Technical Appendix M: Needs Assessment Results

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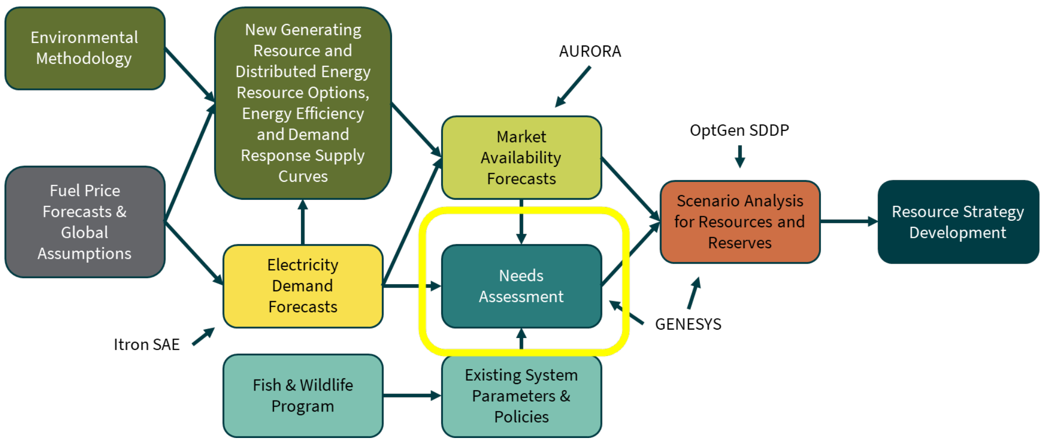
Introduction

The needs assessment is an important component of the Power Plan process to evaluate the need – also known as the resource gap – in a future year close to the end of the action period. Meeting this need is necessary for the region to be adequate. For the Ninth Plan, the needs assessment analyzed 2031. The need is evaluated with GENESYS, the Council's adequacy model, a multi-stage production cost model that co-optimizes energy and reserves while accounting for fuel use, forecast error and system constraints. Using the Council's multi-metric adequacy framework, the need is translated into capacity and energy signals for OptGen, the portfolio expansion model. These signals are called planning reserve margins (PRM) for capacity, and adequacy reserve margins (ARM) for energy. Both the PRM and ARM serve as a percentage above load that must be met to be considered adequate. OptGen then determines a resource strategy that meets the region's needs under different futures, ensuring OptGen's resource builds are resource adequate, which is then tested back in GENESYS to confirm adequacy

The needs assessment takes place at an important junction in the Power Plan process. It occurs before the portfolio model (OptGen) is run, and takes inputs from the market availability forecasts, electricity demand forecasts, and existing system parameters and policies to simulate the Northwest power system in a future year as can be seen in Figure M - 1.[1]

Figure M - 1: Power Plan Process



The needs assessment is done for multiple sensitivities in 2031, which align with the scenarios and sensitivities in the Ninth Plan. Each needs assessment test creates a specific PRM and ARM to be used with the corresponding scenario in OptGen.[2] While the PRM and ARM inform OptGen, the resulting resource buildout still needs to be tested in GENESYS to ensure the adequacy criteria are satisfied. This step – known as the adequacy check – is not part of the needs assessment, but comes later in the resource strategy development.[3]

A distinction should be made between the Council's needs assessment and adequacy assessment. Needs assessments are conducted during a power plan to define the need that the region is facing in the future year. The needs assessment does not contain new resources and typically sees a resource deficit. An adequacy assessment looks at a future year with power plan recommended resources included, with the goal of ensuring that strategy provides for an adequate system.

Council's Adequacy Criteria

Though the need is defined in terms of the PRM and ARM, it is based on the Council's multi-metric adequacy criteria. While in the past adequacy was determined if a strategy resulted in a Loss of Load Probability (LOLP) of 5% (no more than one in 20 years with any shortfalls), the new multi-metric criteria ensures specific frequency, duration, and magnitude perspectives are met based on shortfall risks the region wants to protect against.

[1] See Technical Appendix K - Modeling Framework, Technical Appendix L – Wholesale Market Availability Results, Technical Appendix F – Electricity Demand Forecast, and Technical Appendix B – Existing System Parameters and Polices
[2] See Technical Appendix N – Scenario Modeling and Results.
[3] Ibid.

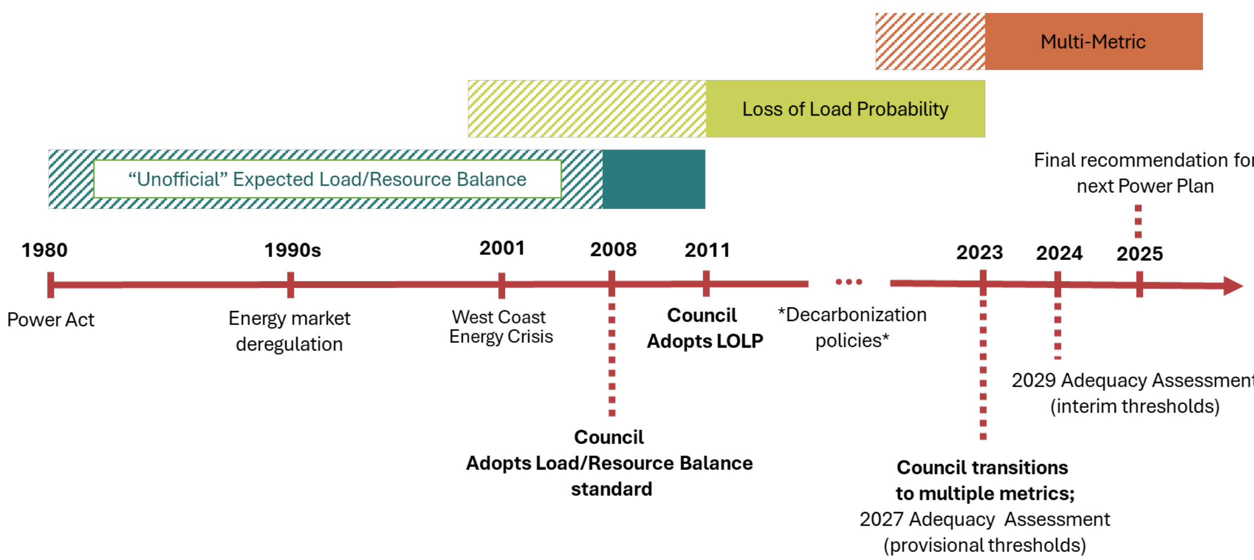
Council staff closely engaged with the Resource Adequacy Advisory Committee (RAAC) and regional partners to define and quantify the shortfall risks to avoid, and which specific metrics and thresholds are associated with them.[4] Overall, the region is considered adequate if the adequacy metrics indicate that the simulated shortfall record statistics are at or below the risk tolerance for the frequency, duration, and magnitude of events.

Part of this process was defining and quantifying risk of taking emergency measures into account (more extreme actions utilities and decision-makers can take to avoid a curtailment event). Though these emergency measures are not modeled in Council tools, understanding the characteristics of simulated shortfalls sheds light on frequency, duration, and magnitude of emergency measures that would be necessary to mitigate events. As such, staff collaborated with stakeholders on aggregating regional emergency capabilities and considering the risk tolerance for using (and not over relying on) these emergency capabilities.

Metrics and Thresholds

The Council's process to evaluate the metrics and threshold took several years, with 2022 dedicated to developing a provisional framework and culminated in official adoption of the proposed multi-metric criteria in April 2025,[5] seen in Figure M - 2.

Figure M - 2: Council's Evolving Approach to Adequacy



The first use of the provisional multi-metric framework was in the 2027 Adequacy Assessment, which included provisional threshold ranges for each metric to capture both lower and higher risk tolerances. In January of 2023, the Council decided to transition to the new multi-metric framework –

[4] See Resource Adequacy Advisory Committee resources.
[5] See Proposed Final Adequacy Criteria for Ninth Plan, https://www.nwcouncil.org/fs/19330/2025_04_06.pdf.

while recognizing it will be an ongoing, evolutionary process – and tasked staff to collaborate with the region on finetuning the thresholds. Over the course of 2023, staff engaged with utilities, regional organizations, and public utility commissions to solicit feedback on the multiple metrics, thresholds, and approximation of emergency measures. Interim findings of the stakeholder engagement process were presented at the May 2023 Council meeting and the findings in January 2024 with the RAAC Steering Committee and Technical Committee that have since been updated per April 2025.

The metrics are calculated from GENESYS, which simulates the region's bulk power system. In each simulation, representing one year, a simulated model shortfall event occurs over a period when load or required reserves cannot be served by resources in the model. However, a shortfall in the model does not mean an outage will take place. Instead, the modeled shortfall signals that emergency measures are necessary to avoid the outage. Emergency measures could include high operating cost resources not in an active utility portfolio, high priced market purchases above the import limit (such as those that occurred during January 2024's winter storm event), and calls for conservation by government officials (as in the September 2022 California heatwave), or curtailment of fish and wildlife hydro operations (like during the 2001 Energy Crisis). Council staff distinguished the emergency measures available to the region in two groups:

- Within Utility Control ("low lift"): refers to measures that are typically within a utility's control, such as relying on costly resources outside of the active portfolio, industrial back-up generators, load buy-back provisions, and larger and costlier market purchases above normal market reliance limits.
- Outside Utility Control (less desirable, "heavy lift"): refers to extraordinary measures of extreme cases where customers may experience direct impacts, such as official's call to conservation, emergency load shedding protocols (rolling brownouts), or curtailing fish and wildlife operations.

Using multiple metrics – frequency, duration, and magnitude – gives decision makers the opportunity to understand the adequacy risk and how it relates to reliance on emergency measures. To be deemed adequate, all metrics must be satisfied (within their thresholds), and they include: [6]

- Annual Loss of Load Events (LOLEV) of 0.2:
  Sets a limit for the expected frequency of shortfall events to not exceed one in five years
- Winter and Summer Loss of Load Events (LOLEV) of 0.1:
  Sets a limit for the expected frequency of shortfalls in winter and summer (each) to not exceed one in ten years

[6] For an illustrative example of the calculation method, see May 2023 Council's presentation "Multi-Metric Approach to Adequacy: Progress Report" slide pages 5-12 (other sections have been updated since).

- Duration Value at Risk (VaR) 97.5th Percentile:
  Sets a limit for shortfall duration to protect against tail-end (extreme) duration use of emergency measures, not to exceed 8 hours in more than 39-out-of-40 years
- Peak Value at Risk (VaR) 97.5th Percentile:
  Sets a limit for maximum hour capacity shortfall to protect against tail-end (extreme) magnitude use of emergency measures, not to exceed 1,200 MW in more than 39-out-of-40 years
- Energy Value at Risk (VaR) 97.5th Percentile:
  Sets a limit for total annual energy shortfall to protect against tail-end (extreme) annual aggregate energy use of emergency measures, not to exceed 9,600 MW in more than 39-out-of-40 years

The calculation methodology differs for LOLEVs and VaRs. For LOLEVs, the number of events throughout the years and those only in winter and summer are divided by the total number of simulations (90 in the case of the Council representing the 90 climate years) seen in the equations below. The resulting value can be interpreted as the average number of events in each year/season.

$$Annual\ LOLEV = \frac{\sum Events_j}{N\ simulations}$$

$$Winter\ LOLEV = \frac{\sum Events_{winter}}{N\ simulations}$$

$$Summer\ LOLEV = \frac{\sum Events_{summer}}{N\ simulations}$$

The tail-end VaR metrics instead focus on first creating the distribution of shortfall quantities, including: the distribution of unserved energy for every simulation, the distribution of maximum single-hour shortfall magnitude for every simulation, and the distribution of maximum shortfall event-duration for every simulation. Then, the 97.5th percentile of each distribution is calculated and is the metric value.

By bridging modeled shortfalls to the need of emergency measures, the Council's multi-metric adequacy framework is aimed at protecting against the risk of Outside Utility Control emergency measures. As such, quantifying the region's aggregate Within Utility Control's emergency measures, and setting the metric thresholds to those capabilities, enables a probabilistic approach to how often extreme measures (Outside Utility Control) are expected (but not which measure would be used).

This approach can be summed up as "Let's make sure any emergency measures aren't used too often" (satisfying LOLEV), and "For the vast majority of the time let's make sure the emergency measures we rely on are not used too long or are too big" (satisfying duration, peak and energy VaR). The significance of the VaR metrics at the 97.5th percentile with a threshold associated with Within Utility Control emergency measures means we can expect to avoid the extreme, less desirable, emergency measures 39 out of 40 years.

However, because it is difficult to fully and accurately account for the magnitude and duration of all emergency measures, staff recognize that thresholds are approximations. Further, there is no clear line in the sand between magnitude of Within Utility Control and Outside Utility Control measures as these may vary by utility and circumstance. As such, the framework should be understood as an evolutionary process towards redefining tail-end system risk, rather than a complete characterization of emergency measures.

Lastly, an important connection should be understood between the metrics, specifically the thresholds, and the Council's longstanding market reliance limit. This limit – 2,500 MW in winter and 1,250 MW in summer – was developed with the Resource Adequacy Advisory Committee and acts as a philosophical hedge against over relying on market imports at time of system stress. As the market is a dynamic resource in GENESYS, it means the shortfall record – the direct link to calculating adequacy metrics – is reflecting the shortfalls given the market limit. This means that the thresholds described above consider the market reliance limits and any future change to the market reliance limit would require an evaluation of how the thresholds (and emergency measures) would be influenced.

Loss of Load Events

As the frequency of shortfalls is equivalent to the frequency of using emergency measures, a limit can be set for the frequency of simulated shortfalls as it relates to preventing overly frequent use of emergency measures. The Council chose the Loss of Load Events (LOLEV) to meet this objective, which is the expected number of shortfall events per desired period. LOLEV is equal to the total number of shortfall events divided by the total number of simulation periods (for example, number of years or number of seasons). Because periods of most concern include summer and winter, staff heard feedback to align with the Western Resource Adequacy Program (WRAP) seasonal approach and decided to set a threshold value for both summer and winter at 0.1 (expected frequency of events to not exceed one in ten years in each season). However, risk may change over time, so considering shortfall risk throughout the year is important as well. Therefore, an annual LOLEV is also used to cover risk across a year set at 0.2(expected frequency of events to not exceed one in five years).

Duration Value-at-Risk 97.5th Percentile

Long shortfall events can indicate insufficient system energy (i.e. fuel). Long shortfall events can occur during periods of prolonged extreme weather (like during the January 2024 winter storm), due to fuel supply issues (for example a low water year), or other disruptions. The Council chose the Value at Risk (VaR) for shortfall event duration at the 97.5th percentile over all simulation years to capture this risk. To calculate this metric, the duration of the longest shortfall event for each simulation year is recorded (and noted as zero if there is no shortfall in a year). Then, the Duration VaR97.5 is the 97.5th percentile of the distribution of this record from all simulation years. Choosing the 97.5th percentile limits the risk of an excessively long shortfall event to no more than once per 40 years. The threshold for this metric is set to 8 hours, to reflect the minimum shortfall duration that could lead to severe customer risk.

Peak Value-at-Risk 97.5th Percentile

The Pacific Northwest's power supply has historically been capacity long, but energy short. The region has had an excess of peaking capacity but is limited by the water supply that powers the hydroelectric system, which provides more than half of the grid's nameplate capacity. While the hydroelectric system's nameplate capacity is about 35,000 megawatts, it generates about 16,000 average megawatts per year, on average, and only around 12,000 average megawatts during a low water year. However, due to significant increases in loads, especially peaking loads of (heating and cooling and transportation electrification), alongside increases invariable energy resources, changes in hydroelectric operating constraints, and other added complexities, the region can no longer assume that it has sufficient capacity to meet all demand. Thus, it is important to include a metric to protect against excessively high-capacity shortfalls.

The Council chose the Value at Risk (VaR) for capacity shortfall at the 97.5th percentile over all simulation years to manage this risk. To calculate this metric, the highest single-hour shortfall for each simulation year is recorded. The Peak VaR97.5 is the 97.5th percentile of the distribution of this record from all simulation years. While this frequency is smaller than that chosen for the LOLEV, it represents the risk of exceeding Within Utility Control emergency measure capability, whereas the LOLEV frequency represents the risk of using emergency measures too often.

The limit for this metric represents the amount of single hour demand the region is willing to risk. As such, the limit is set equal to the aggregate amount of emergency peaking capability. The risk of curtailment is high when the Peak VaR97.5 exceeds this limit because avoiding a loss of service depends on the availability of emergency measures not accounted for in the adequacy limit. The threshold for this metric is set at 1,200 megawatts (the amount of emergency resources estimated to be in the region). Note that using the full 1,200 megawatts of resource would require coordination across multiple utilities.

Energy Value-at-Risk 97.5th Percentile

The region's power supply is energy limited because hydroelectric resources make up the lion's share of the supply. It is important to include a metric to protect against annual energy shortfalls. Unlike the capacity metric, whose limit is tied to the highest single-hour shortfall, the energy metric is tied to the entire year's unserved energy. This is because energy shortfalls are often equated to a lack of fuel, whereas capacity shortfalls are often equated to a lack of steel-in-the-ground capability. Once the capability is sufficient to offset the highest capacity shortfall, all remaining shortfalls can also be offset. However, sufficient fuel to offset the highest energy shortfall does not guarantee that other energy shortfalls throughout the year can also be offset.

The metric chosen to achieve this objective is the VaR for energy shortfall at the 97.5th percentile over all simulation years. To calculate this metric, total annual unserved demand for each simulation year is recorded. The Energy VaR97.5 is the 97.5th percentile of the distribution of this record from all simulation years. Similar to Peak VaR, this frequency is smaller than that chosen for the LOLEV, representing the risk of exceeding Within Utility Control emergency measures.

The limit for this metric represents the amount of annual energy demand the region is willing to risk. As such, the limit is equal to the aggregate amount of emergency energy generating resources. But because it is difficult to accurately assess the amount of available emergency energy, the limits assumes the "worst acceptable" annual unserved energy as the longest allowed 97.5th duration of 8 hours, where each hour has the largest allowed 97.5th hourly peak magnitude of 1,200 MW, the limit can be set at 9,600 MWh for the year.

Needs Assessment Methodology for Ninth Plan

As discussed in the introduction, the outcome of the needs assessment is the signal to OptGen, the capital expansion model, to develop a resource strategy for the region to be adequate in a future year. The need is calculated in GENESYS, and it can be defined in terms of energy and capacity needed for adequacy. These values are then translated into a percentage-based planning reserve margins (PRM) for peak, and an annual energy target for the adequacy reserve margin (ARM).

Role of Planning and Adequacy Reserve Margins

The PRM tells the model the level of resources required to stay adequate for a specific period. For example, a 20% PRM in January tells OptGen that the resource strategy should ensure resource (including generation and demand side management) have a capability at least 20% above load for the month of January. For example, if the January load is 34,000 MW, then the resource capability should be 34,000 MW+ 6,800 MW (20% of load) for a total of 40,800 MW.

For the ARM, the model is given an annual energy target for new resources only, effectively telling the model how many new resources in addition to the existing system are needed for adequacy. For example, an ARM of 5,000 aMW tells the model to acquire new supply side and demand side resources that provide that level of annual energy.

To help guide the description, keep in mind that LOLEV and Peak VaR 97.5th percentile influence the PRM for peak capacity, and Duration and Energy VaR 97.5th percentile influence the ARM for energy.

Peak – Planning Reserve Margin

The PRM is derived from three important components, including the implied need to satisfy the adequacy criteria, the load resource balance (LRB) in regards to the capability of the existing system and load growth, and temperature-sensitive extreme conditions. The implied need to satisfy adequacy is derived from GENESYS's shortfall record, the LRB is derived from OptGen, and temperature-sensitive extreme conditions are derived from GENESYS-OptGen dynamics.

Defining Need from GENESYS

While GENESYS simulates the region's power supply, the determination whether the region is adequate is calculated in post-processing from analyzing the shortfall record. The shortfall record includes all hours in a year from all years in the simulation, and records 0 for no shortfalls or a positive value if there was a shortfall. In total, each study has 786,240 hours of observations (90 unique climate years * 8,736 hours).[7] Part of the shortfall record development includes post-processing assumptions about whether the load forecast includes elastic loads. These loads, like hydrogen production, are assumed to be curtailed (i.e. not met) during stressful system conditions. However, as GENESYS does not differentiate elastic from inelastic loads, the magnitude of the elastic load needs to be netted out of the shortfall as it theoretically would have been curtailed. In the High Growth pathway, there is 461 aMW of hydrogen, and therefore 461 MW are netted out of each shortfall in the High Growth trajectory. In other trajectories, shortfalls below 25 MW are assumed to be market noise and therefore removed from the record as well.

From this record, the annual and seasonal LOLEVs are calculated, as are the 97.5th percentiles of longest durations, peak magnitude, and annual unserved energy. The post-processing analysis also includes a dataset of all shortfall events identified by scenario, month they occurred, day in the month, event duration, peak hour (MW) in the event, total event unserved energy (MWh), an hourly dataset of all shortfall hours, and monthly statistics for each of the duration, peak, and energy Value-at-Risk 97.5th percentiles. If any metric is violated, there is an implied capacity or energy need that, theoretically, if it were to be added to the system, would make the system adequate. The detailed shortfall dataset then helps identify the temporal and magnitude dimensions of the need.

An important note – there may be hours where GENESYS computation reaches an infeasibility, and no value is recorded until the computation reaches another stage or seam where it can reach a solution. Though infrequent, it tends to happen when the model is experiencing a simultaneous convergence of challenging water conditions and system constraints that make finding a solution infeasible within the time allowed. As it is theoretically possible to "miss" shortfalls if they could have occurred in these missing hours, staff proposed a conservative approach of replicating the applicable data of the closest available previous day or days. For example, if a shortfall happened on Feb 10th from 10-12pm, but then Feb 11 experienced an infeasibility, the shortfall record will also include the same Feb 10th shortfall from 10-12pm on Feb 11. This is a post-processing modification, and why it is possible to see "duplicated" events in the shortfall record.

Satisfying LOLEV

With most adequacy metrics the system is not designed to be 100% adequate under all conditions. An adequate system will still, in modeling, have outages. In the adequacy assessment, we define these outages as “keep.” For example, a winter LOLEV of 0.1, calculated from 90 simulations, means no more than 9 (0.1 * 90 = 9) events may occur in the winter. However, if the simulated shortfall record had 20 events in winter (LOLEV of 0.22), then 11 of them would have to be mitigated to reduce the number of events to 9, the allowed limit. In other words, any event past the allowed simulated threshold must be mitigated – and the MW capacity to do so is the implied need to satisfy LOLEV.

This means that the first step in identifying the need requires categorizing each event as either “keep” (allowed to occur under the adequacy thresholds) or “mitigate.” Theoretically, if the largest peak

[7] For multi-stage modeling purposes that require dividing the year to 52 stages (weeks), December 31st is ignored.

hourly shortfall is mitigated by adding the capacity to satisfy it, then all remaining shortfalls would also be mitigated, resulting in an LOLEV of 0. This would result in an overly adequate, and expensive, system. On the opposite side, adding capacity to satisfy only the smallest peak shortfall would only mitigate 1 shortfall, resulting in an LOLEV of 0.21, still not adequate. The solution is in identifying the largest events that can be "kept" from the shortfall record, in this case the top 9 events, and then require the mitigation from the 10th event until the last one. The peak capacity to mitigate the 10th event is the implied need to satisfy LOLEV. This is the case whether there are 20 events, 100 events, or 2,000 events across the 90 simulations.

The Council's frequency criteria includes both an annual LOLEV of 0.2, and winter and summer LOLEVs of 0.1. This means that annually 18 events are allowed to be "kept" (0.2 * 90 simulations), but only 9 events are allowed each in winter and summer. This also means that a shortfall record with exactly 9 winter events and 9 summer events would be adequate, as annually there are no more than 18 (LOLEV 0.2) and both winter and summer have no more than the allowed 9 (LOLEV 0.1).

However, consider the case when the top 18 annual events have 11 winter events, 6 summer events, and one fall event. Annually speaking, all events would be categorized as "keep" and the system would be adequate from an annual perspective. However, the 11 winter events are above the 9 allowed to meet the winter LOLEV criteria. In this situation, the shortfall record needs to account for a seasonal category of "keep" and "mitigate" as well.

To reconcile the annual and seasonal differences, the analysis requires mitigation of annual, winter, and summer events to meet both thresholds (annual and seasonal). The question becomes which need, annual or seasonal, is the resulting signal. Here, the analysis requires breaking down the shortfall record by month, and then looking at the peak shortfall in each period that must be mitigated. If the winter and summer implied need is larger than the annual implied need for that month, then the seasonal need is the signal. If the implied annual need is larger than the implied winter and summer need, then the annual need is the signal.

Satisfying Peak VaR 97.5th Percentile

After calculating the implied monthly need to satisfy both annual and seasonal LOLEVs, the analysis turns to the implied need to satisfy the Peak VaR 97.5th percentile. While LOLEVs have a monthly component to the annual and seasonal LOLEVs, the Peak VaR is different.

As a tail-end metric from a distribution of maximum shortfalls, the implied annual need to satisfy the Peak VaR metric is the difference between the metric value and the threshold. If the metric result is, for example, 11,000 MW, then the implied need is 9,800 MW (11,000 – 1,200). Again, the 1,200 MW threshold is based on estimated emergency resource capabilities. Theoretically, if the system had an additional 9,800 MW of peaking capability, the shortfall record would reflect that all peaks would be 9,800 MW lower (or zero), and the system would be adequate.

Similar to LOLEV, a temporal nuance is needed to finetune the Peak VaR signal in OptGen. Building to the annual Peak VaR value every month would likely result in a resource overbuild, so the Peak VaR analysis requires understanding the monthly Peak VaR values. These are calculated by taking the

97.5^{th} percentile of peak events within each month, seen in Figure M - 3, alongside the 1,200 MW threshold.

Figure M - 3: Example of Monthly Peak VaR 97.5^{th} Percentile

Notice that the shortfalls are not equal throughout the year, with winter and summer months experiencing the largest shortfall risks, with other months are below the threshold. While the monthly VaR is not an adopted adequacy metric, it can be used to guide the decision on which month has the risk for highest shortfalls – in this example January. For the Ninth Plan the month with the highest risk is given the annual signal to protect against the annual peak.

Reconciling the Need Signal Between LOLEVs and Peak VaR 97.5^{th} Percentile

Once the monthly need from both LOLEVs (annual and seasonal) and Peak VaR (guided by monthly Peak VaR) are calculated, the next step is determining if the month receives the annual Peak VaR or the LOLEV value. An example of this is seen in Table M - 1.

1 **Table M - 1: Example Selection of Monthly Need Signal**

	Annual Frequency (MW)	Seasonal Frequency (MW)	Monthly Peak VaR (MW)	Annual Peak VaR (MW)	Season	Is Seasonal_F > Annual_F?	Is Highest Monthly Peak VAR?	Is Annual VaR largest?	Monthly Need (MW)
Jan	7,743	9,245	9,457	9,845	winter	TRUE	TRUE	TRUE	9,845
Feb	8,270	8,270	8,121	9,845	winter	FALSE	FALSE	FALSE	8,270
Mar	1,482	-	1,195	9,845	shoulder	FALSE	FALSE	FALSE	1,482
Apr	3,305	-	326	9,845	shoulder	FALSE	FALSE	FALSE	3,305
May	5,408	-	2,534	9,845	shoulder	FALSE	FALSE	FALSE	5,408
Jun	5,170	4,752	4,524	9,845	summer	FALSE	FALSE	FALSE	5,170
Jul	5,551	4,886	4,006	9,845	summer	FALSE	FALSE	FALSE	5,551
Aug	8,256	5,015	4,586	9,845	summer	FALSE	FALSE	FALSE	8,256
Sep	5,649	-	1,703	9,845	shoulder	FALSE	FALSE	FALSE	5,649
Oct	-	-	-	9,845	shoulder	FALSE	FALSE	FALSE	-
Nov	6,882	-	4,234	9,845	shoulder	FALSE	FALSE	FALSE	6,882
Dec	7,053	8,770	6,966	9,845	winter	TRUE	FALSE	FALSE	8,770

The table is used to determine which need signal – satisfying annual or seasonal LOLEV, or Peak VaR – will be used in each month. With the logic columns of TRUE/FALSE indicating whether seasonal frequency MW is larger than annual frequency MW, which month has the highest monthly Peak VaR and therefore should be linked with the Annual Peak VaR, and is the Annual Peak VaR in the selected month larger than both the annual and seasonal frequency MWs. The equations below describe the selection logic for the need in each month.

$$\text{Is Seasonal}_{\text{F}} > \text{Annual\_F}_i = \begin{cases} \text{TRUE,} & \text{if Seasaonl Frequency}_{\text{i}} > \text{Annual Frequency}_{\text{i}} \\ \text{FALSE,} & \text{otherwise} \end{cases}$$

$$\text{Is Highest Monthly Peak VaR}_{\text{i}} = \begin{cases} \text{TRUE,} & \text{if Monthly Peak VaR}_{\text{i}} = \text{Max(Monthly Peak VaR)} \\ \text{FALSE,} & \text{otherwise} \end{cases}$$

$$\text{Is Annual VaR largest?}_{\text{i}} = \begin{cases} \text{TRUE,} & \text{if Annual Peak VaR}_{\text{i}} > \text{Seasonal\_F and Annual\_F} \\ \text{FALSE,} & \text{otherwise} \end{cases}$$

$$\text{Monthly Need}_i = \begin{cases} \text{Annual\_F}_i, & \text{if Seasonal\_F}_i \; is\ FALSE \; \text{ and Annual VaR FALSE} \\ \text{Seasonal\_F}_i, & \text{if Seasonal\_F}_i \; is\ TRUE \; \text{ and Annual VaR FALSE} \\ \text{Annual\_Peak\_VaR,} & \text{otherwise} \end{cases}$$

Following the selection logic, each month is further broken down for the peak hour-month capacity shortfall from the shortfall record. Months whose need signal is driven by either the seasonal LOLEV or the annual Peak VaR have all hours superimposed by the larger value (in the example, all of January is superimposed with the Peak VaR and December the Winter with the LOLEV frequency signal), as seen in Table M - 2. The shortfall record uses the specific hourly level data of each shortfall event to know the peak need in every hour in every month just from the events that need to be mitigated.

Table M - 2: Peak Hour-Month MW of the Implied Need to Satisfy LOLEV & Peak VaR

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	9,845	5,256	504	3,289	4,760	4,425	2,575	3,267	-	-	-	8,770
1	9,845	3,555	111	1,858	4,690	1,877	1,159	1,343	-	-	-	8,770
2	9,845	2,960	111	1,850	1,246	2,370	1,050	447	-	-	-	8,770
3	9,845	3,158	118	2,003	1,544	1,926	571	1,481	-	-	441	8,770
4	9,845	3,827	171	1,988	2,075	2,001	1,138	1,505	-	-	1,069	8,770
5	9,845	5,044	298	2,112	2,500	2,720	1,531	1,046	-	-	1,452	8,770
6	9,845	6,836	642	2,192	1,954	2,821	2,795	2,621	117	-	4,400	8,770
7	9,845	8,013	1,198	2,210	2,367	3,212	2,807	2,030	-	-	6,228	8,770
8	9,845	8,116	1,361	2,174	2,968	4,285	3,203	2,865	-	-	6,882	8,770
9	9,845	8,270	868	2,115	3,389	3,907	2,734	3,186	-	-	6,340	8,770
10	9,845	7,637	1,218	2,086	2,208	2,744	3,296	2,096	244	-	3,423	8,770
11	9,845	5,429	578	2,074	2,323	2,284	3,073	3,998	168	-	2,591	8,770
12	9,845	4,170	279	2,069	1,882	2,847	2,766	4,610	404	-	1,068	8,770
13	9,845	4,429	946	2,064	1,792	2,446	3,472	5,303	1,767	-	1,435	8,770
14	9,845	3,080	623	2,051	1,986	2,316	3,664	6,019	2,778	-	1,004	8,770
15	9,845	3,576	808	2,045	1,785	3,017	4,092	6,273	3,266	-	1,167	8,770
16	9,845	4,531	1,018	2,065	2,236	3,589	4,808	7,626	4,548	-	2,560	8,770
17	9,845	7,216	542	2,090	3,870	4,752	5,551	7,664	5,302	-	4,363	8,770
18	9,845	6,944	635	2,220	4,574	4,552	5,296	8,256	5,649	-	4,620	8,770
19	9,845	7,324	1,304	2,378	5,408	5,170	5,367	7,501	4,791	-	3,848	8,770
20	9,845	7,637	1,482	2,663	3,233	4,842	4,642	5,935	3,242	-	2,920	8,770
21	9,845	6,071	102	3,305	1,549	3,618	3,607	3,180	2,087	-	1,799	8,770
22	9,845	3,329	-	1,996	1,949	2,675	1,941	-	529	-	1,260	8,770
23	9,845	4,162	1,120	-	807	2,090	-	-	381	-	-	8,770

Next, the analysis needs to net out the simulated balancing up reserves that GENESYS holds to account for forecast error, otherwise it may be double counted in OptGen. Table M - 3 provides the balancing up reserve example, with each month holding a constant reserve requirement on all hours.

Table M - 3: Example of Monthly Balancing Reserves Held on Every Hour (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Balancing Up Reserves (MW)	2,220	2,411	1,781	1,832	1,845	1,651	1,507	1,497	1,755	1,927	1,927	1,811

The resulting subtraction of balancing up reserves from the implied need may result in negative numbers in some hours – this is not wrong, rather means the balancing reserves would be sufficient to handle the deficit event – and in those hours the new assumed value is zero, as seen in Table M - 4.

Table M - 4: Net Implied Need (MW) to Satisfy LOLEV & Peak VaR 97.5th Percentile

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	7,625	2,845	-	1,457	2,915	2,774	1,068	1,770	-	-	-	6,959
1	7,625	1,144	-	26	2,845	226	-	-	-	-	-	6,959
2	7,625	549	-	18	-	719	-	-	-	-	-	6,959
3	7,625	747	-	171	-	275	-	-	-	-	-	6,959
4	7,625	1,416	-	156	230	350	-	8	-	-	-	6,959
5	7,625	2,633	-	280	655	1,069	24	-	-	-	-	6,959
6	7,625	4,425	-	360	109	1,170	1,288	1,124	-	-	2,473	6,959
7	7,625	5,602	-	378	522	1,561	1,300	533	-	-	4,301	6,959
8	7,625	5,705	-	342	1,123	2,634	1,696	1,368	-	-	4,955	6,959
9	7,625	5,859	-	283	1,544	2,256	1,227	1,689	-	-	4,413	6,959
10	7,625	5,226	-	254	363	1,093	1,789	599	-	-	1,496	6,959
11	7,625	3,018	-	242	478	633	1,566	2,501	-	-	664	6,959
12	7,625	1,759	-	237	37	1,196	1,259	3,113	-	-	-	6,959
13	7,625	2,018	-	232	-	795	1,965	3,806	12	-	-	6,959
14	7,625	669	-	219	141	665	2,157	4,522	1,023	-	-	6,959
15	7,625	1,165	-	213	-	1,366	2,585	4,776	1,511	-	-	6,959
16	7,625	2,120	-	233	391	1,938	3,301	6,129	2,793	-	633	6,959
17	7,625	4,805	-	258	2,025	3,101	4,044	6,167	3,547	-	2,436	6,959
18	7,625	4,533	-	388	2,729	2,901	3,789	6,759	3,894	-	2,693	6,959
19	7,625	4,913	-	546	3,563	3,519	3,860	6,004	3,036	-	1,921	6,959
20	7,625	5,226	-	831	1,388	3,191	3,135	4,438	1,487	-	993	6,959
21	7,625	3,660	-	1,473	-	1,967	2,100	1,683	332	-	-	6,959
22	7,625	918	-	164	104	1,024	434	-	-	-	-	6,959
23	7,625	1,751	-	-	-	439	-	-	-	-	-	6,959

The final step to isolate the need from GENESYS is to align the temporal scale with that of OptGen. OptGen is set up to simulate the power system by distinct periods. Staff evaluated the optimal configuration for result convergence and run time and determined that dividing the months to 6 groups throughout the year (instead of using 12 groups, one for each month) is ideal. In that configuration, the groups included Jan-Feb, Mar-Apr, May-Jun, Jul-Aug-Sep, Oct-Nov, and Dec. Though Dec is a winter month, OptGen is not able to group non-consecutive months, and the simulation starts in January. Based on these groupings, the maximum of each month is used as the final need (MW) to satisfy the adequacy metrics, such as the one seen in Table M - 5 (Dec is considered with Jan and Feb). Each study has its own unique need results.

Table M - 5: Example Need Signal From GENESYS

Season	Need (MW)
Jan/Feb	7,625
Mar/Apr	1,473
May/Jun	3,563
Jul/Aug/Sep	6,759
Oct/Nov	4,955
Dec	7,625

OptGen Load Resource Balance

Developing the PRM for peak capacity requires not only the need signal from GENESYS but also the LRB of the existing system, while making sure the temperature-sensitive extreme conditions are protected against.

All needs assessment studies share the same existing system capability and temperature-sensitive extreme conditions as they share assumptions on load pathway and existing in-region resources. This is shown in the example in Table M - 6, including the GENESYS average seasonal peak load, the OptGen seasonal peak load, and the capability of the hydro, thermal, battery, wind & solar, and market to calculate the total resources ($TR_i = \sum_i Resource\_Type_j$).[8]

Table M - 6: Shared Load & Resource Assumptions in OptGen Across Sensitivities

Season	GENESYS Average Seasonal Peak Loads (MW)	OptGen Seasonal Peak Loads (MW)	Avg 2-hr Sustained Peaking Hydro (MW)	Ther-mal (MW)	Battery (MW)	Wind & Solar (MW)	Market (MW)	Total Resources (MW)	Load Re-source Balance
Jan/Feb	42,868	38,096	15,977	12,213	1,160	3,155	6,100	38,604	-4,264
Mar/Apr	35,975	32,429	16,441	12,213	1,160	4,063	4,850	38,727	2,753
May/Jun	36,813	32,357	18,811	12,213	1,160	4,143	4,850	41,177	4,364
Jul/Aug/Sep	40,541	34,826	15,035	12,213	1,160	5,418	4,850	38,675	-1,866
Oct/Nov	37,933	32,366	11,003	12,213	1,160	3,306	6,100	33,782	-4,151
Dec	41,246	36,453	12,946	12,213	1,160	2,296	6,100	34,715	-6,531

The total resources in each season is the sum of each type of resource, and the LRB is the difference between the GENESYS average seasonal load and the total seasonal resource. A negative LRB

[8] The assumed market capability is the total allowed sum-of-circuit transfer throughout the region. This number assumes the market reliance limit is met: 2,500 MW in winter and 1,250 MW in summer.

indicates the season is short. There is no consideration of need at this point, and the fact that the season is short is solely driven by the expected load growth in the future year (2031). Additionally, note that the GENESYS peak load is higher than the OptGen peak load. This is due to GENESYS seeing a full set of temperature informed loads, whereas OptGen uses a typical day load.

Developing Final Peak Planning Reserve Margin

For simplicity in the following tables the seasonal resource breakdowns are removed to focus on the connection to resource need and development of the PRM, illustrated in Table M - 7, with the equations used below. The need column (N) is the same need as developed in the section above.

Table M - 7: Development of Planning Reserve Margin for Peak Capacity

Season	GL **GENESYS Average Peak Loads (MW)**	OL **OptGen Peak Loads (MW)**	TR **Total Resources (MW)**	N **Need (MW)**	LRB **Load Resource Balance (MW)**	AM **Eq1 Adequacy Margin**	SPCR **Eq2 Seasonal Peaking Margin + Contingency Reserves**	PRM **Eq3 Planning Reserve Margin (PRM)**
Jan/Feb	42,868	38,096	38,604	7,625	-4,264	7.8%	19.3%	28.6%
Mar/Apr	35,975	32,429	38,727	1,473	2,753	11.7%	17.6%	17.6%
May/Jun	36,813	32,357	41,177	3,563	4,364	21.5%	20.6%	20.6%
Jul/Aug/Sep	40,541	34,826	38,675	6,759	-1,866	12.1%	23.4%	38.3%
Oct/Nov	37,933	32,366	33,782	4,955	-4,151	2.1%	24.2%	26.9%
Dec	41,246	36,453	34,715	7,625	-6,531	2.7%	19.9%	23.1%

Eq (1):
$$\mathrm{AM}_i = \begin{cases} \frac{\mathrm{TR_i+N_i-LRB_i-GL_i}}{\mathrm{GL_i}}, & \text{if } \mathrm{LRB_i} > 0 \text{ and } N_i > LRB_i \\ \frac{\mathrm{TR_i+N_i-GL_i}}{\mathrm{GL_i}}, & \text{otherwise} \end{cases}$$

Eq (2):
$$\mathrm{SPCR}_i = \left(\frac{\mathrm{GL_i}}{\mathrm{OL_i}}\right) x\,(1.06) - 1$$

Eq (3):
$$\mathrm{PRM}_i = \left[\left(1 + \begin{cases} \mathrm{AM}_i, & \text{if } \mathrm{AM}_i > 0 \text{ and } \mathrm{LRB}_i < 0 \\ \mathrm{AM}_i, & \text{if } \mathrm{AM}_i > 0 \text{ and } \mathrm{Need}_i > \mathrm{LRB}_i \\ 0, & \text{otherwise} \end{cases}\right) \times \left(\frac{\mathrm{GL_i}}{\mathrm{OL_i}}\right) x\,(1.06) - 1\right]$$

Following the three equations helps to understand the PRM process. First, in Eq1 the adequacy margin (AM) is calculated for each period i as the percentage above GENESYS peak load that the LRB and need account for. Second, as mentioned before, as GENESYS observes larger loads, OptGen needs to account for this seasonal peaking margin, which is separate from the need. In Eq2, this takes place, and a contingency of 6% is included to account for the load and generation contingency risk.

Eq3 then integrates the AM and seasonal peaking margin and contingency reserves (SPCR) into the final PRM calculation for each season and defines the percent above load that OptGen must satisfy to meet peak capacity from the existing and new resource strategy. Here, it is important to understand that the need is driven by the higher loads, and the methodology should avoid double counting the impact of higher loads. In this example, notice that as the LRB is positive in Mar/Apr and May/Jun, the SPCR and PRM values are the same – indicating that load growth alone is explains the increase in reserve margins, as opposed to other seasons with negative LRB, and the adequacy need is also a component and resulting in higher PRMs.

Energy – Adequacy Reserve Margin

The process to determine the energy ARM – or firm energy – that OptGen requires relies on the implied need to satisfy the Duration and Energy VaR 97.5th percentiles. Determining this value requires evaluating and manipulating the shortfall record until the metrics are satisfied.

Mitigating Annual Duration VaR 97.5th Percentile Risk

The duration metric is a tail-end statistic of the distribution of longest shortfall durations with the adequacy threshold of 8-hours. As you add more resources to a deficit, system duration VaR is lowered until reaching the allowed limit of 8 hours. Determining how many resources are needed requires iterations of resource additions through post-processing of the shortfall record and rerunning the adequacy analysis until the Duration VaR is satisfied.

Consider the example in Table M - 8 representing a 17-hour long shortfall from one illustrative simulation year that occurred on Feb 10th. In the first iteration 1,000 aMW were added, and every shortfall hour was subtracted by 1,000, and in the second an additional 500 aMW for a total of 1,500 aMW were added. Notice that the 17-hour event became smaller, shorter events.

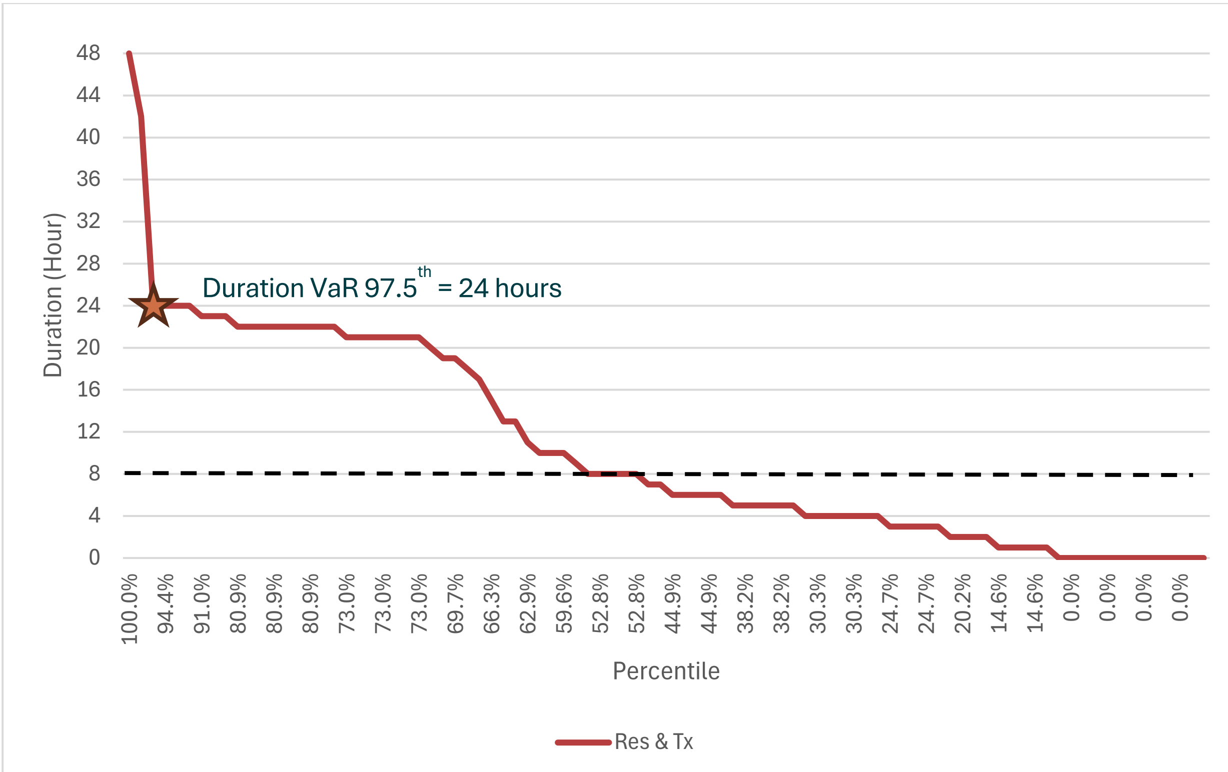
Table M - 8: Illustrative Example for Process to Satisfy Duration VaR

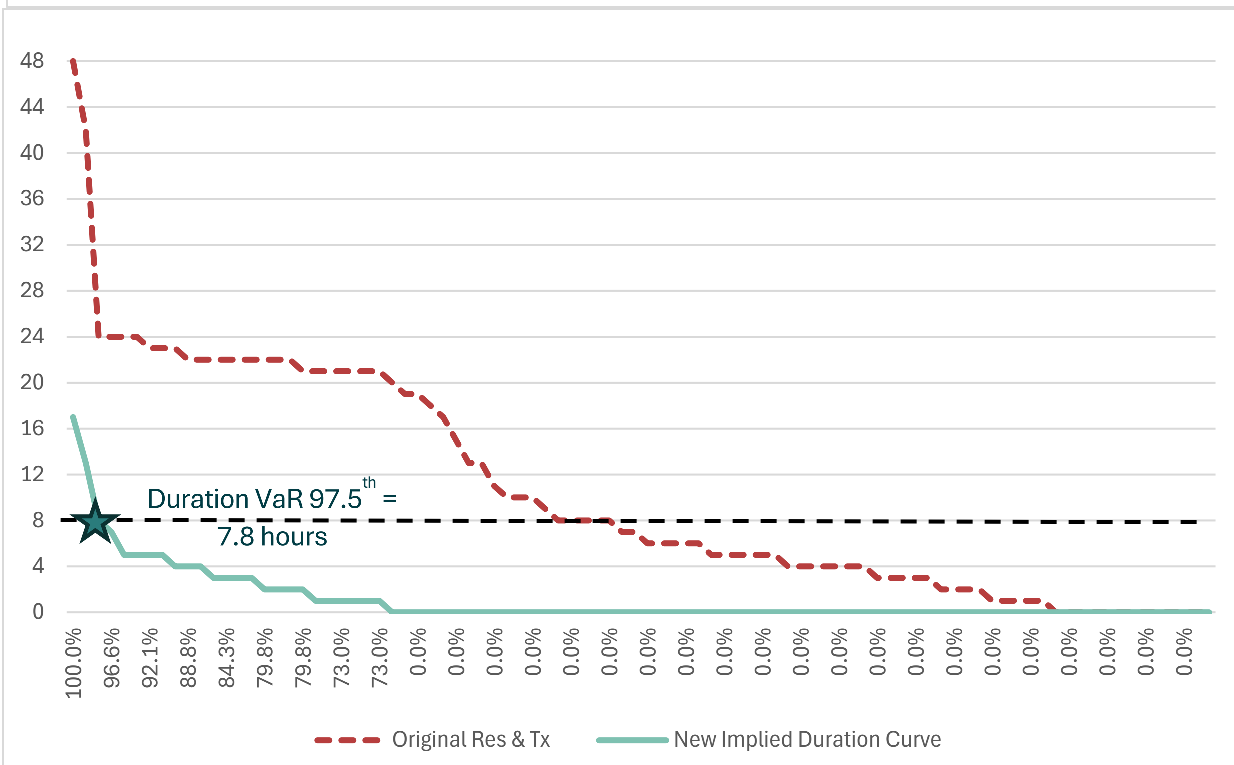
		Firm Energy Addition	
Simulation Date	Original Shortfall (MW)	Adding 1000 aMW (remaining shortfall MW)	Adding 1,500 aMW (remaining shortfall MW)
Feb-10 5am	751	0	0
Feb-10 6am	3,836	2,836	2,336
Feb-10 7am	4,572	3,572	3,072
Feb-10 8am	4,889	3,889	3,389
Feb-10 9am	2,824	1,824	1,324
Feb-10 10am	2,880	1,880	1,380
Feb-10 11am	1,331	331	0
Feb-10 12pm	1,876	876	376
Feb-10 1pm	1,278	278	0
Feb-10 2pm	127	0	0
Feb-10 3pm	1,701	701	201
Feb-10 4pm	1,256	256	0
Feb-10 5pm	3,719	2,719	2,219
Feb-10 6pm	3,715	2,715	2,215
Feb-10 7pm	4,256	3,256	2,756
Feb-10 8pm	2,298	1,298	798
Feb-10 9pm	3,422	2,422	1,922
# of Events	1	2	4
Max Duration	17	8	5

The full methodology does not require observing every single shortfall. Rather, the adequacy analysis focuses on the 97.5th percentile of the new maximum duration shortfalls from each iteration. When the Duration VaR 97.5 value drops to (or closest below) 8, the process stops and the firm energy used is recorded.

Figure M - 4 shows an example from an original shortfall curve (top) and the new implied duration curve (bottom) after adding enough aMW to reach the Duration VaR 97.5th percentile value just below 8.

Figure M - 4: Maximum Duration Curve Example

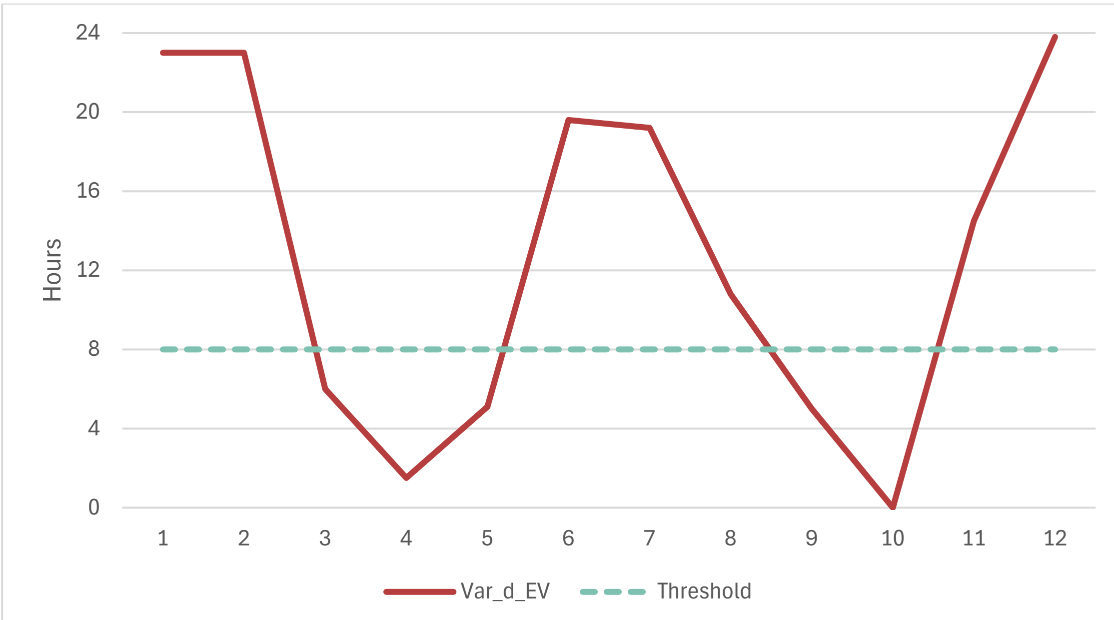




Developing Final Energy Adequacy Reserve Margin

In the example above, the firm energy needed to satisfy the Duration VaR was 5,900 aMW. This value is compared to the Energy VaR 97.5th percentile value, and if it is larger than the aMW implied to satisfy energy VaR (Energy VaR value minus the threshold), then the value to satisfy the Duration VaR is used. For example, if the Energy VaR 97.5th percentile is 880,638 MWh (Table M - 13), the implied firm energy throughout the year to mitigate it is 871,038 MWh (888,638 - 9,600), and dividing by 8,760 hours results in a firm energy of 99.4 aMW, lower than the implied firm energy to satisfy Duration VaR. Similar to Peak VaR, it's important to understand the months that exhibit the long duration risks ,as seen in the monthly duration VaR in Figure M - 5.

Figure M - 5: Monthly Duration VaR 97.5th Percentile



In the example, winter and summer experience the highest risk of long durations, and serve as the signal for which to base the annual firm energy on. The next step is to determine what percent above load does this aMW represent in each month that surpasses the threshold, seen in Table M - 9.

Table M - 9: Energy ARM Development

Month	Monthly Duration VaR	Threshold	Firm Energy Adjustment (aMW)	GENESYS Avg Monthly Load	Monthly Energy ARM	Annual Energy ARM
Jan	23	8	5,900	34,506	17%	Max of monthly (20%)
Feb	23	8	5,900	33,001	18%	
Mar	6	8	-	30,182	0%	
Apr	1.5	8	-	28,108	0%	
May	5.1	8	-	27,631	0%	
Jun	19.6	8	5,900	29,073	20%	
Jul	19.2	8	5,900	30,890	19%	
Aug	10.8	8	5,900	30,679	19%	
Sep	5	8	-	27,851	0%	
Oct	0	8	-	27,724	0%	
Nov	14.5	8	5,900	31,066	19%	
Dec	23.8	8	5,900	33,870	17%	

$$\text{Annual EnergyARM}_{\text{i}} = \text{Max}\left(\frac{\text{FirmEnergy}_{\text{i}}}{\text{AverageLoad}_{\text{i}}}\right)$$

The final step is to take the maximum percentage and apply that as the annual percentage needed to be held across the years. This percent is then multiplied by the annual load, and OptGen must ensure sufficient firm energy is available every month for it.

Reminder of the Existing System and Data Assumption

The needs assessment is a forward look into the region's power supply in 2031. As such, the need, gap in resources for the region to be adequate, is related to the load growth pathway as well as what resources are existing as of May of 2025. For a full description of the existing system assumed in the Ninth Plan, see Technical Appendix B – Existing System Parameters and Policies.

For the needs assessment, the Council used the electricity demand from the high growth pathway in 2031. This pathway was chosen to ensure the plan strategy will be adequate under all plan futures. For a full description of the load forecasts, see Technical Appendix F – Electricity Demand Forecast.

Two other assumptions play a large role in the needs assessment. First, transmission and wholesale market availability assumptions. GENESYS uses a representative transmission topology on a balancing authority (BA) spatial level for in-region and out-of-region BAs with their allowed transfer (transmission) capabilities. For the Ninth Plan, the Council's modeling is aligned as much as possible with the results of the Western Transmission Expansion Coalition (WestTEC) 10-year study. [9] For the

[9] 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.

wholesale market availability, GENESYS relies on the results of market study (Figure M - 1) to provide the out-of-region resources for the market fundamental component that influences the export and import dynamics in the model. For a full description of the market assumptions, see Technical Appendix L – Wholesale Market Availability Results.

Second, the Council uses climate-informed future projections for temperature-sensitive stream flows and loads. These are based on the data developed by the River Management Joint Operating Committee (RMJOC) that the Council has used in the 2021 Power Plan.[10] For the Ninth Plan, staff further enhanced the climate-informed modeling of wind generation and solar generation in the region, which is also aligned with the coincident temperature-sensitive conditions of stream flows and loads. For a full description of the climate data assumptions see Technical Appendix D - Climate Model Data and Assumptions, as well as Technical Appendix G – New Generating Resource for description of solar and wind generation assumptions.

Tested Sensitivities

This section is meant to briefly list the five tested sensitivities that are the core of the Ninth Plan needs assessment. These include four changes to hydro operation (Hydro Op) studies and one resource and transmission risk (Res & Tx). A detailed account is provided in Technical Appendix N – Scenario Modeling and Results.

Changing Hydro Operations Studies

The Hydro Op studies test the intersection between hydro system operations and adequacy needs to develop new resources in the future. The changing operations are 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 timing of the needs assessment for the Ninth Plan aligned with the development of the Council's Fish and Wildlife Program and allowed an unique opportunity to evaluate the resource need implications to help inform the program.[11] To that end, the four sensitivities covered a range of

[10] See "*Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part I: Hydroclimate Projections and Analyses*" at https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-ll-report-part-l.pdf.

[11] Under the Northwest Power Act, the Council is required to develop a Fish and Wildlife Program to protect, mitigate, and enhance the fish and wildlife affected by the development and operation of any hydroelectric project in the region. The Program is also expected to establish objectives for the development and operation of such projects in the region in a manned designed to protect, mitigate, and enhance fish and wildlife [§4(h)(2)(A), 94 Stat. 2708]. The Northwest Power Act also calls on the Council to "set forth a general scheme for implementing conservation measures and developing resources … to reduce or meet the Administrators obligations" [§4(e)(2), 94 Stat. 2708]. These obligations include Bonneville's obligations to implement the Council's Fish and Wildlife Program. Therefore, the Act intended that there would be some deration of the system for the benefit of fish and wildlife, and it is the task of the power plan to make up any resulting power needs.

operations selected in response to recommendations from the 2021 Power Plan and the 2026 Fish and Wildlife Program amendment process. The four sensitivities are described in Table M - 10.

Table M - 10: 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 round 2026 operations.
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 into 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 systems 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.

Determining the Hourly Ramping Limitation for the Limited Flex Sensitivity

One of the outcomes of the 2021 Power Plan was to highlight the benefits of leaning into the flexibility (hourly or daily fluctuations) of the hydro system for power generation and reserves. However, the Council's 2014 Fish and Wildlife Program contains measures calling on the system to minimize or reduce daily fluctuations (i.e. flexibility) and several entities submitted recommendations and comments into this amendment process calling on recommendations to reduce flow fluctuations. To provide insight into the implications of limiting the flexibility of the Lower Snake and Lower Columbia projects, the Limited Flex sensitivity was developed.

GENESYS sees more operational flexibility on a daily basis, while meeting all the existing constraints, than is currently being utilized in today's actual operations. As such, the guiding principle of this sensitivity is to limit the model's ability to flex the eight lower projects akin to current system dynamics on the daily range of outflows at these projects.

Recognizing the model sees more flexibility than is used in actual operations, the Council set flexibility limits based on 2020-2024 changes in elevations and flows. These years were chosen due to alignment with BiOp operations, as well as years with RCBA operations. The process to mimic the daily operations starts by calculating the daily range of outflows (the difference between the maximum hourly outflow and minimum hourly outflow in a calendar day) for each project in day, starting Jan 1st 2020 and ending December 31st 2024[12]. Then, the monthly average of daily outflow fluctuations is developed, seen in Table M - 11 as a tradeoff in seasonal monthly variation.

Table M - 11: Average Daily Range of Outflows 2020-2024 (kcfs/day)

Month	LWG	LGS	LMN	IHR	MCN	JDA	TDA	BON
Jan	29.7	33.8	34.0	32.7	47.5	58.4	63.5	33.1
Feb	32.6	32.9	34.0	33.0	49.4	55.3	57.8	32.4
Mar	31.4	32.1	31.1	28.3	58.7	59.6	59.0	20.4
Apr	8.8	11.3	14.4	14.0	26.3	34.7	42.2	14.8
May	15.5	18.6	32.0	24.7	25.3	43.0	45.4	28.3
Jun	16.1	21.3	28.5	24.8	36.3	45.7	48.5	27.5
Jul	14.0	18.7	16.8	19.5	48.0	68.9	66.7	31.7
Aug	10.7	13.0	12.2	16.6	40.2	65.0	66.6	32.6
Sep	19.2	19.5	18.8	21.0	42.3	43.3	43.3	24.8
Oct	15.0	14.2	14.6	15.8	42.2	38.3	38.6	24.6
Nov	19.2	18.4	18.4	19.0	59.1	53.9	55.6	29.3
Dec	25.0	25.3	26.3	26.6	48.0	45.4	57.7	38.3
Average kcfs/day	**19.7**	**21.6**	**23.4**	**23.0**	**43.6**	**51.0**	**53.8**	**28.1**
Average cfs/day	19,708	21,555	23,376	22,974	43,599	51,004	53,780	28,145
Average cfs/min	13.7	15.0	16.2	16.0	30.3	35.4	37.3	19.5
Adjusted cfs/min	16	16	16	16	40	40	40	40
Adjusted kcfs/hr	0.96	0.96	0.96	0.96	2.4	2.4	2.4	2.4
WMP Appendix 2 kcfs/hr	70	70	70	20	150	200	150	25[13]
Adj Limit % of WMP	1.37%	1.37%	1.37%	4.80%	1.60%	1.20%	1.60%	9.60%

As very tight ramping bounds were too challenging to model, the Council ultimately relied on the average daily outflow fluctuation as the representative flexibility limitation for each project. These outflow ranges of thousands of cubic feet per second (kcfs) per day then need to be converted into cubic feet per second (cfs) per minute, the parameter utilized in GENESYS to control for outflow discharge. Table M - 11 also provides the modeled cfs/min ramping rates for each project (“adjusted cfs/min” in the table). The final rates are slightly higher than the average ranges due to enabling slightly more modeling slack and to ensure GENESYS was able to simulate. Also in Table M - 11 are the allowed kcfs/hr ramping of the Lower Snake and Lower Columbia projects in Water Management Plan Appendix 2.[14] One reason GENESYS utilizes more ramping flexibility is specifically because Appendix 2 allows these ramp rates, though actual ramping operations are more narrow in real world operations.

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[12] US Army Corps of Engineers Dataquery 2.0 https://www.nwd-wc.usace.army.mil/dd/common/dataquery/www.

[13] Bonneville’s 25 kcfs/hr outflow ramp rates is based on tailrace operations.

[14] 2026 Water Management Plan Appendix 2 https://public.crohms.org/tmt/documents/wmp/2026/Appendix/Appendix_2_2026_Project_Data_20250731.pdf.

Resource & Transmission Risk

The New Resource and Transmission Risk (Res & Tx) scenario sensitivities test different power system characteristics under the hydro operations outlined in the Draft 2026 Columbia River Basin Fish and Wildlife Program.[15] High-level, these include (1) spring spill as defined in 2023 RCBA of 24 hour 125% total dissolved gas (TDS) and summer performance spill end date of August 1st (Lower Snake) and August 15th (Lower Columbia), (2) limiting 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, and (3) no change to pool elevation operations from the ones described in the 2020 Biological Opinion.[16] The tested sensitivities are described in Table M - 12. While there are several sensitivities, they all share the same underlying existing system, and therefore the same needs assessment study and PRM and ARM signals.[17]

Table M - 12: 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 will inform 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.[18] 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.

[15] See Draft Fish & Wildlife Program measures.
[16] The final 2026 Columbia River Basin Fish and Wildlife Program removed the provision on summer spill, but the other elements remained the same. The Council took this change into account as part of the final adequacy check on the proposed regional resource strategy. See Technical Appendix N – Scenario Modeling Results for more information.
[17] This is since the hydro operations are consistent across these sensitivities, and the need impact due to variation in out-of-region market buildout and transmission availability was expected to not yield significant differences; at the expense of substantially more modeling time.
[18] 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.

Sensitivity	Description
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 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.

Needs Assessment Results

The results show a significant regional resource need in 2031 across all studies. Three main takeaways include: there are peak needs in all seasons, particularly in winter and summer, there is an energy signal for summer and winter, and the longest and largest events are in the winter. The main driver for these needs is the expected load growth.

Roughly speaking, all scenarios experience similar large peak tail-risk between 9,300-11,500 MW and long duration shortfalls (ranging from 22 to above 40 hours) as well as many outage events throughout the year. Staff caution from over interpreting or over emphasizing individual study results because they are sensitive to the nuance of translating the shortfall record to the reserve margins.

Table M - 13: Adequacy Criteria Results

	Frequency			Extreme Deficits		
Metric	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
BiOp	6.76	4.58	1.37	23	9,352	543,010
RCBA	8.71	6.04	1.54	22.8	10,128	590,842
MOP Op	10.23	5.32	2.62	44	9,666	912,141
LimFlex	21.33	14.14	3.86	49.5	11,504	2,692,698
Res & Tx	10.50	6.96	2.32	24	11,045	880,638

Figure M - 6 and Figure M - 7 highlight the monthly duration and peak VaRs, showing how winter and summer outages dominate the shortfall risk. The thresholds are included for guiding purposes.

Figure M - 6: Monthly Duration VaR 97.5)

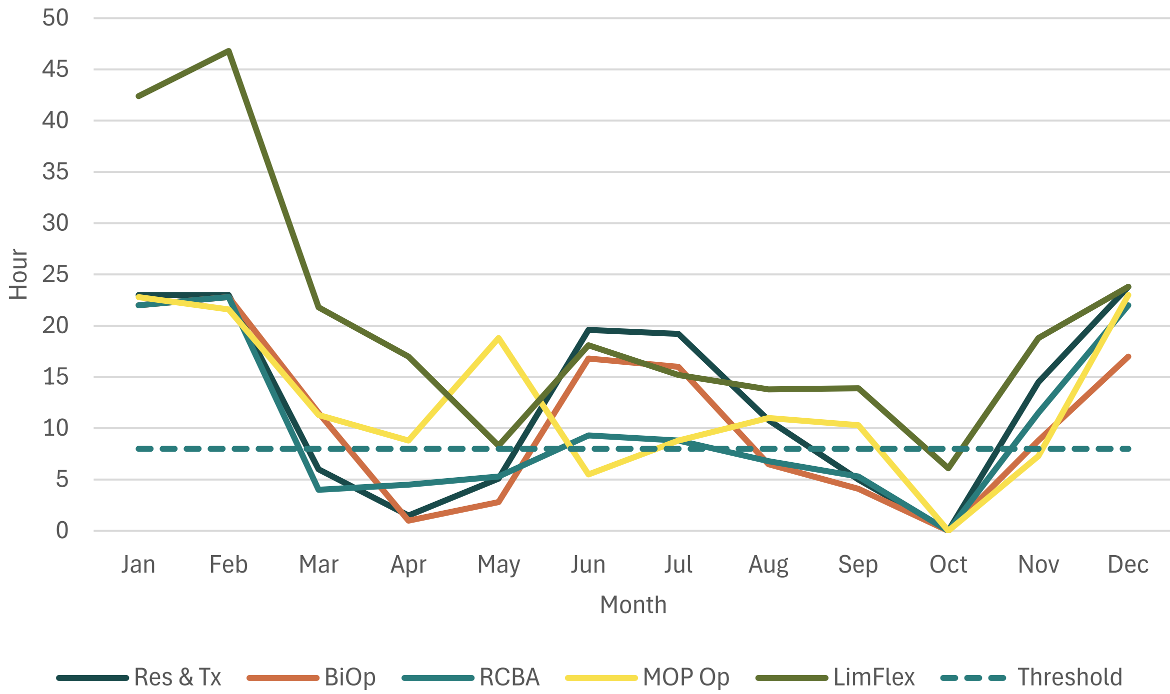
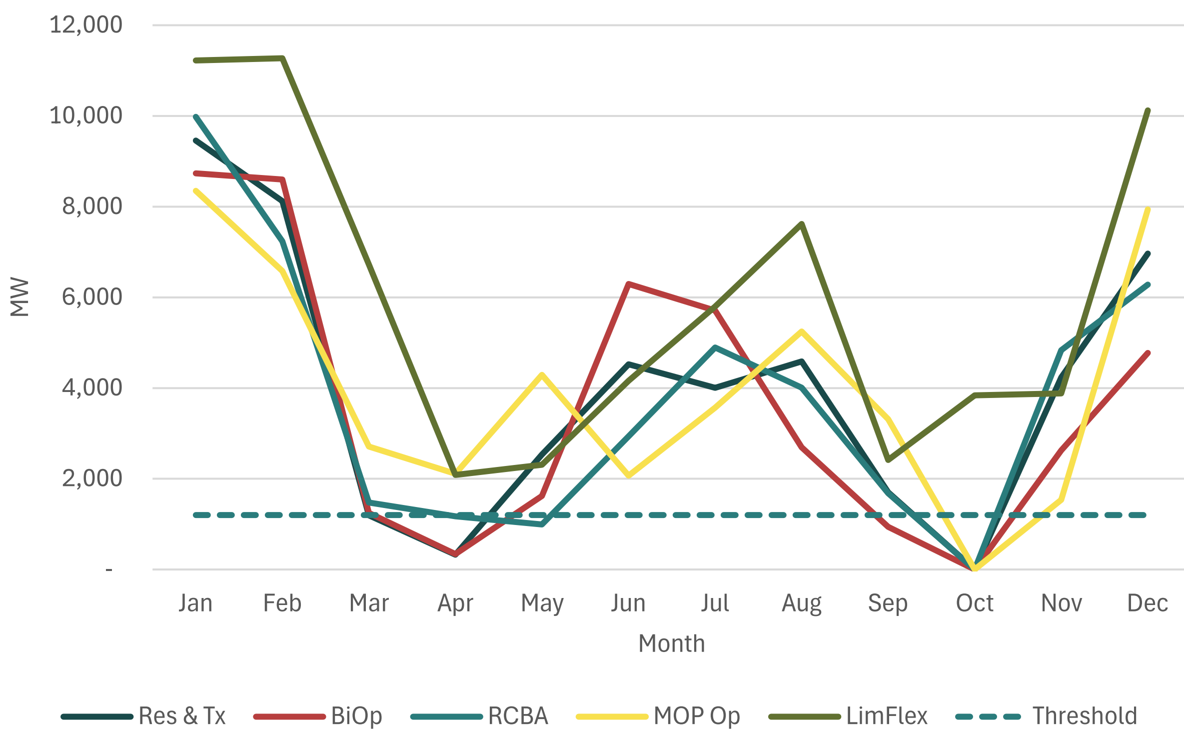


Figure M - 7: Monthly Peak VaR 97.5



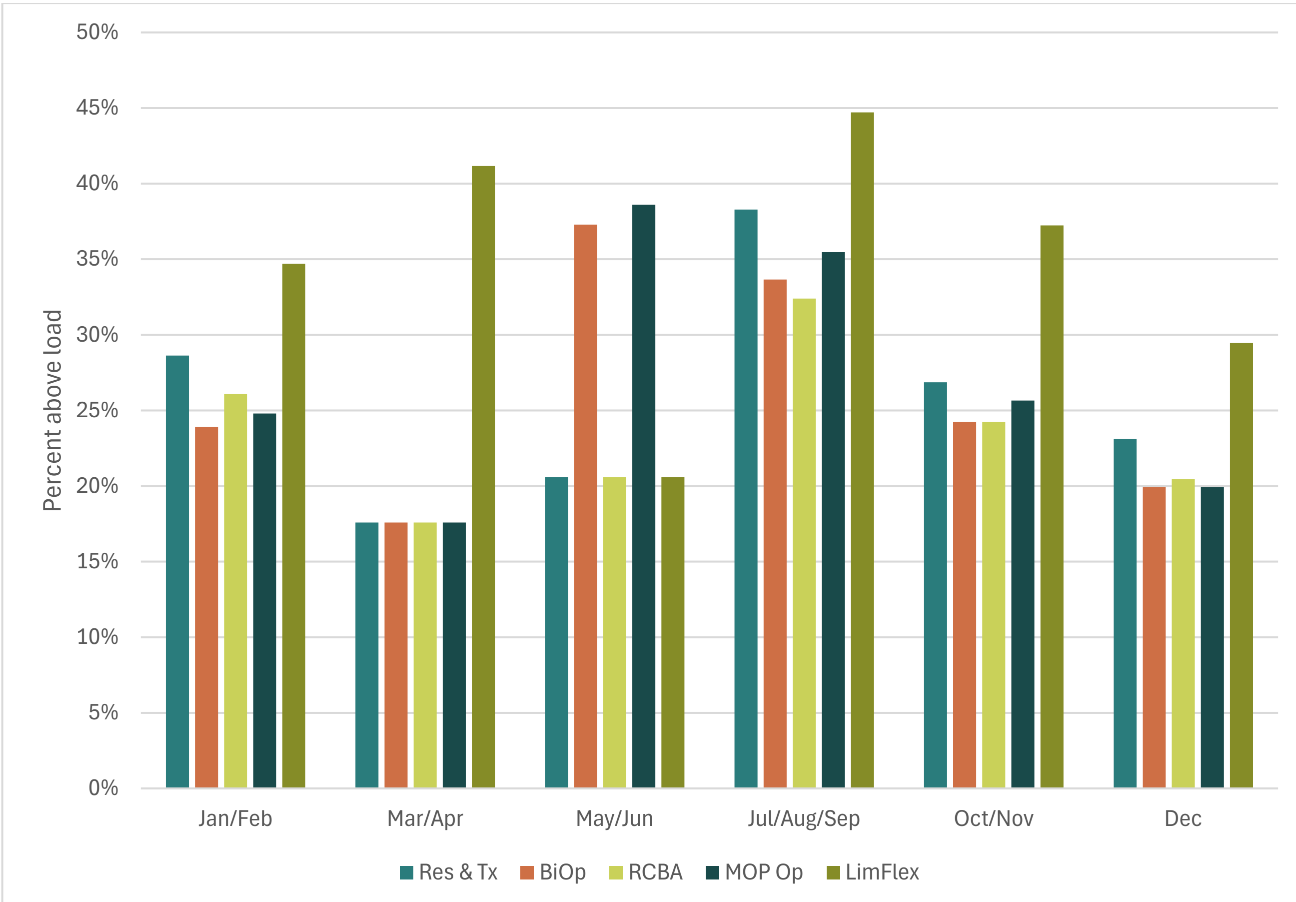
Peak Planning Reserve Margin

The metric values feed into the PRM and ARM as outlined in the methodology section above. The full results are presented in Table M - 14, with Figure M - 8 focusing on the final PRM for each study.

Table M - 14: PRM Calculation

Study	Period	GENESYS Average Peak Loads (MW)	OptGen Peak Loads (MW)	Total Resources (MW)	Need (MW)	Load Resource Balance (MW)	AM Eq1 Adequacy Margin	SPCR Eq2 Seasonal Peaking Margin + Contingency Reserves	PRM Eq3 Planning Reserve Margin (PRM)
Res & Tx	Jan/Feb	42,868	38,096	38,604	7,625	-4,264	7.8%	19.3%	28.6%
	Mar/Apr	35,975	32,429	38,727	1,473	2,753	11.7%	17.6%	17.6%
	May/Jun	36,813	32,357	41,177	3,563	4,364	21.5%	20.6%	20.6%
	Jul/Aug/Sep	40,541	34,826	38,675	6,759	-1,866	12.1%	23.4%	38.3%
	Oct/Nov	37,933	32,366	33,782	4,955	-4,151	2.1%	24.2%	26.9%
	Dec	41,246	36,453	34,715	7,625	-6,531	2.7%	19.9%	23.1%
BiOp	Jan/Feb	42,868	38,096	38,604	5,932	-4,264	3.9%	19.3%	23.9%
	Mar/Apr	35,975	32,429	38,727	1,289	2,753	11.2%	17.6%	17.6%
	May/Jun	36,813	32,357	41,177	5,095	4,364	13.8%	20.6%	37.3%
	Jul/Aug/Sep	40,541	34,826	38,675	5,239	-1,866	8.3%	23.4%	33.7%
	Oct/Nov	37,933	32,366	33,782	2,969	-4,151	-3.1%	24.2%	24.2%
	Dec	41,246	36,453	34,715	5,932	-6,531	-1.5%	19.9%	19.9%
RCBA	Jan/Feb	42,868	38,096	38,604	6,708	-4,264	5.7%	19.3%	26.1%
	Mar/Apr	35,975	32,429	38,727	1,832	2,753	12.7%	17.6%	17.6%
	May/Jun	36,813	32,357	41,177	2,318	4,364	18.2%	20.6%	20.6%
	Jul/Aug/Sep	40,541	34,826	38,675	4,823	-1,866	7.3%	23.4%	32.4%
	Oct/Nov	37,933	32,366	33,782	3,970	-4,151	-0.5%	24.2%	24.2%
	Dec	41,246	36,453	34,715	6,708	-6,531	0.4%	19.9%	20.5%
MOP Op	Jan/Feb	42,868	38,096	38,604	6,246	-4,264	4.6%	19.3%	24.8%
	Mar/Apr	35,975	32,429	38,727	2,717	2,753	15.2%	17.6%	17.6%
	May/Jun	36,813	32,357	41,177	5,497	4,364	14.9%	20.6%	38.6%
	Jul/Aug/Sep	40,541	34,826	38,675	5,833	-1,866	9.8%	23.4%	35.5%
	Oct/Nov	37,933	32,366	33,782	4,586	-4,151	1.1%	24.2%	25.7%
	Dec	41,246	36,453	34,715	6,246	-6,531	-0.7%	19.9%	19.9%
LimFlex	Jan/Feb	42,868	38,096	38,604	9,803	-4,264	12.9%	19.3%	34.7%
	Mar/Apr	35,975	32,429	38,727	7,213	2,753	20.1%	17.6%	41.2%
	May/Jun	36,813	32,357	41,177	3,810	4,364	22.2%	20.6%	20.6%
	Jul/Aug/Sep	40,541	34,826	38,675	8,870	-1,866	17.3%	23.4%	44.7%
	Oct/Nov	37,933	32,366	33,782	8,123	-4,151	10.5%	24.2%	37.2%
	Dec	41,246	36,453	34,715	9,803	-6,531	7.9%	19.9%	29.5%

Figure M - 8: Final PRM



Energy Adequacy Reserve Margin

The implied firm energy to satisfy the Duration VaRs ranges between 4,250 to 6,000 aMW across the studies, and all are greater than the implied energy to satisfy the Energy VaR and therefore are used for the firm energy signal. Table M - 15 shows the annual firm energy percent that serve as the ARM in OptGen. This value (in each study) is scaled up and down to be used in other years (the needs assessment focuses on 2031, but OptGen simulates a wider range of years).

Table M - 15: Final Annual ARM

Study	Annual Firm Energy
Res & Tx	20.3%
RCBA	14.6%
BiOp	14.6%
MOP Op	15.5%
LimFlex	20.6%