Long-Term Assessment of Load-Resource Balance in the Pacific Northwest

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Agenda

- Study scope & overview
- Review of existing regional studies
- Modeling overview & approach
- Scenario inputs & assumptions
- Results & conclusions
STUDY SCOPE AND OVERVIEW
In 2017, the OPUC acknowledged PGE’s request to conduct a study related to the treatment of existing capacity available in the market in future Integrated Resource Plans.

To inform the development of its 2019 Integrated Resource Plan (IRP), PGE is seeking to understand:

- How future changes in resources and loads in the Pacific Northwest might affect the region’s overall capacity position;
- How constraints within the region might impact the ability to deliver excess capacity in the region to PGE loads; and
- What implications of these factors have for PGE’s long-term planning assumptions of market purchases of available surplus capacity.
The key trends shaping the Northwest power sector are:

- Increasing peak loads, especially in the summer
- Coal plant retirements
- Few thermal power plants being expected to be built in the coming years
- Addition of new renewables
- The high level of energy efficiency that is already achieved as well as expected to be realized by utilities

The expected capacity need is primarily driven by the retirement of almost 1,800 MW of coal over the next few years.
1. **Review existing studies by regional entities**
   - Northwest Power & Conservation Council (NWPCC)
   - Bonneville Power Administration (BPA)
   - Pacific Northwest Utilities Conference Committee (PNUCC)

2. **Develop a simple heuristic-based scenario tool to test impact of various assumptions on market surplus and deficit results**
   - Designed to be consistent with existing studies, but provides more flexibility for scenario analysis

3. **Use spreadsheet tool to design a range of scenarios to inform recommended assumptions for PGE 2019 IRP**
LITERATURE REVIEW
Four Existing Studies Surveyed

+ **NWPCC: Pacific Northwest Power Supply Adequacy Assessment for 2023**
  - Time horizon: 2023
  - Seasons: winter & summer

+ **NWPCC: 7th Northwest Conservation and Electric Power Plan**
  - Time horizon: 2015-2035
  - Seasons: winter & summer

+ **PNUCC: Northwest Regional Forecast of Power Loads & Resources**
  - Time horizon: 2019-2028
  - Seasons: winter & summer

+ **BPA: 2017 Pacific Northwest Loads and Resources Study (The White Book)**
  - Time horizon: 2019-2028
  - Seasons: winter only
<table>
<thead>
<tr>
<th>Assumption</th>
<th>PNUCC Study 2018</th>
<th>BPA Whitebook 2017</th>
<th>NWPC 7th Power Plan</th>
<th>NWPC 2023 Assessment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Analytical Approach</td>
<td>Deterministic</td>
<td>Deterministic</td>
<td>Deterministic</td>
<td>Stochastic</td>
</tr>
<tr>
<td>Peak Load Calculation</td>
<td>NCP of all participating utilities</td>
<td>BPA Load Forecasts</td>
<td>Ranges of load forecasts tested</td>
<td>Distribution of peak loads for 80 temperature year modeled in GENESYS</td>
</tr>
<tr>
<td>Resources</td>
<td>Existing and committed; IPPs not included</td>
<td>As per utility IRPs, IPPs included</td>
<td>Existing, IPPs included</td>
<td>Existing and planned, IPPs included</td>
</tr>
<tr>
<td>Adequacy Metric</td>
<td>PRM of 16%</td>
<td>Adjustment to available resources based on operating reserves and transmission losses</td>
<td>Adequacy Reserve Margin instead of PRM</td>
<td>LOLP</td>
</tr>
<tr>
<td>Hydro Capacity</td>
<td>8th percentile based on average water</td>
<td>BPA internal Hourly Operating and Scheduling Simulator (HOSS) model</td>
<td>P2.5% 10-hour sustained peaking ability</td>
<td>A wide range of hydro conditions modeled in GENESYS</td>
</tr>
<tr>
<td>Wind Capacity</td>
<td>5%</td>
<td>Wind capacity not counted as firm</td>
<td>5% for Adequacy Reserve Margin</td>
<td>ELCC endogenously calculated in GENESYS</td>
</tr>
</tbody>
</table>
Key Results of Existing Studies

- **PNUCC study shows a ~1.8 GW winter capacity in 2020, and ~0.5 GW summer capacity need starting in 2021**
  - Primarily different from BPA White Book and NWPC in not including regional IPPs

- **BPA White Book shows a winter capacity need starting in 2021 of 1.1 GW**
  - No summer analysis provided

- **NWPC RA assessment shows a need of 300-400 MW by 2021, with an additional 300-400 MW needed by 2022**
  - RA assessment shows need only for the winter by 2022

- **NWPC 7th Power Plan shows a capacity need of 1 GW in 2021 for the high need scenario, and a capacity surplus of 700 MW for the low need scenario**
Summary of Literature Review

+ Under current assumptions, new capacity is required by 2021 in all studies reviewed
  • If unknown status in-region IPP generation is not available, new capacity is required in 2019

+ PNUCC and BPA White Book use different metrics and have a different time horizon compared to NWPPCC
  • Comparing across studies is difficult due to range of approaches and time horizons

+ Key uncertainties include loads, new build expected to come online before 2021, level of DSM that is realized, contribution of unknown status IPP generation, and external market purchases
NORTHWEST CAPACITY SCENARIO MODELING TOOL
E3 developed a spreadsheet tool to analyze expected regional net capacity position under a range of different assumptions.

Model uses input assumptions from regional outlook studies.

Model can be used to replicate results from studies or create custom scenarios.

- E3 calibrated the model to align with NWPCC 2023 RA assessment.

### E3 PNW Load Resource Balance Tool

<table>
<thead>
<tr>
<th>INPUTS - Scenario Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Active Scenario</td>
</tr>
<tr>
<td>Saved Scenario</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>INPUTS - Peak Load and Generator Options</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Load (MW)</td>
</tr>
<tr>
<td>E3 Recommendation Base Load</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Generator Classifications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Load</td>
</tr>
<tr>
<td>Planning</td>
</tr>
<tr>
<td>Planned</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Dependable Capacity Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermal</td>
</tr>
<tr>
<td>Hydro</td>
</tr>
</tbody>
</table>

OUTPUTS - Annual Load Resource Balance

- Total Imports
- Oil
- Gas
- Nuclear
- Thermals
- Hydro
- Steam/Coal
- Natural Gas
- Hydro
- Total Demand
- Net Imports

OUTPUTS - Summer Load Resource Balance

- Total Imports
- Oil
- Gas
- Nuclear
- Thermals
- Hydro
- Steam/Coal
- Natural Gas
- Hydro
- Total Demand
- Net Imports

Energy + Environmental Economics
Model Overview

- E3 developed a spreadsheet tool to analyze expected regional net capacity position under a range of different assumptions.

- Model uses input assumptions from regional outlook studies.

- Model can be used to replicate results from studies or create custom scenarios.
  - E3 calibrated the model to align with NWPCC 2023 RA assessment.

  - Calibration helps benchmark to regional outlook studies.
  - Using the calibrated model, additional scenarios and sensitivities not tested in the existing studies can be examined.
E3 used the NWPCC 2023 RA Assessment to calibrate the E3 model

- For calibration, assumptions are consistent with NWPCC 2023 assessment for 2023; NWPCC 7th Power Plan values are used when applicable

The PRM requirement assumed in E3’s model is derived from the results of NWPCC’s RA assessment

- PRM value was calculated to yield “need” results consistent with NWPCC’s 2023 assessment

<table>
<thead>
<tr>
<th>Category</th>
<th>GENESYS</th>
<th>E3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Approach</td>
<td>Stochastic</td>
<td>Deterministic</td>
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<tr>
<td>Adequacy Metric</td>
<td>LOLP</td>
<td>PRM</td>
</tr>
<tr>
<td>Horizon</td>
<td>One year snapshot</td>
<td>10 year outlook</td>
</tr>
<tr>
<td>Hydro</td>
<td>Stochastic simulation of 80+ years</td>
<td>Assumed contribution (%) to winter &amp; summer peak</td>
</tr>
<tr>
<td>Renewables</td>
<td>Stochastic simulation of hourly renewable output</td>
<td>Static assumed ELCC (%)</td>
</tr>
</tbody>
</table>
E3’s capacity model uses a PRM approach that is calibrated to yield comparable results to the NWPC 2023 Adequacy Assessment:

1. Gather key assumptions from 2023 Adequacy Assessment (demand forecast, installed capacity, etc.)
2. Choose capacity counting conventions for each type of resource (firm, variable, hydro, etc.)
3. Derive PRM requirement to align timing and magnitude of “need” with 2023 Adequacy Assessment

After calibration process, inputs & assumptions may be varied to examine alternative scenarios.
## Model Calibration
### NWPCCE GENESYS vs E3 Model

- Align 2023 **summer and winter peak loads** net of EE
- Use NWPCCC 2023 estimates of **DR**
- Use NWPCCC 2023 contracted **non-NW imports + exports**
- Benchmark total **thermal dependable capacity**
- Assume NWPCCC 2023 **in-region unknown status IPPs**
- Assume NWPCCC 2023 **seasonal external markets imports**
- Estimate **renewables ELCC**
  - NWPCCC 7th Power Plan wind ELCC; E3 estimates for solar ELCC in summer
- Estimate **hydro dependable capacity**
  - NWPCCC 7th Power Plan 10 hr sustained winter and summer peaking
- Calculate **implied PRM** to yield NWPCCC 2023 capacity need

- **NWPCCC 2023 Assessment**
- **NWPCCC 7th Power Plan**
- **Calibration Parameter**
Key Assumptions for Model Calibration
Hydro Dependable Capacity

- The Pacific Northwest region has more than 34 GW of nameplate hydro capacity

- However, the hydro resources are limited in their ability to provide power during a sustained peak load event
  - Hydro resources are energy limited and cannot output generation at their full nameplate capacity for multiple consecutive hours

- To account for their energy limits, the nameplate capacity is derated to reflect the hydro fleet’s sustained peaking ability
  - Similar to assumption used by NWPCC 7th Power Plan for its system adequacy assessment
  - Use of critical water year to determine capacity credit does not imply analysis assumes critical water conditions exist

The winter sustained peaking ability is 50% of nameplate capacity, whereas the summer is 45%
Due to their intermittent generation, variable renewables usually do not contribute their full nameplate capacity towards meeting system peak.

To estimate the contribution of renewables to system peak, effective load carrying capacity (ELCC) of renewables is used.

- Determines renewable production as a fraction of nameplate capacity during peak load event.

For wind and solar ELCC estimates, E3 used the NWPCC 7th Power Plan:

- Adequacy reserve margin results for wind peaking capability.
- Associated system capacity contribution (ASCC) for seasonal solar ELCC.
Derivation of a Planning Heuristic for the Northwest

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<tr>
<th>Resource</th>
<th>Nameplate MW</th>
<th>Dependable MW</th>
<th>Notes</th>
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<tbody>
<tr>
<td>Thermal</td>
<td>14,667</td>
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<td>Assumed 100% availability</td>
</tr>
<tr>
<td>Hydro</td>
<td>34,697</td>
<td>17,790</td>
<td>Based on critical water 10-hr sustained peaking capability</td>
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<tr>
<td>Solar</td>
<td>448</td>
<td>116</td>
<td>Assumed 26% ELCC</td>
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<td>Wind</td>
<td>6,264</td>
<td>313</td>
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<tr>
<td>Other</td>
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<td>DR</td>
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<tr>
<td>Imports</td>
<td>2,565</td>
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<td>2,500 MW from CA + 65 MW firm imports</td>
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<td>Generic Need</td>
<td>700</td>
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**Total Resources** 37,675

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**Total Load** 34,532

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<th>Reserve Margin Need</th>
<th>10%</th>
<th>Ratio between Total Resources &amp; Total Load</th>
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Energy + Environmental Economics
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**Reserve Margin Need** | 10% | Ratio between Total Resources & Total Load
## Alternative Hydro Conventions Yields Same Capacity Need

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| **Total Load** | **34,532** |

| Reserve Margin Need | 19% | Ratio between Total Resources & Total Load |

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Changing the convention used to count hydro towards the reserve margin does not change the capacity need.
Summary of Model Conventions

+ Load-resource tool estimates resulting regional capacity surplus or deficit in the Northwest for the summer and winter using implied planning reserve margin.

+ Planning reserve margin (PRM) requirement of 10% calibrated based on MW of need in NWPCC 2023 RA Assessment.

+ PRM calculation dependent on capacity accounting conventions in load-resource tool:
  - Contribution of hydro towards reserve margin based on seasonal 2.5 percentile 10-hr sustained peaking capability.
  - Wind and solar resource contributions based on assumed effective load carrying capability.

+ Assumptions & conventions used in this tool are derived to reflect loads & resources of the broader Northwest, but are not directly applicable to individual utilities (e.g. PGE).
KEY SCENARIO INPUTS AND ASSUMPTIONS
### Scenario Input Summary

<table>
<thead>
<tr>
<th>Assumption</th>
<th>Low Need</th>
<th>Base Need</th>
<th>High Need</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Load Forecast</strong></td>
<td>1.46%/yr (W)</td>
<td>1.74%/yr (W)</td>
<td>1.94%/yr (W)</td>
</tr>
<tr>
<td><em>(pre-EE)</em></td>
<td>1.73%/yr (S)</td>
<td>1.92%/yr (S)</td>
<td>2.21%/yr (S)</td>
</tr>
<tr>
<td><strong>Energy Efficiency</strong></td>
<td><strong>100%</strong> of cost-effective EE</td>
<td><strong>100%</strong> of cost-effective EE</td>
<td><strong>75%</strong> of cost-effective EE</td>
</tr>
<tr>
<td><em>(treated as a resource)</em></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Demand Response</strong></td>
<td>NWPCC Low</td>
<td>NWPCC Med</td>
<td>NWPCC High</td>
</tr>
<tr>
<td><strong>Thermal Generation</strong></td>
<td>Announced retirements</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Hydro Generation</strong></td>
<td>Constant at today’s levels</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Renewable Generation</strong></td>
<td>Current plans</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Market Imports</strong></td>
<td>3400 MW through 2023, 2100 MW by 2030 (W)</td>
<td>2500 MW (W)</td>
<td>3400 MW through 2021, 0 after 2023 (W)</td>
</tr>
<tr>
<td></td>
<td>1400 MW in the near term, 0 in the long term (S)</td>
<td>0 (S)</td>
<td>0 (S)</td>
</tr>
</tbody>
</table>
NWPCs sources are used to develop a “pre-EE” demand forecast in three steps:

1. NWPCs RA assessment peak loads net of EE for 2023 are used as a starting point
   - E3 received additional data from NWPCs for 2020-22 peak loads net of EE from their RA assessment
2. Loads before the impact of EE are backed out by adding back in the embedded cost-effective EE from NWPCs 7th Power Plan
3. The implied gross peak loads for the 2020-2023 period are used to extrapolate the gross loads post 2023

Extrapolate load growth using CAGR for 2020-2023

- Begin with NWPCs RA Assessment peak loads (net of cost-effective EE)
- Add in embedded cost-effective EE from 7th Power Plan

MW

- 60,000
- 50,000
- 40,000
- 30,000
- 20,000
- 10,000

2020 2025 2030
Recommended Demand Forecasts

- “Mid” load forecast consistent with NWPCC RA Assessment
- “High” and “Low” forecasts reflect range of long-term growth rates considered in the NWPCC 7th Power Plan

### Winter Peak Demand (MW)

**Gross load growth for winter peak ranges from 1.5% – 1.9%**

### Summer Peak Demand (MW)

**Summer peak grows more than winter; load growth range is 1.7% - 2.1%**

* Note: demand forecast does not include impact of EE, which is treated as a resource
NWPC 7th Power Plan assumes lower levels of realized energy efficiency for low load and mid load forecasts; for high loads 75% of cost-effective EE is assumed to be achieved.

**Winter Peak EE Impact (MW)**

- EE impact is ~6.5 GW by 2030 and grows slowly thereafter; high need scenario assumes 75% of available EE is achieved.

**Summer Peak EE Impact (MW)**

- EE impact is ~4.5 GW by 2030 and grows slowly after; high need scenario assumes 75% of available EE is achieved.
Demand Response

- Demand Response (DR) assumptions from NWPCC 7th Power Plan are used
- Winter DR availability is reduced to 2/3rd of that identified in the NWPCC 7th Power Plan based on RA adequacy assessment

<table>
<thead>
<tr>
<th>Winter Peak DR Impact (MW)</th>
<th>Summer Peak DR Impact (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Range from 600‐1,200 MW in the near term; 900-2,000 MW by 2035</td>
<td>Range from 800-1,700 MW in the near term; 1,300-3,000 MW by 2035</td>
</tr>
</tbody>
</table>

![Graph showing Winter Peak DR Impact (MW) from 2020 to 2035 for E3 High, E3 Mid, and E3 Low scenarios.](image)

![Graph showing Summer Peak DR Impact (MW) from 2020 to 2035 for E3 High, E3 Mid, and E3 Low scenarios.](image)
Thermal Generation Resources

- Characterization of coal & gas resources in the Northwest based on NWPCC powerplant database
- Key planned retirements based on announced retirements

Thermal Generation Installed Capacity (MW)

No changes to assumed natural gas resources
### Key Assumptions for Model Calibration

**IPPs Availability**

- **Unknown status IPPs assumption for winter** is derived using the NWPCC power plants database.
- **For the summer**, the winter capacity is derated to account for competing demands for capacity from California, consistent with the NWPCC’s approach.

---

*Graph showing MW availability for 2020, 2025, and 2030.*

*Lower level of IPPs available in the summer due to competition from California.*
Existing renewables resources are assumed to stay online through the analysis period.

Wind resources dominate installed capacity for renewables.
**External Market Imports Availability**

**Scenario Specific**

### Winter

- **Scenario Winter Summer**
- **Low Need**
  - E3 CAISO Surplus Calculations
- **Base Need**
  - NWPCC
- **High Need**
  - E3 CAISO Surplus Calculations

### Summer

- **Scenario Winter Summer**
- **Low Need**
  - E3 CAISO Surplus Calculations
- **Base Need**
  - NWPCC
- **High Need**
  - E3 CAISO Surplus Calculations

**Total surplus capped at 3400 MW developed by the NWPCC as the available capacity 95% of the times (actual transfer capacity is ~4 GW from CAISO)**
RESULTS
Results: Base Need Scenario

Winter Capacity Balance (MW)

Summer Capacity Balance (MW)

+ Winter: Capacity deficit starting in 2021
+ Summer: Capacity deficit starting in 2026
Results: Low Need Scenario

Winter Capacity Balance (MW)

Summer Capacity Balance (MW)

- Winter: Capacity deficit starting in 2026
- Summer: Capacity deficit starting in 2029
Results: High Need Scenario

Winter Capacity Balance (MW)

Summer Capacity Balance (MW)

- Winter: Capacity deficit starting in 2021
- Summer: Capacity deficit starting in 2023
Results Summary

- Scenarios show region will reach winter load resource balance between 2021-2026 and summer balance between 2023-2029
- Region remains tighter on capacity in the winter despite growing summer peak demands

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Winter Year of Capacity Deficit</th>
<th>Summer Year of Capacity Deficit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low Need Scenario</td>
<td>2026</td>
<td>2029</td>
</tr>
<tr>
<td>Base Need Scenario</td>
<td>2021</td>
<td>2026</td>
</tr>
<tr>
<td>High Need Scenario</td>
<td>2021</td>
<td>2023</td>
</tr>
</tbody>
</table>
Allocating Regional Surplus to PGE

+ In years of regional capacity surplus, PGE is allocated its peak load share of the market surplus capacity
  • In years of regional capacity deficit, no market surplus is available for PGE

+ PGE’s share of market surplus is assumed to be ~10% in the winter, and ~12% in the summer
  • Share of available surplus is calculated using the ratio between PGE winter and summer peak and the winter and summer peak for the region
Except for the Low need scenario, the region is capacity short in the winter starting in 2021

- No market surplus available for PGE if region is net short

For the Low need scenario, surplus capacity is available through 2025
Region has surplus summer capacity through 2022 for all scenarios.

For the High need scenario, no market surplus capacity is available starting in 2023, whereas for the Base scenario, a small market surplus is available through 2025.
ADDITIONAL CONSIDERATIONS
Additional Considerations

In addition to loads, resource additions and retirements could change the net capacity position of the region

- Economic thermal plant retirements could result in a net short position sooner
- New resource buildout in the near term could push out the need for capacity in the region to a later year

Higher level of IPP resources being contracted to in-region entities in the summer could push out need for new capacity to meet summer peak
Thank You!

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