Technical Appendix K: Modeling Framework

Contents

Discussion of Power System Model Scope

At a basic level, effective power system planning requires a deep understanding of how, why, and where power is created, transmitted and delivered. Understanding the costs and implications of the power system can require many specialized modeling techniques and methodological approaches, since the system is complex and all aspects can rarely be understood by using just one analytical approach as a lens. Adding to that complexity, the Northwest region is one part of the greater Western Interconnection, which spans three countries and is managed by a disparate group of entities.

Therefore, analyzing power system cost and risk requires an approach to modeling that is based on economic fundamentals. This involves evaluating generation costs, fuel availability, fuel pricing, and environmental impacts. It also requires accounting for the transmission system's capacity to deliver power across a broad footprint to meet fluctuating electric demand. Some aspects of the power system can be modeled in varying degrees of detail, based on available public information and time available to develop such an analysis. Similarly, some policies and operational realities affecting the power system are cross sectoral and not easily separable from the system impacts of other sectors. Due to all these nuances and more, the Ninth Power Plan’s modeling approach splits this complex problem into simpler problems that can be solved using analytical methodologies and computer modeling software.

The Council uses many models to support the analysis of the Ninth Plan. Each model is designed and configured to answer different questions about the power system. The Council uses three primary models to understand cost and risk tradeoffs associated with different resource portfolios representing the bulk power system for the greater West or inside the Northwest region:

1. OptGen coupled with SDDP is used for evaluating costs and risks associated with different regional strategies over many future power system environments.[1]
2. The GENESYS model is used to evaluate hourly system operations within the region and for resource adequacy.[2]
3. Aurora is used to evaluate hourly operations and market fundamentals across the Western grid.[3]

The high-level flow of how the Council uses these three models in its analysis is represented in the Introduction section of the Technical Appendix N – Scenario Modeling and Results.

Resource Strategy Analysis

Focus of Modeling

The primary goal of power system analytics supporting resource strategy selection is to understand the implications of costs and risks (tail-end costs, undesirable outcomes, etc.) of investments in portfolios containing new resources and reserves. For a model to be able to estimate total costs, it needs to be able to calculate the investment costs of a set of resources and reserves, the production costs of those and existing system resources and reserves, and any additional costs such as those related to public policies or regulations that are not already included within the production costs.

Capital expansion models seek to minimize total costs by simulating investment in a set of resource/reserve solutions that meet a set of obligations (load, adequacy, policies, etc.) over a certain period of time. The fixed cost (capital and fixed operations and maintenance) of a set of resources is one piece of the overall objective to be minimized. Production costs and other costs are also needed to determine if the investment is least cost. A production cost model or module of a capital expansion model simulates how a new set of resources/reserves fits into the existing power system by minimizing the variable cost of production required to meet electric demand and other obligations. This includes any costs associated with the production of power such as fuel costs, variable costs

[1] OptGen and SDDP are commercial products licensed from PSR. See https://www.psr-inc.com/en/software/ for more details.
[2] GENESYS was codeveloped by Council staff with EPIS (now Energy Exemplar) and PSR and is maintained by PSR.
[3] AURORA is a commercial production cost model licensed from Energy Exemplar.

associated with policy compliance, costs to transmit the power from one place to another, and variable operations and maintenance costs.

Sometimes production-cost modeling can be very detailed, like understanding the uncertainties and costs of fueling generating resources or providing operational level of detail like the co-optimization of providing generation and holding reserves. Additionally, the complexity of these problems can grow as the duration and fidelity of the problem being optimized increases, resource types and attributes are modeled in more detail, and the topology of the problem grows in complexity and size.

Over time, these problems have grown in complexity to necessitate the problem being split into parts. The Council's methodology has been to separate the parts into a wholesale market study (outside the region capital expansion and production cost modeling), a needs assessment (within region production cost modeling that focuses on identifying the existing power system's needs given increasing obligations), and a resource strategy analysis (regional capital expansion and production cost modeling that identifies the least cost/risk strategy to meet regional obligations over time).

General Discussion About Modeling in OptGen/SDDP

OptGen is a long-term expansion planning model that determines the least-cost sizing and timing decisions for construction, retirement, and reinforcement of generation capacities, transmission network, and natural gas pipelines. OptGen calls on SDDP, a production-cost model, to determine the variable costs associated with a particular investment strategy. OptGen seeks to minimize costs by making particular investments to meet growing system obligations and co-optimizing simulated power plant operations considering both energy and reserve requirements.

Due to the complexity of this analysis, OptGen and SDDP employ mixed integer programming methods to solve this cost minimization. Mixed integer programming (MIP) is a mathematical optimization technique that minimizes or maximizes an objective function within constraints involving a mix of different decision variable types including: continuous variables (i.e. size of transmission flows), discrete variables (i.e. number of new thermal plants in which to invest), and binary variables (i.e. unit commitment of certain power plants). Another feature of mixed integer programming is that optimality cannot be guaranteed "exactly," but within a particular range (gap) from the optimal linear solution.[4] For the Ninth Plan, and due to time and feasibility constraints, OptGen was set to stop attempting to solve the problem at a 3 percent gap.

Resource Parameters

Resources that are part of the existing system and candidate new resources are specified in SDDP via operational parameters and constraints. A candidate resource must be specified in SDDP to be available for selection in OptGen. Resource investment parameters are specified in OptGen. All

[4] The optimal linear solution in this case is the solution with all the non-linear constraints relaxed to make the problem linear which is generally much easier to solve.

generation and storage resources are defined to be in an electric bus along with different demands. All transmission resources are defined in SDDP to connect different electric buses and reserve sharing areas and new transmission resources can be selected in OptGen. Not all new resource types modeled necessarily fit into an explicitly defined resource in SDDP, so their operations are emulated by modeling them as similar resources.

For all resources, OptGen can specify the following: investment cost, fixed and variable operations and maintenance (O&M) costs, capacity, firm energy/capacity contribution, construction schedules, retirement/decommissioning options, environmental characteristics (emissions, clean-energy certificates, etc.), resource relationships, and more.

Resources Modeled as Hydro Resources

For resources represented as hydro generation resources, SDDP can specify the following parameters: minimum and maximum reservoir volumes, reservoir bathymetry, project spill and generation capabilities, turbine efficiency, water travel time and routing between cascading reservoirs, minimum and maximum outflows, spills, and reservoir volumes, initial reservoir contents, irrigation and flood control requirements, plant discharge and ramp rates, maintenance schedule and capability to provide reserves. The existing regional hydropower system has parameters that are often changing per the history described in Technical Appendix B – Existing System Parameters and Policies. Hydro generation resource operations constraints, with the exception of what is defined by the sensitivities described in Technical Appendix N – Scenario Modeling and Results, are defined through discussions with regional utility planners, hydro operators, and technical documents including the Water Management Plan and license documents.[5] Due to the need to account for reservoir/storage/fuel inventory constraints, in addition to the existing hydropower system, certain candidate new resources are modeled as hydro resources. These include clean long-duration storage and clean mid-duration storage/peaker.[6] Please see Technical Appendix G – New Generating Resources for more information on these proxy resources.

Resources Modeled as Thermal Resources

For resources represented as thermal generation, SDDP can specify the following parameters: fuel consumption constraints, efficiency curves, variable operations and maintenance cost, minimum and maximum generation levels, ramp rates, unit commitment parameters (startup costs, minimum up and down times, etc.), forced outage rate, maintenance schedule, and capability to provide reserves. Thermal unit commitment constraints are primarily utilized for in region dispatch of existing and new plants (specifically, larger combined cycle gas turbines and coal plants) whereas outside the region

[5] For a more complete list of the documentation please follow up with Council staff.

[6] In SDDP, the longest cycle contemplated by the model for storage resources is 24 hours which does not capture the possibility for longer cycles that are some of the defining attributes of longer duration storage resources whereas hydro inventories are evaluated on a year-long basis.

thermal resources are represented by resource bundles by efficiency and resource type.[7] The resources modeled as thermal resources in SDDP are: new and existing gas plants, existing coal plants, geothermal plants, nuclear plants, clean baseload resources, and dynamic voltage regulation.[8]

Resources Modeled as Renewable Resources

For resources represented as renewable generation resources, SDDP can specify the following parameters: availability shape, variable operations and maintenance cost, minimum and maximum generation levels, maintenance schedule and curtailment cost.[9] Existing and new in-region resources are represented as individual resources. Outside the region renewable resources are represented by resource bundles by availability and resource type. The resources modeled as renewable resources in SDDP are as follows: stand-alone solar, the solar part of a solar hybrid,[10] and onshore and offshore wind generators.

Resources Modeled as Storage Resources

For resources represented as storage resources, SDDP can specify the following parameters: charge/discharge efficiency, minimum and maximum storage, initial storage, variable operations and maintenance cost, minimum and maximum generation levels, maintenance schedule and capability to provide reserves. The resources represented as storage resources in SDDP are stand-alone short-duration storage, the battery part of the solar hybrid, and pumped storage plants.

The costs and attributes of all new generating and storage resources parameters are described in more detail in Technical Appendix G – New Generating Resources. Technical Appendix B – Existing System Parameters and Policies provides more information on the existing system capabilities, both in region and across the West

Resources Modeled as Demand-Side Resources

For resources represented as energy efficiency resources, SDDP can specify the size and shape of the resources as load modifiers and associated with a particular demand segment. The Council used this resource type to model all the demand side resource bundles (conservation, demand response, and rooftop solar) aside from the voltage regulation. Further information on parameters for conservation and demand response resources is defined in Technical Appendix H – Conservation Methodology and

[7] This simplification helps improve computational speed without significant loss of fidelity as was discussed in the November 6, 2024 System Analysis Advisory Committee meeting.
[8] From an operational perspective, dynamic voltage regulation was modeled using the potential and treating that potential reduction in demand as a non-emitting thermal generator.
[9] Curtailment of a renewable generation is when a renewable generator could generate more power, but, often for transmission or operational constraints, chooses to dispatch down to a level of generation that can be handled by the grid. These costs can include wear and tear costs for curtailment or foregone revenue from Renewable Energy Credits.
[10] Solar hybrid resources were modeled as a stand-alone solar plant and battery must be associated when acquired.

Potential, Technical Appendix I – Demand Response Methodology and Potential, and Technical Appendix J – Rooftop Solar Methodology and Potential.

Zonal Transmission Topology

Ninth Power Plan SDDP modeling clusters resources and demands associated with specific utility service areas (or subsets of the service areas) across the west into buses. These areas are connected to each other in the model via transmission paths (the Ninth Plan does not model transmission inside of buses). This representation of buses and transmission lines is called a transport model. It is an abstraction of the actual electric transmission topology into a representation that can be solved at a tractable granularity as opposed to a power flow model which more accurately represents the system but is currently too computationally intensive to use while also solving the investment problem.

In addition to the assignment of loads and resources to buses, those buses and subsets of the demands and resources are assigned to reserve sharing groups. The assignment of buses to reserve sharing groups is similar to the participation of utilities in planning reserve pools. For the Ninth Power Plan the Western Power Pool is split into two reserve sharing groups: the northwest region and the mountain west region. This is done for consistency with interpretation in other models. These reserve sharing groups are assumed in SDDP to share planning reserves, balancing reserves, and contingency reserves. Per the discussion in Technical Appendix L – Wholesale Market Availability Results, this pool and bus representation is a simplification that reflects the uncertainty around the changing market landscape of the Western Electricity Coordinating Council (WECC). Along the same lines, the net import capability into the pool representing the Northwest was limited to the seasonal limits from the needs assessment per Technical Appendix M – Needs Assessment Results.

Plant dispatch and reserve assignment are simulated for 35 load-resource buses and 5 pools as specified in Table K - 1 **Error! Reference source not found.**which comprise the SDDP representation of the WECC.

Table K - 1: OptGen/SDDP Topology

Pools	**Zones**
Western Power Pool (inside the region)	17 buses - Pacificorp (West and East Idaho), Portland General Electric, Bonneville Power Administration (Oregon, Washington, Idaho/Montana), Northwestern, Avista, Tacoma Power, Seattle City Light, Puget Sound Energy (North, Central, and Olympia), Idaho Power, Chelan County PUD, Douglas County PUD and Grant County PUD

Pools	Zones
Western Power Pool (outside the region)	9 buses – Pacificorp East (Wyoming and Utah), Public Service Colorado, Nevada Power (North and South), Western Area Power Administration (Upper Missouri, Colorado, Wyoming), New Mexico[11]
California Independent System Operator	6 buses – Northern California[12], Southern California[13], Imperial Irrigation District, San Diego Gas and Electric, LADWP, and Baja California
Southwest Power Pool	1 bus - Arizona[14]
Canada	2 buses - BC Hydro, Alberta Electric System Operator

Electric transmission between these buses is limited by the rated transport capability between the buses. The ratings are a representation of the capability of large transmission infrastructure connecting the buses, with the exception of the Northwest region which has an additional seasonal net import limitation in and out of that pool as described above. A history of the existing transmission and description of new transmission assumptions are described in more detail in Technical Appendix B – Existing System Parameters and Policies. Transmission lines in the model, which as described above are an interpretation of actual transmission infrastructure, can be defined by the capability of transmitting power in either direction between buses, directional wheeling rates between buses, directional loss factors between buses, and at times seasonal availability.

Regional Versus Outside the Region Modeling

As alluded to above, the regional resources, transmission, and loads are modeled in greater detail than outside the region resources, transmission, and loads. This is due to a few factors: the availability and granularity of public information outside the region, the primary scope of Council staff on in-region concerns, and computation simplifications that allow for speedier OptGen/SDDP simulation time that enables for more complexity elsewhere. In particular, some simplifications of note are as follows: the bundles of outside the region resources by attribute and type, bundles of outside the region demands into one demand per bus, and simplifications of the topology by clustering some out-of-region utilities into larger buses.

[11] Public Service New Mexico and El Paso Electric are combined in this representation.
[12] Pacific Gas and Electric (North, Bay Area and Path 26) and Balancing Area of Northern California are combined in this representation.
[13] Southern Cal Edison and VEA are included in this representation.
[14] Arizona Public Service, Salt River Project, Tucson Electric, and Western Area Power Administration (WAPA) Lower Colorado Area are combined in this representation.

Policies

OptGen and SDDP modeling incorporates policies via many mechanisms including, but not limited to, energy targets, tax credits, and emissions pricing. Some policies require multiple model mechanisms to emulate the actual implementation of a policy. Some policies require simplification to best quantitatively enforce policy language that does not have a viable analogue in the modeling. **Error! Reference source not found.Error! Reference source not found.Error! Reference source not found.**Table**Error! Reference source not found.** K - 2 describes at a high-level the implementation of some of the major policies in the regional strategy modeling.

TableError! Reference source not found. **K - 2: Policy Implementation in OptGen/SDDP**

Policy or Collection of Policies	OptGen Mechanism	SDDP Mechanism
WECC-wide aggregation of Zero Emissions Policies and Renewable Portfolio Standards	Annual firm energy minimums of zero emitting or renewable WECC resources as a percentage of WECC demand	Curtailment costs of WECC renewables and discretionary spill of northwest hydro linked to imputed zero emissions or renewable energy credit pricing[15]
Emissions Pricing in WA, CA and Canada	None	Emissions pricing on emitting units within and imputed emissions pricing on wheeling costs into the jurisdictions with pricing[16]
Clean Energy Transformation Act in WA	Annual firm energy minimums of zero emitting or renewable regional resources as a percentage of WECC demand[17]	None

The policies incorporated into plan work are described in more detail in Technical Appendix B – Existing System Parameters and Policies.

[15] Imputed pricing based on California carbon pricing when non-zero and only non-zero when the existing system requirements did not add up to the aggregate policy obligation.
[16] Imputed pricing based on the average emissions associated with an unspecified market purchase. The average emissions are calculated using an assumption that the product of the emissions rate of a combined cycle and the remainder of the load when netting the aggregate zero emissions obligation for the WECC with the WECC load divided by the WECC load.
[17] The penalty for violation of this soft constraint is set to the social cost of carbon.

Testing Risk

The resource strategy analysis considers the costs and risks of many different future outcomes explicitly in the analysis. Modeling different future combinations of demand for electricity, natural gas prices and price volatility, and fuel availability for hydro, wind and solar generation for all scenarios and sensitivities explores the uncertainty around major power system fundamentals forecasts. Modeling scenarios and sensitivities explicitly explores specific concerns around the possible pace for new resource development, the cost of new resources, the future availability of transmission, and future hydropower operations. This allows the Council to better understand uncertainty in the cost and availability of tools to meet growing power system obligations in the long term. In addition, by holding both planning and operating reserves throughout all futures and scenarios/sensitivities, the modeling implicitly explores the operational risk required to maintain an adequate and economic system.

Futures

A future is defined as one particular realization of major uncertainties affecting the power system. In the Ninth Power Plan this is represented as a particular combination of forecasts for the demand for electricity, natural gas prices and price volatility, and fuel availability for hydro, wind and solar generation. One resource strategy likely has a different cost over each future. Minimizing the expected value of the costs over all the futures tested is used to determine the optimized strategy for a particular scenario and sensitivity.

History of Planning for Uncertainty

The history of the Council and the Power Act explicitly addresses the need to plan for uncertainty in demand. This is partly due to the outcome of Northwest power system planning practices in the 1960-70s that led to expensive resource decisions for the region (the decision to pursue multiple large nuclear projects in the Northwest, many of which were not finished and resulted in a large debt default).[18] In the Ninth Power Plan, five different demand forecast pathways were created to test the uncertainty in the underlying non-weather drivers of power demand. This is explored in more detail in Technical Appendix F – Electricity Demand Forecast. Additionally, each of those fundamental forecasts was represented for three different views of the future climate, as is explored in more detail in Technical Appendix D – Climate Model Data and Assumptions. These 15 demand futures represent the range of demand uncertainty explored explicitly in the resource strategy analysis. Temperature sensitive demand uncertainty is considered as well within the needs assessment modeling and implicitly is considered as part of the reserve margin to maintain adequacy.

[18] https://www.nwcouncil.org/reports/columbia-river-history/northwestpoweract/

Current Futures Methodology

Future uncertainty of electricity supply is explored through a couple different lenses: price and availability of the primary fuels used in the Northwest power system. Since the Council does not currently perform detailed fuel fundamentals modeling on natural gas, price is used as a proxy for understanding supply fundamentals uncertainty, whereas forecasts of wind speed and direction, solar irradiance, and hydro runoff throughout the region are used explicitly to understand the fundamentals of the fuels of other major regional power sources. The Council uses one expected price forecast for coal, fuel oil, and other fuels. This is due to the lower penetration of those resource types in the region, and for coal lower historical price volatility, and thus the lessened fuel risk exposure.

Natural gas resources are often on the margin for the power system and thus affect the wholesale price of power. For natural gas in the Ninth Power Plan, uncertainty is represented via price pathways (three different trajectories, low, medium and high) and price volatility (10 different seasonal price multipliers). The forecasts and the methodology used to create them are discussed in detail in the Technical Appendix E – Thermal Fuels Forecast.

Forecasts of hydro runoff, solar irradiance, and wind speed/direction are built from same 30 years of climate data from the three different climate models used for the temperature sensitive loads. The development of these data are discussed in more detail in Technical Appendix D – Climate Model Data and Assumptions.

Representative Futures Sampling Methodology

If used in full, the futures discussed above would create 13,500 different combinations of outcomes. Some of those combinations of futures are very similar, and thus simulations of these futures might yield similar outcomes and create unnecessary simulation time and cost. A methodology using a linear program was used to determine a distributionally relevant representative sample of 10 combinations from the entire range of 13,500 future combinations for each of the seven years evaluated in the regional strategy analysis modeling.[19] Using a representative sample of futures ensures that any resource strategy would be subjected to a wide array of hydro conditions, prices, and demand which represent the highest up and downside risks for the region.

Scenarios

A scenario, or sensitivity, in power plans has been used to explore an area of risk not represented within the uncertainty explored by the futures. In recent plans, it has been exploring some of the biggest issues leading up to that plan, like policies or resource availability uncertainty. In the Ninth Plan, there is significant uncertainty around how the hydro system will be operated going forward and

[19] Discussed during a OptGen Methodology Update: Clustering topic in a January 29, 2026 System Analysis Advisory Committee meeting, https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2026-01-29.

what resources and transmission will be available when, and at what cost. The specific scenario descriptions are explored in more detail in Technical Appendix N – Scenario Modeling and Results Draft.

Each scenario is made up of multiple sensitivities and in each of those sensitivities the same set of futures is explored in the years sampled (2028, 2030, 2032, 2034, 2038, 2042, and 2046). The capital expansion for each sensitivity is meant to inform resource selection from 2027 through 2046, however for this plan OptGen was run in snapshot expansions with some decisions locked from previous years as described in Table K - 3**Error! Reference source not found.Error! Reference source not found.Error! Reference source not found.Error! Reference source not found.**.

Table K - 3: Snapshot Years Description

Sample Year	Resource Decisions Locked	Available Resources	Other Details of Note
2028	Lock supply-side resources	Only planned supply-side resources and all demand-side resource	Limited supply-side resource availability due to overall resource ramping
2030	Lock demand-side resources	New wind, solar, hybrid and simple cycle gas generators available	Clean Energy Transformation Act in WA begins and additional planned transmission in region
2032	Lock supply and demand-side resources	New combined cycle gas generation and long duration energy storage (in most sensitivities)	End of action plan period of plan and additional transmission in region in some sensitivities.
2034		New pumped storage and geothermal	Additional transmission available in one sensitivity.
2038	Lock supply and demand-side resources		In most scenarios, WECC-wide zero emissions policies are binding in mid-2030's, Additional transmission available in some sensitivities.
2042		Mid-duration energy storage and clean baseload proxy resources	
2046	Lock supply and demand-side resources	Offshore wind	Many emissions policy resource targets increase in 2045

OptGen has two modes for running the model. The first allows for the production cost modeling and capital expansion modeling decisions to be co-optimized.[20] Running the model this way requires running a single year at the time. This method also ensures that balancing reserves for renewables are calculated dynamically, rather than iteratively. The second mode for Option is a full 20 year of investment decisions to be solved at the same time, requiring less fidelity on operations and an iterative calculation of balancing reserves.[21] There were many discussions coming out of the 2021 Power Plan about cost-effective reserves required to support a resource strategy and thus, as an area of emphasis in this Power Plan, it was determined that it would be better to have a dynamic reserve determination. Therefore, the Council used the first approach for the Ninth Plan. This methodology of running snapshot years was discussed in more detail at the System Analysis Advisory Committee.[22]

Reserves

A reserve requirement in the resource strategy modeling represents any additional obligation over and above what is required for meeting the demand and policies. These reserves are held as an additional obligation and the resources holding those reserves cannot use that capability for meeting typical day load. This methodology in OptGen/SDDP incorporates the effect of holding reserves in terms of limiting market resource availability, where some of the available resource capability to meet typical day load are not available for economic exchange outside the particular reserve sharing pools. Those reserves are held collectively by appropriate resources in the same pool (defined in Table K - 1 above) and can be split into planning and operating reserves.

Planning Reserves

The planning reserves for the region contain a few interactive components: the reserve required to maintain enough resources to meet seasonal peak demand in a pool, and the reserve over and above the seasonal peak reserve, when necessary, needed to maintain adequacy and additional energy required to maintain adequacy. The calculation of the components of planning reserves is defined in detail in Technical Appendix M – Needs Assessment Results. The planning reserves philosophy for outside the region is discussed in more detail in Technical Appendix L – Wholesale Market Availability Results.

Seasonal Peaking Reserve Requirement

The seasonal peaking reserve is necessary because OptGen dispatches using typical days, in which a sample weekday and weekend day are sampled for the following 6 seasons: January/February, March/April, May/June, July/August/September, October/November, and December. The typical day weekday hour's demand is the average demand for that hour in the day for all weekdays in the season and similarly, typical day weekend hour's demand is the average demand for that hour in the day for

[20] Called OptGen 2 in the PSR documentation.
[21] Called OptGen 1 in the PSR documentation.
[22] Discussed during a OptGen Methodology Update: Snapshot Years topic in a January 29, 2026 System Analysis Advisory Committee meeting, https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2026-01-29.

all weekends in the season. Since it is important to ensure there are enough resources available to meet the demand in all the hours, including when loads are above average, a seasonal peaking reserve is specified that holds back an additional percentage over every hour's demand in a typical day. The typical day methodology and logic was discussed in more detail in the System Analysis Advisory Committee.[23]

Additional Reserve Requirement for Adequacy

OptGen does not explicitly include the full suite of temperature sensitive loads and the interaction of all those loads with varying hydro and renewable conditions. These potential additional needs are calculated as an adequacy reserve margin over and above the seasonal peak reserve, and as an additional firm energy requirement for new resources, as defined in detail in Technical Appendix M – Needs Assessment Results. This reserve should account for situations not directly simulated in OptGen to ensure a resource strategy adheres to the Council's adequacy criteria.

Operating Reserve Requirements

OptGen holds operating reserves over and above the planning reserves to account for the uncertainty of supply delivery. For example, there may be forced outages on thermal or hydro generation (contingency reserves) or there will be uncertainty of the forecast of wind, solar, and small hydro generation (balancing reserves). The contingency reserves held are 6% of load in all hours.[24]

Dynamic Probabilistic Reserve Requirement

The balancing reserves are estimated via a methodology called dynamic probabilistic reserve (DPR) and are calculated based on the estimated reserves required to cover the forecast error of an entire pool's renewable generation.

Equation K - 1: Calculation of Dynamic Probabilistic Reserves

$$DPR = (1 - \lambda) * E[\Delta FE] + \lambda * CVaR_{1-\alpha}[\Delta FE]$$

The dynamic probabilistic reserves are defined in more detail in Equation K - 1**Error! Reference source not found.Error! Reference source not found.**. The variables in the equation are:

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[23] Discussed during the OptGen Methodology Updates topic in a January 29, 2026 System Analysis Advisory Committee meeting, https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2026-01-29 and October 1, 2025 System Analysis Advisory Committee meeting, https://www.nwcouncil.org/meeting/system-analysis-and-resource-adequacy-combined-advisory-committees-2025-10-01.

[24] This is a proxy of the 3% load and 3% generation simplification of the reserve sharing rule Bal-002-WECC 3, https://www.nerc.com/globalassets/standards/reliability-standards/bal/bal-002-wecc-3.pdf.

- λ is a risk aversion weight in %. This weight is set at λ=100 for the Ninth Power Plan putting all the weight on the tail end of the distributions of ΔFE.
- 1-α is a reliability level in %. Set at α =5 in the Ninth Power Plan, meaning the ΔFE protected against is the 95 percentile of all ΔFE.
- ΔFE is the difference between the forecast error in solar and wind generation from one hour to the next and the forecast error is defined as the difference between the forecast renewables in an hour in the typical day and the generation in that hour for any other future.

Due to the dynamic nature of this calculation, as the model adds renewable generation it also must add additional resources that hold the balancing reserves (or utilize more existing resources for reserves). One effect of this is higher value for renewable generation diversity because it lowers the reserve burden.

Reserves Summary

In summary, the planning reserves primarily account for uncertainty in forecasted demand represented in the typical day operations, and the operating reserves the uncertainty in the availability of resources to meet those demands. These reserves are significant portion of the obligations of the power system. By including these reserves into typical day operations, the modeling incorporates the resource signal to meet resource adequacy needs and also considers the effect of holding reserves as an important economic component of broader power system market fundamentals.

Resource Selection

In OptGen the model can select either supply or demand side resources to minimize costs in the objective function, and each of the resources has attributes that are useful for meeting system obligations and economics within the regional portfolio.

Focusing on the region economics defines when a resource may be least cost for meeting in region resources and also for exporting power to meet out-of-region loads. All resources can be acquired for economic purposes and can meet load when fuel is available. Some resources like storage and hydro can choose to save (in the case of hydro) or create (in the case of storage) fuel for other hours rather than meeting a need in the current hour. In some cases, specifically when interacting with Northwest hydro resources which are primarily fuel limited (rather than capacity limited), adding resources at a non-coincident time to need can free up fuel to serve peaking, reserves, spill, or other river system needs that are time dependent in later hours. This means that Northwest resource economics are best considered from a portfolio lens.

Additional regional obligations are primarily meeting reserves, policy, or non-power obligations on the hydro system. Resource types that can provide peaking, contingency or dynamic probabilistic reserves in OptGen are as follows: new and existing thermal, hydro, and storage. For a resource to get credit for providing peaking reserves it must have the capability available to hold the reserve and fuel to generate if the reserve was called upon. Resource types that can provide energy reserves in OptGen are as follows: conservation, new thermal, and new renewable generation. Resource types that can help meet public policies are described above in Table**Error! Reference source not found.** K

- 2. Firm energy reserve provision is based on the expected fuel availability of the resource regardless of the obligation. Resource types that can reduce obligation burden in general are new energy efficiency and demand response as they directly reduce the load driving peaking and energy reserve requirements, public policies, and reduce the obligation of regional hydro to serve the power grid.

Needs Assessment and Adequacy Check

One of the most important obligations considered in the resource strategy analysis is regional power system adequacy. The Council's regional adequacy methodology is a multiple metric probabilistic approach focusing on thresholds of frequency, magnitude, and duration of potential wholesale power system shortages that meet the expectations and criteria of regional planners as a reasonable cost versus risk tradeoff. The approach is probabilistic and the operational modeling includes additional risk factors not exogenously included in the resource strategy. Some of the additional risk factors modeled include multiple stage uncertainty and the realization of that uncertainty for load and renewable generation, hourly exploration of temperature sensitive load excursions with all 90 climatic hydro and renewable availability conditions, and more operational detail reflected in the modeling of the regional hydro system. This general approach is described in more detail in Technical Appendix M – Needs Assessment Results.

Since the modeling approach is complex and time consuming, the Council uses the GENESYS model separately from OptGen/SDDP to calculate a set of reserves that account for system needs and to check a resource strategy for adequacy once a candidate strategy has been adopted.[25]

Methodology for Checking for Adequacy

GENESYS and OptGen/SDDP are models with similar transmission topology and market setups. Unlike GENESYS, though, the resource strategy in OptGen/SDDP does not simulate the operations nearing stressful events. Instead OptGen/SDDP uses a reserve margin that is calculated via the needs assessment to send the signal for capacity and energy on a seasonal or annual basis. OptGen seeks to meet any needs by adding resources with attributes that add to reserve capability to meet the seasonal reserve margins but may not perfectly fit the need in some seasons. Since OptGen may also add resources for policies and broader economics, sometimes the system may be long in comparison to load and reserves in a particular season. Since the reserve margin from the needs assessment is simplified and imperfect method for translating all the fidelity of the operational record from GENESYS, it is not expected that the check will yield a system that exactly meets the thresholds of all the metrics. It is expected, however, that an adequate strategy will not violate any of the adequacy criteria.

In other words, when the candidate resource strategy is put into GENESYS, run with the same setup as a needs assessment but with the additional resources from the strategy, the system may be more

[25] As described in the Additional Reserve Requirement for Adequacy section in this appendix above.

than sufficient on some of the adequacy metrics. If the strategy does not check as adequate, then an iterative process is required to modify the portfolio selected to become adequate. As this iteration process can be timely and costly, when the adequacy criteria are developed into reserve margins the process of creating the reserve signal tends to err on the conservative side (i.e. err towards something that would incentivize slightly more than less resource additions).

Temperature Sensitive Load Forecast

In the Ninth Power Plan, the Itron load forecasting model was used to produce load forecasts for all 13 Northwest Balancing Authorities (BAs) for five pathways: High Growth, Low Growth, Mixed Bag, Early Growth and Late Growth.[26] The forecasts are calculated under the influence of temperatures from the three climate models selected for the Power Plan whose Global Climate Models (GCM) are CanESM2 (A), CCSM4 (C), and CNRM-CM5 (G).[27]

In the GCM data, each temperature year varies based on underlying trends and simulated weather. As a result, extreme temperatures vary in timing and severity each year. The temperature year of the climate model is used for the same year in the Itron load model. For example, temperature data for year 2031 from the three selected GCMs is used in Itron to produce the three years of hourly load forecasts for 2031. In addition to temperature effects, Itron also has calendar date effects of year 2031, which include the influences of weekdays, weekends, holidays, and months (which represent the seasons).

However, Power Plan test year 2031 could also be under the influence of other climate model years from the 30-year set, 2020 to 2049, of the three GCMs, for a total of 90 possible climate model years. For the capital expansion model (SDDP/OptGen), only the Itron load forecasts were directly used. But to determine system needs, which are used to define reserves input to the capital expansion model, the full set of 90 possible weather years are used. Since needs and adequacy were primarily checked for year 2031 in the Ninth Plan, these additional forecasts were created for that year.

While Itron could be used to generate all 90 forecasts, this would be a lengthy endeavor. To save time, a simpler and faster regression model was developed to produce load forecasts based on the Itron model results. More specifically, the regression model was developed to reproduce the temperature-sensitive portion of the Itron load forecasts which mainly comprises the residential, commercial and industrial (RCI) loads. Among the five load pathways, the High Growth and the Late Growth share the same Itron RCI load forecasts; similarly, the Mixed Bag and Early Growth also share the same RCI load forecasts. Resultingly, the regression model is developed for only three pathways: High Growth, Low Growth, and Mixed Bag. To develop the regression model for the Itron RCI load forecast, the Council decided to adopt the Multivariate Adaptive Regression Spline (MARS) statistical algorithm.[28]

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[26] See Technical Appendix F – Electricity Demand Forecast for more details.
[27] See Technical Appendix D – Climate Model Data and Assumptions for more details on climate scenarios A, C and G.
[28] See https://bradleyboehmke.github.io/HOML/mars.html for details of MARS implementation in R.

As an example, for Power Plan year 2031, Itron produces three years of hourly load forecasts using data from climate model year 2031 of the three climate models, A, C, and G. However, the hourly load data set (consisting of three years) is too small to train the MARS model to fit Itron's hourly load shapes (i.e., simulate hourly loads for different types of days, for example, winter days and summer days). For simplicity, the MARS model was developed on three years of ITRON *daily average* (RCI) loads, totaling $(3 \times 365) = 1{,}095$ data points.

To describe development of MARS in more detail, let $i \in (1, 2, \cdots, 365)$ be the index of a day of year 2031 and $j \in (0, 1, \cdots, 23)$ be the index of an hour of a day. Furthermore, let the ITRON *daily average* load of day i be represented by $\bar{L}_i$, and the ITRON hourly load for hour j of day i be represented by L_{ij}, and let r_{ij} be defined as the ratio $r_{ij} = L_{ij}/\bar{L}_i$. Therefore, the output of the MARS model is the *daily average* load forecast $\bar{L}'_i$ for day i which then could be used to calculate the 24-hourly load forecasts of day i as $L'_{ij} = r_{ij} \times \bar{L}'_i$.

The ITRON daily input and output data represented in Table K - 4 below are used to develop (i.e., train) the MARS model:

Table K - 4: Types of ITRON Data for The MARS Model

GCM	Day Index i	Month	Day of Week	Holiday	Daily Avg. Temp.	Daily Avg. Load
A	1	1	Wed	Y	$T_{A,1}$	$\bar{L}_{A,1}$
A	2	1	Thu	N	$T_{A,2}$	$\bar{L}_{A,2}$
⋮	⋮	⋮	⋮	⋮	⋮	⋮
A	365	12	Wed	Y	$T_{A,365}$	$\bar{L}_{A,365}$
C	1	1	Wed	Y	$T_{C,1}$	$\bar{L}_{C,1}$
⋮	⋮	⋮	⋮	⋮	⋮	⋮
C	365	12	Wed	Y	$T_{C,365}$	$\bar{L}_{C,365}$
⋮	⋮	⋮	⋮	⋮	⋮	⋮
G	1	1	Wed	Y	$T_{G,1}$	$\bar{L}_{G,1}$
⋮	⋮	⋮	⋮	⋮	⋮	⋮
G	365	12	Wed	Y	$T_{G,365}$	$\bar{L}_{G,365}$

In Table K - 4, the first column GCM lists the GCM (A, C, or G) of the row of the Itron data.

The second column Day Index i lists the index of the day of a year. For example, the index of January 1st is $i = 1$; the index of January 2nd is $i = 2$; and the index of December 31st (of the non-leap year 2031) is $i = 365$.

In addition, the third column Month lists the month corresponding to day i, and the fourth column Day of Week lists the weekday of the day i, which for January 1st, 2031, is a Wednesday.

Also, the fifth column Holiday lists Y (representing Yes) if day i is a holiday and N (representing No) if day i is not a holiday. For example, day $i = 1$ corresponds to January 1st, New Year's Day, which is a holiday, and therefore is listed as Y. On the other hand, day $i = 2$ corresponds to January 2nd, which is not a holiday, and thus is listed as N. Finally, day $i = 365$ corresponds to December 31st, New Year's Eve, which is considered as a holiday in Itron, and thus listed as Y.

The last two columns are the climate model daily average temperature and the daily average load of day i (an Itron model output), respectively.

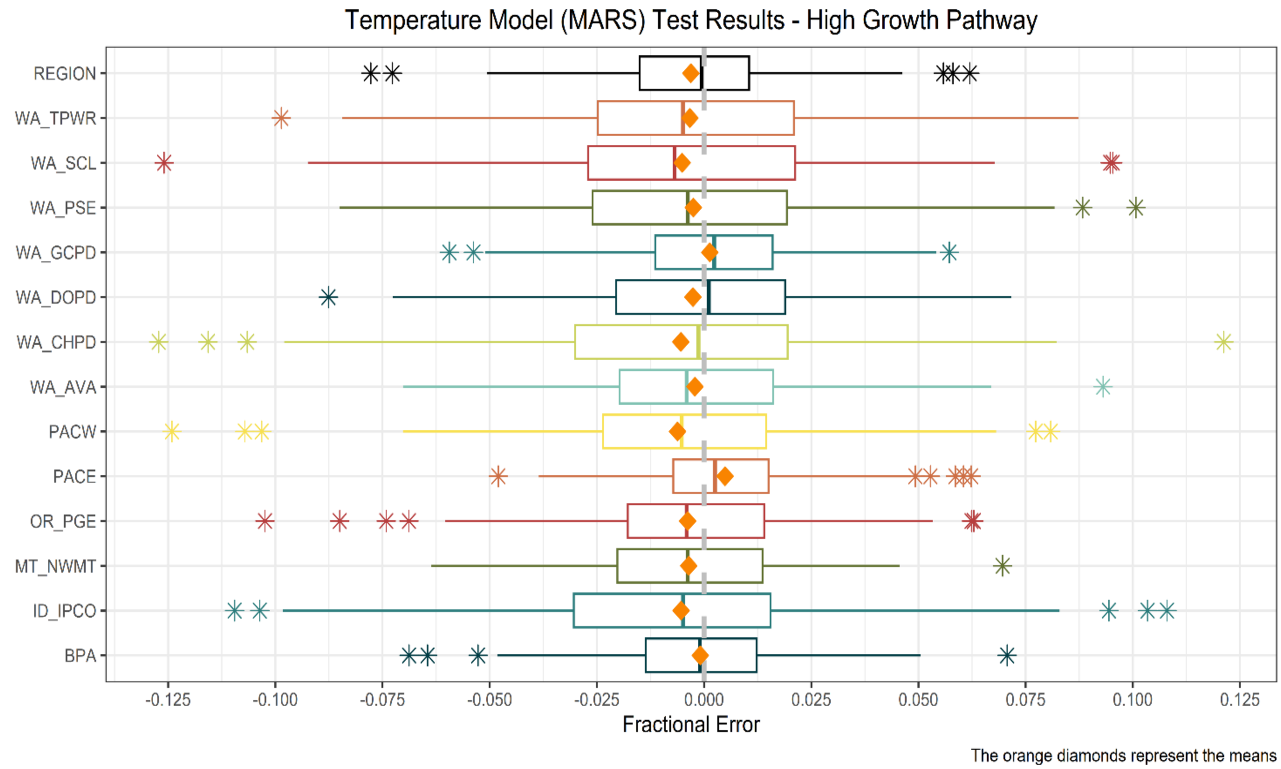
Itron data in columns Month, Day of Week, Holiday, Daily Average Temperature and Daily Average Load are used to develop the MARS model. In data science jargon, Month, Day of Week, Holiday, Daily Average Temperature are the predictors, and Daily Average Load is the target.

In developing the MARS model, following standard practice, the Itron data for year 2031 in Table K - 4 is divided into a training data set which is used to calculate an optimized set of parameters for which a representative error of the MARS load forecast is minimized with respect to the Itron load forecasts.

With the optimized parameters calculated, the MARS model is then evaluated on the test data set which is the remaining data in Table K - 4 after the training set has been removed. Typically, around 80% of the total data goes to training, and the remaining 20% is reserved for the test data set. The MARS optimized parameters were calculated only from the training set and not from the test set, so the test forecast error should be more likely to represent errors of the MARS model forecast when MARS is applied to relevant predictor data from other climate model years.

For Power Plan year 2031, a MARS model is developed for each of the 13 BAs for all three relevant pathways, High Growth, Low Growth, and Mixed Bag, using input and output training data from Itron. The MARS forecast errors of the test data set for the High Growth Pathway for the 13 BAs and the entire region (whose load is the sum of all 13 BA loads) are plotted below in Figure K - 1.

Figure K - 1: MARS Model Test Data Forecast Error for the 13 BAs and the Region



In Figure K - 1, the test data forecast errors for day i in the test data set is defined as a fractional error $E_i = (\overline{L}_i' - \overline{L}_i)/\overline{L}_i$ where $\overline{L}_i'$ and $\overline{L}_i$ are the MARS forecast and the Itron forecast, respectively. Therefore, a fractional error $E_i = 0.01$ means that for day i, the MARS forecast over-predicts the Itron forecast by 1%.

In more detail, the distributions of the test data daily forecast (fractional) errors for the 13 BAs and the region are plotted as horizontal boxplots where the orange diamond inside each boxplot represents the average. Furthermore, for each BA and the region, its boxplot (the box, the whiskers and the outliers) represents a distribution of 108 test data forecast errors.

In Figure K - 1, the BAs are listed along the y-axis, in alphabetical order starting at the bottom, and the fractional error E_i is plotted along the x-axis.[29] In addition, the vertical gray dashed line represents $E_i = 0$, and helps to visualize any positive or negative bias of the boxplots. For example, if the boxplot is biased to the left of the gray dashed line, then the MARS forecasts tend to under-predict the ITRON forecast. It could be seen that for 10 BAs and the region the MARS forecast tends to slightly under-predict the Itron forecast.

[29] The 13 Balancing Authorities (BAs) and their corresponding acronyms are listed in Technical Appendix I – Demand Response Methodology and Potential.

The largest errors are those outliers (plotted as $*$s) with magnitudes at about 12.5%. However, there are only four such large outlier errors from three BAs: Seattle City Light (WA_SCL), Chelan PUD (WA_CHPD) and PacifiCorp West (PACW). Furthermore, for all 13 BAs and the region, there is a total of only 14 outliers (out of a total $14 \times 108 = 1{,}512$ test forecast errors) with magnitudes above 10%, and the bulk of their distributions (i.e., the box and both whiskers) have magnitudes below 10%. In particular, for BPA (plotted at the bottom) which has the highest load magnitude and the entire region (plotted at the top), their forecast error distributions have magnitudes below 7.5%, with all whisker magnitudes around 5%.

The MARS models were also developed for the two remaining pathways, Low Growth and Mixed Bag. The model forecast errors have similar distributions as those plotted in Figure K - 1 in that there are few outliers with magnitudes above 10% with the bulk of the distributions being below 10%.[30] Therefore, the MARS models could be considered as being acceptable in reproducing the Itron RCI daily average loads for climate model year 2031 of A, C and G. The models are then applied to relevant predictor data from the 29 remaining climate model years of A, C, and G to forecast their RCI loads.

Wholesale Market Availability

While OptGen evaluates outside the region resources and loads in its regional resource strategy evaluation, the buildout of outside the region market resources is performed in Aurora. Since OptGen and GENESYS can dispatch and evaluate the resources outside the region in more detail than Aurora with respect to operating reserves, the Council uses the buildout of resources (rather than market prices) from the Aurora analysis. The goal is to better capture market fundamentals in the regional resource selection, the needs assessment, and the adequacy check. The buildout parameters and results in Aurora are described in more detail in Technical Appendix L – Wholesale Market Availability Results.

Buildout Representation in Other Models

The buildout in Aurora includes the buildout of regional resources. Those resources are removed from available market in SDDP/OptGen and GENESYS. Out of region resources built by Aurora are aggregated into bundles for modeling simplicity and speed when used in OptGen/SDDP and GENESYS. All resources are represented as bundles by resource type and zone. Existing thermal resources are bundled by heat rate and fuel type for each bus. New thermal resource bundles are by resource type (combined cycle gas turbines, simple cycle gas turbines, geothermal and clean baseload proxy resource). New combined cycle gas turbine (CCCT) resource bundles must be committed to the minimum generation of the smallest resource in the bin to be accessible for

[30] There is one exception: for the Mixed Bag pathway, the MARS model for Idaho Power (ID_IDPO) has a lower whisker *just slightly* below -10%.

generation or reserves in OptGen/SDDP and GENESYS dispatch. Unit commitment is inactive for existing out-of-region CCCTs and simple cycle gas turbines. Existing and new renewable resources are aggregated by renewable availability, type and bus. Existing and new storage resources are aggregated by type and bus. Existing out of region hydro is bundled by bus and modeled with simple inventory management and capability with the exception of British Columbia hydro in the Columbia River watershed which are modeled individually and with similar detail to in-region hydro resources. The outside the region existing hydro availability is described in more detail in the Technical Appendix D – Climate Model Data and Assumptions.

Further Reference

For more information pertaining to the public process of vetting the assumptions and methodologies in this technical appendix please reference the following meetings:

- **November 6, 2024 SAAC Meeting:** https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2024-11-06
- **February 27, 2025 SAAC Meeting:** https://www.nwcouncil.org/meeting/resource-adequacy-and-system-analysis-advisory-committees-combined-meeting-2025-02-27
- **April 1, 2025 Council Meeting:** https://www.nwcouncil.org/fs/19331/2025_04_07.pdf
- **July 17, 2025 SAAC Meeting:** https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2025-07-17
- **August 26, 2025 SAAC Meeting:** https://www.nwcouncil.org/meeting/system-analysis-and-resource-adequacy-combined-advisory-committees-2025-08-26
- **October 1, 2025 SAAC Meeting:** https://www.nwcouncil.org/meeting/system-analysis-and-resource-adequacy-combined-advisory-committees-2025-10-01
- **November 5, 2025 SAAC Meeting:** https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2025-11-05
- **January 6, 2026 Council Meeting:** https://www.nwcouncil.org/fs/19713/2026_01_3.pdf#page=8
- **February 26, 2026 Council Meeting:** https://www.nwcouncil.org/fs/19748/2026_02_7.pdf
- **April 26, 2026 SAAC Meeting:** https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2026-04-22
- **May 6, 2026 SAAC Meeting:** https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2026-05-06