Chapter 4. Futures and uncertainties

To meet the evolving needs of the electricity grid and customers, it is critical to assess the wide range of uncertainties impacting different elements within the power system. Estimating the compounded effects of the different drivers and their impacts is foundational to ensuring the robustness of our resource actions by minimizing risk over time for customers across a wide range of potential futures.

The previous chapter discussed the broader policy and macroeconomic environment in which we are creating these plans. In this chapter we detail how we are incorporating this environment, including all the associated uncertainty, into our IRP. First, we discuss the different Need Futures, which describes the range of resource needs in terms of capacity and energy. This is followed by descriptions of the variation in technology costs of resources and wholesale electricity prices. This approach informs how resource actions taken by Portland General Electric (PGE) will account for future risks and uncertainties.

Chapter highlights

- Key drivers of uncertainty in this Integrated Resource Plan (IRP) include demand growth, economic trends and technological innovation, rate of electrification and customer adoption of new technologies, regional resource adequacy and buildout of new non-GHG-emitting resources.
- PGE's portfolio analysis accounts for uncertainty in future resource needs, technology costs, wholesale energy markets and hydro conditions.
- Portfolio analysis was conducted across 351 potential futures, defined by the range of resource needs, technology costs and wholesale electricity market prices

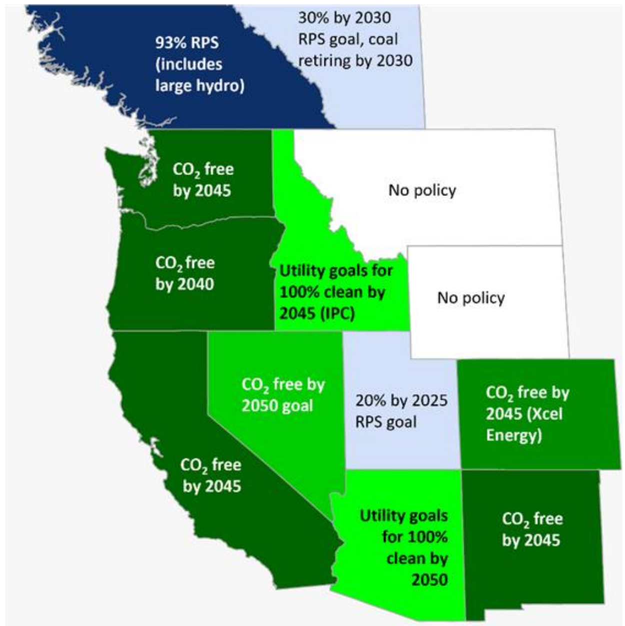
4.1 The changing Western Interconnection

The power system landscape across the Western Interconnection is changing rapidly.[68] At the start of 2018, there were no policies in the West that mandated a 100 percent clean/non-GHG-emitting power system. In September 2018, California signed Senate Bill (SB) 100 into law, which directed the state to reduce electric system GHG emissions to zero by 2045.[69] In

[68] Information about the Western Interconnection is available at: https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/The-Western-Interconnection.aspx
[69] CA Senate Bill (SB) 100 (2018), available at: https://www.energy.ca.gov/sb100

the following years many states, including Oregon in 2021, passed similar bills targeting a non-emitting power system in the 2040s (**Figure 17**).[70] Additionally, several utilities in states without clean energy policies have made company-level decarbonization pledges.[71] **Figure 17** shows key state-level GHG reduction and renewable portfolio standard policies.[72] These policies will likely bring more wind, solar, storage and other non-emitting resources to the West and transition away from coal and gas-fired generation.

Figure 17. Western clean energy policies



Forecasting Western energy markets requires predicting how quickly non-GHG-emitting resources will arrive and how quickly GHG-emitting generation will decrease, considering market and transmission interoperability issues, and assessing if the transition creates adequacy challenges. Resource adequacy challenges have occurred in recent years in the Western Interconnection. In California, the California Independent System Operator (CAISO) system experienced blackouts in August 2020 and issued a Stage 3 emergency alert in September 2022.[73] Prior to 2020, CAISO had yet to issue a Stage 3 alert since the 2001 energy crisis. Due to reliability concerns, California passed AB 205 in the summer of 2022, which includes an electric reliability reserve fund, among other provisions. California also

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[70] OR: HB 2021 (2021); WA: SB 5116 (2019); NM: SB 489 (2019); NV: SB 358 (2019); and CO SB 19-236 (2019).
[71] Available at: https://www.idahopower.com/news/idaho-power-long-range-plan-focuses-on-reliable-affordable-clean-energy/, and at https://www.aps.com/en/About/Our-Company/Newsroom/Articles/APS-sets-course-for-100-percent-clean-energy-future, January 22, 2020
[72] Policies listed on the map may not apply to smaller power providers; additional policies may exist.
[73] A Stage 3 alert indicates blackouts are imminent.

passed SB 846 in 2022, which attempts to extend the life of the Diablo Canyon nuclear power plant, mainly for grid reliability.[74]

Beyond the changing supply side landscape, there is uncertainty regarding Western electric demand. Many states and municipalities have passed laws encouraging and/or mandating building and vehicle electrification that could bring new loads to the Western Interconnection. For example, Oregon, Washington and California are banning the sale of gasoline passenger vehicles by 2035, accelerating the push toward electric vehicles.[75] In spring 2022, Washington amended its building codes to require electric heating in most large multifamily construction and commercial buildings.[76] These policies, which aim to reduce GHG emissions, may lead to increased demand for electricity. Beyond electrification, the Northwest has also seen increased demand for electricity in recent years from industrial customers, often in the form of data centers.

In late 2019, the Western Power Pool (then the Northwest Power Pool) reviewed reliability studies conducted by BPA, Energy and Environmental Economics, Inc. (E3), Pacific Northwest Utilities Conference Committee (PNUCC) and the Northwest Power and Conservation Council. The studies "identify an urgent and immediate challenge to the regional electricity system's ability to provide reliable electric service."[77] They also note that "studies have shown that it is possible to cost-effectively replace coal generation with… lower carbon resources and significantly reduce electricity sector carbon emissions."[78]

The Western Power Pool's findings helped spur the creation of the Western Resource Adequacy Program (WRAP). The WRAP is still under development. If it succeeds, it may change how the IRP examines power market availability, resource adequacy and resource capacity contributions (more information on the WRAP is in **Section 3.2, Regional planning: resource adequacy**).

As part of the Western Interconnection, PGE routinely buys and sells power with other Western power market participants. As noted earlier in this section, predicting how much power will be available to buy and sell in future years is challenging. However, the IRP considers short-term power markets as a resource adequacy tool. To accomplish this, the IRP includes an analysis that approximates how much power will be available in future years during peak hours. This analysis focuses more on power availability in Oregon, Washington,

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[74] Available at: https://www.utilitydive.com/news/california-sweeping-climate-package-carbon-neutrality-2045-clean-electricity-2035-diablo-canyon/631099/
[75] Available at: https://www.oregon.gov/deq/rulemaking/Pages/CleanCarsII.aspx
[76] Available at: https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/washington-state-to-require-electric-heating-in-building-code-update-69960737
[77] See "Exploring a Resource Adequacy Program for the Pacific Northwest", Northwest Powerpool, October 2019, at page 7, available at: https://www.westernpowerpool.org/private-media/documents/2019.11.12_NWPP_RA_Assessment_Review_Final_10-23.2019.pdf
[78] *Id.* at page 8.

Idaho and Western Montana and is used as an input into the resource adequacy model, Sequoia, that determines PGE's need for power. More information on the analysis is in **Appendix G, Market capacity study**.

For the Reference Case, the amount of market power available to the Sequoia model is in **Table 6.** Heavy load hours defined as 6:00 AM to 10:00 PM, Monday-Saturday, excluding holidays. Light load hours are all other hours. The light load hour range is dependent on load (lower load is associated with more market availability). The decrease in winter market availability starting in 2026 is largely due to coal unit retirements.[79]

Table 6. PGE 2023 IRP spot market power availability assumptions for resource adequacy

All values in MW	2025 and earlier		2026 and later	
	Winter	Summer	Winter	Summer
Heavy load hours	200	0	150	0
Light load hours	400-999	400-999	400-999	400-999

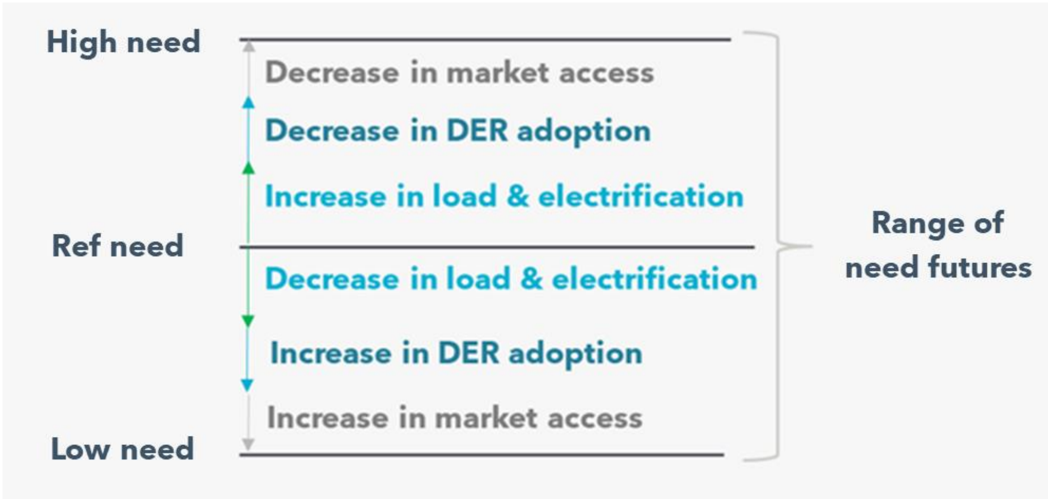
4.2 Need Futures

One of the two key objectives of the IRP process is to estimate system need under a variety of scenarios.[80] The IRP creates individual Need Futures that aggregate the impact of load growth, distributed energy resources (DERs) and market access assumptions. Different permutations of the load, DERs and market access assumption form the basis for the range of Need Futures in the IRP. The range of Need Futures is a vital input to determine the robustness of the proposed set of resource additions to a variety of conditions. The Need Futures not only capture the costs and risks associated with large and long-lived resource actions given the uncertainty in future resource needs but also highlight critical considerations for PGE's non-GHG-emitting resource procurement strategy.

PGE designed the Need Futures to capture a broad variation from the Reference Case by varying drivers that would impact the resource need.[81] **Figure 18** visually represents the driving variables that change the Reference Case to the High and Low Need Futures.

[79] The coal fired Centralia Unit 2 and Valmy Unit 2 are expected to retire at the end of 2025.
[80] The other key objective is to propose the optimal combination of resources, their size and timing, to address the identified system need. This culminates in **Chapter 11, Portfolio analysis**.
[81] The Reference Case refers to the collection of assumptions made across all applicable variables. These assumptions were made based on analysis and studies. Low and High Case assumptions are applied in relativity to the Reference Case.

Figure 18. Visualization of the range of Need Futures captured within the IRP



Articulated in this section is a comprehensive list of variables that result in the three Need Futures, which are summarized in **Table 7.**

- **Top-down Load Forecast.** This IRP considers three scenarios related to macroeconomic and policy trends and impacts on future loads. In addition to the reference load forecast, the low and high growth scenarios capture uncertainty in economic drivers and forecast model uncertainty. The top-down load forecast and associated high and low growth scenarios are detailed further in **Section 6.1, Load forecast,** and **Appendix D, Load forecast methodology**.
- **Energy Efficiency.** This IRP considers three scenarios related to energy efficiency adoption. In addition to the Reference Case, the Low Need Future assumes a higher acquisition of energy efficiency than the Energy Trust of Oregon's (ETO's) cost-effective forecast based on the ETO's high avoided cost scenario (which assumes a 25 percent increase in avoided costs as defined by UM 1893).[82] Similarly, the High Need Future is based on Energy Trust's low avoided cost scenario, which assumes a 25 percent decrease in avoided costs relative to the Reference Case. Energy efficiency that was deemed cost-effective by ETO is discussed in **Section 6.2, Distributed Energy Resource (DER) impact on load**.

[82] *In the Matter of Public Utility Commission of Oregon, Investigation Into the Methodology and Process for Developing Avoided Costs Used in Energy Efficiency Cost-Effectiveness Tests*, Docket No. UM 1893, available at: https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=20999

- **Market Capacity.** This IRP considers three scenarios for the availability of capacity from the market across seasons, years and hours of the day. The High Need Future assumes reduced market capacity, indicating the minimal ability to serve load via market purchases during summer and winter high load hours. Conversely, the Low Need Future assumes higher market availability during the high load hours in summer and winter. These assumptions are based on the findings and recommendations in **Appendix G, Market capacity study**.

This IRP leverages the analytical work within PGE's Distribution System Plan Part 2 (DSP) to determine the range of impact of DER, using it as the primary source of data for the adoption of rooftop PV, building and transportation electrification loads and their integration with PGE through demand response programs.[83]

- **Distributed Photovoltaics (PV).** This IRP aligns with the three adoption cases developed within the DSP. High adoption of PV results in a lower resource need and is consequently included in the low Need Future. Similarly, low adoption of solar PV is included in a high Need Future, as shown in **Table 7**.
- **Transportation Electrification (TE) Load.** High TE adoption results in a higher resource need and is included in the high Need Future. Conversely, low adoption of TE load is included in the low Need Future.
- **TE-related Demand Response (DR) programs.** Unlike TE load, the low participation in TE-related DR programs is included in the High Need Future to ensure we capture the broadest range of potential futures. However, in the Low Need Future, we use a Reference Case of the adoption of TE-related DR programs because the low adoption of EVs would not have sufficient vehicles to be combined with a high adoption of TE-related DR programs.
- **Demand Response (DR).** Like energy efficiency and PV, this IRP models an inverse relationship between Need Futures and customer participation in DR programs.[84]
- **Building electrification (BE) Load.** This IRP introduces three BE load adoption scenarios to align with the DSP's adoption scenarios, so the high adoption scenario of BE load is included in the high Need Future.

[83] PGE's Distribution System Plan Part 2, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAD&FileName=um2197had151613.pdf&DocketID=23043&numSequence=21

[84] High adoption of demand response programs results in lower needs and low adoption of demand response programs results in higher needs. The customer adoption of batteries is included within the demand response variable of each Need Future.

- **BE-related Demand Response (DR) programs.** However, just as with TE-related DR load, low participation in BE-related DR programs is included in the High Need Future to ensure we are capturing the broadest range of potential futures, and in the Low Need Future, we use a Reference Case of the adoption of BE-related DR programs creating an appropriate lower bound to the Need Future.

Table 7. Need Future variables

	Low need	Reference need	High need
Top-down Load Forecast	Low growth	Reference	High growth
Energy Efficiency	High EE	Reference	Low EE
Distributed PV	High adoption	Reference	Low adoption
Transportation Electrification (TE) load	Low adoption	Reference	High adoption
TE-related DR programs	Reference	Reference	Low adoption
Demand Response programs	High adoption	Reference	Low adoption
Market capacity	High availability	Reference	Low availability
Building electrification load	Low adoption	Reference	High adoption
Building electrification-related DR programs	Reference	Reference	Low adoption

In addition to the three Need Futures, PGE examined sensitivities to provide insight into other uncertainties that may impact need. These are described in **Section 6.10, Need sensitivities**.

4.3 Energy technology capital cost scenarios

Throughout **Chapter 2, Accessing support for energy transition** and **Chapter 3, Planning environment**, PGE describes the developments since the 2019 IRP that impact the current and expected costs of resources:

- Tax credit changes (see **Section 2.1, Federal support for energy transition**)
- Clean Energy Policy (a reference to **Section 3.1, Federal and state law and regulatory policy**)

Capital cost estimates are uncertain. Evaluating this capital cost uncertainty in a period of rapid technological change, inflation and supply chain shortages is critical to creating a long-term plan robust to potential changes. In addition to the reference costs (see **Chapter 8, Resource options**, and **Appendix M, Supply-side options**), PGE uses low and high capital cost trajectories for supply-side resources. Reference Case trajectories are primarily informed by the Energy Information Administration (EIA) 2020 Annual Energy Outlook (AEO) and the National Renewable Energy Laboratory (NREL) 2021 Annual Technology Baseline (ATB) analyses.[85,86] The high- and low-cost sensitivities generally rely on the scenarios presented in the NREL ATB; however, resource-specific assumptions are discussed in **Appendix M, Supply-side options**. Capital costs are included in PGE's IRP resource modeling via the revenue requirements model (**Section 10.1, Fixed costs**).

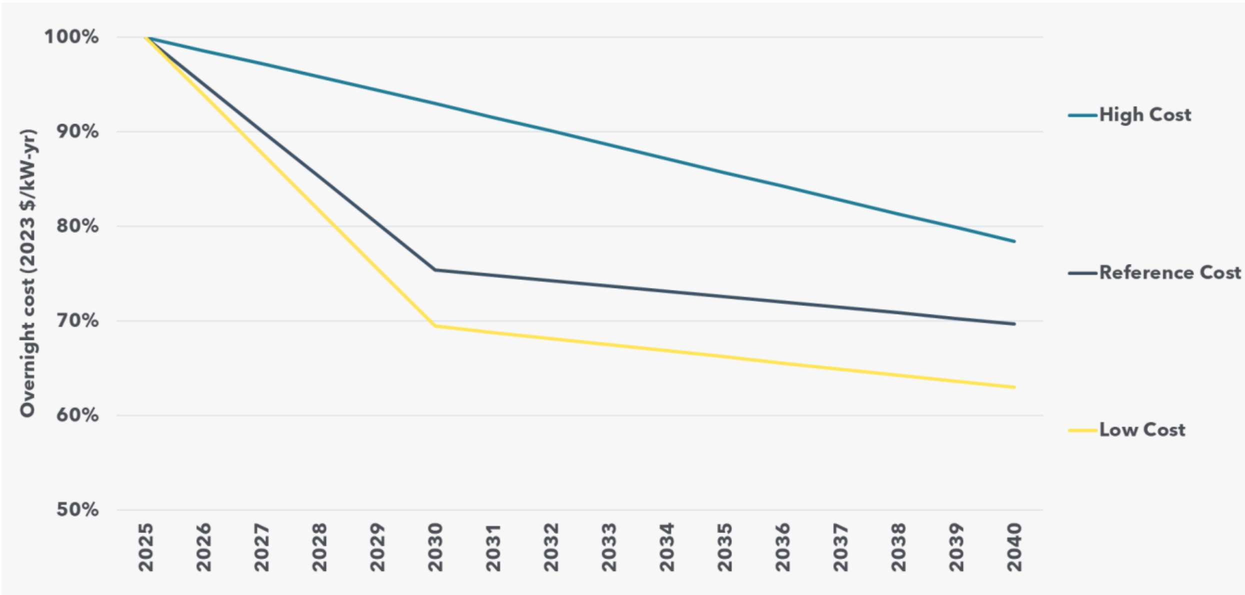
NREL summarizes the general technology innovation scenarios as follows:[87]

- Conservative scenario (high cost) In the NREL ATB Conservative scenario, historical investments come to market with continued industrial learning. The technology available is similar to the current day with a few technological innovations. Public and private investment in research and development (R&D) decreases.
- Moderate scenario (reference) NREL ATB describes this scenario as the expected level of technological innovation. The innovations observed in today's marketplace have become more widespread, and nearly market-ready innovations have come into the market. Public and private R&D investments continue at the current levels.
- Advanced scenario (low cost) Innovations far from market-ready today are successful and have become widespread in the NREL ATB Advanced scenario. Innovative technology architectures could look different from those observed today due to increased public and private R&D investment.

To illustrate the relationship between these three technology capital cost scenarios, fixed cost trajectories for the Christmas Valley Solar resource under each are presented in **Figure 19**.

[85] EIA 2020 Annual Energy Outlook, available at: https://www.eia.gov/outlooks/archive/aeo20/
[86] NREL 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/index
[87] NREL 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/definitions

Figure 19. Christmas Valley solar resource overnight cost trajectory (2023$)



See also the discussion of technology costs with respect to the Scenarios discussed in **Chapter 11, Portfolio analysis**.

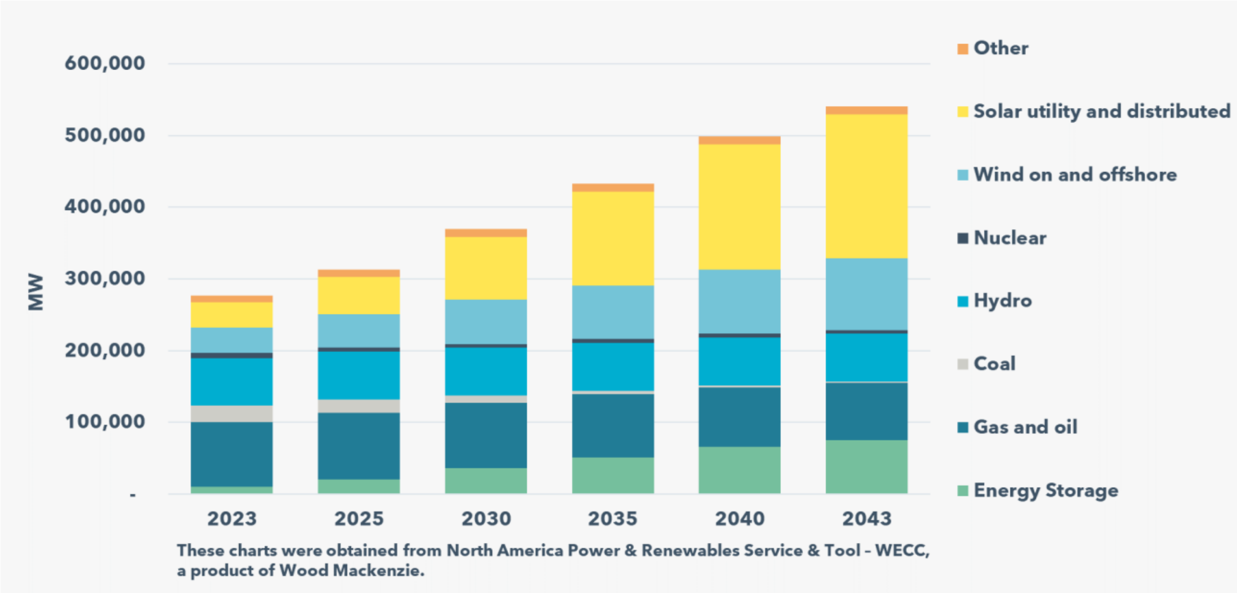
4.4 Long-term fundamental price forecast

The natural gas price forecast strongly influences the forecast of wholesale market prices for electricity.[88] PGE relies on the expertise of a power research consultancy, Wood Mackenzie (WM), to project the Western Electricity Coordinating Council (WECC) resource development and its impact on electricity prices in this IRP. Consequently, PGE incorporates WM's natural gas price forecasts into its long-term price forecasts, which reflects a declining reliance on the thermal fleet in the WECC as the region transitions to non-GHG-emitting resources. PGE also uses WM's WECC resource buildout outlook, shown in **Figure 20.**

The figure reflects the magnitude of the WECC effort to decarbonize, with resource additions being mainly renewables and storage. While the contribution share of gas and oil capacity is forecasted to decline over time as loads increase and non-GHG resources are brought on-line, the capacity of gas and oil capacity remains steady. The WECC capacity will nearly double the current level by 2043, with solar having the majority share and on and offshore wind being the next major contributor.

[88] Coal price forecasts have some influence on the wholesale electricity prices up until the end of 2029 as PGE's candidate resource portfolios include a coal-fired resource, Colstrip, that PGE is set to exit by January 1, 2030.

Figure 20. WECC capacity installed by year and generation source



PGE benefitted from extensive discussions on our electricity price forecasts with stakeholders in several IRP Roundtables.[89] These identified the following risk drivers to be considered in the IRP forecasts:

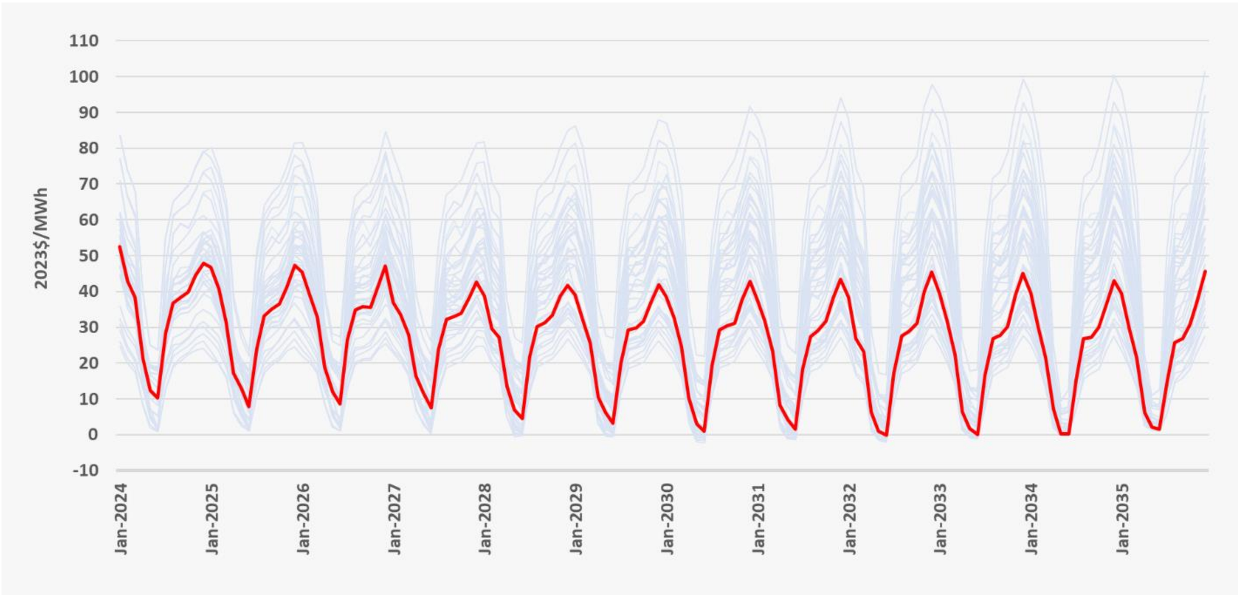
1. Gas prices and hydro conditions
2. Cost of compliance with carbon policies
3. Uncertainty in net load
4. Scarcity of committed dispatchable resources

PGE used the planning software Aurora with the WM WECC assumptions to generate 39 electricity price futures from permutations of risk drivers and carbon policy. This analysis aimed to identify a reference electricity price and a range of reasonable electricity prices in the Pacific Northwest in the next 20 years.[90] **Figure 21** displays forecasted monthly average electricity prices for each future, with the red reflecting reference prices. Simulated electricity prices then become an input for dispatch of existing PGE resources and are used to create energy value for new candidate resources.

[89] See **Appendix C.1.3, 2022 Public meetings** and **Appendix C.1.4, 2023 Public meetings** for more detail

[90] To reflect plausible scenarios in the simulation model, PGE capped energy prices at $1000 per MWh to reflect the price level that would trigger the FERC to investigate the incremental price increase. For price futures where significant commitment errors are considered and may consequently observe frequent breaches to the price cap, PGE reduced the price cap to $250 per MWh to reflect the price experienced during the 2000 energy crisis.

Figure 21. Average annual PNW electricity price futures



Results suggest that the forecasted growth in renewable generation resources across the WECC will generally reduce annual average prices, but the variability associated with their generation profiles will have a significant impact throughout the planning horizon. Winters continue to be forecasted times of high average monthly prices. The months of May and June exhibit low average monthly prices given low demand and high generation supply. The large distribution of potential market outcomes of forecasted prices highlights the uncertainty in forecasts of economic conditions. An important consideration is that IRP price forecasts do not necessarily represent the operational prices that utilities might face in real time due to the operating conditions utilities face and the unpredictable forward procurement costs. Instead, the IRP's forecasted prices are the results of a balanced system and normal conditions, and they benefit from a good forecast of load and renewable production. The prices are representative of hour-of-dispatch cost once reserves are procured. The long-term assumption is that the system finds adequate supply to meet demand and reserves. In contrast, operational prices do not have any of the mentioned elements. Operational prices, instead, are strongly dependent on short-term market variables.[91]

[91] Short-term market variables are factors that influence the operational prices of natural gas because of shocks to the supply or demand side of the natural gas market. These shocks, for example, could be caused by weather events or political events that increase or decrease the level of supply or demand in energy markets.

Acknowledging that our model will likely not accurately predict actual prices, PGE forecasted hourly prices with a variety of market price drivers: the quantity of available renewable capacity across the WECC, carbon policies, natural gas prices and hydropower generation in the Pacific Northwest. **Section 4.5, Uncertainties in price forecasts,** describes these market price drivers in more detail.

4.5 Uncertainties in price forecasts

PGE uses a scenario approach to model economic and technological uncertainty. In this section, we describe the risks and uncertainties that are evaluated in price forecasting, along with the price futures summarized in **Section 4.4, Long-term fundamental price forecast**.

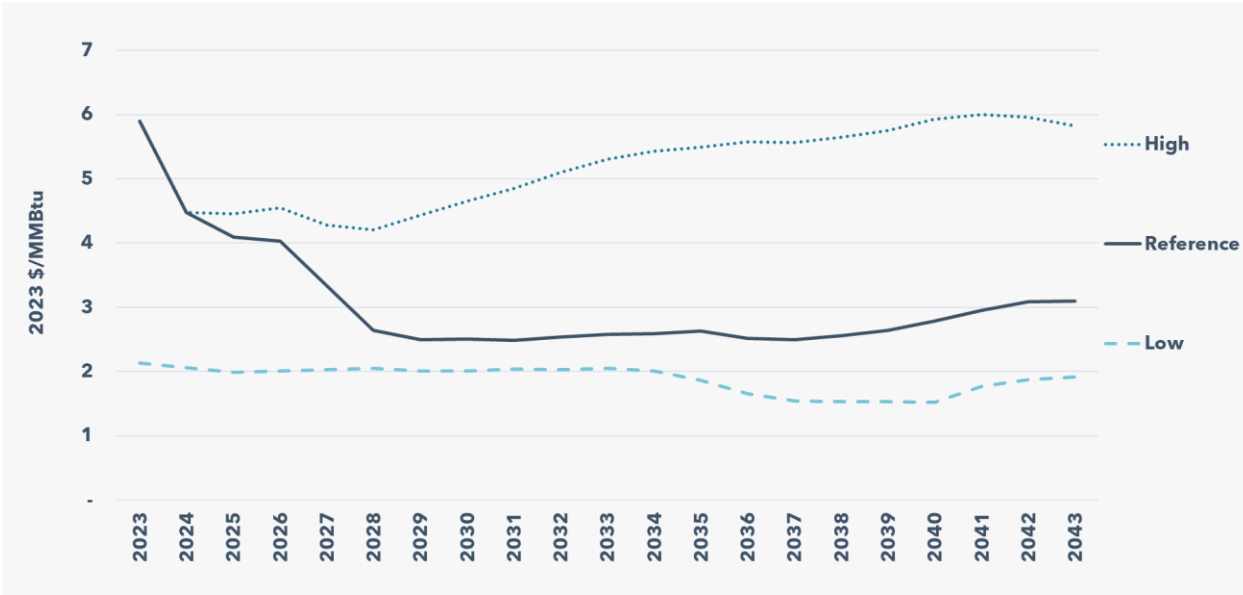
4.5.1 Commodity risk: natural gas prices

The price of natural gas has been and will continue to be a significant driver of wholesale electricity prices as natural gas-fueled power plants are used to meet loads, particularly during times of energy scarcity. The marginal units of power generated by natural gas-fueled power plants often set the market clearing price. While the contribution of gas-fueled power plants in the WECC declines in a high-renewable transition, the capacity of individual plants remains unchanged. With the significant increase of energy scarcity events, the forecasted price and availability of natural gas will continue to influence the electric power market while storage resources are not yet long-term multi-day capable.

PGE updated the gas price forecast input with Wood Mackenzie's long-term gas price forecast available in June 2022 to reflect the market sentiment prices following Russia's invasion of Ukraine in February 2022. The war triggered market volatility as the global sanctions against Russia's gas supply and increased export of liquefied natural gas (LNG) put a strain on the US oil and gas supply, causing historically high gas prices. WM's forecast also reflects the expectation of declining natural gas demand as states transition away from fuel-powered plants toward renewable generation.

Figure 22 shows the resulting Sumas hub gas price levels and trends. When simulating WECC prices, all gas hubs are input using the same input methodology previously described so that all WECC hubs are stressed simultaneously.

Figure 22. Natural gas price forecast Sumas Hub



4.5.2 Commodity and scarcity risk: hydropower generation

Hydropower generation (hydro) in the Pacific Northwest also strongly influences electricity prices. In addition to average hydro, PGE simulated a high and low hydro future. The average hydro is the Wood Mackenzie default and equal to the 2000-2011 average generation published by EIA. High hydro is 10 percent more than default and low hydro is 10 percent lower. See **Appendix H, 2023 IRP modeling details**, for more detail on this assumption. This hydro generation variability assumption is in line with the results observed in **Ext. Study-III, Climate adaptation**.

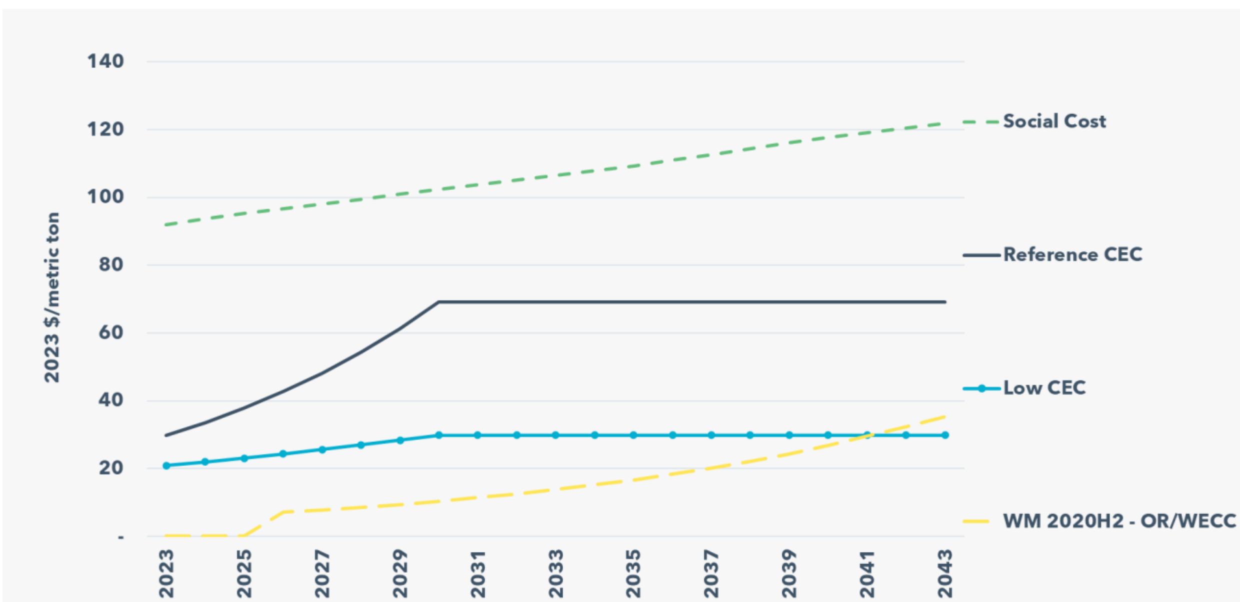
4.5.3 Carbon policies and emissions targets in WECC

This section explains how PGE modeled carbon price risk to market prices and unit dispatch simulations. PGE developed carbon adders to represent the cost of carbon policy compliance on power generation. These adders are added to dispatch cost based on individual resource fuel type and location.[92] The carbon adders are incorporated into three different carbon futures for the US portion of the WECC:

[92] A carbon adder is a modeling step in the PGE Zone Model (PZM) simulation where a cost is added to the dispatch cost of a carbon-emitting resource proportional to its emissions rate.

- Reference Case: No carbon adders are applied to WECC except for California and Washington, where there is existing carbon pricing legislation. California and Washington carbon adders apply the 2019 Reference GHG Allowance Price Projections published by the California Energy Commission (CEC).[93]
- Low carbon: No carbon adders are applied to WECC except for California and Washington, where there is existing carbon pricing legislation. California and Washington carbon adders apply the 2019 Low GHG Allowance Price Projections published by the California Energy Commission (CEC).[94]
- High carbon: California, Washington and Oregon apply the social cost of carbon (SC-CO2) defined by the United States Environmental Protection Agency (US EPA) and other federal agencies.[95] PGE selected 2.5 percent as the discount rate in intergenerational discounting to represent the social cost of carbon. For the rest of WECC, PGE applied Wood Mackenzie's reference carbon adder forecast to proxy for the cost of compliance with new carbon regulation.[96]
- Across each future, British Columbia and Alberta have a carbon tax adder that reflects Canadian legislation. **Figure 23** shows the forecasted level of the carbon adders.

Figure 23. Carbon adders in WECC economic analysis



[93] CEC's Integrated Energy Policy Report (IEPR) 2019, available at: https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report
[94] *Id.*
[95] See, The Social Cost of Carbon, US Environmental Protection Agency, available at: https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html
[96] Wood Mackenzie 2020H2 WECC Carbon Adder Forecast, shown in **Figure 23**.

4.5.4 Uncertainty and scarcity risk

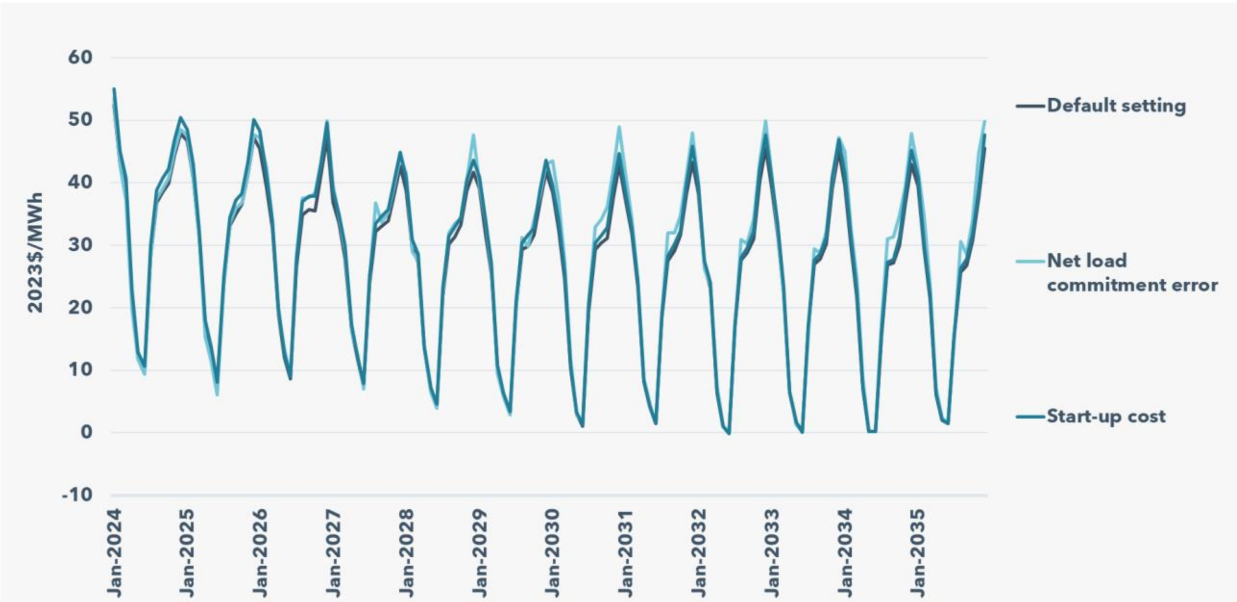
An important outcome of the public process leading to this IRP was the recognition of a disconnect between operational prices and fundamentals forecast, as mentioned in **Section 4.4, Long-term fundamental price forecast**. Traditionally, fundamental models do not embed operational difficulties experienced in actual operations as the model assumes that new dispatchable resources can be added to overcome operational obstacles. However, stakeholders and PGE agreed that the energy transition to non-dispatchable new additions would likely result in increasing difficulty in committing the resources at the right time. This volatility and scarcity price premiums have never been modeled in PGE's IRP. Hence, PGE created resource imbalance and scarcity premiums on prices by:

- **Introducing commitment error.** PGE purposely input a discrepancy between the wind forecast and the actual wind generation to represent the possibility of not having the right resources online and ready to generate when the net load is not what is expected. A 15 percent increase or decrease forecast error is randomly imposed on wind nameplate capacity hourly.
- **Adding start-up costs to simulated prices.** In our model, electricity prices are set by the marginal cost of the most expensive resource in the stack that is used to meet loads. When capacity is scarce, the marginal cost might underestimate prices, which demands a trade/bidding premium. We add the start-up cost to prices to reflect this premium.

This approach attempts to mimic the large generation and load swings with limited spare dispatchable resources. Additionally, we anticipate the magnitude of intermittent generation is and will increasingly be unprecedented, and climate change's impact on load, hydro and wind generation is largely unknown. The uncertainty and scarcity risk drivers were discussed in the April 22-3 roundtable, and more modeling detail is described in **Appendix H, 2023 IRP modeling details**.

Figure 24 illustrates the average electricity prices of the 39 price futures created in the WECC-wide Aurora simulation, organized into three categories: no modeling input, net load commitment error and start-up cost price futures. There is a pattern of more volatile electricity prices in the summer when net load commitment error, represented in light blue, is introduced. **Appendix H, 2023 IRP modeling details**, compares the intra-month hourly price range of reference and reference price future with start-up cost introduced.

Figure 24. Monthly average electricity prices across modeling specifications



By combining all the economic risk factors previously listed, we generated 39 price futures identified by a four-letter code for each risk model shown in **Table 8**.

Table 8. Simulated price futures

	Aurora Setup			Carbon Adder			Gas Price Forecast			Hydropower Generation		
	WM Model	Start-up cost	Net load commitment	Reference	Low	High	Reference	Low	High	Reference	Low	High
Number of price futures with risk factor	27	6	6	21	9	9	15	9	15	13	13	13

4.6 Addressing uncertainties

When the Capacity Need, Market Price and Technology Cost Futures are considered together, they explore a wide range of potential future conditions that influence the size and timing of resource additions. **Table 9** describes how these 39 price futures are combined with three Need Futures and three technology cost futures to consider 351 unique futures for each portfolio. Conducting portfolio analysis across these 351 alternative futures allows us to evaluate portfolios that meet system needs across a wide range of potential futures and score them based on cost and risk performance. While cost and risk metrics vary across all futures, resource builds do not vary by hydropower condition.

Table 9. Number of futures evaluated in portfolio analysis

	Market Price Futures		Capacity Need Futures		Technology Cost Futures		Total Futures Evaluated
Number of Futures	39	x	3	x	3	=	351

The WECC-wide simulation (conducted in Aurora) process is the first step to portfolio analysis and GHG emission forecasting. The simulated WECC electricity prices of the 39 price futures become the input for the PGE Zone Model simulation. Sequentially, the economic dispatch simulation results of new resources become inputs for the capacity expansion model, ROSE-E and the results of GHG-emitting resources become inputs for GHG emission forecasting. The following section discusses the GHG emission forecasting process in greater detail, and **Appendix H, 2023 IRP modeling details** explains the construct and relationships among models.