Technical Appendix N: Scenario Modeling and Results

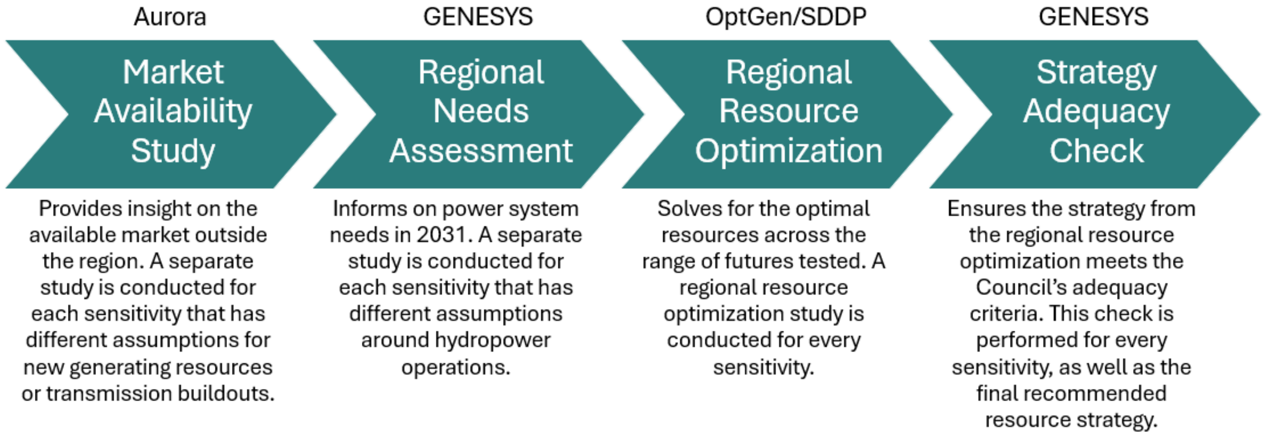
Contents

Introduction

The Council uses scenario modeling to plan under uncertainty. The scenarios considered in the Ninth Plan were designed to address the key challenges and uncertainties facing the regional power system at the time of power plan development. These include uncertainties around the pace of new resource development, the cost of new resources, the future availability of transmission, and future hydropower operations.

In total, scenario modeling covers a suite of studies providing information on system needs, market availability, regional resource optimization, and ensuring adequacy checks of the resources. Figure N - 1 illustrates the overall scenario modeling approach, including the model used for each step in the analysis.

Figure N - 1: Scenario Modeling Approach for Ninth Plan



This technical appendix focuses on the results from the regional resource optimization and strategy adequacy check steps of the scenario modeling. More information on the overall modeling framework for scenario modeling, as well as results from other stages of analysis can be found in other technical appendices. Specifically:

- **Technical Appendix K – Modeling Framework.** This technical appendix provides more detail on how the modeling suite connects, as well as key decisions around the modeling setup for the Ninth Plan analysis. This includes the development of futures to represent uncertainty around a range of assumptions feeding into modeling, including future loads, natural gas prices and volatility, and fuel availability for hydro, solar, and wind.
- **Technical Appendix L – Wholesale Market Availability Results.** This technical appendix provides more information on specific assumptions required for each of the market availability studies conducted and provides the results from those studies.
- **Technical Appendix M – Needs Assessment Results.** This technical appendix provides more specific information about the GENESYS setup for the modeling of the different sensitivities and walks through the results of the needs assessments for the Ninth Plan.

Description of Ninth Plan Scenarios

Scenario modeling provides an approach for exploring uncertainty around an otherwise deterministic set of assumptions. The Ninth Plan includes two scenarios that have within each of them a suite of sensitivities to explore a range of risk. This section describes the two scenarios and the specific assumptions behind each one.

New Resource and Transmission Risk

The Council's power plans have often included scenarios that explore how resource decisions change with changes in the availability (or pace) of potential resource development. Historically, much of this analysis focused on the pace of demand-side resource development, particularly conservation. For the Ninth Power Plan, the Council broadened this to include other resources. This scenario also explored implications of different transmission buildout trajectories and changing costs for some new resources. Table N - 1 outlines the sensitivities explored in this scenario and the sections below provide more detail on the specific assumptions changed for each sensitivity.

Table N - 1: New Resource and Transmission Risk Sensitivities

Sensitivity	Description
Constrained Resources and Transmission	Constrains supply-side resources in the near-term (first 6 years), limits transmission to the existing system, and delays emerging technologies by 10 years. Sensitivity informs how the region maintains adequacy when the system is constrained on the supply-side.
Changing Transmission Availability	Includes three sensitivities with different levels of transmission development: existing transmission, transmission consistent with the WestTEC 10-year study, and additional transmission.[1] Sensitivities will inform how resource decisions change with more or less transmission availability.
Changing Emerging Technology Costs	Includes two sensitivities with different cost assumptions for emerging technologies: 25 percent lower costs and 50 percent higher costs. Sensitivities will provide insight on at what costs different emerging technologies might provide value to the system.
Limited Short-Duration Storage Availability	Constrains the availability of short-duration (lithium ion) battery storage in the near-term (first 6 years). Sensitivity will provide insights into the potential value of short-duration storage to the region and how the region will maintain adequacy if that resource is not available.
Slower Demand-Side Availability	Slows down the pace of potential demand-side resource acquisition, including conservation, demand response, and rooftop solar. Sensitivity will provide insights on how the system maintains adequacy if less demand-side resources are available in the near-term.
Evolving Federal Policy Landscape	Assumes a change in Federal policy in 2030, shifting to policies similar to Biden-era policies. Sensitivity provides insights on how resource decisions change in the region with changes in policies at the federal level.

Constrained Resources and Transmission

This sensitivity was developed to address concerns about the availability of new generating resources and transmission. The worldwide Covid pandemic caused supply chain challenges for many goods, including materials for the development of resources. This coincided with a period of increased

[1] WestTEC is the Western Transmission Expansion Coalition, a west-wide voluntary effort to conduct long-term transmission planning for the west. The 10-year study is available at: https://www.westernpowerpool.org/about/programs/western-transmission-expansion-coalition.

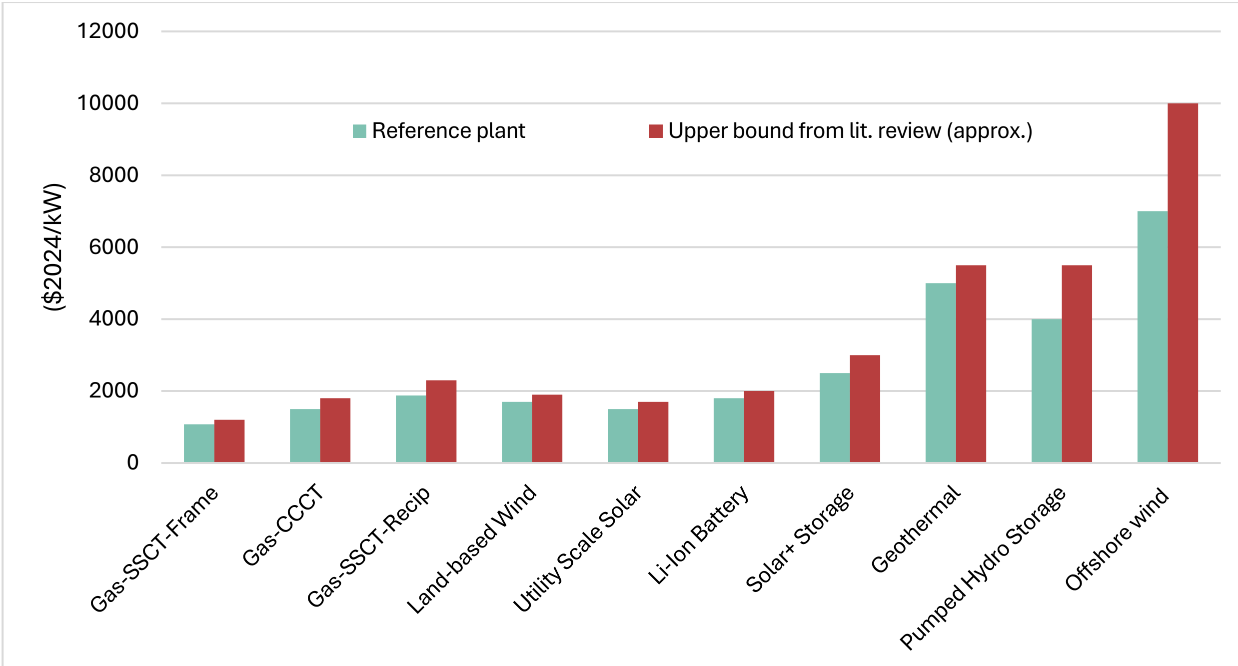
demand for new resources, and the resulting concern that these supply chain challenges would persist in the years to come. The Council also recognizes the concerns around resource development, including permitting challenges and interconnection queue timelines. Taken together, there was interest in exploring the risk of resource acquisition being more limited than initially assumed, and the cost for those new generating resources being higher due to these constraints. The Council also recognized the concerns around the pace of future transmission development and the potential that new emerging technologies might not be available on the anticipated timelines. These limitations are also included in this sensitivity to provide a very conservative look at the future.

Generating Resource Availability and Costs

This sensitivity includes two types of constraints on new generating resources that are in the primary and limited availability categories.[2] The first was to assume a higher cost of these resources. This was to reflect that fact that in a constrained system, supply and demand dynamics would suggest that costs would increase as demand exceeds supply. To develop these higher cost assumptions, the Council leveraged the higher bound of the data from the literature review informing the initial cost estimates. This resulted in a roughly 10 to 20 percent increase in cost for most resources, with some being closer to a 40 percent increase. Figure N - 2 shows the initial cost assumptions developed for each generating resource reference plant, as well as the upper bound cost from the literature review. The Council used these upper bound costs for this specific sensitivity.

[2] For more information on the classification of new generating resources and the core assumptions assumed in the Ninth Plan, see Technical Appendix G – New Generating Resources.

Figure N - 2: New Generating Resource Cost Assumptions



In addition to an increase in costs, the Council assumed the amount of new generating resources would be limited in the near-term, 2027 through 2032. Table N - 2 shows the total annual build limit assumptions for the Constrained Resources and Transmission sensitivity, relative to the reference build limit assumed across the other sensitivities. This limit essentially cuts the assumed allowable buildout in half for most of the years.

Table N - 2: Annual Build Limit Assumptions

Build Limit (MW)	2028	2030	2032
Build Limit in Constrained Resources and Transmission Sensitivity	2,600	6,900	12,100
Reference Build Limit Assumptions	6,900	13,800	23,000

Emerging Technology Delays

Between the clean policies and goals throughout the region and the anticipated new load growth, there is interest in the development of new, clean, emerging technologies that will provide important value to the system. There is also recognition that the future of these emerging technologies is highly uncertain. Recognizing this uncertainty, commenters on the Council's Issue Paper on the Preparation for the Ninth Plan asked the Council to be conservative in the assumptions around readiness of new emerging technologies.[3] Based in part on these comments, this sensitivity includes additional

[3] The Council released this issue paper in March 2024. The issue paper and a summary of comments are available on the Council's website at: https://www.nwcouncil.org/reports/2024-1.

assumptions around the delayed timelines for emerging technologies. Specifically, the Council assumed a 10-year delay in the availability of these resources.

For generating resources, this essentially pushes the timing of two of the three technologies outside of the study timeframe.[4] Only the clean long-duration storage proxy plant remains. For conservation, the Council removed the emerging technology from the supply curve entirely. This results in a sensitivity with very limited new emerging technologies available to help meet adequacy.

Table N - 3: Emerging Technology Availability Assumptions

Resource	Reference Assumption	Sensitivity Assumption
Clean Long Duration Storage	2030 selection, 2032 online date	2040 selection, 2042 online date
Clean Baseload	2035 selection, 2040 online date	Not available
Clean Peaker/Medium Duration Storage	2038 selection, 2040 online date	Not available
Conservation	Available starting 2032	Not available

Transmission

Another risk to future resource adequacy is the availability of new transmission to support bringing resources to load. Consistent with the rest of this sensitivity, the Council assumed a constrained transmission buildout by assuming only the existing transmission system (including projects under construction) was available for the entire planning period.

Changing Transmission Availability

Transmission is an important asset to the power system. This is particularly true in a system that relies more heavily on renewable resources. Renewable resources provide clean energy for the system. At the same time, due to the nature of the resource, they are often located far away from the urban load centers. Transmission is needed to deliver energy from those resources to those load centers. As loads grow and more resources are needed to meet load growth, more transmission may be needed to support the addition of those new resources.

Building on the concerns around future transmission availability, the Council developed a suite of sensitivities to isolate the impacts of varying amounts of future transmission development. The goal of these studies was to inform how resource decisions change as the transmission system changes.

[4] For simplification of OptGen modeling in the Ninth Power Plan, OptGen modeling, the online date in Table N-3 was the first date available for the model to select a resource.

The Council developed three different sensitivities with different transmission buildouts. This is intended to provide insights into what resource solutions are robust across a range of transmission buildouts and might mitigate the risk of an uncertain transmission future.

The Ninth Plan tests three different transmission buildouts in this sensitivity. One assumes the existing transmission system. This includes all the existing transmission in the ground, as well as projects that are currently under construction. The other two sensitivities are transmission plus and transmission max (see Table N - 4). The additional projects assumed in transmission plus are planned projects estimated to come online during the Action Plan period (2027-2032) with some additional transmission also on the east side of the region. The transmission max sensitivity includes additional planned projects anticipated after 2033.

Table N - 4: Transmission Sensitivities

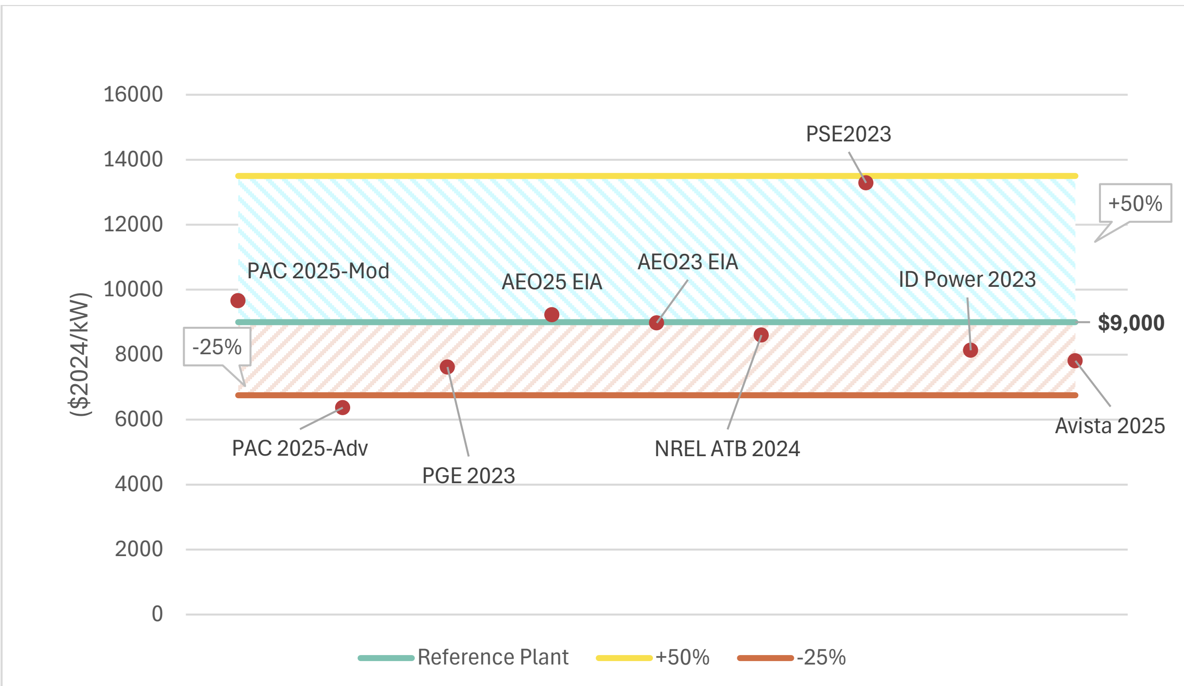
Project	Description	Date	Sensitivity	
			Plus	Max
Cross Cascades North	650 MW across the Cascades in Washington	2031	X	X
Cross Cascades South	1,500 MW across the Cascades in Oregon	2031	X	X
Path 8 Upgrade 1	600 MW upgrade between Montana and Oregon	2035	X	X
Gateway West Segment D3	1,000 MW between Wyoming and Idaho	2035		X
Gateway West Segment E	2,000 MW upgrade across Idaho	2036		X
Path 8 Upgrade 2	Added 200 MW west to east and 1,500 MW east to west on Path 8	2036		X
Path 14 Upgrade 2	650 MW west to east and 1,000 MW east to west between Idaho and Oregon	2036		X
North Plains Connector	1,000 MW interconnection into the Dakotas	2033		X

Changing Emerging Technology Costs

The future cost of emerging technologies is more uncertain than that of other resources. These technologies are either still in development or at very early stages of pilots and case studies. When these technologies become commercially viable, it is possible that the actual costs will be significantly lower or higher than those assumed in this study. The Council included this sensitivity to explore how resource decisions change with different assumed costs for these emerging technologies. Specifically, is there a price point at which any of the technologies become a more viable solution for meeting future resource needs; and is there a price point at which a technology would no longer be a part of the cost-effective strategy once it became available and reliable?

The Ninth Plan includes two sensitivities to explore the impact of changing emerging technology costs. One tested lower costs for these technologies, the other tested higher costs. To define the specific change in costs, the Council looked at cost estimates included in the literature review of the emerging technologies the reference proxy plants were based on. The Council used information from its literature review of small modular reactors, because it was the resource with the most data available (see Figure N - 3). This showed a range of costs roughly 25 percent lower than the assumed reference plant cost to 50 percent higher. The Council decided this range was an appropriate one to use for all emerging technologies, including the assumed emerging conservation technologies. The thought was that a new resource in the market is unlikely to have a cost much lower than expected today (at least not initially). On the other hand, as these technologies develop and prove out, there is risk that the costs might be significantly higher (again, at least initially). This frame also provided a more conservative set of assumptions from which to plan and explore this uncertainty.

Figure N - 3: Cost Range for Small Modular Reactors from Literature Review



Limited Short-Duration Storage Availability

With the increase of variable energy resources on the system, there is significant interest in adding battery storage. This interest across the region, and more broadly in power systems across the globe, has the potential to create supply chain challenges that limit the availability of this resource in the near-term. To explore the implications of this risk, the Council included a sensitivity that limited the availability of short-duration, lithium-ion batteries in the Action Plan period (2027-2032). Table N - 5 provides the assumed annual limit for battery storage in this sensitivity. After the Action Plan period, the limits go away, and the model can select as many batteries as makes sense based on system needs and transmission constraints.

Table N - 5: Assumed Annual Battery Build Limit in Sensitivity

Annual Limit (MW)	2028	2030	2032
Annual Battery Build Limit	3,000	3,500	4,350

Slower Demand Side Availability

The Council's recent power plans have explored the implications of changing availability in demand side resources by including sensitivities that both increase the availability (e.g. assuming more conservation is available in the near term) and delay the availability. For the Ninth Plan, the Council updated its approach to modeling demand side potential. Specifically, the Council assumed in the initial ramp rates that the availability of new demand side resources was subject to physical constraints (e.g. contractor availability, product availability, etc.) and not subject to budgetary considerations. With this update, the Council was less concerned with the implications of the resource being developed more quickly, but still very much interested in understanding the risks of limited availability in the near-term. To answer that second question, the Council included this sensitivity that limited the availability of demand side resources by selecting slower ramp rates for all the demand side resources. Technical Appendices H, I, and J provide more information on the conservation, demand response, and rooftop solar potential, respectively. This includes a discussion of the ramp rates used generally across the supply curves and how those are limited in this specific sensitivity.

Evolving Federal Policy Landscape

Over a 20-year planning horizon, there are always elements of policy uncertainty. The Ninth Plan was developed during a period of significant change in policy at the federal level. There was a substantial shift in policies between the Biden and Trump Administrations impacting resource costs and other decisions. Recognizing that these shifts may continue, the Council developed a sensitivity to explore how resource decisions in the region are influenced by changes in policy at the federal level. The two key areas of federal policy change explored through this sensitivity were changing resource costs caused by changes in available tax credits for clean resources and changing emissions requirements for new natural gas plants.

During the Biden Administration, the Inflation Reduction Act extended and expanded tax credits for clean generating resources, making tax credits technology neutral and allowing developers to choose between the investment or production tax credits for their project. Resources taking the investment tax credit could receive up to 70 percent back for every dollar spent on the development of eligible resources.[5] Under the production tax credit, the producer could get up to 3.35 cents for every 1

[5] The base credit is 30%, with the potential for a 10% adder (up to 40%) for using domestic materials. Additionally, resources could receive an additional 30% (for up to 70%) for energy community and low-income benefit bonus.

kilowatt of production. In July 2025, the One Big Beautiful Bill Act was enacted. This policy removed tax credits for renewable resources and conservation.

The Inflation Reduction Act also implemented updates to the Clean Air Act, specifically to section 111(b) that concerns emissions standards for new stationary combustion turbines. The policy change required that base load combustion turbines with capacity factors above 40 percent implement 90 percent carbon capture and storage by 2032. In essence, this policy targeted combined cycle combustion turbines, as simple cycle combustion turbines generally operate at lower capacity factors. The rollback of the Inflation Reduction Act under the Trump Administration reverted this requirement to the best system of emissions reduction.

The Ninth Power Plan analysis assumes all policies in place at the time of modeling. For the bulk of the modeling in the plan, this was the Trump Era policies described above. Recognizing the potential for policies to reverse in some future year, the Evolving Federal Policy Landscape sensitivity tested what happens if policies like those passed during the Biden Administration resume. This includes assuming tax credits and emissions requirements for new natural gas resources return in 2030.

For the tax credits, based on advice from the Council's Generating Resource Advisory Committee, the Council assumed that new resources would select the investment tax credit more often to avoid risk of policy changes. Specifically, the Council assumed that clean resources would receive the 30 percent base credit. The Council did not include the energy community and low-income bonus, as those were less universal and more site specific. On the demand side, the Council also included tax credits for rooftop solar and conservation consistent with the Inflation Reduction Act. For new combined cycle combustion turbine natural gas plants, the Council limited the capacity of these reference plants to below 40 percent after 2030. [6, 7]

It should be noted that these policies changed after Power Plan work was already underway. Due to the timing of modeling, all sensitivities in the Changing Hydro Operations scenario (discussed below) assumed the tax credits and emissions requirements for new gas resources were in place for the entire planning horizon. In addition to providing insight on the resource decisions under different hydro conditions, these sensitivities will add to the information around how federal policy impacts resource decisions in the region and more generally, what would happen if renewable generation is relatively less expensive compared to other resources.

Changing Hydro Operations

Heading into the development of the Ninth Plan, the Council anticipated the need for analysis to explore the intersection between hydropower operations and new resource development. The

[6] This limitation was modeled explicitly in the AURORA modeling for the west-wide capital expansion. This was not modeled explicitly in OptGen although in practice new combined cycle turbines tended to dispatch to low capacity factors in this sensitivity.
[7] Technical Appendices G through J provide more detail on the assumptions for new generating and demand side resources. This includes the specific treatment of tax credits or emissions requirements for this sensitivity.

Council's 2021 Power Plan identified a new tension with hydropower operations around the daily flexibility of the system. The Council's Columbia River Basin Fish and Wildlife Program has long included measures seeking to reduce the daily flow fluctuations of the system to benefit the migration of juvenile fish. At the same time, the Council's power planning analysis has shown value in ramping the system on a daily basis to support power system needs and the integration of new renewable resources in the region. Given this tension, the Council planned a scenario to explore these trade-offs in flexibility.

Adding to this, the Ninth Plan was developed at a time of particularly high uncertainty around future hydropower operations, particularly those operations designed to protect and mitigate for the impacts on fish and wildlife. The Council was in the process of developing the 2026 Columbia River Basin Fish and Wildlife Program, which was grappling with incorporating recommendations and comments on the recommendations into the amendment process, including recommendations for different hydro system operations. At the same time, in June of 2025, President Trump issued a Presidential Memorandum withdrawing from the 2023 Resilient Columbia Basin Agreement, which, among other things, had established a set of operations for fish that was expected to hold for ten years.[8] Withdrawing from the agreement created uncertainty not just for long-term operations, but for the near-term 2026 operations as well.

In August 2025, the Council scoped out four sensitivities to include in this scenario. The purpose was to reflect the uncertainty around future operations, while also providing insights to inform the ongoing Fish and Wildlife Program amendment process. Table N - 6 outlines the sensitivities explored in this scenario and the sections below provide more detail on the specific assumptions changed for each sensitivity.

Table N - 6: Changing Hydro Operations Scenario Scope

Sensitivity	Description
2020 BiOp Flex Spill Operation	Assumes the operations based on the 2020 Columbia River System Operations Environmental Impact Statement. This sensitivity was intended to provide one end of the bounds for potential 2026 operations, based on the assumption that legally, until another agreement was in place, the system should revert to these operations.
2023 RCBA Operations	Assumes the operations as defined in the 2023 Resilient Columbia Basin Agreement. This sensitivity was intended to provide an alternative set of operations with a focus on steady spill throughout the spring, acting as a potential bookend to the range of uncertainty around 2026 operations.

[8] In December 2023, the U.S. Government released a set of commitments in partnership with the Nez Perce Tribe, Confederated Tribes and Bands of the Yakama Nation, the Confederated Tribes of the Warm Springs Reservation of Oregon, the Confederated Tribes of the Umatilla Indian Reservation, and the States of Oregon and Washington. These commitments included a range of actions related to fish and wildlife and power planning, that ultimately resulted in a 10-year stay in the long-standing National Wildlife Federation et al v. National Marine Fisheries et al litigation.

Sensitivity	Description
Recommended Spill and MOP Targets	Analyzed specific minimum operating pool elevations and limits, and spill operations, as recommended by some of the states and tribes in the Fish and Wildlife Program amendment process. This sensitivity was intended to provide insights on potential hydropower system impacts of those specific recommendations.
Limited Flex Operation	Analyzed limitations of the hydro system's ability to change daily elevations and outflows at the lower Columbia and lower Snake River projects. This was intended to inform on the hydropower system implications of limiting the daily flexibility of the system.

The bulk of the hydropower system operations are consistent across these four sensitivities. This includes requirements for hydropower, flood control, fish passage and protection, irrigation, recreation, navigation, municipal and industrial use, wildlife habitat, cultural resources, and water quality and temperature. The Council uses data from the Council's Fish and Wildlife Program, biological opinions, the Water Management Plan, the Fish Operations Plan, the Columbia River Treaty, and other such documents to define these operations. The changes focus on the minimum elevations and targets, spring and summer spill for juvenile fish passage, outflow ramps of projects, and reserve allocations.

More information on the hydro generation set up and assumptions is included in Technical Appendix M – Needs Assessment Results.

2020 BiOp Flex Spill Operation

This sensitivity was intended to provide a potential bookend to reflect "current" operations. By current, the focus was operations currently planned for 2026 and beyond, assuming they held over the planning horizon. The Council selected the 2020 Columbia River System Operations Environmental Impact Statement to represent the current operations, under the assumption that with the withdrawal from the 2023 Resilient Columbia Basin Agreement, operations would revert to this Biological Opinion (BiOp). The specific element of these operations that is different from other sensitivities is the assumed spring and summer spill levels and dates. Table N - 7 outlines the specifics of those spill operations. As seen in Table N - 7, the spring spill operations at most of the lower Snake River and lower Columbia River projects assumed a flex spill approach, spilling to 125 percent total dissolved gas for 16 hours of the day and then lower spill levels for the other 8 hours. This operation was designed to balance periods of spill for juvenile migration with periods of reduced spill and more power generation during key hours.

Table N - 7: 2020 BiOp Spill Operations[9]

Project	Spring Operation Lower Snake: 4/3-6/20 Lower Columbia: 4/10-6/15	Summer Operation Lower Snake: 6/21-8/14 Lower Columbia: 6/16-8/14	Summer Operation 8/15-8/31
Lower Granite	16 hour: 125% TDG 8 hour: 20 kcsf	18 kcsf	RSW or 7 kcsf
Little Goose	16 hour: 125% TDG 8 hour: 30%	30%	ASW or 7 kcsf
Lower Monumental	16 hour 125% TDG 8 hour: 30 kcsf	17 kcsf	RSW or 7 kcsf
Ice Harbor	16 hour: 125% TDG 8 hour: 30%	30%	RSW or 8.5 kcsf
McNary	16 hour: 125% TDG 8 hour: 48%	57%	20 kcsf
John Day	16 hour: 125% TDG 8 hour: 32%	35%	20 kcsf
The Dalles	24 hour: 40%	40%	30%
Bonneville	16 hour: 125% TDG 8 hour: 100 kcsf	95 kcsf	50 kcsf

2023 RCBA Operations

The Council included a second sensitivity assuming spill operations from the 2023 Resilient Columbia Basin Agreement. The spill operations under the Resilient Columbia Basin Agreement provide steady spill at the lower Snake and lower Columbia River projects. In other words, rather than deploying the flex spill operations in the spring as defined in the 2020 BiOp, this agreement established a 24 hour spill up to 125 percent total dissolved gas for most of the lower river projects. The Council chose this set of operations to represent a steady spill operation as an alternative bookend to the 2020 BiOp operations defined above. The intent was that these two sets of operations would provide a range of information that could reasonably represent possible operations for 2026.

In addition to increasing spring spill, the 2023 Resilient Columbia Basin Agreement changed the end dates for summer spill operation. These were moved forward two weeks, from mid-August to the end of July. Table N - 8 outlines the specific spill assumptions for each of the projects.

[9] Acronyms in Table N - 7 are: TDG – total dissolved gas; kcsf – thousand cubic square feet; RSW – removable spillway weir and ASW – adjustable spillway weir.

Table N - 8: 2023 Resilient Columbia Basin Agreement Spill Operations

Project	Spring Operation Lower Snake: 4/3-6/20 Lower Columbia: 4/10-6/15	Summer Operation Lower Snake: 6/21-7/31 Lower Columbia: 6/16-7/31	Summer Operation 8/1-8/31
Lower Granite	125% TDG	18 kcsf	Spillway weir flow
Little Goose	125% TDG	30%	ASW or 7 kcsf
Lower Monumental	125% TDG	17 kcsf	SW flow or 8 kcsf
Ice Harbor	125% TDG	30%	SW flow or 9 kcsf
McNary	125% TDG	57%	20 kcsf
John Day	16 hour: 40% 8 hour: 125% TDG	35%	20 kcsf
The Dalles	40%	40%	30%
Bonneville	125% TDG	95 kcsf	50 kcsf

Recommended Spill and MOP Targets

The Council began development of the Ninth Plan while it was also working on the Columbia River Basin Fish and Wildlife Program amendment process. To provide information for that process while also informing power planning, the Council developed a third sensitivity to model some of the recommendations submitted to the Council through that amendment process. Specifically, this included recommendations from some of the states and tribes on spill operations and minimum operating pool elevations and targets.

The Council received recommendations from some of the states and tribes about extending summer performance spill through August 31. The baseline spill operations assumed at the time of these comments were those defined in the 2023 Resilient Columbia Basin Agreement, in Table N - 8 above. This recommendation essentially would change the end date for summer performance spill from the July 31 date in the agreement to August 31.

Additionally, the Council received recommendations from some of the states and tribes around changes to minimum operating pool elevations and targets for the lower Snake and lower Columbia projects. These were part of a suite of recommendations seeking to reduce water travel time to support juvenile migration. The lower Snake River projects currently operate at minimum operating pool elevations with a 1.5-foot hard constraint and 1.0-foot soft constraint from April 3 to August 14. The recommendations were to tighten these elevations to a 1.0-foot hard constraint and a 0.5-foot soft constraint, and also to extend the period to March 1 to September 30. The lower Columbia River projects do not currently have minimum operating pool target elevations for the spill season. The joint entities recommended that operations at these projects be kept within 1.5 foot of minimum operating pool hard constraint and 1.0-foot soft constraint for this same period of March 1 to September 30.

This sensitivity models both the spill and minimum operating pool elevation targets. The specific minimum operating pool targets modeled in this sensitivity are in Table N - 9.

Table N - 9: Minimum Operating Pool Elevations

Project	Current Pool Elevation Operations (feet)	Recommended Operations Modeled in Sensitivity (feet)
Lower Granite	773-734.5	773-734
Little Goose	633-634.5	633-634
Lower Monumental	537-538.5	537-538
Ice Harbor	437-438.5	437-438
McNary	337-340	337-338.5
John Day	262-266.5	262.5-264
The Dalles	157-160	157-158.5
Bonneville	71.5-76.5	71.5-73

Limited Flex Operation

The final sensitivity included in this scenario focuses on the question of power system implications from reduced daily flexibility of the hydropower system. As discussed above, the ability to ramp the hydropower system on a daily basis to meet power system needs can provide value for integrating new renewable resources into the system. At the same time, the Council's Fish and Wildlife Program has called on the region to minimize daily fluctuations for the benefit of fish. This sensitivity aims to provide more insight on the power system implications of this balance.

The Council's GENESYS model sees more operational flexibility than is currently being utilized in the system today. To guide this sensitivity, the model was limited to represent operations more akin to current system dynamics. Specifically, the daily outflow range for each project was limited to align more closely with 2020-2024 actual operations. Additionally, the Council reduced the reserve requirements on the lower projects. [10]

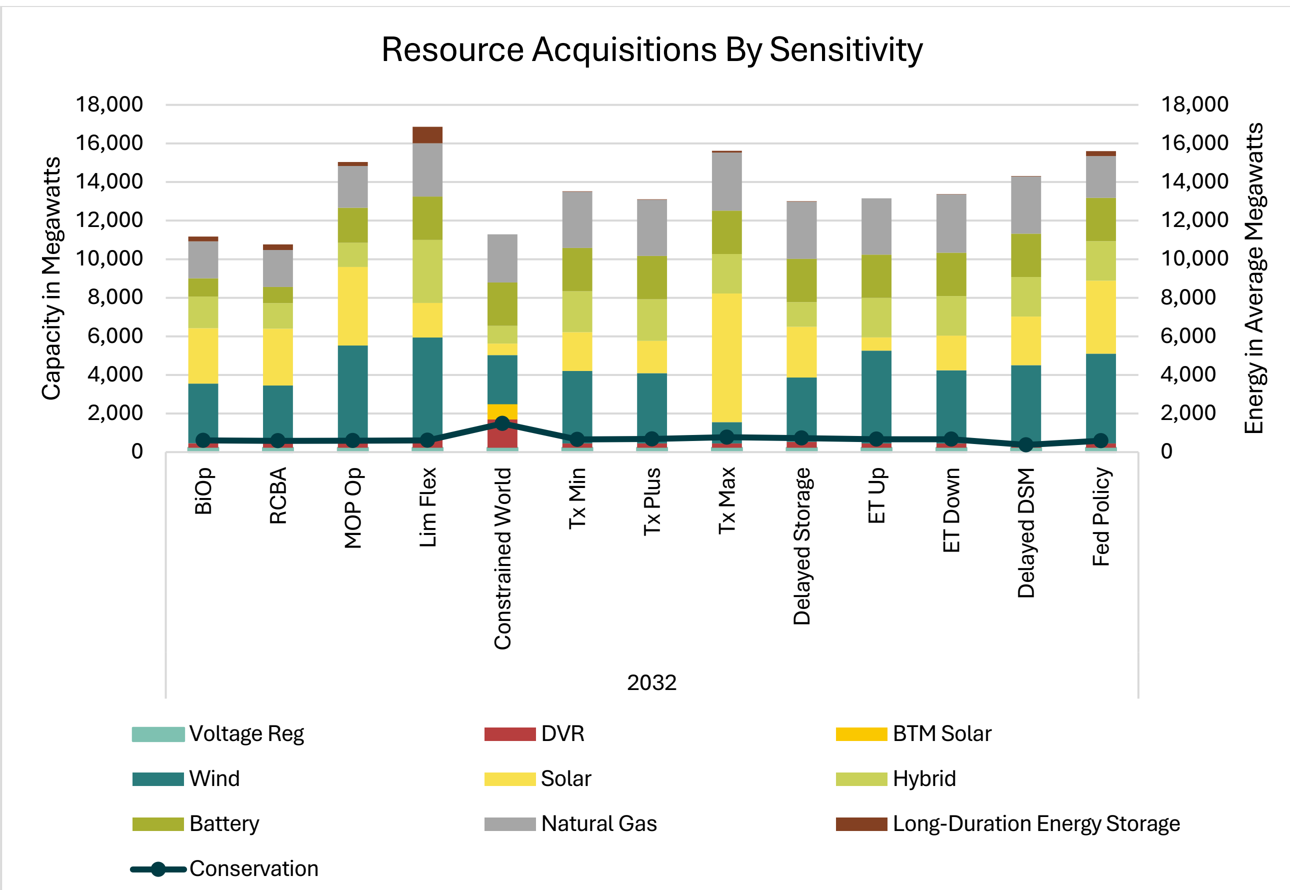
[10] See Technical Appendix M – Needs Assessment Results for more information on the assumed outflows.

Modeling Results

This section walks through the results of the regional resource optimization modeling, conducted in OptGen/SDDP. This builds on the work from the Council's needs assessment and west-wide market availability studies.[11]

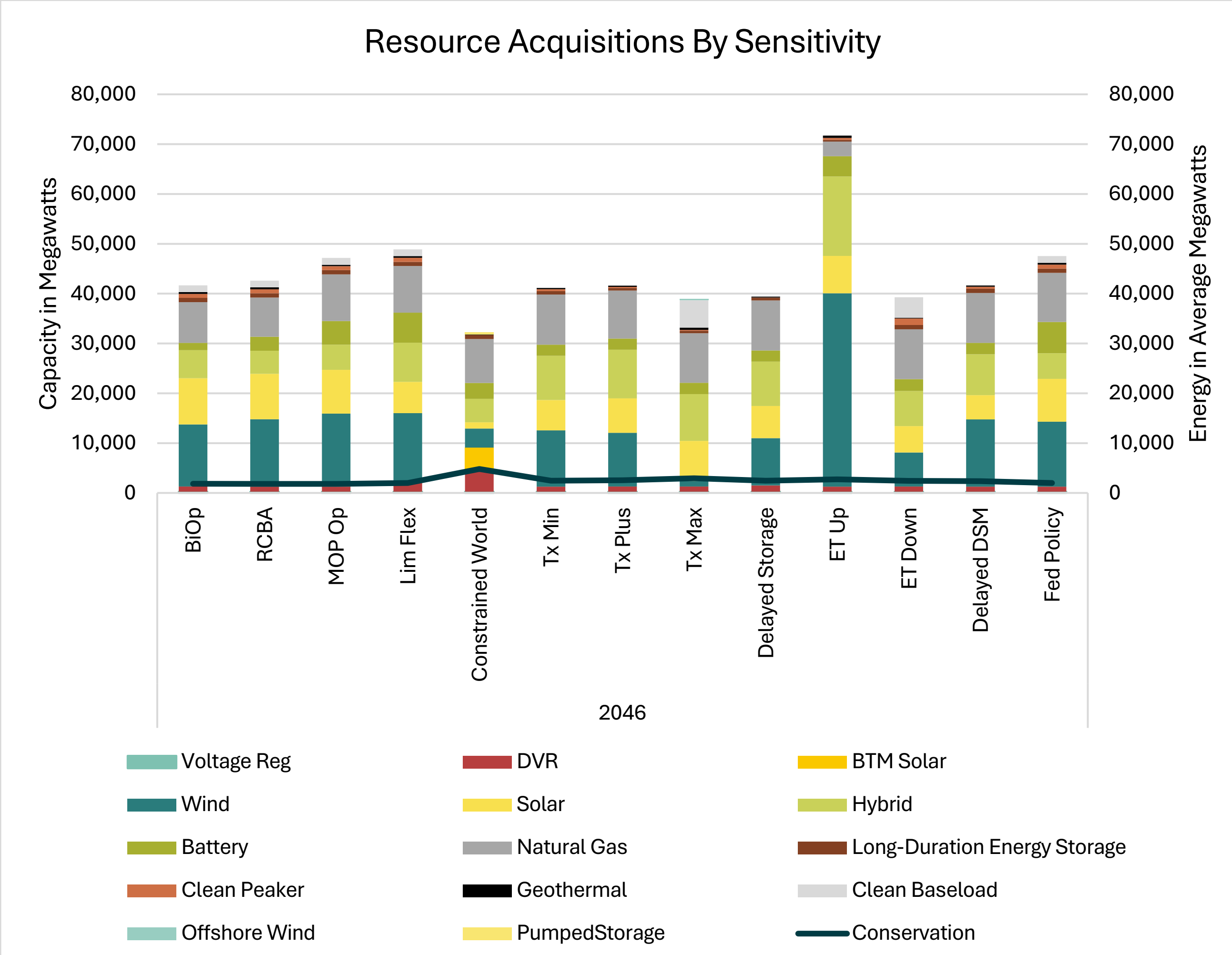
The modeling showed a suite of resources being selected across every sensitivity. In the Action Plan period (2027-2032) this includes: conservation, demand response, voltage regulation, renewables, storage, and natural gas as can be seen in Figure N - 4. In the broader study (through 2046), geothermal, long-duration energy storage, and medium duration energy storage were selected in all sensitivities for which the resource was available as can be seen in Figure N - 5. The clean baseload emerging technology was selected in roughly 60% of the sensitivities. Only three resources were not selected in a robust fashion across the modeling: offshore wind, pumped storage, and rooftop solar.

Figure N - 4: Resource Acquisition by Sensitivity in 2032



[11] See Technical Appendix L – Wholesale Market Availability Results and Technical Appendix M – Needs Assessment Results for more information on these studies.

Figure N - 5: Resource Acquisitions by Sensitivity in 2046



Primary Resource Themes

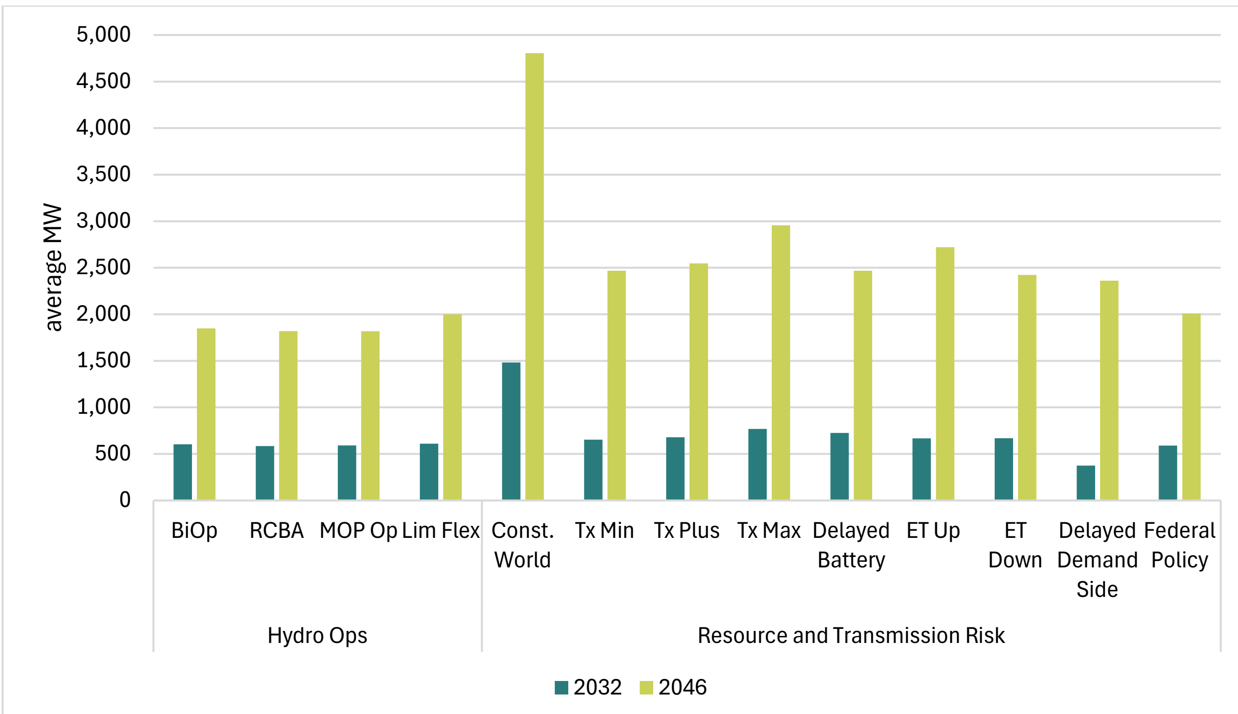
This section focuses on the results for those resources considered to be commercially available today that were selected in all sensitivities.

Conservation

Conservation was acquired in every sensitivity to provide energy, reduce loads and thereby lower the planning reserve margin requirements, and meet clean policies and goals. The amount of conservation acquired in each sensitivity varied based on the assumed costs and constraints of other resources. To maintain adequacy, the model selected more conservation when supply side resources were limited and costs for those resources were higher. Less conservation was selected in sensitivities with lower price for supply side resource, particularly renewables, as those resources start to become a more cost-effective way to provide energy to the system.

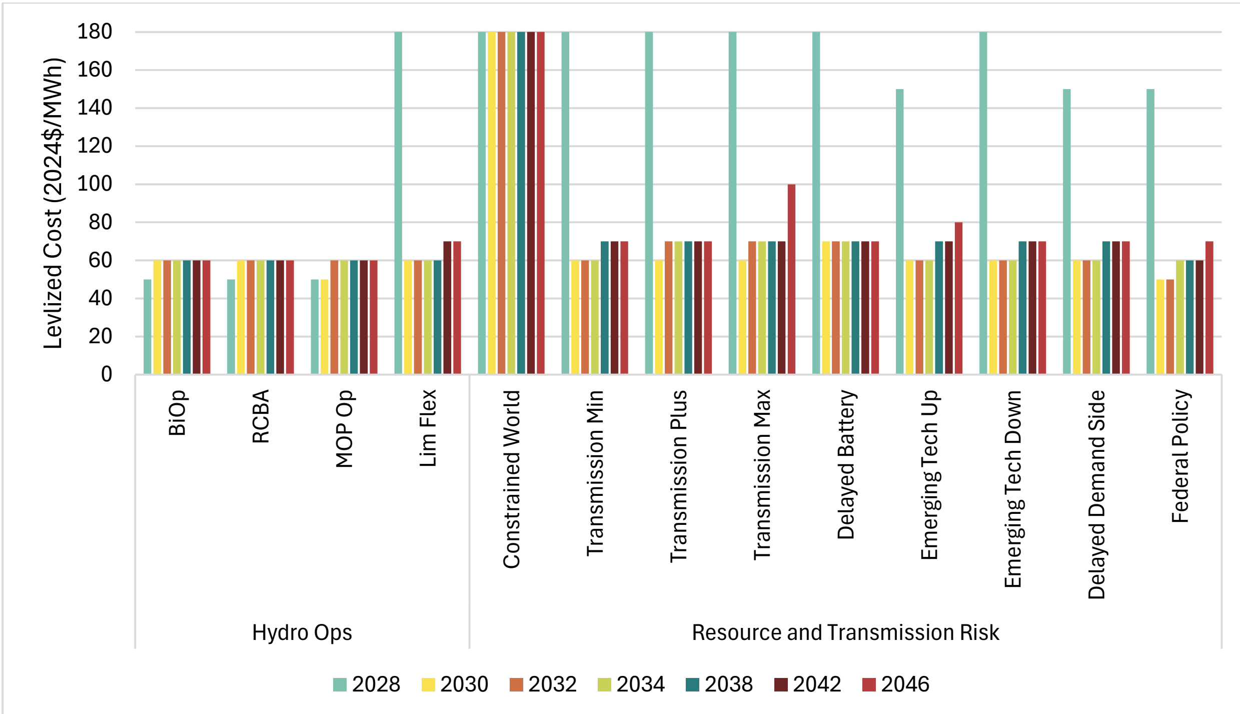
Figure N - 6 provides the conservation build by 2032 and by 2046. The highest build is in the Constrained New Resource and Transmission sensitivity. In this sensitivity, the supply side is constrained to the point that to maintain resource adequacy, the model selects all available conservation. The least amount of conservation in the near-term (2032) is acquired in the Delayed Demand Side sensitivity, as there is less available to the model. The amount of conservation acquired both in the near-term and long-term is similar across the Changing Hydro Operations sensitivities and the Changing Federal Policy sensitivity. These are the sensitivities that assume federal tax credits for renewables, akin to Biden Administration-era policies. The result is that renewables become more cost-competitive and are therefore more readily acquired by the model, offsetting the need for conservation.

Figure N - 6: Conservation Build by 2032 and 2046



Another finding in the conservation results was that generally the model wanted to acquire conservation higher up the cost curve as it moved through time. Figure N - 7 shows the maximum levelized cost-bin acquired in each sensitivity. A couple important notes: First, for some of the 2028 years and the Constrained New Resource and Transmission sensitivity, the figure shows costs going up to the top of the chart. In all cases, the model acquired all available conservation, including conservation over $200/MWh. This is a clear signal from the modeling that at times when the supply side is constrained, for example in 2028 with limited planned resource options and in the Constrained Resource and Transmission Risk sensitivity, the model sees value in acquiring more expensive conservation as a way to maintain adequacy. Second, generally, the model wants to go higher up the cost curve over time. This can be seen in most sensitivities where the value of conservation acquired by the end of the study (2046) is higher than that acquired in 2030, the first year the model is less constrained on supply side resources.[12]

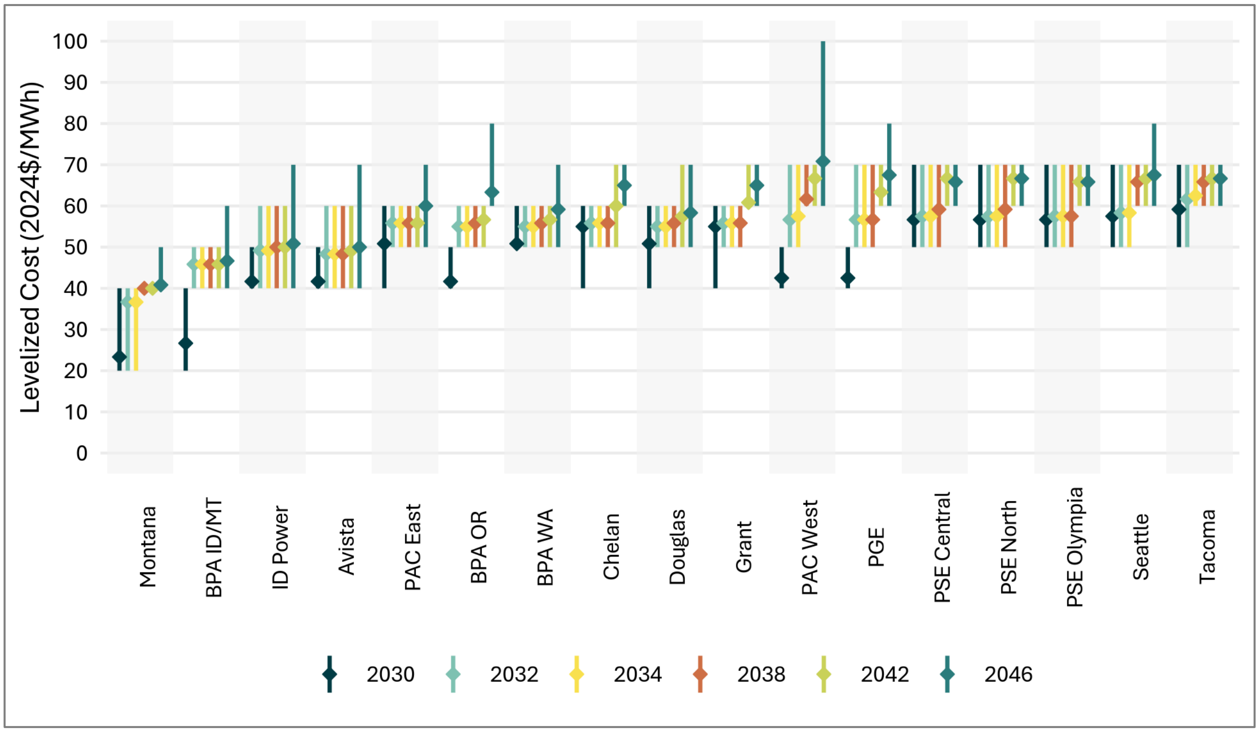
Figure N - 7: Maximum Cost Bin Acquired in Each Sensitivity



While Figure N - 7 provides the maximum levelized cost bin across the region for each sensitivity, Figure N - 8 digs deeper to show how the levelized cost changes across the region. This is a line range plot showing the range of costs acquired for each zone across the sensitivities. It excludes the Constrained Resource and Transmission Risk sensitivity and 2028, as both of those skew the overall trend due to the supply side challenges. As shown in this figure, there is a difference in the value of conservation being acquired across the modeling zones. The diamonds show the average cost for each zone across the sensitivities.

[12] In the 2028 snapshot year, the only generating resources available in the model are planned resources already identified by regional entities. The rationale is that, due to lead times for developing resources, it is unlikely other new options would be available if not already planned. By 2030, there is the potential for resources beyond those planned resources to be identified and developed, and so those constraints are lifted from the model.

Figure N - 8: Levelized Cost Bins Across Sensitivities for Each Zone



In Figure N - 8, Montana zones consistently show the lowest signal, starting off at $20/MWh and going up to $50 or $60 in the final year. The zones in the Puget Sound area, however, start off at around $50/MWh and generally get to $70 by the end of the study. When looking at the averages, a broader trend emerges. The averages for the Montana zones are on the low end of the line range, whereas the averages for the Puget Sound zones are on the top end.

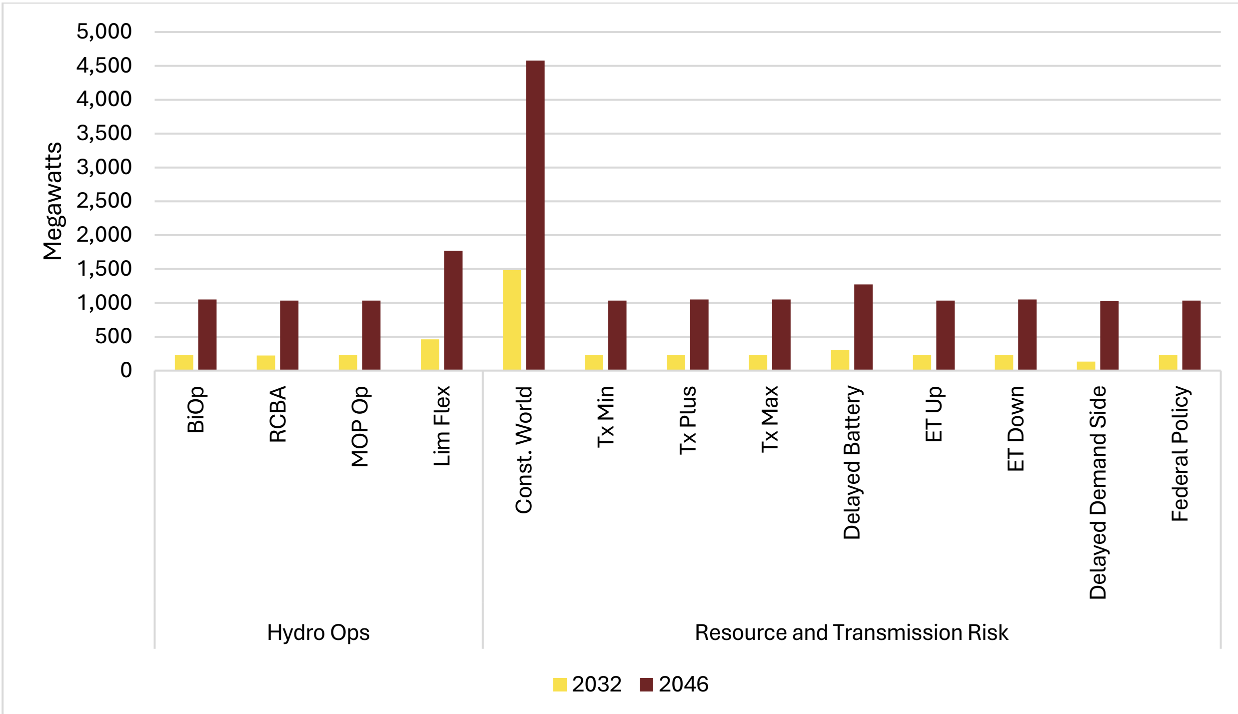
These main findings of locational value, increased value over time, and increased value under periods of supply chain constraints and resource cost increases all informed the overall conservation target recommended in the regional resource strategy.

Demand Response

Demand response was selected in every sensitivity. Demand response lowers loads at certain times, which reduces the required planning reserve margin at those times. Demand response is also an emissions-free option that can support policy during the times when it reduces load.

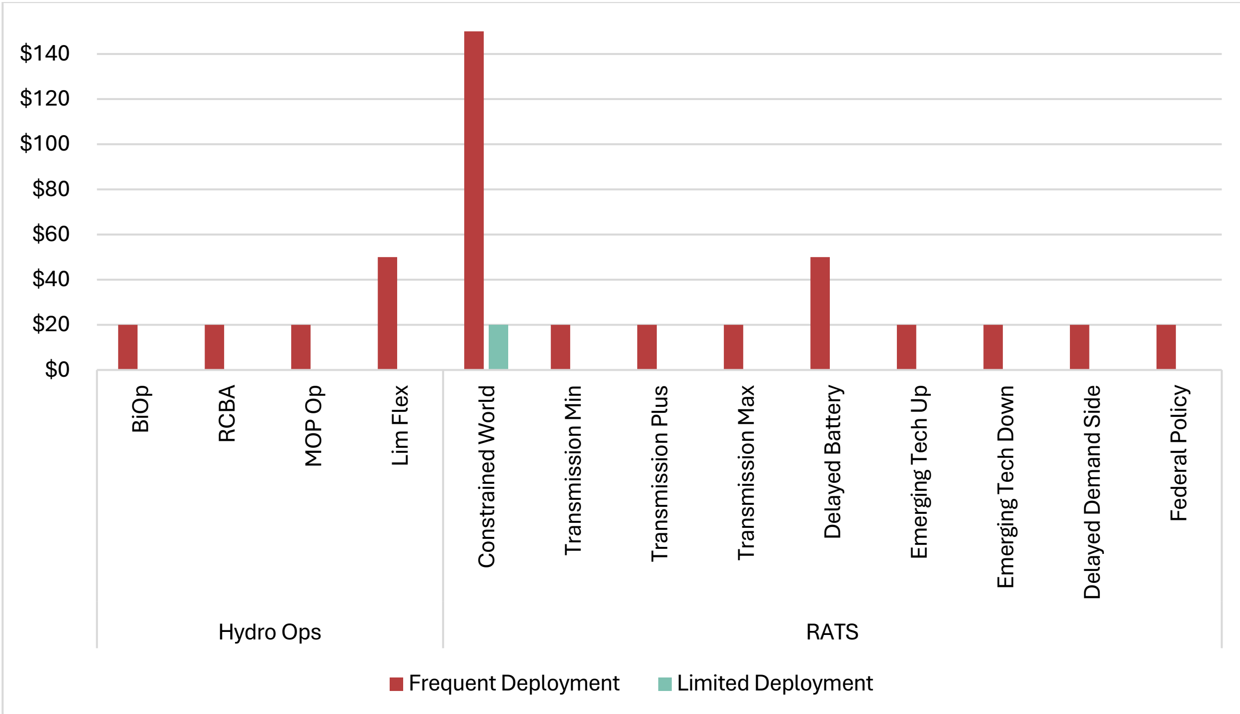
The amount of demand response acquired in each sensitivity varied based on assumed constraints of supply side resources and costs of those resources, as well as overall system flexibility. Figure N - 9 shows the demand response build across the sensitivities for 2032 and 2046. The highest levels of demand response were acquired in the Constrained Resource and Transmission, Delayed Battery Storage, and Limited Flexibility sensitivities. In the first two of these, supply side resources, including standalone storage which competes with demand response, were limited. This resulted in a higher investment into demand response to maintain adequacy. In the Limited Flexibility sensitivity, the existing hydropower system was limited in its ability to ramp on a daily basis to provide flexibility and support the integration of renewables. This resulted in the model needing to acquire more new resources to provide flexibility, including demand response.

Figure N - 9: Demand Response Build in 2032 and 2046



Beyond those three sensitivities, the overall demand response build was fairly limited. Figure N - 10 shows the maximum levelized cost bin acquired for demand response by 2032 for each sensitivity. This figure breaks out the frequent deployment and limited deployment demand response. This figure shows that the model prefers the frequent deployment products, providing more regular flexibility to the system. It also shows that generally the model does not want to go higher than the lowest cost bin for demand response. Unlike conservation, which shows a signal for higher cost conservation over time, the demand response acquisition looks similar in 2046 as is shown for 2032. In other words, the model does not show value for higher cost demand response in the future to meet needs.

Figure N - 10: Maximum Demand Response Cost Bin, by Type, in 2032



One likely reason for this result is how demand response competes with other resources in the system. As discussed more below, the model acquires both natural gas and hybrid solar plus storage resources in large amounts. These resources provide energy for the system, as well as provide flexibility. They also can provide reserves. Once these resources are acquired, there is less of a role for demand response specifically to meet needs.

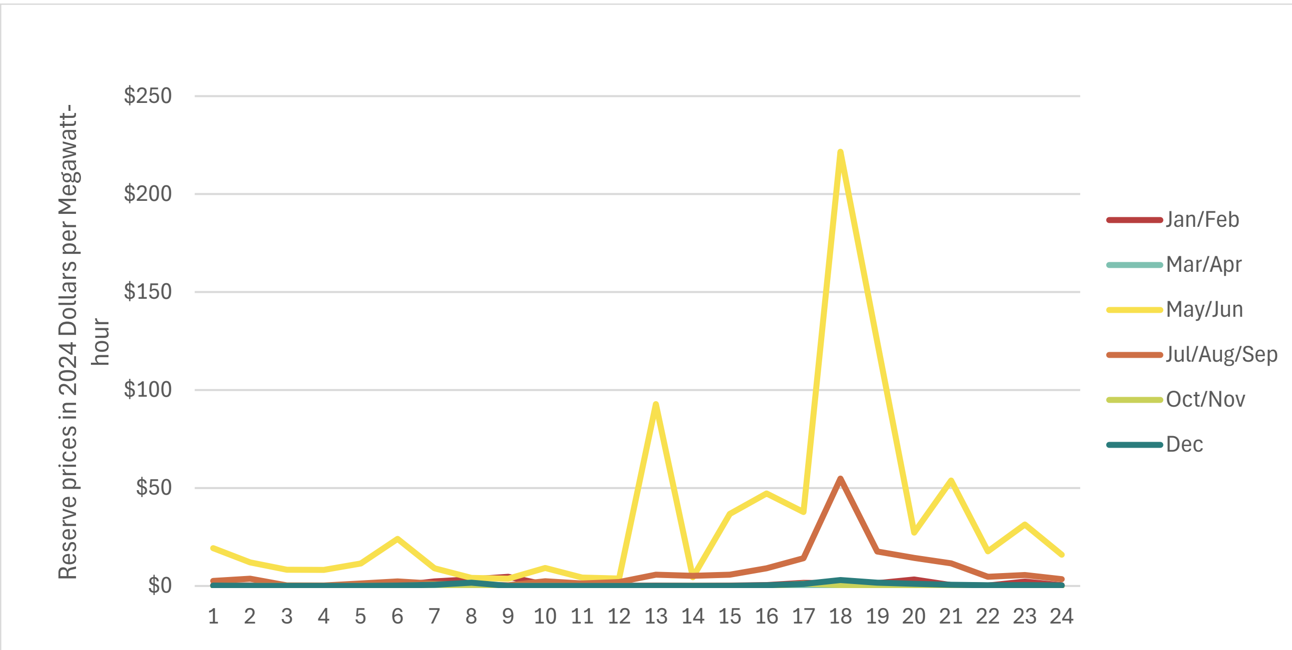
The Council also identified another potential challenge for the modeling of demand response in the Ninth Plan. For this plan, demand response was provided to the model as an "energy efficiency" resource. This means that once the model selected the resource, it was deployed as shaped to meet needs, regardless of the underlying future conditions. For example, the same amount of demand response was used in a future with low market prices as in a future with high market prices. This is not the reality of demand response implementation, as utilities will use price signals to guide demand response events. Second, the model uses a typical day format, which likely reflects less volatility in market prices as seen in reality. This too likely masks the signal for demand response in the model.

Additionally, as described above, in the typical day modeling as described in Technical Appendix K – Modeling Framework, power prices are defined for a typical day with expected demand for that season. To account for the difference between the expected demand peak and seasonal peak, additional reserves were added so the model would know to have enough resources to meet seasonal peaks. These seasonal peak reserves make up a large portion of the reserves in the model, over 75 percent of the total reserves in 2032 in all sensitivities.

The model creates reserve prices when meeting reserves is marginal, or reserve providing resources are scarce. Unfortunately, in the modeling, while demand response could lower demand in certain hours, it was not one of these resources that could meet these seasonal peaking reserves directly. Thus, instead of using the model resource selection in this case it could be useful to see what price signal is left to mitigate.

For example, the model shows a reserve price signal that is high[13] during certain hours in the late spring and summer, per Figure N - 11. It is clear the model did not see additional other resources as advantageous to addressing those peak needs, since it could have lowered the price and selected those resources as part of the strategy. However, since demand response was not available to address this need directly, it is unclear if the model would have chosen demand response if given an opportunity.

Figure N - 11: Reserve Prices by Season in 2032



The Council did identify other results that might suggest value for a product similar to demand response. These include the curtailment of hydrogen demand in the model.

Voltage Regulation

Voltage regulation is a demand side resource that regulates the voltage on the distribution system to provide energy system. This can be operated in a couple of different ways. One approach is to lower the voltage once and keep it at that lower level. This approach is akin to conservation and is typically called conservation voltage reduction. The second approach is to lower the voltage at times when it

[13] The signal in practice is higher than this from the model results because the model in spring often bumped against the reserve requirement as a constraint. In the figure prices are capped at 1,000 dollars per megawatt hour for illustration.

provides value to the system, but keeps the voltage higher at other times for economics. This approach is called demand voltage regulation.

For the Ninth Plan, the Council modeled this resource separately from both conservation and demand response, allowing the model to determine whether there was value in this product, and if so, what strategy would best meet regional needs. This entire resource was selected in every sensitivity, driven by the near-zero to negative levelized cost of this resource. Generally, the model operated this more as conservation resource in the early years of the power plan (see Figure N - 12) and more of a demand response product in the later years (see Figure N - 13). These utilization charts show when the resource is operating. In Figure N - 12, the resource is maxing out its operations for most hours of the day across all seasons, except some minor drops in the spring period. Figure N - 13 shows more variability, however, particularly in the spring.

Figure N - 12: Voltage Regulation Utilization in 2032 for Region

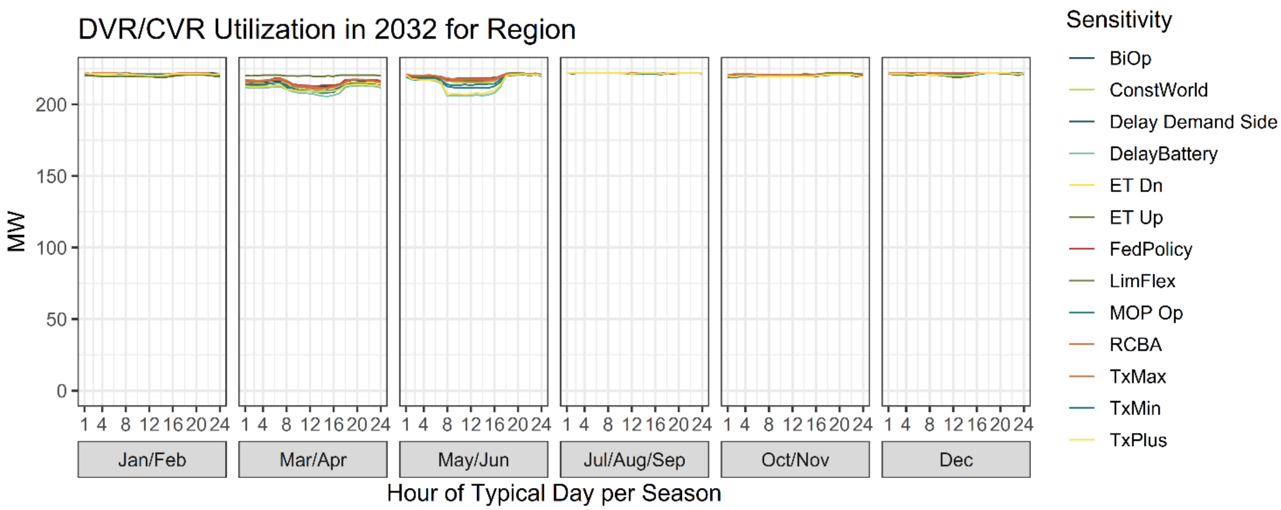
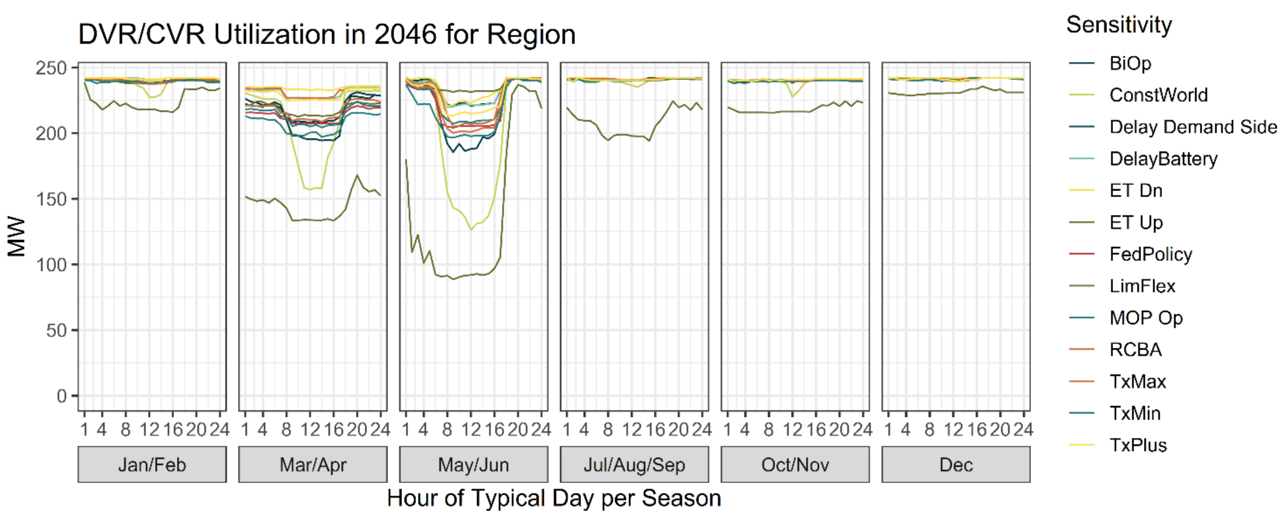


Figure N - 13: Voltage Regulation Utilization in 2046 for Region



The figures above show the regional approach to voltage regulation, but there are differences seen across the zones. Figure N - 14 through Figure N - 19 show the utilization for 2032 and 2046 in Oregon, Washington, and Idaho/Montana, respectively.

Figure N - 14: Voltage Regulation Utilization in 2032 in Orgon

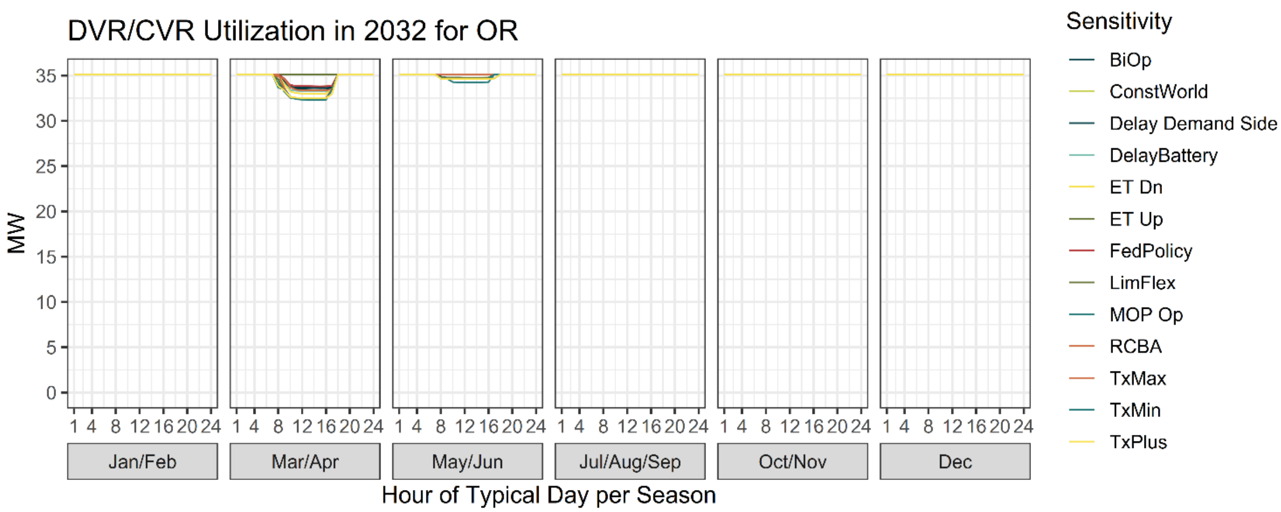


Figure N - 15: Voltage Regulation Utilization in 2046 in Oregon

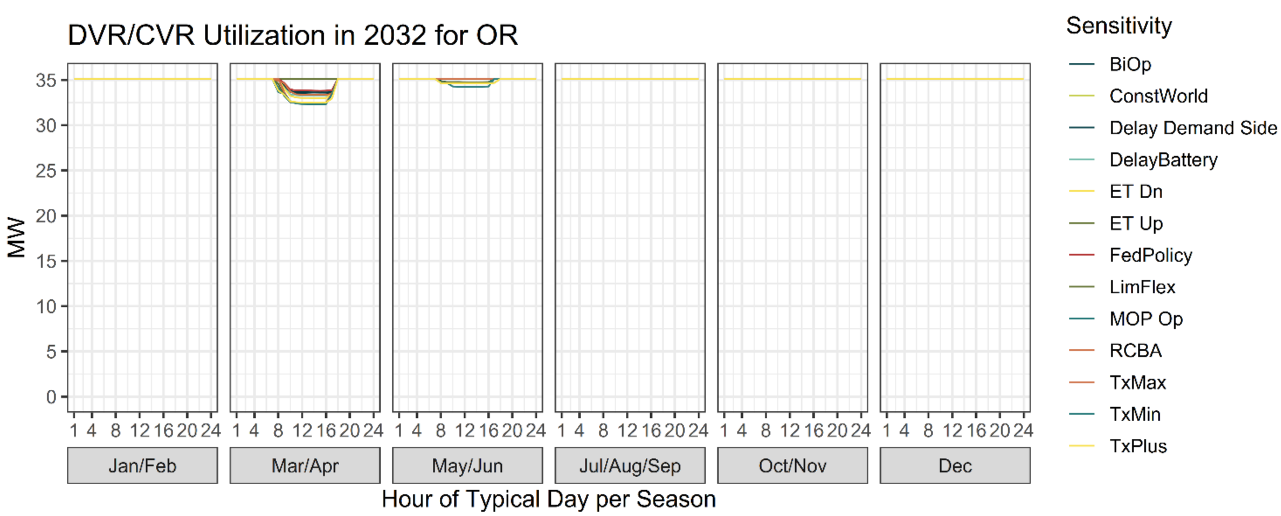


Figure N - 16: Voltage Regulation Utilization in 2032 in Washington

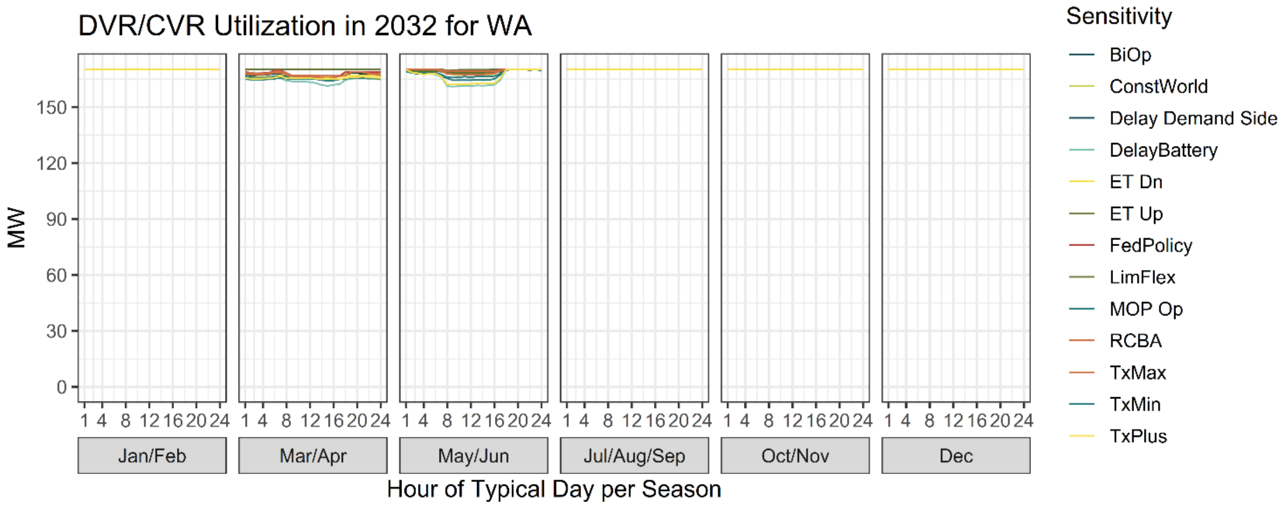


Figure N - 17: Voltage Regulation Utilization in 2046 in Washington

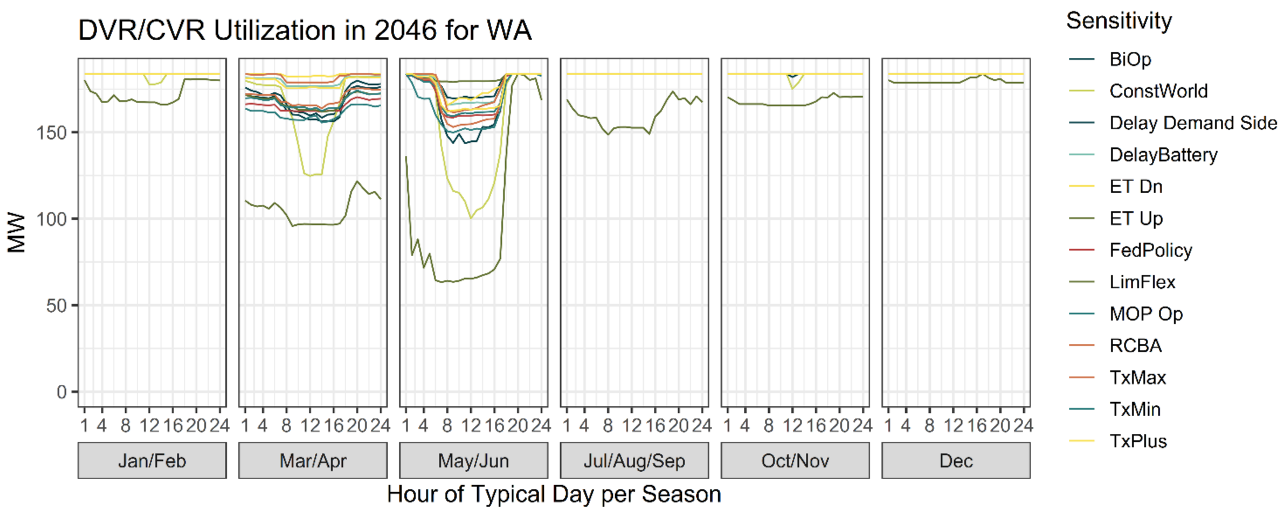


Figure N - 18: Voltage Regulation Utilization in Idaho and Montana in 2032

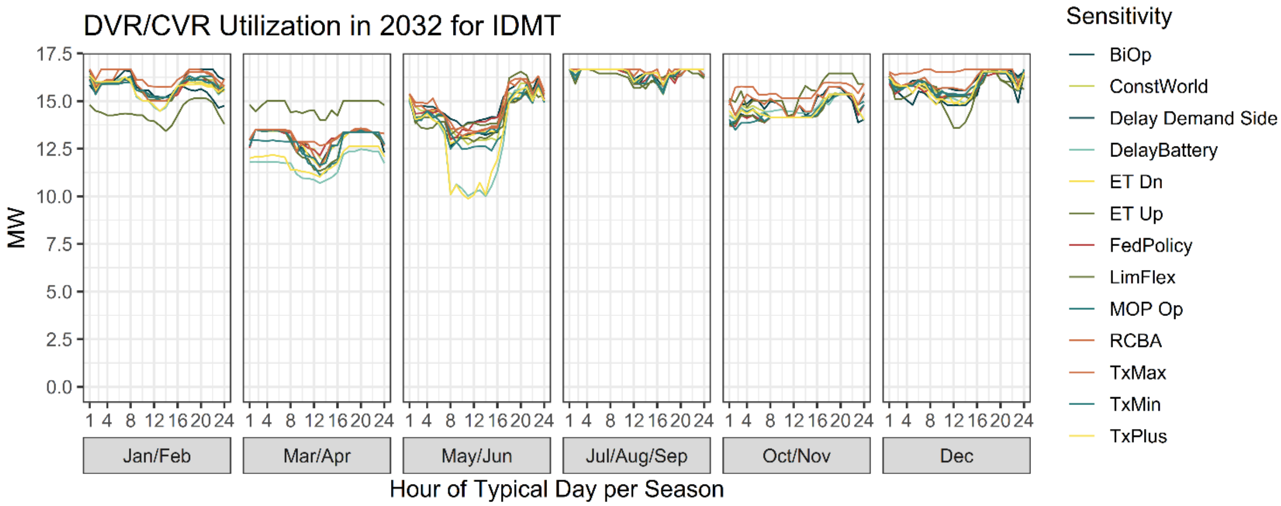
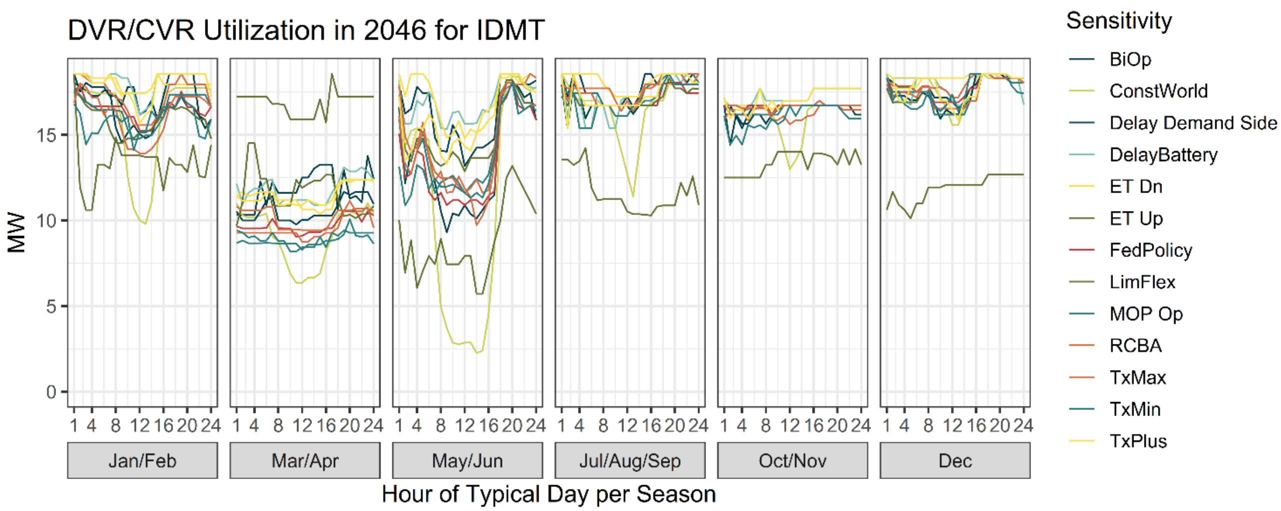


Figure N - 19: Voltage Regulation Utilization in Idaho and Montana in 2046



Renewables

This section focuses on solar and onshore wind, including solar plus storage. Conventional geothermal and offshore wind are covered in separate sections below. Solar, wind, and solar plus storage were selected in all sensitivities. These resources provide energy to the system and support the region in meeting clean policies and goals. Solar plus storage hybrid resources also support the system in meeting its planning reserve margins.

Figure N - 20 and Figure N - 21 show the renewable build across sensitivities by 2032 and 2046, respectively. One trend seen in both these figures is a general preference for a balanced approach between wind and solar. While this is not always the case, there is roughly a 50:50 split between wind and solar (including solar plus battery) resources.

Figure N - 20: Renewable Build by 2032

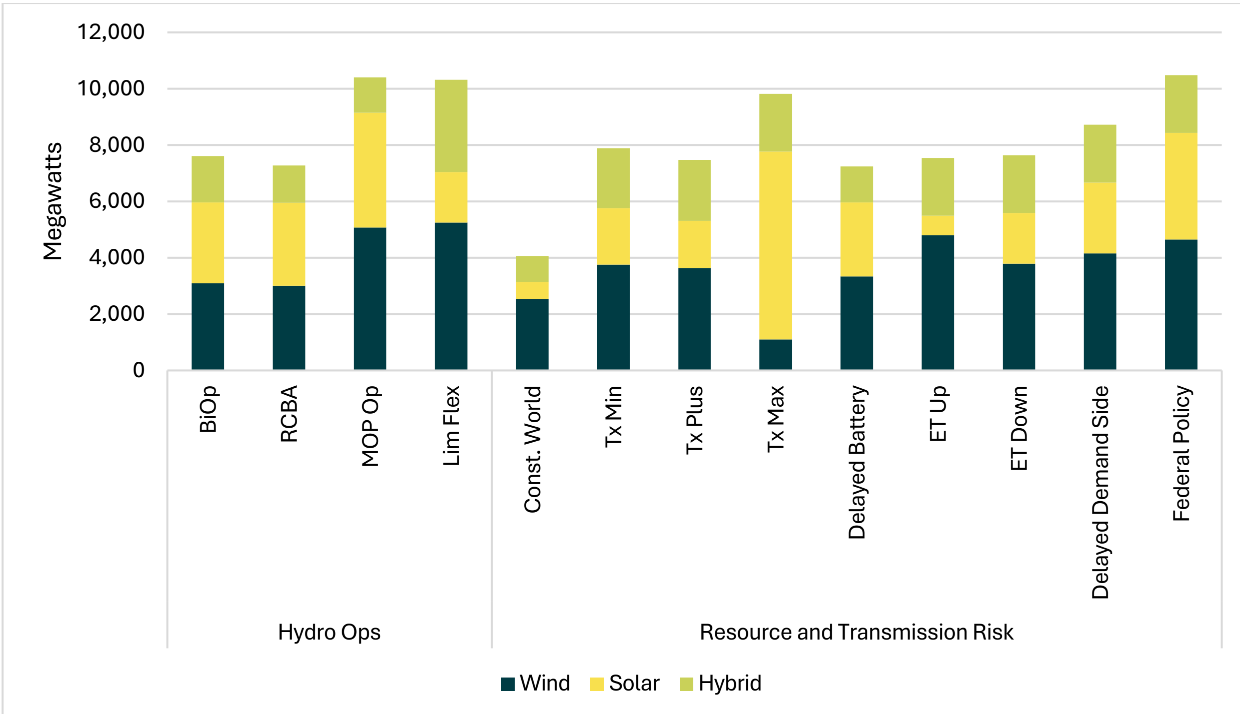
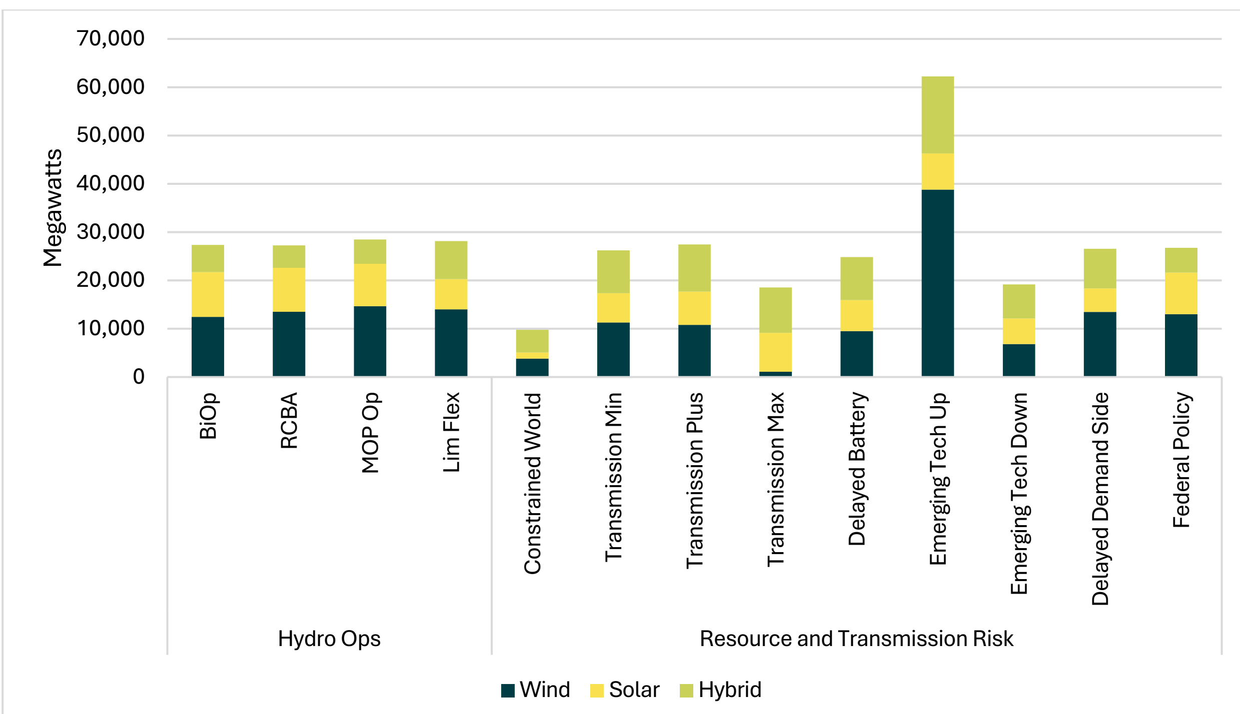


Figure N - 21: Renewable Build by 2046



The sensitivities that show differences in this trend connect back to the overall market studies results. For example, the Transmission Max sensitivity shows significantly more solar (particularly as a percentage of renewable build) than any of the other sensitivities. The main driver of this difference is the market study and the amount of wind developed across the broader West, as discussed more in Technical Appendix L – Wholesale Market Availability and Results. With additional transmission connectivity, the market study developed more wind, particularly in the Mountain West, as this provided a more efficient way to meet loads and policy goals. This resulted in less solar being developed across the West. This shift in market study results then caused a shift in what the regional results developed to optimize diversity of renewable resources. Rather than further adding to the amount of West-wide wind, the model optimized with greater amounts of in-region solar to provide overall fuel diversity of renewables.

Storage

The Ninth Plan modeled a range of storage resources, including standalone battery storage, hybrid renewable resources (specifically solar plus battery storage), and two emerging technology reference plants. This section discusses the findings of standalone battery storage and hybrid systems.

Standalone battery storage and hybrid systems were selected in all sensitivities. In most sensitivities, the models selected 2,245 megawatts of storage in 2028 and never adds more of this standalone storage resource (see Figure N - 22). That 2,245 megawatts of storage represents planned projects that the Council identified as being available in the near-term. These are projects that have been announced, but are not yet under construction and therefore not included in the representation of the existing system as defined and described in Technical Appendix B – Existing System Parameters and Policies.

The sensitivities that add more standalone storage over time are those that tend to have more standalone renewables. For example, the four different Changing Hydro Operations sensitivities and Changing Federal Policy sensitivity all assume clean tax credits. These credits bring down the cost of renewable resources, making the pairing of standalone renewables and standalone storage a more economical path. The Emerging Technology Cost Increase sensitivity has significantly more wind than the other sensitivities, and these additional standalone batteries are providing some additional reserves to account for that added resource.

Figure N - 22: Short-Duration Storage Build in 2032 and 2046

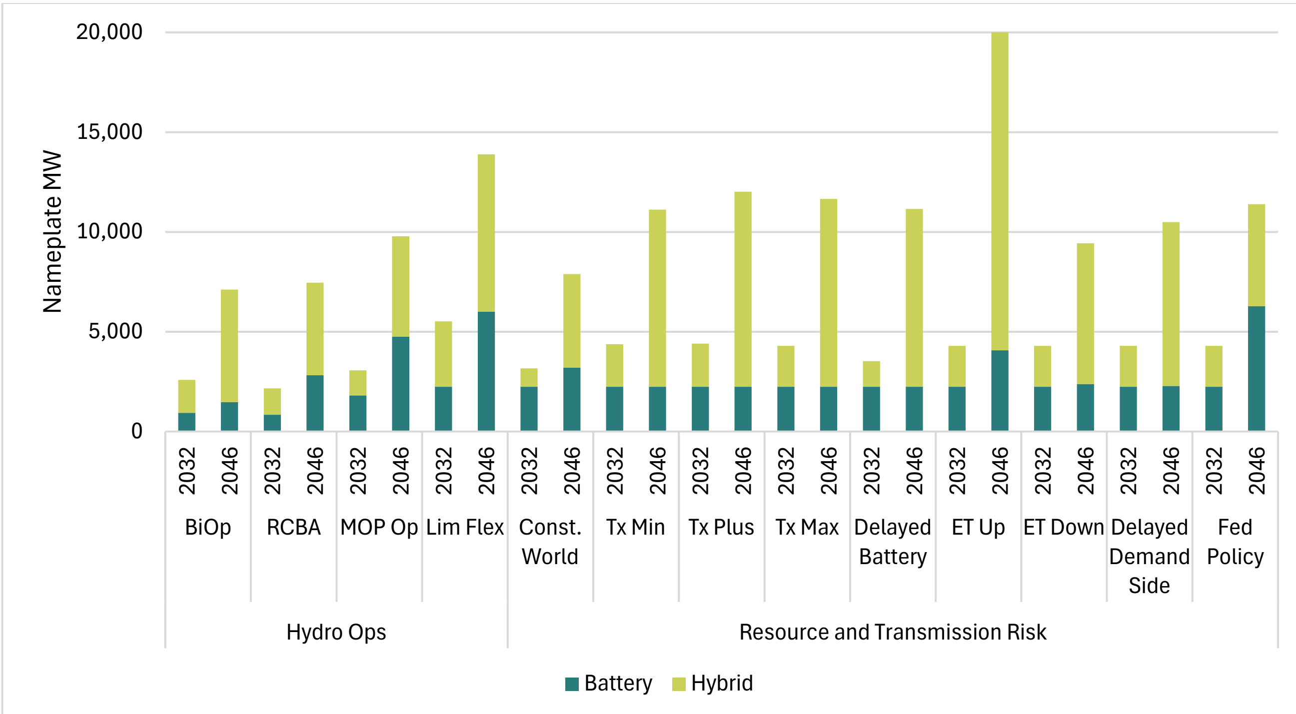
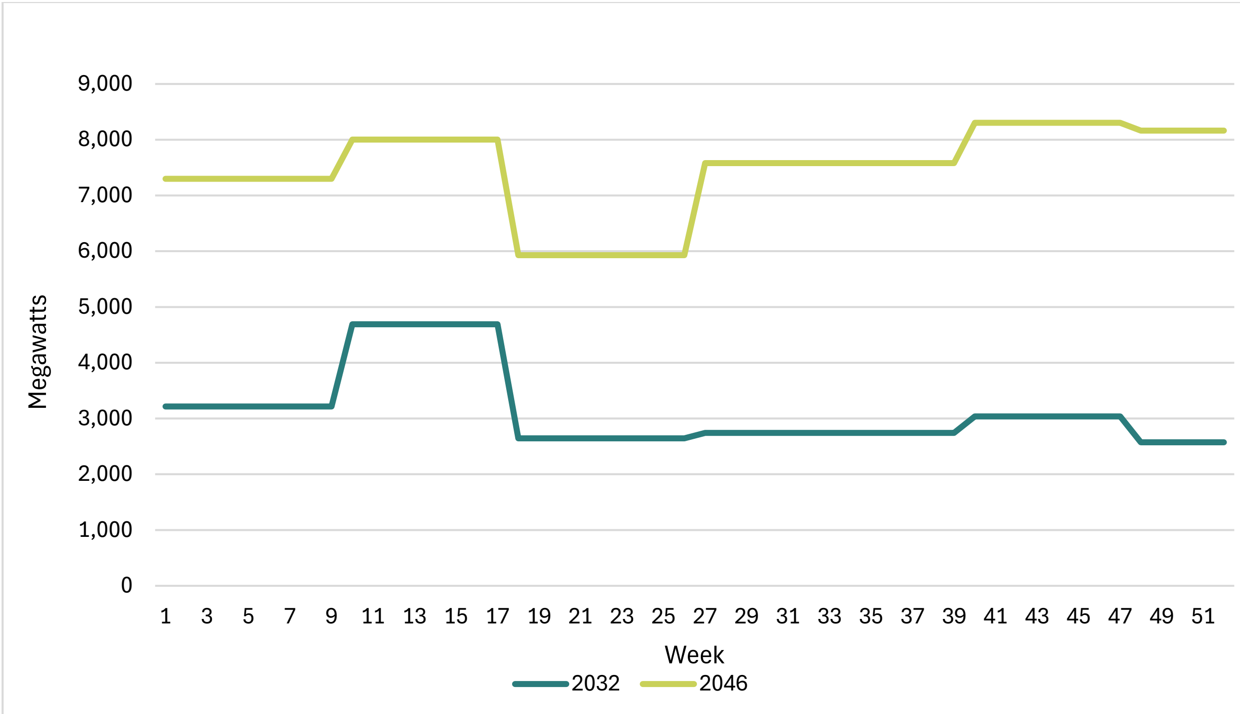


Figure N - 22 also shows that as storage is added to the system post 2028, it tends to be in the form of hybrid solar plus storage resources. This provides a way to bring the energy requirement for the system, while also meeting the flexibility and reserve needs.

One important feature of OptGen is the dynamic probabilistic reserves functionality. This functionality allows the model to dynamically adjust and solve for the reserve requirement over time as resources are added to the system. Particularly, as renewables are added to the system, greater amounts of reserves are required to account for the increased risk of uncertainty around fuel availability. This can be seen in Figure N - 23, which captures the reserves required for renewables in the Transmission Plus sensitivity. In this specific sensitivity, the model built 7,472 MW of variable energy resources by 2032 and 27,453 MW by 2046. That roughly 20,000 MW increase over the years required an additional roughly 4,000 MW of reserves. The specific amount varies by season.

Figure N - 23: Reserve Requirement for Renewables in Transmission Plus Sensitivity

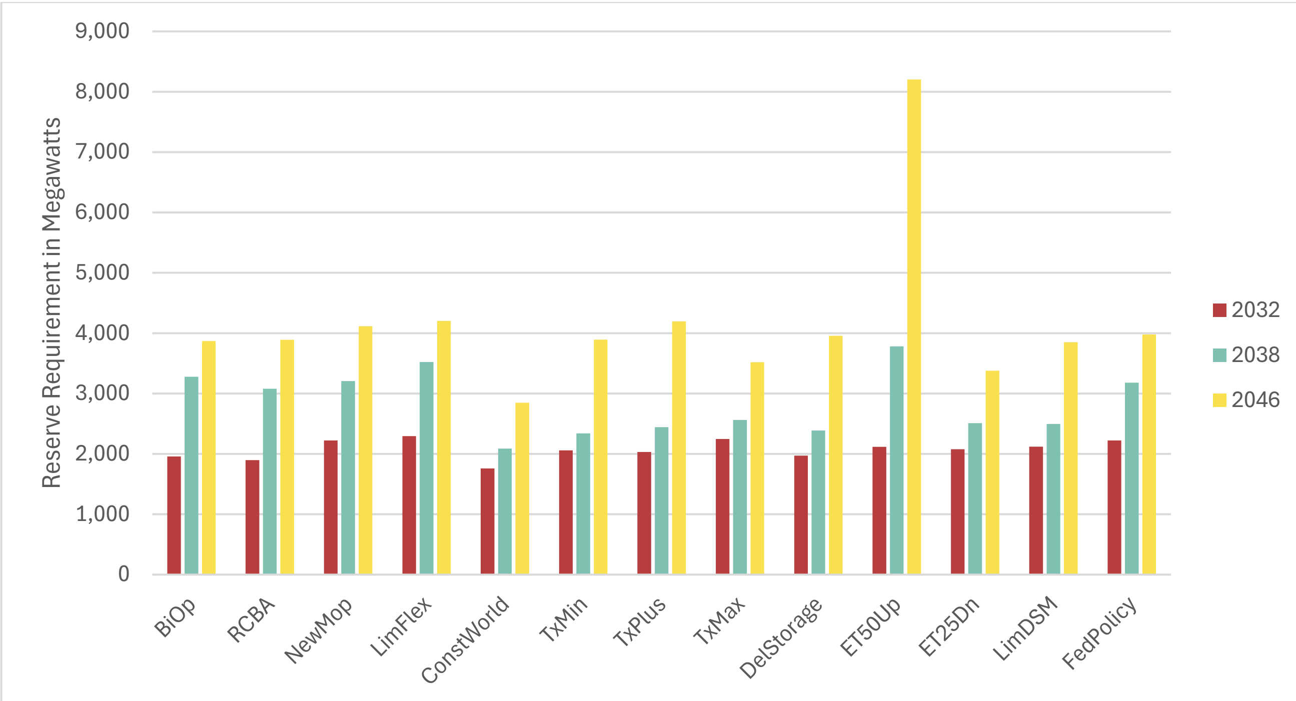


The new storage that is developed in the model is primarily used to provide reserves. The average reserve percentage across all sensitivities and zones in 2032 is close to 90%, although the specific amount varies by sensitivity, future, and zone.[14] In 2046, that average reserve percentage drops to closer to 70%.

Another example reflecting the association between short duration storage and its role in meeting reserve needs can be seen in Figure N - 25. Note the dynamic probabilistic reserve requirement (reserve requirement for renewables) is nearly twice as much during the Emerging Tech Cost Increase sensitivity per the observations above about the significant investment in wind and thus the investment in short duration storage as a resource to meet those reserve requirements. Similarly, when the balancing reserve requirement is less due to lower renewable investment in the Constrained Resources and Transmission sensitivity the short duration storage investment is also less.

[14] Reserve percentage refers to the percent of the batteries nameplate capability that is used for reserves.

Figure N - 24: Average Annual Dynamic Probabilistic Reserve Increasing Over Time



Natural Gas

As discussed in Technical Appendix G – New Generating Resources, the Council modeled three natural gas technologies: combined cycle combustion turbine, simple cycle combustion turbine, and a reciprocating engine. The model selected natural gas in all sensitivities, predominantly peakers (simple cycle and recip technologies), particularly in the earlier years of the study. The overall build by 2032 and 2046 is in Figure N - 25 and Figure N - 26, respectively.

Figure N - 25: Natural Gas Build by Sensitivity for 2032

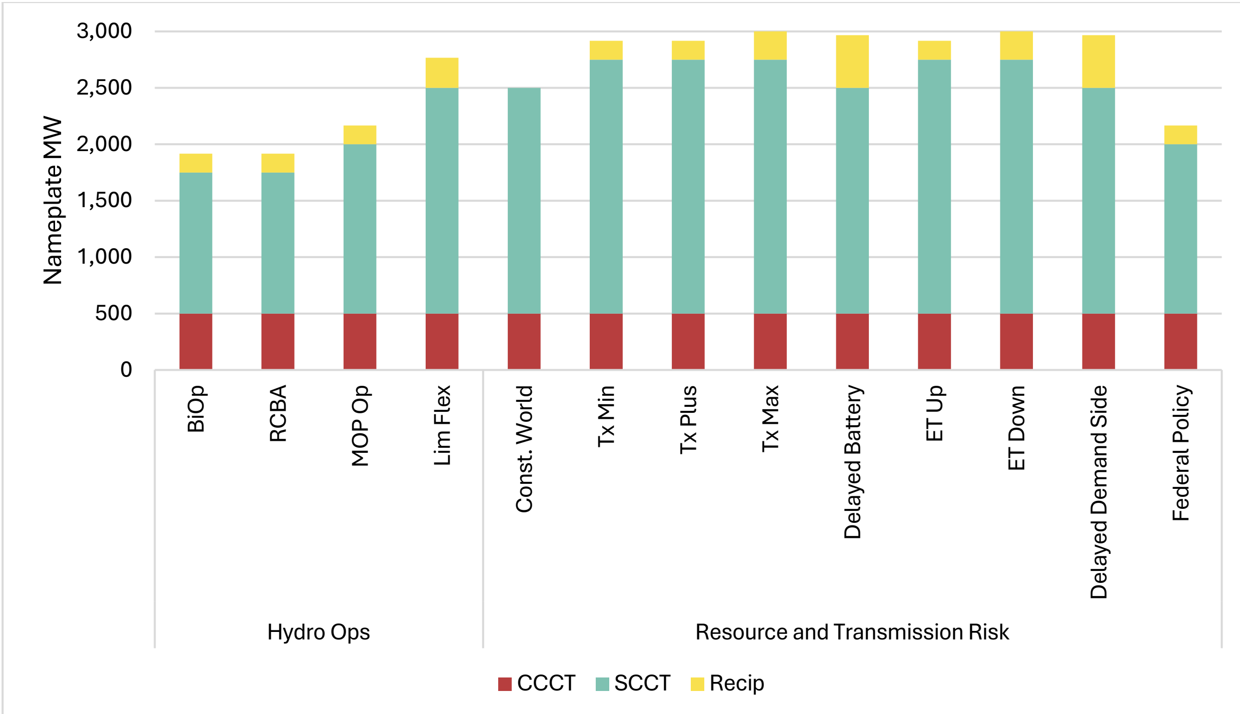
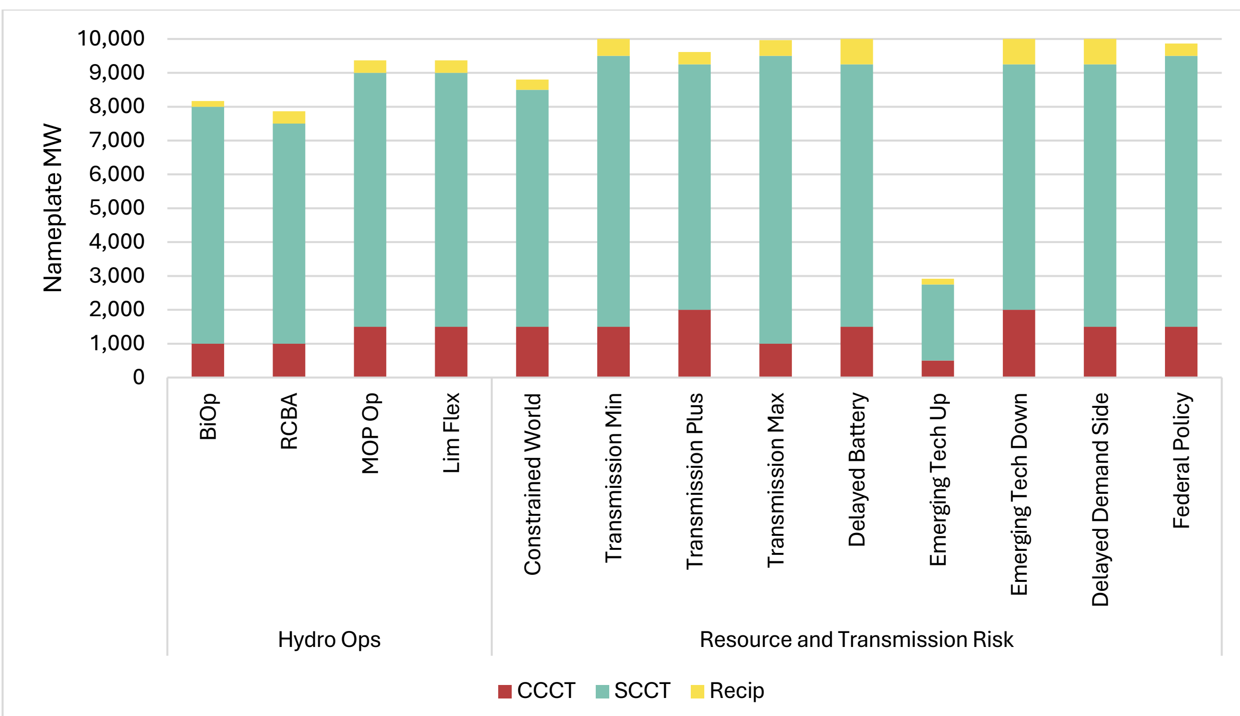


Figure N - 26: Natural Gas Build by Sensitivity for 2046



To account for existing constraints in the natural gas pipeline system, the Council assumed a 3,000 MW limit of new gas by 2032. That limit was expanded to 10,000 MW, essentially the existing system capacity, after 2032. As is clear in the above two figures, the model selects up to the limit for natural gas across many of the sensitivities. The one notable exception in the long-term is the Emerging Technology Costs Up sensitivity. In this specific sensitivity, the overall market build is driving a different result for the region. To meet clean policies West-wide with assumed increases in emerging technology costs, the market study developed more resources in the Northwest zone. Those resources were removed from the West-wide market buildout that was then provided to OptGen, resulting in a larger resource whole in the Northwest. This resulted in a build of significantly more renewable resources in the region (see Figure N - 21) as a way to meeting West-wide policy requirements. Additionally, also in this sensitivity, outside the region more gas resources were developed, which also may have dampened the signal for gas resources inside the region.

Natural gas utilization is an important element in understanding the overall role that new natural gas is playing in the system. The utilization of natural gas is a combination of generation and reserves. The Ninth Plan modeling shows a couple of general trends:[15]

- **New natural gas is primarily utilized for reserves**: The new units added to the system generally show greater utilization for reserves. This is particularly true in Washington, but the trend holds for the new units in Idaho and Montana. Considering the bulk of these new units are peaker plants, this makes sense. The modeling does show that the Idaho Power zone, the zone that acquired the combined cycle unit by 2032, utilizes the new gas more for generation.
- **New natural gas generates more in low hydro conditions**: When digging into the utilization across futures, the new natural gas units show the highest generation in futures with the lowest hydro or years with the highest net loads (combination of loads minus existing generation from variable energy resources). This suggests that these peaking plants provide a good hedge against low hydro conditions.
- **Existing natural gas is more often utilized for generation**: Much of the existing natural gas consists of combined cycle units. These tend to be more efficient, less flexible units. The modeling shows that, generally, the existing system is being utilized more for generation, although there are still some levels of reserves held on these units.
- **Existing natural gas generates more in low hydro conditions and high loads**: The existing system is utilized more in futures with low hydro (similar to the new units) as well as high loads, including futures with high loads *and* high hydro. These higher loads, particularly in the near-term, are primarily from large loads like data centers, which tend to be relatively flat, benefiting from more of an energy resource than a peaking one.

[15] This is discussed in more detail in April 28, 2026 work session: https://nwcouncil.box.com/v/April29-PowerPlanWorkSession

Conventional Geothermal

Due to the timelines for identifying and developing the resource, conventional geothermal was not available to the model until 2034. Geothermal was selected in every sensitivity once available to the model (see

Figure N - 27) and generally selected more geothermal through the end of the study, hitting the maximum allowed in some sensitivities, as represented by the dashed line in Figure N - 28. These results show a robust signal for the role that conventional geothermal can play in meeting system needs. This suggests that if more geothermal potential were available at a cost competitive price point, that it might provide even greater value for the system. This is explored more in the discussion of the results around the emerging technologies below.

Figure N - 27: Geothermal Build Across Sensitivities in 2034

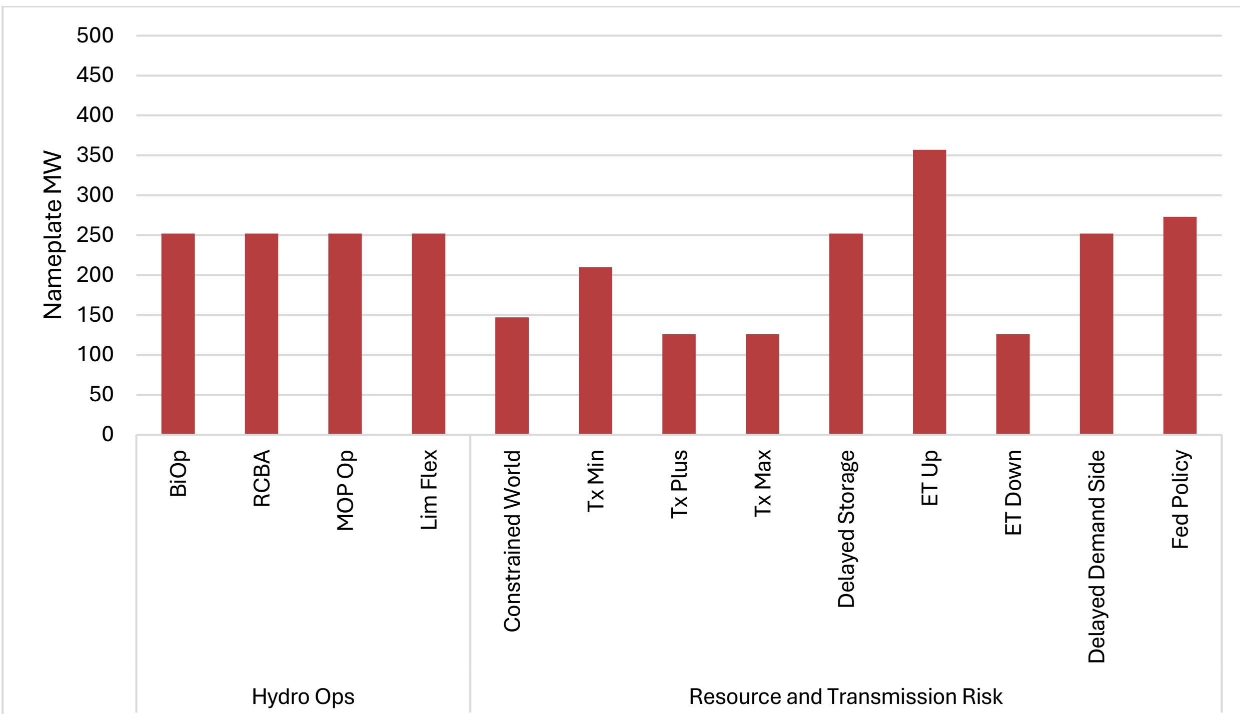


Figure N - 28: Geothermal Build Across Sensitivities by 2046

Emerging Technology Resource Themes

The Ninth Plan modeled three different emerging technology reference proxy plants to provide insight around what potential resource attributes will provide value to the system in the long term. This includes:

- Clean Long Duration Storage Proxy: Helps the grid better integrate variable resources, provides operational flexibility, and offers demand shifting on a seasonal scale. Represented by an iron-air battery.
- Clean Peaker and Medium Duration Storage Proxy: Mitigates high peak demand, while extending operational flexibility and shorter term, daily/hourly demand shifting. Represented by a hydrogen peaker plant with on-site production and storage.
- Clean Baseload Proxy: Offers reliability and firm supply to the grid. Represented by a small modular nuclear reactor.

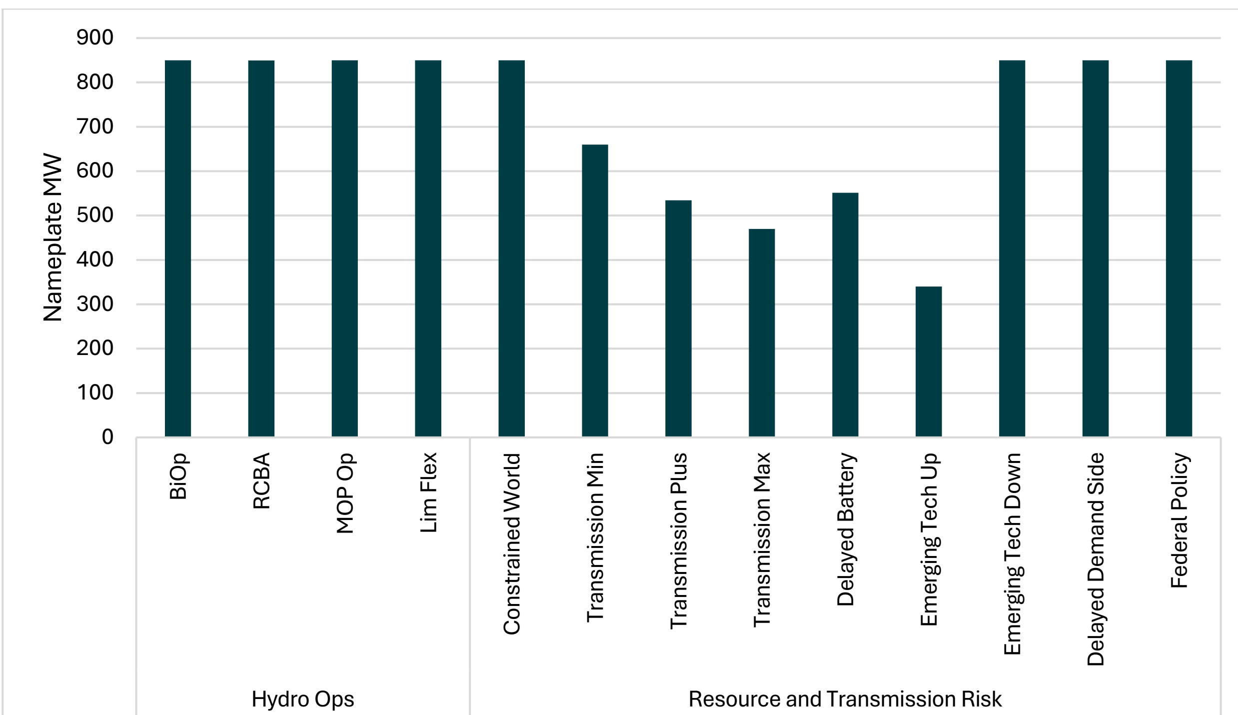
All of these resources were selected by the model, with the storage resources being selected in all sensitivities in which they were available, and the clean baseload proxy being selected in roughly 60% of the sensitivities. This section provides more information about the modeling results of these resources.

Clean Long-Duration Energy Storage Proxy

Clean long-duration energy storage was available to the model starting in 2032 for all sensitivities, except for the Constrained Resource and Transmission Risk sensitivity when the availability timeline was pushed out 10 years to 2042. This resource was selected in all sensitivities by the end of the study. The model selected this resource as soon as it was available in all sensitivities, except for the Emerging Technology Costs Up sensitivity, in which the costs were increased by 50%.

The maximum buildout allowed for this resource in the modeling was 850 MW. Most sensitivities hit this build limit (see Figure N - 29). These highest build sensitivities include those where there was either generally larger amounts of renewables and/or less natural gas. The Hydro Operations sensitivities and Changing Federal Policy sensitivity assume tax credits for renewable resources and as a result these sensitivities generally build larger amounts of renewables and less natural gas. In those cases, a resource that provides long-duration storage brings value by supporting integration and seasonal shifting. The other sensitivities where more long-duration storage is acquired are those that have constraints in other resources (either all supply-side through the Constrained Resource and Transmission Risk or on the demand side with the Delayed Demand Side) or in the sensitivity when the costs all emerging technologies are decreased by 25%.

Figure N - 29: Long-Duration Storage Build by 2046

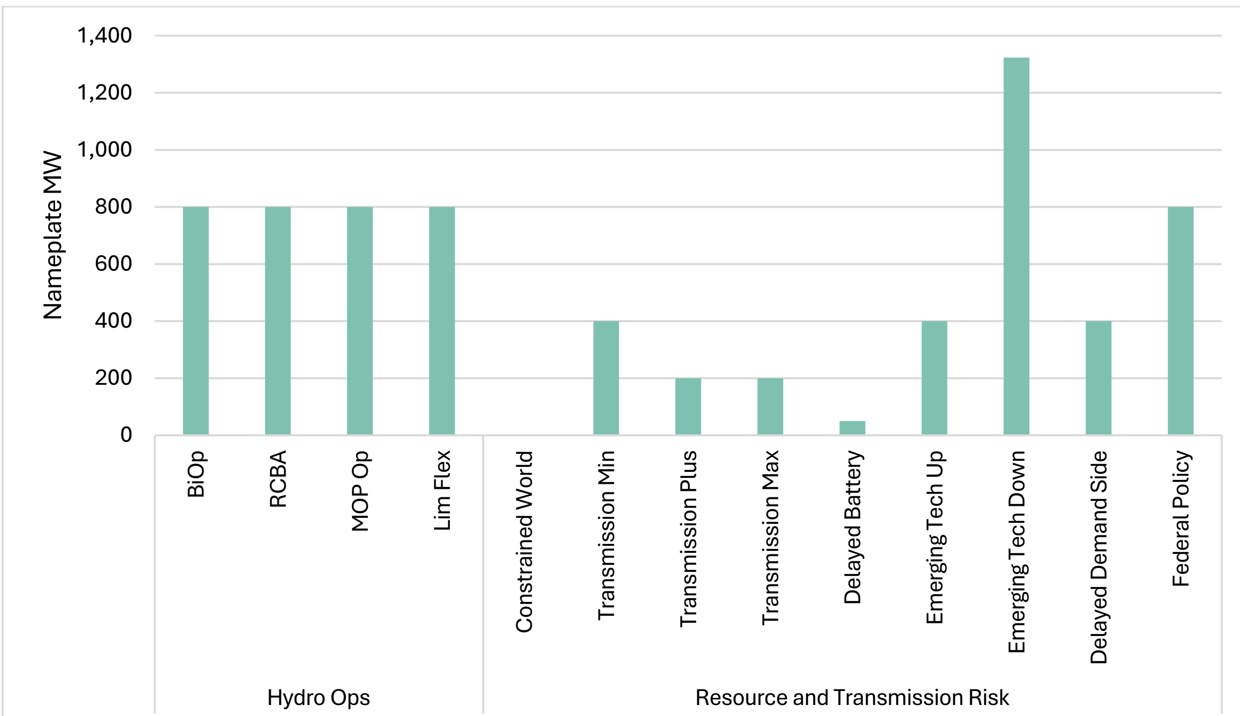


Clean Medium-Duration Energy Storage/Peaker Proxy

The clean medium-duration storage/peaker proxy reference plant was first available to the model in 2042, except for in the Constrained Resource and Transmission Risk sensitivity when all emerging technologies were delayed by 10 years resulting in this reference plant not being available within the plan timeframe. This resource was generally selected in the first year it was available to the model and selected in all sensitivities for which it was an option by 2046.

Similar to the long-duration energy storage, the model selected more of this proxy reference plant in sensitivities that generally had higher renewable builds and lower natural gas builds driven by differences in federal policy (the Changing Hydro Operations sensitivities and the Changing Federal Policy sensitivity). The model also selected significantly more in the sensitivity that decreased the emerging technology costs by 25%. Given the overlap in results between this and the clean long-duration storage proxy resource described above, it is possible that if a higher limit (or no limit) were placed on the clean long-duration storage resource, less medium duration storage would have been acquired.

Figure N - 30: Clean Medium Duration Storage Build by 2046

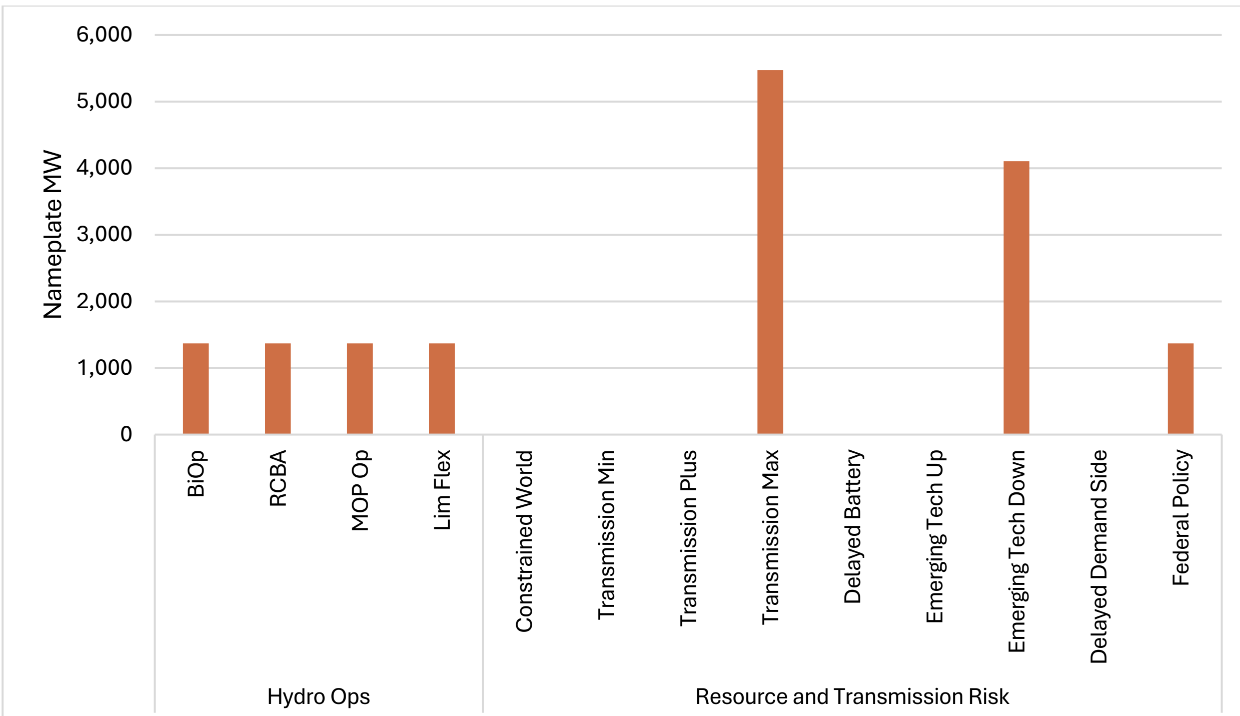


Clean Baseload Proxy

The clean baseload proxy reference plant was available to the model starting in 2042 in all sensitivities, except the Constrained Resource and Transmission Risk sensitivity in which the resource was not available within the study horizon. Unlike the other emerging technology proxy resources described above, the model did not select the clean baseload proxy in any sensitivity when it was first available (in 2042). The resource was, however, selected in seven of the sensitivities in 2046, always in Washington.

The results for the clean baseload proxy show similar themes to the other emerging technologies (see Figure N - 31). This resource is selected in the five sensitivities that have tax credits for renewables, resulting in both an increase in renewable builds and a decrease in total natural gas builds. In these cases, this resource provides additional baseload energy to the system. Consistent with all three emerging technologies, the model also selects more of this resource in the sensitivity when the costs come down by 25% (Emerging Technology Costs Down). In a departure from the other emerging tech results, the sensitivity with the largest build of the clean baseload proxy is the Transmission Max sensitivity. In this sensitivity, the west-wide market study had a larger overall build in the Pacific Northwest. When those resources were removed for the final stage of modeling in OptGen, there was a bigger hole in the west-wide need for meeting adequacy and clean policies. This resulted in a very different regional buildout, with the lowest natural gas build (3,000 MW by 2046), and a shift in the wind/solar build balance with the lowest wind build and highest solar build.

Figure N - 31: Clean Baseload Build in 2046



Remaining Resource Themes

As noted above, only three resources were not selected in a robust way across the sensitivity analysis. This section provides more on those findings.

Offshore Wind

Offshore wind was available to the model starting in 2035. The total potential for this resource in the region is 3,000 MW. This is informed by the lease area descriptive statistics for the two identified zones off the Oregon coast. Of the 3,000 MW potential, only 235 MW of this resource was selected by the model in 2046 in the Transmission Max sensitivity. As discussed above, this sensitivity required significantly more clean resources to be developed in the region to meet adequacy and clean policies. Under this condition, offshore wind became a viable resource to add to the mix.

Pumped Storage

Pumped storage was available to the model starting in 2029. The Ninth Plan estimate of potential for the region was 4,000 MW. Of this potential, the model selected only one reference plant, at 400 MW, in 2034 in the Constrained Resource and Transmission Risk sensitivity. In this sensitivity, the two clean emerging technology proxy resources were delayed 10 years, which resulted in long-duration energy storage not being available until 2042 and medium-duration energy storage not available in the study. In this case, when that resource was not available, the model deferred to pumped storage as a longer duration storage resource.

Rooftop Solar

The Ninth Plan is the first to model rooftop solar as a resource option.[16] The goal was to understand whether, and under what circumstances, this resource would be part of a cost-effective resource strategy for the region. Rooftop solar was selected in only one sensitivity, the Constrained Resource and Transmission Risk sensitivity. This sensitivity significantly limited the availability of supply side resources and increased the costs of those resources. Under these constraints, the model selected more demand side resources of all types to support resource adequacy. This includes acquiring all available conservation, selecting all of the frequently deployable demand response, and selecting rooftop solar. This result suggests that rooftop solar can be a cost-effective way of supporting resource adequacy if there are challenges in acquiring supply side resources. It also suggests that, when available, supply side resources are a lower cost option for meeting power system needs.

Market Price Results

Themes

Market prices on an annual and seasonal basis tend to follow a few themes that are discussed in more detail in Technical Appendix L – Wholesale Market Availability Results. Annual average wholesale market prices over all the sensitivities slightly increase in the middle and western parts of the region and slightly decrease in the eastern part of the region as seen in Figure N - 32.[17] These trends track with out-of-region prices, the prices nearer the load centers on the west coast slightly increase and prices near more of the development of high capacity factor renewable generation with lower loads in the interior of the WECC slightly decrease.

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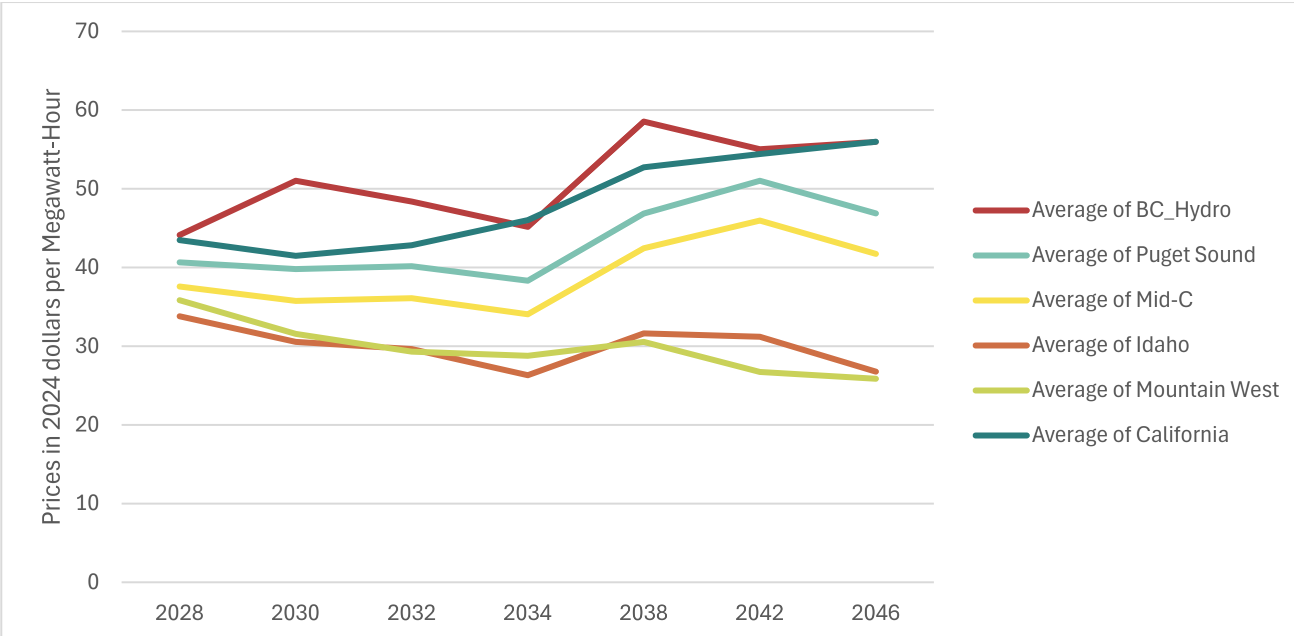
[16] Previous power plans accounted for rooftop solar in the load forecast. As discussed in Technical Appendix E and Technical Appendix J, for the Ninth Plan some rooftop solar naturally occurring is captured in the load forecast, with the remainder captured in the supply curves as potential.

[17] Associated with OptGen regional buildouts and production cost simulation for the WECC rather than AURORA prices as reported in Technical Appendix L.

Figure N - 32: Annual Wholesale Prices Over Time



The price of market imports and the value of market exports, in addition to the cost of meeting regional demand, is a key piece in the economics of an investment strategy. Often comparing regional to neighboring region prices can be useful to see some of the key economic signals that drive market imports and exports without examining the load resource balance in both regions. Seasonal price differentials between the region and neighboring regions for the most part maintained recent historical trends throughout the sensitivities with a few exceptions.

In all sensitivities, annual regional prices depend on future conditions. Low hydro runoff conditions and high loads resulted in high prices, and high runoff conditions and low loads resulted in low prices as can be seen in Figure N - 33 through Figure N - 38. The different sensitivities seem to slightly change dependency on future conditions primarily when Emerging Technology Costs are increased and the west-wide market conditions depend more on the buildout in the region.

For Mid-Columbia and Puget Sound prices, this spread increases over time as can be seen by the difference between 2032 prices in Figure N - 33 and Figure N - 37 and 2046 prices in Figure N - 34 and Figure N - 38, respectively. This shows that for the westside and center parts of the region, prices vary more due to fuel and demand risk which is represented in the future conditions tested.

However, the Idaho price spread does not change much, as can be seen in by the difference between 2032 prices in Figure N - 35 and 2046 prices in Figure N - 36. Additionally, the smaller price spread in Idaho implies eastside prices are less dependent on the future condition likely due to more fuel diversity of supply resources.

Figure N - 33: Mid-Columbia Prices in 2032 by Future and Sensitivity

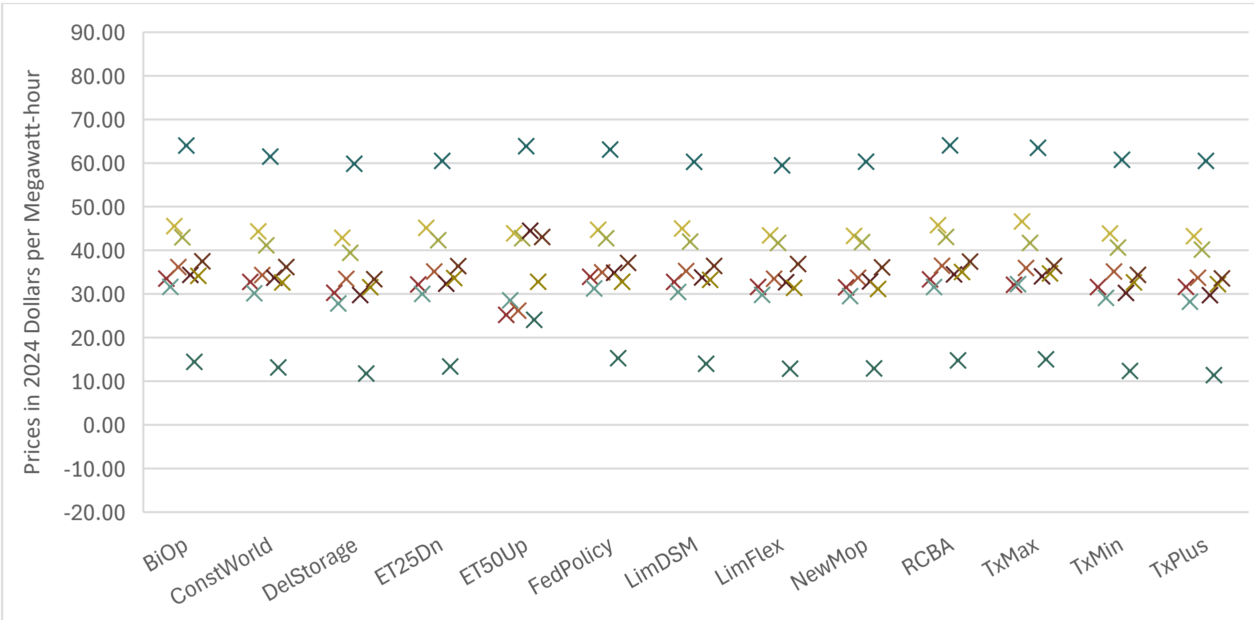


Figure N - 34: Mid-Columbia Prices in 2046 by Future and Sensitivity

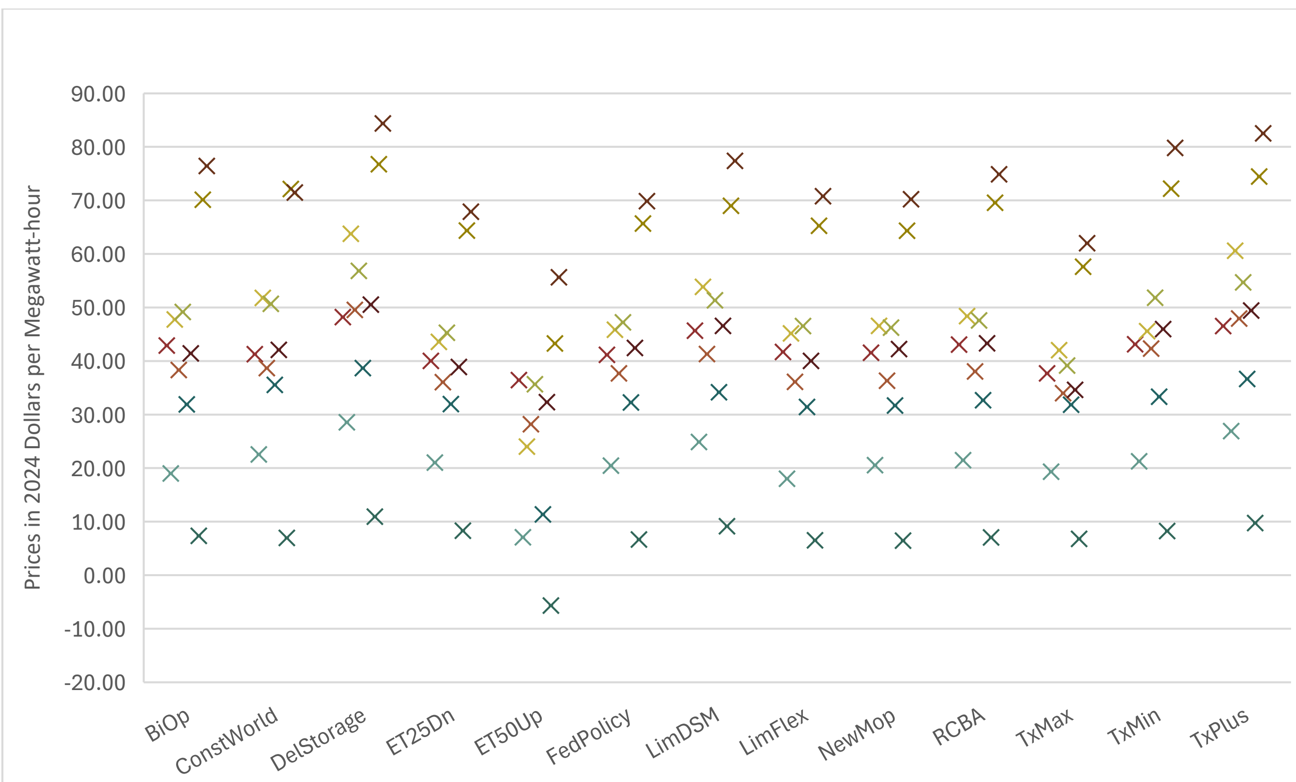


Figure N - 35: Idaho Prices in 2032 by Future and Sensitivity

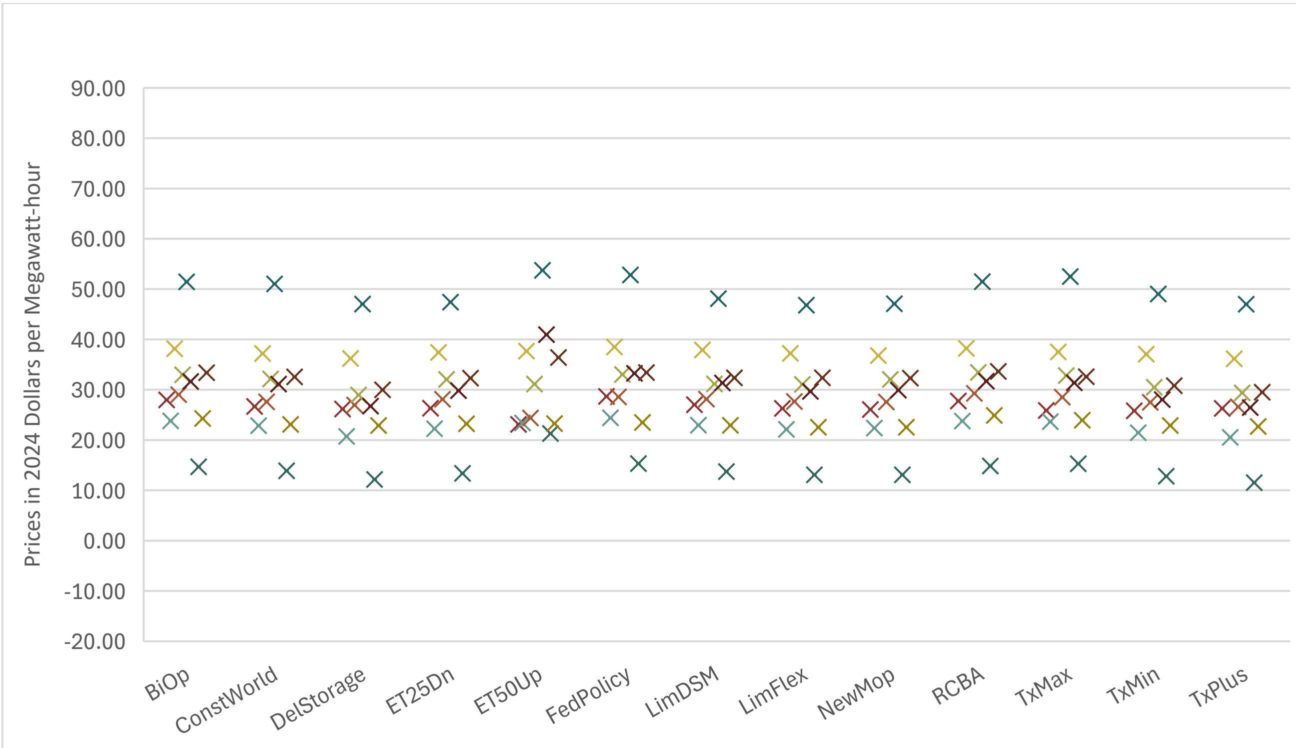


Figure N - 36: Idaho Prices in 2046 by Future and Sensitivity

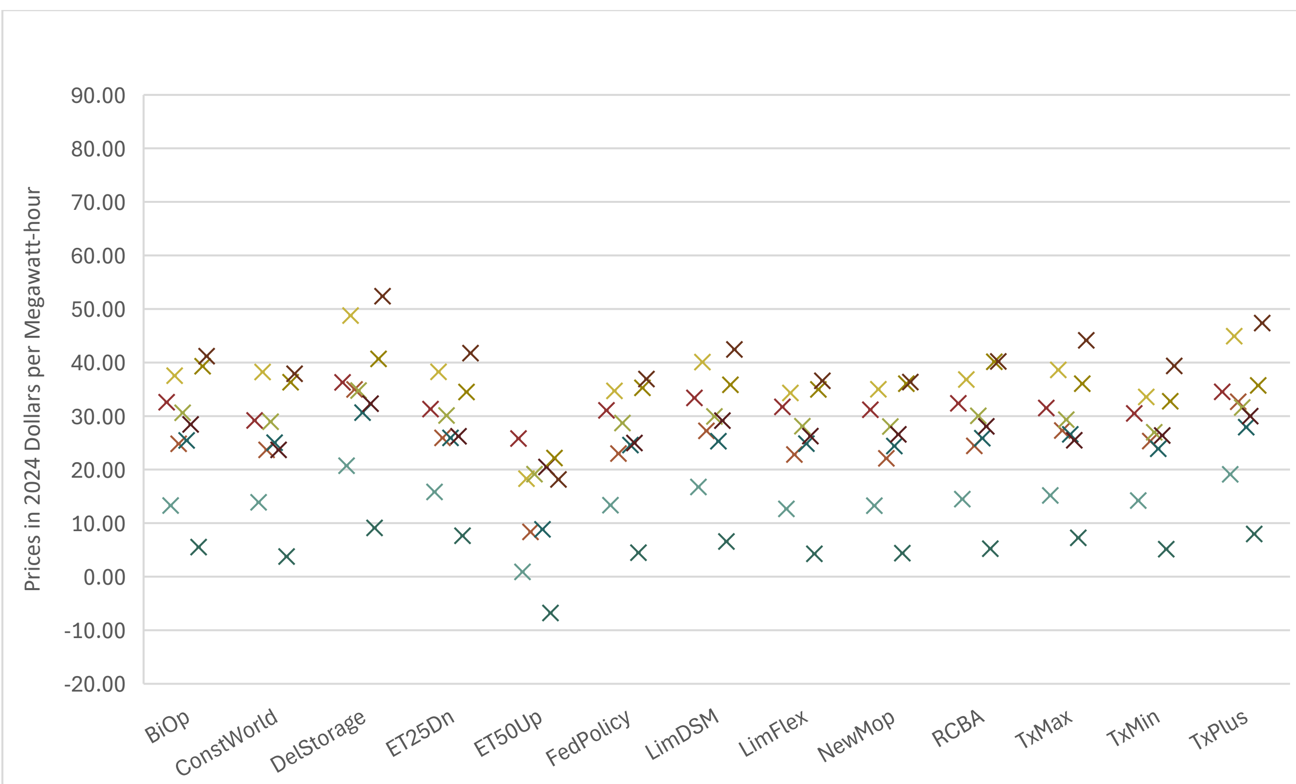


Figure N - 37: Puget Sound Prices in 2032 by Future and Sensitivity

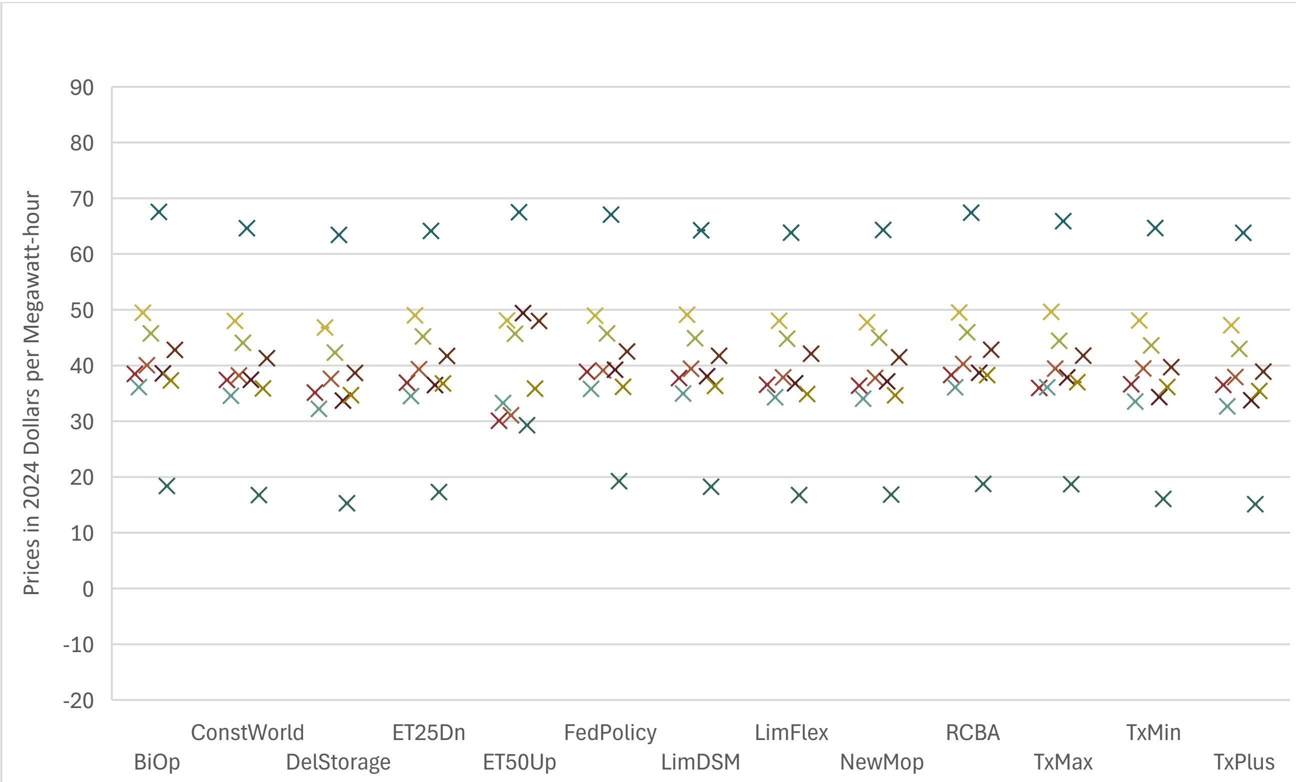
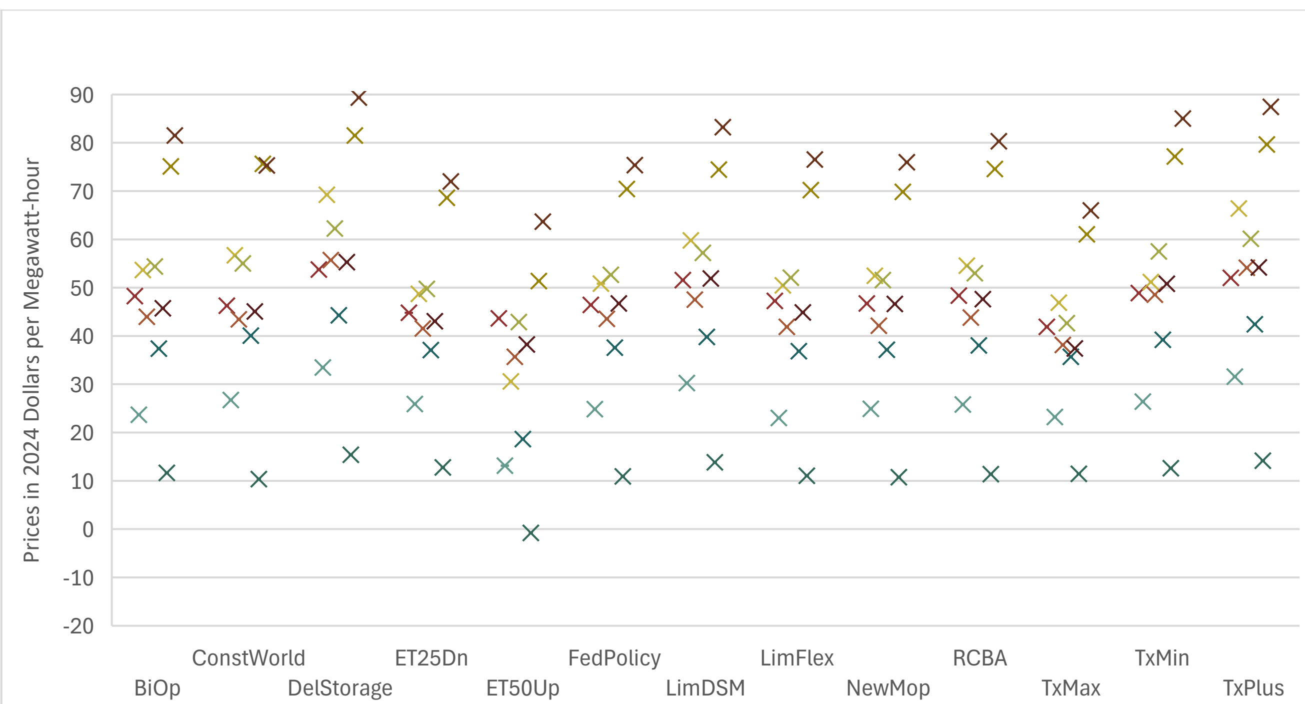


Figure N - 38: Puget Sound Area Prices in 2046 by Future and Sensitivity



Outside of the Mountain West and Idaho, winter prices increased over time, particularly the lower midday prices as can be seen in Figure N - 39 and Figure N - 40. This implies that some of the market value in the middle of the day due to solar builds outside the region tends to lessen over time. More specifically, the value to the region of importing less expensive power midday decreases, which likely improves the value of resources that provide power during that period in the latter years of the plan.

Figure N - 39: Winter Prices in 2032

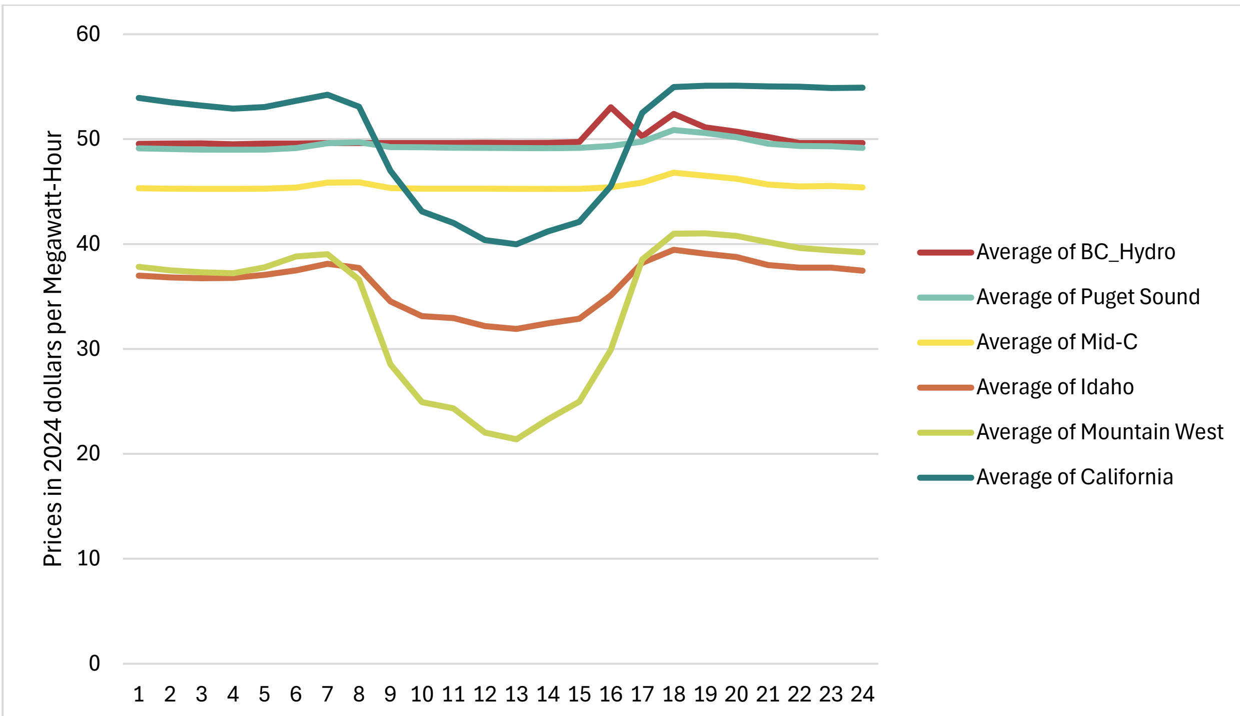


Figure N - 40: Winter Prices in 2046

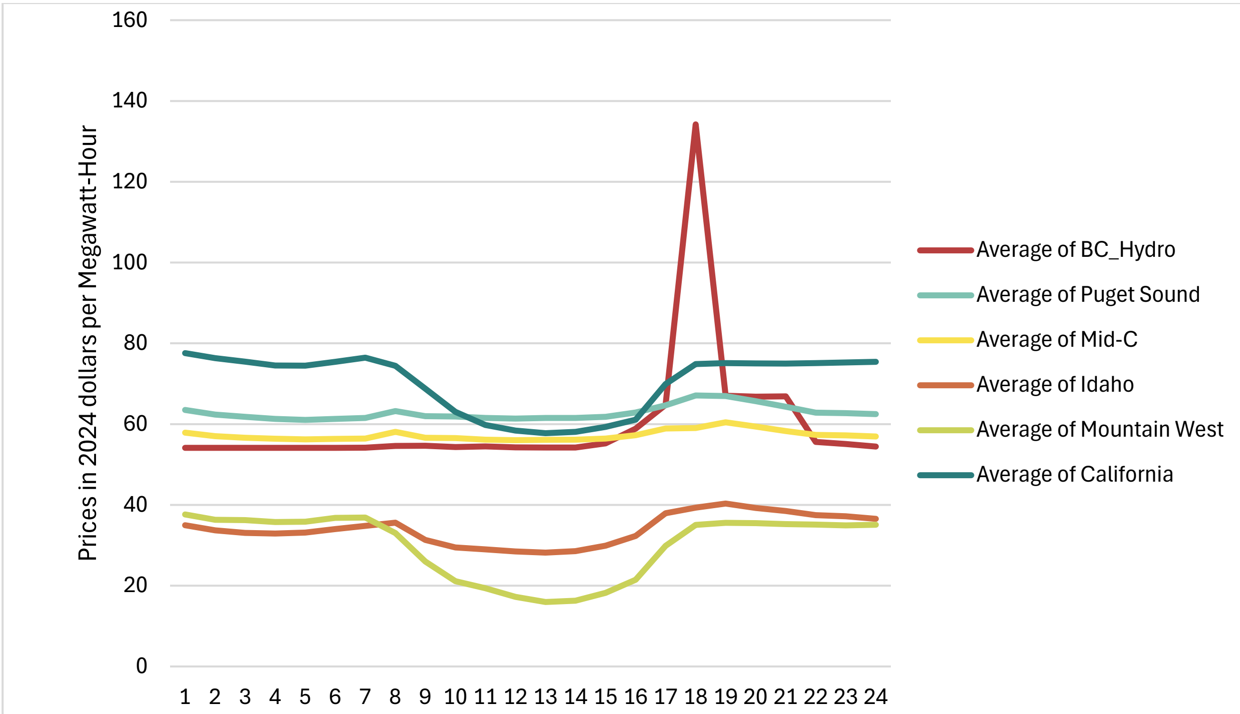


Figure N - 41: Summer Prices in 2032

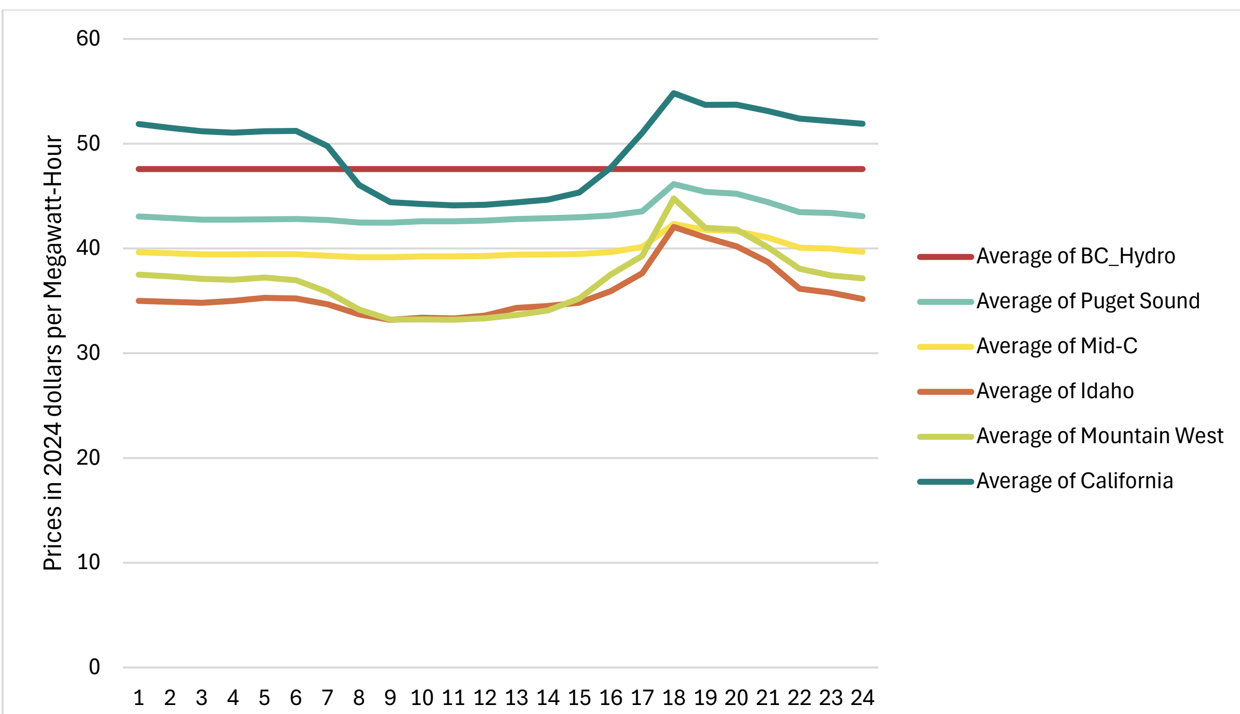
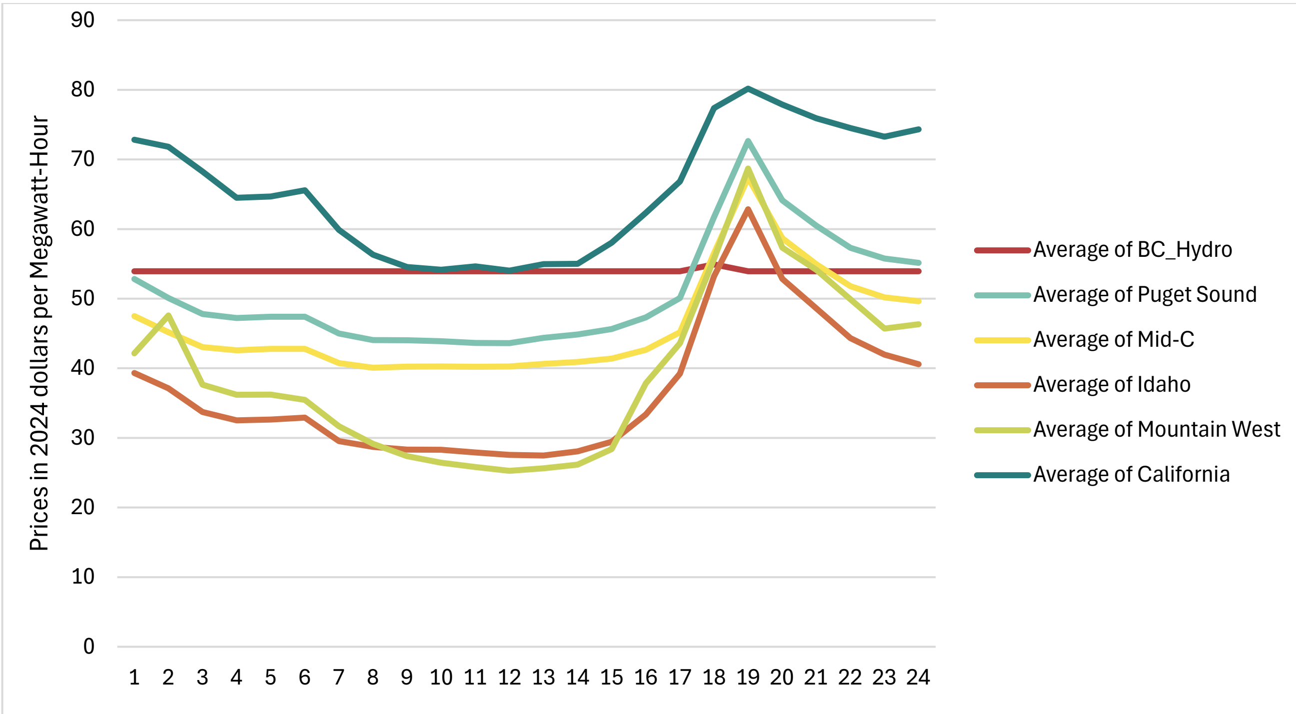


Figure N - 42: Summer Prices in 2046



Summer peak prices in the evening ramp go up everywhere over time. Since the WECC is summer peaking in general this is to be expected, but interestingly some parts of the region that were traditionally winter peaking are now seeing similar peak prices in winter and summer on average.

Figure N - 43: Spring Prices in 2032

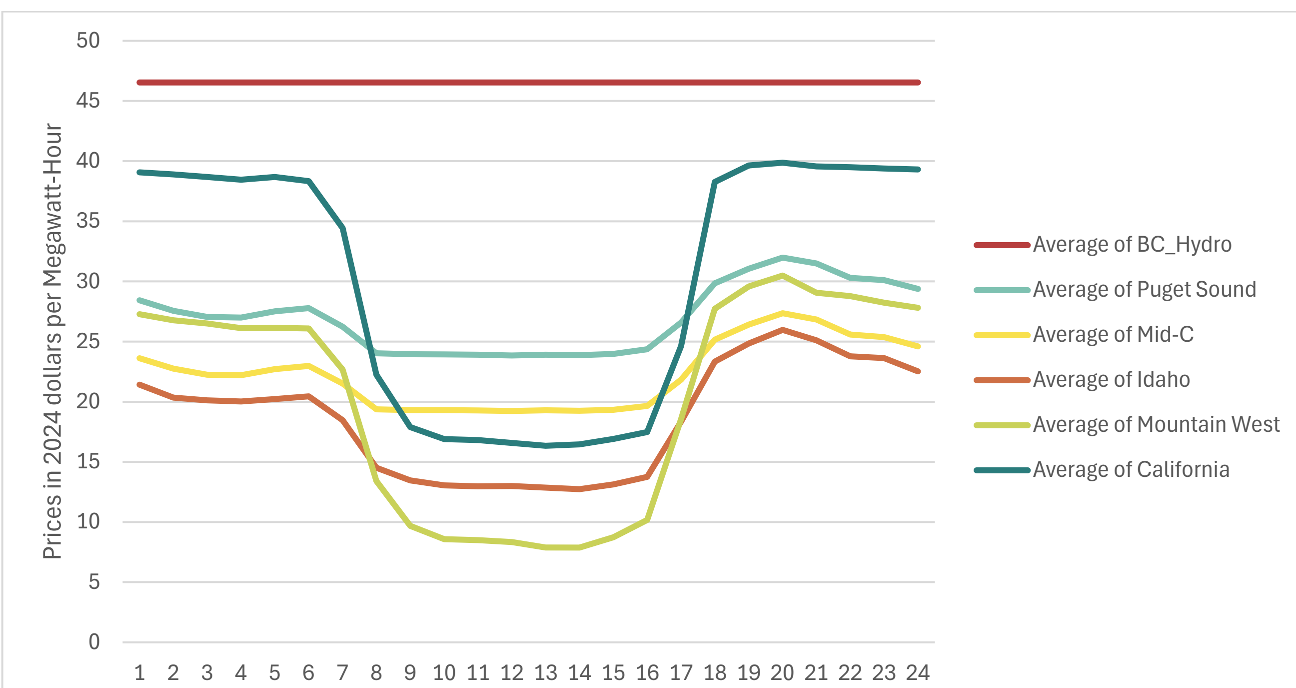
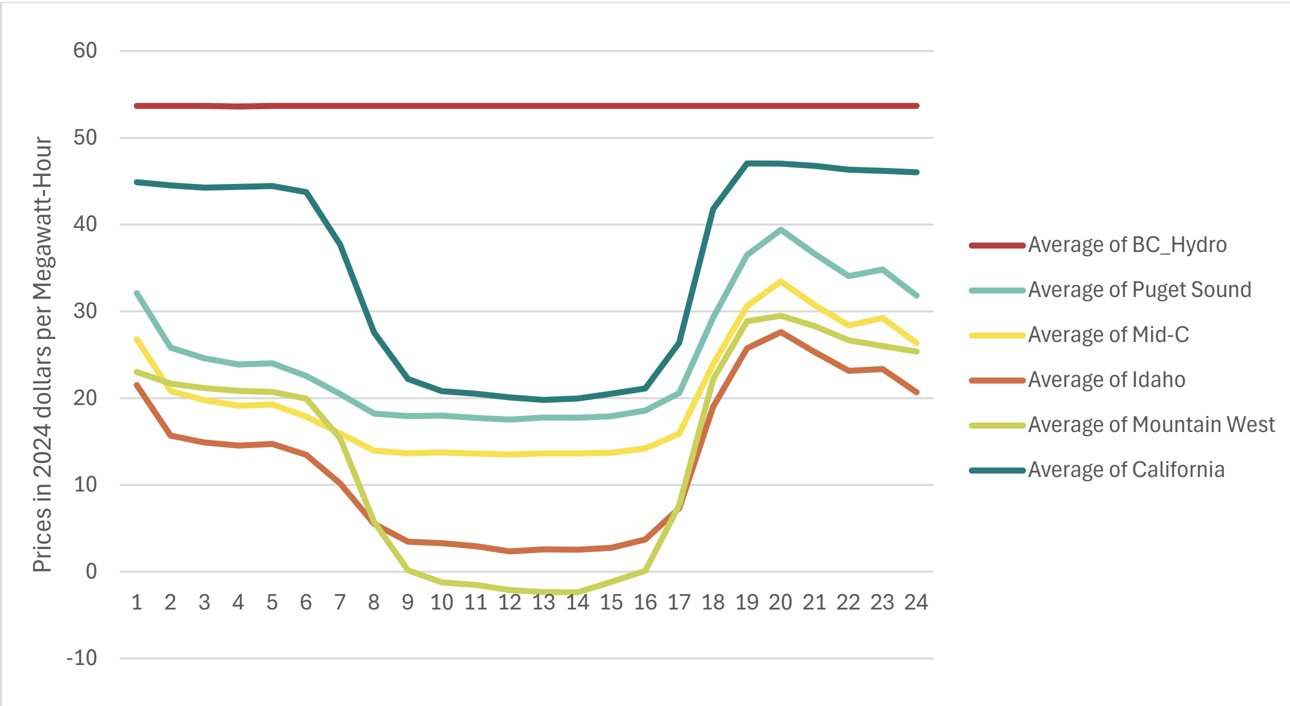


Figure N - 44: Spring Prices in 2046



Spring prices morning and midday go down over time except for Canada and California. During non-evening and nighttime hours prices go slightly up as seen in Figure N - 43 and Figure N - 44. These lower prices make market imports more attractive than most new resources in the spring.

Market prices on the eastside of the region and in the Mountain West are generally lower than the westside of the region and trading partners like California and BC. While prices increase over time, they get lower midday, especially in the spring. New resources that are available during the evening and to a lesser extent the early morning can get more value in deferring market purchases.

Emissions

The Pacific Northwest regional emissions are not direct outputs from the scenario modeling for the Regional Resource Optimization through OptGen/SDDP, as it models the broader WECC. However, they can be estimated from direct outputs of various resource and market utilization results.

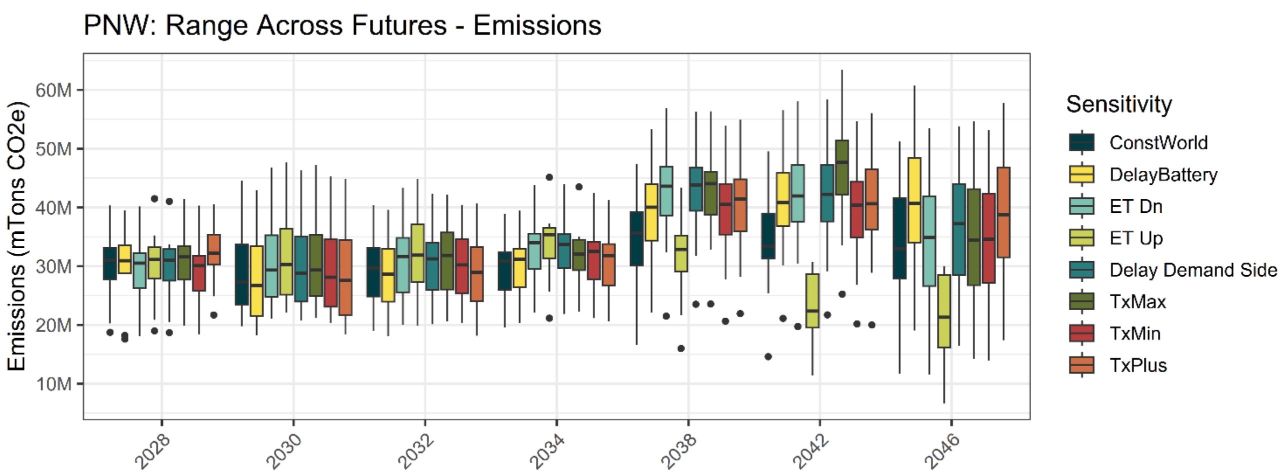
To estimate the emissions for the Pacific Northwest, Council staff aggregated the emissions associated with in-region thermal generation and the emissions associated with net market imports.[18]

[18] To account for 'pass-through' energy or energy transmitted through the Pacific Northwest region but serving load in the broader WECC or Canada, Staff chose to count net imports towards the emissions accounting. Additionally, not all market imports are assumed to be emitting resources. Rather net imports are weighted in alignment with carbon pricing assumptions for the percentage of emitting resources to total generating resources. This aligns our post-modeling

In-region thermal generation emissions are the sum of each thermal plant's generation multiplied by that plant's specific heat rate multiplied by the respective emissions factors for that plant's primary fuel type. The emissions associated with market imports are the net imports to serve PNW load multiplied by the percentage assumption of generation that is emitting multiplied by the heat rate for a combined cycle natural gas plant multiplied by the emissions factor assumption for natural gas. [19] For a more in-depth explanation on the Council's environmental and emissions-related assumptions please refer to both Technical Appendix B – Existing System Parameters and Policies and Technical Appendix C - Methodology for Quantifiable Environmental Costs and Benefits.

Council staff estimated total emissions across both scenarios and all respective sensitivities discussed above. Figure N - 45 shows the distribution of emissions across 10 futures for each of the New Resource and Transmission sensitivities for years modeled in the forecast. Similarly, Figure N - 46 shows the same for the Changing Hydro Operations sensitivities.

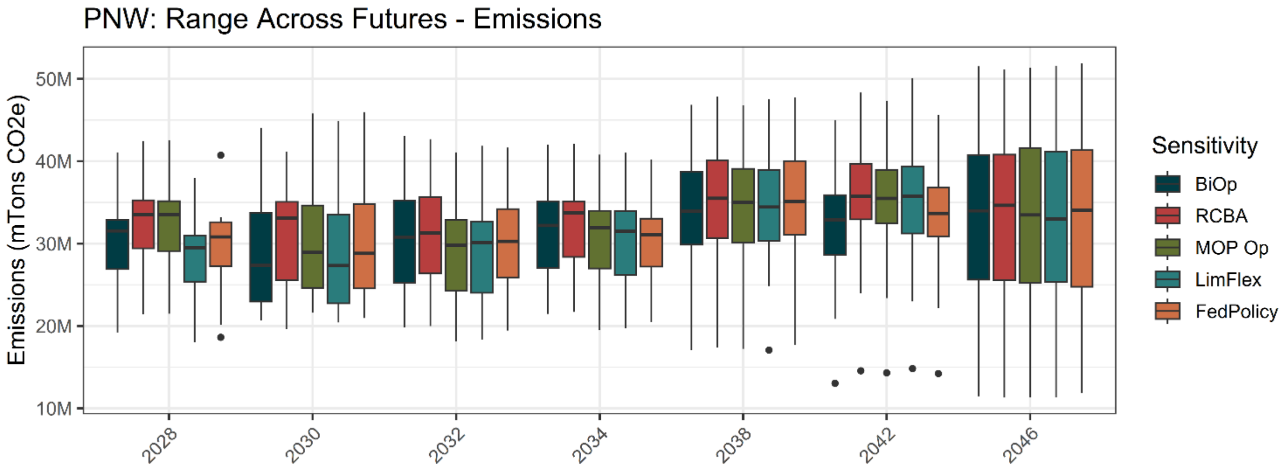
Figure N - 45: Northwest Emissions, Resource and Transmission Risk Sensitivities



emissions accounting with our pre-modeling carbon pricing assumption inputs into OptGen/SDDP. Lastly, net imports do account for line losses to ensure fair comparison with in-region generation.

[19] To calculate the emissions associated with market imports, Council had to impose an assumption on what the marginal emitting generation resource would be and conservatively selected a combined cycle natural gas plant.

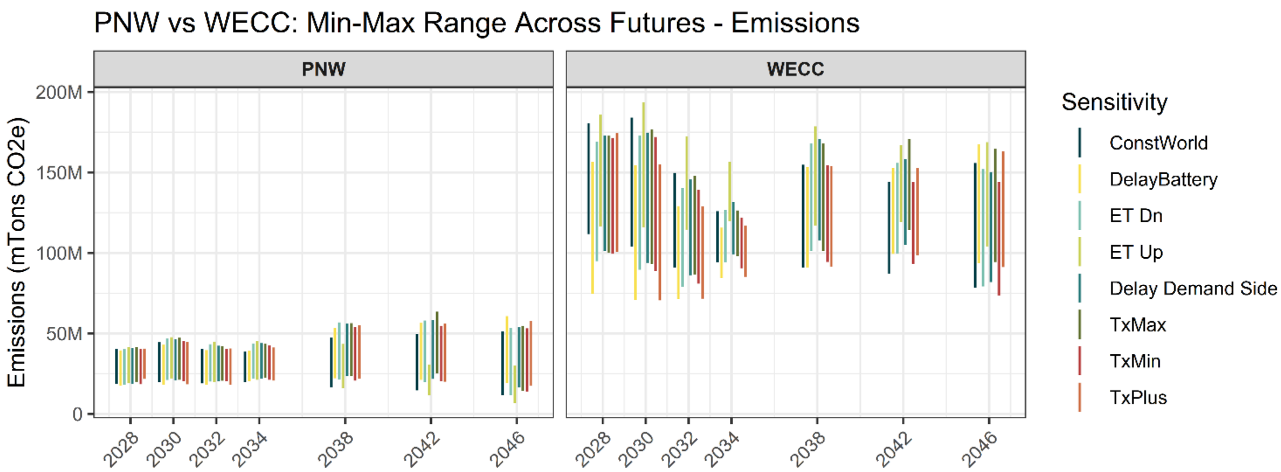
Figure N - 46: Northwest Emissions, Changing Hydro Operations Sensitivities



As can be seen in both plots, the Pacific Northwest emissions are sensitive to the demand pathway, hydro availability, and gas price future the model sees. This is driven largely by how in-region thermal plants are utilized (for generation vs reserves) and market reliance to meet in-region demand giving them wide-ranging distributions which grow in the outer forecast years as the demand distribution (difference in the Low Growth pathway to the High Growth pathway) widens.

Additionally, differences across the sensitivities begin to increase more in the outer years as the resource acquisition paths diverge. The clearest example of this is in the New Resource and Transmission sensitivity where emerging tech costs are assumed to increase (ET Up). In the market availability study for this sensitivity the market buildout was larger in the Pacific Northwest resulting in significantly more renewables and fewer natural gas plants within the region. This in turn lowered the median in-region emissions respective to other sensitivities in the outer years of the forecast range. However, Figure N - 47 highlights the complexity of the interplay between geographical boundaries and global emissions. While the large renewable build within the Pacific Northwest helps meet in-region and WECC-wide policy goals and significantly reduces in-region emissions, it does not change the broader WECC emissions similarly, relative to other sensitivities.

Figure N - 47: Northwest and West-Wide Emissions



In general, all three (Figure N - 45 to Figure N - 47) tell a similar emissions story: emissions are sensitive to the unique combination of demand, hydro availability, and gas prices which directly affect the in-region thermal utilization (both new and existing) and market reliance within the region. Lastly, despite significant load growth across all load pathways, the emissions in the Pacific Northwest and WECC-wide remain relatively flat throughout the forecast period. [20]

For further discussion on greenhouse gas emissions from generation and for historical context please refer to Technical Appendix B – Existing System Parameters and Policies.

Additional Sensitivities

Data Center Sensitivity

Following discussion of initial results at the April 2026 Council meeting, Council members asked staff to run additional analysis to provide context on what resources are being selected to support data center loads. Staff conducted two studies that approach the question from different angles.

The first adjusted the planning reserve margin to account for loads based on some of the lower trajectories. This approach tests what the region would build if some new data centers and chip fabrications were responsible for their own resource adequacy. The load growth from this sector stays in the model, but the adequacy reserve margins are reduced.

The second approach tests what the region would build if tech loads did not show up as forecasted. In this approach, staff removed the load trajectories with the highest forecasted data center growth from

[20] For discussion on the 5 load pathways and load growth over the forecast period, see Technical Appendix F – Electricity Demand Forecast.

the range of futures (this removes the high and early growth pathways). In addition to lowering loads, this approach changes the general supply and demand economics in the model.

Table N - 10 summarizes the overall buildout by 2032 for these two studies as compared to the Transmission Plus sensitivity (used here as a baseline). The largest differences are seen in storage resources, with decreased acquisitions of hybrid renewable and stand-alone storage. Note that while stand-alone renewables increase in sensitivity 2, the increase is offset by the decline in hybrid renewables.

Table N - 10: Data Center Sensitivities

Resource	Transmission Plus	1 – Less DC Adequacy	2 – Less DC Load
Conservation (aMW)	678	555	626
Demand Response (MW)	228	228	224
Voltage Regulation (MW)	222	222	222
Natural Gas (MW)	2,917	2,917	2,850
Wind and Solar (MW)	5,314	5,202	6,780
Hybrid (MW)	2,158	1,110	17
Storage (MW)	2,245	806	0
Long Duration Storage (MW)	20	0	0

Hydrogen and Centralia Modeling Correction

After running the initial full sets of modeling runs, Council staff found two notable errors in the capital expansion model (OptGen).

1) Only the low growth trajectory for hydrogen/industrial decarbonization load was used in the modeling. This was due to a software issue that caused the model to only use data from the low forecast pathway. The impact on the model was largely economic, since hydrogen load is elastic (curtailable at high power prices), and many model build decisions are driven by adequacy and policy needs. Hydrogen loads were modeled correctly in other elements of the Power Plan (including the resource adequacy check).
2) The coal unit Centralia 2 was left active in OptGen throughout the modeling runs, as well as also being modeled as a coal-to-gas conversion. The error likely occurred when staff were trying different approaches to modeling the coal-to-gas conversion at Centralia 2. While available for economic dispatch, the inclusion of the unit does not impact resource adequacy

since it was modeled correctly (removed) in the needs assessment. It was also modeled as a single unit in the market availability study (the coal-to-gas conversion was also not included in the market availability study, given the information available at the time). As a result, like the hydrogen error, this issue was largely economic.

To test the impact of these errors Council staff ran three modeling sensitivities, using Transmission Plus as the baseline for comparison. The results are shown in Table N - 11. Based on the similarity of these results, and discussion with the System Analysis Advisory Committee, Council staff concluded that there was not a need to further re-run the model, and that the original modeling results were sufficient for providing information to the Council for Ninth Plan resource selection.

Table N - 11: Model Correction Runs, Year 2032

Resource	Transmission Plus	1 – Centralia 2 corrected	2 – Hydrogen corrected	3- Both corrected
Conservation (aMW)	678	672	663	663
Demand Response (MW)	228	223	224	224
Voltage Regulation (MW)	222	222	222	222
Natural Gas (MW)	2,917	2,917	3,017	2,917
Wind and Solar (MW)	5,314	5,510	5,317	5,521
Hybrid (MW)	2,158	2,050	2,050	2,050
Storage (MW)	2,245	2,245	2,245	2,245
Long Duration store. (MW)	20	13	0	32

Adequacy Check of Proposed Resource Strategy

The process to develop the resource strategy requires a combination of understanding the buildouts to meet each tested sensitivity and inferring what strategy would satisfy future uncertainties while accounting for considerations and feedback from stakeholders. Once a strategy is developed, it needs to be tested in GENESYS, the Council's resource adequacy model, to determine if the adequacy criteria are all met. Testing the resource strategy is generally a similar process to conducting a needs assessment as described in Technical Appendix M – Needs Assessment Results, but with three main differences. First, the resource strategy is incorporated into the model, unlike the needs assessment that only includes the existing system and therefore evaluating a gap (resource need) in a future year. Second, while the needs assessment was conducted on the high load growth trajectory, the adequacy check considers all load trajectories. Third, the adequacy check only asks whether the region is adequate in 2031 with the resource strategy and is not looking at planning reserve margins and firm energy requirements. If the adequacy criteria is satisfied – meaning all metrics are within their thresholds – then the resource strategy is deemed adequate.

Methodology for Checking Strategy Adequacy

The adequacy check considers all load trajectories, which is an important feature of ensuring adequacy. Typically, as is the case with the needs assessment studies or adequacy assessments, a study that represents a buildout (whether just the existing system or the existing system plus additional resources) and load trajectory is evaluated as a standalone case with its own adequacy results. However, as a resource strategy in a power plan must be robust to account for future uncertainties, including load trajectories, a different nuance is necessary.

Instead of evaluating adequacy under each load trajectory future, the adequacy results of all load trajectories are combined, and the adequacy criteria are evaluated based on the full probabilistic range of uncertainties. This is significant – the question is no longer “is the region adequate in 2031 with the resource strategy under a specific load trajectory?” but rather “is the region adequate in 2031 under the range of load uncertainty?” The quantitative meaning of this philosophical difference can be seen in Table N - 12 shows how the adequacy metric calculations are influenced when adequacy is determined as part of a full distribution of five load trajectories, where calculations are no longer based on 90 years per study, but rather out of 450 years (90 for each load trajectory).

Table N - 12: Changes to Metric Calculations When Considering Full Distribution

Metric & Threshold	0.2	0.1	0.1	8 Hour	1,200 MW	9,600 MWh
	Annual LOLEV	Winter LOLEV	Summer LOLEV	Duration VaR	Peak VaR	Energy VaR
Standalone Study (one load trajectory)	no more than 18 events	no more than 9 events	no more than 9 events	out of 90 simulations		
Full Distribution (five load trajectories)	no more than 90 events	no more than 45 events	no more than 45 events	out of 450 simulations		

Though adequacy is considered on the full distribution of results, each trajectory is simulated independently in GENESYS. Then, all the shortfall records from each study (90 years) are combined into an aggregate 450-year shortfall record. The adequacy metrics are then calculated based on the full distribution of results. If all metrics are satisfied, the strategy is adequate.

Technical Appendix M includes important reminders about the existing system and data assumptions in GENESYS. One emphasis here is the role of market reliance, where the region hedges against over-relying on out-of-region market imports in winter and summer. The Council’s market reliance limit is 2,500 MW in winter and 1,250 MW in summer, which was developed with the Resource Adequacy Advisory Committee many years ago. Future work will be conducted on re-evaluating these limits and how new limits would influence the Council’s multi-metric adequacy criteria thresholds.

Lastly, as described in Technical Appendix M, sometimes GENESYS computation reaches an infeasibility, and no value is recorded until the computation reaches another stage or seam where it can reach a solution. Staff developed a methodology to replicate any missing values based on previous days, but it is also possible that an infeasibility occurs during a shortfall. Staff developed another methodology to identify whether these shortfall-infeasibility situations are a model artifact associated with the infeasibility and not "real simulated shortfalls." For a shortfall to be considered an infeasibility artifact it must: (1) experience an infeasibility after first hour, i.e. the shortfall event doesn't end, but rather terminates "mid-event," (2) the thermal system behaves in an unexpected/unrealistic operation during the first hour of the event, such as a sharp drop or below minimum generation, and (3) the region is exporting during the deficit. If these conditions are present, then the shortfall is considered an infeasibility artifact and does not get included in the shortfall record.

The Tested Hydro Conditions

The adequacy check for the Ninth Power Plan includes two different hydro operation regimes: those described in the 2026 Columbia River Basin Fish and Wildlife Program, and those described in the preliminary injunction issued by the federal district court in Oregon in March 2026. The adequacy check will test the resource strategy under both regimes; each tested under the five load trajectories. For a complete list of operations under each regime, see the 2026 Fish and Wildlife Program[21] and the Amended Preliminary Injunction Order.[22]

The following sections are not meant to be detailed summaries, but rather highlight some high-level operations, and there's an important reminder that GENESYS cannot model adaptive management practices – i.e. are no dynamic changes to spill obligation that could occur due to fish count or temperature control, and the model operates given specific operational dates.

2026 Fish and Wildlife Program

The Council's 2026 Fish and Wildlife Program calls for a wide range of measures. As described in Technical Appendix M – Need Assessment Results, several hydro conditions were tested during the needs assessment to help inform the Program and Power Plan.[23] The various operations related to the spill and reservoir operation of the four Lower Snake projects (Lower Granite, Little Goose, Lower Monumental, and Ice Harbor) and the four Lower Columbia projects (McNary, John Day, the Dalles, and Bonneville).

The Program adopted spill measures based on the operations as defined in the 2023 Resilient Columbia Basin Agreement, but without a specific end date to the August performance spill. For spring, this means 24 hour 125% total dissolved gas (TDS) spill. For summer, since the 2026 Fish and Wildlife Program does not include a measure on summer spill, the Council assumed extended

[21] https://www.nwcouncil.org/fs/19912/2026-1.pdf.
[22] *National Wildlife Federation v. National Marine Fisheries Service*, Case No. 3:01-cv-640, Amended Preliminary Injunction Opinion and Order (D. Or. March 2, 2026) https://public.crohms.org/tmt/2674_Amended-PI-Order.pdf.
[23] See Technical Appendix M – Needs Assessment Results.

performance spill until August 31 at the associated Lower Snake and Lower Columbia projects, because this is a more conservative approach for testing power system adequacy.

In addition, the Council's Fish and Wildlife Program calls on operators to limit the flexibility (daily ramping) of the Lower Columbia and Lower Snake projects during the migration season of April-August to minimize the impact on migratory fish populations. [24] The reduced flexibility during this period is as described in the Resource and Transmission Risk scenario.

Preliminary Injunction

The operations described in the Preliminary Injunction (PI) focus on the Lower Columbia and Lower Snake projects. High-level, they call for spring spill of 24-hour 125% TDG and expended summer performance spill until August 31, including at John Day. These operations also call for some changes to winter and fall spill of continuous 24-hour surface weir spill instead of only 4 hours in the mornings in the March 1-20 and September 1-November 15 time frames. The injunction does not change pool elevation operations from the 2020 Biological Opinion, nor does it specifically call for limiting flexibility of the Lower Snake and Lower Columbia projects during the spring and summer.

Adequacy Check Results

The adequacy check of the 2026 Fish and Wildlife Program shows the region will be adequate in 2031 with the Ninth Plan resource strategy. Seen in Table N - 13, all adequacy metrics in the criteria are met when considering the full load trajectory distribution. While this is the main takeaway, Table N - 14 shows the adequacy metrics when considering the load trajectories separately. While the strategy is adequate on the full distribution, the high growth trajectory does exhibit metrics that are violated, suggesting that the resource strategy is not built just to meet adequacy under the highest loads.

Table N - 13: Adequacy Results of Full Trajectory Distribution

Metric	Frequency			Extreme Deficits		
	Annual LOLEV (events)	Winter LOLEV (events)	Summer LOLEV (events)	VaR Duration (hr)	VaR Peak (MW)	VaR Energy (MWh)
Study/Criteria	0.2	0.1	0.1	8	1,200	9,600
2026 F&W Program	0.068	0.053	0.006	1.8	582	1,452
Court Ordered PI	0.073	0.067	0.007	2.5	579	579

[24] See Technical Appendix M – Needs Assessment Results and 2026 Columbia Basin Fish and Wildlife Program.

Table N - 14: 2026 Fish and Wildlife Program Adequacy Results of Individual Trajectories

Metric	Frequency			Extreme Deficits		
	Annual LOLEV (events)	Winter LOLEV (events)	Summer LOLEV (events)	VaR Duration (hr)	VaR Peak (MW)	VaR Energy (MWh)
Study/Criteria	0.2	0.1	0.1	8	1,200	9,600
High Growth	0.233	0.2	0.02	7.5	2,835	11,312
Late Growth	0.067	0.067	0	0	0	0
Early Growth	0.022	0	0	0	0	0
Mixed Bag	0.011	0	0.01	0	0	0
Low Growth	0.011	0	0	0	0	0

When evaluating the adequacy metrics, it is important to keep in mind the significance of each metric and the interpretation of the value. For frequency metrics of LOLEV, a value of 0 means that no simulated events took place during the relevant period of the metric. For example, in the table above, the resource strategy resulted with no winter events under the Early Growth, Mixed Bag, and Low Growth load trajectories. This means that in 10 years, the resource strategy (in these load trajectories) would not expect to have a winter event. To find the number of simulated events under the standalone load trajectories, either annual or seasonal, each value can be multiplied by 90 (the number of simulation years by trajectory) and rounded up. For example, under the High Growth study, there were 21 total events with 18 in winter and 2 in summer (this annual and winter result violates the criteria).

Interpreting the extreme deficit VaR metrics is a little different. Here, the metric represents the 97.5th value of a distribution, either duration, peak magnitude or energy. Unlike 0 in the LOLEV metric that means no events occurred, a zero value for a VaR metric only means that the 97.5th percentile value is zero and it is possible that higher percentile values have non-zero deficits (as long as events occurred). In other words, as long as the annual LOLEV is non-zero, it means events occurred in at least one simulation. For example, the Mixed Bag trajectory only had one event (Annual LOLEV of 0.011* 90 simulation = 1) in the summer. Because only one simulation had an event, out of 90, it means that the 97.5th percentile of a distribution of 1 simulation with a deficit and 89 simulations without deficits, is zero. However, in the High Growth trajectory, the 97.5th percentile of Peak is 2,835 MW, which means that in 39 out of 40 years, the region would be expected to experience peak events up to 2,835 MW, exceeding the 1,200 MW threshold.

The adequacy check for the Court ordered Preliminary Injunction also shows the region will be adequate in 2031, as seen in Table N - 13 showing the results across the full range of load trajectories. One key difference between the two sets of operations is the amount of assumed flexibility in the system. As the Preliminary Injunction does not specifically limit daily ramping, the Council's GENESYS model sees potential to ramp the existing system during the spring and summer (while continuing to meet all other requirements for hydro operations). Analysis has shown this flexibility can improve the adequacy of the system when allowed and under certain conditions.

Similar to the check against the 2026 Fish and Wildlife Program, while the strategy is adequate when considering the full range of load uncertainty, not all individual trajectories are adequate by themselves (see Table N - 15). This further emphasizes that the strategy is not only tuned for high demand growth. While there are some differences in adequacy signals in standalone load trajectories, what matters is that both regimes satisfy the Council's adequacy criteria when considering the full load trajectories. Individual operations may vary due to the influence of limiting or not limiting flexibility, which (1) may result in seasonal operational changes and (2) how the system responds to stressful conditions.

Table N - 15: Preliminary Injunction Adequacy Results of Individual Trajectories

Metric	Frequency			Extreme Deficits		
	Annual LOLEV (events)	Winter LOLEV (events)	Summer LOLEV (events)	VaR Duration (hr)	VaR Peak (MW)	VaR Energy (MWh)
Study/Criteria	0.2	0.1	0.1	8	1,200	9,600
High Growth	0.011	0.011	0	0	0	0
Late Growth	0.189	0.189	0	18.8	3,458	34,578
Early Growth	0.133	0.133	0	4.5	2,248	9,239
Mixed Bag	0.033	0	0.033	0	0	0
Low Growth	0	0	0	0	0	0