Cascade Renewable Transmission Project Analysis

Prepared for

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Prepared by

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Executive Summary

Cascade Renewable Transmission, LLC (CRT) proposes to develop and construct a 1,100 MW underground and underwater transmission line between The Dalles and Portland, OR (Project) for the purpose of enhancing transmission transfer capability of the West of Cascades – South (WOCS) Transmission Path[1]. The Project is scheduled to become operational in 2028. This study, conducted by Energy GPS Consulting LLC, analyzes the costs and benefits of the Project, taking into account legislation in Washington and Oregon requiring 100% clean energy retail sales by 2045 in Washington, and 100% clean energy generation by 2040 in Oregon.

Under current conditions, the WOCS transmission constraint limits the transfer of least-cost renewable energy to load centers west of the Cascades. Moreover, this constraint may require more expensive resources to be sited west of the Cascades. Therefore, upgrades to the existing transmission constraint may reduce overall system production costs.

The study envisions two scenarios: 1) "Business As Usual" load growth projections in Washington and Oregon between 2022 and 2040 representing annual growth rates in energy and peak demand of 0.6% and 0.9%, respectively; and 2) partial electrification of the transportation and heating sectors representing annual growth rates in energy and peak demand of 3.0% and 1.8%, respectively.

For Scenario 1 (Business As Usual), the study shows that without the CRT Project, clean energy capacity additions of 52.9 GW for Washington and Oregon would be needed by 2040, whereas the reductions in transmission constraint resulting from the CRT Project would lower this need to 43.5 GW, or a reduction of 9.4 GW, nearly 18%. This reduction in aggregate GW of new build renewables would also significantly decrease the amount of land needed for solar and wind farms. Moreover, alleviating the WOCS constraint reduces the need to build more expensive west-of-Cascades capacity, and significantly reduces the need for curtailments of renewable generation. (In other words, renewable generation becomes both less expensive and more efficient.) The resulting Production Cost Savings between 2028 and 2040 are estimated to have a Net Present Value (NPV) of $4.1 billion.

For Scenario 2 (Electrification), the need for clean energy capacity additions by 2040 increases to 138 GW without the CRT Project, while the Project would reduce this need by 14.7 GW (10.7%). As in Scenario 1, the Project reduces the need for more expensive western renewable generation while also reducing curtailments, with an estimated resulting Production Cost Savings NPV of $5 billion between 2028 and 2040.

For both Scenarios 1 and 2, extrapolating growth rates beyond 2040 for the duration of the useful life of the Project significantly increases the NPV in Production Cost Savings attributable to the CRT Project.

[1] The WOCS Transmission Path, or Path 5, is a major east-west high voltage transmission intertie path from east of the Cascades into the Portland area within the Western Electricity Coordinating Council (WECC), currently with a maximum transfer limit of 7,600 MW in the winter and 5,930 MW in the summer.

Background

Energy GPS Consulting (EGPSC) was retained by Cascade Renewable Transmission, LLC (CRT) to conduct a cost-benefit analysis of enhancing the transmission transfer capability of the West of Cascades - South (WOCS) Transmission Path. The WOCS transmission constraint exists between the west of Cascades load areas (e.g., Portland) and the east generating resources (e.g., generators in eastern Oregon and Washington). CRT has proposed the Cascade Renewable Transmission Project (CRT Project, or Project), an underground and underwater High Voltage Direct Current (HVDC) transmission line between The Dalles and Portland, OR that would add 1,100 MW of east-to-west transfer capability. The Project is currently in development with a target in-service date of 2028.

The WOCS transmission constraint may play a major role in determining the location of new generating capacity required to meet clean energy laws in Washington and Oregon. That is, there is a significant amount of capacity required to meet the clean energy laws and the least cost location for this new capacity is east of the Cascades in Washington, Oregon, Idaho, Montana, and Wyoming. However, the current transfer capability to enable east-of-the-Cascades capacity to serve west-of-the-Cascades load may limit the feasibility of adding the least cost capacity. Moreover, the absence of increased transfer capability from the east to the west may require more expensive west-sited resources such as commercial and industrial (C&I) solar. Therefore, upgrades to the transmission constraint may allow for lower cost eastern generation to serve western load and thereby reduce overall system production costs.

Goals and Scenarios

The overarching goal of this analysis is to demonstrate the benefits in Oregon and Washington, if any, of increasing the WOCS path capability in future years 2028 to 2040. (For the purposes of this study, we refer to the Pacific Northwest (PNW) power grid which includes the Balancing Authorities that cover Oregon, Washington, and Montana. The NWMT Balancing Authority was included to capture the likelihood of significant wind generation resources in Montana that could be available to west-of-Cascades load). The chosen study years were selected to coincide with the anticipated initial first few operating years of the Project and a reasonable projection of future years that reflect progress towards Washington's CETA law[2] of 100% clean energy retail sales by 2045 and Oregon House Bill 2021[3] requiring 100% clean energy by 2040. There are many uncertainties with meeting these clean energy laws and maintaining reliability. Focusing the analysis on years before both laws require 100% clean energy helps address the uncertainty of the ability to meet the laws by target dates.

In addition, two scenarios were chosen to quantify uncertainty in load growth: 1) benefits of the Project under business-as-usual (BAU) load growth (i.e., current P50 load growth representing a 0.6% and 0.9% annual growth rate in energy and peak demand, respectively, in Washington and Oregon from 2022 to 2040), and 2) benefits of the Project under a high load growth projection that represents partial electrification of the transportation and heating sectors (representing a 3.0% and 1.8% annual growth

[2] WA CETA; https://www.commerce.wa.gov/growing-the-economy/energy/ceta/

[3] OR HB 2021; https://www.oregon.gov/puc/Documents/HB2021-Summary.pdf

rate in energy and peak demand, respectively, in Washington and Oregon from 2022 to 2040, equaling a 40% increase in energy and 14% increase in peak demand by 2040 as compared to the P50 case). These were selected because there is great concern that the conversion of heating units to electricity, addition of air conditioning units in the PNW, and plans of electric vehicles replacing gas vehicles will cause significant increases in load growth over the next several decades.

Approach

To quantify the benefits of the Project under each scenario we ran a zonal production cost model of the geographic area covered by the Western Electricity Coordinating Council (WECC) from 2022 to 2040. The model was used to estimate two capacity expansion plans, one with and one without the Project's increased transmission capability for each scenario (four expansion plans in total). Since the model has perfect foresight, with the CRT line assumed to be operational January 1, 2028, we established the 2027 results of the case without CRT as the starting point from which to optimize the CRT case. The model was analyzed for future years 2028 to 2040 in terms of ability to meet reliability and policy goals of Washington and Oregon. Outputs include hourly generation at each zone and transmission flows on major paths. Differences between runs in terms of the capacity expansion plans and associated total system production costs were used to demonstrate benefits of the Project. Detailed information on the methods, models, and inputs for these simulations are described in Appendix A.

The model simulations are summarized below.

Table 1. Summary of each production cost model simulation as proposed. LTCE = Long-term capacity expansion.

Scenario	Name	Type	Notes
1	Case 1 – Base	LTCE and Dispatch	Most likely outcome w/o Project
1	Study Case 1 – CRT	LTCE and Dispatch	Most likely outcome w/ Project
2	Case 2 – Base	LTCE and Dispatch	High load growth scenario w/o Project
2	Study Case 2 – CRT	LTCE and Dispatch	High load growth scenario w/ Project

Results and Discussion

Scenario 1: P50 Load Growth

Significant clean energy capacity additions are required to meet reliability standards and clean energy laws in Washington and Oregon. Using Aurora to simulate the PNW system as defined here, we estimate that by 2040 capacity additions for Washington and Oregon are 52.9 GW without the CRT transmission line (see Figure 1). In addition to meeting clean energy laws, these capacity additions are also required to meet reliability standards assuming a projected peak load growth and planning reserve margin. These large amounts of capacity additions are driven by declining peak capacity contributions of renewable energy (as you add more and more capacity while pushing the net peak load hour back) and significant energy curtailment due to load and generation mismatch and transmission constraints.

As also shown on Figure 1, under Scenario 1 – Study Case 1, with the CRT line, capacity additions across the PNW system are forecast to be reduced by 9.4 GW to 43.5 GW. The rationale for lower capacity requirements with the CRT line is explained in the following paragraphs.

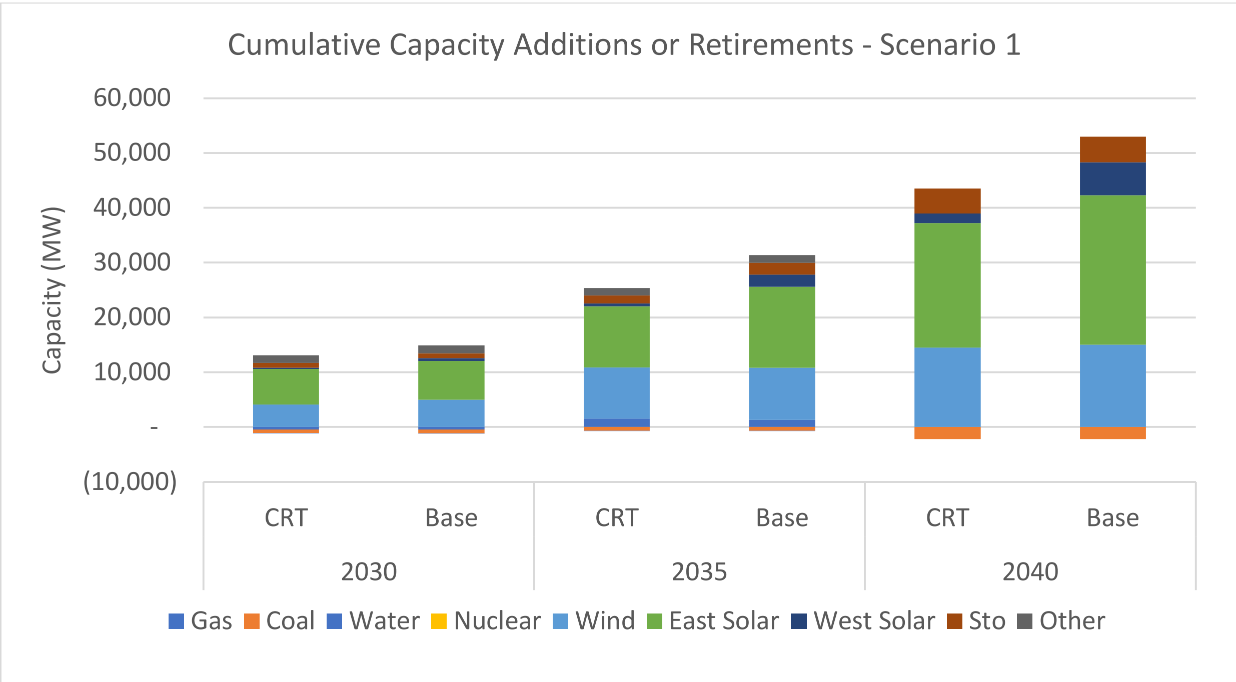

Figure 1. Capacity addition and retirement mix in Washington and Oregon for future years for Scenario 1 model runs with CRT transmission upgrade (CRT) and without CRT (base).

The CRT line reduces the WOCS transmission constraint across all study years. The projected percent at max (amount of time the transmission line is fully loaded) of the WOCS is reduced from 19% to 6% in 2028 and from 38% to 24% by 2040 (Figure 2). This reduction in transmission line constraints in turn reduces renewable curtailment, thereby requiring fewer clean energy resources to meet reliability standards and clean energy laws. In addition to the significant cost savings from being able to construct fewer clean energy resources, there is the additional benefit of preserving significant acres of land from being impacted by solar and wind farms.

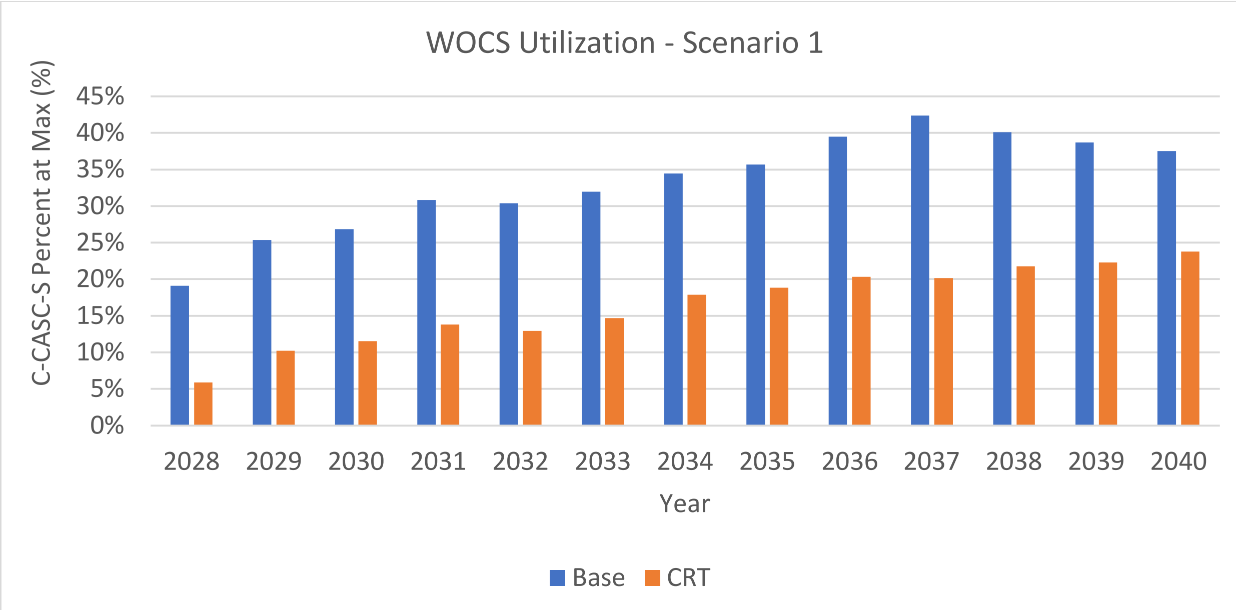

Figure 2. West of Cascades South (WOCS) line percent at max capacity with and without the CRT upgrade. Declining percent at max in the base case after 2037 is likely due to significant capacity additions west of the Cascades.

When adding such large amounts of renewable capacity, the curtailment rates can become significant. In the base case without CRT, the curtailment of renewable energy in the PNW is estimated to be 4,602 GWh, 25,141 GWh and 66,204 GWh by 2030, 2035, and 2040, respectively (Figure 3). With already low capacity factors from these variable energy resources, this significantly reduces the energy delivered to the grid by these resources. By adding additional transfer capability with the CRT Project, these estimated curtailments are reduced by 1,556 GWh, 7,272 GWh, and 16,558 GWh in 2030, 2035, and 2040, respectively. Lower curtailment means that fewer capacity additions are needed to meet clean energy laws and maintain reliability. Assuming a 30% capacity factor and 25% curtailment rate, this would equate to 8,400 MW fewer capacity additions resulting from lower curtailment alone.

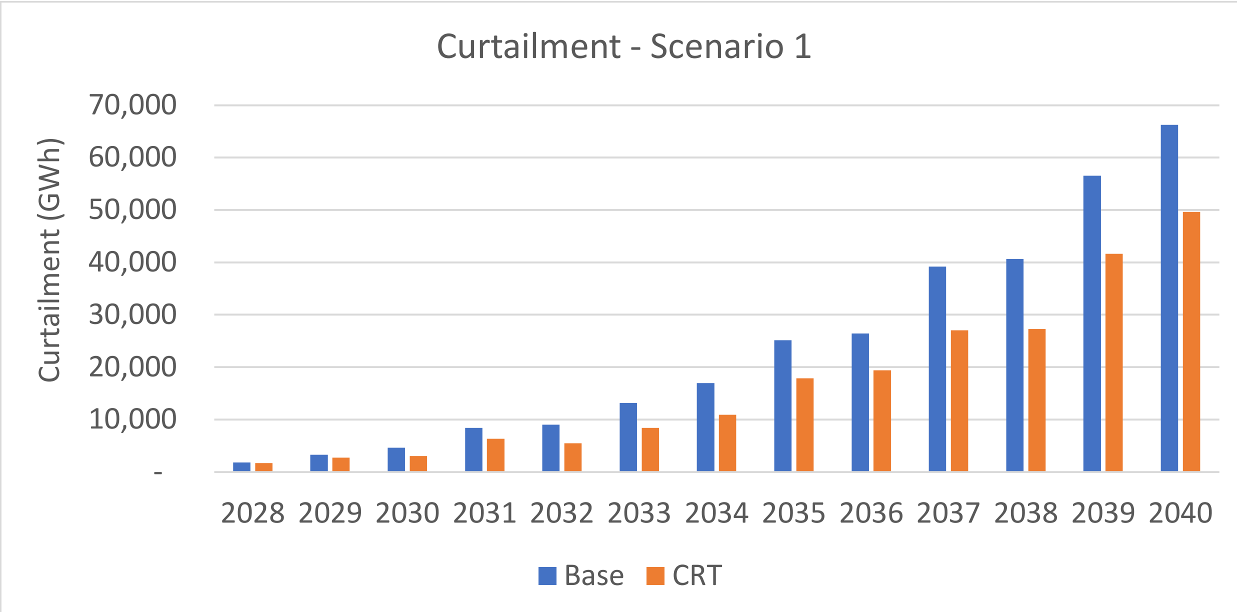

Figure 3. Renewable curtailment in the PNW for Scenario 1 model runs with CRT transmission upgrade (CRT) and without CRT (base).

Another benefit of the CRT Project relates to the location of the capacity additions. That is, increasing the WOCS transfer capability reduces the amount of capacity additions west of the Cascades. For Scenario 1, it is forecast that by 2040 4.2 GW less of solar is constructed west of the Cascades (Figure 4). This is an important cost reduction because this capacity would largely be higher cost C&I scale solar.

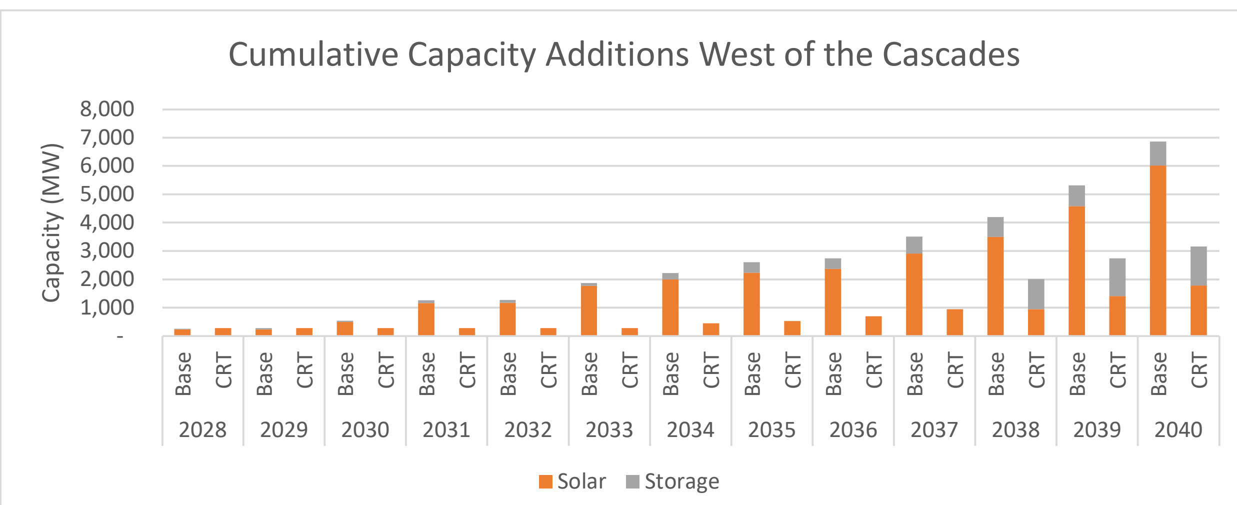

Figure 4. Capacity additions by type and location in the West of the Cascades.

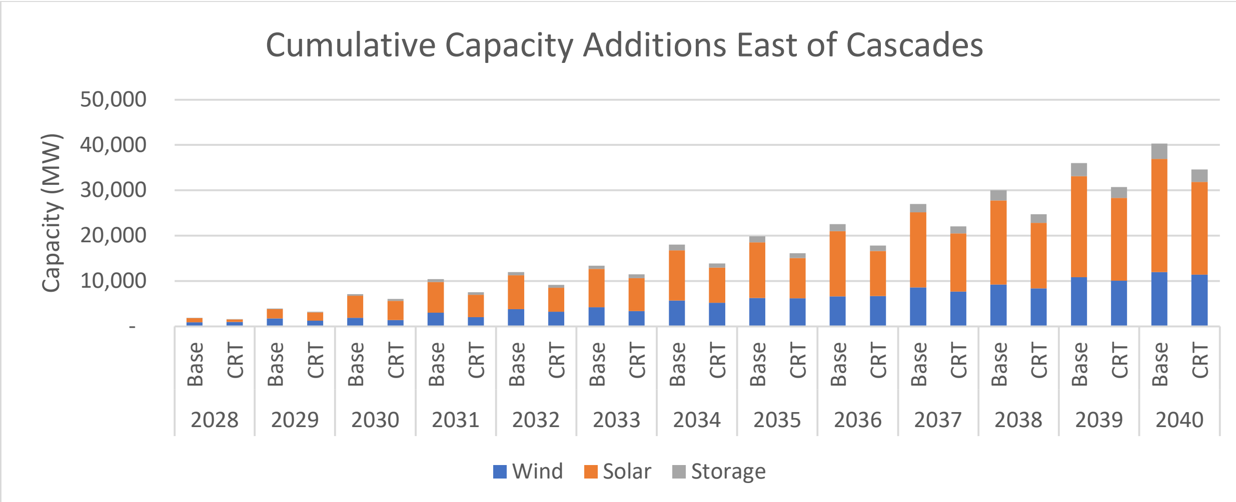

Figure 5. Capacity additions by type and location East of the Cascades.

By reducing the amount of required renewable capacity additions in total, as well as shifting away from higher-cost western resources, the CRT Project reduces total system production costs. The savings expressed as a net present value (NPV[4]) from 2028 to 2040 are $4.1 Billion (Figure 6). There are nearly $1B in cost savings in 2040, the last year of analysis. Thus, extrapolating these savings over an assumed 40-year project lifetime leads to an estimated NPV savings of $9.9 Billion from 2028 to 2067.

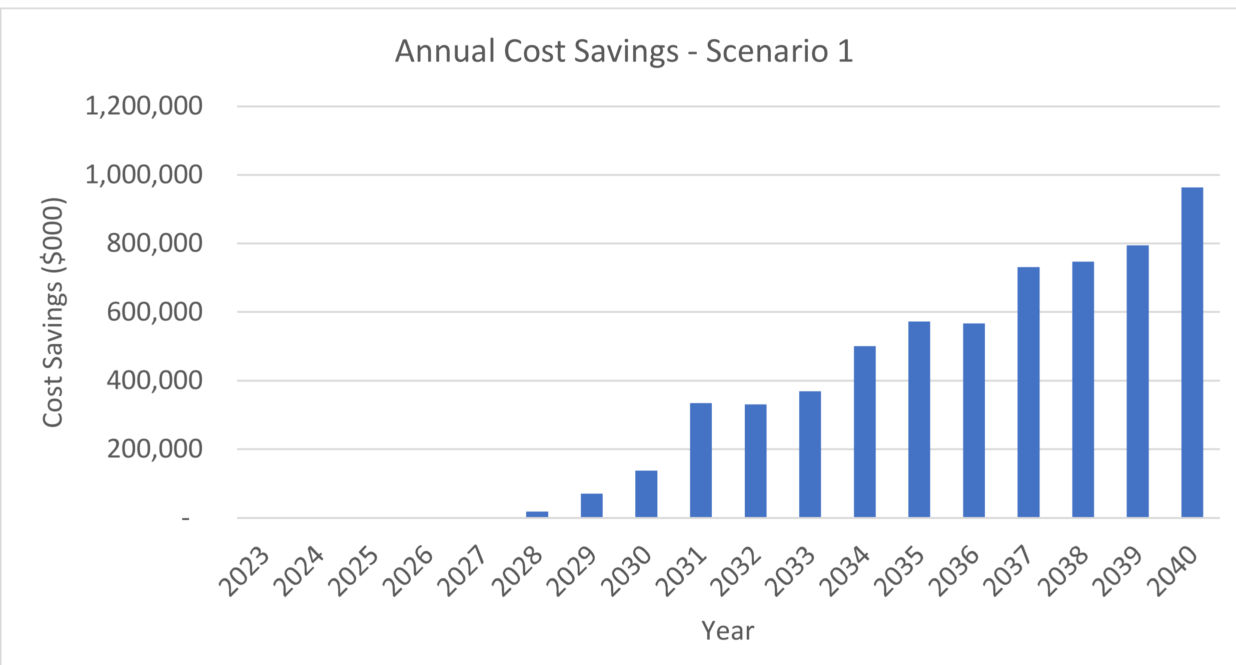

Figure 6. Annual system cost savings due to the CRT transmission addition.

[4] NPV calculation assumes an inflation rate of 2.5% annually and a 7% discount rate.

Scenario 2: Electrification

To develop new load forecasts to account for electrification, we estimated base load growths, electric vehicle load growth, and heating conversion load growth using the 2021 Washington State Energy Strategy[5]. Average annual load growth rates were increased to represent base load and heating load growth using the same hourly shape as Scenario 1. New hourly profiles[6] and load forecasts were also added to represent electric vehicle load growth. These changes were applied throughout the WECC for this scenario. The results were an increase from 0.6% to 3.0% annual average load growth rates and increase from 0.9% to 1.8% in annual average peak load growth rates in Washington and Oregon from 2022 to 2040. Stated differently, the electrification scenario adds 40% more energy and a 14% increase in peak load in 2040 as compared to the P50 business as usual load growth (Figure 7).

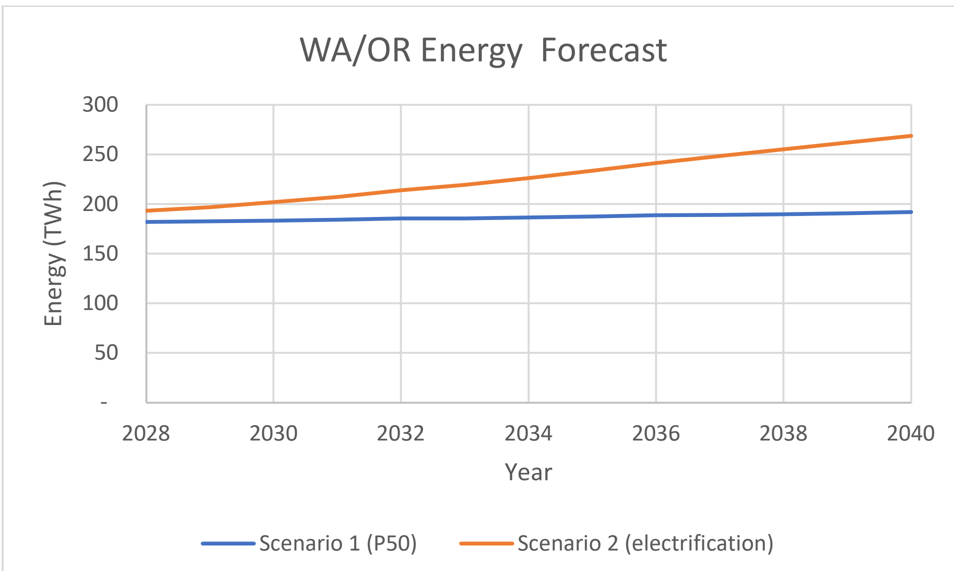

Figure 7. Load forecast in WA and OR under Scenario 1 and 2.

This additional load growth requires more renewable capacity additions in the PNW to meet clean energy laws and maintain system reliability as compared to Scenario 1: more than 138 GW in Scenario 2 by 2040 compared with 52.9 in Scenario 1. The CRT line is forecast to reduce the Scenario 2 amount by 14.7 GW. The reason for the reduction is the same as in Scenario 1, that is by reducing curtailment and allowing for more higher quality resources in the east-of-Cascades regions and fewer high-cost additions west of the Cascades. Under this scenario the CRT Project reduces total system production costs expressed as an NPV by $5 Billion for the period 2028 to 2040. There are nearly $1.6B in cost savings in 2040, the last year of analysis, resulting in an NPV reduction of total system production costs of $15 billion over an assumed 40-year life of the CRT project.

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[5] https://www.commerce.wa.gov/growing-the-economy/energy/2021-state-energy-strategy/

[6] Derived from Mort and Mort (2019) https://www.iepec.org/wp-content/uploads/2019/02/abstracts_presentations_mort.pdf

Conclusions

This study demonstrates that significant levels of new clean energy capacity are required to meet the reliability standards and clean energy laws of Washington and Oregon by 2040. Beyond 2040 these requirements are expected to grow even larger. Because of the level of capacity required, the existing transmission constraints between the lower-cost and higher producing clean energy locations east of the Cascades and the load centers in the west become significantly more constrained. This transmission constraint, WOCS, leads to significant curtailment rates. Therefore, the combination of higher-cost west-side sited resources, such as C&I solar, and overbuilding of generation resources located east of the Cascades, becomes the least cost solution. However, if the transmission capability across the WOCS constraint is increased, less of the more expensive west of the Cascades resources are necessary and fewer high quality east renewable resources are needed to maintain system reliability and meet clean energy laws.

The economic benefits of the CRT line are driven by capital cost savings from reduced renewable resources and are estimated at $4.1 B in NPV (from 2028 to 2040) in Scenario 1 with current load forecasts and $5.0 B in NPV (from 2028 to 2040) in Scenario 2 with partial electrification of the transportation and heating sectors.

Table 2. Summary of CRT Economic Benefits.

Scenario	Capacity Reduction (GW)	NPV (2028 to 2040)	NPV (2028 to 2067)
#1 (P50)	9.4	$4.1 B	$9.9 B
#2 (Electrification)	14.7	$5.0 B	$15.0 B

An added benefit is minimizing land usage. Under Scenario 1, in 2040, with CRT, there is over 4,500 MW of solar and 560 MW of wind which no longer needs to be constructed east of the Cascades. Given average land usage for solar and wind farms, this equates to 25,000 – 32,000 acres of land which would not be impacted by the construction of new renewable generation.

Our assumptions did NOT include certain variables that might increase the benefits of the Project if they were included in this analysis:

- We assumed implementation of clean energy laws as RPS standards. We did not implement a strict definition of clean energy laws into the model, such as strict emission limits including tracking imports into Washington and Oregon. Enforcement of these laws in a stricter sense would lead to an increase in the capacity required to meet the laws and thus an increase in cost savings of the CRT project.
- We carried out our simulations only to 2040. Ending the simulation in 2040 did not simulate 100% clean energy laws for Washington, which set a 2045 deadline for achieving this goal.

Carrying out the simulation to 2045 would result in an increase in the amount of capacity required to meet clean energy laws and thus have an increase in cost savings of the CRT project.

Other considerations for future analyses:

- Demand response programs. Demand response was included in the model to avoid load shedding but was utilized for a very limited number of hours and only in the last few study years. Wide-scale demand response programs implemented earlier could change the capacity expansion plans and requirements to meet clean energy laws. The cost and magnitude of these programs vary widely. Future analyses of demand response programs may impact cost savings estimates depending on the design and cost of the demand response programs.
- Alternative technologies. Not-yet-established technologies in the WECC were not included such as hydrogen, small nuclear reactors, and offshore wind in the Pacific. Including these technologies may alter the capacity expansion plans and capacity additions and location to meet clean energy laws. Future analyses of alternative technologies may impact the cost savings.

Appendix A. Methods, Models, and Inputs

Production cost models ("PCM") are widely used to forecast future electrical system generating capacity mix to meet growing electricity demand and clean energy laws at the least cost solution. Inputs to PCM include the expected electricity demand forecast, the existing generators available to meet the load forecast, future candidate generators than can be added to meet growing load, physical constraints to either the generator operation or transmission line constraints, and policy constraints to meet laws. The inputs are formatted by the PCM to be read into an optimization engine that solves for the least cost solution to meet demand at each interval (e.g., hour). Outputs from the PCM include a new supply stack (retirements and additions from the optimization) and the performance of that supply stack for each forecast interval (e.g., generation, fuel consumption, emissions, fixed and variable costs, imports, exports). Reliability metrics such as curtailed demand (loss of load) or required demand response are also available.

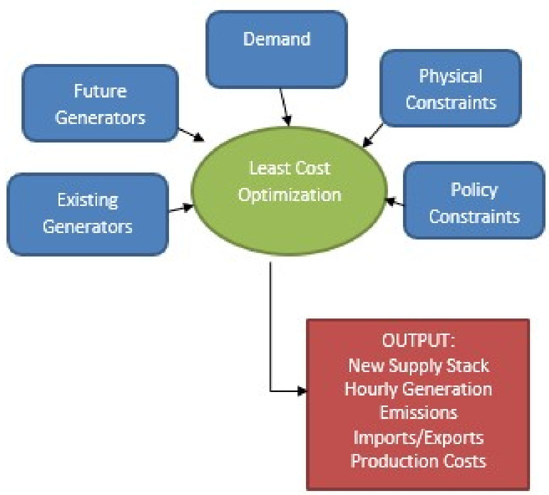

Figure 8.

We have been developing a PCM at EGPS for about a year now using a commercial PCM called Aurora. The inputs to our PCM have been derived from our internal power database as well as publicly available data. We have carefully calibrated the PCM to historical conditions from 2018 to 2021. Included in this is a unique hourly hydro generation calibration to historical hourly hydro generation data. Additional details and model inputs are described below.

The WECC is represented in our model by 40 zones including many of the 38 balancing authorities shown in Figure 9 with increased granularity for BPAT to separate the NW, SW, and Eastern zones of BPAT.

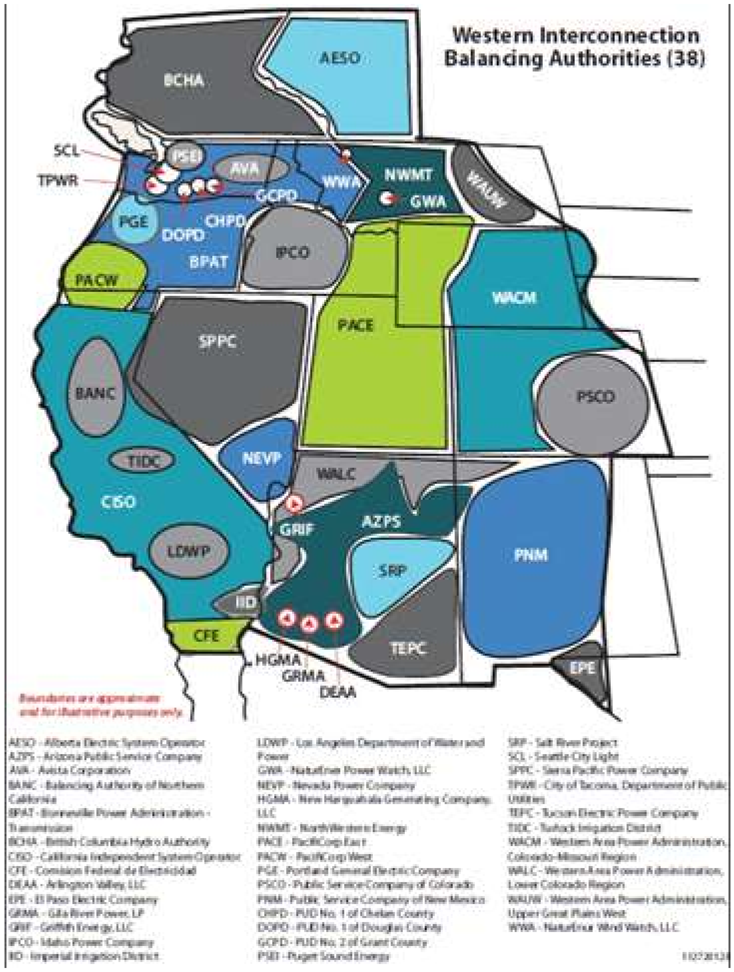

Figure 9. Balancing Authorities in the WECC.

This breakout allows us to capture the Cross Cascades and South of Allston transmission constraints. Transmission limits between zones are derived from historical flow limits, the CPUC RA and IRP Model7, and the WECC Power Supply Assessment8. A summary of the transmission assumptions in the PNW is shown below. Important considerations are that the cross cascades transmission limit is captured in our model through both the north and south constraint. In addition, there is some PacifiCorp load on the east side of the SWOCS constraint that is not split out in FERC 714 filings. To capture this, we applied a portion of the PACW load (500 MWa) to the BPAT_E zone.

[7] CPUC RA and IRP Model, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2019-20-irp-events-and-materials/unified-ra-and-irp-modeling-datasets-2019

[8] WECC Power Supply Assessment, https://www.wecc.org/Reliability/2016PSA_Final.pdf

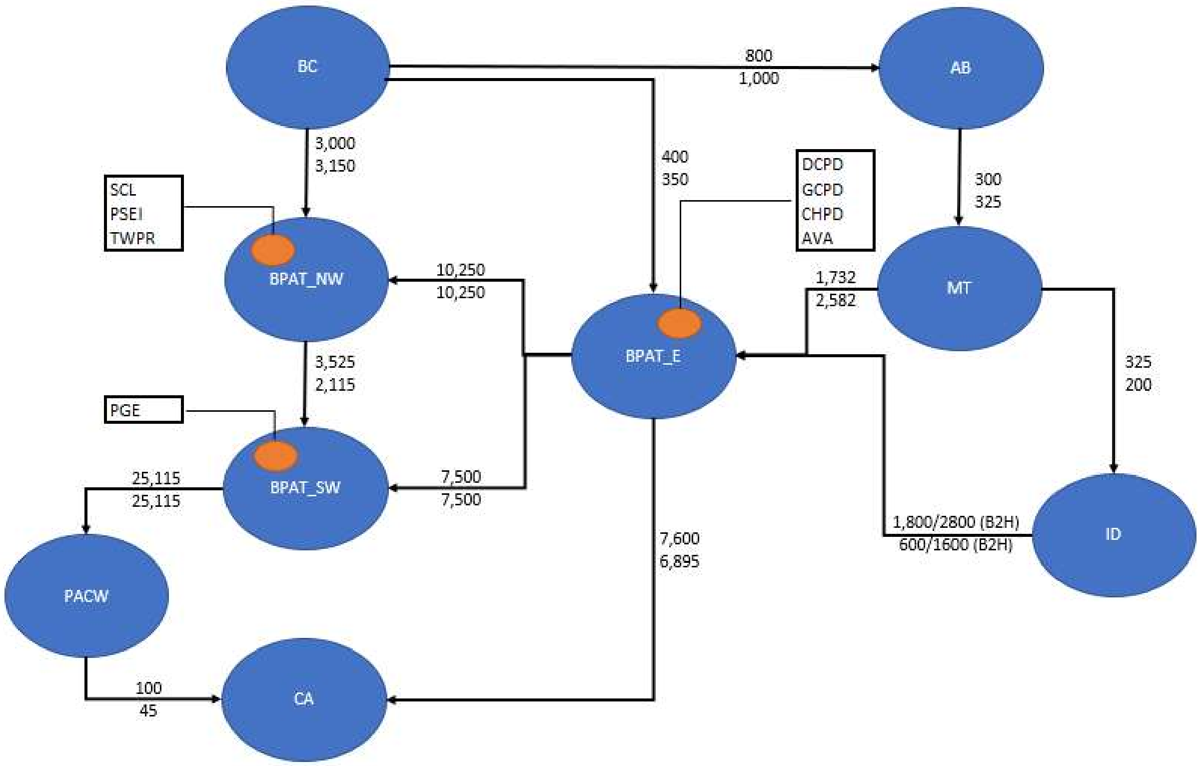

Figure 10. PNW transmission topology used in the PCM. Notes: 1) transmission outside of the PNW not shown here but the model does represent the entire WECC footprint. 2) a portion of PACW load is located in BPAT_E load zone.

Load forecasts for each zone are derived from the FERC 714 for zones in the U.S, the NERC ES&D for zones in Canada, and the PRODESEN for Mexico Baja California. Hourly load shapes are derived from the WECC Anchor Data Set (ADS). The load forecast for the NWPP is shown below.

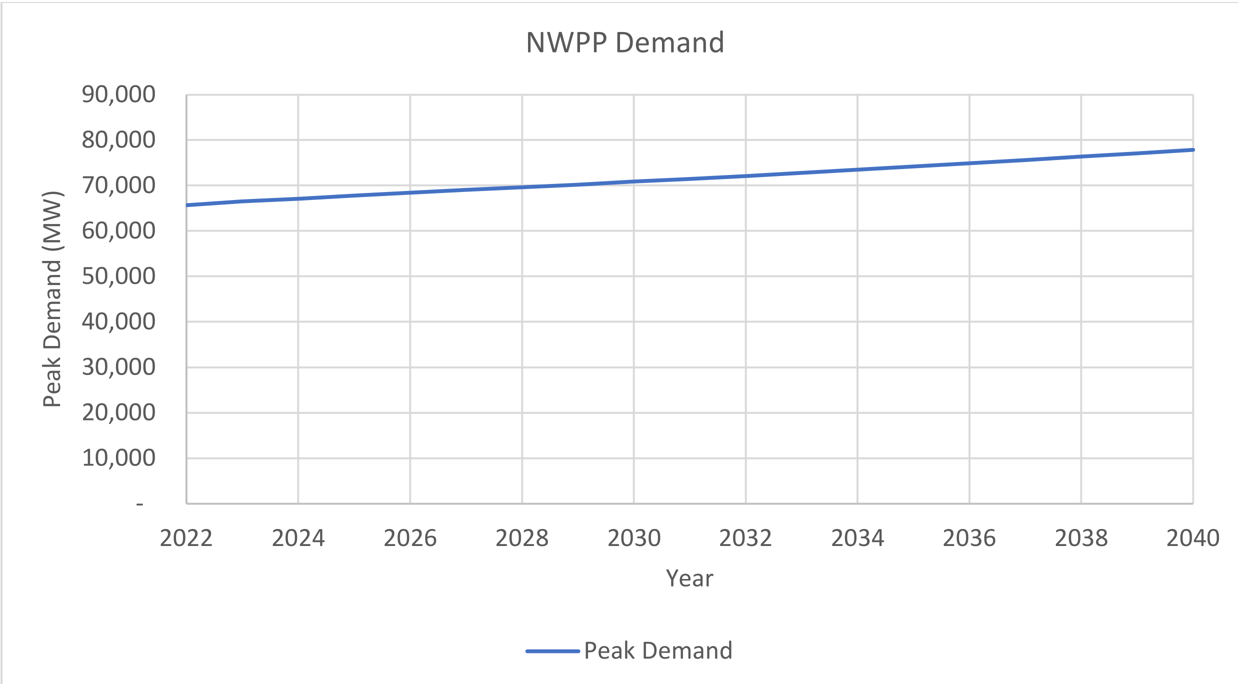

Figure 11. Peak load growth in the NWPP.

The EGPS Power Database is used to determine the existing supply stack within WECC and is built off a variety of sources including the EIA 860 and 923. Future generator candidates are derived from the EIA and NREL. Capital cost curves are derived from the NREL Advance Technology Baseline (ATB) and shown below.

Table 3. Summary of new generating technology options used in the PCM.

Region-Technology	Size (MW)	Duration (MWh)	Capacity Factor (%)	2023 Cost ($/kW)
West-Solar	100	-	16%	1,508
East-Solar	100	-	24%	888
East-Wind	150	-	35%	1,237
MT-Wind	150	-	40%	1,237
West-Storage	100	400	-	1,147
East-Storage	100	400	-	1,147
Hybrid Solar + BESS	100	400	-	1,306

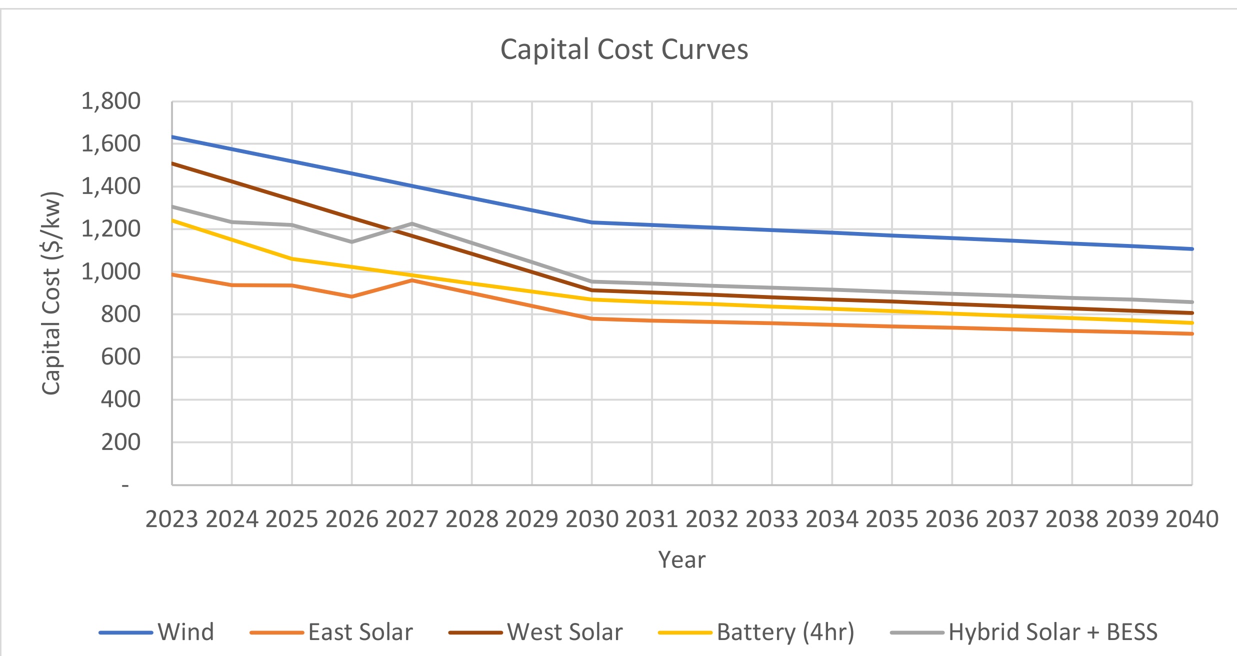

Figure 12. Capital cost curves for various technologies derived from the NREL ATB.

Generator operational and financial properties are derived from the WECC ADS, the CPUC RA and IRP model, and general rules of thumb from the EPA and NREL. Fuel forecasts for thermal generators are derived from the EIA and forward trading curves. The model contains seven natural gas hubs in the west and unit-level gas transportation cost adders.

Clean energy laws are represented in the model through minimum renewable generation constraints similar to RPS constraints. These are summarized below.

Table 4. RPS Targets used in the PCM.

State	Target	Year	Comments
California	100%	2045	RPS
Colorado	100%	2050	Clean Energy
Nevada	100%	2050	RPS
New Mexico	100%	2045	Carbon Free
Oregon	100%	2040	RPS
Washington	100%	2045	Clean Energy

We implemented utility-level constraints on Pacificorp (PACW), Portland General Electric (PGE), and Puget Sound Energy (PSEI) to ensure both state-level laws and individual utility requirements were met. Assuming a blended clean energy technology capacity factor of 30%, the capacity additions for Puget Sound Energy, Portland General Electric, and Pacificorp West are estimated at 3 GW, 4.3 GW, and 4.3 MW by 2030 (assuming 7,756, 11,309, and 11,322 GWh incremental clean energy requirement) and 6.5 GW, 6.8 GW, 5.8 GW by 2040, respectively (assuming 17,054, 17,909, and 15,211 GWh incremental clean energy requirement).

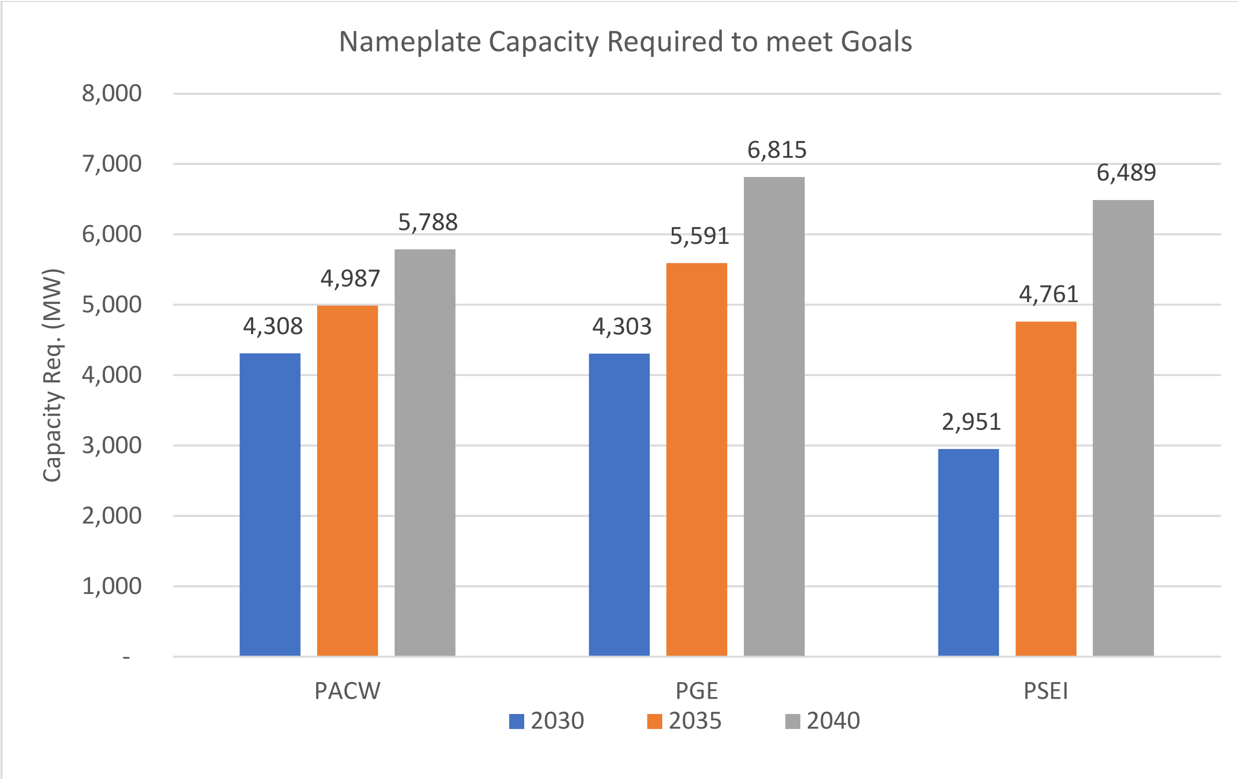

Figure 13. Incremental capacity requirements for utilities in the PNW. Note, assumes a 30% capacity factor.

Our production cost model has been carefully benchmarked to the last three full years of energy data in terms of installed capacity, generation by fuel type, unit-level hourly hydro generation, transmission flows on major paths, and power prices. Our base long-term capacity expansion has been evaluated against publicly available expansion plans including the 2021 NW Power Plan[9].

Our model has several differentiators that benefited this analysis including:

- Separate zones for BPAT into NW, SW, and E with current transmission limits between,
- Hydro model in PNW integrated in PCM,
- Tethered to reality with benchmarking three years, and
- Iterative approach to capacity expansion.

[9] 2021 NW Power Plan, https://www.nwcouncil.org/sites/default/files/2021powerplan_2021-5.pdf

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