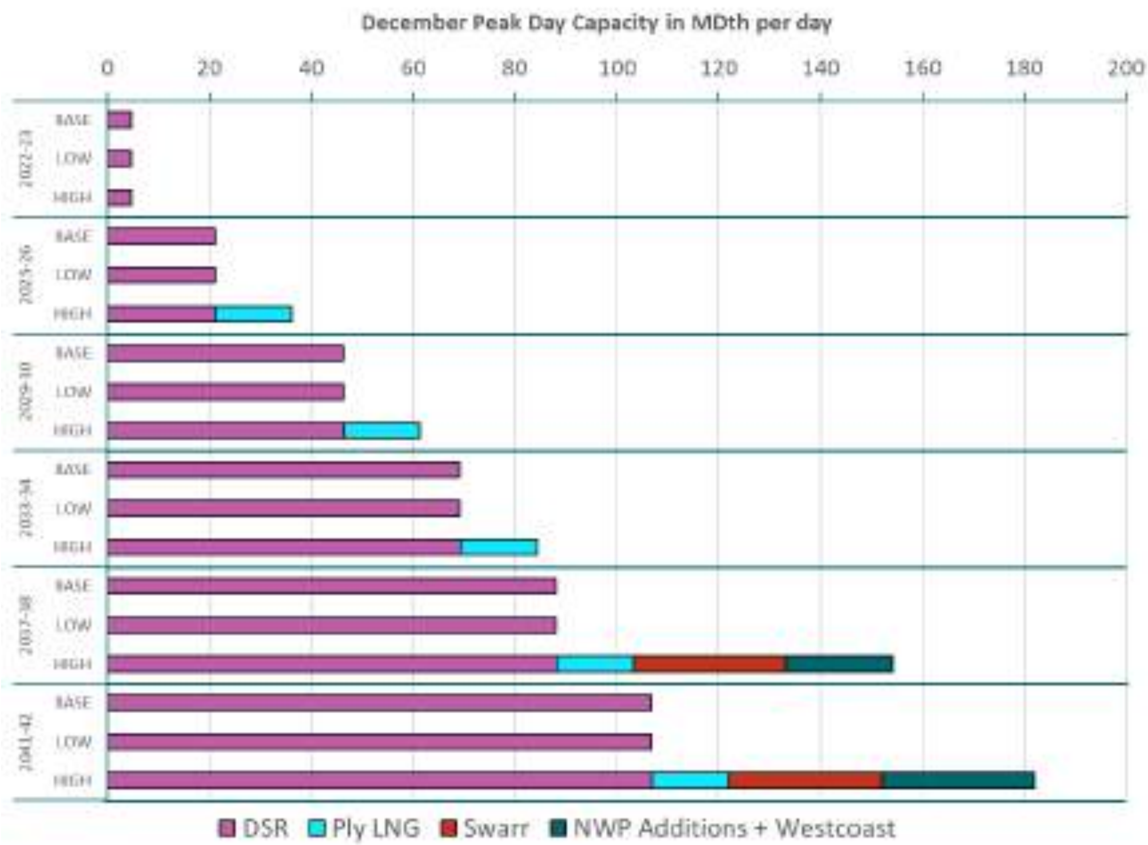
8. **Increased Northwest Pipeline and Westcoast capacity from Station 2 is the favored pipeline alternative in only the High scenario.** The GPM indicates this pipeline capacity is cost effective starting in 2034/35.
9. **Neither the Cross Cascades TC new pipeline or the Fortis BC KORP project are selected in any scenario.** The resource need is low enough to be satisfied by DSR and thus did not warrant a need for these resources. Additionally, these options present other constraints, such as requiring significant demand by third parties or reliance on other projects and timing outside the control of PSE to become viable.
10. **The Mist Storage project was not selected in any of the Scenarios.** The resource need is low in the 2021 IRP and is mostly filled with cost-effective DSR.
11. **The carbon cost assumption was significantly higher in the 2021 IRP compared to the 2017 IRP, and this impacted resource choices.** The levelized cost of carbon adders, which included social cost of greenhouse gases (SCGHG) and upstream emissions, was more than double the levelized natural gas commodity price in all three scenarios. This high cost resulted in greater volumes of demand-side resources being selected in all three scenarios. The high total natural gas cost drove the selection of cost-effective DSR in all three scenarios.
12. **The level of cost-effective DSR found in the deterministic Mid-Low-High Scenarios is a robust result**. In the stochastic analysis, this level of DSR was the preferred resource in over 80 percent of the 250 stochastic runs in which demand and natural gas prices were varied randomly.
13. **Cost-effective DSR reduced both cost and risk in the natural gas portfolio** according to the stochastic analysis.

Natural Gas Sales Portfolio Resource Additions Forecast

Differences in resource additions were driven primarily by three key variables modeled in the scenarios: load growth, natural gas prices and CO_2 price assumptions. Demand-side resources are influenced directly by natural gas and CO_2 price assumptions because they avoid commodity and emissions costs by their nature; however, the absolute level of efficiency programs is also affected by the new supply curve and load growth assumptions. Also, the timing of pipeline additions was limited to five-year increments, because of the size that these projects require to achieve economies of scale.

The optimal portfolio resource additions in each of the three scenarios are illustrated in Figure 9-21 for several winter periods. Combination #1 (NWP plus Westcoast), Combination #5 (Plymouth LNG peaker) and Combination #7 (Swarr LP Plant) are chosen only in High Scenario. The Low and Mid Scenarios both chose only DSR.

Figure 9-21: Natural Gas Resource Additions in 2022/23, 2025/26, 2029/30, 2033/34 and 2041/42 (Peak Capacity – MDth/day)



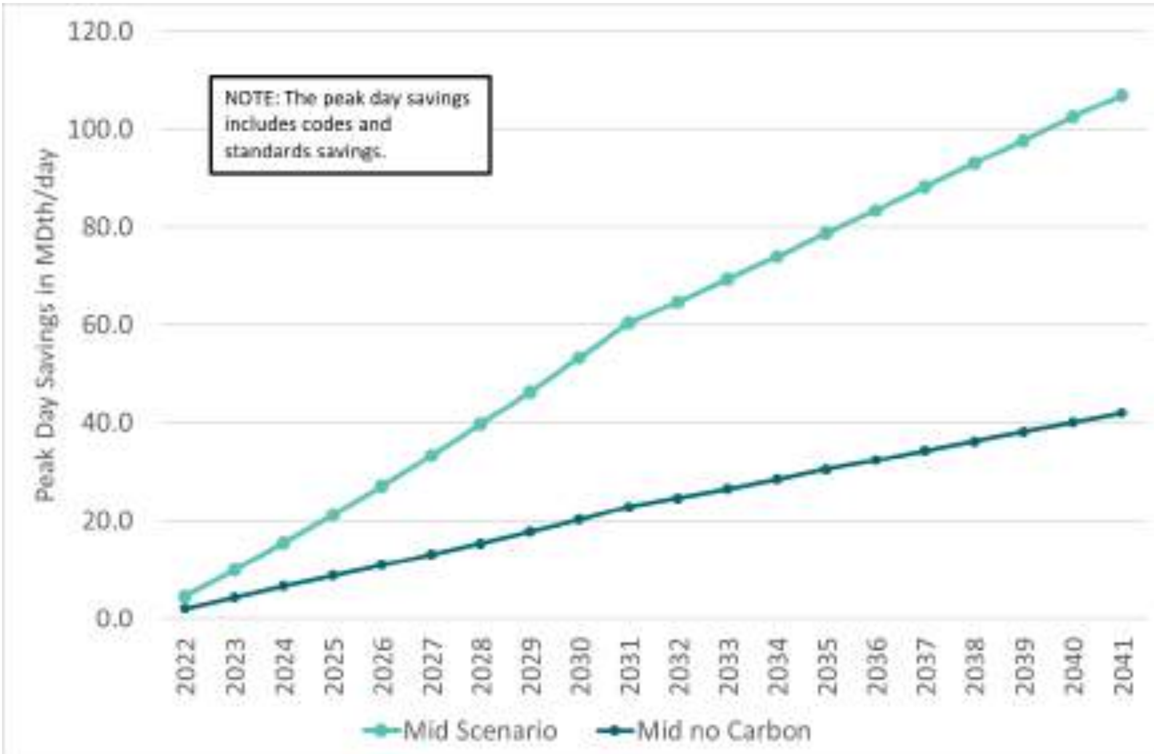
Demand-side Resource Additions

Two categories of demand-side resources are input into the GPM: codes and standards and program measures. Codes and standards is a no-cost bundle that becomes a must-take resource; it essentially functions as a decrement to natural gas demand. Program measures are input as separate cost bundles along the demand-side resource supply curve. The bundles are tested from lowest to highest cost along the supply curve until the system cost is minimized. The incremental bundle that raises the portfolio cost is considered the inflexion point, and the prior cost bundle is determined to be the cost-effective level of demand-side resources.

Carbon costs do impact the amount of cost-effective DSR. Compared to the 2017 IRP, the 2021 IRP carbon costs in the Mid Scenario are significantly higher relative to natural gas prices, which is a function of both declining natural gas prices and higher carbon cost assumptions resulting from carbon legislation passed in the state of Washington in 2019. The carbon legislation requires the inclusion of SCGHG and upstream related carbon emissions. Including these two adders in the price of natural gas results in a total natural gas cost that is over three times the cost of the natural gas itself. This total natural gas cost is what is used to make capacity expansion decisions in the GPM, and in these conditions, DSR is preferred in all scenarios since it is a resource that directly offsets the high total natural gas cost and helps to minimize the portfolio cost.

The sensitivity of DSR to carbon prices is illustrated in Figure 9-22. In the Mid Scenario, when including the carbon adders, cost-effective DSR is 107 MDth per day by 2041/42. This amount is actually more than the resource need in 2041/42 of 88 MDth per day, meaning DSR is being over built by about 19 MDth per day. When the Mid Scenario is run with no carbon adders, using only the natural gas cost, the cost-effective DSR drops to 42 MDth per day. In terms of natural gas supply planning, 42 MDth per day is not a significant volume; however, it does highlight that including a CO_2 price in the IRP Mid Scenario increases conservation. The carbon adders more than double the cost-effective DSR over the 20-year period.

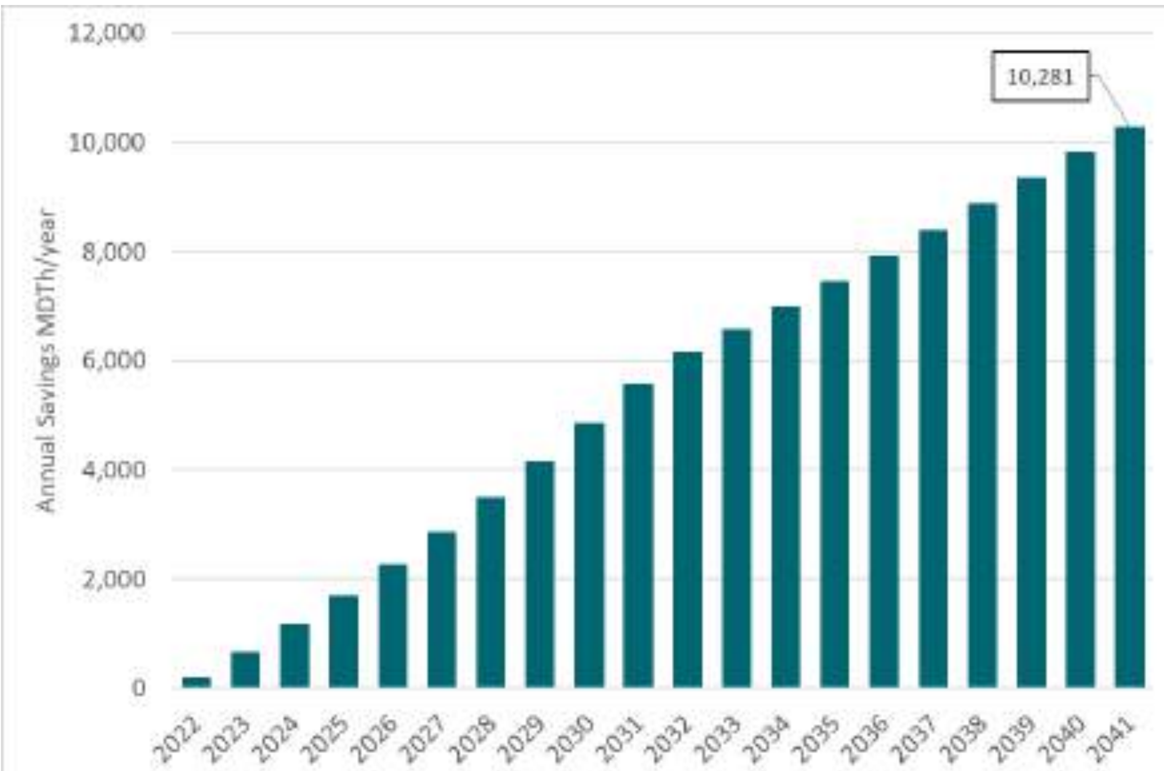
Figure 9-22: Sensitivity of Carbon to Cost-effective Natural Gas Energy Efficiency Savings in the Mid Scenario



DSR is not very sensitive to high avoided costs in the natural gas analysis. The amount of achievable energy efficiency resources selected by the portfolio analysis in this resource plan did not vary by scenario.

Energy savings for all three scenarios are shown in Figure 9-23.

Figure 9-23: Cost-Effective Natural Gas Efficiency, Annual Energy Savings for Mid/Low/High Scenario



The optimal levels of demand-side resources selected by customer class in the portfolio analysis are shown in Figures 9-24 and 9-25, below.

> > > See Appendix E, Conservation Potential Assessment and Demand Response Assessment, *for more detail on this analysis.*

Figure 9-24: Natural Gas Sales Cost-effective DSR Bundles by Class and Scenario

Cost-effective Bundles	Mid	Low	High
Residential Firm	9	9	9
Commercial Firm	9	9	9
Commercial Interruptible	6	6	6
Industrial Firm	9	9	9
Industrial Interruptible	9	9	9

Figure 9-25: Natural Gas Sales Cost-effective Annual Savings by Class and Scenario (MDth/year)

Savings (MDth/year)	Mid	Low	High
Residential Firm	7,984	7,984	7,984
Commercial Firm	2,093	2,093	2,093
Commercial Interruptible	39	39	39
Industrial Firm	156	156	156
Industrial Interruptible	8	8	8
Total (MDth per year)	**10,281**	**10,281**	**10,281**

Overall, the economic potential of DSR in the 2021 IRP is higher than in the 2017 natural gas sales Mid Scenario, and higher-cost bundles are being selected by the analysis as the most cost-effective level of DSR (see Figure 9-26).

The upward shift in overall savings is due to two factors:

- Higher total natural gas costs that include carbon adders for both end-use and upstream emissions.
- Updates to the measure costs and savings assumptions such that the achievable technical potential was higher and some measures shifted to lower cost effective bundles in the 2021 IRP.

It is notable that the two factors above were a much stronger influence than the following factors, which would have reduced the available DSR under normal circumstances:

- A lower demand forecast in the 2021 IRP than the 2017 IRP
- Four additional years of program implementation will elapse between the 2017 IRP and 2022 when the 2021 IRP study starts, which means that four years of conservation implementation will have reduced the available DSR from the supply curve

> > > See Appendix E, Conservation Potential Assessment and Demand Response Assessment, *for more information on the development of DSR bundles.*

Figure 9-26: Cost-effective Natural Gas Energy Efficiency Savings, 2017 IRP vs 2021 IRP

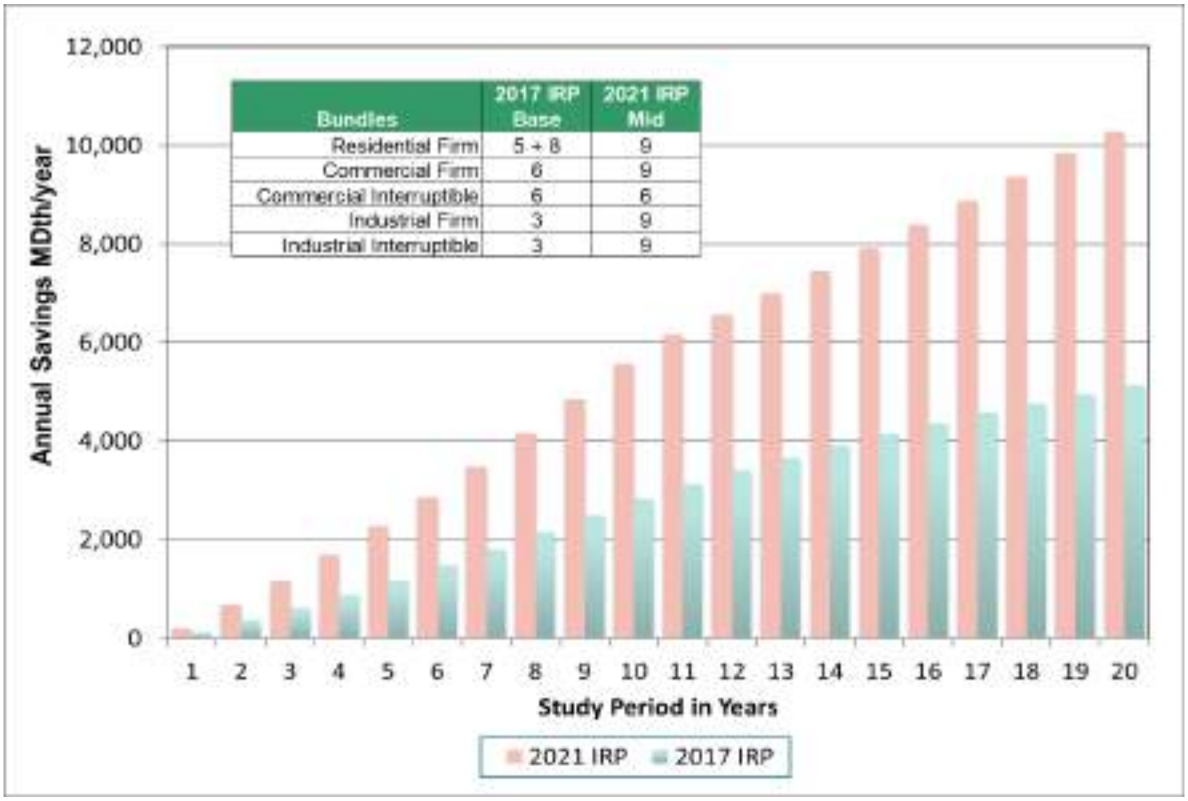


Figure 9-27 compares PSE's energy efficiency accomplishments, current targets and the new range of natural gas efficiency potentials determined by the 2021 IRP. In the short term, the 2021 IRP indicates an economic potential savings of 1,192 MDth for the 2022-2023 period for all three scenarios.[11] These two-year program accomplishments and projections show an upward trend, with the 2021 IRP results indicating that the trend is accelerating due to higher avoided costs and more cost-effective saving measures in the supply curve.

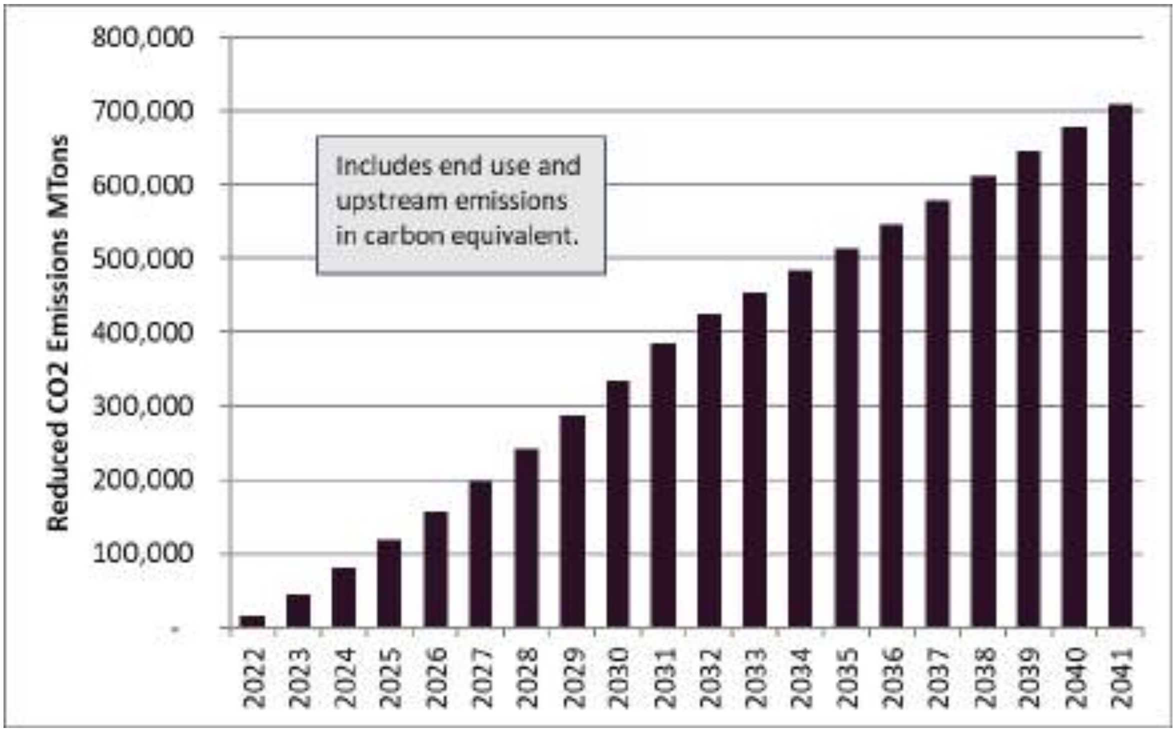
Figure 9-27: Short-term Comparison of Natural Gas Energy Efficiency in MDth

Short-term Comparison of Natural Gas Energy Efficiency	2-year Program Savings (Mdth)
2018-2019 Actual Achievement	699
2020-2021 Target	795
2022-2023 Economic Potential in 2021 IRP Scenarios	1,192

11 / *These savings are based on a no-intra year ramping, which is used to set conservation program targets.*

Figure 9-28 shows the impact on CO_2 emissions from energy efficiency measures selected in the Mid, Low and High Scenarios.

Figure 9-28: CO_2 Emissions Reduction from Energy Efficiency in Mid, Low and High Scenarios



Peaking Resource Additions

The Swarr LP-Air upgrade project and the Plymouth LNG peaker contract were selected as least cost in only the High Scenario due to the higher resource need created by the higher demand forecast in this scenario.

Pipeline Additions

Pipeline expansion alternatives were made available as early as the 2025/26 winter season, a bit later than the other non-pipeline alternatives were made available. The pipelines were not available earlier due to the lead time needed to develop these resources, but this was not a constraint to the portfolio model. The pipelines were chosen only in the High Scenario, which had a higher resource need due to higher demand. In the High Scenario, the GPM selected 30MDth a day of NWP with Westcoast from Station 2 in the out year.

The other pipeline additions offered in Combinations #2 (KORP) and #3 (Cross Cascades) were not economical in any of the scenarios.

Observation

All of the selected resources (listed here in general order of least cost) – DSR, Plymouth LNG Peaker, Swarr LP-Air, and Northwest + Westcoast pipeline expansion – are within PSE's control (with the exception of the pipeline expansion). The timing of individual projects can be fine-tuned by PSE in response to load growth changes, and none of these projects rely on participation by another contracting party in order to be feasibly implemented.

Complete Picture: Natural Gas Sales Mid Scenario

A complete picture of the Mid Scenario optimal resource portfolio for natural gas sales is presented in graphical and table format in Figures 9-29 and 9-30, respectively.

> > > ***See Appendix I, Natural Gas Analysis Results,*** *for additional scenario results.*

Figure 9-29: Natural Gas Sales Mid Scenario Resource Portfolio

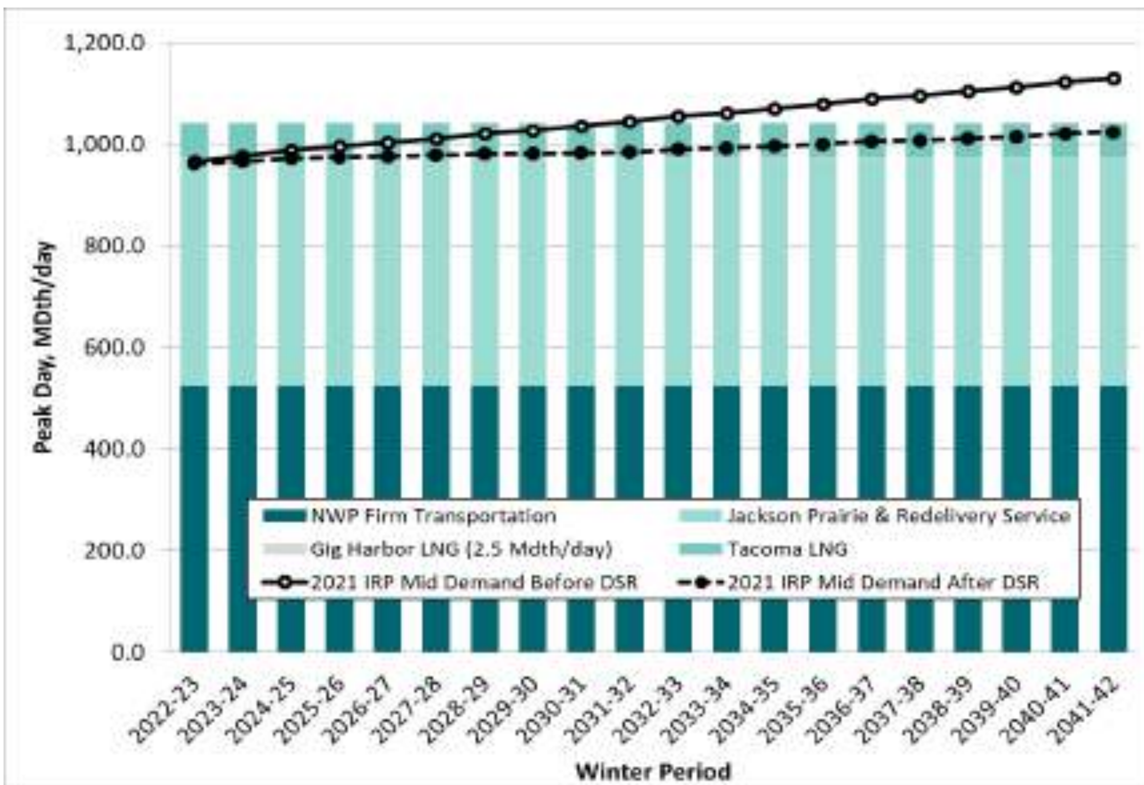


Figure 9-30: Natural Gas Sales Mid Scenario Resource Portfolio (Table)

		Winter Period		
Resource Alternative	Option	2025/26	2030/31	2041/42
NWP Additions + Westcoast	#1	-	-	-
KORP	#2	-	-	-
NWP from AECO	#3	-	-	-
Mist Storage	#4	-	-	-
Ply LNG	#5	-	-	-
LNG Tacoma Distr	#6	-	-	-
Swarr	#7	-	-	-
DSR	DSR	21	53	107
Total in MDth/day		**21**	**53**	**107**

Average Annual Portfolio Cost Comparisons

Figure 9-31 should be read with the awareness that its value is comparative rather than absolute. It is not a projection of average purchased gas adjustment (PGA) rates; instead, costs are based on a theoretical construct of highly incrementalized resource availability. Also, average portfolio costs include items that are not included in the PGA. These include forecast rate-base costs related to Jackson Prairie storage, the Tacoma LNG Project and Swarr LP-Air, as well as costs for energy efficiency programs, which are included on an average levelized basis rather than a projected cash flow basis. Also, note that the perfect foresight of a linear programming model creates theoretical results that cannot be achieved in the real world.

Figure 9-31: Average Portfolio Cost of Natural Gas for Gas Sales Scenarios

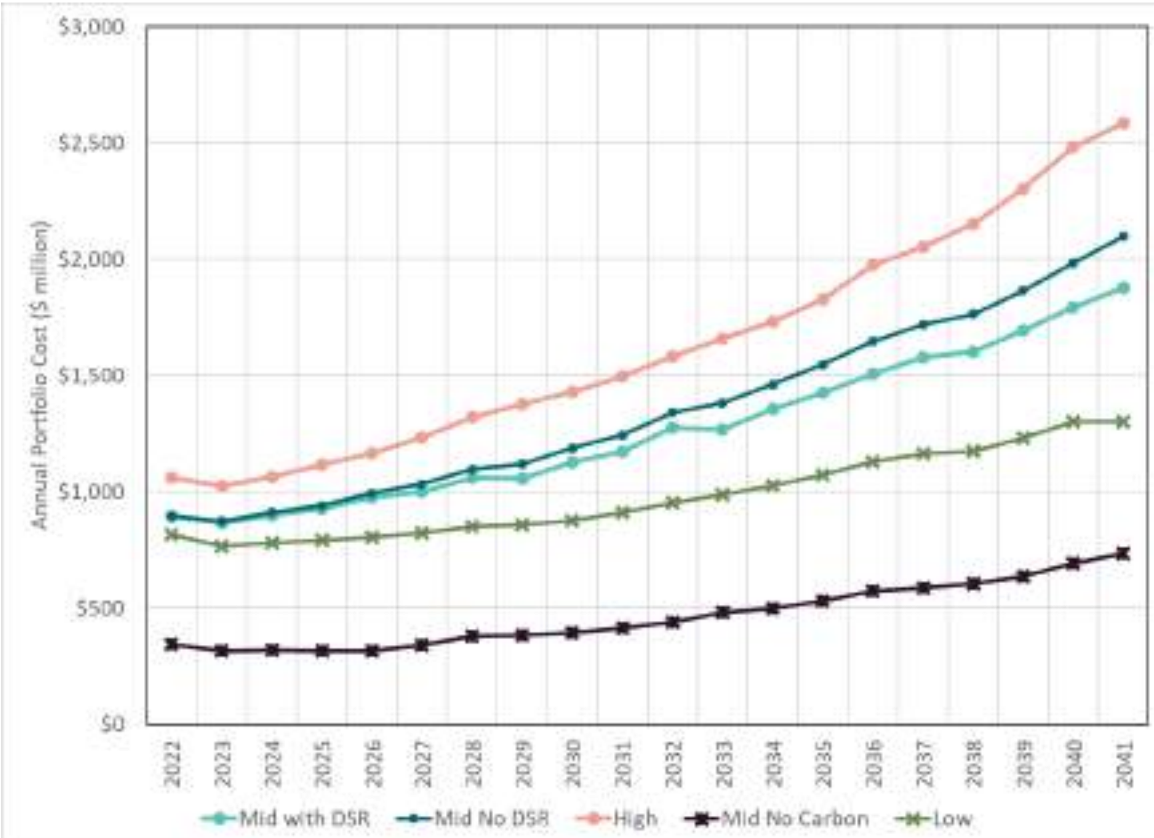


Figure 9-31 shows that average optimized portfolio costs are heavily impacted by natural gas prices and CO_2 cost assumptions included in each scenario.

- The assumed total cost of natural gas supply has the greatest influence on portfolio costs. Natural gas costs were high and relatively close in all three scenarios, and the resulting average portfolio costs were also high and fairly close to each other in comparison to the Mid No Carbon case shown above.
- DSR produces significant savings, as shown by the Mid Scenario with DSR versus the Mid No DSR lines. The approximate NPV benefit to the portfolio from DSR is about $500 million.

Sensitivity Analyses

Five sensitivities were modeled in the natural gas sales analysis for this IRP. Sensitivities start with the Mid Scenario portfolio and change one resource, regulation or condition. This allows PSE to evaluate the impact of a single change on the portfolio.

A. AR5 Upstream Emissions

This sensitivity uses the AR5 methodology for calculating the upstream natural gas emissions rate instead of the AR4 methodology.

BASELINE ASSUMPTION: PSE will use the AR4 Upstream Emissions calculation methodology.
SENSITIVITY > PSE will use the AR5 Upstream Emissions calculation methodology.

This sensitivity results in higher emission rates for both the Canadian and U.S. sourced natural gas. Figure 9-32 shows the emission rates for AR4 and AR5.

Figure 9-32: Upstream Emissions for AR4 and AR5

Sensitivity A	(Canadian Supply) gCO2e/MMBtu	(Domestic Supply) gCO2e/MMBtu
AR4	10,803	12,121
AR5	11,564	13,180

AR5 slightly increased total natural gas costs (see Figure 9-33), but made no change to the resource mix in the Mid Scenario. The GPM selected the same level of DSR as in the Mid Scenario, but portfolio costs were higher due to the increased upstream emissions adder (see Figure 9-34).

Figure 9-33: Upstream Emission Costs in $/MMBtu AR4 vs. AR5

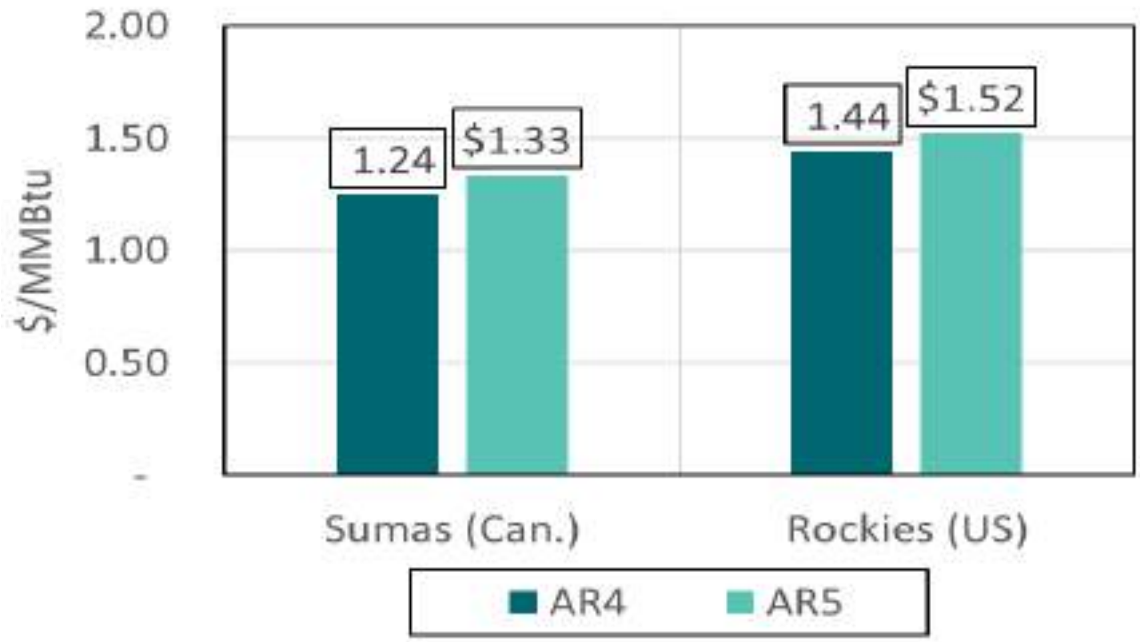


Figure 9-34: 20-year NPV for AR5 Portfolio vs. AR4 Portfolio

Sensitivity A	Portfolio NPV, $ billion
Mid Scenario with AR4	$12.660
Mid Scenario with AR5	$12.758

B. 6-year Conservation Ramp Rate

This sensitivity changes the ramp rate for conservation measures from 10 years to 6 years, allowing PSE to model the effect of faster adoption rates.

BASELINE ASSUMPTION: Conservation measures ramp up to full implementation over 10 years.
SENSITIVITY > Conservation measures ramp up to full implementation over 6 years.

The GPM selected the same bundles as in the Mid Scenario, however, the DSR was front-loaded due to the faster ramp rate on the discretionary DSR measures. The overall savings in the 20-year study period did not change (see Figure 9-35), but since the DSR was captured earlier, the NPV of the portfolio was lower (see Figure 9-36)

Figure 9-35: Savings from 6-year Ramp Rate vs. 10-year Ramp Rate

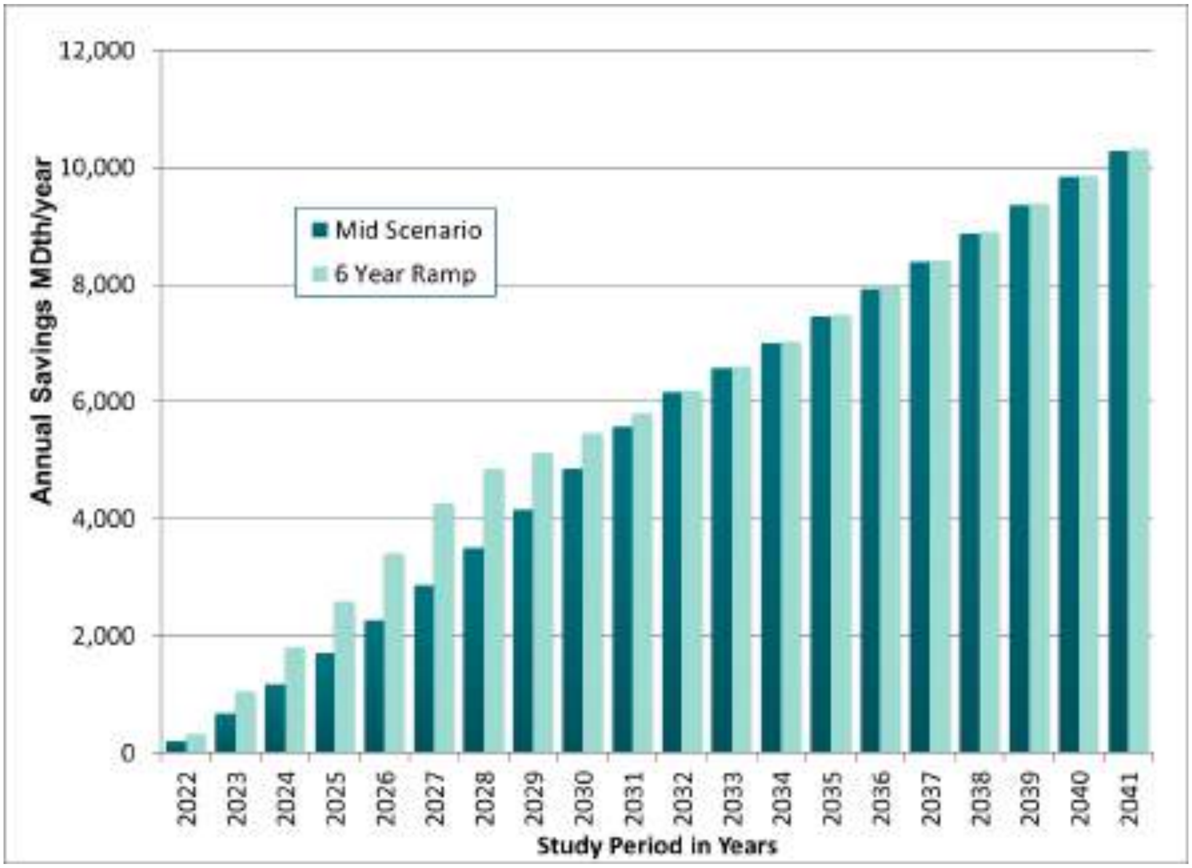


Figure 9-36: NPV for 6-year Ramp Rate vs. 10-year Ramp Rate

Sensitivity B	Portfolio NPV, $ billion
Mid Scenario with 10-year Ramp Rate	$12.660
Mid Scenario with 6-year Ramp Rate	$12.623

C. Social Discount Rate for DSR

This sensitivity changes the discount rate for DSR projects from the current discount rate of 6.8 percent to 2.5 percent. By decreasing the discount rate, the present value of future DSR savings is increased, making DSR more favorable in the modeling process. DSR is then included as a resource option with the new financing outlook.

BASELINE ASSUMPTION: The discount rate for DSR measures is 6.8 percent.
SENSITIVITY > The discount rate for DSR measures is 2.5 percent.

A social discount rate that was lower than PSE's assigned WACC was applied to the demand-side resource alternative in this sensitivity analysis to find out if it would result in a higher level of cost-effective DSR. The alternate discount rate was modeled as the 2.5 percent nominal discount rate referenced in CETA SCGHG legislation. The 2.5 percent discount rate shifted measures to lower cost points on the conservation supply curve. Since the social discount rate caused the measures to shift to lower cost bundles, the net effect was that cost-effective savings were slightly higher using the social discount rate.

See Figures 9-37 and 9-38 for the DSR savings comparison.

Figure 9-37: Savings by Bundle, 6.8% Discount Rate in IRP Mid Scenario vs. 2.5% Social Discount Rate in Sensitivity C

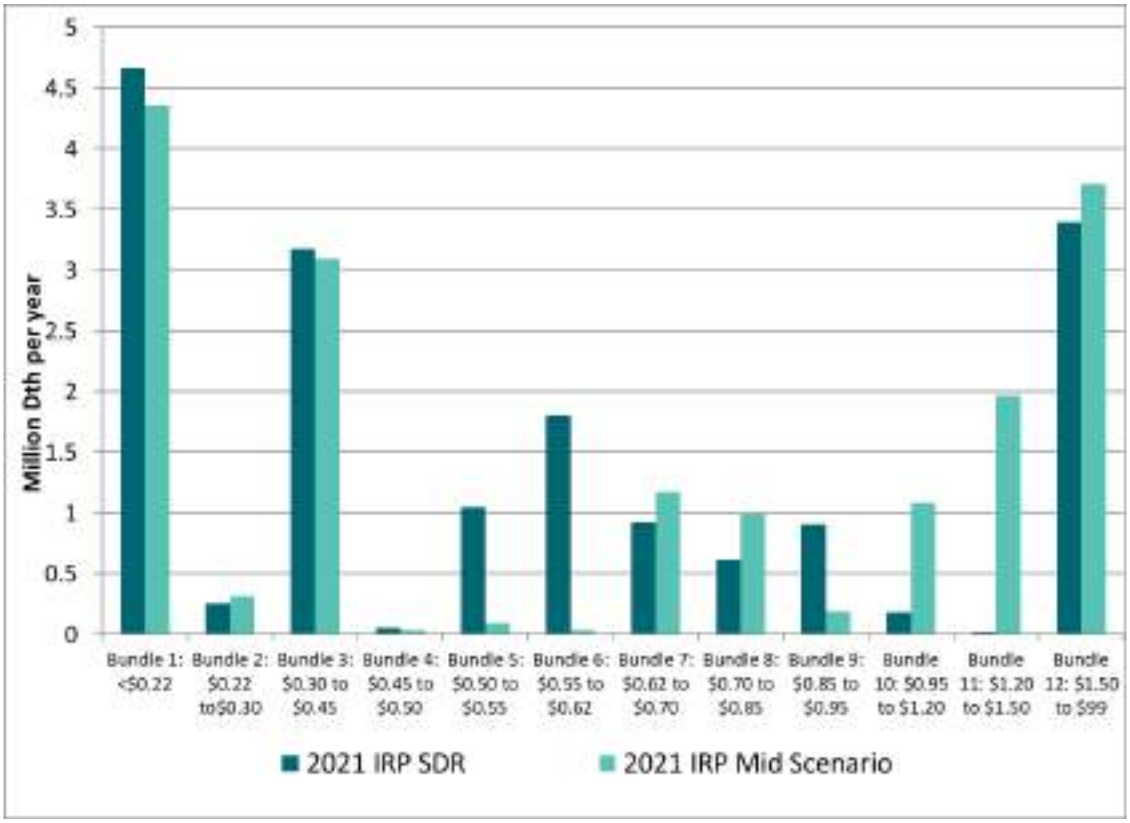


Figure 9-38 Cost-effective Level of Natural Gas DSR, 6.8% Mid Scenario Discount Rate vs. 2.5% Social Discount Rate

Sensitivity C Savings	6.8% Mid Scenario (Mdth/year)	2.5% Social Discount Rate (Mdth/year)
Residential Firm	7,984	9,613
Commercial Firm	2,093	2,107
Commercial Interruptible	39	39
Industrial Firm	156	156
Industrial Interruptible	8	8
Total (MDth per year)	**10,281**	**11,923**

D. Fuel Switching, Gas to Electric

This sensitivity models accelerated adoption of gas-to-electric conversion within the PSE service territory. Results from this sensitivity illustrate the effects of a rapid replacement of gas end uses with electricity as their fuel on the portfolio and the demand profile of the PSE service territory. For the purpose of this IRP and this gas to electric scenario, electric energy and peak demand potential estimates apply only to PSE's electric service territory and exclude the impacts on other electric utilities. There are many possible fuel switching pathways, and PSE presents this sensitivity as one possible view. Further analysis is required to understand all of the impacts and costs associated with fuel switching.

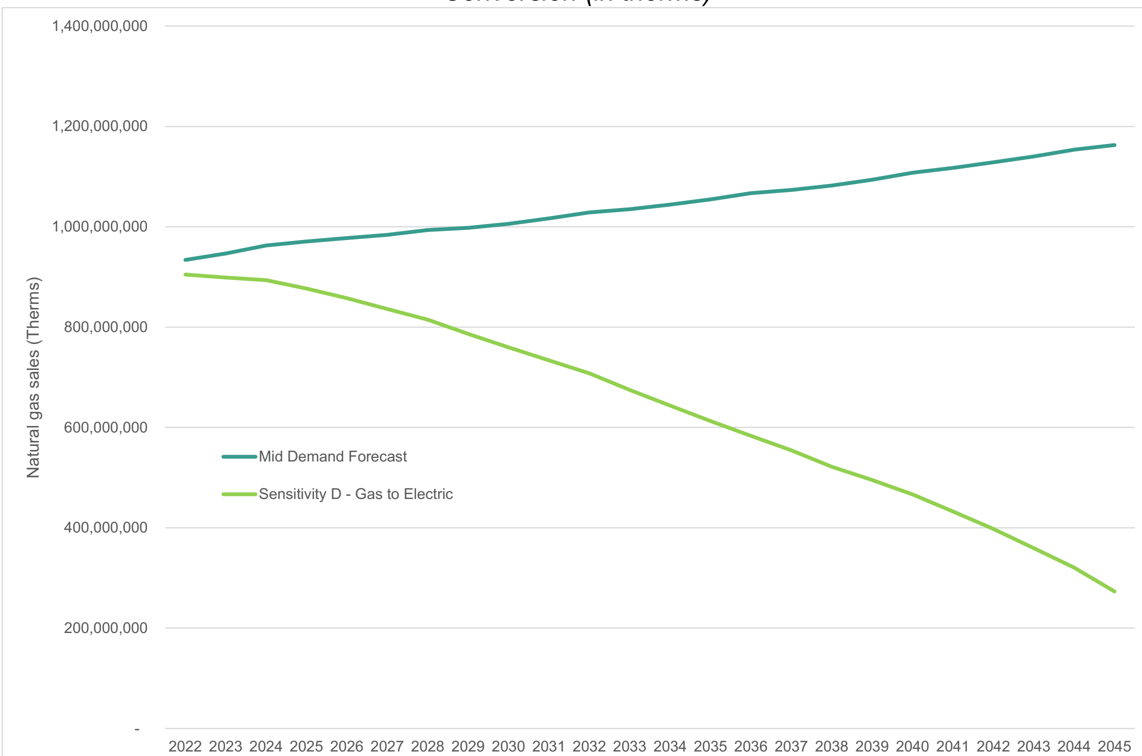
Figure 9-39: Gas to Electric Fuel Switching Assumptions

	Assumption
PSE Customer Base	Energy demand is reduced based on the hybrid heat pumps included in the mid demand forecast for the natural gas portfolio.
Hybrid Heat Pumps	Hybrid heat pumps rolled out for existing and new construction. By 2030, 50% of the total addressable achievable potential will be attained, and by 2050, 100% of the achievable technical potential will be completed. The end uses will include space heating loads with a natural gas backup heat pump.
Other End Uses (water heating, cooking, etc)	Converted to electric uses
Industry Electrification	30% of all the electric loads in the industrial sector are converted from natural gas to electric by 2050

BASELINE ASSUMPTION: The portfolio uses the demand forecast for the Mid Scenario.
SENSITIVITY > The demand forecast is adjusted to include an accelerated replacement of natural gas end uses with electricity in the PSE service territory resulting in a lower natural gas demand forecast.

This sensitivity looks not only at the impacts to the natural gas portfolio, but it also accounts for the cumulative annual electric energy impacts to PSE's system of converting natural gas equipment for each customer sector. The residential sector shows the biggest impact, accounting for 53 percent and 60 percent of the total cumulative energy impacts in 2030 and 2045, respectively. Compared to the total PSE electric load forecast in the Mid Scenario, these impacts represent additional electric energy loads of 7.9 percent in 2030 and 35.5 percent in 2045, and additional electric peak demands of 6 percent and 17 percent in 2030 and 2045, respectively. For the natural gas sales system, the residential sector accounts for 68 percent of the total natural gas reductions in 2030 and 73 percent of total natural gas reductions 2045. Compared to PSE's total 2019 natural gas sales, natural gas sales decrease by 21 percent by 2030 and 74 percent by 2045.

Figure 9-40: Annual Natural Gas Sales – Mid Demand Compared to Sensitivity D, Electric to Gas Conversion (in therms)

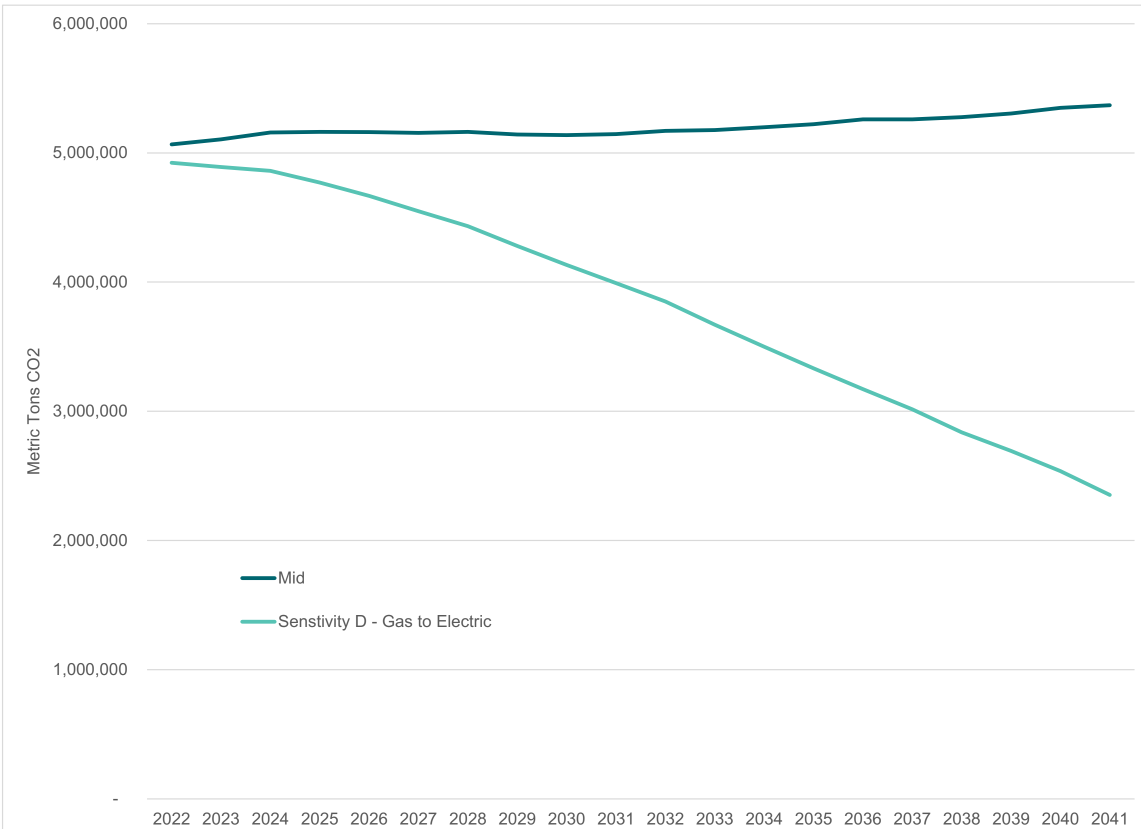


For the residential and commercial sectors, PSE calculated the number of natural gas equipment units that could be converted to electric equipment in PSE's service area for both existing equipment and new construction. Then each natural gas unit was matched to an equivalent electric equipment; annual energy consumption, peak demand and cost assumptions were then applied to the electric equipment to calculate the total impact of conversion.

To mitigate the peak demand impacts of additional winter space heating loads to the electric system, this sensitivity modeled replacing existing residential construction natural gas furnaces with a hybrid air-source heat pump with natural gas backup that switches from electric space heating to natural gas when the outdoor air temperature is equal to or less than 35 degrees Fahrenheit. This had little impact on natural gas peak demand since the hybrid heat pump still relies on natural gas as a backup fuel. A full discussion of equipment and impacts by sector is located in Appendix E.

The cost of the conversion was added to the natural gas portfolio. Because of this, portfolio costs increased from $12.66 billion in the Mid Scenario to $14.95 billion in Sensitivity D. The conversion also decreased loads and emissions in the natural gas portfolio. Emissions decreased by 20 percent in 2030 and 47 percent by 2040

Figure 9-41: Natural Gas Emissions – Mid Scenario and Sensitivity D (metric tons CO_2)



Since this sensitivity affects both the natural gas and electric portfolios, combined portfolio costs are also provided. Figures 9-42 and 9-43 compare the combined electric and natural gas portfolio costs for the Mid Scenario and Sensitivity D, and Figure 9-44 compares the direct (generation) and indirect (market) emissions of the combined portfolios. For this analysis, the electric portfolio did not include alternative compliance to achieve carbon neutrality by 2030. Also not included were additional costs associated with fuel switching (such as appliance or process replacement), changes to the electric and natural gas distribution systems and any incremental transmission needs.

Figure 9-42: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity D

		24-year Levelized Costs (Billions $)			
	Portfolio	Electric	Natural Gas	Total	Change from Mid
1	Mid Scenario	$15.53	$12.66	$28.19	--
D	Fuel Switching, Gas to Electric	$19.56	$14.95	$34.51	$6.32

Figure 9-43: Natural Gas and Electric Annual Portfolio Costs

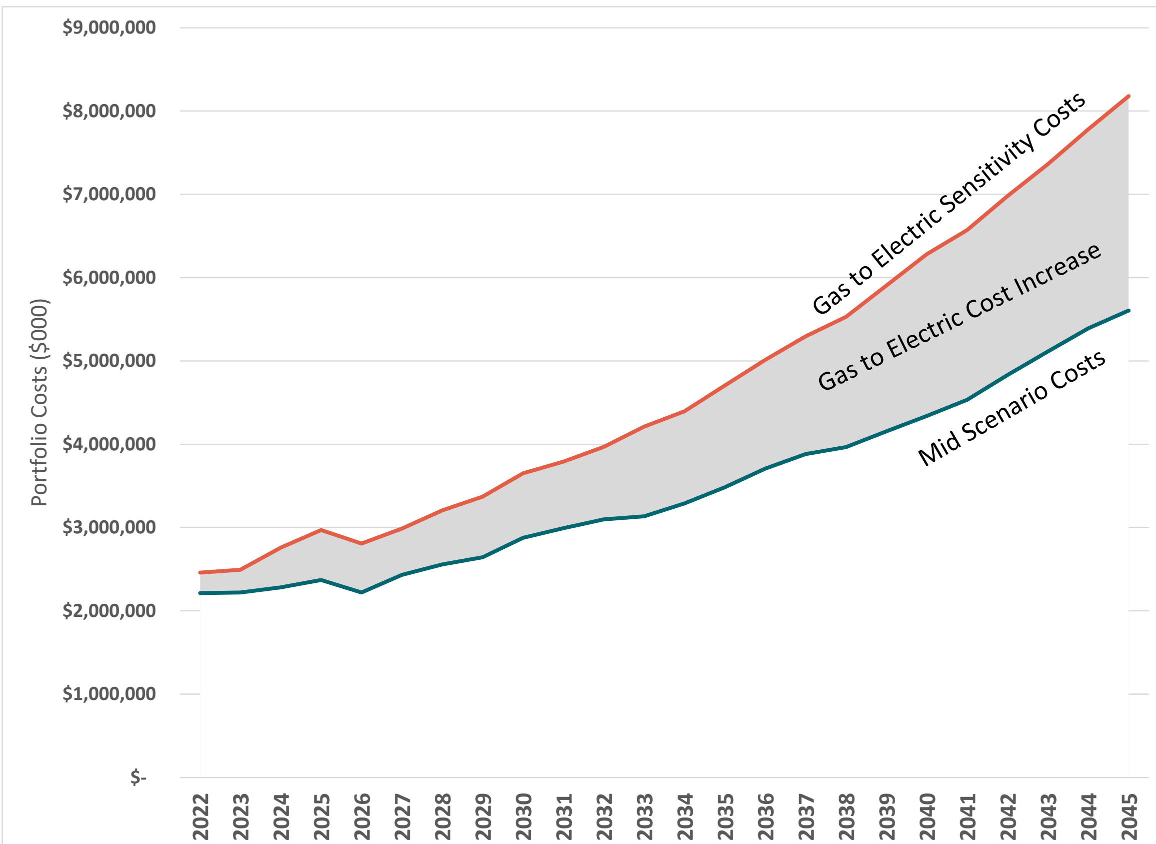
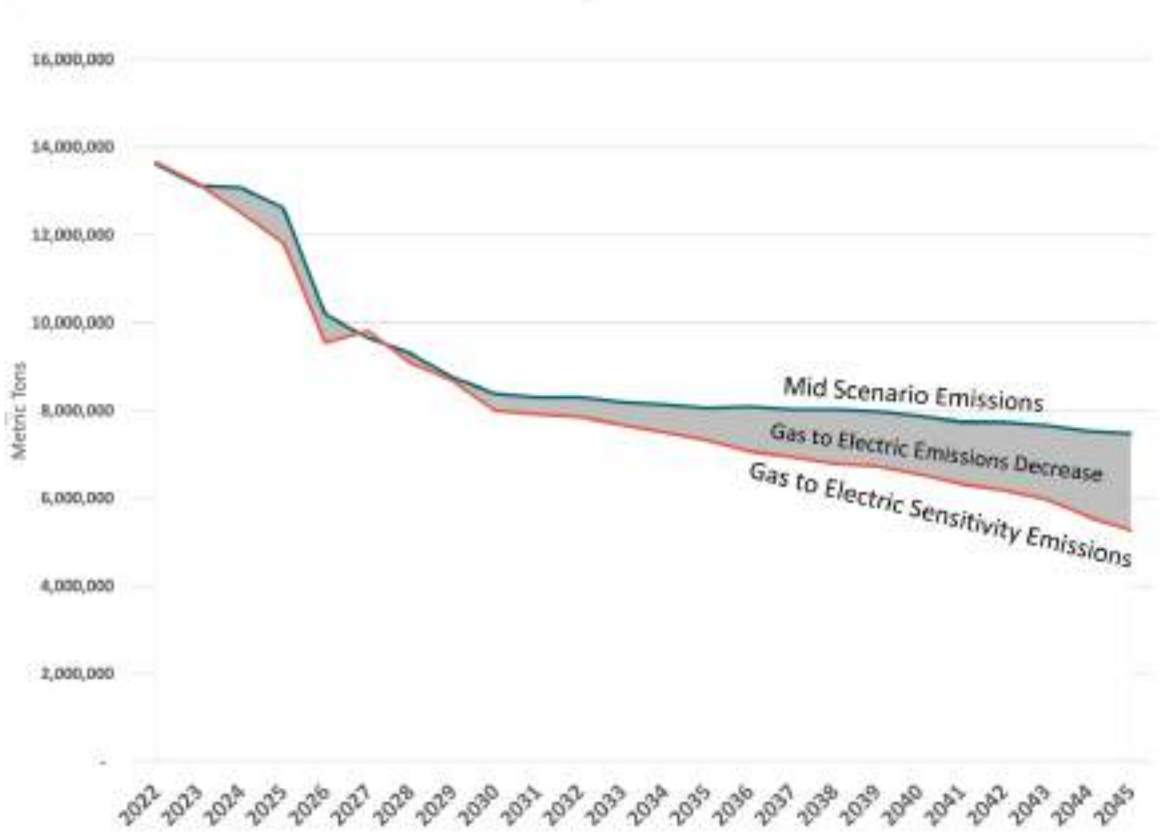


Figure 9-44: Direct and Indirect Portfolio Emissions – Mid Scenario and Sensitivity D, (not including alternative compliance for the electric portfolio)



To put emission reductions into perspective, it is useful to look at the reduction in emissions as a function of portfolio cost (or, the cost of emissions reduction). To calculate this metric, PSE divides the difference in the 24-year levelized cost between the sensitivity and the Mid Scenario by the difference in 24-year levelized emissions between the Mid Scenario and the sensitivity:

$$\frac{Sensitivity\ 24yr\ Levelized\ Cost\ - Mid\ Sc\ 24\ yr\ Levelized\ Cost}{Mid\ 24yr\ Levelized\ Emissions - \ Sensitivity\ 24yr\ Levelized\ Emissions}$$

Figure 9-45 shows the results of this calculation for Sensitivity D. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent.

Figure 9-45: Cost of Emissions Reduction – Mid Scenario and Sensitivity D

Portfolio	Combined GHG Emissions (millions tons CO_2eq, 24-year levelized)	Combined Portfolio Cost ($ billions, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	116	$28.19	-
D Gas to Electric	109	$34.51	1.11

E. Temperature Sensitivity

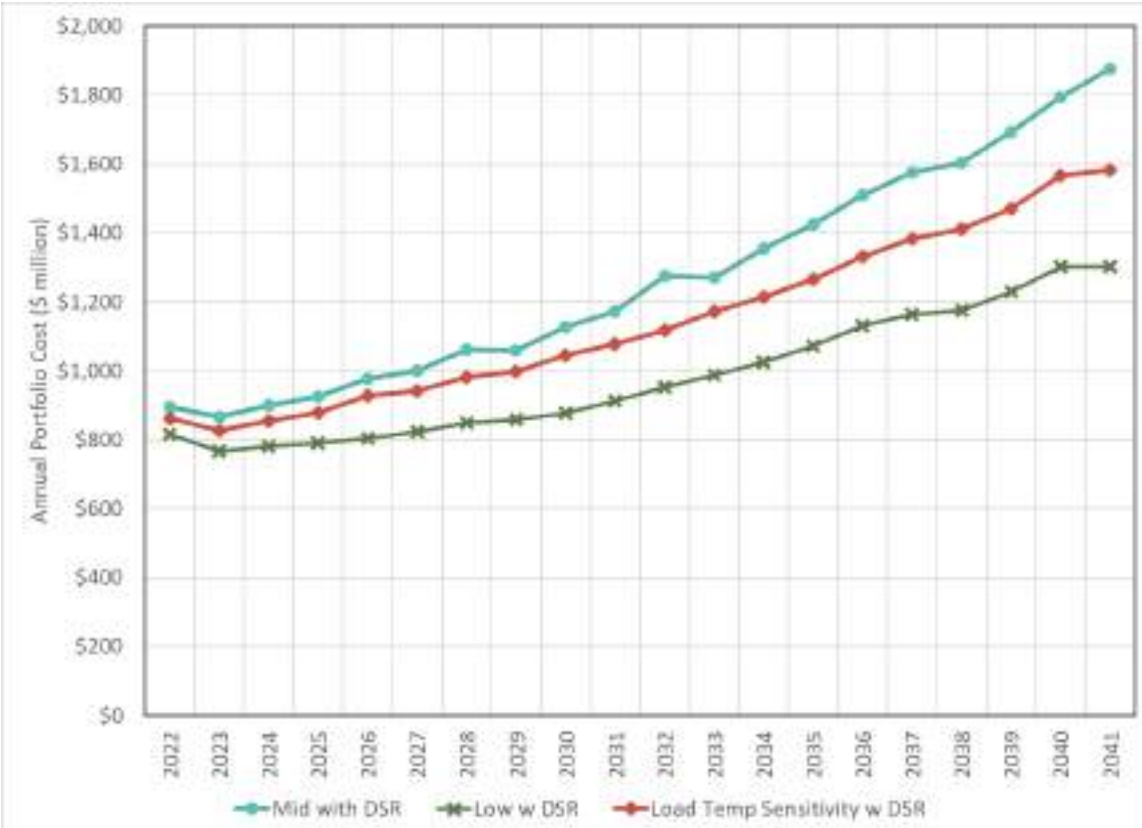
This sensitivity models a change in temperature trends, adjusting the underlying temperature data of the demand forecast to emphasize the influence of more recent years. This change attempts to show the effect of rising temperature trends in the Pacific Northwest. Results from this sensitivity will illustrate changes in PSE's load profile.

BASELINE ASSUMPTION: The Base Demand Forecast used in the Mid Scenario is based on "normal" weather, defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the past 30 years ending in 2019.

SENSITIVITY > PSE uses temperature data from the Northwest Power and Conservation Council (the "Council"). The Council is using global climate models that are scaled down to forecast temperatures for many locations within the Pacific Northwest. The Council weighs temperatures by population from metropolitan regions throughout the Northwest. However, PSE also received data from the Council that is representative of Sea-Tac airport. This data is, therefore, consistent with how PSE plans for its service area and is not mixed with temperatures from Idaho, Oregon or eastern Washington. The climate model data provided by the Council is hourly data from 2020 through 2049. This data resembles a weather pattern in which temperatures fluctuate over time, but generally trend upward. For the load forecast portion of the temperature sensitivity, PSE has smoothed out the fluctuations in temperature and increased the heating degree days (HDDs) and cooling degree days (CDDs) over time at 0.9 degrees per decade, which is the rate of temperature increase found in the Council's climate model.

The temperature sensitivity resulted in higher average temperatures, and a reduction in the load forecast of about 15 percent by 2045. This did not impact the peak design day, so the GPM selected the same resource mix in the capacity expansion; in other words, the same cost-effective DSR was selected as in the Mid Scenario portfolio. Total system costs were slightly lower than the Mid Scenario portfolio, as a lower load led to lower natural gas need, but they were not as low as system costs in the Low Scenario portfolio. This is shown in Figure 9-46 below.

Figure 9-46: Total Portfolio Cost of Natural Gas for Gas Sales Temperature Sensitivity



F. No DSR

This portfolio looks at the benefits associated with demand-side resources.

BASELINE ASSUMPTION: New energy efficiency resources are acquired when cost effective and needed.

SENSITIVITY > No new energy efficiency is allowed in the portfolio and all future needs will be met by supply-side resources.

Because the assumed total cost of natural gas supply has the greatest influence on portfolio costs and natural gas costs were high and relatively close in all scenarios, DSR produces significant savings. The approximate NPV benefit to the portfolio from DSR is about $500 million.

Stochastic Analyses

In order to test the portfolios developed in the deterministic scenario analysis under a wider range of demand and natural gas prices, PSE completed three stochastic runs in the GPM, with each run consisting of 250 draws:

1. **Resource/Cost Optimization**: This analysis tested the Mid Scenario deterministic portfolio against 250 variations (draws) of different demand and natural gas price combinations. The model was allowed to change the resource additions to optimize portfolio cost for the different demand and price conditions.
2. **No DSR Portfolio:** Starting with the Mid Scenario deterministic portfolio and the same 250 variations of demand and natural gas price combinations, this analysis removed DSR as a resource option to learn what other resources would be selected to fill need, and to compare the portfolio costs and risks of the No DSR portfolio with the portfolio optimized with DSR.
3. **Mid Fixed Portfolio:** This analysis tested the robustness of the Mid Scenario deterministic portfolio.The Mid Scenario final resource portfolio was fixed and then run through the 250 demand and natural gas price combinations to evaluate the portfolio's cost and reliability risks.

Development of Input Draws

The development of natural gas price draws and demand draws is the starting point for the stochastic analysis. Eighty natural gas price draws were developed using the risk functionality tool in the electric AURORA model, mirroring the gas price and demand draws used in the electric analysis. For the demand draws, the 250 draws that the load forecasting group used to develop the Low and High Scenarios were used.

NATURAL GAS PRICE DRAWS. For the Sumas, AECO, Rockies and Stanfield natural gas hubs, the natural gas stochastic analysis used the same 80 natural gas price draws developed for the electric stochastic analysis.[12] Natural gas prices for Station 2 and Malin were generated in the GPM using the basis differential pricing off one of the four hubs. The 80 draws were also repeated to create 250 draws. For each hub, a total of 19,200 prices (80 draws x 12 months/year x 20 years), were repeated to obtain 60,000 prices for each hub.

12 / The natural gas price draws were developed from the monthly forecasts that were used in the deterministic models, taking hub and lag correlations into account. See Appendix G, Electric Analysis Models, for a more detailed description of the methodology.

Each natural gas price draw was then adjusted to include the SCGHG and upstream emission adders in the GPM. Figures 9-47 and 9-48 below show the adjustment for Sumas hub for 2022 prices. With the addition of SCGHG and upstream emissions, the expected natural gas price shifted from $2.25/MMBtu to $7.57/MMBtu.

Figure 9-47: Sumas Price Draws for 2022 without SCGHG and Upstream Emission Adders

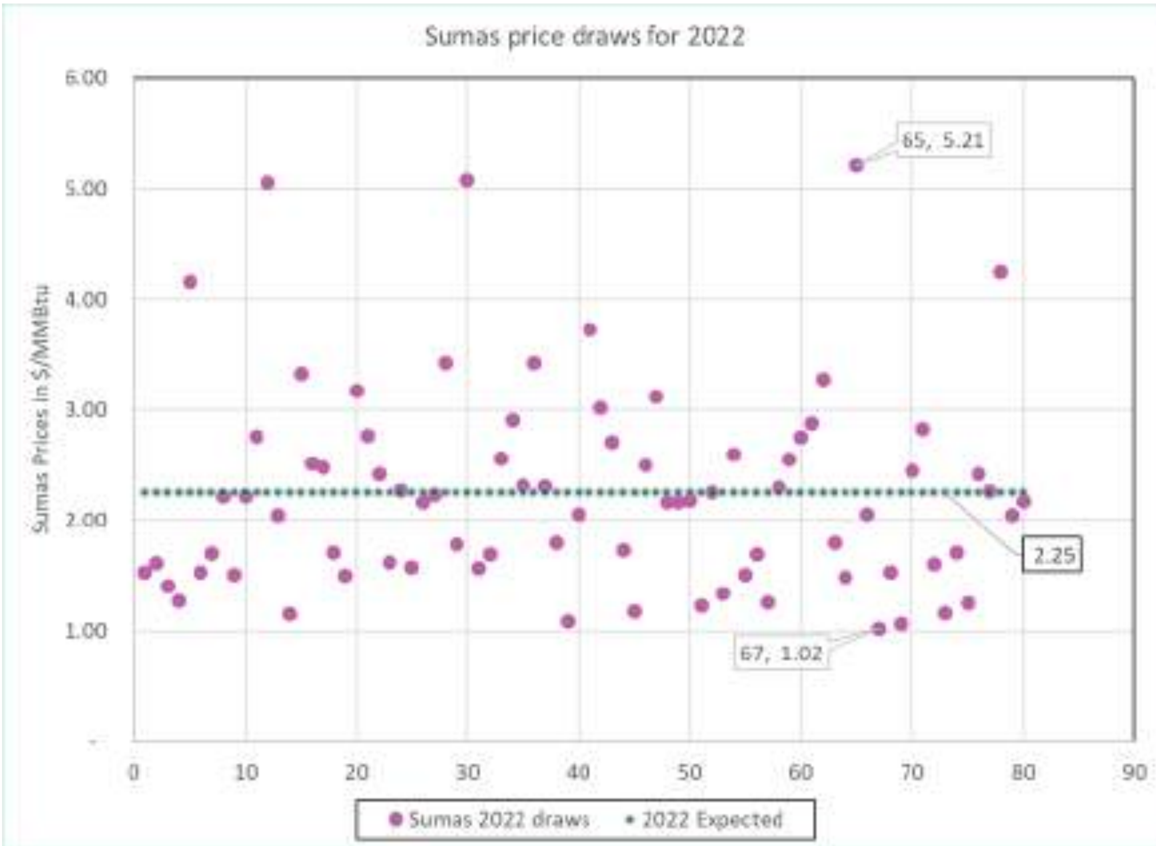
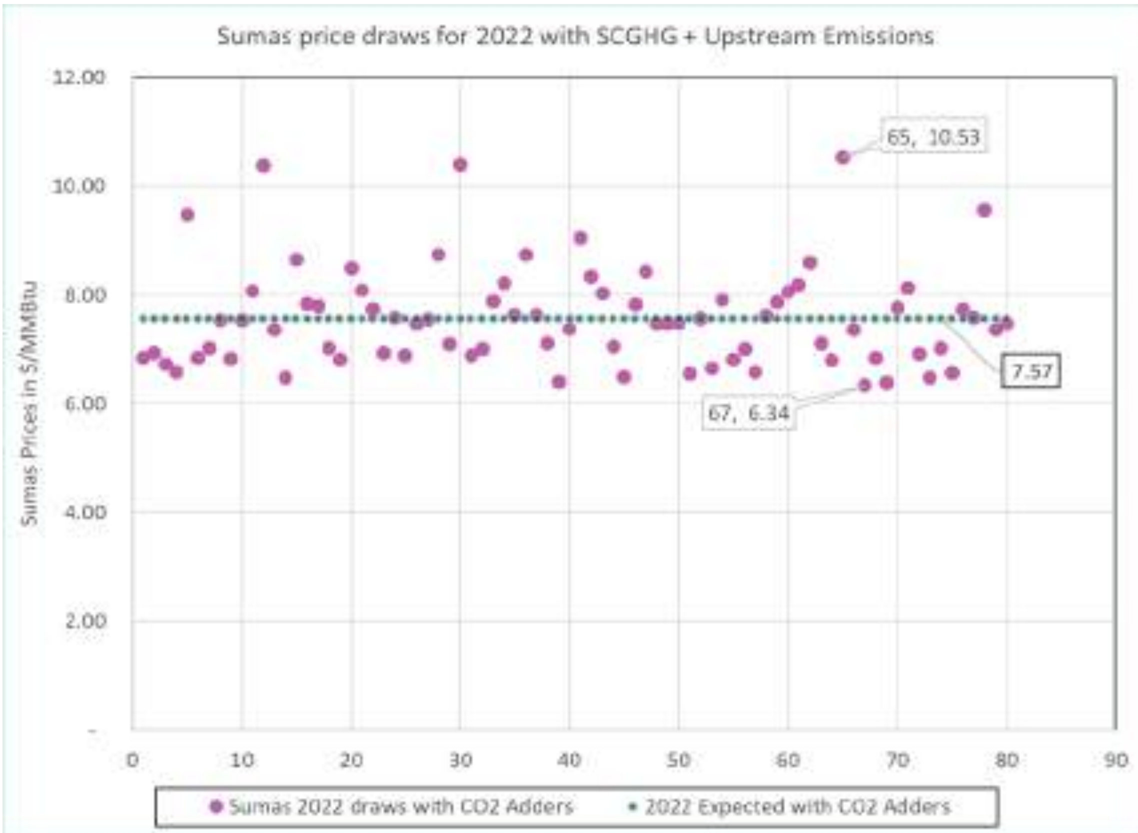
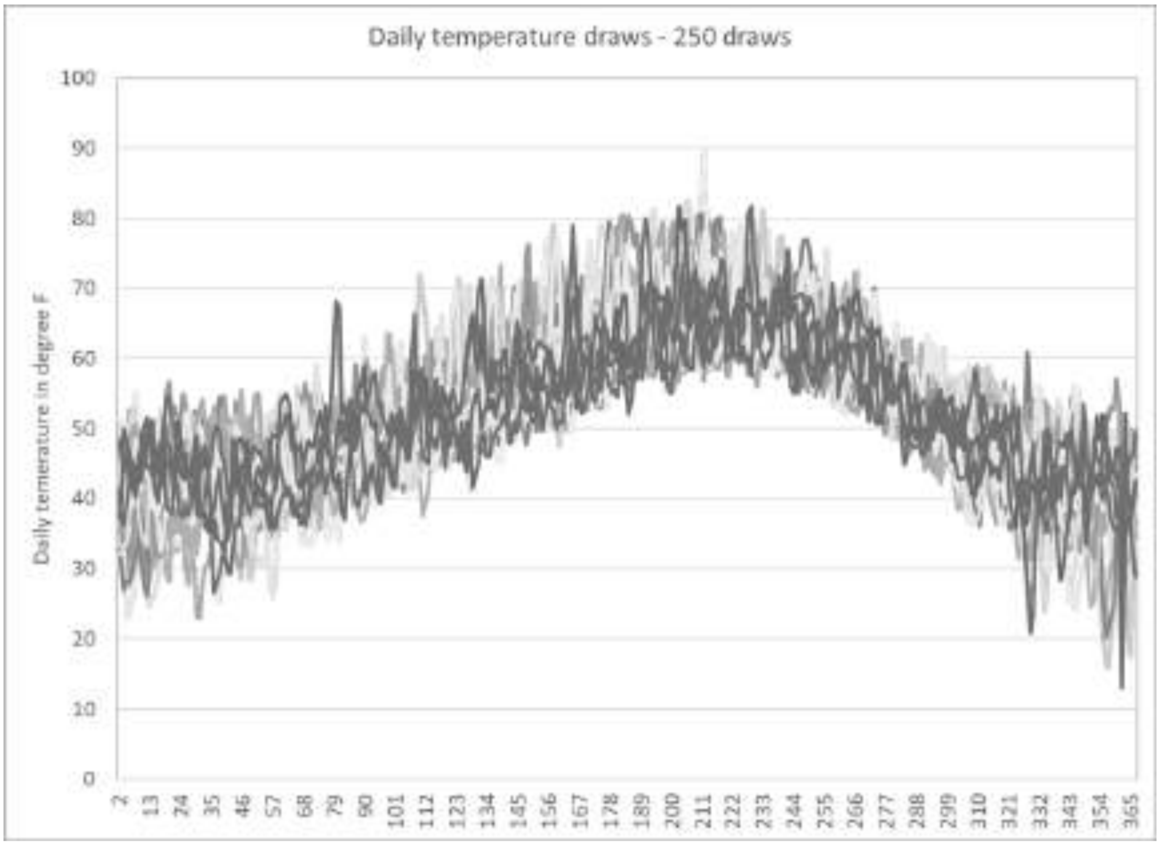


Figure 9-48 – Sumas Price Draws for 2022 after Adjusting for SCGHG and Upstream Emissions Adders



DEMAND DRAWS. The GPM uses temperature draws to calculate demand. The 250 demand draws were developed from the "normal" weather data used in the Base Demand Forecast, defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the past 30 years ending in 2019. Before the draws were imported into the GPM, they were adjusted to include the natural gas planning peak day temperature. Figure 9-49 below shows the temperature draws.

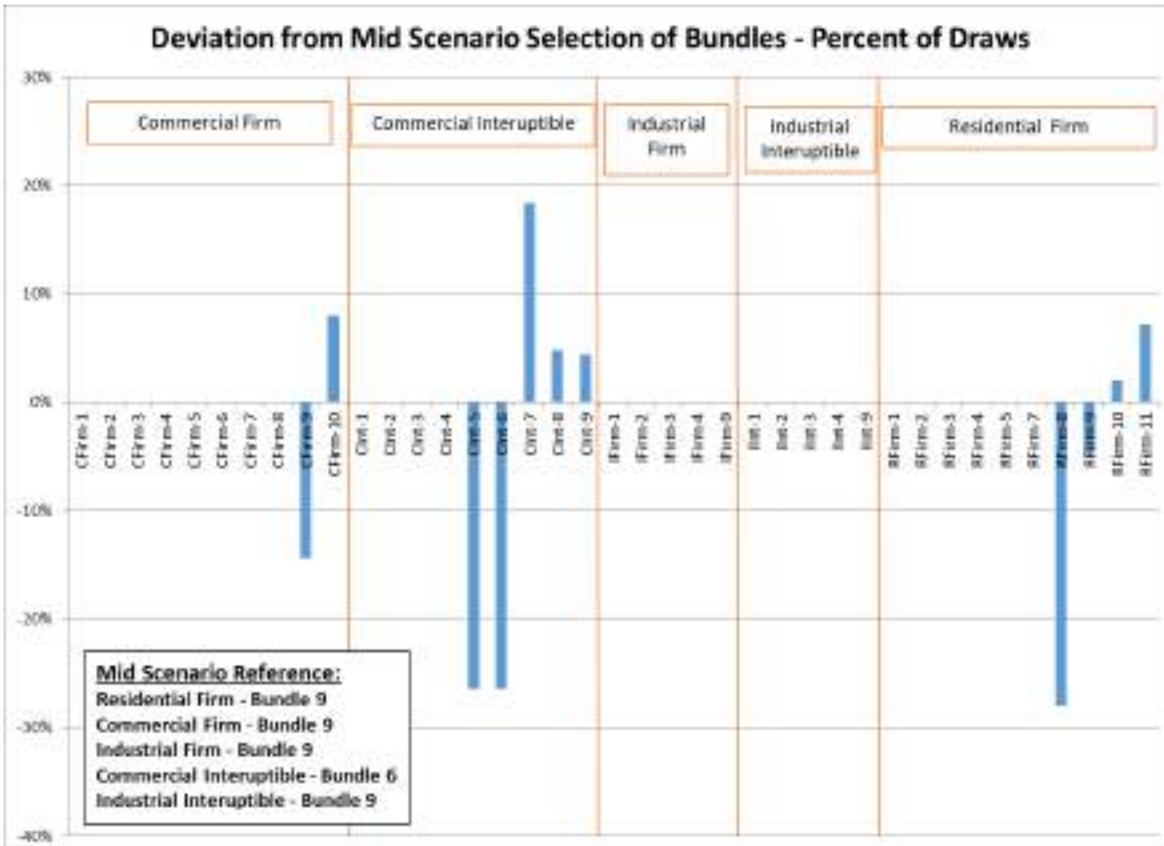
Figure 9-49 – Daily Temperature Draws for Demand



Stochastic Analysis Results

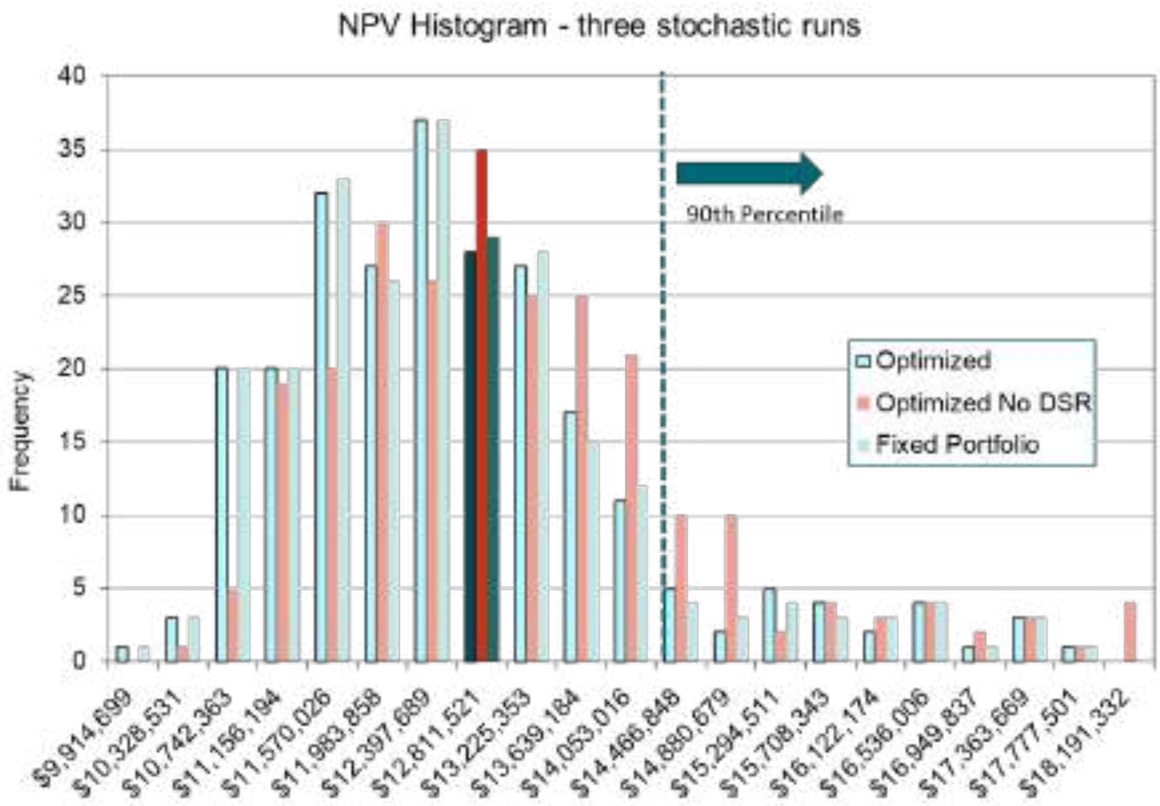
In the 250 optimal portfolios built in the stochastic analysis, the results showed that the DSR quantity chosen in the deterministic scenarios held up in over 80 percent of the draws as shown in Figure 9-50. Therefore, the risk of over-building or under-building DSR appears to be low.

Figure 9-50: Results of DSR Selection in the 250 Fully Optimized Portfolio Runs



The results of all three stochastic analyses are plotted in the histogram shown in Figure 9-51. The portfolio with No DSR has higher costs and more draws in the 90th percentile of total system cost, showing that DSR reduces both cost and risk to the natural gas portfolio.

Figure 9-51: Distribution of Portfolio System Costs



6. NATURAL GAS DELIVERY SYSTEM ANALYSIS

Overview

PSE's natural gas delivery system is responsible for delivering gas safely, reliably and on demand. PSE is also responsible for meeting all regulatory requirements that govern the system. To accomplish this, PSE must do the following.[13]

- Operate and maintain the system safely and efficiently on an annual, daily and real-time basis.
- Ensure the system meets both peak demands and day-to-day demands at the local level and system level.
- Meet state and federal regulations and complete compliance-driven system work.
- Address reliability performance and system integrity concerns.
- Integrate natural gas supply resources owned by PSE or others.
- Monitor and improve processes to meet future needs including customer and system trends and customer desires so infrastructure will be in place when the need arrives.

The goal of PSE's planning process is to fulfill these responsibilities in the most cost-effective manner possible. Through it, PSE evaluates system performance and bring issues to the surface; identify and evaluate possible solutions; and explore the costs and consequences of potential alternatives. This information helps us make the most effective and cost-effective decisions going forward.

Delivery system planners prepare both 10-year plans required for the IRP and annual implementation plans. This section describes the current process for developing both. Planning begins with assessing needs followed by evaluating solution alternatives and recommendations. Need assessments begin with county- and local-level load forecasts and an evaluation of the system's current performance and future needs based on data analysis and modeling tools. Planning considerations include internal inputs such as integrity indices, company goals and commitments, and the root causes of historic events. External inputs include service quality indices, regulations, municipality infrastructure plans, customer complaints and ongoing service issues. Solution assessment includes identifying alternatives to meet the need and comparing these alternatives against one another. A recommended

13 / These obligations are defined by various codes and best practices such as WAC 480-90 Gas Companies - Operations; WAC 480-93 Gas Companies - Safety; WAC 480-100-358:398 Part VI Safety and Standard Rules; Code of Federal Regulations (CFR) Title 18; CFR Title 49; FERC Order 1000; Occupational Safety and Health Administration; and Washington Industrial Safety and Health Administration.

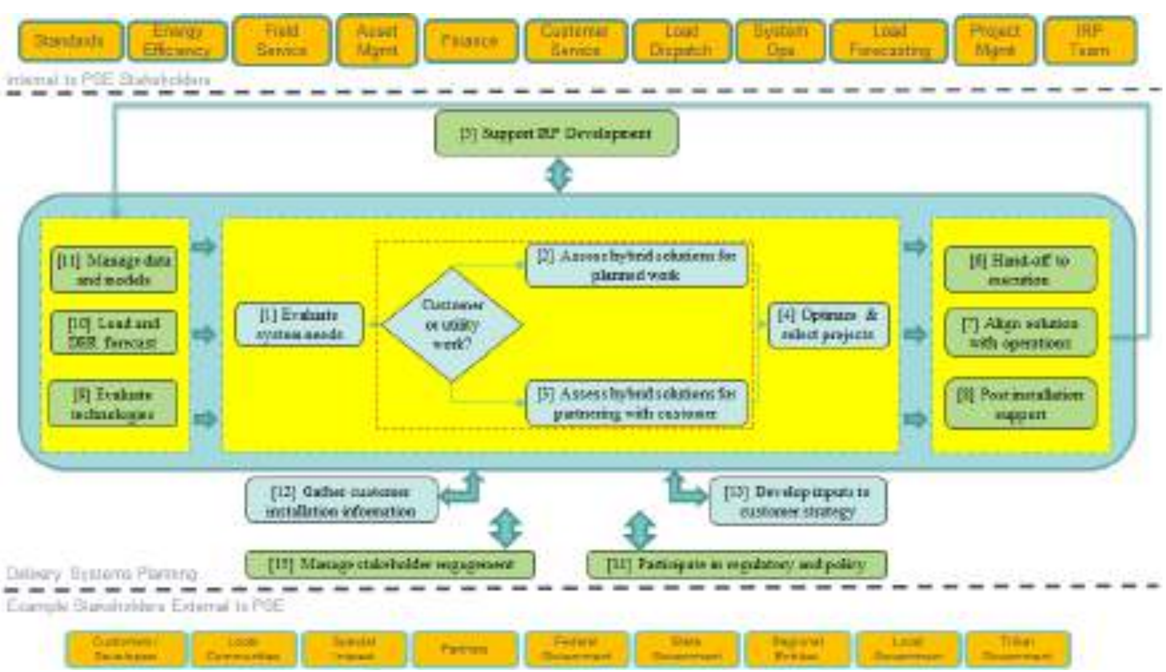
alternative(s) is identified that will proceed to project planning if approved. PSE identifies the portfolio of projects that will proceed based on optimizing benefit and cost for a given funding level that is supported by approval within the overall company budget. The process is the same for both long-term and short-term planning. Typically, utilities align investment in non-revenue producing infrastructure to customer revenue associated with growth, which further defines a given funding level or constraint for optimization of the portfolio of infrastructure work.

> > > See Appendix M, 10-Year Delivery System Plan, for the Natural Gas System 10-year plan.

Analysis Process and Needs Assessment

PSE follows a structured approach to analyze delivery system needs and potential solutions. The Delivery System Planning (DSP) operating model incorporates inputs from both external stakeholders and groups within PSE; gathers input data for planning studies (represented by the yellow box on the left in Figure 9-52 below); analyzes system needs; develops solutions (which may consider customer-side assets and be a hybrid of traditional and non-traditional alternatives); selects preferred project alternatives (depicted in the central yellow box); and communicates the selected projects for execution of detailed design, construction/implementation, integration with operations and post-installation support (described in the yellow box on the right).

Figure 9-52: PSE Delivery System Planning Operating Model



Natural Gas delivery system needs are driven by a number of different key factors as described below. All of these factors to be considered to identify the right needs across the system.

DELIVERY SYSTEM DEMAND AND PEAK DEMAND GROWTH. Demands on the overall system increase as the population of PSE's service area grows and economic activity increases, despite the increasing role of energy-conserving demand-side resources. Within the service area, however, demand is uneven, with much higher demand growth in the central business districts surrounding the urban centers. Peak loads occur when the weather is most extreme. PSE carefully evaluates system performance during peak load periods each year, updates its system models and compares these models against future demand and growth forecasts. Taking these steps prepares PSE to determine where additional infrastructure investment is required to meet peak firm loads. Customer usage patterns determine the peak conditions that the natural gas delivery system must be designed to accommodate. PSE's natural gas load is primarily residential in nature, therefore, peak conditions align with cold-temperature weather events that occur during the winter months (November – March) each year. On a daily basis, the greatest draw on the system occurs between 4 AM and 8 AM, the four-hour period when most households begin their morning routine of waking up to a warm house, taking hot showers and cooking morning meals. It is during these high demand periods that the lowest pressure in the system occurs. Low system pressures that cannot support proper operation of customer equipment affects not only comfort, but safety concerns during a failure event. This requires the operator of the natural gas system to manually close each customer meter until proper pressures are reestablished, perform a safety check and relight each appliance, further inconveniencing the customer. As a result, the natural gas planning criteria is conservative with regard to both the minimum pressures allowed and the anticipated cold weather extremes. System investments are sometimes required to serve specific "point loads" that may appear at specific locations in PSE service area.

Energy efficiency consists of measures and programs that replace existing building energy using components and systems such as heating, water heating, insulation, appliances, etc., with more energy efficient ones. These replacements can reduce both peak demand and overall energy consumption for residential and commercial customers. Customers who agree to reduce their energy use during periods of system stress, system imbalance or in response to market prices are participating in demand response (DR). Interruptible rates are a subset of demand response. When used to relieve loading at critical times, demand response can offset anticipated loads and reduce the need for traditional delivery infrastructure. Interruptible rates are used in PSE's service area, and there is a high dependence on curtailment of these customers in order to meet demand.

RESOURCE INTEGRATION. FERC and state regulations require PSE to integrate generation resources into our electric system according to processes outlined in federal and state codes. A new natural gas generation facility will require careful planning to ensure the availability of fuel.

AGING INFRASTRUCTURE. Aging infrastructure refresh is an important element of modernizing the delivery system. Equipment that has reached end of life create integrity issues potentially causing leaks or failure to operate when needed.

SYSTEM INTEGRITY. Pipeline and Hazardous Materials Safety Administration (PHMSA) require PSE to monitor and remediate risks to both the natural gas transmission and distribution programs.

OPERATIONAL FLEXIBILITY. The ability to isolate pipelines and transfer load, is important in responding to unplanned and planned outages, and the ability to perform necessary maintenance on equipment.

DISTRIBUTED ENERGY RESOURCES. While more commonly discussed in the context of the electric system, natural gas generators can impact demand as well and must be considered.

SAFETY AND REGULATORY REQUIREMENTS. These requirements drive action for mitigation in short order and/or are dictated through contractual agreements and as a result are identified and resolved outside of this long term planning process.

The energy delivery system is reviewed each year to ensure pipeline integrity and mitigate risk. Past leaks, equipment inspection, maintenance records, customer feedback, PSE employee knowledge and analytic tools identify areas where improvements are likely required and where such improvements mitigate elevated risks to the public and PSE's customers. PSE collects system performance information from field charts, remote telemetry units, SCADA, employees and customers. Per regulation, PSE has a robust distribution integrity management program and a transmission integrity management program that requires a risk based approach to identify and mitigating integrity concerns. Programs to address these risks are implemented, often resulting in the replacement of assets or increased monitoring. Programs are also in place to address aging infrastructure by replacing pipelines that are nearing the end of their useful life.

External inputs such as new regulations, municipal and utility improvement plans, and customer feedback, as well as company objectives such as PSE's asset management strategy, are also included in the system evaluation. These inputs help us to understand commitments and opportunities to mitigate impact or improve service at least cost. For example, the WUTC issued a policy statement in 2012 allowing natural gas utilities to file a plan for replacing pipes that represent a higher risk of failure, and PSE's commitment to this plan is considered in the evaluation. In 2016, the NTSB recommended the pipeline industry develop guidance on safe pipeline operations to ensure protection of communities and the environment. The Pipeline Safety Management System (PSMS) helps operators understand, manage and continuously improve safety efforts at any stage of their safety programs through a Plan-Do-Check-Act cycle. The PSMS is intended to provide the tools needed to continuously and comprehensively track and improve safety performance. PSE obtains the annual updates to local jurisdiction six-year Transportation Improvement Plans to gain long-term planning perspective on upcoming public improvement projects. As transportation projects develop through design, engineering and construction, PSE works with local jurisdictions to identify and minimize potential utility conflicts and to identify opportunities to address system deficiencies and needs.

PSE relies on several tools to help identify needs or concerns and to weigh the benefits of alternative actions to address them. Figure 9-53 provides a brief summary of these tools, the planning considerations (inputs) that go into each and the results (outputs) that they produce. Each tool is used to provide data independently for use in iDOT,[14] which then creates a full understanding of all the benefits and risks.

Figure 9-53: Natural Gas Delivery System Planning Tools

TOOL	USE	INPUTS	OUTPUTS
Synergi®	Gas and Electric network modeling	Gas and electric distribution infrastructure from GIS and load characteristics from CIS; load approvals; load forecast	Predicted system performance
Gas Outage Spreadsheet	Gas outage predictive analysis	Gas Synergi system performance data for future capacity	Predicted outage savings
Distribution / Transmission Integrity Management Risk Assessment	Gas pipeline risk analysis	Gas infrastructure operating or maintenance concerns from various databases	Program funding options to mitigate higher risk facilities
All data collected by the tools above are input into iDOT			
Investment Decision Optimization Tool (iDOT)	Gas and electric project data storage & portfolio optimization	Project scope, budget, justification, alternatives and benefit/risk data collected from above tools and within iDOT; resources/financial constraints	Optimized project portfolio; benefit cost ratio for each project; project scoping document

14 / *Investment Decision Optimization Tool which is a software tool called Folio by PwC.*

PSE's natural gas system model is a large integrated model of the entire delivery system using a software application (Synergi® Gas) that is updated to reflect new customer loads and system and operational changes. This modeling tool predicts capacity constraints and system performance on a variety of temperatures and under a variety of load growth scenarios. Results are compared to actual system performance data to assess the model's accuracy.

Modeling is a three-step process. First, a map of the infrastructure and its operational characteristics is built from the GIS and asset management system. For natural gas, this includes the diameter, roughness and length of pipe, connecting equipment, regulating station equipment and operating pressure. Next, we identify customer loads, either specifically (for large customers) or as block loads for address ranges. Existing customer loads come from PSE's customer information system (CIS) or actual telemetry readings. Finally, we take into consideration seasonal variations, types of customers (interruptible vs. firm), time of daily peak usage, the status of components (valves or switches closed or open) and forecast future loads to model scenarios of infrastructure or operational adjustments. The goal is to find the optimal solution to a given issue. Where issues surface, the model can be used to evaluate alternatives and their effectiveness. PSE augments potential alternatives with cost estimates and feasibility analysis to identify the lowest reasonable cost solution for both current and future loads.

The performance criteria that lie at the heart of PSE's infrastructure improvement planning process are summarized below in Figure 9-54. Evaluation begins with a review of existing operational challenges, load forecasts, demand-side management (DSM), commitments, obligations and opportunities. Planning triggers are specific performance criteria that trigger a need for a delivery system study. There are different triggers or thresholds for transmission, bulk distribution (high pressure) and distribution (intermediate pressure), as well as for capacity[15] and reliability. A "need" is identified when performance criteria is not met.

15 / New methods of extracting and producing natural gas have accessed vast reserves of natural gas in the U.S. and North America. This has resulted in U.S. gas prices falling to levels not seen since the 1970s. In response to these depressed market prices, processing facilities no longer find it economic to strip out the heavier hydrocarbons (ethane, propane, butane, etc.) often found in raw natural gas. This has had the unexpected effect of increasing the Btu content[15] of the gas received from historic levels of 1,030 btu per standard cubic foot to more than 1,100 btu per standard cubic foot, essentially increasing system throughput capability by five to 10 percent, avoiding pressure and capacity concerns that need addressing. A change in gas quality (lower btu gas), while still within required tariffs, may result in more system analysis.

Figure 9-54: Performance Criteria for Natural Gas Delivery Systems

Gas delivery system performance criteria are defined by:
Safety and compliance with all regulations and contractual requirements (100 percent compliance)
The temperature at which the system is expected to perform (52 DD Peak Hour)
The nature of service each type of customer has contracted for (firm or interruptible)
The minimum pressure that must be maintained in the system (level at which appliances fail to operate)
The maximum pressure acceptable in the system (defined by CFR 192.623 and WAC-480-93-020)
The historical or future pipeline integrity performance indicators that elevate risk relative to safety or methane release which may be caused by aging infrastructure, third party damage, or equipment location or condition.
The ability to remove equipment from service for maintenance and provide flexibility for emergency response.

PSE expects the planning assumptions, described in Chapter 5, guidelines, and performance criteria to change over time due to the current policies pursuing electrification, demand side resources dependency at the local neighborhood level, and deferral of traditional infrastructure. PSE expects delivery system planning margins to increase to account for operating concerns relating to behavior based conservation and demand response programs. PSE's delivery system planning assumptions relative to conservation and demand response, have historically incorporated outputs generically, but these assumptions, while appropriate for resource planning, may not be appropriate for local neighborhood decisions and reliability. Higher cost conservation is likely customer type specific and as a result greater study and specific application of targeted conservation programs is necessary in order for conservation to be reliable. PSE may also need to develop assumptions regarding demand response programs as customer adoption may change as home occupancy changes over time.

PSE engages with WUTC pipeline safety staff in various forums such as annual audits and quarterly roundtable discussions that also inform PSE's considerations about concerns and solutions.

Solutions Assessment and Criteria

The alternatives available to address delivery system capacity, integrity, aging infrastructure, and operational flexibility are listed below. Each has its own costs, benefits, challenges and risks.

Figure 9-55: Alternatives for Addressing Delivery System Capacity and Reliability

ALTERNATIVES	NATURAL GAS SYSTEM
Add energy source	City-gate station; District regulator
Strengthen feed to local area	New high pressure main; New intermediate pressure main; Replace main
Improve existing facility	Regulation equipment modification; Uprate system
Load reduction	Conservation; Load control equipment; Possible new tariffs

Load reduction alternatives are a focus of improvement in the planning process. Alternatives may depend on customer participation for siting, control or actionable behavior, and PSE continues to gain understanding and confidence in these as deferral and permanent solution alternatives are considered. Conservation above cost-effective measures and demand response can be incorporated as alternatives as our understanding of their effectiveness and the role of customer participation increases.

PSE is monitoring and investigating technologies that will prove to be useful low carbon alternatives in the future including renewable natural gas injection into a needed location, hydrogen blending similar to renewable natural gas, greater use of demand response through smart thermostat technologies, and higher efficiency and hybrid or dual fuel customer equipment.

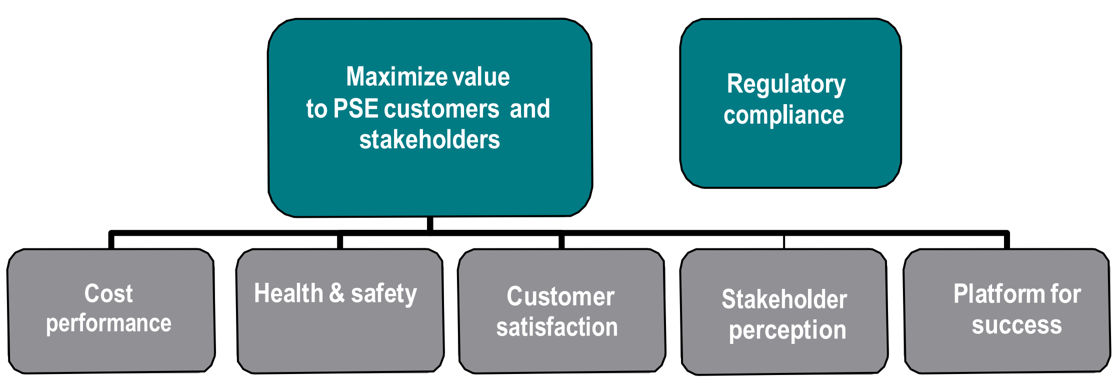
The same alternatives can be used to manage short-term issues like peaking events or conditions created by a construction project. For example:

- Temporary adjustment of regulator station operating pressure as executed through PSE's Cold Weather Action Plan
- Temporary siting of mobile equipment such as compressed natural gas injection vehicles and liquid natural gas injection vehicles

Technical and non-technical solution criteria are established to ensure PSE implements the right solutions that fully address the needs. Based on the need identified, a Solutions Study is performed in which project alternatives are developed. The Solutions Studies will consider the opportunity to partner with customers, PSE programs or a PSE pilot. The solution alternatives are vetted and evaluated to meet specific solution criteria. Technical solution criteria includes meeting all performance criteria as described in Figure 9-55 as well as consideration of the avoidance of adverse impacts to integrity or operating characteristics and the requirement of solution longevity delaying the need to retrigger additional investments for an established number of years, considering customer rate burden as investments are recovered. Non-technical solution criteria includes feasible permitting, environmental and community acceptance as facilitated through permitting processes, reasonable project cost, the maturity of technology, and constructability within a reasonable timeframe.

To evaluate alternatives, PSE compares the relative costs and benefits of various solutions (i.e., projects) using the iDOT Tool. iDOT is a project portfolio optimization based on PriceWaterhouseCooper's Folio software that allows us to capture project and program criteria and benefits and score them across thirteen factors associated with 6 categories. These include meeting required compliance with codes and regulations; net present value of the project; improvement to integrity, reliability and safety; future possible customer/load additions; deferral or elimination of future costs; customer satisfaction; improved external stakeholder perception; and opportunities for future success gained by increasing system flexibility or learning about new technologies and methods or drivers of specific company objectives. iDOT makes it easier to conduct side-by-side comparisons of projects and programs of different types, thus helping us evaluate infrastructure solutions that will be in service for 30 to 50 years.

Figure 9-56: Benefit Structure to Evaluate Delivery System Projects



Project costs are calculated using a variety of tools, including historical cost analysis and unit pricing models based on estimated internal engineering costs and service provider contracts. Cost estimates are refined as projects move through detailed scoping. Through this process, alternatives are reviewed and recommended solutions are vetted and undergo an internal peer review process. Projects that address routine infrastructure replacement are proposed at a program level and incorporated into a parallel path within the iDOT process. Risk assessment tools are used to prioritize projects within these programs for example particular vintages of wrapped steel and polyethylene facilities are prioritized for replacement based on known risks such as leakage history, pipe condition and the proximity of the pipe to certain structures.

iDOT builds a hierarchy of the value these benefits bring to stakeholders against the project cost. The benefits are reviewed and reassessed periodically with senior management to ensure proper weight and priority is assigned throughout the evaluation process. Using project-specific information, iDOT optimizes total value across the entire portfolio of non-mandated or discretionary natural gas system infrastructure projects which results in a set of capital projects that provide maximum value to PSE customers and stakeholders relative to given financial constraints. Further minor adjustments are made to ensure that the portfolio addresses resource planning and other applicable constraints or issues such as known permitting or environmental process concerns. Periodically, PSE has reviewed this process and the optimization tool along with the resulting portfolio with WUTC staff.

The iDOT tool also helps PSE examine projects in greater detail than a simple benefit/cost measure. iDOT includes factors such as brand value, health and safety improvements, environmental impact, sustainability, customer value and stakeholder perception. As a result, projects that contribute intangible value receive due consideration in iDOT.

Future iDOT enhancements could incorporate benefits such as carbon emissions reduction or methane emissions reduction benefit, more transparently. PSE recognizes that carbon emissions reduction is an important objective as it builds implementation plans towards meeting CETA compliance, 100 percent clean electricity by 2045. The IRP captures greenhouse gas benefits relative to electric and natural gas energy and so in order to prevent double counting of benefits, delivery system projects, may be more appropriately focused capturing these types of benefits as they relate to the manufacturing or transportation of the different types of assets that support different alternatives. PSE’s delivery system planning process will mature with clarity of the customer benefit assessment process prescribed in CETA, specifically as energy security and resilience is defined and the considerations and applications of energy and non-energy benefits relative to vulnerable populations and highly impacted communities evolves through required advisory group engagements.

Non-pipe Alternative Analysis

PSE's planning process has incorporated non-pipe alternative analysis. The planning process may result in a lengthy project initiation phase as the need and alternatives are evaluated with a broader team. PSE's non-pipe alternative analysis is a screening process that breaks down of the problem utilizing existing resources, emerging technologies like renewable natural gas injection and hydrogen blending, or reducing customer demand, performs an economic and feasibility analysis, and then results in a recommended solution. The planning process is a comparison of alternatives searching for the least cost solution that maximizes value for customers and stakeholders and as such evaluates a traditional pipeline solution, a full non-pipe solution, and any potential hybrid across the problem components.

All types of pipeline alternatives are considered, but some key facts must be considered:

- PSE has an obligation to serve existing natural gas customers within its certificate area approved by the WUTC.[16]
- PSE has an obligation to new natural gas service requests as long as a customer meets the tariff requirements,[17] and PSE is not authorized under Washington State to abandon its natural gas service for all, nor is it authorized to pay to electrify natural gas customers

With these facts as backdrop, PSE is committed to decarbonizing the natural gas system, pursuing greener energy and maximizing natural gas energy efficiency and the IRP highlights that opportunity to meet all future growth with demand side resources. Capacity needs may be able to be met with technologies such as demand response and more energy efficiency and understanding local customer behavior and adoption will be important to see these opportunities realized.

With the learnings of a more mature electric non-wire alternatives analysis, PSE has begun similar analysis in the natural gas system. More detail can be found in Appendix M.

16 / RCW 80.28.190
17 / RCW 80.28.110

Project Planning and Implementation Phase

Once the above process for a particular project and portfolio is completed, reviewed by senior management and approved for funding, the Delivery System Planning initiation phase is complete and the project planning phase begins. The outcome of project initiation is a needs assessment and solutions assessment document. For small projects this may be captured in PSE's SAP system through a notification process or supported from a business case that addresses needs programmatically. The project planning phase involves detailing engineering and technical specifications, pursuing real estate right-of-way needs, planning stakeholder communications and considering potential coordination with other projects in the area. Implementation risks are assessed and mitigation plans are developed as needed. PSE's 10 year plan included in Appendix M reflects projects that are largely in project initiation. Once a project moves to the project planning phase, the need has been established and IRP stakeholder engagement ends while community engagement begins.

Once project need and initiation recommendations are reviewed, annual and two-year work plans are developed for project planning and implementation feasibility. Work plans are coordinated with other internal and external work and resource plans are developed. Final adjustments may be made as the system portfolio is compared with other objectives of the company such as necessary generator or dam work, or customer initiatives. While annual plans are considered final, throughout the year they continue to be adjusted based on changing factors (such as public improvement projects that arise or are deferred; changing forecasts of new customer connections; or project delays in permitting) so that the total portfolio financial forecast remains within established parameters. As plans and projects develop through the design and permitting phases, cost and benefit are routinely evaluated and confirmed before progressing. Alternatives may be reviewed through project lifecycle phase gates and through detailed routing and siting discussions.

Long-range plans are communicated to the public through local jurisdictional tools such as the city and county Comprehensive Plans required by the Washington State Growth Management Act. Often this information serves as the starting point for demonstrating the need for improvements to local jurisdictions, residents and businesses far in advance of a project moving to project planning, design, permitting and construction. Project maps and details are updated on PSE.com as well.

EXHIBIT 50-4

December 31, 2025

The Honorable Bob Ferguson, Governor of Washington
The Honorable Sarah Bannister, Secretary of the Senate
The Honorable Bernard Dean, Chief Clerk of the House

Re: Summary of the 2025 Winter Preparedness Resource Adequacy Meeting

Dear Governor Ferguson and Members of the State Legislature,

Please find the attached summary of the 2025 winter preparedness resource adequacy meeting held November 4, 2025. This year, in response to public feedback, we expanded our annual resource adequacy meeting under RCW 19.280.065 to three gatherings: one each for summer readiness, long-term resource adequacy, and winter preparedness. The meeting agenda, recording, and presentation materials are available on the Department of Commerce webpage and the Utilities and Transportation Commission webpage.

Winter reliability assessments, presented by regional resource adequacy experts, the North American Electric Reliability Corporation and Western Electricity Coordinating Council, indicate the Northwest's electric grid meets national resource adequacy criteria under normal conditions this winter. Extreme weather poses an elevated risk of short-duration outages absent additional measures, such as utilities following their emergency policies and procedures or firing up their backup generators. The Bonneville Power Administration and Washington utilities do not forecast outages this winter.

At the November 4 meeting, the Bonneville Power Administration and utilities shared the steps they are taking in preparation for the season. This includes daily monitoring of weather conditions, regular calls with reliability coordinators and fuel suppliers, maintenance of the system, and updates to their operations and emergency planning procedures. Utilities reported they have maximized hydro and natural gas storage ahead of winter and ensured facilities are operating properly. Some, such as Seattle City Light and Puget Sound Energy, noted voluntary customer curtailment programs intended to help offset electricity demand if needed.

The meeting highlighted the need for coordination between the natural gas system and the electric system to ensure a reliable energy supply throughout winter. The Northwest Gas Association and Pacific Northwest Utilities Conference Committee discussed collaboration between the electric and gas industries to prepare for winter, as well as broader efforts to bring utility leaders, regulators, state policymakers, power producers, and other stakeholders together, for the purposes of better cross-sector planning and operations. This ensures discussion around the increased interdependence of gas and electric systems as the region continues its transition to clean energy and state-level climate goals. We appreciate seeing natural gas and electric utilities working together to ensure affordable, reliable, and equitable services for Washington customers.

Preparing for this winter
Washington has already seen some extreme weather as the winter season begins. Utilities can take near-term steps to preserve reliable service in case of extreme weather. These include:

- Ensuring customers' backup generators are in service and ready to be deployed,
- Ensuring the industry's emergency and curtailment plans and procedures are in place, and
- Coordinated planning and response between electric and natural gas systems.

Preparing for future winters
While this meeting focused on readiness for winter 2025-2026, there is a clear need for concerted action to prepare for future winters. Washington law provides utilities with flexibility to use gas-fired generating facilities and, if needed, to expand gas-fired capacity to meet winter peaks. In the meantime, Washington must do more to streamline siting and permitting, add in-state and out-of-state transmission capacity, proactively pursue transmission enhancements and expansions and demand flexibility, and improve resource forecasting for large new loads, such as data centers and advanced manufacturing facilities.

Our energy system is deeply interconnected, and every aspect is vulnerable to extreme weather events fueled by climate change. We remain committed to working with our natural gas and electric utility partners to further our joint efforts to maximize the reliability and affordability of our state's energy system as we decarbonize our economy.

Sincerely,

Brian J. Rybarik	Jennifer Grove
Chair	Assistant Director, Energy Division
WA Utilities and Transportation Commission	WA Department of Commerce

Attachment (1)

2025 Winter Preparedness Adequacy Meeting Summary

Introduction

On November 4, 2025, the Washington Utilities and Transportation Commission (UTC) and the Washington Department of Commerce (Commerce) convened a public meeting to review the adequacy of energy resources to serve the state's electricity and natural gas needs.

We convened this meeting and submit this summary in response to public feedback to expand our annual resource adequacy meeting under RCW 19.280.065 to three annual meetings: one meeting in the spring focused on summer readiness, one meeting in late summer to discuss long-term resource adequacy, and another in late fall to focus on winter preparedness.

RCW 19.280.065(1) says:

> At least once every twelve months, the department and the commission shall jointly convene a meeting of representatives of the investor-owned utilities and consumer-owned utilities, regional planning organizations, transmission operators, and other stakeholders to discuss the current, short-term, and long-term adequacy of energy resources to serve the state's electric needs, and address specific steps the utilities can take to coordinate planning in light of the significant changes to the Northwest's power system including, but not limited to, technological developments, retirements of legacy baseload power generation resources, and changes in laws and regulations affecting power supply options. The department and commission shall provide a summary of these meetings, including any specific action items, to the governor and legislature within sixty days of the meeting.

Maintaining an adequate supply is a core obligation of the utilities that provide energy service to the residents and businesses of Washington. State policy reinforces this obligation as Washington transforms its electric power system and economy, reducing and eventually eliminating emissions from fossil fuel combustion for electricity generation.[1]

The state's 100% clean electricity law, the Clean Energy Transformation Act,[2] includes requirements for utilities to establish specific standards for resource adequacy and incorporate those standards into their planning and compliance.[3] As utilities reduce reliance on coal-fired and gas-fired power plants and add renewable resources such as wind and solar, new approaches and resources will be required to maintain resource adequacy. Utilities must also incorporate equally-important risks associated with fossil generating resources, including fuel supply risk and weather-driven forced outage risk.

While resource adequacy is an obligation of each electric utility serving end-use customers in the state, it also is a shared responsibility of the overall energy system and the entities that operate, plan, regulate, design, and fund that system.

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[1] Washington 2021 State Energy Strategy, page 119-120. https://commerce.wa.gov/energystrategy

[2] Chapter 19.405 RCW.

[3] RCW 19.280.030. This resource planning statute was amended by the CETA legislation to add explicit resource adequacy provisions.

Northwest Gas Association (NWGA)—Gas-Electric Integration and Regional Winter Readiness

NWGA represents the Pacific Northwest gas industry, which includes regional natural gas distribution companies and pipeline operators. Natural gas is used for space and water heating, and process heat for industrial applications. In addition, natural gas is used to generate electricity and, in some cases, provides feedstock for other products.

Natural gas and electric systems operate differently. Electrons move instantly and operate at a frequency and not at a speed. The legacy electric grid had no inherent way to store electricity. Meanwhile, natural gas molecules move at about 25 miles an hour, and the natural gas pipeline serves as inherent storage with the packing and drafting of gas molecules. When the electric system experiences systemwide outages, the system can be restored in segments, with power returning when each segment is energized. By comparison, when the gas system experiences a system outage, the system requires door-to-door service to turn off service, and then again for restoration when gas is flowing again.

Today the Pacific Northwest natural gas pipeline system delivers 33 percent more gas than 25 years ago. The majority of the gas, 75 percent, is weather-dependent, used in the winter and summer months. During winter peaks, gas supplies can supply over 75 percent of the total energy customers use in Oregon and Washington. To ensure the gas system can meet this demand, natural gas utilities and suppliers conduct long-term plans that consider pipeline constraints, contract terms, policies, and local distribution, consumption, and generation analyzed in tandem to determine contract needs.

Many natural gas utilities and suppliers participate in mutual assistance agreements, such as the Northwest Mutual Assistance Agreement (NWMAA), to maintain the natural gas system. NWMAA is a voluntary collaboration among entities that control natural gas assets in the Northwest, primarily focused on enhancing reliability during emergencies, such as by providing neighbors with gas. Many utilities have daily communication between gas suppliers and system operators, conduct simulated emergency scenario simulations, and have some level of generation that can switch to secondary fuel, such as fuel oil. Lastly, members of Reliability Coordinator (RC) West, the California Independent System Operator's electricity reliability coordinator in the western US, convene ahead of winter to prepare for regional cold weather events.

Winter Reliability and Electric-Gas Coordination—North American Electric Reliability Corporation (NERC) and Western Electricity Coordination Council (WECC)

NERC is the Electric Reliability Organization for North America, with a mission to assure the effective reduction of risks to reliability and security of the grid. NERC is subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. WECC is one of six regional entities under NERC that has authority delegated under the Federal Power Act to ensure a reliable and secure bulk power system throughout the Western Interconnection. WECC has the responsibility to create, monitor, and enforce reliability standards and promote activities, such as regional resource adequacy assessments, of the bulk power system in the Western Interconnection.

WECC's Winter Reliability Assessment finds long duration cold snaps are the primary concern for grid reliability in the Northwest, British Columbia, and Alberta. Low temperatures can lead to elevated demand, reduced output from renewable and fossil generation facilities, gas delivery constraints, and unplanned transmission and generation outages. The Pacific Northwest is one of a handful regions that face an elevated risk[4] of operating reserves or energy shortfalls in instances of a regionwide cold snap, in which case the region would need to take additional steps, such as running back-up generators or importing power from other regions, to maintain services.

Utilities in the WECC flagged survey responses to NERC that there should be an increased emphasis on regional gas-electric coordination, stressing the need to continue regional tabletop exercises between gas and electric operators to simulate emergency scenarios and improve readiness. Utilities in the West also reported updating pipeline operation logic and expedited emergency protocols, as well as deployment of limited duration battery energy storage systems to increase capacity on the grid.

Winter Preparedness—PacifiCorp

PacifiCorp is an investor-owned electric utility. It serves 141,000 customers in Washington, and a total of 2.1 million customers across Washington, Oregon, Idaho, California, Utah, and Wyoming.

PacifiCorp's Pacific Northwest service territory is winter-peaking, and its southwest is summer-peaking. Based on National Oceanic and Atmospheric Administration (NOAA) weather forecasts from September 2025, the utility anticipates average temperatures in most of the Northwest in October through December, below average temperatures in most of the Northwest in January through March, and above average temperatures in the Southwest portions of WECC throughout winter. PacifiCorp plans to take advantage of its transmission system and regional generation and load diversity to move energy across its Northwest and Southwest territories to meet its Northwest load this winter.

PacifiCorp's operational planning for winter readiness includes securing and maintaining firm gas transportation and power transmission contracts for its electric generation fleet, improved operational coordination between the generation fleet and the natural gas system, extensive winter scenario modeling, and leveraging storage, flexible resources, and regional markets.

Bonneville Power Administration (BPA)

BPA is obligated under the Pacific Northwest Electric Power Planning and Conservation Act to assure the adequate supply of power to its load-following customers. Those obligations are satisfied through 20-year contracts due to be updated in 2028. Utilities that elect slice or block contracts retain responsibility for their own resource adequacy.

BPA is not forecasting any unusual system outages during this winter and has regular capability to meet load during short-term cold snaps. Long-duration cold snaps would introduce more

[4] Elevated risk is an indication of insufficient operating reserves or energy shortfalls in above-normal peak-day demand or outages.

uncertainty and risk to the reliability of BPA's system. Fish passage constraints are currently uncertain and could impact BPA's ability to respond to extreme weather events in March, but BPA observed that extreme weather events in March are rare.

Seattle City Light (SCL)

SCL delivers electricity to approximately 513,500 customers in Seattle and a handful of surrounding communities. SCL expects this winter to be wetter and cooler with healthier snowpacks; however, these weather patterns could make polar vortex events more likely in mid-to-late winter as the polar jet stream weakens. SCL shared it has outage and water management procedures, and has maximized capacity of its system and conserved its hydro storage for use in peak winter events. The utility practices proactive forward hedging when necessary to ensure resource availability and closely monitors weather forecasts.

SCL also has implemented a new large industrial curtailment program, in which large industrial customers can receive incentives to curtail their load during key events. The events in this program are scheduled a day ahead for a 24-hour period, and there are no limits on the number of times the utility can call for industrial customers to curtail. Incentives for participating are based on the day-ahead market value of electricity.

NW Natural Gas (NWN)

NWN plans for all resources to be available at their maximum output. The utility shared that regional natural gas prices are still highly volatile, and cold weather can lead to infrastructure constraints and higher prices. While national natural gas production reached record highs in 2025, NW Natural Gas noted new liquified natural gas (LNG) export facilities are coming online, driving higher demand. Meanwhile, natural gas use for electric power generation remains high.

Cascade Natural Gas (Cascade)

Cascade shared that at 100 percent demand on its system it can meet approximately 53 percent of peak day needs with its storage resources. Total storage capacity accounts for approximately 14.75 percent of winter demand, and winter demand is approximately 68 percent of its annual demand. It has eight natural gas generation plants behind its system, highlighting the importance of gas and electric coordination efforts.

Avista

Avista reported it has prepared for the winter through diversifying their electric and gas portfolio, grid maintenance, regular winter prep calls with natural gas suppliers, increasing planning reserve margins, internal planning, refueling storage facilities, and participation in mutual assistance check-ins.

Avista participated in a NWGA and Pacific Northwest Utilities Conference Committee (PNUCC) symposium created to discuss gas-electric coordination issues, including a tabletop exercise to practice coordination during key events. The utility highlighted that sustained regional cold fronts, bulk electric or gas system issues, or regional transfer constraints could lead to high prices for customers.

Avista is continuing to explore multiple winter strategies. These include requesting customers to conserve, diversifying energy supply, conducting full system integrated resource planning, evaluating back up fuel supplies, exploring the need for regional infrastructure, continuing to evolve gas and electric coordination, and participating in regional resource adequacy initiatives and electricity markets.

Puget Sound Energy

Puget Sound Energy serves over 1.2 million electric customers and nearly 900,000 natural gas customers primarily in Western Washington. Winter readiness and energy emergency operations contingency plans span both its gas system and electric system.

On its gas system, PSE has a comprehensive cold weather action plan based on peak morning forecasts. The plan includes its LNG peak shaving plant, compressed natural gas injection sites, bypassing operations at key locations, and interruptible customer curtailment. Gas projects target specific inventories prior to winter peak season and PSE validates power plant readiness through vaporization test runs. Gas emergency contingency plans include participation in the NWMAA, curtailable interruptible loads, requests for customer conservation, and curtailment of firm sales customers through system isolation.

Winter readiness on PSE’s electric system begins with resources and capacity contracts established to meet winter planning targets. The utility holds weekly collaborative meetings with PSE meteorologists to ensure early awareness of weather. The Cold Weather Action Plan ensures preparedness for high energy usage days, and electric system and transmission studies ensure reliability. Early and ongoing conservation efforts further reduce peak needs. Electric emergency contingency plans include energy supply monitoring alerts, planning reserve margins, contingency reserve obligations, emergency operations and energy agency plans.

Key Findings from Gas-Electric Integration Literature Review and Regional Symposium—NWGA and PNUCC

PNUCC is a not-for-profit trade association of consumer-owned and investor-owned electric utilities and other power industry partners that share a common interest in the efficacy and reliability of the Northwest power system. PNUCC and NWGA shared their gas-electric coordination initiative, which aims to underscore and strengthen collaboration in maintaining a reliable, affordable, and resilient energy future between the electric and gas sectors.

The initiative began with a literature review of regional energy studies, which underscored the need for better coordination between gas and electric systems. To this end, PNUCC, NWGA, Western Power Pool, and the Public Generating Pool convened a symposium of utility leaders, regulators, state policymakers, power producers, and other key stakeholders to discuss key opportunities and challenges. Key themes from the symposium include a need to (1) establish cross-sector coordination forums to align planning and share data; (2) jointly plan for load growth and peak mitigation, particularly around hybrid systems; (3) integrate models and metrics to stress-test system resilience; and (4) align regulatory frameworks to support long-term, co-optimized planning.

EXHIBIT 50-5

The Month In Review

January 2024

National Weather Service,
Pendleton, Oregon

A snowstorm with arctic air in Pendleton, OR.   Photo by: Roger Cloutier

January 2024 Climate Conditions Summary

There was a major change in the weather pattern during the middle of January from the pattern that dominated most of December. The month began with near to above normal temperatures over most areas from the 1st to the 10th. Then there was an arctic intrusion that began on the 11th that persisted for about a week with very cold temperatures across most areas. There was also moderate to heavy snow in many areas, generally across the mountains between the 8th and 13th. The coldest days were from the 12th to the 17th and then temperatures began to moderate. For example, temperatures dropped to a low of -5 degrees on the 13th at the Pendleton, OR Airport, and -14 degrees at the Walla Walla, WA Airport. The snow depth at the Pendleton Airport reached a maximum of 6 inches on the 19th. The snow mixed with or changed to sleet and freezing rain in most areas for periods between the 16th and 19th as temperatures warmed to above freezing above the cold surface air, especially across north central OR, and south central WA. Some areas along the WA Cascade east slopes received significant ice accumulations of a quarter inch or more.

The overall weather pattern then changed to a progressive flow aloft with frequent weather disturbances embedded in the flow. The warmer air from the Pacific caused temperatures to warm to above freezing at all levels with very high snow levels by the end of the month. These conditions caused appreciable amounts of snow to melt, generally below 5000 ft. Rain on top of the melting snow had caused some rivers and streams to rise with the John Day River at Service Creek briefly reaching flood stage before receding. Some record high temperatures were reported in central OR, as well as along the Blue Mountain Foothills due to downslope winds off the Blue mountains or strong southerly winds during the last few days.

Below and on the next slide are images of weather and climate conditions during the month.

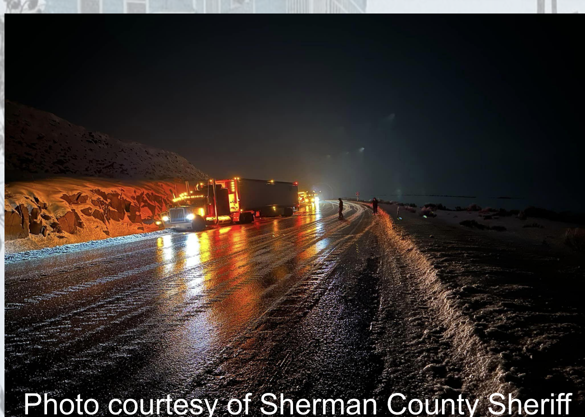
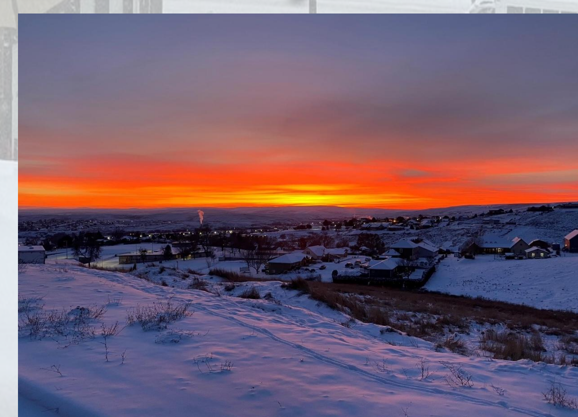


Photo courtesy of Sherman County Sheriff

Black ice on highway in Sherman County, OR

No snow in the Blue Mtns on New Year's Day



Beautiful sunset over snow covered Pendleton

More Images Representing January 2024 Weather/Climate Conditions

Freezing fog & rime ice in the trees at the NWS Forecast Office.

Steam over the water in The Dalles, OR with temperature of 1 °F

Sheen of ice on top of the snow from freezing rain on the 22nd.

Fog moving in over the ridges just west of Pendleton, OR.

Significant Weather Events - Local Storm Reports for January 2024

There were over 450 Local Storm Reports (LSRs) with most of these reports revolving around snow amounts during an arctic outbreak, which occurred during mid January. There were also reports of significant ice accumulations from freezing rain, blizzard conditions (which imply strong winds and near zero visibility in blowing snow), strong non-thunderstorm wind gusts, and significant rainfall amounts. **Since there were so many LSRs issued, these are all listed in slides at the end of this presentation.**

Record Weather Events for January 2024

Record Weather Reports					
Event	**Date**	**Where**	**Previous Record**	**New Record**	**Records Began**
Low Temp	January 13, 2024	Walla Walla, WA	-5 / 2017	-14	1930
Low Temp	January 14, 2024	Redmond, OR	-1 / 2023	1 (tie)	1941
Low Temp	January 15, 2024	Dallesport, WA	6 / 1950	-2	1929
High Temp	January 28, 2024	Redmond, OR	64 / 1971	64 (tie)	1941
High Temp	January 28, 2024	Walla Walla, WA	60 / 1992	65	1930
High Temp	January 30, 2024	Redmond, OR	67 / 1989	68	1941

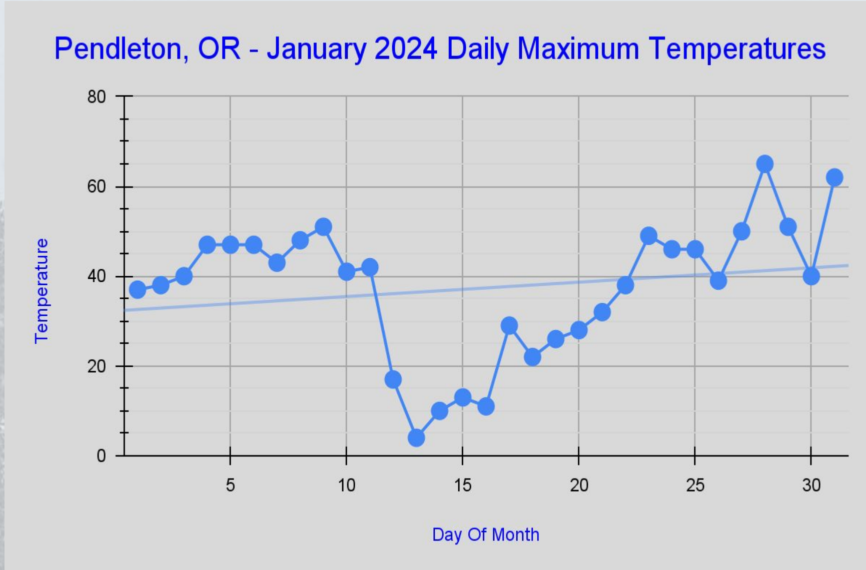
There were a total of 6 record weather events, which were all either record low or record high temperatures. The record lows all occurred during the middle of the month during an arctic outbreak. The record high temperatures occurred at the end of the month during times with a deep southerly flow aloft, with downslope warm winds off the mountains.

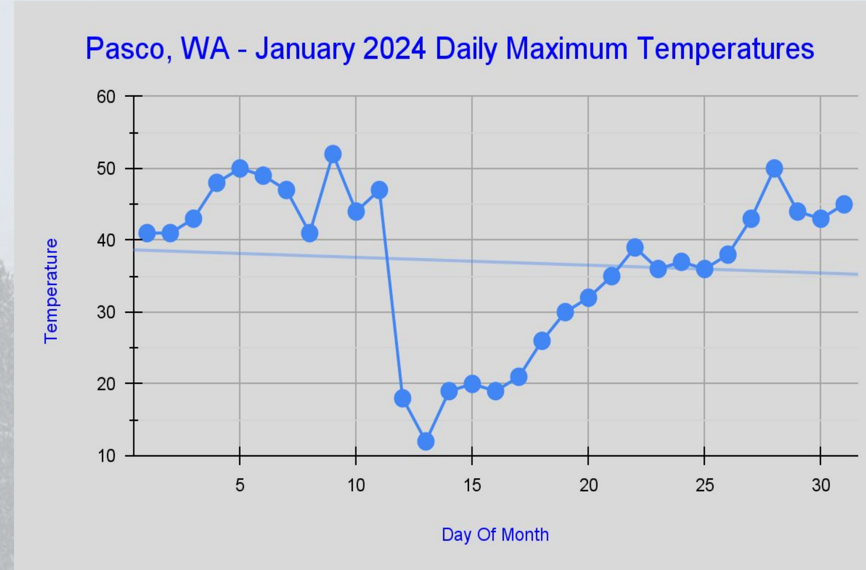
January 2024: Observed Monthly Maximum & Minimum Temperatures

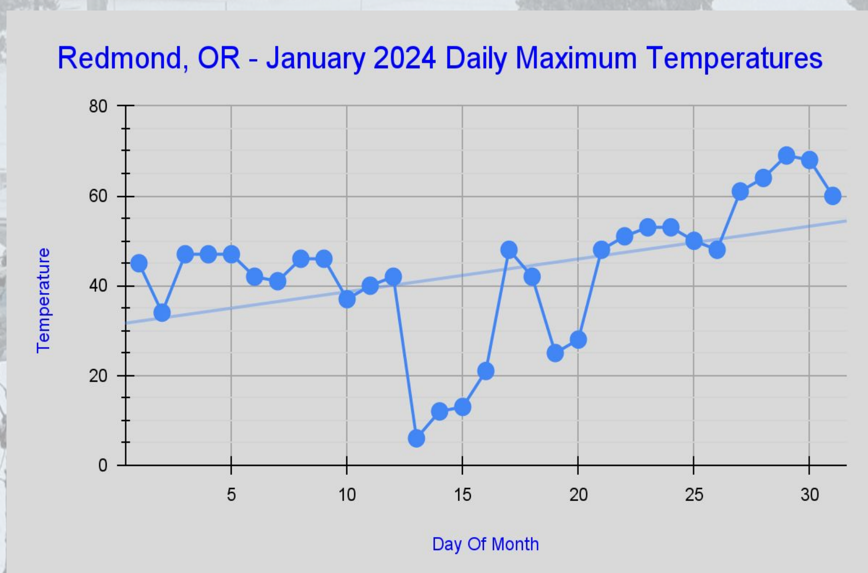
Location Source: airport ASOS, or otherwise stated	Highest Maximum	Lowest Minimum
Pendleton, OR	65	-5
Redmond, OR	69	-3
Pasco, WA	52	2
Yakima, WA	48	-2
Walla Walla, WA	65	-14
Bend, OR CoOp	65	-6
Ellensburg, WA	46	-9
Hermiston, OR	55	-6
John Day, OR CoOp	58	3
La Grande, OR	56	-4
Dallesport, WA	50	-2
Meacham, OR	51	-26
MT Adams R.S., WA CoOp	46	-8

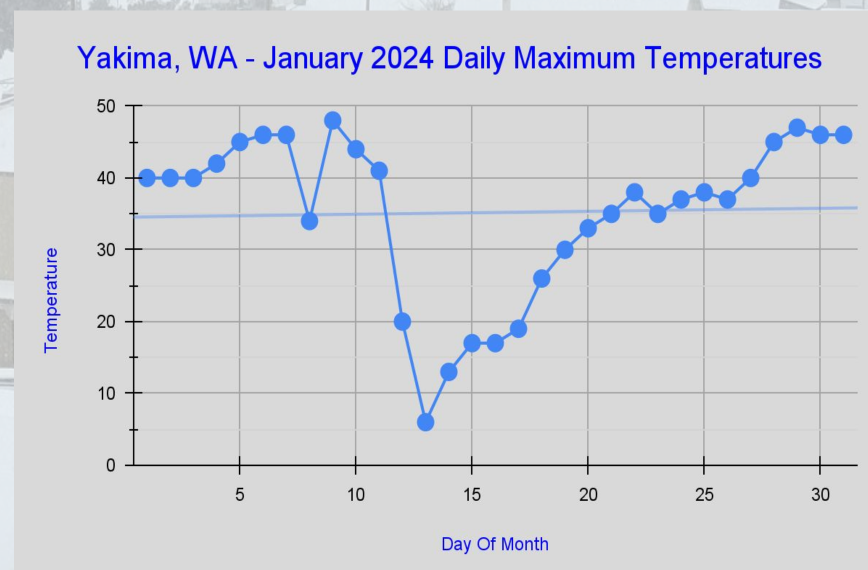
The highest maximum was 69 degrees, at Redmond, OR, and the coldest high temperature was a tie between Ellensburg, WA and the Mt. Adams Ranger Station CoOp weather stations. The warmest reading was in central OR due to the retreat of arctic air with a deep southerly flow aloft. All but 2 stations had lowest minimum temperatures that were below zero. The coldest was at Meacham, OR, which is not a surprise, as Meacham is often the coldest spot, but Walla Walla, WA was also extremely cold, with a low of -14 degrees (lighter shade of blue).

January 2024 - Daily Maximum Temperatures For Select Cities



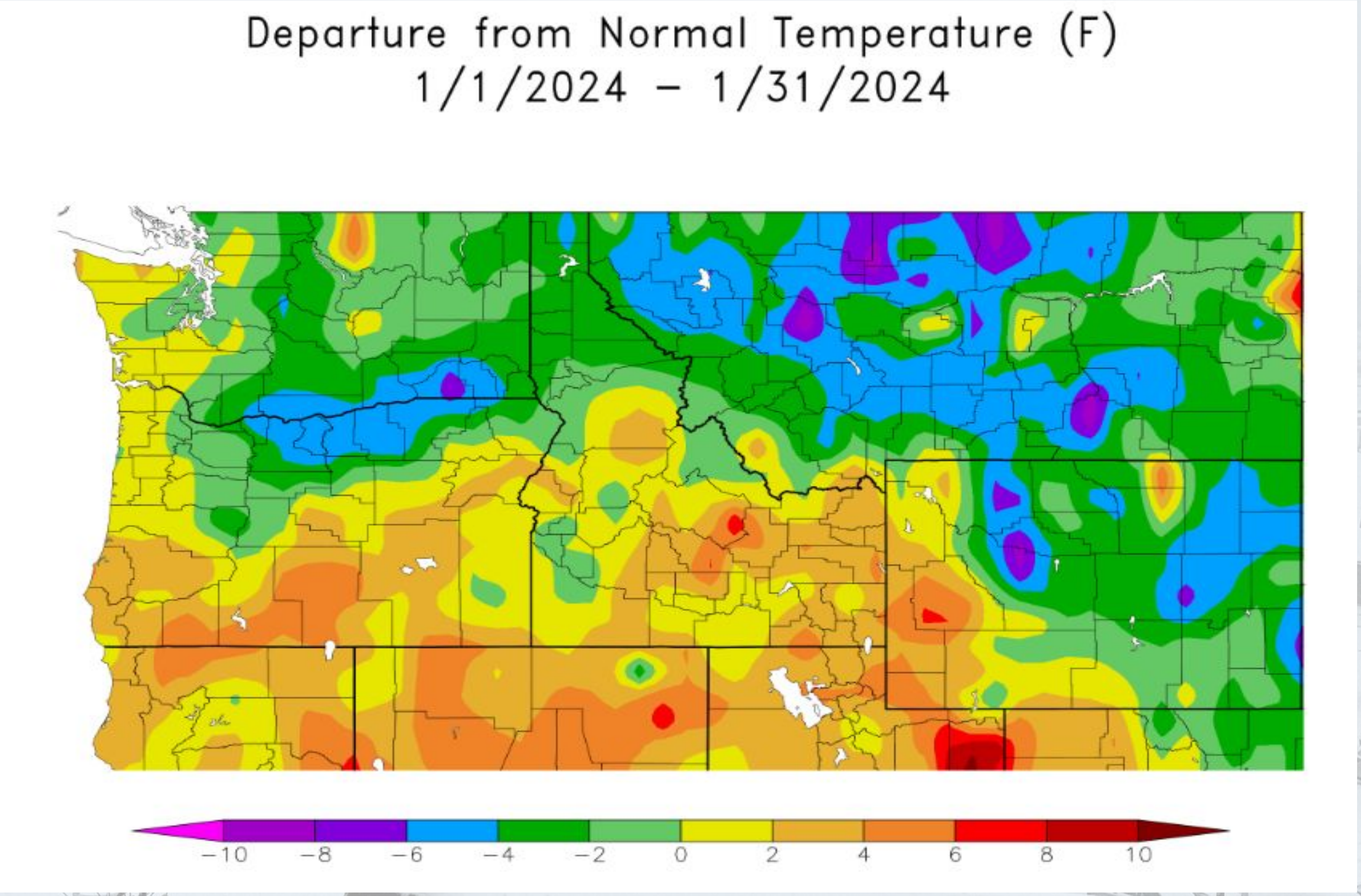






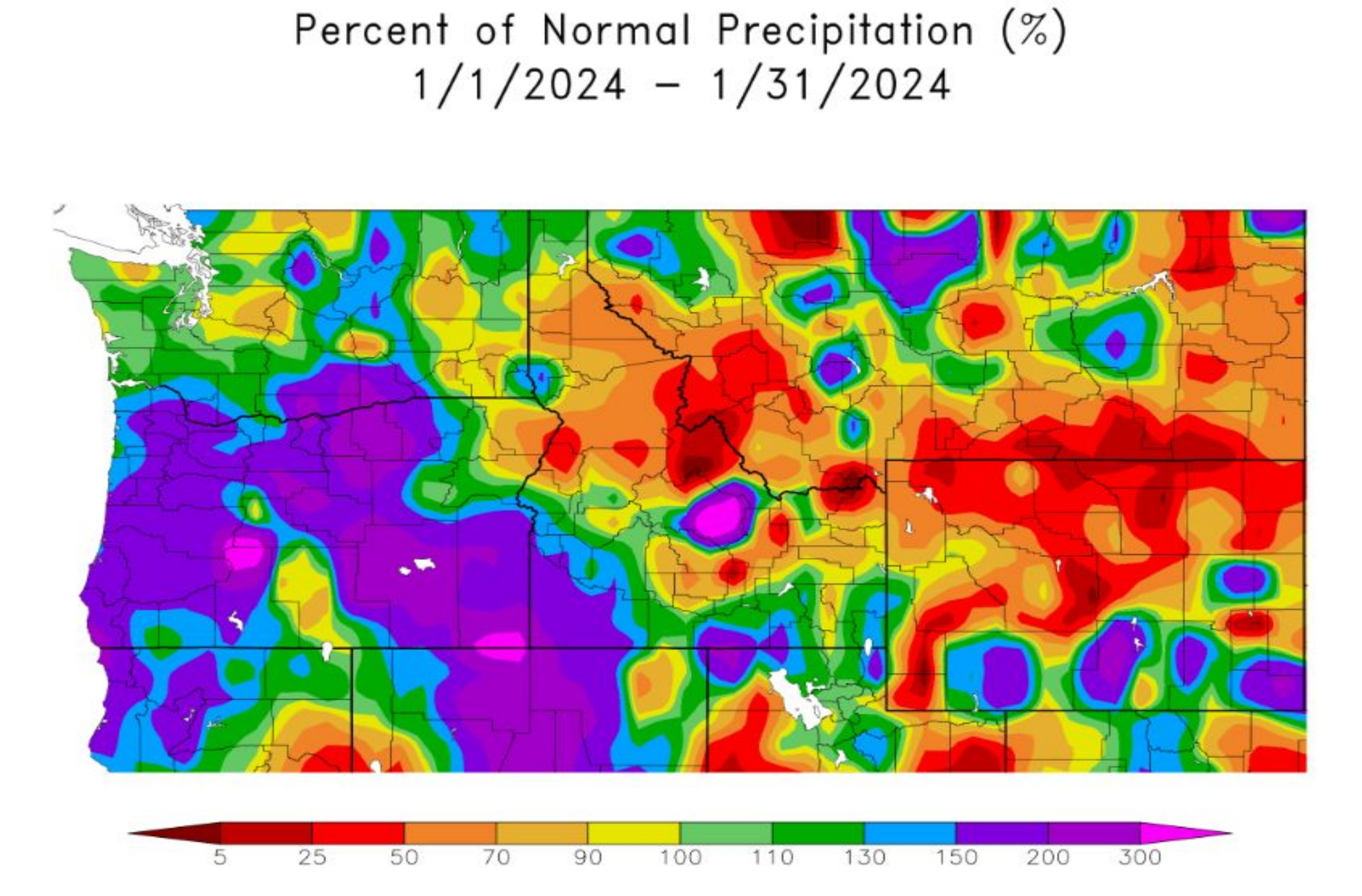
The graphs above clearly show the arctic outbreak that occurred mid month. Pendleton, OR and Redmond, OR showed an overall warming trend through the month, while Pasco, WA showed a slight cooling trend. Yakima, WA showed nearly steady to a slight warming trend.

January 2024: Departure from Normal of Average Temperatures



Most of the forecast area (northeast OR & south central and southeast WA) had below normal temperatures during the month. The coldest areas were over the eastern Columbia Gorge eastward across the Lower Columbia Basin to the Blue Mountain Foothills of the Blue Mountains. In Particular, the Walla Walla area, departures ranged from -6 to -8 degrees below normal. The warmest areas were from central OR northeast across the eastern mountains. The color pattern shows where the coldest air was during the mid month arctic outbreak.

January 2024: Percent of Normal Precipitation



There was a wide swath of well above normal precipitation from south central WA south through portions of central OR to the southeast portions of the state. Departures in these areas ranged from as low as 150 to 300 percent of normal. The driest areas were over portions of central OR, as well as the northeast mountains into the WA Blue Mountain Foothills of the Blues and over northwest corner of the forecast area in Kittitas County over the Cascades.

January 2024: Departures from Normal Means/Sums for Select Cities

	Max T	Max T D	Min T	Min T D	Ave T	Ave T D	PCPN	PCPN D
Yakima, WA	35.2	-4.3	23.1	-0.9	29.1	-2.6	1.91	0.72
Kennewick, WA	35.9	-5.8	25.9	-3.3	30.9	-4.6	2.42	1.29
Walla Walla, WA	36.1	-5.8	23.9	-6.8	30.0	-6.3	1.80	-0.30
Dallesport, WA	36.2	-5.9	27.0	-3.9	31.6	-4.9	3.01	0.63
Redmond, OR	43.0	-1.2	24.4	-0.9	33.7	-1.1	1.69	0.71
Pendleton Airport, OR	37.4	-4.3	24.4	-3.6	30.9	-4.0	2.44	0.92
La Grande Airport, OR	39.0	-0.3	29.0	4.4	34.0	2.1	1.52	-0.15
John Day, OR	41.2	0.9	21.3	0.1	31.3	0.5	1.40	0.31

The above table shows that all, but one, of the mean maximum temperatures were below normal, with the greatest departure of -5.9 degrees at Dallesport, WA. All but two of the stations had below normal mean minimum and mean average temperatures, with the greatest departures both at Walla Walla, WA with -6.8 and -6.3 degrees respectively. With a record low of -14 degrees at Walla Walla, WA (see slide #4), it is not surprising that Walla Walla, WA would have the coldest departures from normal. The stations that had above normal departures were at John Day, OR and La Grande, OR due to being south and east of the Blue Mountains, which acted as a barrier to how far south the coldest air reached southward during the arctic outbreak in mid January. The month was also wetter than normal at all but 2 locations, with the greatest departure of +1.29 inches at Kennewick, WA.

The greatest departures are outlined in black boxes.

January 2024: Observed Total Precipitation and Total Snowfall / Hail

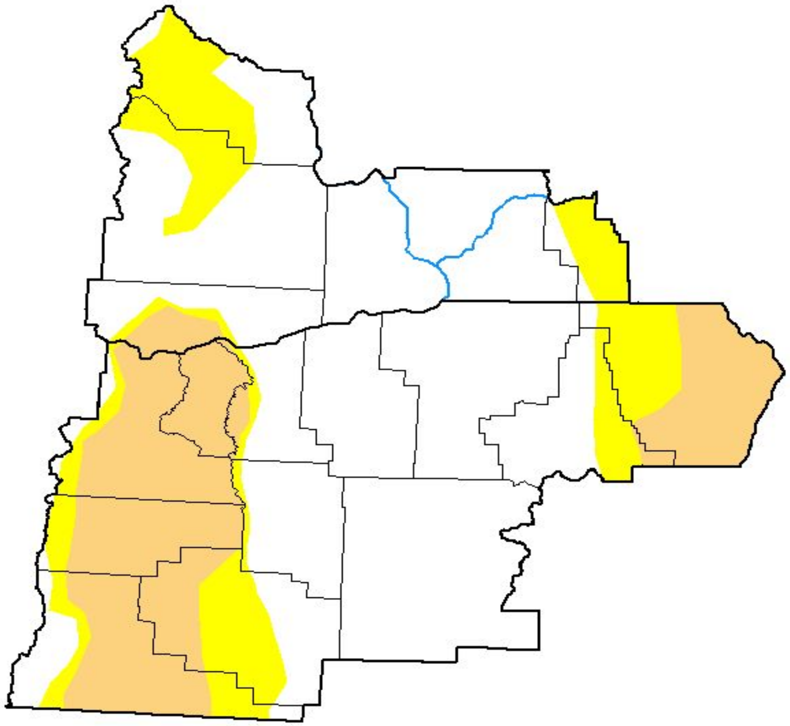
Location Source: airport ASOS, or otherwise stated	Total Precipitation (inches)	Total Snow/Hail (inches)
Pendleton, OR	2.44	9.5
Redmond, OR	1.69	M
Pasco, WA	1.21	M
Yakima, WA	1.91	M
Walla Walla, WA	1.80	M
Bend, OR CoOp	1.21	11.8
Ellensburg, WA	2.02	M
Hermiston, OR	2.10	M
John Day, OR CoOp	1.40	10.9
La Grande, OR	1.52	M
Dallesport, WA	3.01	M
Meacham, OR	6.30	M
MT Adams R.S., WA CoOp	12.21	37.6

The greatest total precipitation was a whopping 12.21 inches at the Mt. Adams Ranger Station CoOp site. It is unknown if this was a record precipitation amount or not. The least amounts of precipitation was a tie at Pasco, WA and the Bend, OR CoOp site with 1.21 inches. All stations had greater than 1.00 inches of precipitation. There were 4 available snowfall reports. The greatest snow amount was at the Mt. Adams Ranger Station CoOp site with 37.6 inches, and the least was at Pendleton, OR with 9.5 inches of snow.

January 2024 - Drought Monitor – Pendleton Forecast Area

U.S. Drought Monitor

Pendleton, OR WFO



January 30, 2024

(Released Thursday, Feb. 1, 2024)

Valid 7 a.m. EST

Drought Conditions (Percent Area)

	None	D0-D4	D1-D4	D2-D4	D3-D4	D4
Current	60.72	39.28	22.58	0.00	0.00	0.00
Last Week *01-23-2024*	56.29	43.71	23.41	3.20	0.00	0.00
3 Months Ago *10-31-2023*	7.74	92.26	65.74	24.92	1.09	0.00
Start of Calendar Year *01-02-2024*	23.75	76.25	24.81	7.08	0.00	0.00
Start of Water Year *09-26-2023*	1.51	98.49	71.11	31.58	1.09	0.00
One Year Ago *01-31-2023*	42.14	57.86	39.97	24.11	14.61	3.17

Intensity:

- None
- D0 Abnormally Dry
- D1 Moderate Drought
- D2 Severe Drought
- D3 Extreme Drought
- D4 Exceptional Drought

The Drought Monitor focuses on broad-scale conditions. Local conditions may vary. For more information on the Drought Monitor, go to https://droughtmonitor.unl.edu/About.aspx

Author:

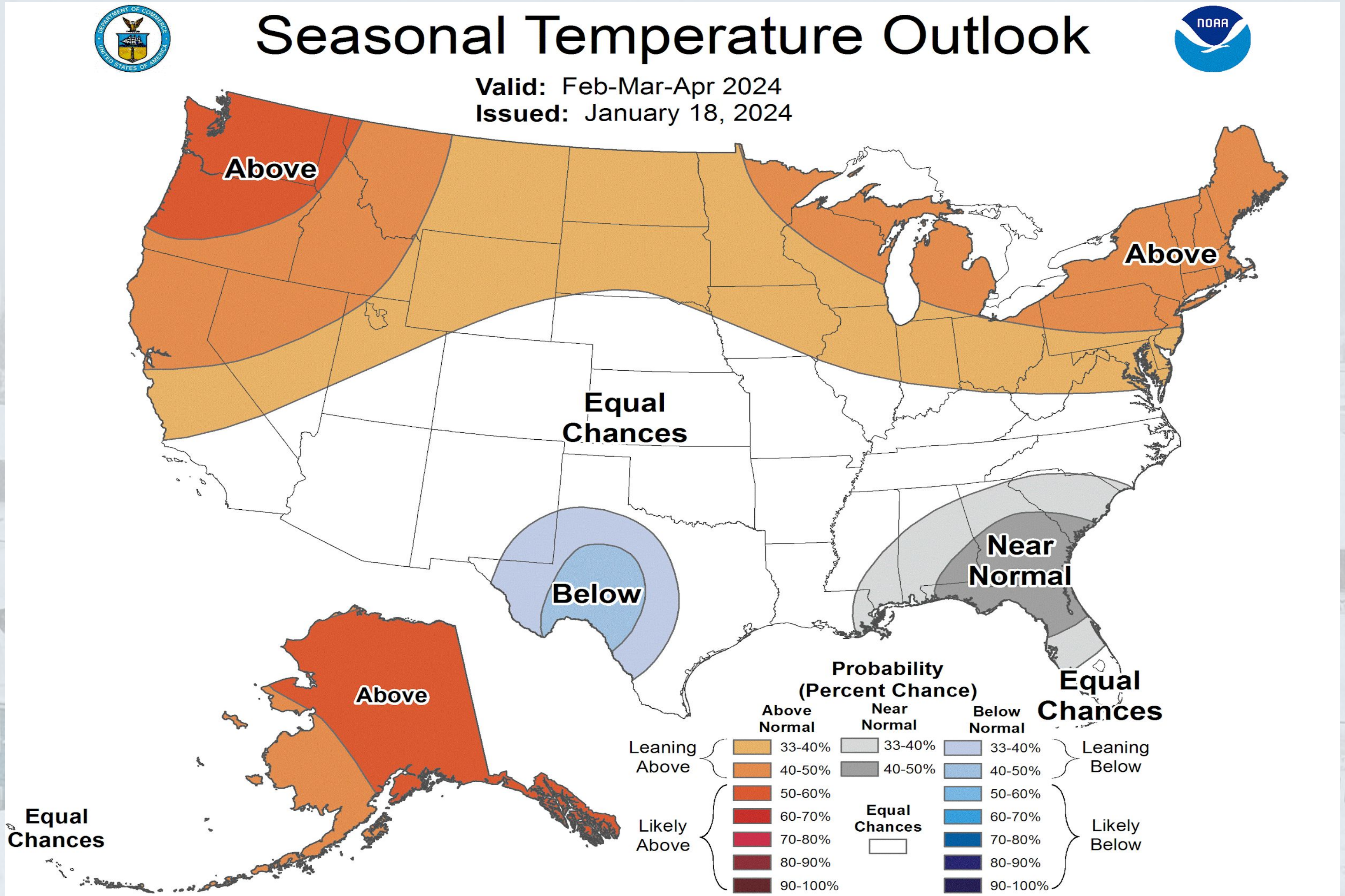
Brian Fuchs

National Drought Mitigation Center

droughtmonitor.unl.edu

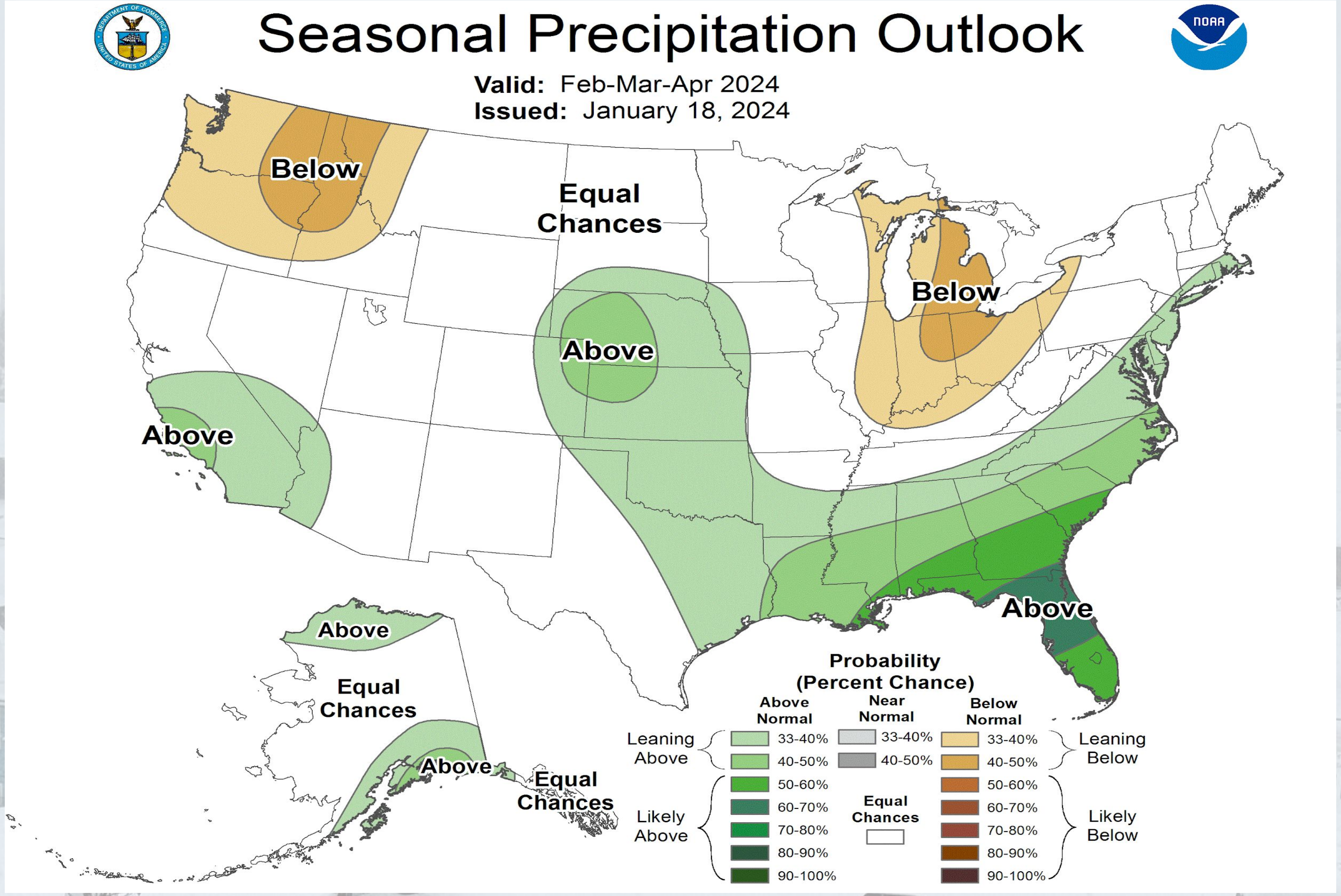
As of February 1st, drought conditions over the forecast area were mostly “None”. The greatest drought conditions was only a “Moderate” drought (D1), over areas east of the OR Cascades, Wallowa County, OR, and Columbia County, WA. There was also an area of “Abnormally Dry” conditions (D0) over the northwest forecast area in Yakima and Kittitas County. The lessened drought conditions were likely a result of the above normal precipitation during the month.

USA Three Month Temperature Outlook



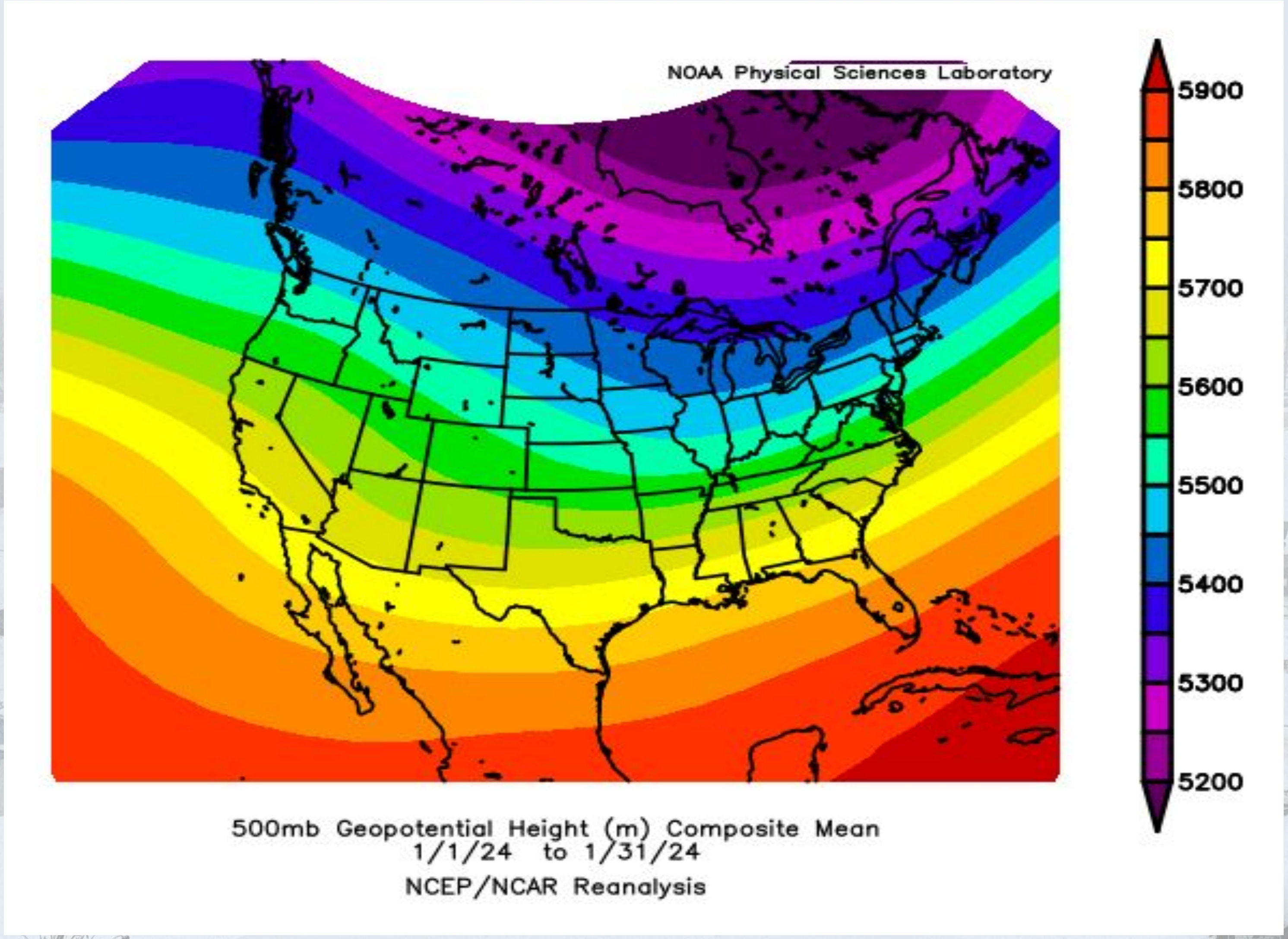
The three month temperature outlook for the period February through April 2024 over the Pacific Northwest shows temperature probabilities are leaning towards above normal (40-60% probability). It should be noted that warmer than normal conditions are typically seen over the Pacific Northwest during a moderate to strong El Niño event during the winter months, of which one is currently ongoing.

USA Three Month Precipitation Outlook



The three month precipitation outlook for the period February through April 2024, over the Pacific Northwest shows that precipitation probabilities are leaning towards below normal, with a 33-50% probability. It should be noted that precipitation is typically lower than normal in the Pacific Northwest during a moderate to strong El Niño event during the winter, of which one is currently ongoing.

January 2024 Average 500 MB Pattern

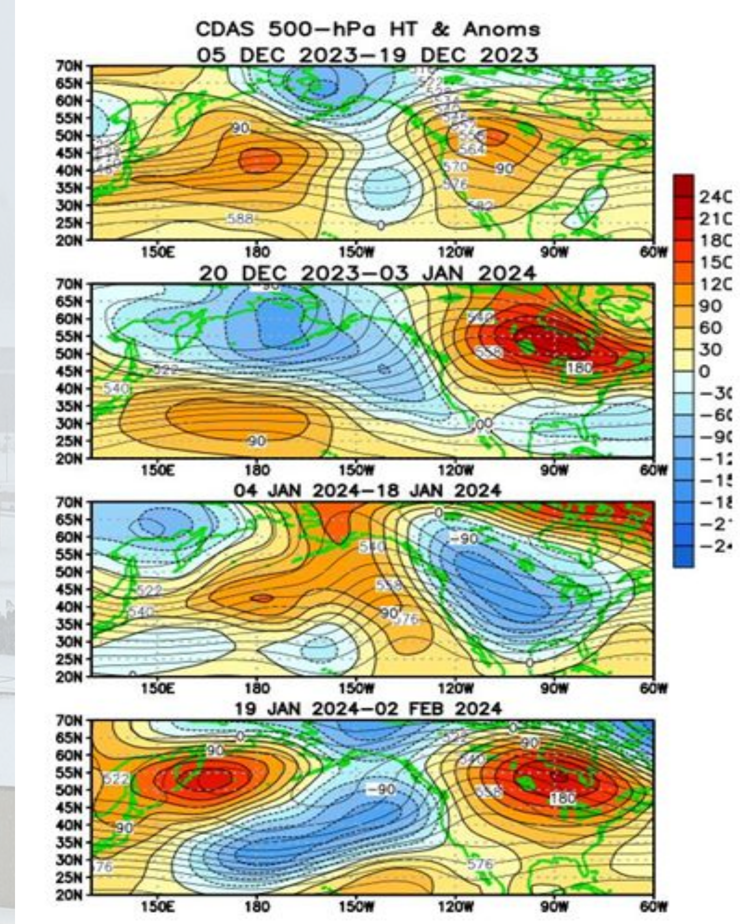


The 500 mb pattern over the Pacific Northwest averaged out to be westerly zonal flow (with only a hint of a northwest component to the flow). This is a progressive pattern, which usually results in frequent weather systems. January indeed had more frequent weather systems, especially during the middle of the month before, during and after an arctic outbreak.

Two Month, average Bi-weekly 500 MB Plots for October - January 2024

These are more detailed bi-weekly average 500 mb pattern plots that were sampled from the near the beginning of December through near the end of January into the first two days of February.

The area of focus is the Pacific Northwest (OR & WA). The land boundaries are shown by the green lines. Yellow and orange shaded color areas represent areas of high pressure or ridges at 500 mb. The blue shaded color areas show low pressure systems or troughs at 500 mb.

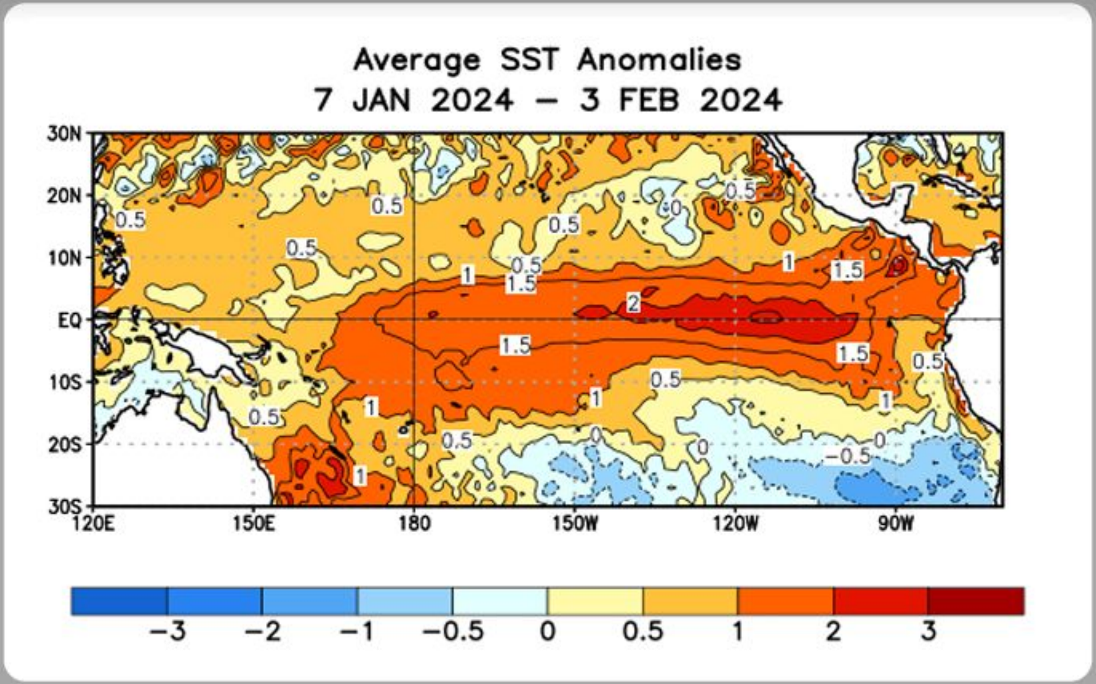


There was an overall southwest flow pattern on the west side of an upper ridge during December (the top two images), with the ridge being the strongest from December 20th - January 3rd. During this period, there was very persistent fog over the forecast area in the valleys and basins. The upper ridge shifted off shore with a northwest flow aloft over the Pacific Northwest on the east side of the ridge January 4th - January 18th. During this period there was a significant arctic outbreak in the northwest flow. A southwest flow then returned on the west side of an upper ridge from January 19th - February 2nd, with warmer conditions.

Sea Surface Temperature (SST) Anomalies for January 2024

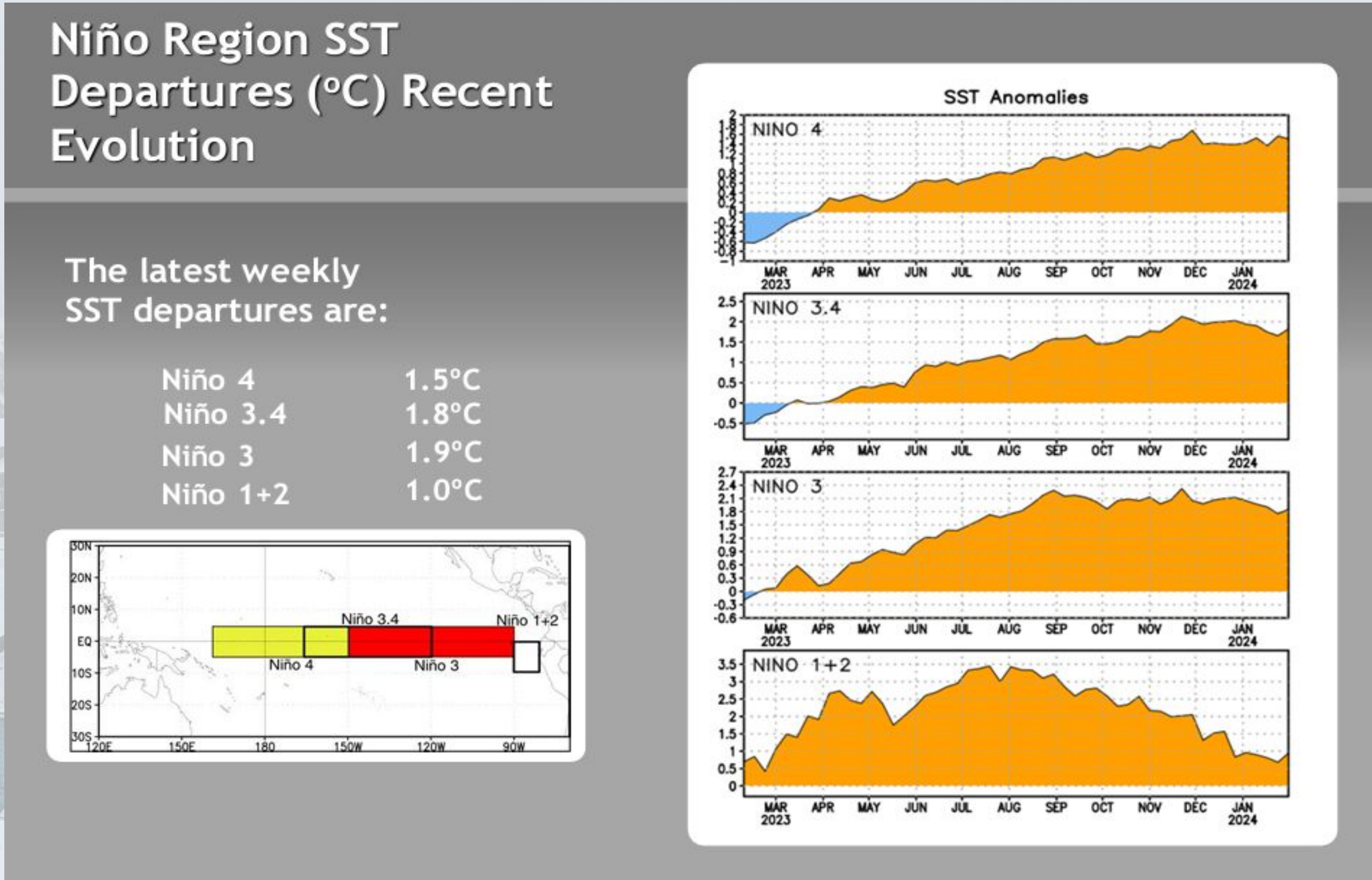
SST Departures (°C) in the Tropical Pacific During the Last Four Weeks

In the last four weeks, equatorial SSTs were above average across the Pacific Ocean, with the largest anomalies in the east-central Pacific Ocean.



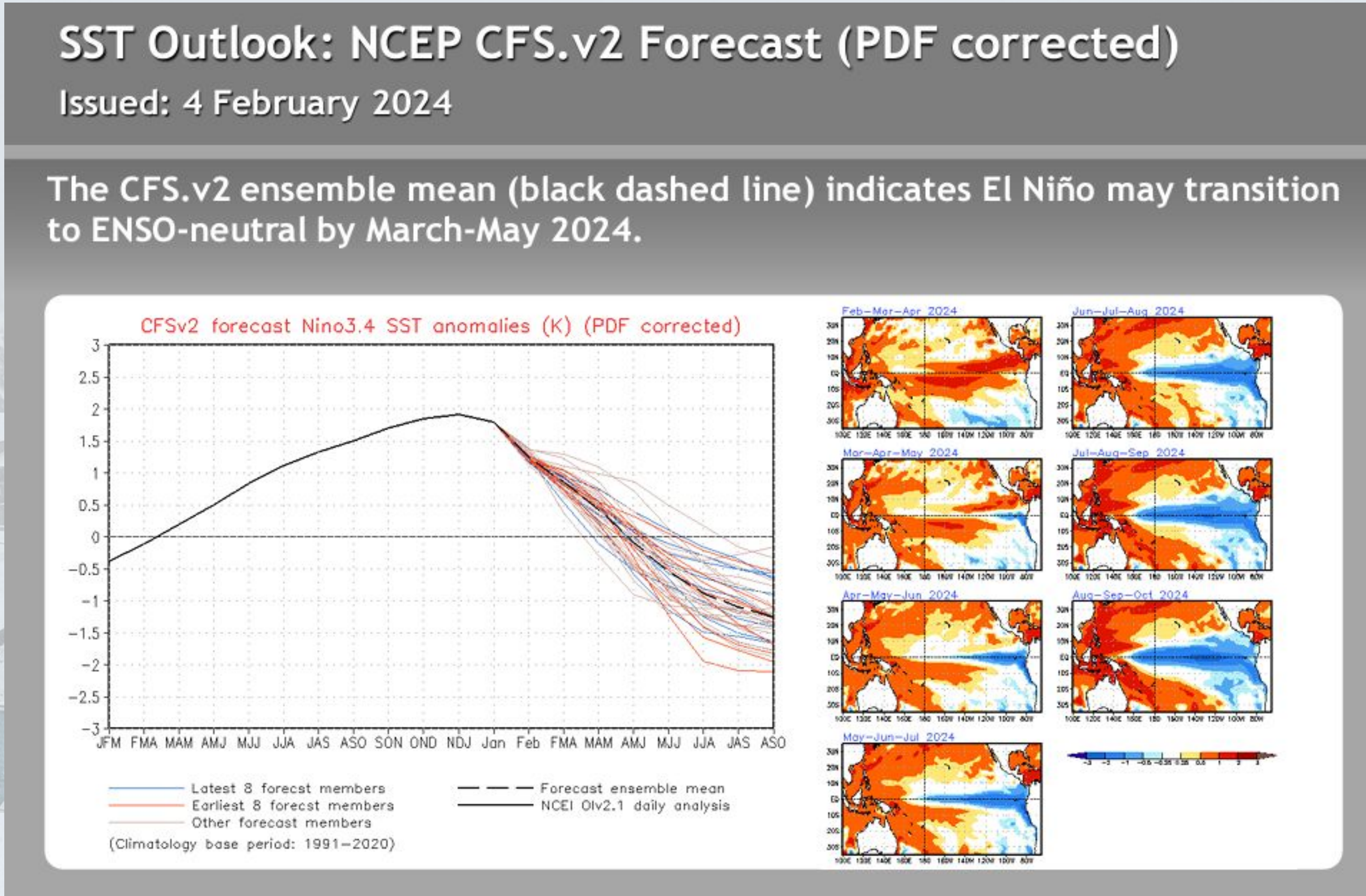
During the last four weeks, equatorial Sea Surface Temperatures (SSTs) were above average over all of the equatorial Pacific Ocean (with the greatest anomalies over the central to eastern Pacific). These persistent, above normal SSTs continue to show the ongoing El Niño event, which is forecast to continue through the early spring of 2024. ENSO conditions are then favored to become ENSO-neutral during mid to late spring, from April through June 2024.

ENSO Niño Regions SST Anomalies Ending in January 2024



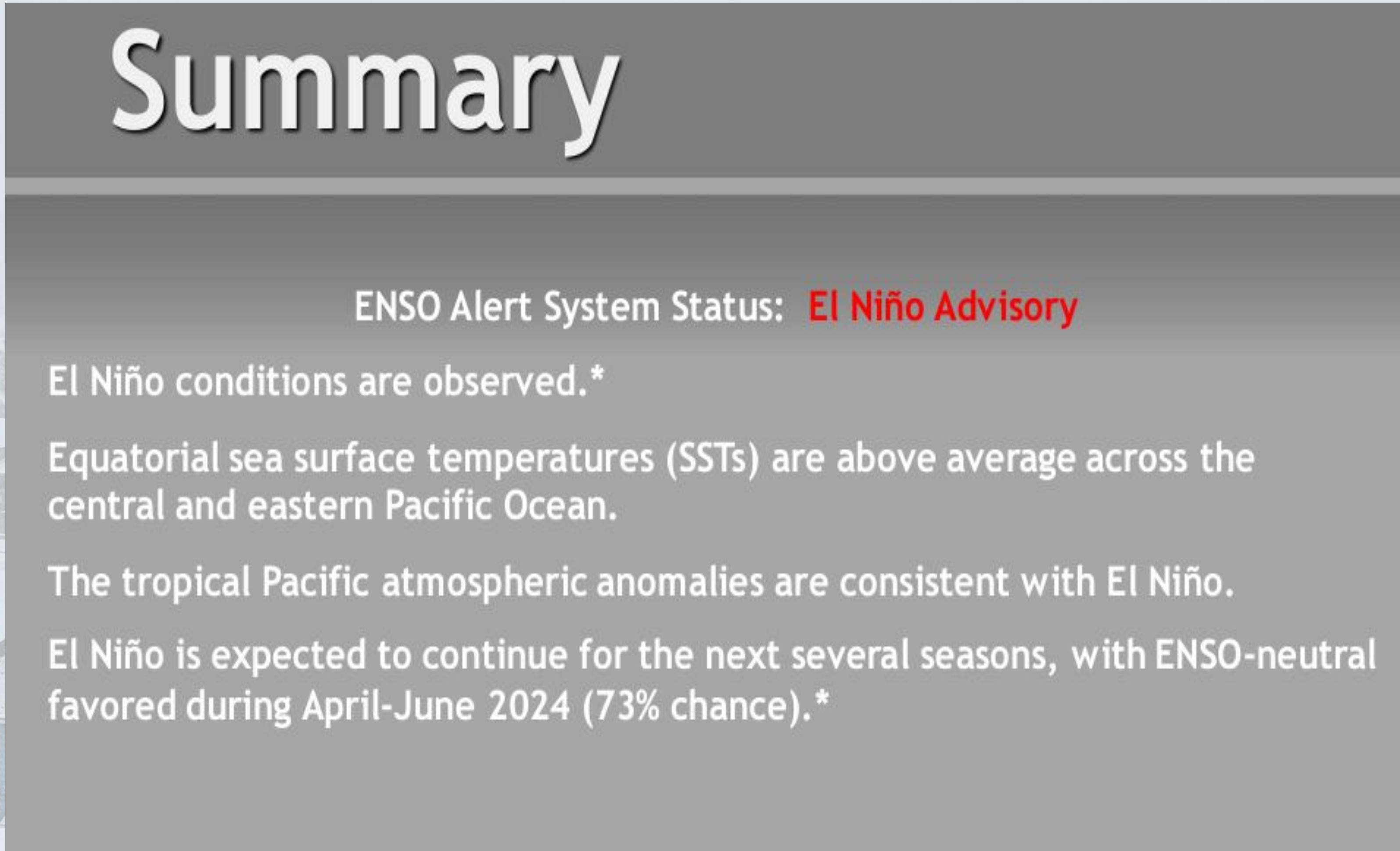
All Niño Regions, except for Niño Region 4, showed a slight dip, and then a slight uptick in Sea Surface Temperatures (SSTs) during January. However, the overall trend has been steady for the last few months, except for Niño Region 1+2, which has been showing a downward trend in SST anomalies since the summer of 2023. However, these SST conditions are still consistent with the ongoing El Niño event with positive SST anomalies in all Niño Regions.

Sea Surface Temperature (SST) NCEP CFS.v2 Ensemble Mean Outlook



The CFS.v2 ensemble mean for Niño Region 3.4 (our most influential Niño Region) will continue warmer than normal through the rest of the Northern Hemisphere winter into early spring of 2024, and then a transition to ENSO neutral during March - May 2024. The bold black line indicates that El Niño has peaked during December, and is now trending downward. The small thumbnail images to the right also show a cooling trend of the eastern equatorial Pacific through the summer into early Autumn.

Current ENSO (El Niño Southern Oscillation) Alert System Status


Summary

ENSO Alert System Status: El Niño Advisory

El Niño conditions are observed.*

Equatorial sea surface temperatures (SSTs) are above average across the central and eastern Pacific Ocean.

The tropical Pacific atmospheric anomalies are consistent with El Niño.

El Niño is expected to continue for the next several seasons, with ENSO-neutral favored during April-June 2024 (73% chance).*

The current ENSO Alert System Status is still **"El Niño Advisory"**. El Niño conditions are still observed with equatorial SSTs above average across the central and eastern Pacific Ocean. The tropical Pacific atmospheric anomalies remain consistent with El Niño, which is expected to continue through at least early spring 2024. ENSO-neutral is favored (with a 73 percent probability) during April through June 2024.

Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 6, 2024	6 SW Three Rivers	OR	SNOW	2	Trained Spotter
January 6, 2024	12 NNW Sisters	OR	SNOW	5	Public
January 7, 2024	29 SSW Dayville	OR	SNOW	1.5	Cocorahs
January 7, 2024	1 NW John Day	OR	SNOW	1.7	Cocorahs
January 7, 2024	9 NW Seneca	OR	SNOW	6.8	Cocorahs
January 7, 2024	Elgin	OR	SNOW	1.5	Cocorahs
January 7, 2024	3 SSW Wallowa	OR	SNOW	0.9	Cocorahs
January 7, 2024	10 N Elgin	OR	SNOW	4.4	Cocorahs
January 8, 2024	17 NW Roslyn	WA	SNOW	12	CO-OP Observer
January 8, 2024	25 ESE Deschutes River	OR	NON-TSTM WND GST	61	Mesonet
January 8, 2024	7 SSE La Grande	OR	NON-TSTM WND GST	56	Mesonet
January 9, 2024	5 WNW Union	OR	NON-TSTM WND GST	54	Mesonet
January 9, 2024	19 NNW West Richland	WA	NON-TSTM WND GST	53	Mesonet
January 9, 2024	22 NE Goldendale	WA	NON-TSTM WND GST	53	Mesonet
January 9, 2024	18 N Roslyn	WA	SNOW	13	Mesonet
January 9, 2024	11 NNE Roslyn	WA	SNOW	15	Mesonet
January 9, 2024	8 W Moro	OR	NON-TSTM WND GST	45	Mesonet
January 9, 2024	1 SSW Long Creek	OR	NON-TSTM WND GST	53	Mesonet
January 9, 2024	2 S Bend	OR	NON-TSTM WND GST	47	Mesonet
January 9, 2024	9 S Pilot Rock	OR	NON-TSTM WND GST	70	Mesonet
January 9, 2024	Shaniko	OR	NON-TSTM WND GST	53	Mesonet
January 9, 2024	11 NW Warm Springs	OR	NON-TSTM WND GST	46	Mesonet
January 9, 2024	6 SSE Mission	OR	NON-TSTM WND GST	60	Mesonet
January 9, 2024	4 NNW Chenoweth	OR	NON-TSTM WND GST	47	Mesonet

Please note: Magnitude units are either inches, mph, degrees F, or miles.

Continued ->

Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 9, 2024	19 N West Richland	WA	NON-TSTM WND GST	63	Mesonet
January 9, 2024	1 NNE Sisters	OR	NON-TSTM WND GST	53	AWOS
January 9, 2024	5 W Shaniko	OR	NON-TSTM WND GST	57	Mesonet
January 9, 2024	2 SSW Chenoweth	OR	NON-TSTM WND GST	52	Mesonet
January 9, 2024	16 ESE Bingen	WA	NON-TSTM WND GST	46	ASOS
January 9, 2024	2 NW Wasco	OR	NON-TSTM WND GST	50	Mesonet
January 9, 2024	12 NW West Richland	WA	NON-TSTM WND GST	55	Mesonet
January 9, 2024	8 S Dufur	OR	NON-TSTM WND GST	47	Mesonet
January 9, 2024	17 NW Goldendale	WA	NON-TSTM WND GST	61	Mesonet
January 9, 2024	11 S Arlington	OR	NON-TSTM WND GST	46	Mesonet
January 9, 2024	10 NNW Benton City	WA	NON-TSTM WND GST	82	Mesonet
January 9, 2024	4 SW Dufur	OR	NON-TSTM WND GST	47	Mesonet
January 9, 2024	5 N West Richland	WA	NON-TSTM WND GST	64	Mesonet
January 9, 2024	3 NNE Dufur	OR	NON-TSTM WND GST	47	Mesonet
January 9, 2024	11 E Shaniko	OR	NON-TSTM WND GST	60	Mesonet
January 9, 2024	1 SSW Walla Walla East	WA	NON-TSTM WND GST	49	Mesonet
January 9, 2024	1 SW Canyon City	OR	NON-TSTM WND GST	52	AWOS
January 9, 2024	6 WSW Union	OR	NON-TSTM WND GST	47	Mesonet
January 9, 2024	12 NNE Lexington	OR	NON-TSTM WND GST	45	Mesonet
January 9, 2024	12 NNE Lexington	OR	NON-TSTM WND GST	46	Mesonet
January 9, 2024	10 NNW Pendleton	OR	NON-TSTM WND GST	62	Mesonet
January 9, 2024	9 ESE Echo	OR	NON-TSTM WND GST	53	Mesonet
January 9, 2024	6 SSE Mission	OR	NON-TSTM WND GST	50	Mesonet
January 9, 2024	11 N West Richland	WA	NON-TSTM WND GST	53	Mesonet

Please note: Magnitude units are either inches, mph, degrees F, or miles.

Continued ->

Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 9, 2024	2 NNW Helix	OR	NON-TSTM WND GST	46	Mesonet
January 9, 2024	4 ESE Walla Walla East	WA	NON-TSTM WND GST	50	Mesonet
January 9, 2024	5 SSE Mission	OR	NON-TSTM WND GST	53	Mesonet
January 9, 2024	15 ESE Moro	OR	NON-TSTM WND GST	56	Mesonet
January 9, 2024	3 SSW Tieton	WA	NON-TSTM WND GST	49	Mesonet
January 9, 2024	1 NNE Fruitvale	WA	NON-TSTM WND GST	46	Mesonet
January 9, 2024	5 S Tieton	WA	NON-TSTM WND GST	55	Mesonet
January 9, 2024	3 NE Terrace Heights	WA	NON-TSTM WND GST	65	Mesonet
January 9, 2024	4 ENE Mission	OR	NON-TSTM WND GST	51	Mesonet
January 9, 2024	21 S Antelope	OR	NON-TSTM WND GST	51	Mesonet
January 9, 2024	3 N Dufur	OR	NON-TSTM WND GST	48	Mesonet
January 9, 2024	11 W Deschutes River Wo	OR	NON-TSTM WND GST	46	Mesonet
January 9, 2024	La Grande	OR	SNOW	4	Public
January 9, 2024	17 NW Roslyn	WA	SNOW	18	Public
January 9, 2024	Cle Elum	WA	SNOW	12	Public
January 9, 2024	Cle Elum	WA	SNOW	7	Public
January 9, 2024	53 SE Prineville	OR	NON-TSTM WND GST	50	Mesonet
January 9, 2024	6 NE Cove	OR	NON-TSTM WND GST	46	Mesonet
January 9, 2024	19 N White Salmon	WA	SNOW	5	Cocorahs
January 9, 2024	0.4 W Elgin	OR	SNOW	4	Cocorahs
January 9, 2024	Ellensburg	WA	SNOW	3	Trained Spotter
January 9, 2024	Blewett Pass	WA	SNOW/ICE DMG		Dept of Highways
January 9, 2024	4 WNW La Grande	OR	SNOW	7	Public
January 9, 2024	8 NW West Richland	WA	NON-TSTM WND GST	63	Mesonet

Please note: Magnitude units are either inches, mph, degrees F, or miles.

Continued ->

Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 9, 2024	8 NW West Richland	WA	NON-TSTM WND GST	63	Mesonet
January 9, 2024	18 SSE Dayton	WA	SNOW	7	Public
January 9, 2024	19 ESE Deschutes River	OR	NON-TSTM WND GST	45	Mesonet
January 9, 2024	2.6 SW Wallowa	OR	SNOW	3	Cocorahs
January 9, 2024	25 NNE Wallowa	OR	SNOW	8	Cocorahs
January 9, 2024	3.9 WSW Canyon City	OR	SNOW	3.2	Cocorahs
January 9, 2024	1 NNW Richland	WA	NON-TSTM WND GST	46	AWOS
January 9, 2024	13 W College Place	WA	NON-TSTM WND GST	51	Mesonet
January 9, 2024	1 NW Heppner	OR	NON-TSTM WND GST	45	Mesonet
January 9, 2024	16 NW Sisters	OR	BLIZZARD		Dept of Highways
January 9, 2024	16 WNW White Swan	WA	NON-TSTM WND GST	61	Mesonet
January 9, 2024	16 NW West Richland	WA	NON-TSTM WND GST	54	Mesonet
January 9, 2024	19 ENE Cle Elum	WA	BLIZZARD		Dept of Highways
January 9, 2024	1 SSW Goldendale	WA	NON-TSTM WND GST	50	Mesonet
January 9, 2024	4 NW West Richland	WA	NON-TSTM WND GST	58	Mesonet
January 9, 2024	6 WSW Echo	OR	NON-TSTM WND GST	50	Mesonet
January 9, 2024	19 NW West Richland	WA	NON-TSTM WND GST	57	Mesonet
January 9, 2024	19 NW West Richland	WA	NON-TSTM WND GST	52	Mesonet
January 9, 2024	9 NNE Richland	WA	NON-TSTM WND GST	51	Mesonet
January 9, 2024	7 SSE Mission	OR	NON-TSTM WND GST	48	Mesonet
January 9, 2024	1 S Hermiston	OR	NON-TSTM WND GST	45	Mesonet
January 9, 2024	4 ENE West Richland	WA	NON-TSTM WND GST	47	Mesonet
January 9, 2024	1 WNW Arlington	OR	NON-TSTM WND GST	48	Mesonet
January 9, 2024	12 SSE Grass Valley	OR	NON-TSTM WND GST	48	Mesonet

Please note: Magnitude units are either inches, mph, degrees F, or miles.

Continued ->

Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 9, 2024	9 S Goldendale	WA	NON-TSTM WND GST	55	Mesonet
January 9, 2024	Richland	WA	NON-TSTM WND GST	67	Public
January 9, 2024	5 SSW Irrigon	OR	NON-TSTM WND GST	55	Mesonet
January 9, 2024	10 ESE Kittitas	WA	NON-TSTM WND GST	48	Mesonet
January 9, 2024	3 NNE Walla Walla East	WA	NON-TSTM WND GST	49	ASOS
January 9, 2024	8 SW Goldendale	WA	NON-TSTM WND GST	52	Mesonet
January 9, 2024	20 NW West Richland	WA	NON-TSTM WND GST	54	Mesonet
January 9, 2024	2 WSW Mission	OR	NON-TSTM WND GST	50	Mesonet
January 9, 2024	8 SE Mission	OR	NON-TSTM WND GST	45	Mesonet
January 9, 2024	1 NNE Pasco	WA	NON-TSTM WND GST	55	ASOS
January 9, 2024	2 NNW Pendleton	OR	NON-TSTM WND GST	58	ASOS
January 9, 2024	2 NNW Richland	WA	NON-TSTM WND GST	48	Mesonet
January 9, 2024	8 WSW Echo	OR	NON-TSTM WND GST	59	Mesonet
January 9, 2024	6 SSW Ione	OR	NON-TSTM WND GST	46	Mesonet
January 9, 2024	6 S Deschutes River Woo	OR	BLIZZARD		Public
January 9, 2024	3 WSW Rufus	OR	NON-TSTM WND GST	51	Mesonet
January 9, 2024	1 E Hermiston	OR	NON-TSTM WND GST	53	ASOS
January 9, 2024	2 NW Kennewick	WA	NON-TSTM WND GST	56	Mesonet
January 9, 2024	22 NE Sunnyside	WA	NON-TSTM WND GST	53	Mesonet
January 9, 2024	2 S Kennewick	WA	NON-TSTM WND GST	47	Mesonet
January 9, 2024	1 ENE Pasco	WA	NON-TSTM WND GST	50	Mesonet
January 9, 2024	3 W Sunnyside	WA	NON-TSTM WND GST	48	Mesonet
January 9, 2024	4 NNW West Richland	WA	NON-TSTM WND GST	48	Mesonet
January 9, 2024	13 NNE Burbank	WA	NON-TSTM WND GST	53	Mesonet

Please note: Magnitude units are either inches, mph, degrees F, or miles.

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Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 9, 2024	1 SE Zillah	WA	NON-TSTM WND GST	46	Mesonet
January 9, 2024	7 SSE Irrigon	OR	NON-TSTM WND GST	53	Mesonet
January 9, 2024	7 W College Place	WA	NON-TSTM WND GST	45	Mesonet
January 9, 2024	11 SE Highland	WA	NON-TSTM WND GST	50	Mesonet
January 9, 2024	14 SE Burbank	WA	NON-TSTM WND GST	60	Mesonet
January 9, 2024	9 ESE Prosser	WA	NON-TSTM WND GST	46	Mesonet
January 9, 2024	5 W College Place	WA	NON-TSTM WND GST	47	Mesonet
January 9, 2024	2 ENE Burbank	WA	NON-TSTM WND GST	50	Mesonet
January 9, 2024	11 SSE Kahlotus	WA	NON-TSTM WND GST	50	Mesonet
January 9, 2024	3 WSW Prosser	WA	NON-TSTM WND GST	65	Mesonet
January 9, 2024	4 SSW Fossil	OR	NON-TSTM WND GST	48	Mesonet
January 9, 2024	26 NNW West Richland	WA	NON-TSTM WND GST	53	Mesonet
January 9, 2024	14 NNW West Richland	WA	NON-TSTM WND GST	59	Mesonet
January 9, 2024	17 NNW West Richland	WA	NON-TSTM WND GST	53	Mesonet
January 9, 2024	11 WNW Roslyn	WA	NON-TSTM WND GST	48	ASOS
January 9, 2024	27 S Mabton	WA	NON-TSTM WND GST	51	Mesonet
January 9, 2024	2 SE Kennewick	WA	NON-TSTM WND DMG		Trained Spotter
January 9, 2024	19 N West Richland	WA	NON-TSTM WND GST	65	Mesonet
January 9, 2024	26 NNE Sunnyside	WA	NON-TSTM WND GST	52	Mesonet
January 9, 2024	26 S Mabton	WA	NON-TSTM WND GST	53	Mesonet
January 9, 2024	14 W College Place	WA	NON-TSTM WND GST	55	Mesonet
January 9, 2024	7 S Richland	WA	NON-TSTM WND GST	48	Mesonet
January 9, 2024	11 WNW Roslyn	WA	NON-TSTM WND GST	48	ASOS
January 9, 2024	12 E Bingen	WA	NON-TSTM WND GST	45	Mesonet

Please note: Magnitude units are either inches, mph, degrees F, or miles.

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Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 9, 2024	8 NNE West Richland	WA	NON-TSTM WND GST	46	Mesonet
January 9, 2024	7 SSE Joseph	OR	NON-TSTM WND GST	68	Mesonet
January 9, 2024	8 SW Highland	WA	NON-TSTM WND GST	51	Mesonet
January 9, 2024	4 WNW Irrigon	OR	NON-TSTM WND GST	46	Mesonet
January 9, 2024	22 N West Richland	WA	NON-TSTM WND GST	50	Mesonet
January 9, 2024	4 W Adams	OR	NON-TSTM WND GST	49	Mesonet
January 9, 2024	2 S Joseph	OR	NON-TSTM WND GST	52	Mesonet
January 9, 2024	25 NNW West Richland	WA	NON-TSTM WND GST	45	Mesonet
January 9, 2024	21 NNW West Richland	WA	NON-TSTM WND GST	47	Mesonet
January 9, 2024	8 WSW Grass Valley	OR	NON-TSTM WND GST	45	Mesonet
January 9, 2024	22 SW Highland	WA	NON-TSTM WND GST	50	Mesonet
January 9, 2024	4 NW Wallowa	OR	NON-TSTM WND GST	48	Mesonet
January 9, 2024	3 S Enterprise	OR	BLIZZARD		Public
January 9, 2024	8 ENE Bingen	WA	SNOW	2.5	Cocorahs
January 9, 2024	15 ESE Moro	OR	NON-TSTM WND GST	66	Mesonet
January 10, 2024	11 S Arlington	OR	NON-TSTM WND GST	63	Mesonet
January 10, 2024	17 WNW Sisters	OR	SNOW	15	Mesonet
January 10, 2024	Prineville	OR	SNOW	4	Public
January 10, 2024	2 SE Kennewick	WA	SNOW	1.5	Trained Spotter
January 10, 2024	2.1 ESE Bend	OR	SNOW	8.4	Cocorahs
January 10, 2024	19 N White Salmon	WA	SNOW	12	Cocorahs
January 10, 2024	2 E Kennewick	WA	SNOW	1.3	Cocorahs
January 10, 2024	0.4 W Elgin	OR	SNOW	6.7	Cocorahs
January 10, 2024	7 WNW Madras	OR	SNOW	3.4	Cocorahs

Please note: Magnitude units are either inches, mph, degrees F, or miles.

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Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 10, 2024	15 SSE Dayton	WA	SNOW	10	Public
January 10, 2024	15 E Weston	OR	BLIZZARD		Public
January 10, 2024	6.5 W Redmond	OR	SNOW	8.7	Cocorahs
January 10, 2024	2 WNW Sisters	OR	SNOW	9.5	Cocorahs
January 10, 2024	9 NW Seneca	OR	SNOW	6.2	Trained Spotter
January 10, 2024	7 ESE Redmond	OR	SNOW	4.2	Cocorahs
January 10, 2024	8 SE Mission	OR	BLIZZARD		Dept of Highways
January 10, 2024	18 ENE Seneca	OR	SNOW	7	Mesonet
January 10, 2024	13 SW Mitchell	OR	SNOW	9	Mesonet
January 10, 2024	14 SE Mitchell	OR	SNOW	8	Mesonet
January 10, 2024	19 W La Grande	OR	SNOW	6	Mesonet
January 10, 2024	19 ENE Ukiah	OR	SNOW	4	Mesonet
January 10, 2024	4 NNW Island City	OR	SNOW	9	Trained Spotter
January 10, 2024	9.8 N Elgin	OR	SNOW	13	Cocorahs
January 10, 2024	0.4 W Elgin	OR	SNOW	6.7	Cocorahs
January 10, 2024	2 S Madras	OR	SNOW	3.5	Cocorahs
January 10, 2024	2.6 SW Wallowa	OR	SNOW	4.4	Cocorahs
January 10, 2024	4.2 NNW Goldendale	WA	SNOW	9	Cocorahs
January 10, 2024	6 SSW Three Rivers	OR	SNOW	14	Trained Spotter
January 10, 2024	10 S Ukiah	OR	SNOW	9	Trained Spotter
January 10, 2024	Ukiah	OR	SNOW	9	Park/Forest Srvc
January 12, 2024	4 W College Place	WA	SNOW	2.2	CO-OP Observer
January 12, 2024	2 WNW Sisters	OR	SNOW	3	Cocorahs
January 12, 2024	3 SSE Pasco	WA	SNOW	0.5	CO-OP Observer

Please note: Magnitude units are either inches, mph, degrees F, or miles.

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Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 12, 2024	Elgin	OR	SNOW	3.4	Cocorahs
January 12, 2024	18 N White Salmon	WA	SNOW	7	Cocorahs
January 12, 2024	4 WNW West Valley	WA	SNOW	1.8	Cocorahs
January 12, 2024	2 WSW Fruitvale	WA	SNOW	0.8	Cocorahs
January 12, 2024	3 SSE Dayton	WA	SNOW	3	Cocorahs
January 12, 2024	17 NW Roslyn	WA	SNOW	6.5	CO-OP Observer
January 12, 2024	9 NE Dayton	WA	SNOW	4.5	Cocorahs
January 12, 2024	4 SSE Pendleton	OR	SNOW	1.9	Cocorahs
January 12, 2024	1 NW John Day	OR	SNOW	2.5	CO-OP Observer
January 12, 2024	10 N Elgin	OR	SNOW	5	Cocorahs
January 12, 2024	1 E Cove	OR	SNOW	4.9	CO-OP Observer
January 12, 2024	1 NW Heppner	OR	SNOW	2	CO-OP Observer
January 12, 2024	3 SE Lostine	OR	SNOW	3	Cocorahs
January 12, 2024	Joseph	OR	SNOW	5.5	Cocorahs
January 12, 2024	Weston	OR	SNOW	2	Public
January 12, 2024	3 SSE White Swan	WA	SNOW	2	Trained Spotter
January 12, 2024	4 NNW Island City	OR	SNOW	13	Trained Spotter
January 12, 2024	2 NW Pendleton	OR	SNOW	1.2	Official NWS Obs
January 12, 2024	Pilot Rock	OR	SNOW	3	NWS Employee
January 12, 2024	1 SW John Day	OR	SNOW	7	Public
January 12, 2024	14 NE Prairie City	OR	SNOW	36	Public
January 12, 2024	4 ESE Pilot Rock	OR	SNOW	6	Trained Spotter
January 13, 2024	Moro	OR	SNOW	10	Public
January 13, 2024	Moro	OR	SNOW	6	Public

Please note: Magnitude units are either inches, mph, degrees F, or miles.

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Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 13, 2024	Moro	OR	SNOW	10	Public
January 13, 2024	7 SSW Three Rivers	OR	SNOW	5	Trained Spotter
January 13, 2024	8 NW Bend	OR	SNOW	6	Public
January 13, 2024	6 SSW Three Rivers	OR	SNOW	10	Trained Spotter
January 13, 2024	7 SSW Three Rivers	OR	SNOW	9	Trained Spotter
January 13, 2024	Bend	OR	SNOW	7	Public
January 13, 2024	Goldendale	WA	SNOW	8	Public
January 13, 2024	Redmond	OR	SNOW	7	Public
January 13, 2024	10 S John Day	OR	SNOW	6	Other Federal
January 13, 2024	10 SE Seneca	OR	SNOW	8	Other Federal
January 13, 2024	City of the Dalles	OR	SNOW	6	Public
January 13, 2024	Mitchell	OR	SNOW	9	Fire Dept/Rescue
January 13, 2024	3 SSW College Place	WA	SNOW	4	Public
January 13, 2024	Pendleton	OR	SNOW	2.5	Public
January 13, 2024	4 W Pendleton	OR	SNOW	4	Dept of Highways
January 13, 2024	Pilot Rock	OR	SNOW	8	Public
January 13, 2024	11 NE Goldendale	WA	SNOW	3	Trained Spotter
January 13, 2024	6 W Condon	OR	SNOW	7	Trained Spotter
January 13, 2024	Prairie City	OR	SNOW	20	Public
January 13, 2024	2 N Prineville	OR	SNOW	8	Public
January 13, 2024	Prineville	OR	SNOW	7	Public
January 13, 2024	1 N Madras	OR	SNOW	7	Public
January 13, 2024	10 S Prineville	OR	SNOW	9.5	Public
January 13, 2024	La Grande	OR	SNOW	12	Public

Please note: Magnitude units are either inches, mph, degrees F, or miles.

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Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 13, 2024	Sunriver	OR	SNOW	15	Public
January 13, 2024	Elgin	OR	SNOW	16	Public
January 13, 2024	Lexington	OR	SNOW	7	Public
January 13, 2024	19 N White Salmon	WA	SNOW	9	Public
January 13, 2024	10 S Prineville	OR	SNOW	9.5	Public
January 13, 2024	Hermiston	OR	SNOW	2	NWS Employee
January 13, 2024	Terrebonne	OR	SNOW	11	Public
January 13, 2024	Goldendale	WA	SNOW	5.5	Public
January 13, 2024	Culver	OR	SNOW	9	Public
January 13, 2024	Heppner	OR	SNOW	7	Public
January 13, 2024	3 SSE White Swan	WA	SNOW	2	Trained Spotter
January 13, 2024	Mount Vernon	OR	SNOW	11	Public
January 13, 2024	Terrebonne	OR	SNOW	10	Public
January 13, 2024	White Salmon	WA	SNOW	8	Public
January 13, 2024	Dayville	OR	SNOW	7	Public
January 13, 2024	3 N Monument	OR	SNOW	9.5	Public
January 13, 2024	Arlington	OR	SNOW	2.5	Public
January 13, 2024	Hermiston	OR	SNOW	2.5	Public
January 13, 2024	17 SE Mission	OR	SNOW	5	Public
January 13, 2024	1 SW Redmond	OR	SNOW	10	Public
January 13, 2024	2 N Sisters	OR	SNOW	14	Public
January 13, 2024	City of the Dalles	OR	SNOW	6.8	Public
January 13, 2024	City of the Dalles	OR	SNOW	6.5	Public
January 13, 2024	6 NNW Bend	OR	SNOW	10.5	Public

Please note: Magnitude units are either inches, mph, degrees F, or miles.

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Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 13, 2024	4 NNW Island City	OR	SNOW	4	Trained Spotter
January 13, 2024	5 N White Salmon	WA	SNOW	8	Public
January 13, 2024	City of the Dalles	OR	SNOW	7	Public
January 13, 2024	John Day	OR	SNOW	14	Public
January 13, 2024	Wasco	OR	SNOW	6	Public
January 13, 2024	6 E Prineville	OR	SNOW	7.5	Public
January 13, 2024	13 S Three Rivers	OR	SNOW	20	Public
January 13, 2024	2 NNW Sunnyside	WA	SNOW	1	CO-OP Observer
January 13, 2024	Seneca	OR	SNOW	8	Public
January 13, 2024	3 NE Bend	OR	SNOW	9	Public
January 13, 2024	White Salmon	WA	SNOW	7.8	Public
January 14, 2024	6 WSW Hermiston	OR	SNOW	3	Dept of Highways
January 14, 2024	2 ESE Bend	OR	SNOW	9.7	Cocorahs
January 14, 2024	18 N White Salmon	WA	SNOW	7	Cocorahs
January 14, 2024	29 SSW Dayville	OR	SNOW	7	Cocorahs
January 14, 2024	1 WSW Terrebonne	OR	SNOW	8.5	Cocorahs
January 14, 2024	2 S Bend	OR	SNOW	8.8	Cocorahs
January 14, 2024	3 ESE Bend	OR	SNOW	8.2	Cocorahs
January 14, 2024	2 NW Redmond	OR	SNOW	6.9	Cocorahs
January 14, 2024	6 SSE Prineville	OR	SNOW	9.5	Cocorahs
January 14, 2024	6 ESE Warm Springs	OR	SNOW	6	Cocorahs
January 14, 2024	9 SE Redmond	OR	SNOW	7.5	Cocorahs
January 14, 2024	7 W Redmond	OR	SNOW	9	Cocorahs
January 14, 2024	2 S Madras	OR	SNOW	5.5	Cocorahs

Please note: Magnitude units are either inches, mph, degrees F, or miles.

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Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 14, 2024	1 SE Pendleton	OR	SNOW	5	Public
January 14, 2024	1 WNW White Salmon	WA	SNOW	8	Cocorahs
January 14, 2024	Elgin	OR	SNOW	2	Cocorahs
January 14, 2024	4 SSE Pendleton	OR	SNOW	2.9	Cocorahs
January 14, 2024	Wasco	OR	SNOW	6	Public
January 14, 2024	6 N Bend	OR	SNOW	8	Cocorahs
January 14, 2024	Wasco	OR	SNOW	6	Public
January 14, 2024	3 NNE Bend	OR	SNOW	4.8	Cocorahs
January 14, 2024	City of the Dalles	OR	SNOW	6.8	Public
January 14, 2024	City of the Dalles	OR	SNOW	7	Public
January 14, 2024	Moro	OR	SNOW	6	Public
January 14, 2024	Terrebonne	OR	SNOW	10	Public
January 14, 2024	6 E Prineville	OR	SNOW	7.5	Public
January 14, 2024	City of the Dalles	OR	SNOW	6.8	Public
January 14, 2024	Terrebonne	OR	SNOW	10	Public
January 14, 2024	6 E Prineville	OR	SNOW	7.5	Public
January 14, 2024	City of the Dalles	OR	SNOW	7	Public
January 14, 2024	4 NNW Goldendale	WA	SNOW	4.5	Public
January 14, 2024	Redmond	OR	SNOW	7	Public
January 14, 2024	6 NNW Bend	OR	SNOW	10.5	Public
January 14, 2024	1 NW John Day	OR	SNOW	6	CO-OP Observer
January 14, 2024	1 SW Redmond	OR	SNOW	10	Public
January 14, 2024	Prineville	OR	SNOW	7	Public
January 14, 2024	6 SSW Antelope	OR	SNOW	5	CO-OP Observer

Please note: Magnitude units are either inches, mph, degrees F, or miles.

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Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 14, 2024	Prineville	OR	SNOW	7	Public
January 14, 2024	Culver	OR	SNOW	9	Public
January 14, 2024	2 N Sisters	OR	SNOW	14	Public
January 14, 2024	13 S Three Rivers	OR	SNOW	20	Public
January 14, 2024	John Day	OR	SNOW	14	Public
January 14, 2024	2 NNW Sunnyside	WA	SNOW	1	CO-OP Observer
January 14, 2024	13 S Three Rivers	OR	SNOW	20	Public
January 14, 2024	Redmond	OR	SNOW	7	Public
January 14, 2024	Hermiston	OR	SNOW	2.5	Public
January 14, 2024	1 WNW Arlington	OR	SNOW	2	CO-OP Observer
January 14, 2024	1 SW Redmond	OR	SNOW	10	Public
January 14, 2024	1 NW Heppner	OR	SNOW	4.5	CO-OP Observer
January 14, 2024	Hermiston	OR	SNOW	2.5	Public
January 14, 2024	Culver	OR	SNOW	9	Public
January 14, 2024	6 NNW Bend	OR	SNOW	10.5	Public
January 14, 2024	White Salmon	WA	SNOW	7.8	Public
January 14, 2024	City of the Dalles	OR	SNOW	6.5	Public
January 14, 2024	Seneca	OR	SNOW	8	Public
January 14, 2024	Mount Vernon	OR	SNOW	11	Public
January 14, 2024	Seneca	OR	SNOW	8	Public
January 14, 2024	Heppner	OR	SNOW	7	Public
January 14, 2024	Mount Vernon	OR	SNOW	11	Public
January 14, 2024	Heppner	OR	SNOW	7	Public
January 14, 2024	White Salmon	WA	SNOW	8	Public

Please note: Magnitude units are either inches, mph, degrees F, or miles.

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Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 14, 2024	5 N White Salmon	WA	SNOW	8	Public
January 14, 2024	15 S Ione	OR	SNOW	7	Public
January 14, 2024	Arlington	OR	SNOW	2.5	Public
January 14, 2024	17 SE Mission	OR	SNOW	5	Public
January 14, 2024	Arlington	OR	SNOW	2.5	Public
January 14, 2024	15 S Ione	OR	SNOW	7	Public
January 14, 2024	Goldendale	WA	SNOW	5.5	Public
January 14, 2024	Dayville	OR	SNOW	7	Public
January 14, 2024	Terrebonne	OR	SNOW	10	Public
January 14, 2024	3 NE Bend	OR	SNOW	9	Public
January 14, 2024	Terrebonne	OR	SNOW	11	Public
January 14, 2024	Lonerock	OR	SNOW	12.5	Public
January 16, 2024	5 WNW Union	OR	NON-TSTM WND GST	60	Mesonet
January 16, 2024	Redmond	OR	FREEZING RAIN	0.02	ASOS
January 16, 2024	15 E Weston	OR	SNOW	2	Public
January 16, 2024	7 SSE La Grande	OR	NON-TSTM WND GST	63	Mesonet
January 17, 2024	29 SSW Dayville	OR	SNOW	2.5	Cocorahs
January 17, 2024	1 WNW White Salmon	WA	SNOW	3.5	Cocorahs
January 17, 2024	6 ENE Goldendale	WA	SNOW	1.6	Cocorahs
January 17, 2024	18 N White Salmon	WA	SNOW	3.5	Cocorahs
January 17, 2024	25 NNE Wallowa	OR	SNOW	2	Cocorahs
January 17, 2024	Prairie City	OR	SNOW	3.5	Cocorahs
January 17, 2024	10 N Elgin	OR	SNOW	1.8	Cocorahs
January 17, 2024	10 S Three Rivers	OR	FREEZING RAIN	0.1	Public

Please note: Magnitude units are either inches, mph, degrees F, or miles.

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Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 17, 2024	1 NE Sunnyside	WA	SNOW	1.1	Cocorahs
January 17, 2024	2 NNE Granger	WA	SNOW	1.3	Cocorahs
January 17, 2024	White Salmon	WA	SNOW	4	Public
January 17, 2024	Wasco	OR	SNOW	2	Public
January 17, 2024	1 WNW Arlington	OR	SNOW	1	CO-OP Observer
January 17, 2024	John Day	OR	SNOW	2	Public
January 17, 2024	2 NNW Sunnyside	WA	SNOW	0.7	CO-OP Observer
January 17, 2024	1 NW Heppner	OR	SNOW	1.5	CO-OP Observer
January 17, 2024	9 S Pilot Rock	OR	NON-TSTM WND GST	56	Mesonet
January 17, 2024	Ione	OR	SNOW	2	Public
January 17, 2024	17 ESE Bingen	WA	SNOW	2	Public
January 17, 2024	Goldendale	WA	SNOW	3	Public
January 17, 2024	13 NE Bingen	WA	SNOW	2	Public
January 17, 2024	Elgin	OR	SNOW	4.5	Public
January 17, 2024	20 N Roslyn	WA	SNOW	9	Mesonet
January 17, 2024	16 NE Cle Elum	WA	SNOW	6	Mesonet
January 17, 2024	28 WNW Tieton	WA	SNOW	10	Mesonet
January 17, 2024	38 W White Swan	WA	SNOW	8	Mesonet
January 17, 2024	13 NW Elgin	OR	SNOW	5	Mesonet
January 17, 2024	18 WNW Roslyn	WA	SNOW	9	Mesonet
January 17, 2024	21 E Milton-Freewater	OR	SNOW	7	Mesonet
January 17, 2024	Pilot Rock	OR	FREEZING RAIN	0.06	NWS Employee
January 18, 2024	18 SSE Dayton	WA	SNOW	6	Public
January 18, 2024	3 SSE Pasco	WA	SNOW	1	CO-OP Observer

Please note: Magnitude units are either inches, mph, degrees F, or miles.

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Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 18, 2024	18 N White Salmon	WA	SNOW	3.5	Cocorahs
January 18, 2024	4 WNW West Valley	WA	SNOW	1.5	Cocorahs
January 18, 2024	1 WNW White Salmon	WA	SNOW	4	Cocorahs
January 18, 2024	17 NW Roslyn	WA	SNOW	9	CO-OP Observer
January 18, 2024	Elgin	OR	SNOW	1.5	Cocorahs
January 18, 2024	10 NNW Naches	WA	SNOW	2.5	Cocorahs
January 18, 2024	25 NNE Wallowa	OR	SNOW	5	Cocorahs
January 18, 2024	Elgin	OR	SNOW	2	Cocorahs
January 18, 2024	3 SSW Wallowa	OR	SNOW	1.6	Cocorahs
January 18, 2024	Joseph	OR	SNOW	1.6	Cocorahs
January 18, 2024	1 E Cove	OR	SNOW	1.4	CO-OP Observer
January 18, 2024	10 N Elgin	OR	SNOW	5	Cocorahs
January 18, 2024	17 SE Milton-Freewater	OR	SNOW	8	Public
January 18, 2024	1 SE City of the Dalles	OR	SNOW	2	Public
January 18, 2024	Mosier	OR	SNOW	3.5	Trained Spotter
January 18, 2024	5 WNW Chenoweth	OR	SNOW	4	Trained Spotter
January 18, 2024	Maupin	OR	SNOW	6	Trained Spotter
January 18, 2024	9 NW Ellensburg	WA	SNOW	4	Trained Spotter
January 18, 2024	10 NW Maupin	OR	SNOW	1.5	Trained Spotter
January 18, 2024	2 SE Mosier	OR	SNOW	1	Trained Spotter
January 18, 2024	2 SSE South Cle Elum	WA	SNOW	12	Trained Spotter
January 18, 2024	2 SE Cle Elum	WA	SNOW	20	Trained Spotter
January 18, 2024	38 W White Swan	WA	SNOW	12	Mesonet
January 18, 2024	12 WSW Ellensburg	WA	SNOW	2	Trained Spotter

Please note: Magnitude units are either inches, mph, degrees F, or miles.

Continued ->

Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 18, 2024	8 NNW Ellensburg	WA	SNOW	7	Trained Spotter
January 18, 2024	6 WNW Ellensburg	WA	SNOW	2	Trained Spotter
January 18, 2024	4 ESE Roslyn	WA	SNOW	7	Trained Spotter
January 18, 2024	9 SE Cle Elum	WA	SNOW	8	Trained Spotter
January 18, 2024	2 ESE Kennewick	WA	SNOW	2	Public
January 18, 2024	4 ENE Moxee	WA	SNOW	2.5	Trained Spotter
January 18, 2024	Condon	OR	SNOW	2	Trained Spotter
January 18, 2024	1 N Ellensburg	WA	SNOW	2	Trained Spotter
January 18, 2024	Dayton	WA	SNOW	2.5	Public
January 18, 2024	2 SE Mosier	OR	SNOW	12	Trained Spotter
January 18, 2024	Richland	WA	SNOW	3	Public
January 19, 2024	Pendleton	OR	FREEZING RAIN	0.01	ASOS
January 19, 2024	Walla Walla	WA	FREEZING RAIN	0.03	ASOS
January 19, 2024	1 SW Finley	WA	SNOW	3	Cocorahs
January 19, 2024	2 WNW Sisters	OR	SNOW	1	Cocorahs
January 19, 2024	10 NNW Naches	WA	SNOW	2.5	Cocorahs
January 19, 2024	2 WSW Fruitvale	WA	SNOW	3.8	Cocorahs
January 19, 2024	18 N White Salmon	WA	SNOW	8.5	Cocorahs
January 19, 2024	1 WNW White Salmon	WA	SNOW	9	Cocorahs
January 19, 2024	1 SW Richland	WA	SNOW	3.7	Cocorahs
January 19, 2024	3 SSW Richland	WA	SNOW	3.8	Cocorahs
January 19, 2024	2 E Kennewick	WA	SNOW	3	Cocorahs
January 19, 2024	2 S Madras	OR	SNOW	1.5	Cocorahs
January 19, 2024	6 ESE Warm Springs	OR	SNOW	2	Cocorahs

Please note: Magnitude units are either inches, mph, degrees F, or miles.

Continued ->

Significant Weather Events - Local Storm Reports for January 2024

Significant Weather Events					
Date	**Location**	**State**	**Event Type**	**Magnitude**	**Source**
January 19, 2024	4 SSE Pendleton	OR	SNOW	2.6	Cocorahs
January 19, 2024	3 SSW Wallowa	OR	SNOW	1	Cocorahs
January 19, 2024	1 NE Sunnyside	WA	SNOW	3.5	Cocorahs
January 19, 2024	City of the Dalles	OR	SNOW	10	Trained Spotter
January 19, 2024	2 NNE Granger	WA	SNOW	4	Cocorahs
January 19, 2024	Prosser	WA	SNOW	3.5	Cocorahs
January 19, 2024	Ellensburg	WA	SNOW	3	Trained Spotter
January 19, 2024	1 WSW Fruitvale	WA	SNOW	2.2	Cocorahs
January 19, 2024	6 SSW Antelope	OR	SNOW	2	CO-OP Observer
January 19, 2024	1 NW Heppner	OR	SNOW	1.5	CO-OP Observer
January 19, 2024	1 WNW Yakima	WA	SNOW	2.5	Cocorahs
January 19, 2024	Pasco	WA	FREEZING RAIN	0.01	ASOS
January 19, 2024	2 NNW Sunnyside	WA	SNOW	3.5	CO-OP Observer
January 19, 2024	10 NNE Pasco	WA	SNOW	3	CO-OP Observer
January 19, 2024	3 SSE Pasco	WA	SNOW	3.5	CO-OP Observer
January 19, 2024	1 WNW Arlington	OR	SNOW	3.5	CO-OP Observer
January 19, 2024	3 NNE Walla Walla East	WA	FREEZING RAIN	0.03	ASOS
January 19, 2024	Meacham	OR	FREEZING RAIN	0.01	ASOS
January 25, 2024	18 N White Salmon	WA	RAINFALL	1.02	Cocorahs
January 25, 2024	1 WNW White Salmon	WA	RAINFALL	0.52	Cocorahs
January 25, 2024	17 NW Roslyn	WA	RAINFALL	0.87	CO-OP Observer
January 25, 2024	11 WNW Roslyn	WA	RAINFALL	0.67	ASOS

Please note: Magnitude units are either inches, mph, degrees F, or miles.


NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION
NOAA
U.S. DEPARTMENT OF COMMERCE
NATIONAL WEATHER SERVICE
Thank You!

EXHIBIT 50-6

Assessment of January 2024
Cold Weather Event

As the Program Administrator of the first regional resource adequacy (RA) program in the Western Interconnect, and as a partner to its members in managing critically important reliability programs, the Western Power Pool (WPP) has a vested interest in ensuring safe and reliable grid operations.

The conditions experienced January 12 through January 16, 2024, highlighted a tipping point and demonstrated how close the region is to a resource adequacy crisis.

This analysis of the January 2024 cold weather event provides a high-level overview of the actions taken by the RC West Reliability Coordinator and the support provided to the Northwest by the Desert Southwest and Rocky Mountain states during the extreme temperature and load conditions. **The amount of inter-regional support necessary to manage Balancing Authority (BA) operations through the cold weather event is indicative of the pressing need to address RA and potential capacity shortfalls as soon as practicable, highlighting the value of an RA program with a broad geographic footprint and diversity of load and resources**.

A significant amount of progress has been made on the Western Resource Adequacy Program (WRAP) since the region's call to action in 2019, and work carries on in earnest.

Since WPP received FERC approval of its WRAP tariff in February 2023, it has been working to ensure broad participation in a binding program that incentivizes resource adequacy planning and operations. The WRAP will help ensure participating load responsible entities (LREs) have sufficient capacity to meet a reliability metric set based on regional analytical modeling results, allowing the LRE and its customers to access load and resource diversity benefits and potential investment cost savings, especially during an event such as this one.

This cold weather event analysis will focus on the Northwest, defined as British Columbia, Washington, Oregon, Idaho, and Western Montana, and uses publicly available data.

Northwest BAs communicated widely that they were experiencing sustained temperatures at or near record lows for the five-day period from January 12 to January 16, 2024, contributing significantly to high loads.

Overview of RC West Reliability Coordinator Actions

During the period beginning the morning of January 13 and ending the evening of January 15, 2024, the RC West Reliability Coordinator placed four entities in either an Energy Emergency Alert Watch (EEA Watch), an EEA 1 (all resources in use or committed, energy deficiencies expected) or an EEA 3 (BA is at risk of not meeting firm load and maintaining contingency reserves and is preparing for potential rotating power outages).

The Role of Imports from the Desert Southwest and the Rockies

As part of a BA's EIA-930 reporting requirements, it must provide data on the interchange (specifically, the sum of the net metered tie line flow) between its BA and any other directly interconnected BAs. This interchange data enables us to identify net importing or net exporting BAs in the Northwest during the five days from January 12 – January 16, 2024. We can also use the data to identify the source of the exports coming into a net-importing region.

When the hourly interchange for the 15 BAs in the Northwest region is summed together, and interchange between entities in the region is excluded (neither an import into or export out of the region), and then the hourly values are averaged, it is revealed that the **Northwest was a net importer of an average of 4,900 MW per hour** during the five days from January 12 – January 16, 2024**.**

This analysis will attempt to attribute the 4,900 MW of support to the Northwest region to BAs in the Eastern/Rockies AC System, the Desert Southwest and California, again underscoring the value of a region-wide RA program that leverages diversity in geography and load.

To determine the support provided by the Eastern portion of the WECC footprint, we summed and averaged the interchange between Northwest BAs and Nevada Power Company, PacifiCorp East and Western Area Power Administration, Upper Great Plains West. Using EIA 930 data, **2,067 MW of imports into the Northwest originated from the Eastern/Rockies AC System.** Of note, 155 MW were transferred from the Eastern Interconnect to the Western Interconnect from the Southwest Power Pool BA.

Summing the CAISO and non-CAISO BAs interchange (and excluding interchange internal to those California BAs) results in an average interchange of -691 MW. This indicates that on average the CAISO and other California BAs were net importers. Since CAISO was exporting 2,833 MW to the Northwest Region but itself was a net importer, CAISO necessarily imported a greater number of MW from elsewhere, in this case the Desert Southwest. Note that there were also exports from California to Mexico.

The same interchange data shows the Desert Southwest/Rockies BAs were net exporters of approximately 5,334 MW on average. **Those exports from the Desert Southwest/Rockies region supported CAISO and other California BAs as well as 2,833 MW of imports to the Northwest on the Pacific AC Intertie.**

These data are represented in Figure 1, showing the average net imports into the Northwest during the cold weather event of January 12 through January 16, 2024.

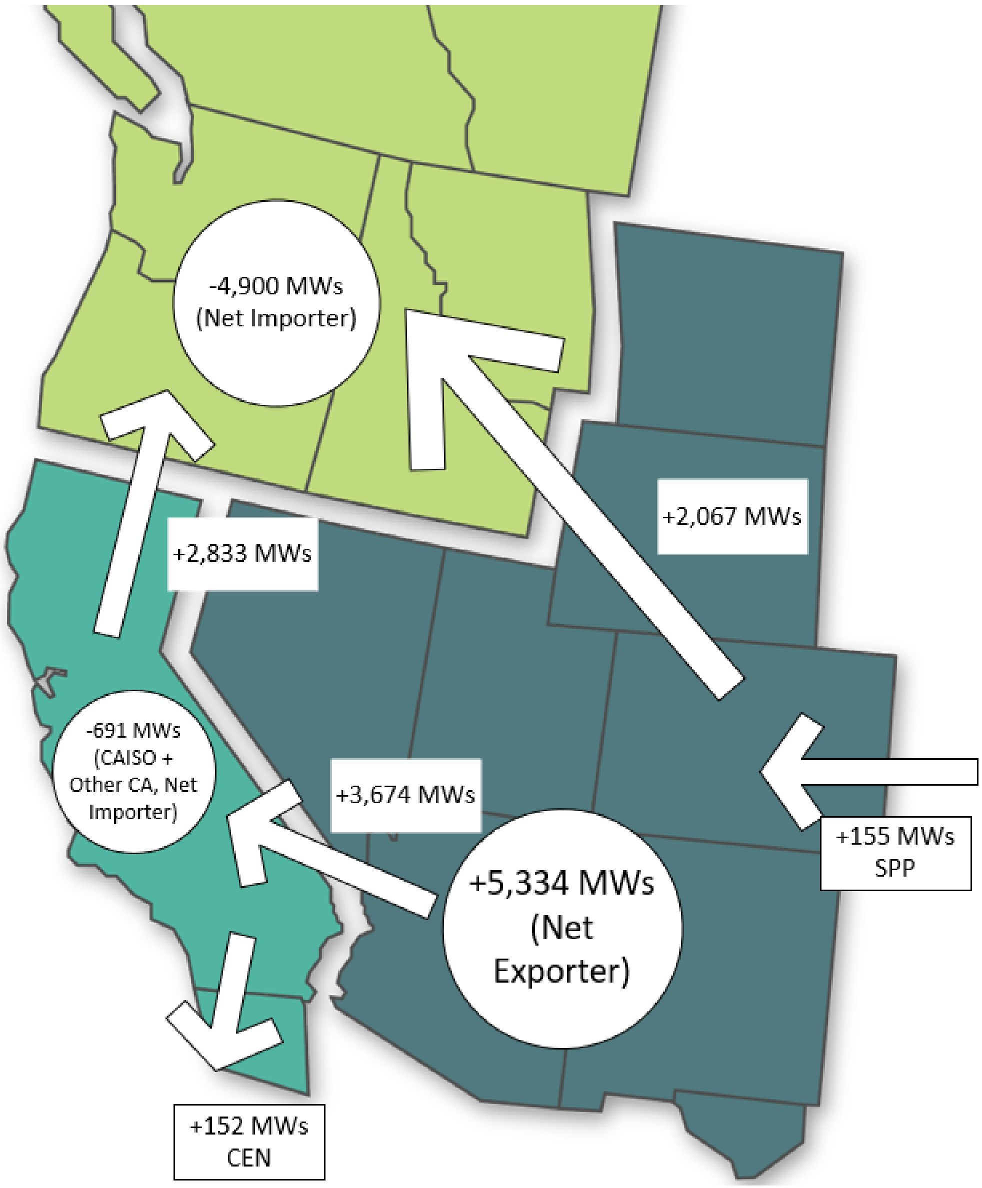


Figure 1 - Average net regional imports into the Northwest during January 12 through January 16, 2024.

As part of this analysis, it should be noted:

1. The EIA data was used as-is without an attempt to correct internal inconsistencies that were identified as part of the analysis. EIA states, "We publish hourly operating data from individual BAs exactly as we received the data. Hourly U.S. and regional aggregations and all daily data aggregations incorporate procedures for handling anomalous values of some data elements. We advise caution when using these data." For this analysis the "FROM_BA" data was utilized. In some cases, it did not exactly match the corresponding "TO_BA" information.

2. The assumed 2,067 MW import from the Eastern AC system could include transfers from PacifiCorp East to PacifiCorp West.
3. It should not be assumed that all 4,900 MW of imports into the Northwest region were day-ahead or real-time transactions.

Overview of Regional Temperatures

WPP used the National Weather Service's Automated Surface Observing System (ASOS) data to visually represent historical temperatures for a set of representative Northwest cities. The minimum temperatures during the peak hours (HE7-HE22, or 6am to 10pm) of each winter season (December-March) for the 20-year period beginning in 2004 and ending in 2024 were plotted to identify the minimum, maximum, median and quartiles, as shown in Figure 2. The lowest temperature during the peak hours on each day in the five-day period in 2024 (January 12–January 16) was overlaid in red on the box and whisker plot below. It is clear from the data that many Northwest cities were experiencing near-record or record-low temperatures, contributing significantly to high loads.

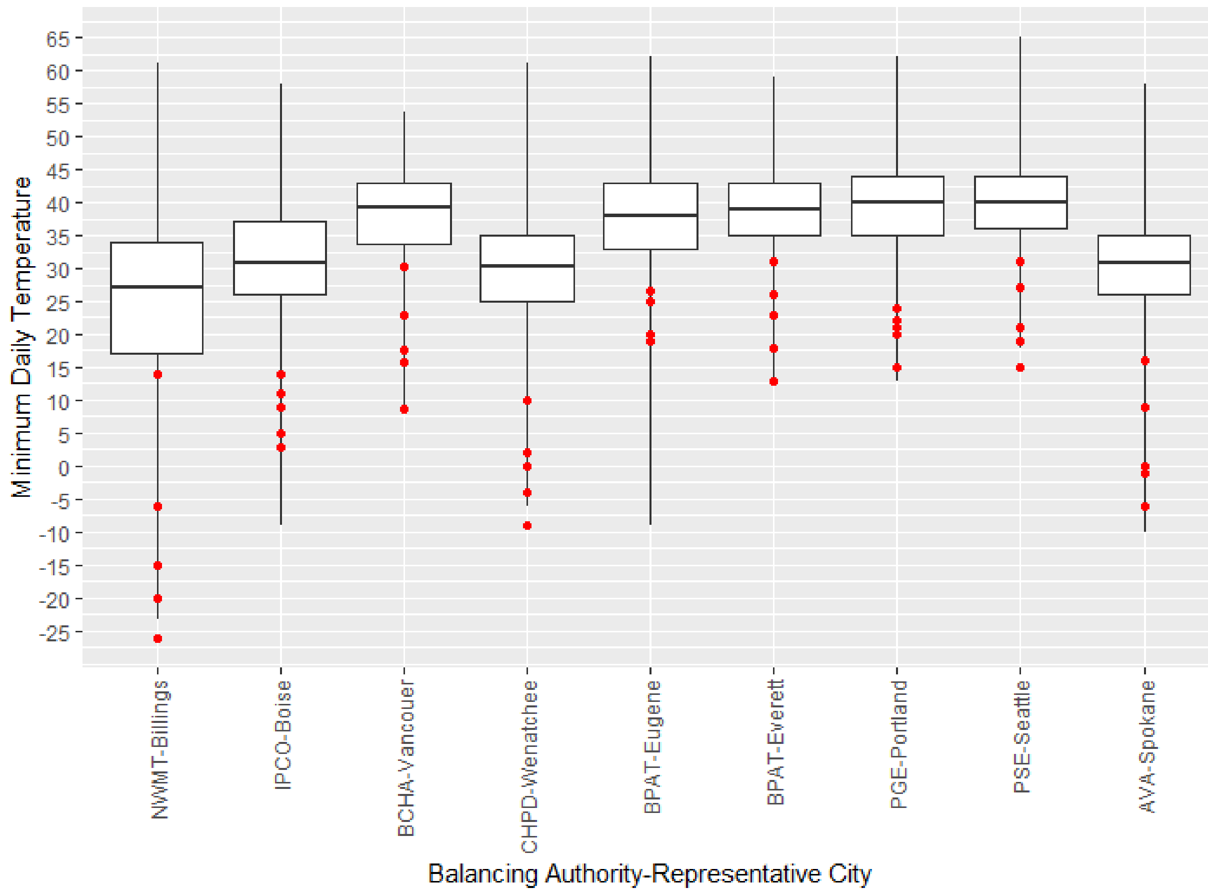


Figure 2 - Comparison of the lowest temperatures in Northwest cities during the peak hours of each day during January 12-16, 2024 (red dots) to the range of lowest temperatures during those hours during winter over the last 20 years (vertical lines indicate minimum/maximum range, box indicates the two quartiles [about half the data] around the bold horizontal median line) (source: htttps//www.weather.gov./asos)

Overview of Balancing Authority Loads

Each BA submits hourly operating data, including demand, as part of its Form EIA-930 obligations. Collection of BA demand data did not begin until July 2015, so it cannot be used to indicate whether a BA has achieved an all-time peak. The demand data can, however, be used to understand how loads compare to the recent historical record. The horizontal line at 1.0 on Figure 3 represents the peak load during the high-load hours (HE7 – HE22) of the winter season (December-March) for the 9-year period beginning July 1, 2015, and ending January 11, 2024, for 12 BAs. The historical data are overlaid with the observed load over the peak hours of each day from January 12 through January 16, 2024. Many BAs had loads that exceeded their previous 9-year peak. In many other instances, BAs had extended periods where loads were greater than 90% of the 9-year peak. Note that the Canadian BA BC Hydro is not included as it does not have an EIA-930 requirement, but it has publicly acknowledged reaching a record high peak of 11,300 MW on the BC Hydro system (which includes most load in the BC Hydro BAA) on Friday January 12, 2024.[1]

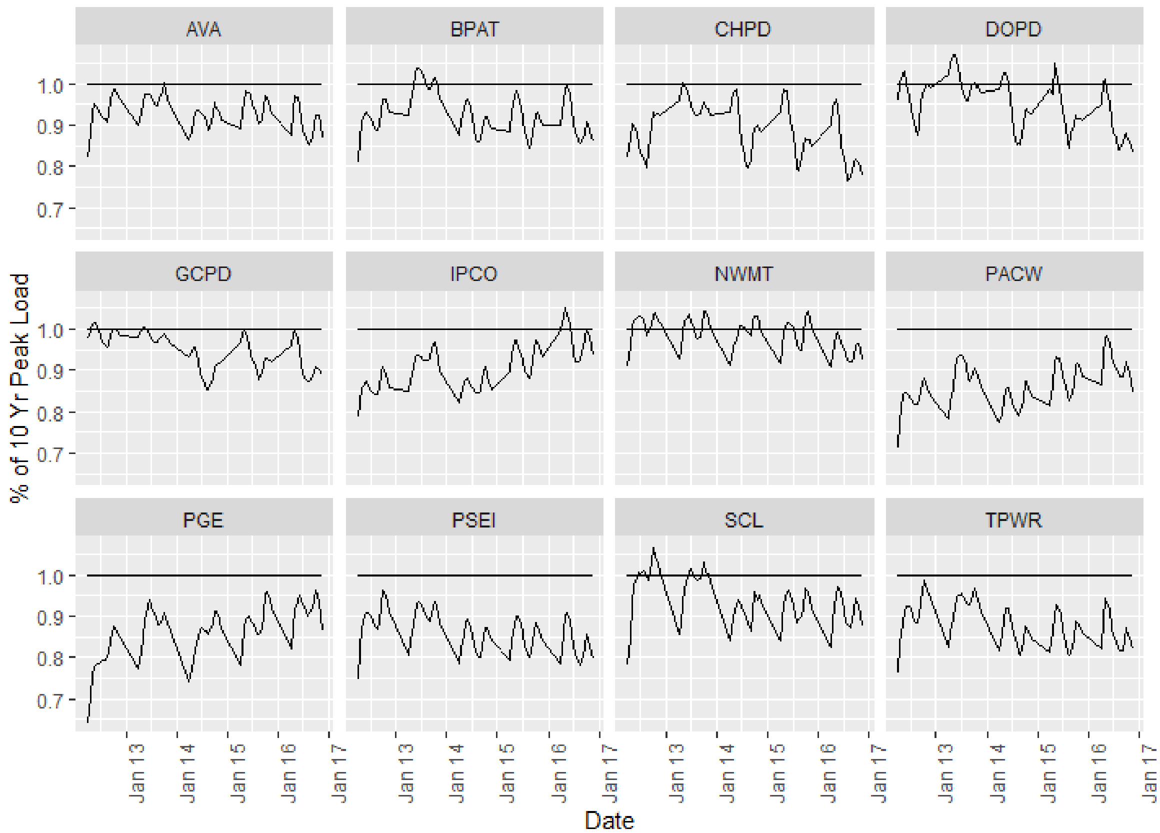


Figure 3 - The observed load for 12 BAs during January 12 – 16, 2024 (trend lines) relative to their peak loads (horizontal line at 1.0) during the winter for the last 10 years (Source: U.S. Energy Information Administration (EIA) - Real-time Operating Grid [select download data -> Balancing Authority/Region Files])

Conclusion

There is no better indicator of the importance of and need for a program like the WRAP than the cold weather event the Northwest recently experienced. Temperatures and loads were at or near historic peaks, BAs were managing through energy emergencies in real time and there was a significant amount of support required from BAs outside of the Northwest Region, particularly from the Desert Southwest and Rockies regions.

All these factors point to the need to act quickly to address potential capacity challenges in the Northwest and realize the benefits afforded by full, binding implementation of a nearly WECC-wide resource adequacy program like WPP's WRAP.

[1] https://www.bchydro.com/news/press_centre/news_releases/2024/record-breaking-electricity-demand-helps-neighbours.html

EXHIBIT 50-7

Table of Contents

Purpose

Provide guidance on mitigating transmission system operating Emergencies, Capacity and Energy Emergencies, and extreme weather and environmental Emergencies. Provide the RC's philosophy on load shedding.

1. Responsibilities

- Reliability Coordinator Operator
- Operations Compliance Support

2. Scope/Applicability

- Reliability Coordination during *Bulk Electric System* (*BES) Emergencies* or during conditions or events that could result in *Adverse Reliability Impact* on the BES.
    - As defined in the NERC Glossary, a BES Emergency is any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the BES.
    - In addition, the NERC Glossary defines Adverse Reliability Impact as the impact of an event that results in frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.

3. Procedure Detail

3.1. Capacity and Energy Emergencies

Each Balancing Authority (BA) shall develop, maintain, and implement an RC-reviewed Operating Plan to mitigate Capacity and Energy Emergencies within its Balancing Authority Area.[1] During a BA Capacity or Energy Emergency, the RC operator will declare an Energy Emergency Alert (EEA) for the affected entity. This may be at the request of the BA, or when deemed necessary in the judgment of the RC operator.

There are three levels of EEAs and an additional termination level.[2] It is not necessary to progress through the levels sequentially, and the RC operator should use good judgment in declaring the level best defined by the criteria. Public appeals for conservation or demand response programs under contractual agreements during normal operations do not qualify as EEA triggering events.

[1] EOP-011-4 R2
[2] Attachment 1-EOP-011-4 Section B

If a BA forecasts a potential energy or capacity deficiency one or more days prior to the operating day, the BA may request the RC operator to declare an *"EEA Watch"* before the operating day. A BA may also choose to request an EEA Watch during the operating day if the BA is concerned about potential energy or capacity issues in advance of the forecasted shortage; or if required to meet internal emergency notification requirements. E.g., for a forecasted shortage at 1300, a BA may request issuing an EEA Watch declaration during the morning hours. An EEA Watch declaration may be helpful to assist the BA procure additional energy or capacity.

Following the activation of Contingency Reserves, a BA or Reserve Sharing Group (RSG) must recover Contingency Reserves within 60 minutes following an event requiring activation. If there is an additional event that takes place during this recovery period, the 60-minute recovery period resets. The RC operator should not declare an EEA for a BA during this recovery period unless requested by the BA, or if the RC operator, after consultation with the BA, has reason to believe that the BA will not be able to recover their Contingency Reserves within the recovery period.

3.1.1. EEA Watch

A BA may request the RC operator to declare an "EEA Watch" one or more days prior to the operating day, or during the operating day, if the BA forecasts being in an EEA level; or if required to meet internal emergency notification requirements.

Reliability Coordinator Actions
• **Discuss** with the BA forecasting a potential energy or capacity deficiency, and **determine** whether an EEA Watch would be desired and the applicable day (date) and/or time period. • Upon request by the BA, **declare** an *EEA Watch* **via** a WECC-wide GMS message, **notifying** all BAs, TOPs and Western RCs (**See** Section 3.1.6 for templates). • **Notify** market participants in the RC Area **via** GMS. • **Cancel** EEA Watch **via** GMS, if conditions change, and the BA no longer forecasts being in an EEA.

3.1.2. EEA 1 – All Available Generation in Use

A BA is considered to be in EEA 1 when all available generation resources are in use and/or:

- The BA is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, reserve commitments, and is concerned about sustaining its required Contingency Reserves.
- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.[3]

Reliability Coordinator Actions

• **Discuss** with BA not meeting its Contingency Reserve requirements <u>and</u> **evaluate** mitigation options, based on guidelines provided in RC West Operating Procedure RC0210 Monitoring Frequency and Balancing Authority Performance.
  ○ **Determine** if the BA is part of an RSG, if Contingency Reserves are deliverable to the BA, and if the BA will require an EEA to get assistance from the RSG (***Refer*** *to Section 3.4.2 of* RC0210*)*.
• **Evaluate** whether the criteria for EEA 1 is met, if the BA is not part of an RSG, or RSG reserves is not adequate or deliverable.
  ○ **Determine** status of generation in the BA and if all generation within the BA is committed to meet firm load, firm transactions, and reserve commitments.
  ○ **Determine** whether the BA is concerned about sustaining its required Contingency Reserves.
  ○ **Determine** whether the BA has curtailed non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements).
• Upon discussion with the BA, **declare** an *EEA 1* for the BA if the criteria for EEA 1 is met, or if requested by the BA.
• **Issue** an *alert* to all impacted entities without delay, but not longer than <u>within 30 minutes</u> from time of the declaration:[4]
  ○ **Notify** all BAs, TOPs, and Western RCs **via** GMS WECC-Wide message.
  ○ **Notify** market participants in the RC Area **via** GMS.
  ○ **Send** RCIS message.
Notification **should include** the name of the BA, the EEA level, and if necessary, contact information that other BAs can use to provide emergency assistance.
• **Update** RCIS and GMS with any changes in information.

[3] Attachment 1-EOP-011-4 Section B-1
[4] EOP-011-4 R5

3.1.3. EEA 2 – Load Management Procedures in Effect

A BA is considered to be in EEA 2 when load management procedures are in effect and/or:

- The Balancing Authority is no longer able to provide its expected energy requirements and is an energy-deficient Balancing Authority.
- An energy-deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.
- An energy-deficient BA is still able to maintain minimum Contingency Reserve requirements.[5]

Once an EEA 2 has been declared, the BA should provide periodic updates to the RC operator at a minimum of every hour until the EEA 2 has been terminated.[6]

Reliability Coordinator Actions

• **Discuss** with BA not meeting its Contingency Reserve requirements and **evaluate** mitigation options, based on guidelines provided in RC West Operating Procedure RC0210 Monitoring Frequency and Balancing Authority Performance.
  ○ **Determine** if the BA is part of an RSG, if Contingency Reserves are deliverable to the BA, and if the BA will require an EEA to get assistance from the RSG (***Refer** to Section 3.4.2 of RC0210)*.
• **Evaluate** whether the criteria for EEA 2 is met, if the BA is not part of an RSG, or RSG reserves is not adequate or deliverable.
  ○ **Determine** whether options available to the BA under the criteria for EEA 1 have been exhausted.
  ○ **Determine** whether the BA is implementing demand response or other load management procedures.
• Upon discussion with the BA, **declare** an *EEA 2* for the BA if the criteria for EEA 2 is met or if requested by the BA.
• **Issue** an *alert* to all impacted entities without delay, but not longer than within 30 minutes from time of the declaration:
  ○ **Notify** all BAs, TOPs, and Western RCs **via** GMS WECC-Wide message.
  ○ **Notify** market participants in the RC Area **via** GMS.
  ○ **Send** RCIS message.
Notification **should include** the time of declaration, the BA name, the EEA level, and contact information that other BAs can use to provide emergency assistance.
• **Update** RCIS and GMS with any changes in information.
• **Review** Transmission *outages* and **work** with TOPs for viability of returning transmission elements that may relieve loading on SOLs or IROLs for the possibility of energy delivery.

[5] Attachment 1-EOP-011-4 Section B-2
[6] Attachment 1-EOP-011-4 Section B-2.2 (applicable to BA)

3.1.4. EA 3 – Firm Load Shedding Imminent or in Progress

A BA is considered to be in an EEA 3 condition when firm load interruption is imminent or in progress, and the energy-deficient BA is unable to meet minimum Contingency Reserve requirements.

Before requesting an EEA 3, the energy-deficient BA must make use of all available resources; this includes, but is not limited to:

- Ensuring all available generation units are online and all generation capable of being on line within the time frame of the Emergency is on line.
- Activating Demand-Side Management within provisions of any applicable agreements.[7]

The energy-deficient BA is responsible for updating the RC operator at a minimum of every hour until the EEA 3 is terminated.[8]

Reliability Coordinator Actions

• **Discuss** with BA not meeting its Contingency Reserve requirements <u>and</u> **evaluate** mitigation options, based on guidelines provided in RC West Operating Procedure [RC0210 Monitoring Frequency and Balancing Authority Performance]().
  ○ **Determine** if the BA is part of an RSG, if Contingency Reserves are deliverable to the BA, and if the BA will require an EEA to get assistance from the RSG (***Refer** to Section 3.4.2 of RC0210*)
• **Evaluate** whether the criteria for EEA 3 is met, if the BA is not part of an RSG, or RSG reserves is not adequate or deliverable.
  ○ **Determine** whether options available to the BA under the criteria for EEA 1 and EEA 2 have been exhausted.
  ○ **Verify** all available generation in the BA are committed to meet firm load, firm transactions, and meet reserves.
  ○ **Verify** all available demand-side management have been activated.
• Upon discussion with the BA, **declare** an *EEA 3* for the BA if the criteria for EEA 3 is met or if requested by the BA.
• **Continue** *actions* initiated during the *EEA 2*.
• **Issue** an *alert* to all impacted entities without delay, but not longer than <u>30 minutes</u> from time of the declaration:
  ○ **Notify** all BAs, TOPs, and Western RCs **via** GMS WECC-Wide message.
  ○ **Notify** market participants in the RC Area **via** GMS.

[7] Attachment 1-EOP-011-4 Section B-2.5
[8] Attachment 1-EOP-011-4 Section B-3.2 (applicable to BA)

Reliability Coordinator Actions
○ **Send** RCIS message. Notification **should include** the name of the BA, the EEA level, and contact information that other BAs can use to provide emergency assistance. • **Update** RCIS and GMS with any changes in information. • **Evaluate** the risks of *revising SOLs* and *IROLs* for the possibility of delivery of energy to the energy-deficient BA. ***Note:*** *This <u>must</u> be coordinated with other RCs with agreement from the responsible TOP.* • **Request** the BA to provide updates at a minimum every hour until the EEA 3 is terminated. • **Notify** internal parties to ensure the appropriate report is submitted, per RC West Operating Procedure RC0420 Event Reporting.

3.1.5. EEA 0 – Termination

When the energy-deficient BA is able to meet its Load and Operating Reserve requirements, it shall request the Reliability Coordinator Operator to terminate the EEA.

Reliability Coordinator Actions
• **Confirm** with BA that it meets the criteria for EEA Termination. • **Notify** all applicable entities of the termination. ○ **Notify** all BAs, TOPs, and Western RCs **via** GMS WECC-Wide message. ○ **Notify** market participants in the RC Area **via** GMS. ○ **Send** RCIS message.

3.1.6. EEA Templates

When declaring an EEA, the RC operator may use the following templates. Include any additional information, as necessary.

- Subject: EEA [1,2, or 3] Declaration
  - Effective XXXX PPT, RC West has declared an EEA [1, 2, or 3] for [entity and/or entity area (if applicable)]. Please contact them at (XXX) XXX-XXXX if you can provide them with emergency assistance.
- Subject: EEA 0 Declaration
  - Effective XXXX PPT, RC West has declared an EEA 0 for [entity and/or entity area (if applicable)].

- Subject: EEA Watch Declaration
  - Effective XXXX PPT, [Entity] is forecasting being in EEA [#] from [XX] PPT to [YY] PPT on [Date]. Please contact the entity at (XXX) XXX-XXXX if you can provide assistance.
- Subject: EEA Watch Cancellation
  - Effective XXXX PPT, EEA Watch for [Entity] has been cancelled.

3.2. Transmission System Emergencies

TOPs are expected to have Operating Plans reviewed by the RC entity to mitigate transmission system Emergencies in their area, and to notify the RC operator in real-time when the TOP is experiencing an Emergency.[9] A Transmission system Emergency may include, but is not limited to:

- An actual or potential IROL exceedance,
- An actual or potential SOL exceedance with potential Adverse Reliability Impact,
- Unacceptable voltage levels with potential Adverse Reliability Impact,
- Loss of reactive reserves with potential Adverse Reliability Impact,
- Loss or potential loss of transmission elements due to fires, earthquakes, storms, physical attacks, vandalism or other reasons with potential Adverse Reliability Impact,
- A single or credible multiple Contingency will result in instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the BES,
- RC Real-time Assessment indicate unplanned loss of 300 MW of load or greater for the next credible contingency,
- System separation, islanding, or open loop,
- Extraordinary Contingency, and
- Any other transmission event that results in an Adverse Reliability Impact.

When the RC operator receives a notification from a TOP of a BES Emergency on the transmission system, or if RC west analysis indicates that an Emergency condition exists,

Reliability Coordinator Actions
• **Confirm** the *Emergency condition* **in collaboration with** the affected TOPs. • Actively **evaluate** system *conditions* <u>and</u> **determine** *mitigation* options **in coordination with** TOPs contributing to and/or affected by the condition. TOP Operating Plans include (but <u>not</u> limited to) mitigation options,[10] such as: ○ Cancelling or recalling transmission and generation outages, ○ Reconfiguring transmission system,

[9] EOP-011-4 R1 (applicable to TOP)
[10] EOP-011-4 R1.2 (applicable to TOP)

Reliability Coordinator Actions
○ Redispatching generation, and ○ Operator-controlled manual load shedding that minimizes overlap with automatic load shedding, and is capable of being implemented in a timeframe for mitigating the Emergency. • **Refer** to RC West Operating Procedure RC0460 Reliability Coordinator Area Restoration Plan if electrical *islanding* has occurred. • **Determine** if there are any *SOL* or *IROL exceedances*. • **Refer** to RC West Operating Procedure RC0310 Mitigating SOL and IROL Exceedances. • **Declare** a *BES Emergency* **via** a WECC-wide GMS message *without delay* (within 30 minutes),[11] **notifying** all BAs, TOPs, and Western RCs. • **Consider initiating** a *conference* call if the condition affects multiple entities and if a conference call will expedite coordination efforts. • **Coordinate** *mitigation* activities with affected TOPs and **determine** if an *Operating Instruction* is needed. • **Coordinate** with BAs, TOPs, and neighboring RCs that may be able to provide *assistance.* • **Issue** *Operating Instructions* immediately, **in accordance with** Section 3.4: Operating Instructions and Section 3.5: Load Shedding Instructions. • **Monitor** system *conditions* to **determine** if the instructed *actions* were implemented, and whether the transmission Emergency will be resolved in a timely manner. • **Issue** *additional Operating Instructions,* if needed. • **Issue** *notification* to all BAs, TOPs, and Western RCs once Emergency condition has been mitigated and the system is stable **via** a WECC-wide GMS message. • **Log** a summary of all *communications* and *actions*.

3.3. Extreme Weather Emergencies

BAs and TOPs are expected to have Operating Plans (reviewed by the RC entity) that address the reliability impacts of extreme weather in their area. They are also required to notify the RC operator in Real-time when experiencing such an Emergency.[12] Extreme weather Emergencies may include, but are not limited to:

- Unanticipated high loading due to high or low temperatures,
- Wind/rain storms,
- Thunderstorms,
- Tsunamis,

[11] EOP-011-4 R5
[12] EOP-011-4 R1.2.6, R2.2.9 (applicable to TOP and BA respectively)

- Hurricanes,
- Floods,
- Snow, and
- GMDs (**See** RC West Operating Procedure RC0430 GMD Operating Plan).

When the RC operator receives a notification from a BA or TOP of an Emergency due to extreme weather:

Reliability Coordinator Actions

• **Issue** an *alert without delay* to all impacted entities, but no longer than within 30 minutes.[13]
  ○ **Notify** all BAs and TOPs in the RC Area and neighboring RCs **via** GMS.
• **Actively evaluate** system *conditions* and **determine** *mitigation* options **in coordination with** the affected BAs/TOPs. BA/TOP Operating Plans include (but not limited to) mitigation options,[14] such as:
  ○ Cancelling or recalling transmission and generation outages,
  ○ Reconfiguring transmission system,
  ○ Redispatching generation,
  ○ Shedding operator-controlled manual load that minimizes overlap with automatic load shedding, and is capable of being implemented in a timeframe for mitigating the Emergency,
  ○ Requesting EEAs (**Refer** to Section 3.1: Capacity and Energy Emergencies),
  ○ Managing generation to address capability and availability, fuel and inventory concerns, fuel and switching capabilities, and environmental constraints,
  ○ Submitting public appeals for voluntary load reductions,
  ○ Requesting government agencies to implement their programs to achieve necessary energy reductions,
  ○ Instructing a reduction of internal utility energy use, and
  ○ Using interruptible load, curtailable load, and demand response.
• **Refer** to Section 3.2: Transmission System Emergencies if the weather Emergency is affecting the transmission system.
• **Refer** to Section 3.1: Capacity and Energy Emergencies if the weather Emergency creates capacity or energy issues.
• **Monitor** *weather* and *forecast* tools to **determine** the effect of current and projected conditions.

[13] EOP-011-4 R5
[14] EOP-011-4 R1.2 (applicable to TOP)

Reliability Coordinator Actions
• **Coordinate** *mitigation* activities with affected BAs and TOPs and **determine** if an *Operating Instruction* is needed. • **Issue** *Operating Instructions* immediately, **in accordance with** Section 3.4: Operating Instructions, and Section 3.5: Load Shedding Instructions. • **Issue** *notification* to all impacted entities when the Emergency condition has been mitigated and the system is back to normal: o **Notify** all BAs and TOPs in the RC Area and neighboring RCs **via** GMS. • **Log** a summary of all communications and actions.

3.4. Operating Instructions

During system Emergencies, the RC operator will actively evaluate system conditions, coordinate mitigation activities with the affected BAs/TOPs and determine if there is a need to issue an Operating Instruction.

During a system Emergency, take the following actions:

Reliability Coordinator Actions

• **Actively evaluate** system *conditions* and **determine** possible *mitigation* options.
• **Coordinate** with affected *BA/TOP* to **determine** if the potential *mitigation* is viable.
  o If not, **advise** the BA/TOP of *alternate* or additional *mitigation* options.
• **Evaluate** the *mitigation* in *progress* to **determine** if the Emergency condition will be resolved in a timely manner.
• **Issue** an *Operating Instruction* without delay if the actions being taken are not adequate or will not resolve the condition in a timely manner (**Refer** to RC West Operating Procedure RC0110 Communications Protocols).
  o If load shedding is required, **refer** to Section 3.5: Load Shedding Instructions.
• **Monitor** system *conditions* to **determine** if the instructed *actions* were implemented and whether the issues will be resolved in a timely manner.
• **Issue** *additional Operating Instructions*, if needed.
• **Log** a summary of all *communications* and *actions*.

3.5. Load Shedding Instructions

Load shedding should be considered a last resort to mitigate reliability issues that occur in Real-time. All appropriate mitigation options should first be explored as time allows, including timely demand-side management or load transfer, before issuing an Operating Instruction to shed firm load. However, during Emergency situations or during situations or events with the potential to result in Adverse Reliability Impact, the RC operator may determine that other mitigation actions will not be adequate, or would not resolve the issue in a timely manner. In such cases, the RC operator should consider issuing an Operating Instruction to shed firm load.

3.5.1. Situations that May Require Load Shedding

The RC operator should consider issuing an Operating Instruction to shed load, when:

- A single or credible multiple Contingency will result in cascading outages, instability or voltage collapse,
- An IROL exceedance is unlikely to be mitigated within 30 minutes or T_V,
- Potential Adverse Reliability Impact due to generation/load imbalance caused by large sustained ACE or frequency excursion, EEA, etc., or
- Following Real-time Assessment, it is unclear whether the system can sustain the next single or credible multiple Contingency.

When the RC operator determines that one of the above Emergency conditions exists and load shedding is being considered as an option:

Reliability Coordinator Actions
• **Perform** Real-time *Assessments* **in collaboration with** the *RTOE* to ***validate*** the reliability *issue*, if time allows.
• **Confirm** results with the affected BAs, TOPs and neighboring RCs.
• **Operate** *conservatively* if there is disagreement in study results between entities.
o If there is disagreement with a neighboring RC on the IROL or T_V for a shared facility, **operate** to most limiting IROL or T_V.[15]
• **Discuss** mitigation *options* with the affected BAs/TOPs and **determine** if those options can resolve the issue in a timely manner.
• **Evaluate** *effectiveness* of mitigation in progress to **determine** if the condition will be resolved in timely manner.
• **Determine** whether *post-Contingency* automatic or manual mitigation *actions* are available or acceptable.

[15] IRO-009-2 R4

Reliability Coordinator Actions
• **Issue** an *Operating Instruction* to shed load if other mitigation actions will not resolve the issue in a timely manner (**Refer** to RC West Operating Procedure RC0110 Communications Protocols). • **Log** a summary of all *communications* and *actions*.

3.5.2. When Load Shedding Instruction May Not Be Viable

Generally, an Operating Instruction to shed firm load may not be viable, when:

- The reliability issue can be mitigated in a timely manner using other mitigation actions.
- Shedding firm load will violate safety, equipment, regulatory or statutory requirements.
- A load shed instruction cannot be physically implemented.
- Studies show that the risk to the system will be contained within a defined area.
- Load at risk is not sufficiently more than the load that would have to be shed pre-Contingency.

3.6. Event Reporting

Certain BES Emergencies, such as IROL violations, system separation (islanding), firm load shedding, etc., require filing a NERC EOP-004 or a DOE OE-417 report. The RC operator will ensure that the appropriate internal parties are notified to ensure that the proper reports are submitted.

Reliability Coordinator Actions
• **Notify** Manager, Real-Time Operations of the BES Emergency **in accordance with** RC West Operating Procedure RC0420 Event Reporting.

3.7. BA and TOP EOP-011 Plan Submissions and Review

The CAISO Operations Compliance team shall work in conjunction with the RC to facilitate reviews of the Emergency Operating Plan(s) submitted by BAs and TOPs.[16]

The EOP-011 plans can be submitted to RC West each time the plan(s) are updated. RC West does not have an annual or periodic update requirement for EOP-011 plans.

The Plan Review Submissions library on the RC West secure website shall be used by the BAs and TOPs to upload Emergency Operating Plan(s) for RC review. The BAs and TOPs shall upload the plan document(s) with a completed RC0410A EOP-011 Plan Review Checklist.

[16] EOP-011-4 R3, R3.1 and sub requirements

Within 30 calendar days of receipt, RC West shall:

- Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other BAs' and TOPs' Operating Plans,
- Review each submitted Operating Plan(s) for coordination, to avoid risk to Wide Area reliability, and
- Notify each BA and TOP of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

Each TOP and BA shall address any reliability risks identified by RC West, and resubmit its Operating Plan(s) to RC West within the specified time period.

Upon RC West's completion of the review process, the RC will post a review letter to the secure site and notify the submitting entity.

4. Supporting Information

Operationally Affected Parties

Shared with the Public and AESO, BCRC, SPP RC and RC West BAs and TOPs.

References

NERC Requirements	COM-002-4; EOP-011-4 R3, R5, R6; IRO-009-2 R2, R3, R4; IRO-014-3.
BA/TOP Operating Procedure	
RC West Operating Procedures	RC0110 Communications Protocols RC0310 Mitigating SOL and IROL Exceedances RC0420 Event Reporting RC0430 GMD Operating Plan RC0460 Reliability Coordinator Area Restoration Plan

Definitions

The following terms capitalized in this Operating Procedure are in accordance with the NERC Glossary, and/or otherwise when used are as defined below:

Term	Description
Emergency or BES Emergency	Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities, or generation supply that could adversely affect the reliability of the Bulk Electric System.
Adverse Reliability Impact	The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.
Extraordinary Contingency	Shall have the meaning set out in Excuse of Performance, Section B.4.c.language in Section B.4.c: Means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity's reasonable control; provided that prudent industry standards (e.g., maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the "Most Severe Single Contingency" as defined in the WECC Reliability Criteria or any lesser contingency).
System Operating Limit (SOL)	The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings), • Transient stability ratings (applicable pre- and post-Contingency stability limits), • Voltage stability ratings (applicable pre- and post-Contingency voltage stability), and • System voltage limits (applicable pre- and post-Contingency voltage limits).

Term	Description
Interconnection Reliability Operating Limit (IROL)	A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.
Contingency Reserve	The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts, as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority: • Is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and is utilizing its Contingency Reserve to mitigate an operating emergency, in accordance with its Emergency Operating Plan, or • Is utilizing its Contingency Reserve to mitigate an operating emergency, in accordance with its Emergency Operating Plan.
Reliability Coordinator (RC) Area	The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
Capacity Emergency	A capacity emergency exists when a Balancing Authority Area's operating capacity plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.
Cascading	The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.
Contingency	The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker switch, or other electrical element.
Energy Emergency	A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options, and can no longer meet its expected Load obligations.

Version History

Version	Change	Date
2.0	Annual Review: Section 3.3: Updated notification information and removed RCIS as a form of notification for extreme weather only. Section 3.7: Clarified plan submission requirements Replaced CAISO RC with RC West and updated to RC West logo. Minor grammar and format updates.	4/21/20
3.0	Annual Review: Updated criteria for issuing EEAs in Section 3.1, and clarified references to RC0210. Updated all RC West procedure references and updated procedure review frequency to "Annual". Approved by Real-Time Working Group (RTWG).	2/04/21
3.1	Added Section 3.1.1 for EEA Watch. Added EEA Watch templates to Section 3.1.6. Clarified criteria and steps for RC declaring a "BES Emergency" in Section 3.2. Minor format and grammar updates. Reviewed and approved by the Real-Time Working Group.	4/15/21
3.2	Section 3.1: Updates made related to EEA Watch based on received feedback.	6/21/21
3.3	Annual Review: Minor format and grammar updates throughout.	2/01/22
3.4	Annual Review: Updated references of EOP-011; minor formatting and grammar updates.	4/01/23
3.5	Section 3.1.6: Minor update to EEA Watch template. Section 3.6: Replaced ERC reference with JIC Lead.	9/05/23
3.6	Section 3.1: Clarified requirements for EEA Watch declaration. Section 3.6: Replaced External Affairs Joint Information Center (JIC) Lead with Manager, Real-Time Operations.	10/26/23
3.7	Annual Review: Minor formatting throughout. Section 3.1.2: Added "non-firm for wholesale energy sales.	5/02/24
3.8	Section 3.2: Additional criteria for RC declaration of transmission emergency – unplanned load loss for next contingency.	6/15/24
3.9	Annual Review: Updated NERC Standard EOP-011 references due to version update. Minor formatting and grammar edits and removed history prior to five years.	5/01/25

5. Periodic Review Procedure

Review Criteria & Incorporation of Changes

There are no specific review criteria identified for this document.

Frequency

Annual.

Appendix

RC0410A EOP-011 Plan Review Checklist

RC0410B Transmission Emergencies Due to Wildfire

EXHIBIT 50-8

The ISO's Western Energy Imbalance Market enhances grid reliability while meeting the needs of an evolving industry through collaborative efforts across the West

Western Energy Imbalance Market (WEIM)

The ISO’s Western Energy Imbalance Market is a real-time energy market, the first of its kind in the western United States.

The WEIM’s advanced market system automatically finds low-cost energy to serve real-time consumer demand across the west. Since its launch in 2014, the WEIM has enhanced grid reliability and generated cost savings for its participants. Besides its economic advantages, the WEIM improves the integration of renewable energy, which leads to a cleaner, greener grid.

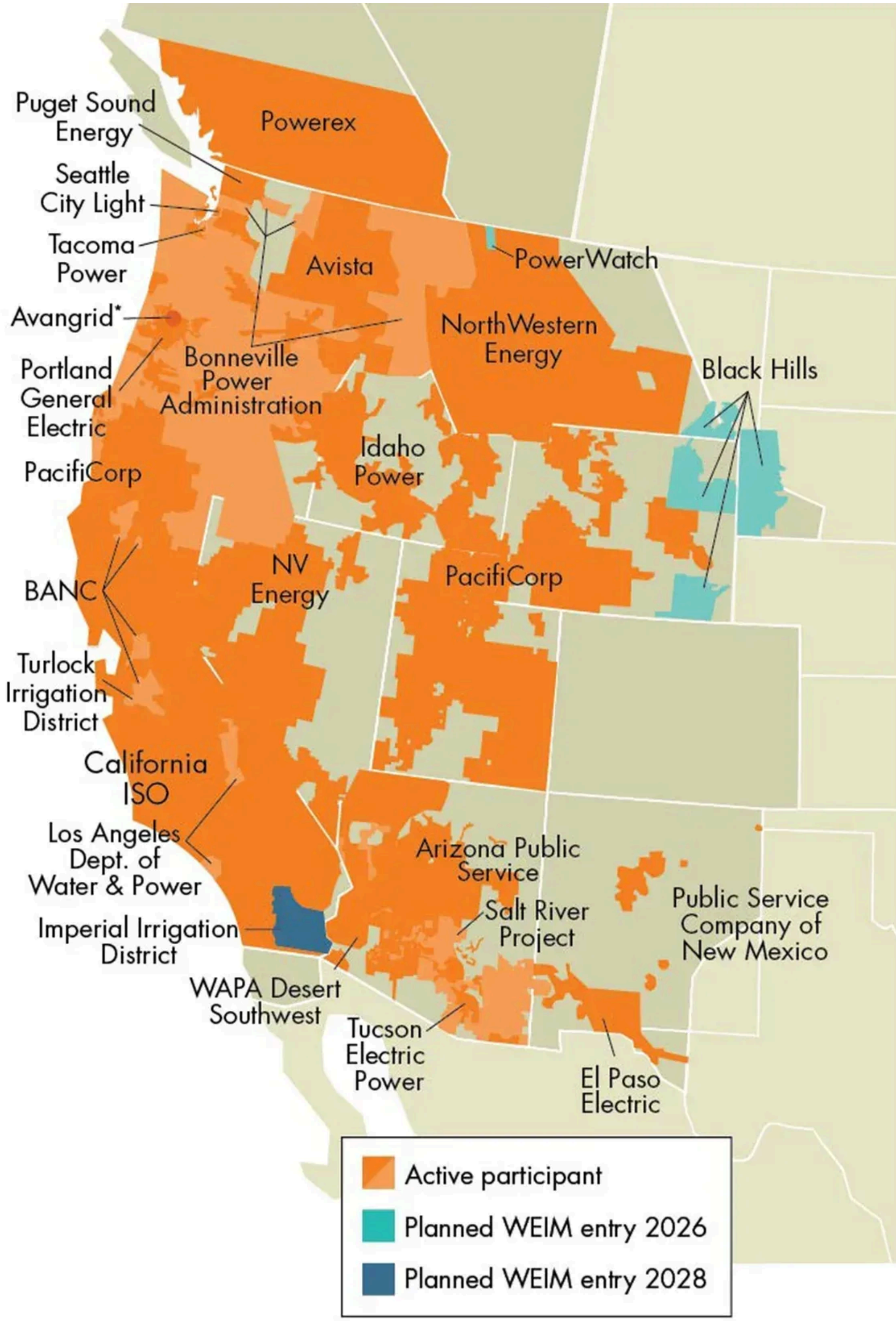
Participants

- Imperial Irrigation District – *planned entry 2028*
- Black Hills – *planned entry 2026*
- PowerWatch (formerly BHE Montana) – *planned entry 2026*
- Avangrid – entered 2023
- El Paso Electric – entered 2023
- WAPA Desert Southwest Region – entered 2023

- Bonneville Power Administration – entered 2022
- Tucson Electric Power – entered 2022
- Avista – entered 2022
- Tacoma Power – entered 2022
- NorthWestern Energy – entered 2021
- Los Angeles Department of Water & Power – entered 2021
- Public Service Company of New Mexico – entered 2021
- Turlock Irrigation District – entered 2021
- Salt River Project – entered 2020
- Seattle City Light – entered 2020
- Balancing Authority of Northern California – entered 2019
- Idaho Power Company – entered 2018
- Powerex – entered 2018
- Portland General Electric – entered 2017
- Puget Sound – entered 2016
- Arizona Public Service – entered 2016
- NV Energy – entered 2015
- PacifiCorp – entered 2014
- California ISO – entered 2014

View implementation documents for participants

Participant map



*Avangrid office; generation only BAA with distribution across multiple states. Map boundaries are approximate and for illustrative purposes only. Copyright © 2025 California ISO

Download map

See the latest quarterly benefits report.

EXHIBIT 50-9

California ISO

FACT SHEET

Western Energy Imbalance Market

In addition to running a day-ahead wholesale electricity market in its balancing authority area, the California ISO also operates the Western Energy Imbalance Market (WEIM). Established in 2014, the WEIM extends the ISO's real-time market to other balancing authority areas in the West. WEIM participants, including the ISO, gain substantial economic, operational, and environmental advantages by trading energy supply and demand across a large geographic area in real time. Since its inception, the WEIM has grown to 22 participating entities representing 79% of the load in the Western Interconnection and has produced more than $5 billion in benefits.

The WEIM is an energy-only market, and participants determine how transmission and generation resources engage in the market. The market platform allows participants the flexibility of controlling their assets and maintaining their own compliance responsibilities for managing their system as required by North American Electric Reliability Corporation and Western Electricity Coordinating Council) standards, while gaining access to a large pool of diverse resources across multiple western states and extending to the border with Canada and Mexico.

The WEIM can help during an emergency

The WEIM allows energy transfers across balancing areas, providing access to least-cost electricity in the broader western region. This increased coordination between areas is particularly helpful during weather events that impact one part of the Western Interconnection but not another. In these cases, participants are able to sell their excess electricity generation to areas in need—creating economic benefits for the seller and operational and reliability benefits for the buyer.

When a region is under stress conditions in real time, the increased coordination through the WEIM provides additional benefits as the market optimally schedules transfers. Given the diversity benefit of the WEIM, these transfers can reduce the probability of an area calling for emergency assistance as the market has automatically resolved the stressed condition for operators.

To learn more about the WEIM, including its economic and environmental benefits, visit www.WesternEIM.com.

> The WEIM allows for energy trading across the West. During emergencies, that coordination can help all WEIM participants share energy. The market can automatically solve grid stress with these energy transfers.

EXHIBIT 50-10

WRAP Area Map

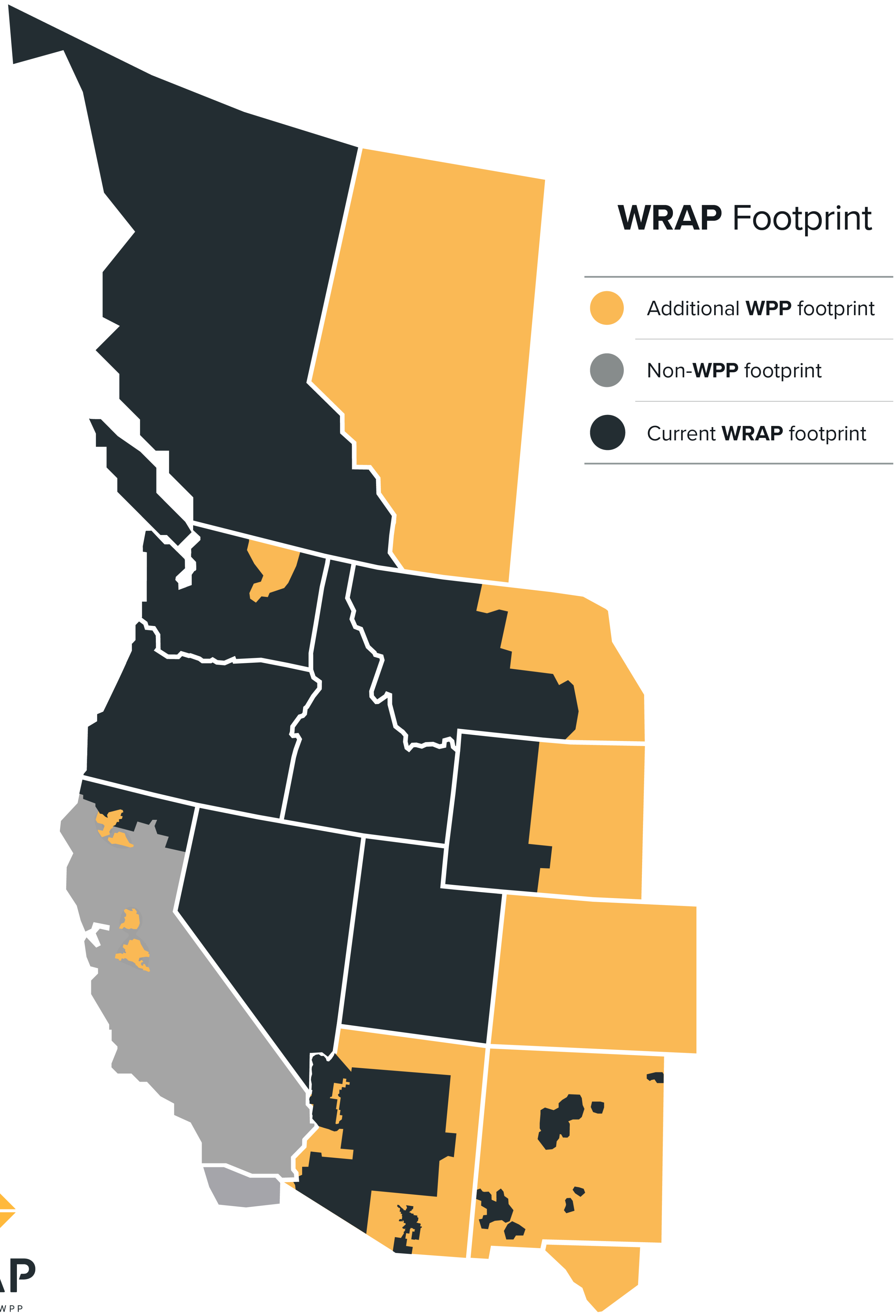
Nov. 19, 2021, 1:58 p.m. by David Pennington | Last modified Oct. 31, 2025, 2:25 p.m.

Current participants in the Western Resource Adequacy Program. All will be part of binding operations beginning in Winter 2027/2028 unless otherwise noted.

- Arizona Public Service Company
- Avista Corp
- Bonneville Power Administration
- Calpine Energy Solutions*
- PUD No. 1 of Chelan County
- Clatskanie People's Utility District
- Constellation
- Eugene Water & Electric Board*
- PUD #2 of Grant County
- Idaho Power
- NorthWestern Energy
- NV Energy*
- PacifiCorp*
- Portland General Electric Company*
- Powerex Corp.
- Public Service Company of New Mexico*
- Puget Sound Energy
- Salt River Project Agricultural Improvement and Power District
- Seattle City Light
- Shell Energy North America^
- Tacoma Power
- The Energy Authority, Inc.
- Tucson Electric Power

* Provided exit notice in October 2025; will leave the program prior to Winter 2027/2028 binding season

^ Provided exit notice in 2024; will leave the program by the end of 2026



WRAP
POWERED BY WPP

David Pennington
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TAGS

Resource Adequacy

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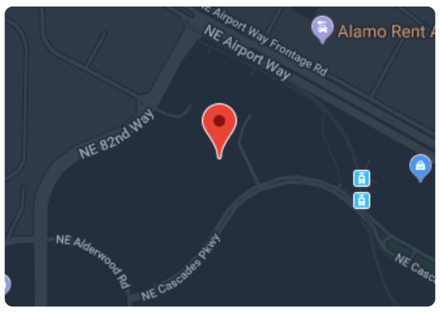

EXHIBIT 50-11

NYSE: AVA

$39.12 +0.19 (+0.49%)

Better energy for life

We are an energy company involved in the production, transmission and distribution of energy as well as other energy-related businesses. Avista Utilities is our operating division, providing electricity to nearly 418,000 customers and natural gas to about 382,000 customers across 30,000 square miles and four northwestern states. Alaska Energy and Resources Company, an Avista subsidiary, provides retail electric service in the city and borough of Juneau through its subsidiary Alaska Electric Light and Power Company. Avista's history of innovations is rooted in the renewable energy we've generated since our founding in 1889.

Avista has been recognized for the fifth time by Ethisphere, a global leader in defining and advancing the standards of ethical business practices, as one of the 2024 World's Most Ethical Companies.

WORLD'S MOST ETHICAL COMPANIES® 2024 ETHISPHERE 5-TIME HONOREE

Latest Quarterly Earnings

Q3 2025

- Q3 2025
- Earnings Results
- Earnings Presentation

Company News

Dec 29, 2025
Avista Foundation awards 76 grants supporting environmental efforts, arts and culture across the Northwest

Dec 23, 2025
Avista Posts Updated Corporate Responsibility Report

Dec 18, 2025
Avista Storm Restoration Substantially Complete

View All

Events

Dec 3, 2025
December 2025 Investor Outreach

Nov 7, 2025
November 2025 Investor Outreach

Nov 5, 2025 at 10:30 AM EST
Avista Corporation Q3 2025 Earnings Conference Call

View All

Featured Documents

- 2024 Annual Report
- 2025 Quick Facts

View All

EXHIBIT 50-12

RC West

The California ISO's RC West is the Reliability Coordinator (RC) of record for 24 balancing authorities and 40 transmission operators in the western United States, some of whom operate as both balancing authorities and transmission operators. An RC oversees grid compliance with federal and regional grid standards, and can determine measures to prevent or mitigate system emergencies in day-ahead or real-time operations. The RC also provides leadership in system restorations following major events.

RC West Oversight Committee

The RC West Oversight Committee is comprised of key representatives from balancing authorities and transmission operators taking RC services from the ISO. The committee provides guidance and fosters consensus on reliability compliance for the RC West.

RC West Portal

Access to this secure site is limited to RC West participants with a certificate.

WECC Interchange Tool Working Group (WITWG)

This working group is open to all WECC Interchange Tool users.

Resources

- RC West Entities 10/13/2025, 11:11 AM
- RC West Annual Payments Calendar 10/29/2019, 8:50 AM
- RC West Operating procedures
- Presentation - RC West Oversight Committee Public Session - Nov 20, 2025 11/20/2025, 9:55 AM

RC West Summer Readiness

- WECC Presentation - 2025 RC West Summer Readiness - May 15, 2025 06/27/2025, 11:34 AM
- Presentation - RC West Oversight Committee Meeting - May 15, 2025 05/16/2025, 1:17 PM

View previous summer readiness meetings.

Customer onboarding

- RC West Customer Onboarding Update 03/28/2025, 8:24 AM
- Electronic Funds Transfer Procedure 06/21/2022, 2:00 PM
- Electronic Funds Transfer or Bank Account Change Form 07/01/2020, 4:25 PM
- Reliability Coordinator Services Agreement 11/15/2018, 9:06 AM
- Reliability Coordinator Services Agreement Information Request Sheet 11/15/2018, 9:06 AM

Non-disclosure agreement

Certain confidential information pertinent to the western interconnection data are available upon compliance with the applicable Submission Instructions and submittal of a non-disclosure agreement. Requesting entities must be members of the Western Electricity Coordinating Council (WECC) or have an approved WECC Base Case Data Request Package prior to requesting access to this data.

See the Western interconnection data sharing agreement and list of signatories .

- Western Interconnection Data Sharing Agreement - List of Signatories 03/05/2025, 9:48 AM
- Western Interconnection Data Sharing Agreement 07/23/2019, 4:14 PM

RC West area alerts

Merchants can subscribe to receive information impacting the reliable operation of the bulk electric System.

Transmission operations

Our operations reporting, coordination and maintenance efforts help keep the lights on for 30 million people in our balancing authority. Find out more about transmission operations.

Foundational documents

Visit the Reliability coordinator rate design, terms and conditions initiative page.

- RC West WECC Certification Review Approval Letter 06/30/2021, 4:54 PM
- RC West Milestones 11/12/2019, 3:23 PM
- RC West NERC Certification Approval Letter 06/05/2019, 10:16 AM
- RC West NERC Certificate 06/05/2019, 10:16 AM
- RC Implementation Plan Overview 11/15/2018, 3:53 PM

Contact us

For more information on RC West services, email us at: RCWest@caiso.com.

Service Desk for RC West participants only:

Local number: (916) 538-5722

Toll-free number: (833) 888-9378

Related ISO Tariff and Business Practice Manuals

- Business Practice Manual for Reliability Coordinator Services

ISO Today

Free mobile app to monitor grid conditions, receive alerts and track calendar events.

Daily Briefing

Daily email summarizing the day's notices.

News releases

Email with the latest Board of Governors decisions and breaking developments.

Flex Alert

A call for consumers to voluntarily conserve electricity when there is a predicted shortage of energy supply.
