Chapter 11. Portfolio analysis

The 2023 Integrated Resource Plan (IRP) represents a significant evolution in Portland General Electric's (PGE's) portfolio analysis. PGE has conducted a comprehensive and robust portfolio analysis with stakeholder input to determine a Preferred Portfolio that best balances cost, risk, the pace of decarbonization and community benefits. Portfolio analysis considers needs such as capacity, energy, flexibility and policy as described in **Chapter 6, Resource needs**, and **Chapter 3, Planning environment**, along with resource options such as distributed energy resources (DERs), supply-side options and new transmission options as described in **Chapter 8, Resource options**, and **Chapter 9, Transmission**.

In this chapter, we first describe the portfolio design requirements that underpin portfolio analysis. On this foundation, we explore specific questions and dynamics within this IRP to inform how we can best balance cost, risk, the pace of decarbonization and community benefits. The insights of these investigations form the basis for the Preferred Portfolio, which is described in detail. Lastly, we conduct various sensitivities using the Preferred Portfolio to examine relevant questions in resource procurement.

Chapter highlights

- Portfolios are designed to meet emissions targets, adequacy needs, transmission and procurement constraints and are solved across all 351 permutations of price futures, Need Futures and technology cost futures.
- Portfolio analysis provides insight on the need for transmission, the cost and risk implications of different greenhouse gas (GHG) glidepaths, community-based renewable energy resources (CBREs) and the role for additional DERs in a decarbonized future.
- The insights from these analyses form the basis of the creation of the Preferred Portfolio.
- The Preferred Portfolio represents the combination and timing of resources that best balance costs, risk, emission reductions and community benefits for customers under the assumptions used in the IRP process.

11.1 Portfolio design requirements

PGE designed 39 distinct portfolios to test key questions concerning potential resource acquisition strategies. Each portfolio was analyzed across a wide range of scenarios varying combinations of potential future conditions for need, price and technology costs using the capacity expansion model ROSE-E.[293] For each portfolio, ROSE-E is given a fixed set of required resource acquisitions that meet a portion of needs. ROSE-E determines the optimal combination of resources to fill the remaining resource need while minimizing system costs for each of the 351 scenarios described in **Section 4.6, Addressing uncertainties**, subject to a variety of constraints.[294] Using this approach, 117 resource buildouts are produced for each portfolio, including one for the Reference Case scenario, which models Reference Case conditions for need, price and technology cost futures.[295]

ROSE-E has the ability to select new resources from a subset of the options described in **Chapter 8, Resource options**, and the transmission options described in **Section 9.4.1, Proxy transmission options identify transmission need**, and bases its decision on the economics presented in **Chapter 10, Resource economics**. To aid the reader, **Table 52** defines key terms within portfolio analysis.

Table 52. Defining key terms within Portfolio Analysis

Terms	Description
Portfolio	A fixed set of resource decisions set in all scenarios. The model (ROSE-E) creates resource buildouts around those choices in each scenario.
Scenario	Refer to elements that are varied within portfolio analysis resulting in multiple resource buildouts. Some of the predefined scenarios are need, technology cost, price, hydro.
Resource buildout	Least cost set of incremental resource additions given a set of specific input conditions such as a portfolio and scenario.
Portfolio sensitivities	Sensitivities test the robustness or provide additional information on the Preferred Portfolio by forcing changes in resource constraints or other inputs.

[293] ROSE-E was developed prior to the 2019 IRP and was used to conduct portfolio analysis in that filing. More information about the use of ROSE-E in the 2023 IRP can be found in **Appendix H, 2023 IRP modeling details**. Details on the use of ROSE-E in the 2019 IRP: *In the Matter of Portland General Electric Company, 2019 Integrated Resource Plan*, Docket No. LC 73, Order No. 20-152 (May 6, 2020), available at: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf
[294] A small number of portfolios designed to test optimization assumptions differ from this protocol by either minimizing cost only with respect to the Reference Case future, or only for a subset of year of the analysis.
[295] System costs are evaluated across futures for price, hydro condition, technology cost and need (13 x 3 x 3 x 3 = 351), while resource buildouts vary across futures for price, and technology cost only (13 x 3 x 3 = 117).

Portfolios are subject to several constraints described in the following sections that ensure portfolios add sufficient resources to meet forecast capacity and energy needs and comply with all applicable regulatory requirements. All portfolios are designed to meet a uniform set of constraints and a default set of assumptions except where individual constraints and assumptions are altered on a portfolio-group-specific basis to test questions of interest. Using a consistent set of assumptions within groups of portfolios allows comparison of resource buildouts and portfolio scoring metrics while isolating the impacts of the specific assumptions being tested.

11.1.1 GHG emissions

Greenhouse gas (GHG) emissions limits are imposed on each portfolio consistent with House Bill (HB) 2021 requirements, limiting GHG emissions to a maximum of 1.62, 0.81 and 0 million metric tons in 2030, 2035 and 2040, as shown in **Figure 26** in **Section 5.1, HB 2021 targets**. HB 2021 does not explicitly set GHG limits for years prior to 2030 but does require continual progress toward meeting the clean energy targets of 2030.[296]

Determining the rate of GHG emissions reductions or GHG glidepath that best balances cost and risk is evaluated in portfolio modeling, which are described in **Section 11.4.1, Decarbonization glidepath portfolios.** Additional information about GHG emissions in the IRP is in **Chapter 5, GHG emissions forecasting**.

11.1.2 Resource adequacy

All portfolios are constrained to meet PGE's resource adequacy requirements in both summer and winter during all years. The calculation of capacity need is described in **Section 6.6, Capacity need**. Capacity needs in portfolio construction are met by adding new resources, which provide the capacity contribution described in **Section 10.5, Resource capacity contribution**.[297]

[296] HB 2021, Section 4 (4)(e), available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[297] In addition to the new resource options described in **Section 8.5, Post-2030 resource options**, each portfolio is given 200 MW of capacity and 90MWa of energy in the years 2026 through 2030 to represent the expected extension of a portion of PGE's existing non-emitting capacity contracts.

11.1.3 Generic resources

Due to the presence of transmission constraints, the quantity of proxy resources available for selection in the model is insufficient to meet energy and capacity needs through 2043 in most portfolios. To allow the model access to the energy and capacity needed beyond the amount available through proxy resource options, all portfolios have access to two 'Generic' non-emitting on-system resources that are not subject to transmission constraints.

- 'Generic Cap' provides 100 percent effective load-carrying capacity (ELCC) and has no associated energy.
- 'Generic VER' provides both energy and capacity, with an ELCC curve and capacity factor defined by a weighted average of proxy variable energy resources (VER) in the Preferred Portfolio.

The generic resources have high costs so that they are available for the model to meet needs without competing economically with proxy resource options. Generic resources have fixed costs equal to 105 percent of the highest-cost proxy resource option (NV Tx). The model has access to 500 megawatts (MW) of each generic resource each year starting in 2026. All else equal, portfolios that require earlier or heavier reliance on generic resources will have increased costs relative to others.

11.1.4 Renewable portfolio standards

All portfolios presented in the IRP comply with Oregon's renewable portfolio standard (RPS) requirements described in **Section 6.7, RPS need**, through the entire planning horizon. ROSE-E simulates the generation, banking and retirement of Renewable Energy Certificates (RECs) from RPS-eligible resources and enforces the five-year lifetime limit on banked RECs consistent with Senate Bill (SB) 1547. For each portfolio to meet RPS requirements in each Future, the retired RECs in each year must meet or exceed the RPS obligation in that year. The resulting RPS position of the Preferred Portfolio is shown in **Section 11.5.2, Resulting RPS position**. With the introduction of HB 2021, the amount of non-emitting resources that need to be built to comply with emissions targets of HB 2021 is larger than the amount needed to comply with RPS requirements. Accordingly, RPS compliance is not forecasted to drive resource additions in this IRP.[298]

[298] It could be the case that PGE acquires non-emitting generation that helps move towards HB 2021 emissions targets but not RPS obligations. However, given the limited availability of non-emitting but non-RPS-qualifying generation the sizeable forecasted additions of RPS-qualifying generation (shown in **Section 11.5.2, Resulting RPS position**, and the size of PGE's REC bank it is a reasonable conclusion that RPS compliance will not drive future resource acquisition.

11.1.5 Energy position

To ensure that incremental resource additions do not put PGE's portfolio in a consistently long position (generating more energy than is needed to serve customers), the amount of energy added by new resources in portfolio modeling is constrained to not exceed PGE's forecasted net market position by more than 100-megawatt average (MWa) in any given year after 2026. The energy surplus constraint is relaxed between 2024-2026 to allow for a long energy position before adding new resources. In addition, the energy surplus constraint is relaxed in certain years for some portfolios to allow the testing of resource options that would otherwise violate the constraint or to avoid unintended confounding effects on resource buildouts that prevent the comparison of portfolios within a given portfolio category. In preventing the building of an overly long portfolio, the energy surplus constraint also helps ensure that the resource buildout contains an appropriate amount of dispatchable capacity resources and is not overly reliant on variable energy resources.

11.1.6 Procurement constraints

PGE has not imposed general limits on the total amount of resources that can be added each year, as PGE seeks to streamline the existing procurement process. To test the impact of procurement limitations, resource limitation constraints are imposed as part of sensitivity analysis, as described in **Section 11.7, Sensitivities**.

11.1.7 Transmission constraints

As renewable energy development grows around the West, the availability of transmission to move energy from the point of generation to load centers is becoming scarce (see **Chapter 9, Transmission**, for more detail). To account for this increasingly important consideration in the siting of resources, we incorporated contractual transmission constraints in portfolio analysis. A detailed description of the methodology, including derivation of transmission inventories, can be found in **Appendix H, 2023 IRP modeling details**.

11.2 Portfolio scoring

Portfolios were evaluated based on the scoring metrics described in **Table 53**. Comparing portfolios consistently based on these metrics allows PGE to quantify the impact of changes in key assumptions on portfolio outcomes. The direction and magnitude of change in these metrics generate beneficial insights that ensure the Preferred Portfolio and Action Plan are robust and represent the best combination of costs and risks.

Table 53. Portfolio scoring metrics

Metric	Description	Units
Cost	Net present value of revenue requirement (NPVRR), calculated for each of the 351 future scenarios and presented for the Reference Case for the analysis timeline (2024-2043).	Million 2023$
Variability	Semi-deviation of NPVRR across all futures, relative to the Reference Case. This metric captures the potential variation in cost outcomes across futures, considering only futures in which NPVRR exceeds the Reference Case. Portfolios with low variability scores tend to provide more cost certainty and lessen the customer's impacts of higher-than-expected cost conditions.	Million 2023$
Severity	The tail value at risk (TailVAR) at the 90th percentile of the NPVRR across futures. This metric measures the potential magnitude of very high-cost outcomes across all futures. Portfolios with low severity scores tend to have less costly worst-case scenarios for customer cost impacts.	Million 2023$
Community Benefits	This metric reflects the portfolio benefits associated with the CBRE additions that deliver community benefits. These benefits are further described in Section 14.2.3.2, CBI community engagement.	N/A

11.3 Yearly price impacts

In this IRP PGE has developed a new model to estimate the annual price impacts of a given portfolio.[299] The Annual Revenue-requirement Tool (ART) was created to provide an additional dimension in the analysis of forecasted system cost when comparing different portfolios. The ART was developed specifically for IRP purposes to evaluate yearly price impacts of planned proxy new resource additions. The model uses the existing and

[299] Developing this model satisfied the 2019 IRP Commission requirement "…PGE will need to continue to evaluate and balance the tradeoffs between more certain near-term rate impacts and less certain long-term projected cost savings.", Docket LC73, Order No. 20-152 at 19, available at: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf, and ORS 469A.400 469.475, Section 4(4)(b) Clean Energy Plans; electric companies, from the CEP as detailed in Chapter 1, topic 3 of the UM 2225 Investigation into Clean Energy Plans Workplan Update and Straw Proposal, regarding annual metrics measuring the impacts of actions, at 7-8, available at: https://edocs.puc.state.or.us/efdocs/HAH/um2225hah11736.pdf.

incremental proxy resource costs described in **Chapter 9, Transmission** and Reference load presented in **Chapter 6, Resource needs**.

The model incorporates the impact of market sales on an annual basis and includes different combinations of ownership structures and tax incentives modeled for each portfolio.[300] Market purchases and thermal sales are calculated on an annual basis within the GHG Intermediary model and imported to ART. Further, ART only focuses on existing and new generating resources, including the associated transmission costs. Estimates do not include costs from the rest of PGE, such as those associated with administrative costs, grid modernization, other transmission and distribution maintenance and upgrades, wildfire mitigation or actual generation costs. Caution is warranted in interpreting these estimates, as these values reflect a change in forecasted annual costs of real and proxy generating assets that only represent a subset of PGE's total annual cost. Accordingly, these yearly price impacts do not represent actual customer price impacts (expressed either as total or a percent) as they only focus on planned generation cost changes and do not incorporate any other cost changes across PGE.

11.4 Portfolio analysis results

PGE has tailored the portfolio analysis in the 2023 IRP to answer key questions in resource planning and leverage insights from those answers in the creation of the Preferred Portfolio. These key questions are explored through different portfolio categories, comprised of multiple portfolios hand-designed to explore the impact of specific potential PGE actions or changes to the operational, economic, and/or policy landscape within which PGE operates. These categories are presented and described in **Table 54**. Some portfolios that PGE cannot effectuate have been intentionally developed to study specific questions. These portfolios are listed as informational in the relevant portfolio categories.

Table 54. List of portfolio categories and their purpose

Portfolio categories	Purpose
Decarbonization glidepath	Explore the relationship between the rate of emissions reduction to serve retail load, cost and risk
Transmission	Study the need for transmission, the timing of this need and the corresponding magnitude needed over time to reliably decarbonize

[300] Modeling assumption of the ownership structures do not impact or reflect future procurement approaches or prejudge outcomes of future procurement processes.

Portfolio categories	Purpose
Community-Based Renewable Energy (CBRE)	Explore the relationship between costs, risk and community benefits
Additional Energy Efficiency and Demand Response	Determine if and how the role of these resources could change with the changing planning environment
Optimized	Explore the relationship between minimizing costs in the short-term and the entire planning horizon and cost of constraining the model
Targeted policy	Inform stakeholder discussions on specific policy questions
Emerging technology	Understand the potential impacts of emerging technologies

All portfolios assume that a portion of PGE's existing long-term contracts for energy and capacity from non-emitting sources set to expire at the end of 2025 are renewed through the end of 2030, representing 90 MWa of energy and 200 MW of capacity contribution annually.

11.4.1 Decarbonization glidepath portfolios

PGE explored the relationship between the rate of emissions reduction to serve Oregon retail load, cost and risk with the Decarbonization Glidepath portfolios (**Table 55**). These portfolios are designed to meet or exceed HB 2021's GHG emissions targets using a variety of glidepaths or trajectories. Decarbonization Glidepath portfolios have identical assumptions and inputs aside from their differing GHG emissions reduction pathways to isolate insights on the impacts of the pace of decarbonization on portfolio costs and risks.[301]

The 'Linear decline, 'Front-loaded decline' and 'Back-loaded decline' portfolios meet HB 2021 emissions reductions targets using different rates of emissions reductions ("glidepaths") from 2026-2030 (as shown in **Table 55**) and converge on a single glidepath thereafter.

[301] Because these portfolios have different energy position inputs, they are not subjected to the energy surplus constraint described in **Section 11.1.5, Energy position**. For the purposes of comparison across these portfolios, the imposition of an energy surplus constraint introduces confounding impacts on resource additions, preventing level comparison.

Portfolios '100 percent emissions reduction by 2035' and 'Two-yr forward shift in targets' rely on glidepaths that achieve emissions targets ahead of regulatory deadlines.

Table 55. List of decarbonization glidepath portfolios

Portfolios	Portfolio condition
Linear decline	Meeting 2030 targets by adopting a linear path in emissions reduction (each year must provide the same reduction in emissions as the previous year)
Front-loaded decline	Meeting 2030 targets by front-loading emission reduction (each year must provide half the reduction in emissions of the previous year)
Back-loaded decline	Meeting 2030 targets by rear-loading emission reduction (each year must provide twice the reduction in emissions of the previous year)
100% emissions reduction by 2035	Achieving 100% GHG emission reduction by 2035
Two-yr forward shift in targets	Achieving each carbon target two years ahead of schedule 80% by 2028, 90% by 2033 and 100% by 2038

Figure 78 visualizes the annual emissions of each of the decarbonization glidepath portfolios. Differences in the rate of decarbonization across the five portfolios can be seen starting in 2026.[302] When emissions targets are attained ahead of schedule, as in '100 percent emissions reduction by 2035' and 'Two-yr forward shift in targets', cumulative emissions from 2024-2043 are reduced relative to on-time attainment with a linear glidepath (**Figure 79**). Amongst the three portfolios that achieve targets on-time with different glidepaths to 2030 ('Linear decline', Front-loaded decline' and 'Back-loaded decline'), the front-loaded glidepath produces the lowest cumulative emissions throughout the portfolio modeling time-horizon and the back-loaded decline in produces the largest quantity of cumulative emissions (**Figure 80**). The linear emissions reduction glidepath falls in the middle, producing approximately 28.68 MMT CO_2e throughout the planning horizon (**Figure 78**). **Appendix O, Thermal Operations/ Output** displays total emissions associated with serving retail load and market sales in each of these three decarbonization glidepaths.

[302] Forecasted emissions for 2023 through 2025 are based on the expected impact of the 2021 All-Source request for proposals (RFP), PGE's Green Future Impact (GFI) program, load growth and other factors. Forecasted emissions from 2026 onwards (when portfolios are able to add incremental resources) are from one of the five tested glidepaths.

Figure 78. Decarbonization glidepath portfolios

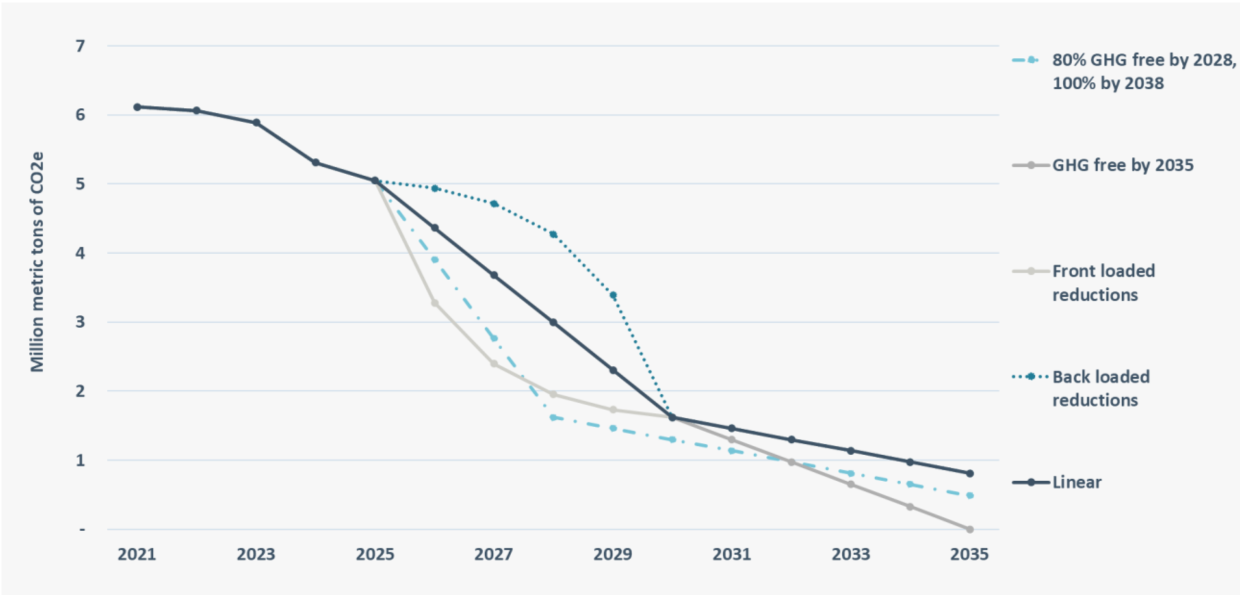


Figure 79. Cumulative emissions 2024-2043, accelerated decarbonization glidepath portfolios

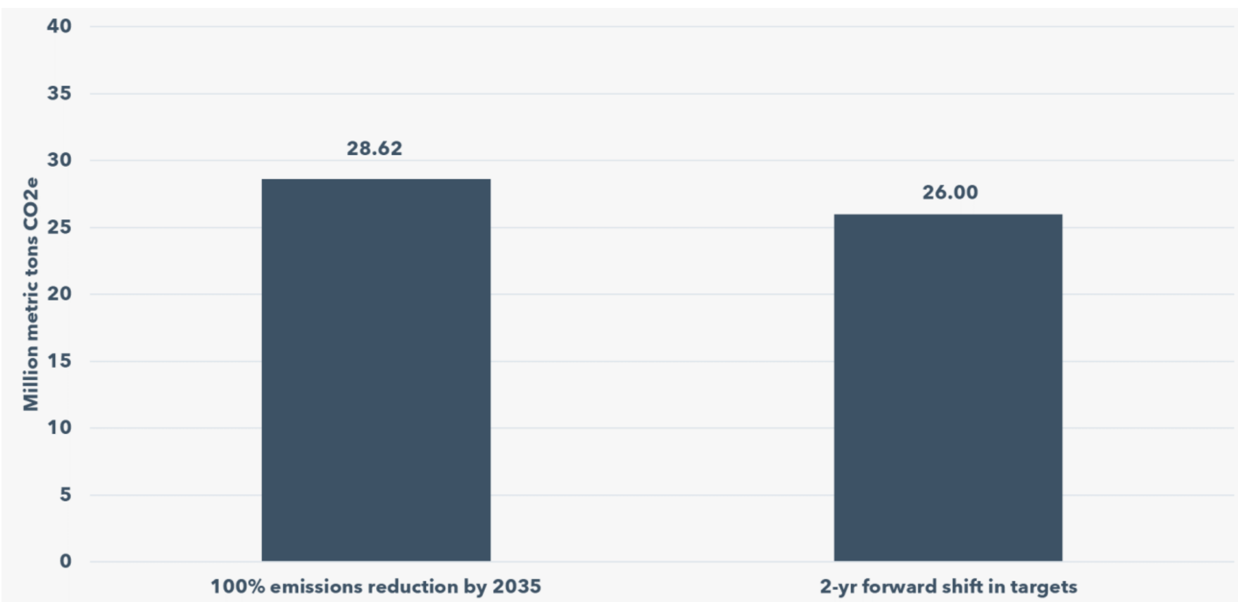
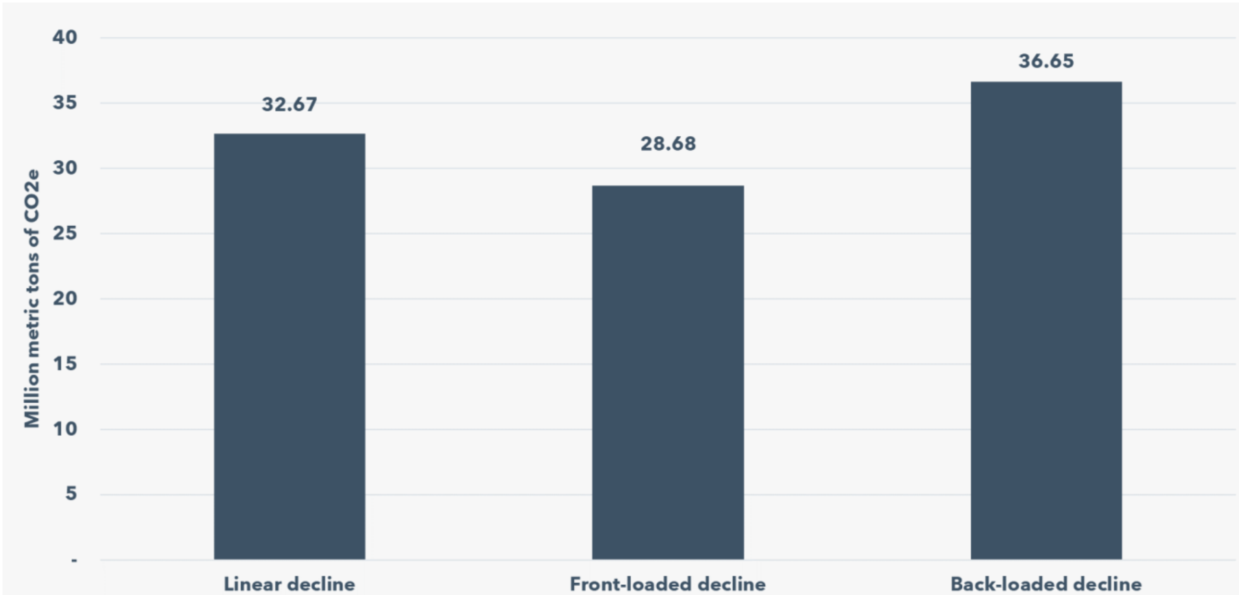


Figure 80. Cumulative emissions 2024-2043, decarbonization glidepath portfolios

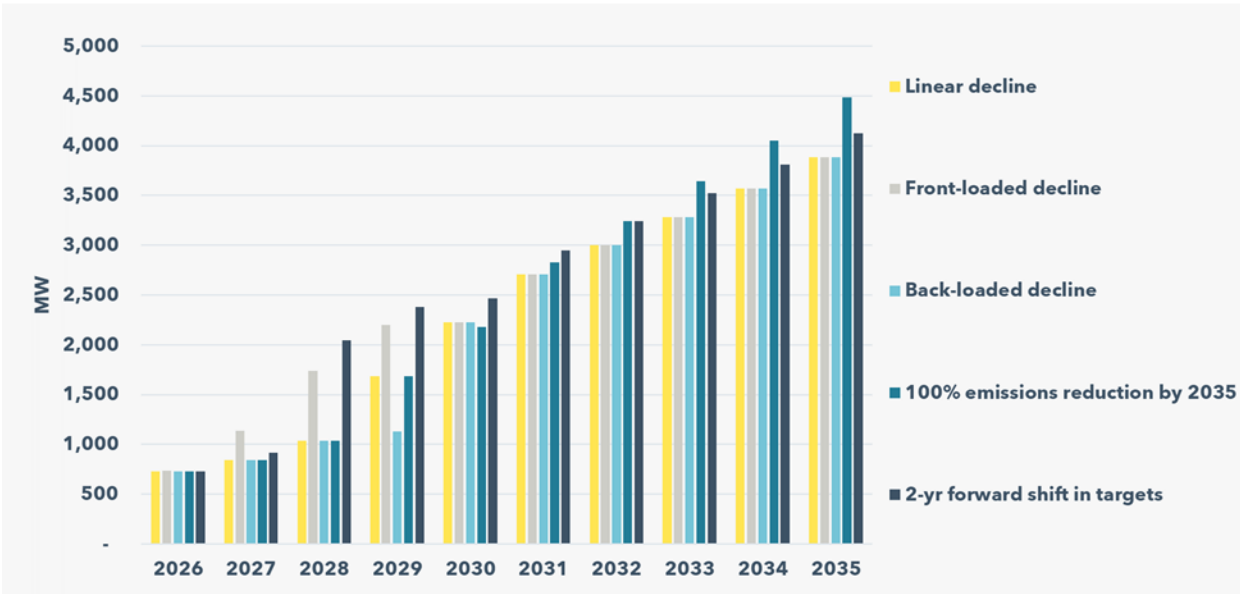


The lower cumulative emissions associated with accelerated rates of decarbonization come with tradeoffs in terms of portfolio cost and risks. Accelerated decarbonization increases the near-term Reference Case need for renewable resource additions (**Figure 81**). The difference between renewable additions in the 'Linear decline' portfolio and the 'Two-yr forward shift in targets' portfolio shows that accelerated decarbonization can increase the need for renewable procurement by over 1,000 MW by 2028 in the Reference Case. The front-loaded decline portfolio also increases procurement need through 2028, requiring 701 more MW than linear decline portfolio by 2028. The energy need in the '100 percent by 2035' glidepath begins to increase relative to the linear glidepath in 2031 and it requires larger energy procurement in 2031-2039 as a result, adding 605 MW more than the linear glidepath by 2035.

'Two-yr forward shift in targets' is unable to meet energy needs without access to the generic VER resource in 2029, showing that in a world with limitations on access to transmission, faster decreases in emissions in the near-term would further increase dependence on transmission and/or emerging technologies that might not be proven, which adds additional risk. While achieving early attainment of HB 2021 targets is possible without utilizing the generic resources in the pre-2030 timeframe in the '100 percent emissions reduction by 2035' portfolio, the need to add resources earlier in the planning-horizon results in increased costs compared to the three glidepaths that achieve compliance on-time.

On-time achievement of targets relying on a back-loaded glidepath to 2030 may also increase procurement risk relative to a linear glidepath, increasing the need to rely on large resource additions concentrated in fewer years approaching 2030. This includes uncertainties in available transmission inventories, procurement delays and other supply chain constraints, operational risks associated with adding large quantities of resources in a small amount of time.

Figure 81. Renewable resource buildout of decarbonization portfolios



Comparison of cost and risk metrics shows that the portfolios that meet HB 2021 targets early (100 percent emissions reduction by 2035 and Two-yr forward shift in targets) have increased system costs relative to meeting targets on schedule using the linear-decline glidepath (**Figure 82**). The increase in cost is driven by the earlier resource additions required for early attainment. This increases costs due to two factors; the discounting of values in the calculation of net present value revenue requirement (NPVRR), which weights the impact of near-term costs more heavily than costs accrued later in time, and the declining cost curves of new resource options (as described in **Chapter 8, Resource options**). The cost and risk tradeoff associated with faster emissions declines can also be seen in comparison between 'Back-loaded decline' and 'Front-loaded decline', with 'Front-loaded decline' being the most expensive and most variable as a result of earlier resource additions and 'Back-loaded decline' being the least expensive and least variable due to later resource additions (**Figure 83**). The linear glidepath in 'Linear decline' falls in the middle for both cumulative emissions and cost and risk metrics.

Figure 82. Cost and risk of accelerated decarbonization glidepath portfolios

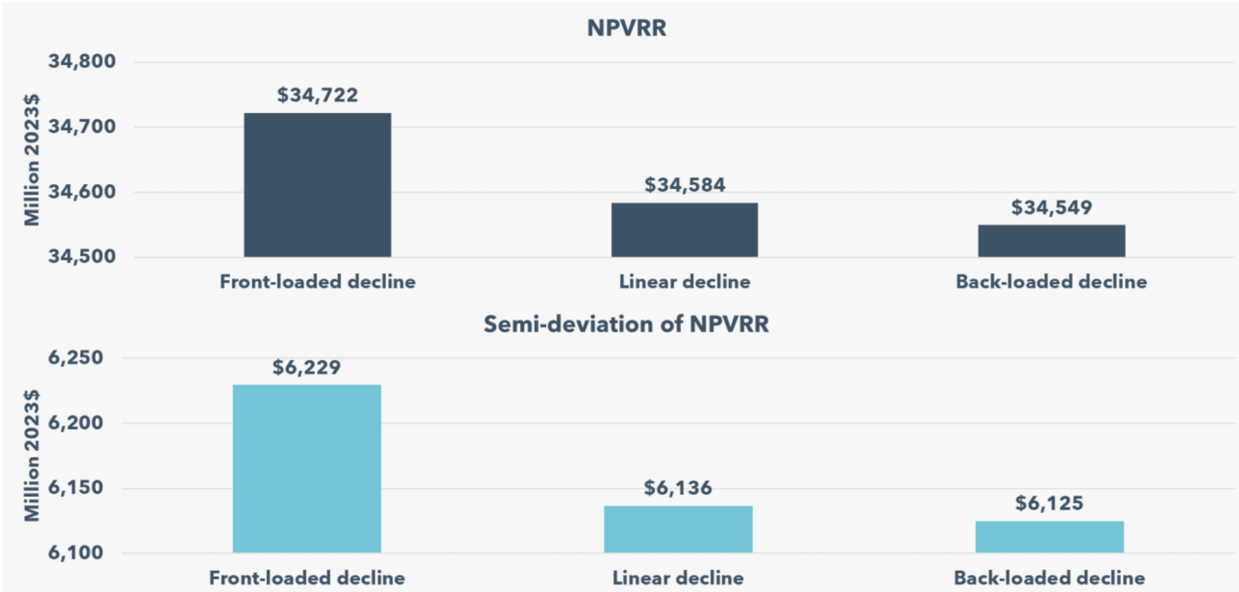
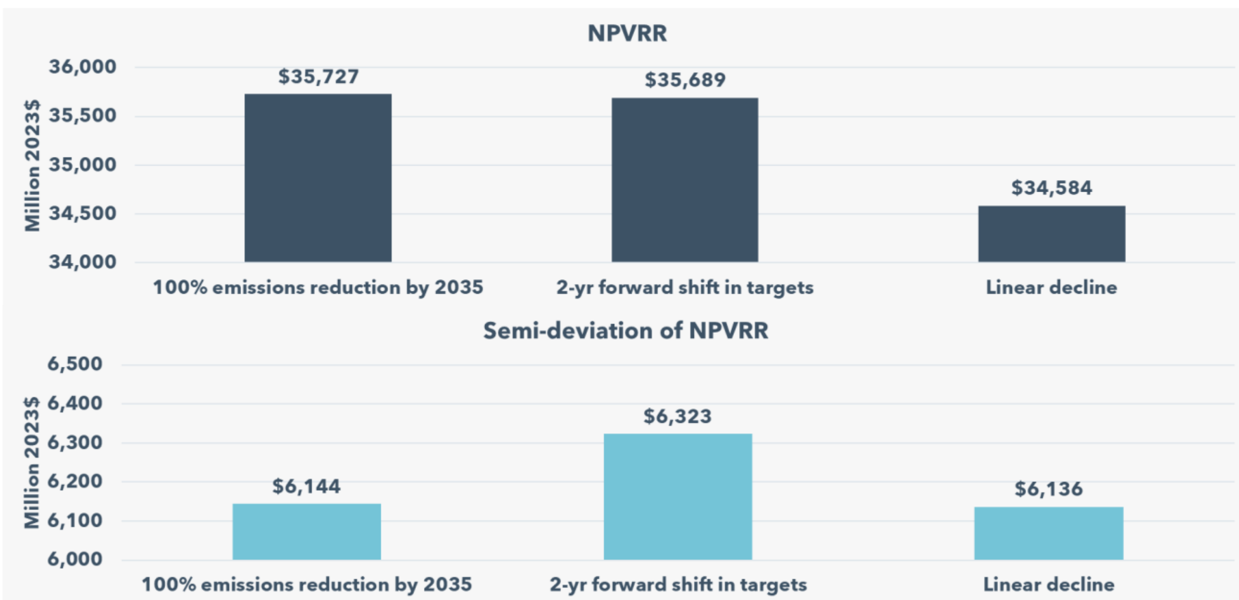


Figure 83. Cost and risk of decarbonization glidepath portfolios



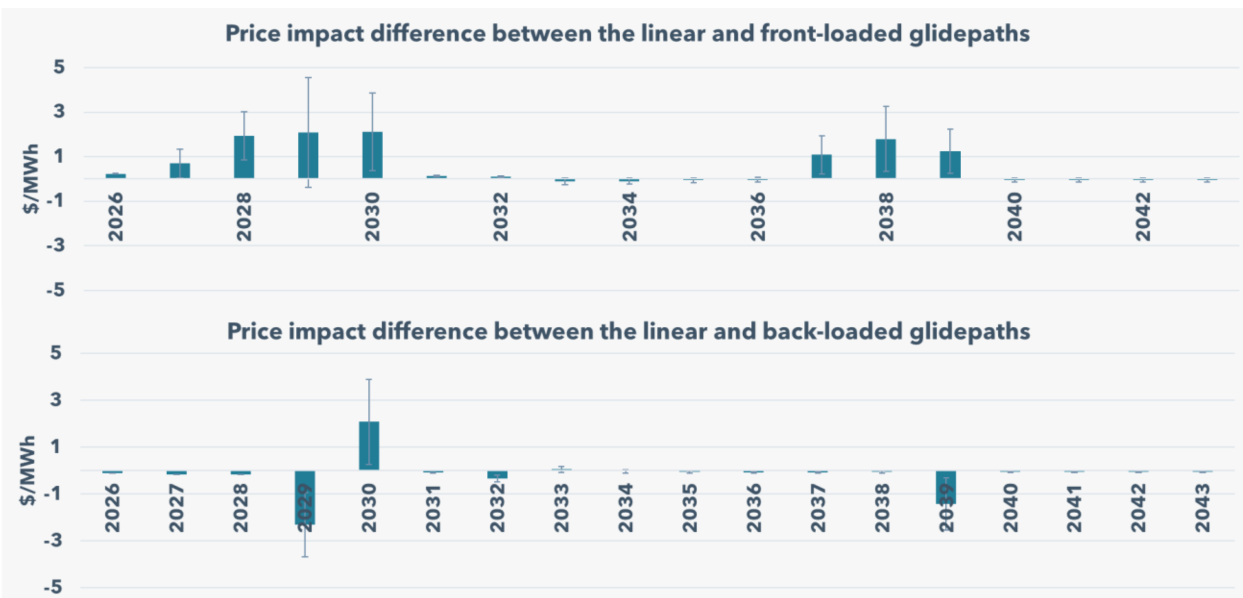
Given the tradeoffs between rate of emissions reduction and portfolio cost and risk, the findings of this analysis indicate that the 'Linear decline' best balances the costs and multiple sources of risk with the rate of emissions reductions to meet HB 2021 targets by 2030 and it is used as the default in all other portfolios, including the Preferred Portfolio.

11.4.1.1 Decarbonization glidepath annual price impacts

The forecasted difference in yearly cost impacts (associated with existing and incremental generation) per megawatt hour (MWh) of retail load between the linear decarbonization glidepath and the front and back loaded decarbonization glidepath can be seen in **Figure 84**.[303] Positive values represent higher costs relative to linear glidepath and negative values represent lower costs relative to linear glidepaths. The differences in portfolio costs are projected through the planning horizon starting in 2026, the first available year of incremental resource additions.

The higher costs of the front loaded decarbonization glidepath are primarily seen in the near-term with the additional costs through 2030. Additional costs in the 2037 through 2039 reflect the earlier expiration of production tax credits (PTC) in the front-loaded portfolio relative to the linear decline portfolio, which is a smaller determinant in decision making. The lower costs of the back-loaded decarbonization glidepath highlight a similar relationship, showing lower costs with a later buildout in the 2020's. These yearly cost forecasts support the finding described previously that GHG emission reductions lead to cost increases.

Figure 84. The annual ($/MWh) impact of Decarbonization Glidepath portfolios through 2035



[303] **Addendum: PGE CEP Data Template** contains the annual price impact in $'s and the annual price impact per unit retail sales ($/MWh) through the planning horizon for each portfolio

11.4.2 Transmission portfolios

PGE designed a set of transmission portfolios to understand the quantity and timing of need for transmission to reliably decarbonize the system and test the impact of assumptions about transmission on other resource choices (described in **Table 56**). To isolate the effect of differences in assumptions related to transmission resource buildout and cost and risk metrics, these portfolios contain otherwise consistent assumptions (i.e., availability of other resources such as CBREs and additional EE and DERs and a linear GHG reduction glidepath).

Table 56. List of transmission portfolios

Portfolios	Portfolio condition
No Transmission (Tx) constraints (informational)	No transmission constraints imposed
No upgrades (informational)	No transmission upgrades or build options available
Unconstrained SoA (informational)	Unlimited South of Alston (SoA) transmission access beginning in 2027
Unconstrained SoA Plus (informational)	Unlimited SoA transmission access beginning in 2027 New transmission options to WY and NV are available in 2026
SoA in 2027 plus	SoA upgrade unlocks 400 MW of IRP proxy resources in the PNW in 2027 New transmission options 400 MW each to WY and NV are available in 2026
SoA in 2027	SoA upgrade unlocks 400 MW of IRP proxy resources in the PNW in 2027
SoA in 2029	SoA upgrade unlocks 400 MW of IRP proxy resources in the PNW in 2029
WY in 2026	New transmission option 400 MW to Wyoming in 2026
NV in 2026	New transmission option 400 MW to Desert Southwest in 2026
WY in 2028	New transmission option 400 MW to Wyoming in 2028
NV in 2028	New transmission option 400 MW to Desert Southwest in 2028

11.4.2.1 Informational transmission portfolios

The informational portfolio 'No Tx Constraints' envisions a world where PGE operates free from contractual limitations in the transmission system. As shown in **Figure 85**, the cost of building a portfolio that meets PGE's resource needs appears to be relatively low cost when the contractual transmission landscape is not accounted for. The large amount of renewable additions that the model selects in the absence of transmission constraints (**Figure 86**) and the low portfolio cost of the 'No Tx Constraints' portfolio (**Figure 85**) suggests that in the absence of transmission constraints, renewables offer the lowest-cost method to decarbonize when paired with sufficient dispatchable capacity resources to meet reliability needs. When compared to other transmission portfolios, PGE finds that the inclusion of transmission constraints increases costs, an intuitive finding because the model has fewer resource options to choose from to meet capacity and energy needs.

In contrast, the 'No upgrades' portfolio evaluates a scenario where no transmission upgrades are actionable to PGE and where PGE must rely on the current estimated available contractual transmission capacity.[304] The resulting resource buildout reveals that without access to additional transmission, the model must rely relatively heavily on the generic resources by 2030 (**Figure 86**), an outcome that results in substantially increased estimated costs and risk (**Figure 85**). Given the uncertainties surrounding the cost and availability of the resources that would be added to fill this need, this also would require further study on their technical and economic feasibility. These results also demonstrate that the current forecasts of transmission capacity are insufficient to meet system needs over the planning horizon even after acquiring the entirety of the available potential for CBREs and cost-effective DERs.

[304] Information on the creation of these estimates can be found in **Appendix H.7, BPA transmission in ROSE-E.**

Figure 85. Cost and risk of informational transmission portfolios

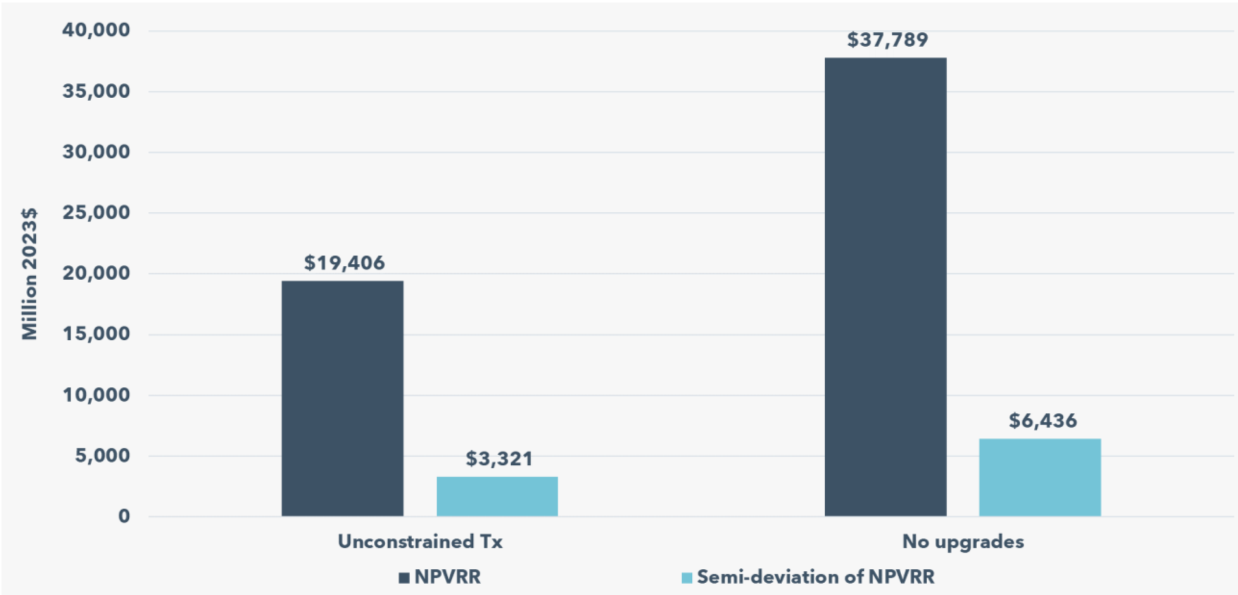
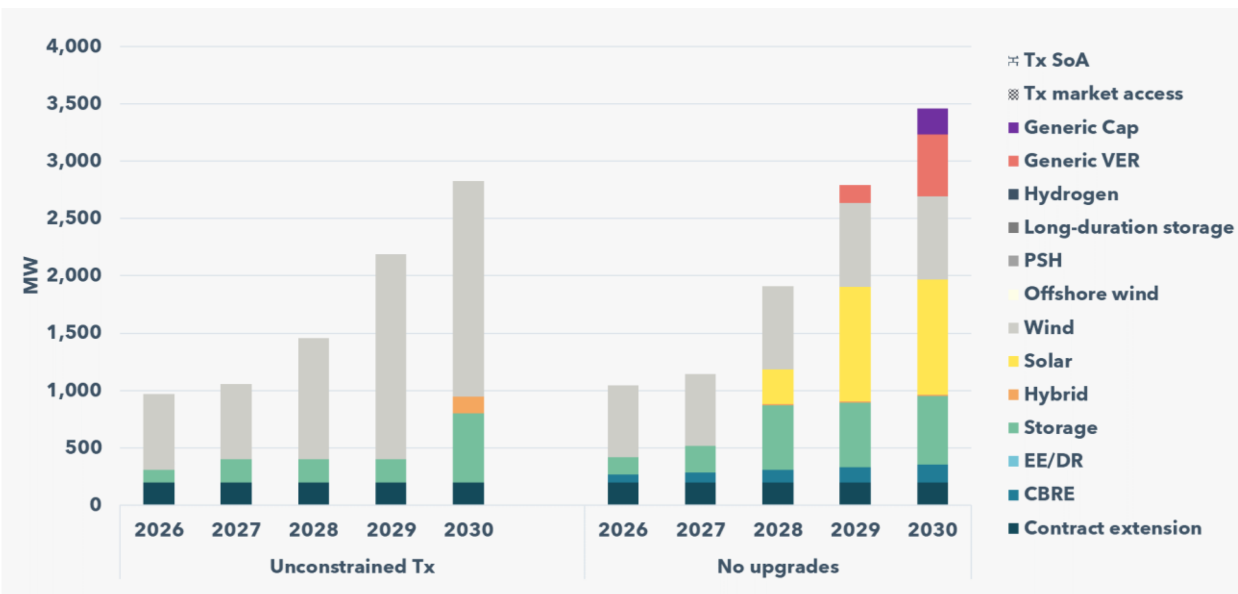


Figure 86. Resource buildout of informational transmission portfolios



With the inclusion of the generic on-system resources noted previously, the 'No Upgrades' portfolio can demonstrate the quantities of additional transmission capacity needed to reliably decarbonize. After accounting for the magnitude of the distribution connected resources that can minimize transmission need, the portfolio has identified the timing and magnitude of the most conservative perfect transmission required over the next 20 years

(**Table 57**).[305] Thus, this portfolio shows that in the absence of a technology breakthrough that yields a low-cost and scalable resource, there is a need to invest in incremental transmission to PGE. Additionally, it also shows that even after accounting for the impact of additional DERs beyond the Distribution System Plan (DSP), the transmission need is significant. This underscores that in the absence of investments in transmission, PGE would not be able to reliably decarbonize and meet the 2030 targets of HB 2021.

Table 57 shows the quantity of transmission that would be required corresponding to the quality of resources available. Resources that can provide significant energy and capacity benefits require the least amount of new transmission, while other resources may increase transmission needs. As these results emphasize, based on the type and quality of resources available, upwards of 800 MW of transmission may be needed as soon as 2030. The appropriate combination of transmission upgrades vs. new transmission required is explored in the following section.

Table 57. Estimated Reference Case transmission need

Year	Generic VER	Generic capacity	Potential transmission need (MW)
2026	-	-	-
2028	-	-	-
2029	159	-	159
2030	541	228	541-768
2035	2,199	807	2,199-3,005
2040	4,285	3,183	4,285-7,468

[305] Assuming that all remaining system needs are met through transmission. Other post-2030 resource options may fill some or all of this need, as discussed in **Section 8.5, Post-2030 resource options**.

11.4.2.2 Transmission diversity portfolios

In the 'Unconstrained SoA' portfolio, the model has unlimited access to add transmission access to Oregon, Washington and Montana proxy renewable resources (Pacific Northwest [PNW] proxy resources) that are otherwise limited by the contractual transmission landscape, beginning in 2027. In the 'Unconstrained SoA Plus' portfolio, the model has the same access to reduce SoA congestion, plus access to 400 MW each of the WY and NV transmission expansion options beginning in 2026.

The resulting Reference Case resource buildout is very similar through 2030 for both portfolios, with the model choosing to rely on the SoA upgrade and not selecting WY or NV transmission expansion. However, later in the planning horizon, the model takes advantage of access to the WY and NV transmission expansion options in 'Unconstrained SoA Plus', adding 600 MW by 2040. As a result, 'Unconstrained SoA Plus' has a lower cost (**Figure 87**).

These resource buildout results demonstrate that significantly increasing access to PNW proxy resources helps delay the need for investments in more expensive transmission expansion options. Additional transmission options are forecasted to be an effective method to reduce both cost and risk, especially in higher-Need Futures.

Figure 87. Cost and risk of transmission diversity portfolios

11.4.2.3 Transmission timing portfolios

The transmission timing portfolios vary the timing of availability of transmission options to compare the transmission options against one another and to compare the impact of timing on the individual options. In 'SoA in 2027', 'SoA in 2029', 'WY in 2026', 'NV in 2026', 'WY in 2028' and 'NV in 2028', the model is required to add 400 MW of the corresponding transmission option in the noted year. In one additional portfolio ('SoA in 2027 plus'), the model is forced to add 400 MW of SoA in 2027 and has 400 MW each of WY and NV transmission options available for selection (but not required) beginning in 2026. The resource buildouts of the transmission timing portfolios are shown in **Figure 88**.

Comparing the cost and risk metrics of these actionable portfolios (**Figure 89**) shows that 'SoA in 2027' and 'SoA in 2029' have lower costs than the WY and NV portfolios. Because of declining resource cost curves and discounting of future costs, 'SoA in 2029' has lower costs than 'SoA in 2027'. However, it has higher risks, in terms of quantified risk metrics (**Figure 89**) and the unquantified risks associated with waiting to procure the necessary resources to comply with HB 2021's 2030 emissions targets.

The lowest costs and risks are found in the 'SoA in 2027 plus' portfolio, demonstrating the benefits of having more transmission options available (**Figure 88**). Comparing these actionable portfolios, PGE finds that investing to increase access to transmission earlier will provide the best balance of system costs and risks. This further reaffirms that PGE should first pursue all available opportunities to increase access to PNW proxy resources, such as the upgrade to the Bethel-Round Butte transmission line. Additionally, studying new transmission options can reduce potential dependence on emerging technologies and reduce costs, as shown in **Figure 89**.

Figure 88. Resource buildout in transmission timing portfolios

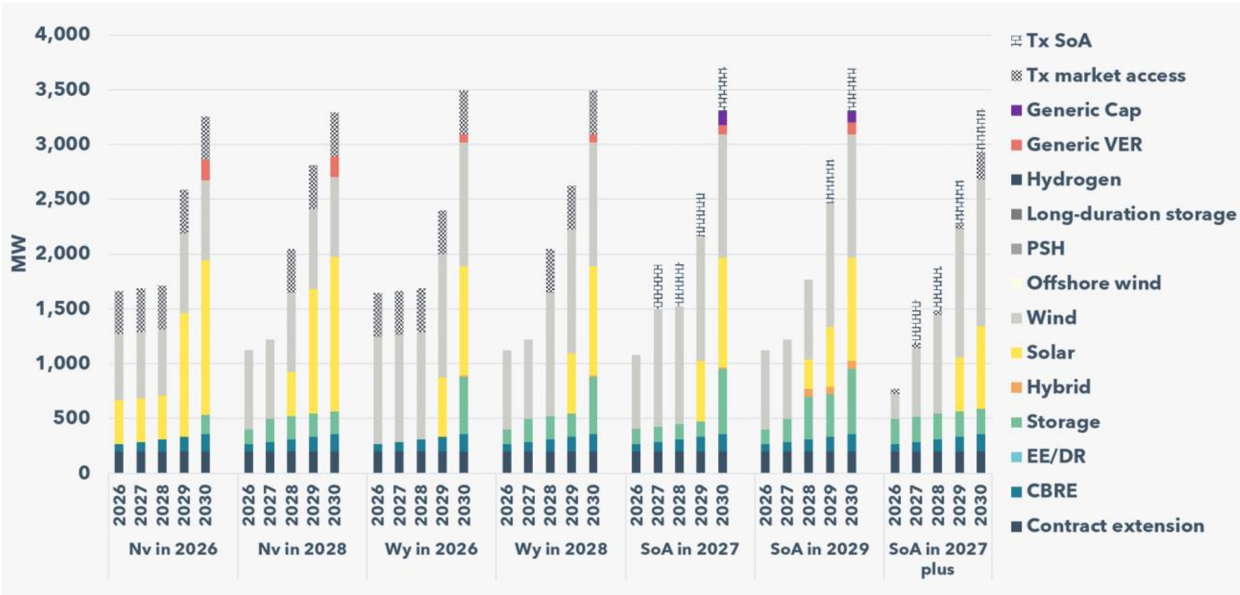
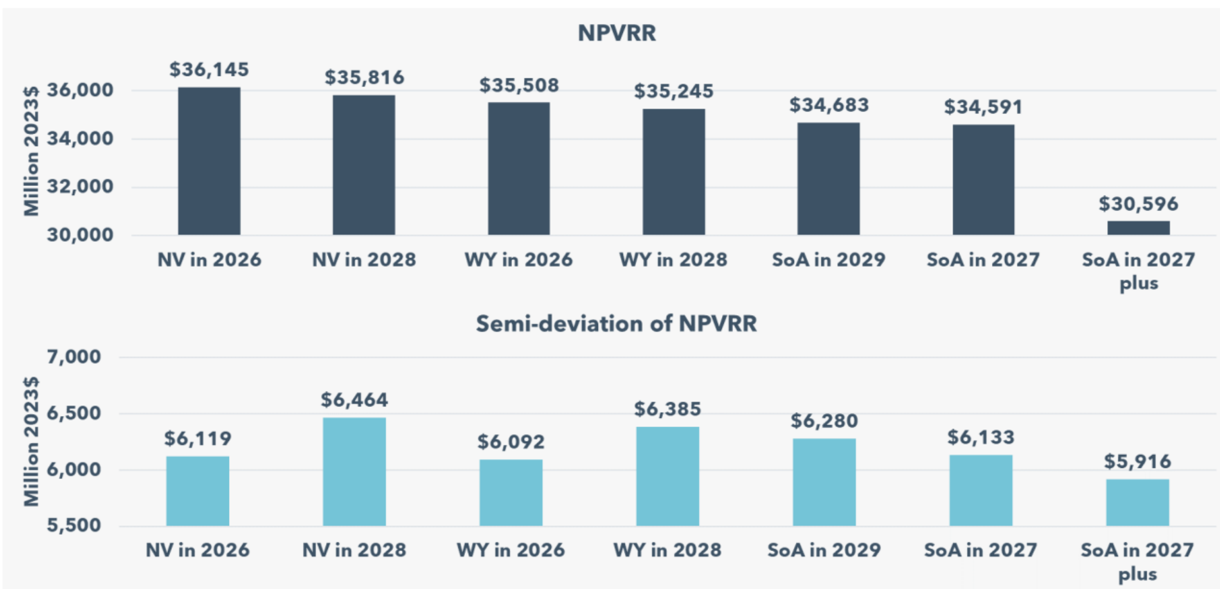


Figure 89. Cost and risk metrics of transmission timing portfolios



11.4.3 Community-based renewable energy (CBRE) portfolios

Studying the relationship between costs, risk and community benefits resulting from the deployment of CBRE resources has been a central discussion of this IRP.[306] PGE developed

[306] See **Sections 7.1 (CBRE), 7.1.3 (rCBI), 7.1.4 (pCBI)** and **7.1.6 (iCBI)**.

the portfolios listed in **Table 58** to explore this relationship. The CBRE portfolios vary the quantity of CBREs and whether they are forced-in or are available for optimized selection in the model. Aside from the variations in CBRE availability, portfolios in this section assume a consistent set of assumptions to ensure comparisons provide insight on the impact of CBRE resources on portfolio outcomes.

Table 58. List of CBRE portfolios

Portfolios	Portfolio Condition
Default CBRE	100% of CBRE achievable potential is selected
CBRE: 75%	75% of CBRE achievable potential is selected
CBRE: Unavailable (informational)	CBRE resources are unavailable
CBRE: Microgrids	Only Microgrid CBRE resources are available
CBRE Optimize	CBRE resources compete economically

11.4.3.1 Results and insights

Results from these portfolios indicate that increasing the amount of CBRE resources decreases portfolio costs and risk (**Figure 90**). Additionally, the 'CBRE Optimize' portfolio selects the full amount of available CBRE resources and, alongside 'Default CBRE', which forces in the full amount of CBRE resources, has the lowest cost and risk. Portfolios community benefits indicators (CBIs), which are a function of the nameplate capacity of CBREs added in each portfolio and represent the level of community benefits provided (described in **Section 7.1.4, Portfolio community benefits indicators**), are shown in (**Table 59**). These results show that in addition to having the lowest cost and risk, the 'CBRE Optimize' and 'Default CBRE' portfolios provide the greatest community benefits.

This finding suggests that in a transmission-constrained system, CBRE resources can decrease cost and increase community benefits. These results drive the conclusion that PGE should include all 155 MW of available CBRE in the Preferred Portfolio. Additionally, it supports the conclusion that community benefits and cost minimization are not mutually exclusive. However, given both the magnitude of long-term transmission needs and the total forecasted technical potential for incremental CBRE additions, CBRE resources cannot be seen as a panacea for the challenges PGE faces with transmission availability.

Figure 90. Cost and risk metrics of CBRE portfolios

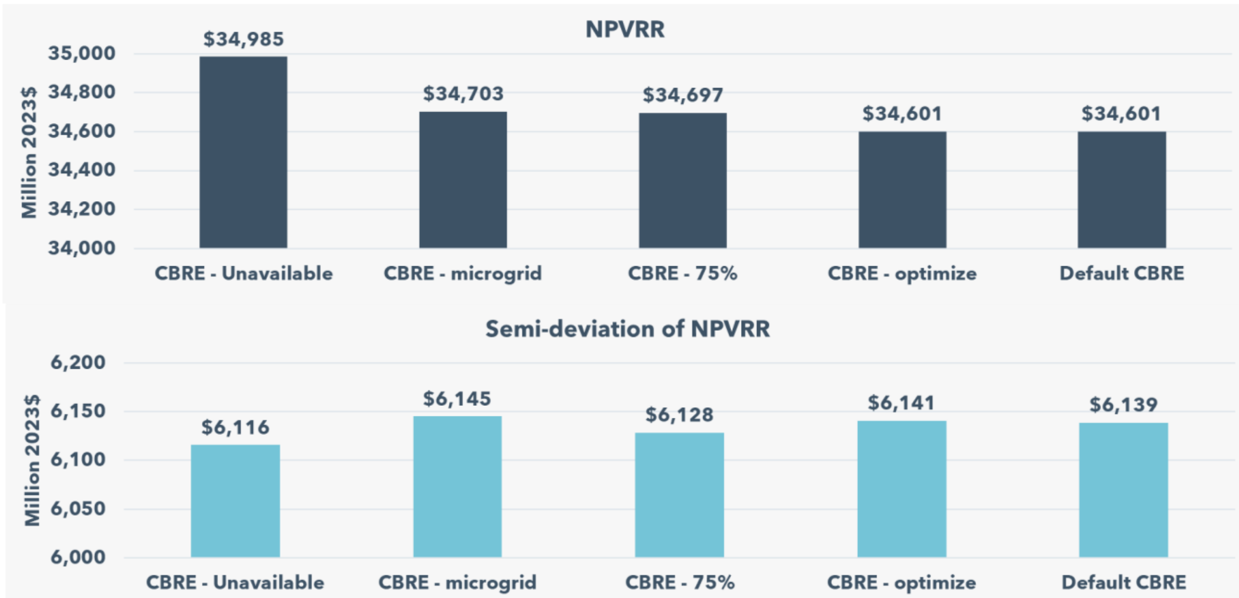


Table 59. Portfolio Community Benefit Indicator of each CBRE portfolio

Portfolios	Portfolio Community Benefit Indicator (pCBI)
Default CBRE	155
CBRE: 75%	116
CBRE: Unavailable	0
CBRE: Microgrids	100
CBRE Optimize	155

11.4.4 Energy efficiency and demand response portfolios

Through the DSP, PGE has committed to expanding the demand response (DR) portfolio to 211 MW of summer and 158 MW of winter demand response by 2028. Additionally, through the Energy Trust of Oregon (ETO) PGE estimates approximately 150 MWa of incremental cost-effective energy efficiency (EE) to be achieved by 2028. These resources are included as a reduction in resource needs, namely capacity and energy (for more detail, see **Section 6.2, Distributed Energy Resource (DER) impact on load**).[307]

In this IRP, we also have estimated the costs and benefits associated with additional quantities of EE and DR (these estimates are described in both **Chapter 8, Resource options**, and **Chapter 10, Resource economics**). **Table 60** lists the portfolios PGE developed to understand whether these additional quantities of EE and DR could provide system benefits at lower cost and risk relative to other supply-side options. All portfolios in this section assume a linear reduction in emissions and the full 155 MW buildout of CBRE resources to ensure comparisons focus on the role of EE and DR. Additional EE and DR resources are available for selection in the years 2026 through 2030.

Table 60. List of EE and DR portfolios

Portfolios	Portfolio condition through 2030
Optimized Non-Cost-Effective (NCE) DERs	Allow model to select from total potential of additional EE and DR
Zero NCE	No additional EE and DR available (ETO and PGE cannot increase savings beyond current commitments)
25 MWa NCE EE	25 MWa of additional EE (5 MWa annually)
50 MWa NCE EE	50 MWa of additional EE (10 MWa annually)
60 MWa NCE EE	60 MWa of additional EE (12 MWa annually)
70 MWa NCE EE	70 MWa of additional EE (14 MWa annually)

The quantity of additional EE and DR added in these portfolios is shown in **Figure 91**. In the 'Optimized Non-cost-effective (NCE) DERs' portfolio, the model selected 53 MWa of the 70 total MWa of EE available. Additional DR was not selected in any of the portfolios as it has higher costs than any other available resources when it is available for selection (2026-2030), highlighting the need for program redesigns that reduce costs. When comparing the scoring metrics in **Figure 92**, increasing the amount of additional EE available for selection decreases portfolio cost and reduces risk up to a point. This shows that there are energy efficiency options that are more expensive than transmission options and the generic resource. Portfolio NPVRR decreases as the model is allowed access to increasing amounts of EE, from the highest costs for the 'Zero NCE' portfolio to the lowest cost for the '50 MWa EE' portfolio. The implications of these results are further discussed in the following section.

[307] These estimates from the DSP and ETO are based on the avoided costs of the 2019 IRP Update and thus do not account for reflect the economic tradeoffs within this IRP.

Figure 91. Resource buildout in energy efficiency and demand response portfolios

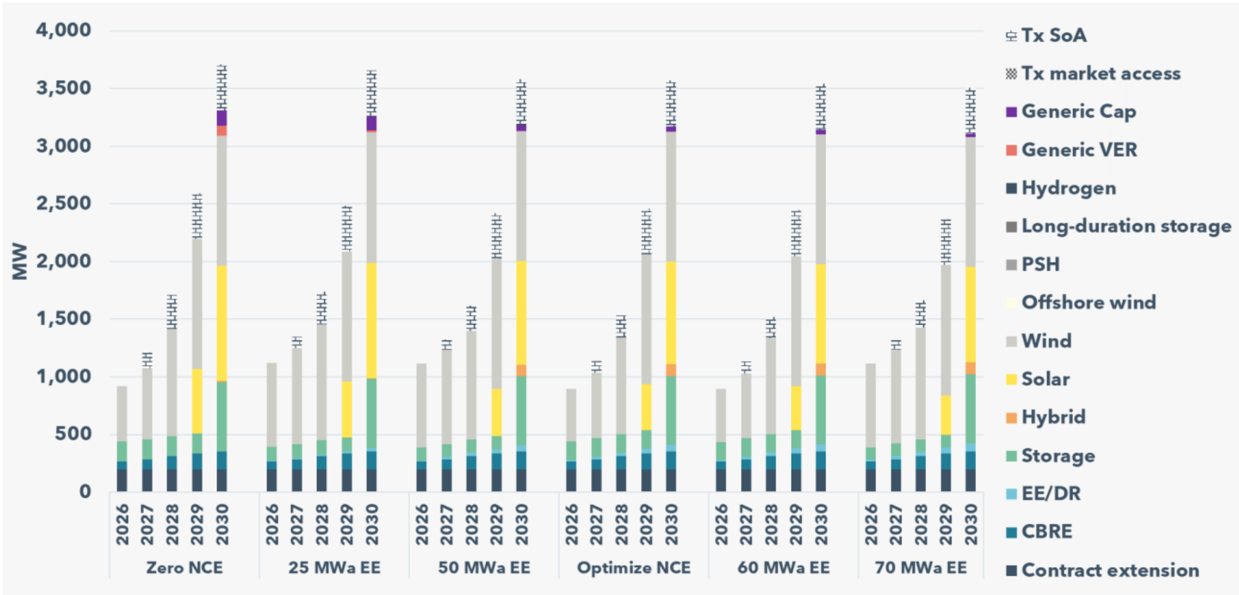
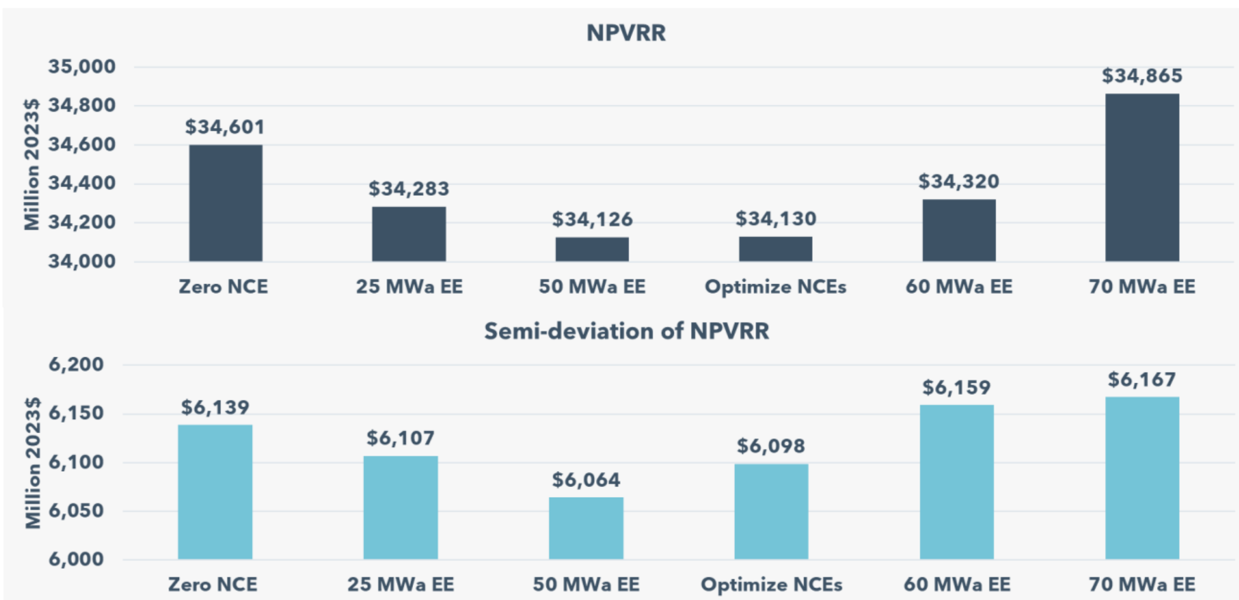


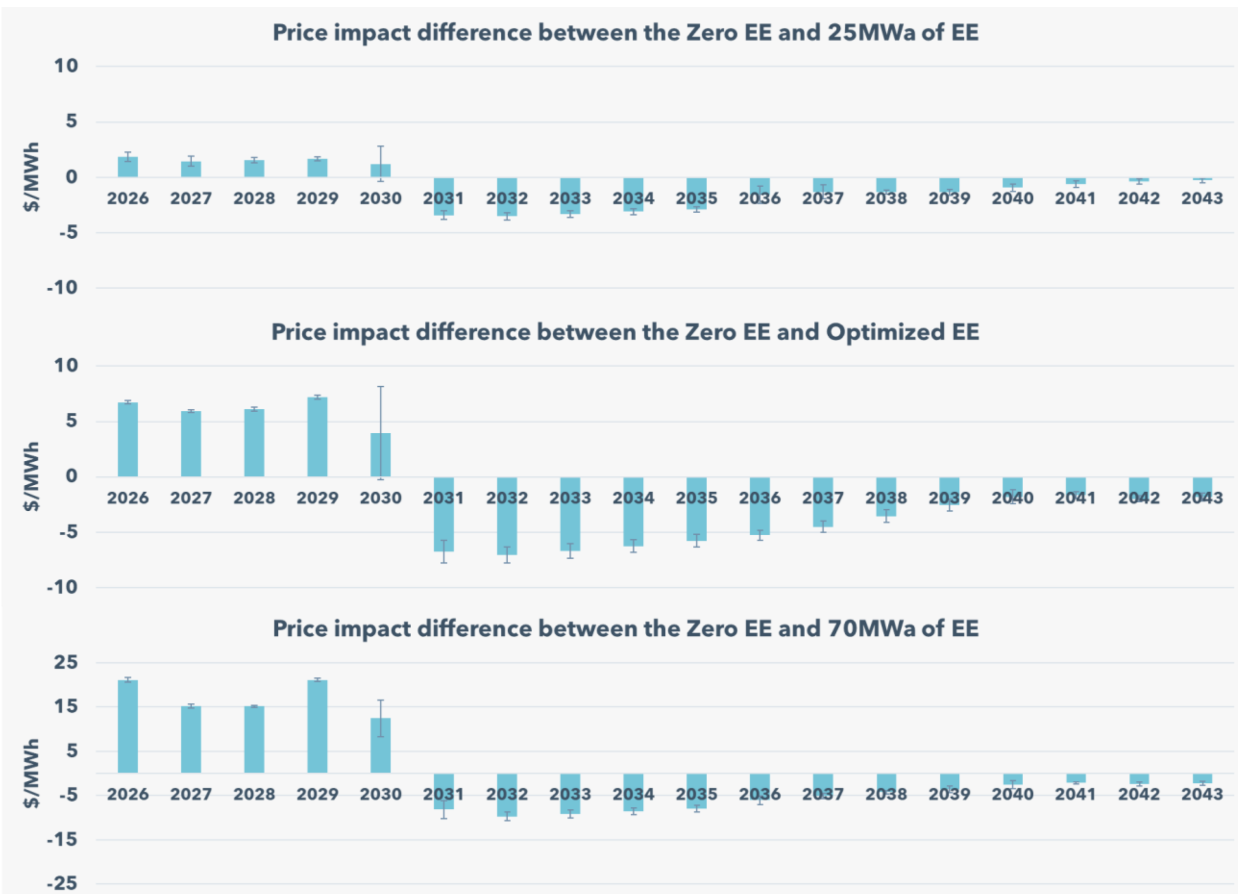
Figure 92. Cost and risk metrics of EE&DR portfolios



These results strongly identify the potential benefits of adding additional EE more than the quantities identified as 'cost-effective' using outputs from the 2019 IRP. This highlights a significant disconnect between resource planning using the current forecasts of costs and benefits in this IRP and resources that use previously calculated cost-effectiveness tests (such as energy efficiency and demand response). This disconnect is further described in **Section 10.7, Cost of clean energy**.

However, examination of the cost impacts of these portfolios identifies challenges related to the near-term cost impacts. **Figure 93** shows the difference in yearly price impact between the Zero EE portfolio and three portfolios with varying levels of additional EE (25MWa, Optimized and 70MWa). This figure underscores the relationship between acquiring increasing quantities of additional EE and the associated near-term price impacts. As additional EE is added the near-term price impact increases rapidly. Two unique policy factors drive these results. First, unlike other assets the additional EE is not financed or securitized, so the full cost is incurred before the generation starts. Second, EE decreases retail sales which leads to increased costs per unit of sales. Aggregated, these two effects lead to much higher near-term cost increases than the relevant comparators. Accordingly, EE under the current state policy creates large near-term price increases. When only considering long-term system cost this near-term effect is not apparent.

Figure 93. Yearly costs per MWh for additional EE portfolios through 2030



Despite ROSE-E suggesting the long-term benefits of adding additional quantities of EE, PGE has determined that the combination of near-term price impacts and the unquantified risk of pursuing the resource outweighs the associated benefit. Accordingly, the Preferred Portfolio described in **Section 11.5, Preferred Portfolio**, does not contain any additional EE.

While the updated avoided costs produced by IRPs (as highlighted in **Section 10.7, Cost of clean energy**) could lead to higher quantities of EE being realized, additional policy changes that could more assuredly lead to procurement and/or securitize the procurement of EE will likely be needed for PGE to achieve the full cost and risk savings articulated in these portfolios. As the modeling suggests, energy efficiency is an increasingly important resource to PGE and the region's decarbonization strategies.

11.4.5 Optimized portfolios

With the Optimized portfolios group, PGE explored the impact of optimization choices on resource buildout, portfolio cost and risk metrics by varying the constraints imposed and the objective functions used to minimize costs. **Table 61** lists the portfolios PGE developed to test different objective functions. All portfolios in this section are built upon a linear reduction in emissions.

The 'Min Avg LT cost' and 'Optimized' portfolios use the default objective function to minimize the average NPVRR across all combinations of price, need and technology cost futures for the full portfolio analysis time horizon (2024-2043). The 'Min Avg ST cost' and 'Min Ref ST cost' portfolios use different objective functions than the rest of the portfolios. 'Min Avg ST cost' minimizes the average of NPVRR outcomes across all combinations of need, price and technology cost futures through the year 2030. 'Min Ref ST cost' minimizes the NPVRR of the Reference Case only and only through the year 2030.

The 'Min Avg LT cost', 'Min Avg ST cost' and 'Min Ref ST cost' portfolios have the default settings used across most portfolios of adding all 155 MW of CBRE resources and access to 400 MW of SoA in 2027. The 'Optimized' portfolio allows the model access to the least-restricted set of resource actions PGE can take.[308] In the 'Optimized' portfolio, the model has access to 400 MW of SoA in 2027, 400 MW each of WY and NV transmission in 2026, the full 70 MWa of additional EE, and has the option of selecting up to 155 MW of CBRE resources.

[308] Some informational portfolios, like the 'No Tx constraints' portfolio' do contain fewer restrictions but are not actionable.

Table 61. List of optimized portfolios

Portfolios	Portfolio condition
Min Avg LT cost	Minimizing average long-term (LT) NPVRR
Min Avg ST cost (informational)	Minimizing average short-term (ST) NPVRR through 2030
Min Ref ST cost (informational)	Minimizing Reference Case short-term NPVRR through 2030
Optimized (informational)	Least constrained

The 'Optimized' portfolio uses the access to additional EE, selecting 53 MWa by 2030 and adding less storage and renewables compared to the 'Min Avg LT cost'. As a result of the additional resources available for selection, 'Optimized' achieves lower costs and risk than 'Min Avg LT cost' (**Figure 94**). Additionally, the portfolio selects the full quantity of available CBRE resources, supporting the robustness of the findings in **Section 11.4.3, Community-based renewable energy (CBRE) portfolios**. And finally, the portfolio selects the SoA option, reinforcing the finding that the full quantity of resources available with existing transmission capacity (described in **Appendix H.7, BPA transmission in ROSE-E**) is insufficient to meet system needs at the lowest cost without also some expansion of transmission access.

Because they are optimized over a shorter timeframe of seven years compared to the standard 20 years for other portfolios, the cost and risk metrics of the 'Min Avg ST cost' and 'Min Ref ST cost' portfolios are not comparable to those of other portfolios for two reasons. First, only seven years of values are accounted for in their cost and risk metrics, so NPVRR outcomes are much smaller, and associated variability is lower. Second, beyond 2030, while the resource additions must still satisfy the constraints imposed on the model, they are not subject to the minimization of costs, and the model does not attempt to create an optimal resource buildout. The 'Min Avg ST cost' and 'Min Ref ST cost' portfolios produce nearly identical resource buildouts to one another and very similar resource buildouts (through 2030) to the 'Min Avg LT cost' portfolio (**Figure 94**).

Figure 94. Resource buildout in optimized portfolios

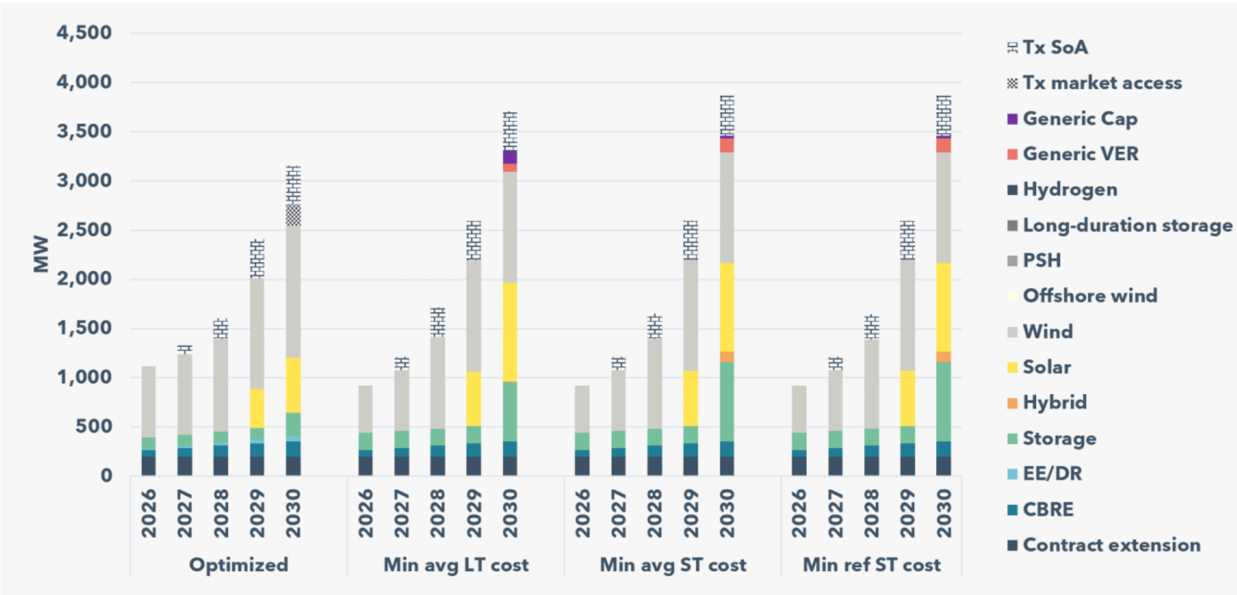
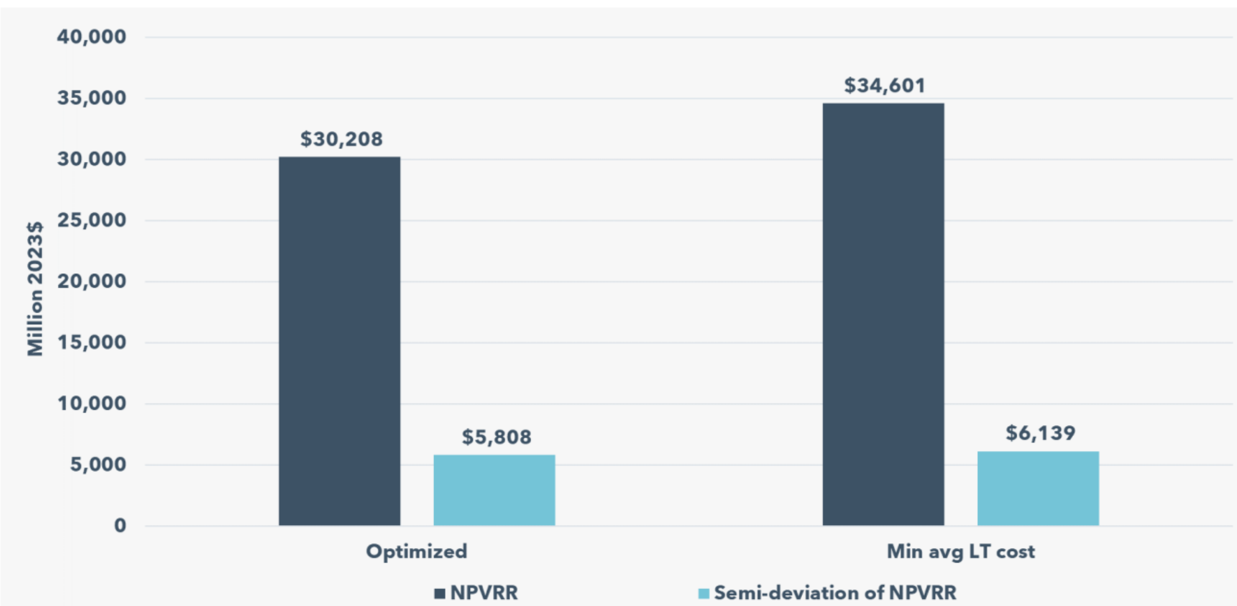


Figure 95. Cost and risk metrics of 'Optimized' and 'Min Avg LT cost' portfolios



11.4.6 Targeted policy portfolios

To inform stakeholder discussions, PGE developed targeted portfolios to study specific policy conditions, listed in **Table 62**. Both 'Targeted Policy' portfolios have a linear GHG-emissions reduction glidepath, have access to 400 MW of SoA upgrade in 2027, and must add all 155 MW of CBRE resources. Neither portfolio has access to WY or NV transmission expansion options.

Table 62. List of targeted policy portfolios

Portfolios	Portfolio condition
Physical RPS	Enforce physical renewable portfolio standard (RPS) compliance
Oregon-only Resources	Limit resource availability to Oregon-sited only

The 'Oregon-only resources' portfolio does not allow the model to select resources sited outside of Oregon (i.e., SE Washington, Wyoming, Montana Wind or NV Solar). Because the portfolio has less access to improved effective load carrying capacities (ELCC) of out-of-state resources and a lower total availability of non-generic resources, a larger quantity of resource additions and increased reliance on generic resources are required to meet energy and capacity needs compared to portfolios that have access to out-of-state resources. The impact on resource buildout is demonstrated in **Figure 96** through comparison with the 'SoA in 2027 plus' portfolio from the transmission timing portfolios, which allows the model to access all out-of-state resources. The increase in quantity of resource additions and reliance on generic resources creates higher portfolio costs and **Figure 97** shows that the NPVRR of the 'Oregon-only resources' portfolio is $4.213 billion higher than the 'SoA in 2027 plus' portfolio. These results suggest that limiting the geographic area available to develop generation resources could lead to increased cost and risk for PGE's customers.

The 'Physical RPS' portfolio requires a resource buildout that ensures physical RPS requirements, meaning REC generation from existing and new resources must meet or exceed RPS obligations in all years. Because the need to add renewable resources to meet the requirements of HB 2021 is greater than is required for RPS compliance, the physical RPS requirement does not impact resource buildout or portfolio cost.

Figure 96. Resource buildout in Oregon-only resources and SoA in 2027 plus portfolios

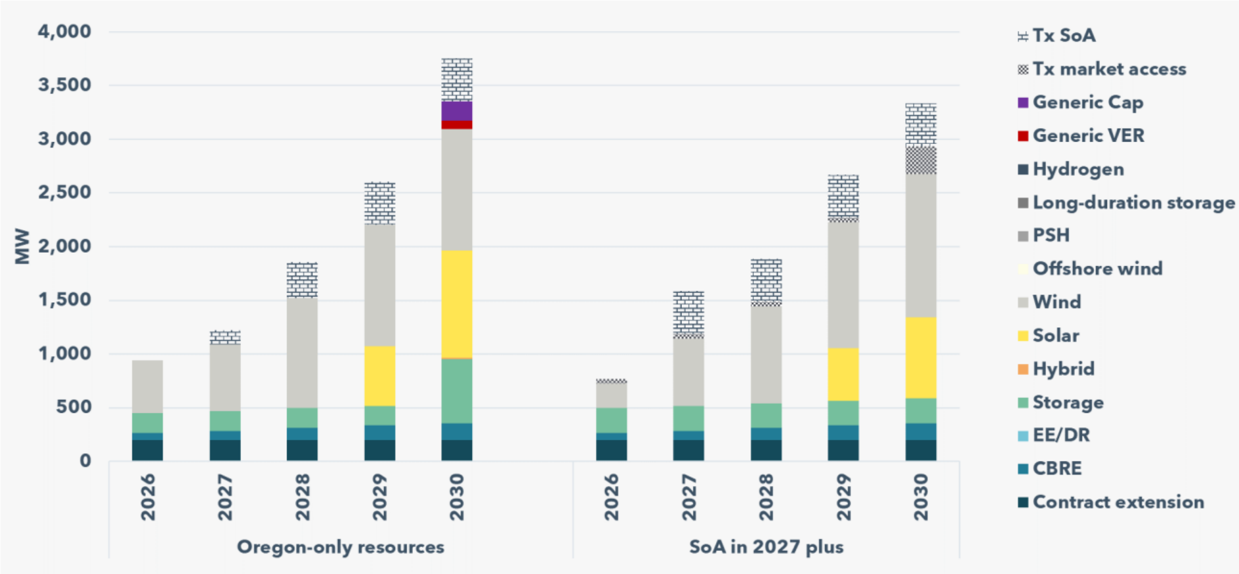
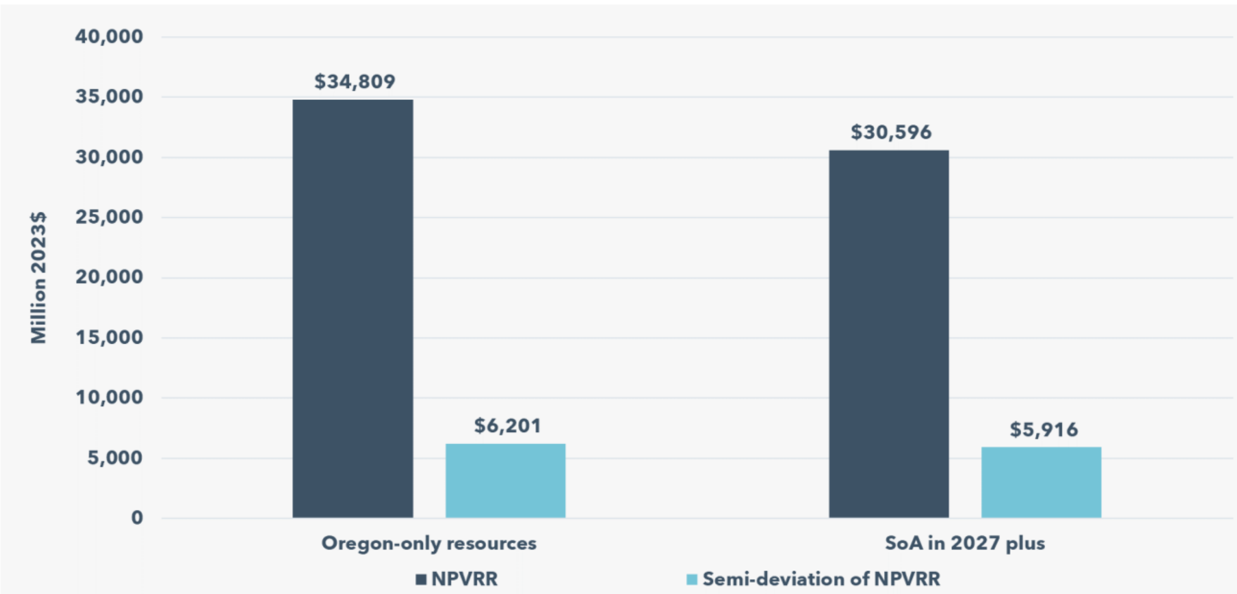


Figure 97. Cost and risk metrics of Oregon-only resources and SoA in 2027 plus portfolios



11.4.7 Emerging technology portfolios

Emerging technologies can potentially reduce portfolio costs and minimize the need for transmission expansion. To understand the potential impact of emerging technologies on transmission, cost and risk, PGE has explored portfolios listed in **Table 63**. The potential for emerging technologies to help PGE meet HB 2021 targets is explored in **Section 8.5, Post-**

2030 resource options, and the implications of the speed of development of and cost declines of emerging technologies are further explored here.

Table 63. List of emerging technology portfolios

Portfolios	Portfolio condition
Pumped hydro	333 MW of pumped storage hydro (PSH) in 2028
Hydrogen blending	Blending of hydrogen at existing natural gas (NG) plants
Hydrogen building	100 MW of hydrogen in 2029
Offshore wind (Informational)	500 MW of offshore wind in 2032
Long Duration Storage (Informational)	139 MW of 24 hr. battery in 2028
RTO (Informational)	200 MW Reduction in Capacity Need

In the 'Pumped hydro' portfolio, 333 MW of 10-hour pumped hydro storage (PSH) is added in 2028.[309] The 'Long Duration Storage (LDS)' portfolio includes 139 MW of 24-hour battery in 2028.[310] The 'Hydrogen blending' portfolio models the conversion of existing PGE-owned NG plants to run on a partial hydrogen fuel blend.[311] The hydrogen-derived non-emitting power provides energy but does not provide additional capacity because the hydrogen is blended into existing power plants. The 'Hydrogen building' portfolio adds 100 MW of new 100 percent hydrogen-fueled dispatchable capacity, providing both energy and capacity. The 'Offshore wind' portfolio adds 500 MW of offshore wind in 2032.[312,313] The 'Regional transmission organization (RTO)' portfolio considers the potential benefits that PGE might

[309] This represents 1/6th of the 2000 MW of known potential projects in the region (Swan Lake 400 MW, Gordon Butte 400 MW and Goldendale 800 MW). A 1/6th portion of the total capacity is representative of the fact that PGE is one of six regional IOU's.
[310] 139 MW of 24-hr storage provides the same amount of energy storage as 333 MW of 10-hour storage.
[311] Hydrogen is blended into PGE's CCCT natural gas plants starting in year 2029. For modeling purposes, the energy generated by hydrogen is additional to the energy generated by burning natural gas and fully serves retail load.
[312] This represents 1/6th of the 3000 MW of potential capacity along the Oregon Coast identified by the Bureau of Ocean Energy Management (BOEM) available at: 2022-Floating-Offshore-Wind-Report.pdf (oregon.gov).
[313] The 2032 expected COD for offshore wind is aligned with findings of the Northwest Power and Conversation Council, available at: https://www.nwcouncil.org/fs/17860/2022_08_p3.pdf.

realize from joining an RTO by reducing capacity need by 200 MW annually beginning in 2031.[314]

The addition of PSH, LDS and Hydrogen can be seen in the resource buildouts shown in **Figure 98**. Resource buildouts for the 'Offshore wind', 'Hydrogen blending' and 'RTO' portfolios are shown in **Figure 99**. The offshore wind addition can be seen in 2032, while for the 'RTO' and 'Hydrogen blending' portfolios, the impact on resource buildout takes the form of a reduced need for resource additions. The resource buildout of the 'Offshore wind' portfolio differs substantially from the other Emerging Technology portfolios beginning in 2032 when offshore wind is added. Because of the high-capacity factor of offshore wind and the resulting large amount of energy added to the portfolio, the model is able to add a large amount of storage to complement the offshore wind addition, reducing reliance on the generic VER resource relative to other Emerging Technology portfolios, which are more reliant on the energy provided by generic VER. As a result of the 'Offshore wind' portfolio's lower reliance on the expensive generic resource, it has the lowest cost outcomes in the group (**Figure 100**).

Some impacts of emerging technologies on the pre-2030 resource buildout can be seen. While all portfolios add the same amount of wind (1128 MW), the 'Hydrogen blending' portfolio adds less solar (668 MW) than the other portfolio (between 1000 MW and 1010 MW). This smaller addition of renewables in "Hydrogen blending' is because of the additional existing energy available associated with hydrogen blending starting in 2029. Additionally, the 'Pumped hydro' and 'Long Duration Storage' portfolios both reduce the addition of other storage options through 2030. The relatively minor impacts on resource builds across the Emerging Technology portfolios highlights that resource actions now are not likely to be majorly impacted by emerging technologies (a finding that is explored further in **Section 11.5.3, Resource buildout robustness analysis**).

However, emerging technologies have a larger impact on longer-term actions, decreasing dependence on transmission expansion and the expensive generic resources. Given the high cost of the generic resources, the larger the addition of an emerging resource, the more costs can be reduced (as shown in **Figure 100** by the relatively low costs of the 'Offshore wind' portfolio, which has the largest addition of emerging technology). Unquantified benefits of these emerging technologies could include reduced dependence on the timing of transmissions projects. Thus, continued investigation of emerging technologies is warranted and can be a strategy for reducing costs in the longer term.

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[314] A 200 MW reduction in capacity need represents 5 percent of PGE's peak load of approximately 4,000 MW. This was used to define the potential benefits of joining an RTO based on SPP's estimate that load diversity reduces their need for capacity by approximately 5 percent of their peak load, described here: [2021 spp mvs methodology.pdf.]

Figure 98. Resource buildout in long duration storage, pumped hydro and hydrogen building portfolios

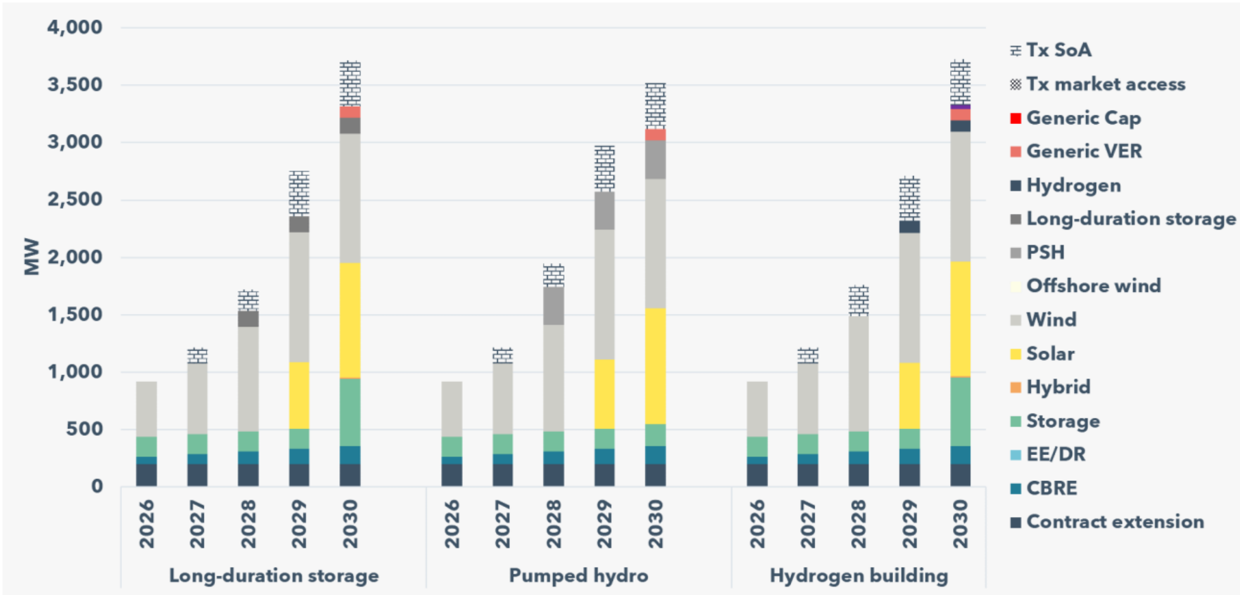


Figure 99. Resource buildout in RTO, hydrogen blending and offshore wind portfolios

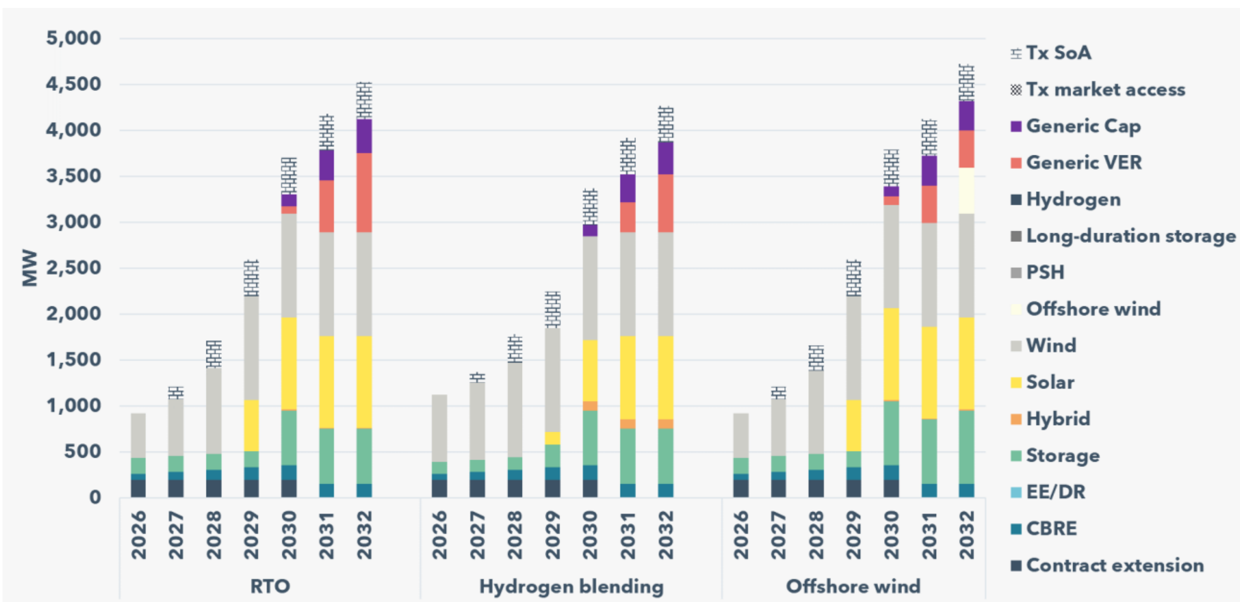
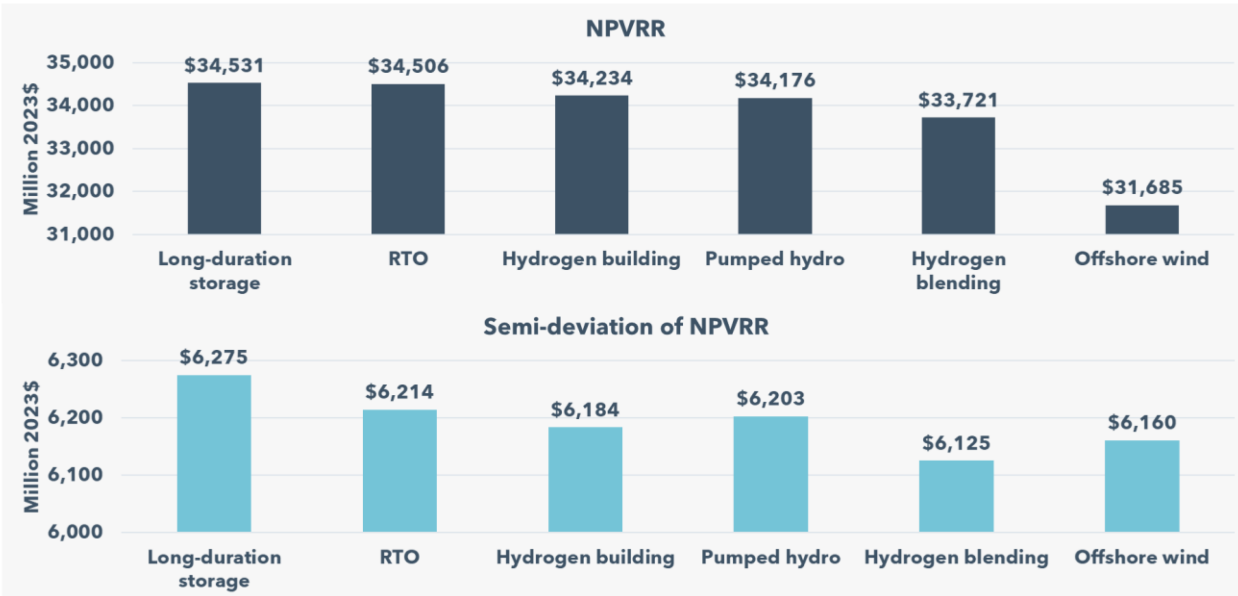


Figure 100. Cost and risk metrics of emerging technology portfolios



11.5 Preferred Portfolio

PGE evaluated 39 portfolios to answer key questions in PGE's current energy economic landscape. Based on these insights, PGE developed a Preferred Portfolio to meet system needs based on the answers to key questions and common themes. The Preferred Portfolio meets HB 2021 emissions reductions targets using the linear decarbonization glidepath and is forecast to emit 32.67 MMTCO2e over the entirety of the 2024-2043 portfolio analysis time-horizon (as shown for the 'Linear decline' portfolio in **Section 11.4.1, Decarbonization glidepath portfolios, Figure 78**). The Preferred Portfolio also complies with RPS obligations, as demonstrated in **Section 11.5.2, Resulting RPS position.** The key findings that emerged from portfolio analysis and were used to define the Preferred Portfolio are presented in **Figure 101**.

Figure 101. Key findings from portfolio analysis used to define the Preferred Portfolio

Key Findings

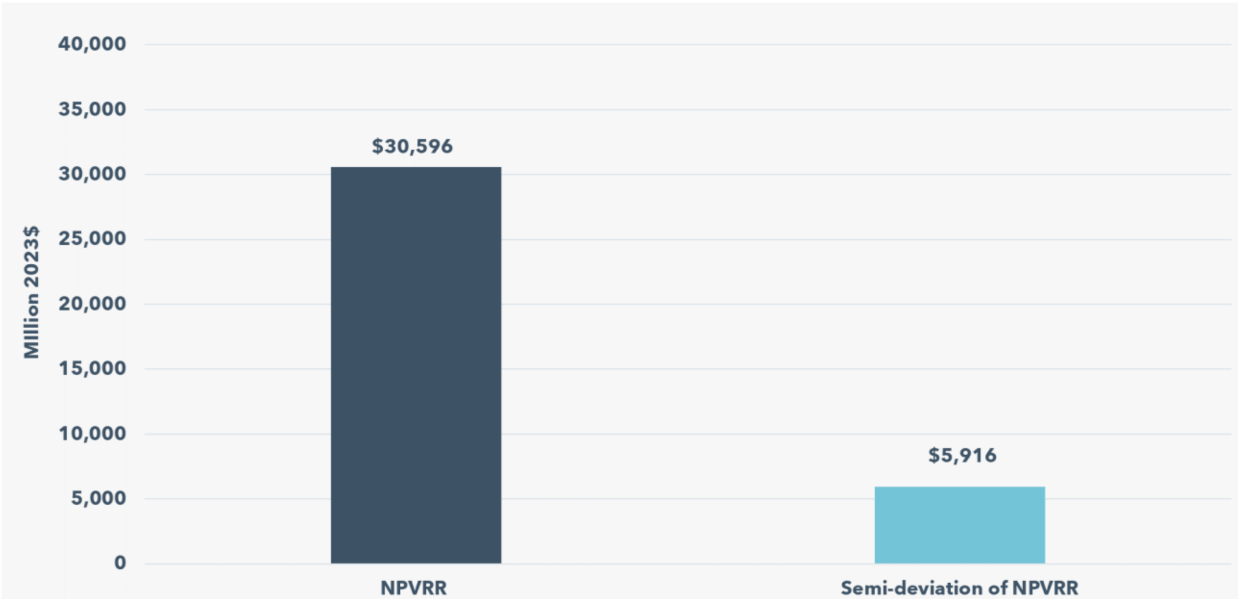
1. A linear glidepath to meet the 80% reduction in emissions by 2030 best balances cost, risk, and pace of emissions reduction.
2. Adding 100% of the CBRE potential would best balance cost, risk, and community benefits.
3. The magnitude and timing of additional transmission capacity is the largest factor that influences resource additions and the cost and risk metrics of portfolios.
4. It is infeasible for PGE to meet the 2030 HB 2021 targets without any transmission upgrades and the magnitude of transmission need increases throughout the planning horizon.
5. Transmission upgrades to connect to off-system resources can be delayed by investing in resources such as energy efficiency, demand response, and distribution connected CBREs. However, given the magnitude of transmission capacity needed, these resources can only marginally delay the need in early years and cannot offset transmission need in the long-term.
6. Upgrades to PGE transmission that unlock additional access to proxy resources is sufficient to address system needs.
7. Increasing access to new transmission expansion options can help reduce costs, variability risk, and resource needs, which reduce potential risks associated with procurement, stemming from supply chain issues.
8. Emerging non-GHG-emitting technologies that could have a high capacity and/or energy contribution such as nuclear, hydrogen, long-duration storage, and advanced geothermal can mitigate this significant dependence on transmission over the long-term.

Through 2030, the Preferred Portfolio selected optimized quantities of VERs totaling 2,090 MW, 232 MW of storage and 255 MW of transmission expansion proxy resources. The 255 MW of proxy transmission resources have an associated 206 MW of WY wind and 49 MW of NV solar, which are included in the total VER quantity. No hybrid resources were selected, with the model instead utilizing existing transmission capacity to select stand-alone VER resources with higher capacity factors paired with stand-alone storage options and capacity-dense Tx expansion proxies. Additionally, the resource buildout of the Preferred Portfolio includes 200 MW of non-GHG-emitting contract extension, 400 MW of SoA Tx upgrade added in 2027 and 155 cumulative MW of CBRE resources. The model was not allowed access to additional EE or DR in the Preferred Portfolio but does include a total of 156 MWa of cost-effective EE and 223 MW of cost-effective DRs, which are accounted for as a reduction in resource needs (see **Section 6.2, Distributed Energy Resource (DER) impact on load**). The Preferred Portfolio meets capacity and energy needs with the resource buildout, shown in **Table 64**, at a cost of $30,596 million (NPVRR in **Figure 102**).

Table 64. Cumulative resource buildout in Preferred Portfolio (MW)

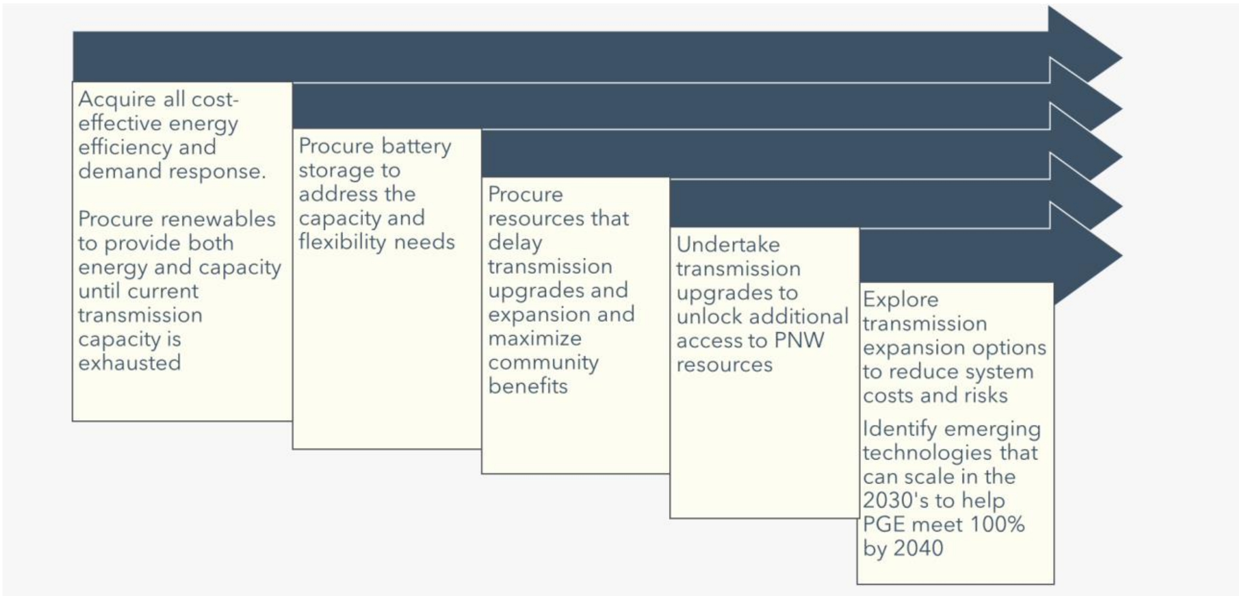
	2024	2025	2026	2027	2028	2029	2030
Wind	0	0	227	627	901	1172	1334
Solar	0	0	0	0	0	490	756
Hybrid	0	0	0	0	0	0	0
Storage	0	0	232	232	232	232	232
CBREs	0	0	65	84	110	133	155
WY Tx	0	0	44	44	44	44	206
NV Tx	0	0	0	0	0	0	49
SoA Tx	0	0	0	400	400	400	400
Additional EE & DERs	0	0	0	0	0	0	0
Non-GHG-Emitting Contract Extension	0	0	200	200	200	200	200
Cost-effective EE (MWa)	30	60	90	120	150	183	216
Cost-effective DR	133	162	183	199	211	218	228
Clearwater Wind	311	311	311	311	311	311	311
Wasco solar (RFP Proxy)	0	230	230	230	230	230	230
Christmas Valley solar (RFP Proxy)	0	180	180	180	180	180	180
4 hr battery (RFP Proxy)	0	400	400	400	400	400	400

Figure 102. Cost and risk metrics of the Preferred Portfolio



When considered in aggregate, these insights highlight how the binding nature of decarbonization and transmission constraints severely limit the options available to PGE and necessitate an approach to pursue all avenues of resource additions that are available and feasible. **Figure 103** visualizes the summary of these insights.

Figure 103. Visualizing the key themes of portfolio analysis that necessitate a 'pursue all' approach to best balance cost, risk, emission reduction and community benefits



11.5.1 Preferred Portfolio yearly price impacts[315]

Although the yearly price impacts do not represent actual customer price impacts, the near-term price impacts are an important concern when evaluating options to decarbonize reliably. Through an extensive analysis of resource additions amongst a variety of portfolios, we have found that while the incremental resource additions included in these estimates represent the least cost and risk manner to meet the emissions targets established in HB 2021, they are anticipated to raise the costs associated with generation resources relative to a 2023 baseline. These Reference Case price changes, normalized by load, are shown in **Figure 104**. In the very near-term, the price impact of the 2021 all-source RFP resources coming online in 2025 can be offset in part by expected increased wholesales sales based on economic dispatch and market prices. The compounded annual growth rates (CAGR) of those price impacts 2024-2030 are displayed in **Table 65**. After 2025, the Preferred Portfolio adds the resources listed in **Table 64**. With a 50 percent ownership assumption, the ITC benefits of storage resources added in 2026 partially offset the impact of cost increases from resources added in the 2021 all-source RFP. Incremental resource additions, including the expansion of the existing transmission system, continue to increase the costs of generation resources through 2030. While this analysis does not represent actual changes to customer prices, it is suggestive that, on a planning basis, system costs are likely to increase through

[315] **Addendum: PGE CEP Data Template** contains the annual price impact in $'s and the annual price impact per unit retail sales ($/MWh) through the planning horizon for each portfolio

2030: the Reference Case costs of generation resources, normalized by load growth, are forecast to increase by approximately 21 percent by the end of the decade.

Given the constraints in the planning environment associated with HB 2021 decarbonization goals and transmission availability, the need for resource procurement identified in this IRP is large and appears to result in substantial impacts on costs. PGE constructed a Preferred Portfolio that minimizes the costs and risk of these new resource acquisitions and maximizes the provision of community benefits by thoroughly investigating key decision points with the potential to impact costs. This includes selecting a linear GHG-emissions reduction pathway that complies with HB 2021 requirements while mitigating costs relative to more-aggressive pathways and reducing risks compared to less-aggressive pathways. Choices that minimize cost or risk were also made regarding additional DERs, the inclusion of CBRE resources and opportunities to expand transmission availability. Mitigating the impact of this increase in costs will be critical and PGE will continue to study all potential options that can help minimize costs, including continuing to explore the potential of emerging technologies as they develop and studying options to expand transmission access.

Figure 104. Yearly price impact (in $/MWh) of the Preferred Portfolio

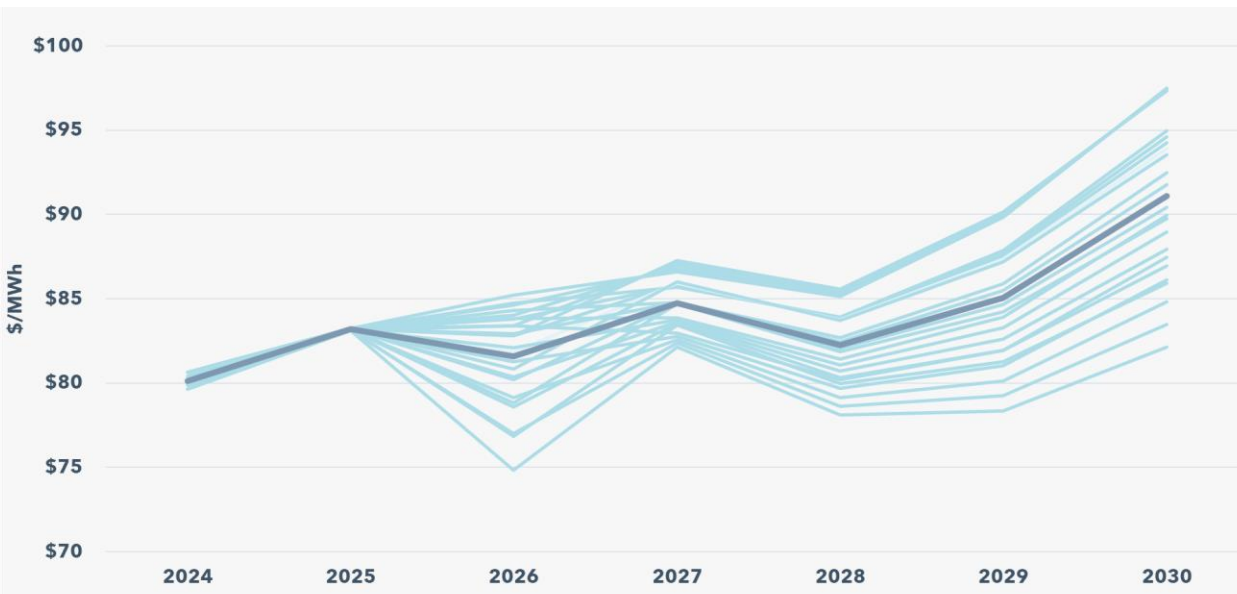


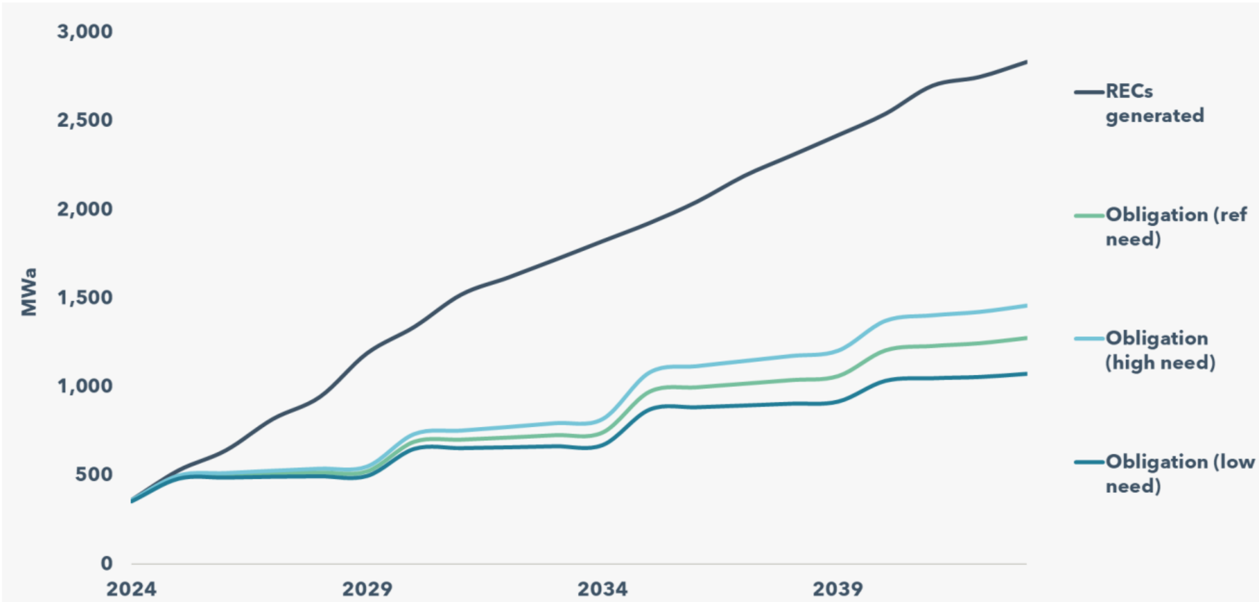
Table 65. Compounded annual growth rate of price impacts of the Preferred Portfolio 2024-2030

		PGE Ownership				
		0%	**25%**	**50%**	**75%**	**100%**
Tax Credit Levels	50%	3.9%	3.9%	3.8%	3.8%	3.8%
	75%	3.4%	3.3%	3.2%	3.2%	3.1%
	100%	2.9%	2.8%	2.6%	2.4%	2.3%
	125%	2.4%	2.2%	1.9%	1.7%	1.5%
	150%	1.9%	1.6%	1.3%	0.9%	0.6%

11.5.2 Resulting RPS position

PGE's RPS requirements are described in **Section 6.7, RPS need**. **Figure 105** shows the number of 5-yr RECs forecast to be generated by adding new resources in the Preferred Portfolio and REC obligations for the low, reference and high Need Futures. The generation of RECs from the existing and incremental RPS resources in the Preferred Portfolio is forecasted to enable PGE to comply with RPS requirements. While HB 2021 regulations are not REC-based, the need to add new non-emitting resources to comply with HB 2021 GHG reduction requirements is larger than is needed to comply with RPS requirements, resulting in the forecast number of RECs generated by PGE's portfolio greatly exceeding RPS requirements.

Figure 105. RPS compliance of Preferred Portfolio[316]



11.5.3 Resource buildout robustness analysis

Portfolio analysis in the 2023 IRP is heavily focused on resource acquisition needs primarily in the Action Plan window of 2026-2028, and secondarily on the crucial years for achieving compliance with HB 2021 emissions reductions targets of 2029 and 2030. Uncertainty surrounding key forecasts and assumptions used in portfolio analysis increases over the planning horizon, making findings for the latter years of the analysis less robust than those for the near-term.

In addition to the increased uncertainty in forecasts of variables like market prices and costs of commercially available technologies like VERs and storage, substantial uncertainty exists about the economic and technological development rate of emerging non-GHG-emitting technologies. It is likely that rapid development in the availability and cost of one or more of these emerging technologies will be needed for PGE to achieve the HB 2021 100 percent reduction in GHG-emissions target by 2040. The potential roles of a variety of emerging technologies in helping PGE fully decarbonize by 2040 are explored in **Section 8.5, Post-2030 resource options**.

Because of the substantial resource needs PGE faces in the near-term, it is infeasible to wait for emerging technologies to develop before taking resource procurement actions: near-term needs must be met using currently available technologies. However, resource

[316] This forecast of 5-year REC generation includes RECs that have been designated for retirement voluntary programs

acquisition decisions made by PGE now should attempt to minimize the risk of negative impacts on the ability to use the range of emerging technologies as they develop in the future.

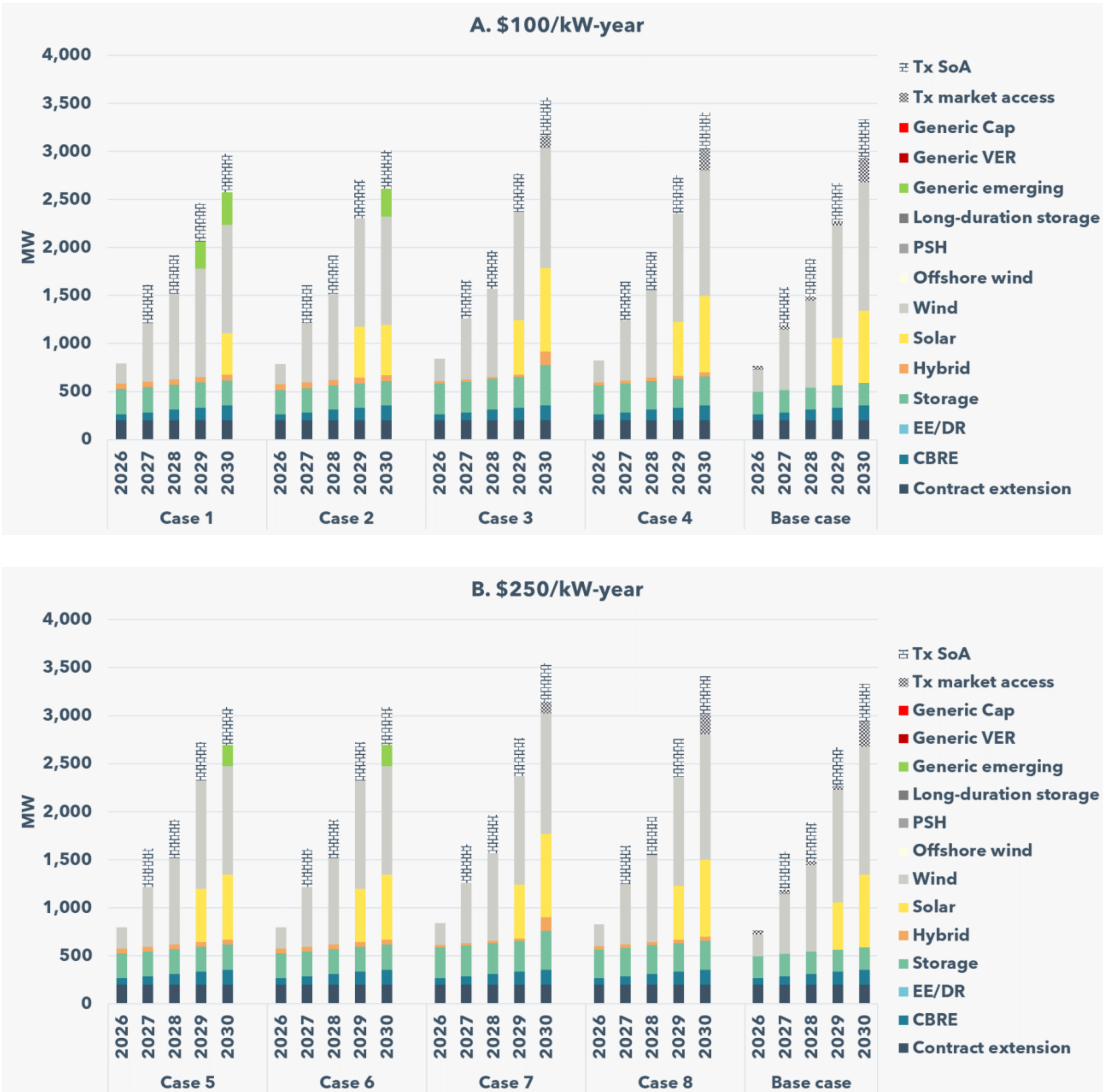
To test the robustness of the resource buildout in the near-term against these sources of uncertainty, PGE conducted an analysis varying the cost and timing of availability across multiple years and cost levels of an additional generic, non-emitting emerging resource with 100 percent ELCC and 50 percent capacity factor, representing a range of rates of development of emerging technologies. As shown in **Table 66**, 16 cases were analyzed with the first year of availability varying from the first-year post-Action Plan (2029) out to 2032 at a cost ranging from $100/kW-year to $1,000/kW-year. All cases have an otherwise consistent set of assumptions and are compared against a base case in which the generic emerging resource is defined in the default manner for portfolio analysis of being available for $1,000/kW-year after 2030.

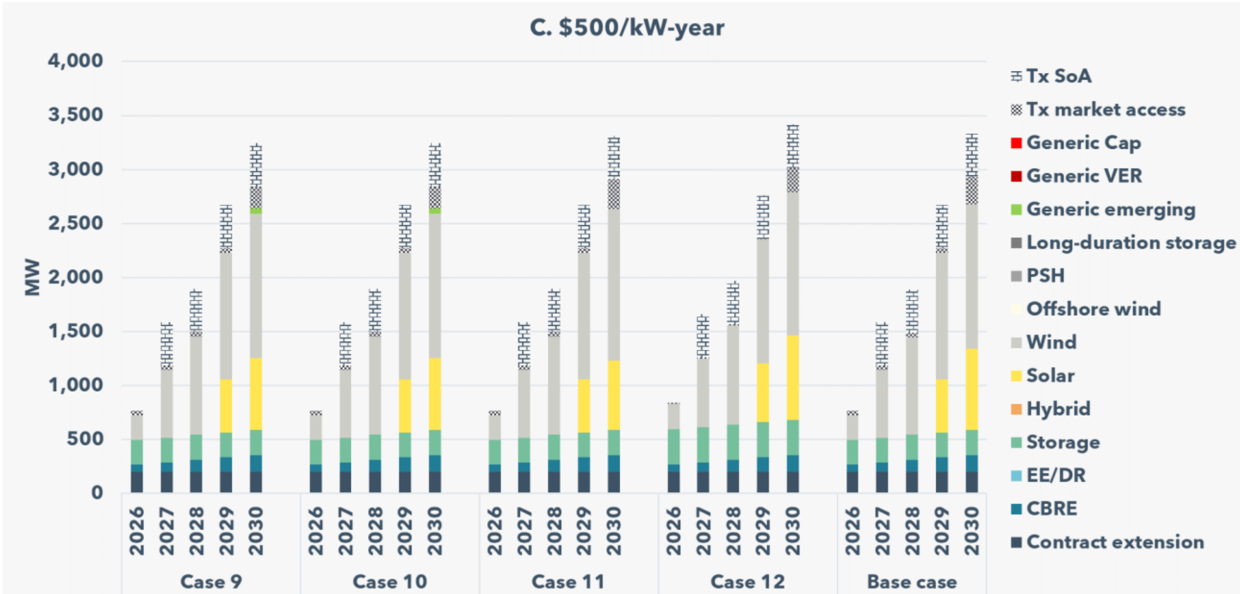
Table 66. Timing and cost of generic resource availability

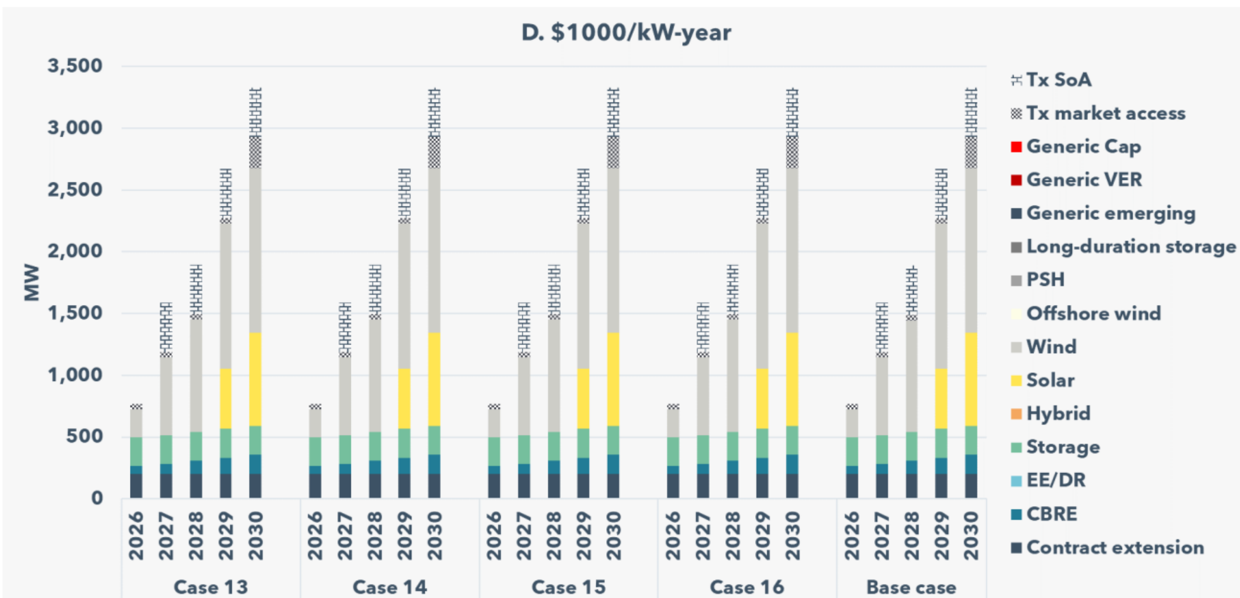
	Cost of generic resource			
Year	**$100/kW-year**	**$250/kW-year**	**$500/kW-year**	**$1000/kW-year**
2029	Case 1	Case 5	Case 9	Case 13
2030	Case 2	Case 6	Case 10	Case 14
2031	Case 3	Case 7	Case 11	Case 15
2032	Case 4	Case 8	Case 12	Case 16

The resulting resource additions are shown in **Figure 106.** When the generic emerging resource is available for $1,000/kW-year, the resource buildout of the Preferred Portfolio is almost entirely unaffected, regardless of the year it becomes available. When the generic emerging resource is available for $500/kW-year, it is selected as early as 2030, and some minor changes in resource buildout are seen across all four cases. Additions of the generic emerging resource in 2030 offset solar and transmission additions. At a cost of $250/kW-year, the generic emerging resource is selected as early as 2030 and is added in larger amounts than at a cost of $500/kW-year. When the generic emerging resource is available for $100/kW-year, it is selected in the first year it becomes available (as early as 2029). In both cases, the most notable impact on the Preferred Portfolio resource buildout is on the selection of WY and NV transmission expansion. When the generic emerging resource becomes available in 2029 or 2030, the model shifts entirely away from transmission expansion, while in the cases in which it becomes available in 2031 or 2032, transmission expansion is selected in 2030, but in smaller amounts than in the Preferred Portfolio.

Figure 106. Resource buildout of resource build robustness analysis scenarios, grouped by generic resource cost







The results of the analysis show that at prices at or above $1,000, the resource buildout of the Preferred Portfolio is unaffected and at prices at or above $500/kW-year the impacts are very slight, regardless of when the generic resource becomes available. Between $250 and $500, there is an inflection point above which the resource buildout of the Preferred Portfolio is robust to the impacts of future technological developments of emerging non-GHG emitting resource options. Transmission expansions are the most expensive proxy resources available for selection (aside from non-cost-effective DR) and are, therefore, likely to be the first additions to be offset by development of emerging technologies. However, given the rapid cost declines and technological advances that would be required for emerging resource options to develop at costs below the inflection point before 2030, these results suggest that the near-term resource additions of the Preferred Portfolio (particularly within the Action Plan window) are robust and are low regret options despite the potential for emerging technologies to disrupt resource additions in the long-term.

11.6 Informational community benefits indicators

PGE reviewed the three CBI pathways with community members and environmental justice (EJ) communities. [317] We began development of Information Community benefits indicators (iCBIs) applying Attachment A from Order 22-390.[318] By providing an initial synthesis of potential focus areas from a diverse group of energy advocates, the attachment provided a starting point for CBI development which was supplemented and refined through our engagement process.

As we continue to engage with our communities through our Community Learning Labs, and as we develop experience designing and implementing CBRE resources, we will leverage Attachment A and additional CBIs identified through our community engagement efforts. **Table 26 (Interim CBI metrics and roadmap for future development)**, found in **Section 7.1, Community benefits indicators (CBIs)**, provides an overview of the interim CBIs for the three, identified pathways that have resulted from our work so far. As we heard from our engagement sessions, PGE will update and refine these metrics through our ongoing community engagement efforts. In addition to this work, we conducted research to address Reduction in High Energy Burden and Weatherization, discussed various methods to value these benefits and what PGE needs are to calculate these values (see **Section 7.1.6, Informational community benefits indicators**, for more details).

[317] PGE defines Environmental Justice communities as communities of color, communities experiencing lower incomes, tribal communities, rural communities, coastal communities, communities with limited infrastructure and other communities historically excluded in public processes and adversely harmed by environmental and health hazards, including but not limited to seniors, youth and persons with disabilities.
[318] *See* Docket No. UM 2225, Order No. 22-390 (Oct 25, 2022), Attachment A at 65, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

11.7 Sensitivities

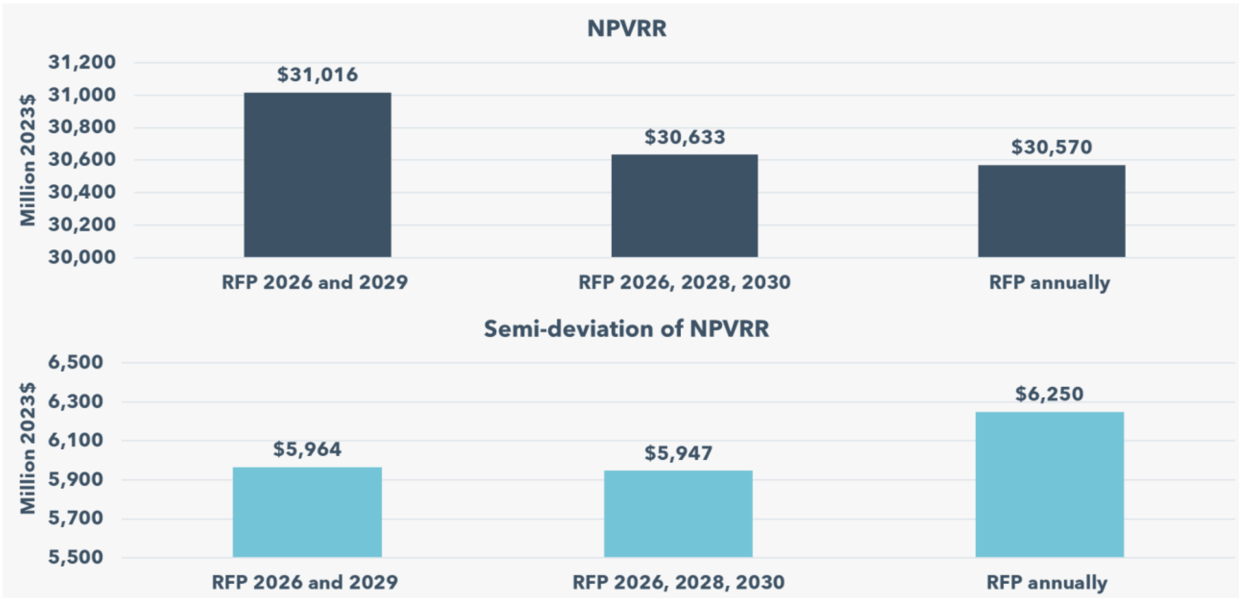
11.7.1 RFP size

Considering the unprecedented increase in the need for resource procurement to accomplish system decarbonization, further examination is needed to evaluate the timing of RFPs. To explore this topic, PGE conducted an analysis of the cost and risk impacts when the Preferred Portfolio is subjected to alternative RFP cadences and magnitude of procurement (**Figure 107**). Three scenarios were analyzed considering alternative procurement schedules by imposing constraints on annual procurement quantities through 2031 (**Table 67**). Aside from the procurement constraints, the portfolio's details match that of the Preferred Portfolio with the exception that all three RFP-size portfolios were not subjected to the energy surplus constraint to facilitate large resource additions where needed. Removal of the energy surplus constraint is necessary to allow the model to concentrate resource additions in 'RFP years', potentially adding more energy than is needed in that year to have sufficient energy in subsequent years when resource additions cannot be made.

Table 67. Procurement constraints through time in RFP size and timing scenarios

Year	Maximum annual resource addition					
	RFP 2026 and 2029		RFP Annually		RFP 2026, 2028, 2030	
	Renewables (MWa)	Storage (MW)	Renewables (MWa)	Storage (MW)	Renewables (MWa)	Storage (MW)
2026	1,000	800	180	133	400	267
2027	0	0	180	133	0	0
2028	0	0	180	133	400	267
2029	1,000	800	180	133	0	0
2030	0	0	180	133	400	267
2031	0	0	180	133	0	0

Figure 107. Cost and risk of RFP size and timing scenarios



Results of the analysis show that the case in which resource additions are limited to occurring only two times before 2032 (RFP 2026 and 2029) produces the largest costs (**Figure 107**). This result is intuitive because this case constrains the model's ability to optimize the timing of resource additions the most, and results in resources being added before they are needed to meet capacity and energy needs. As previously mentioned, the earlier resources are added, the higher costs will be because of discounting in the calculation of NPVRR and the decline in resource costs through time. It is similarly intuitive that the case in which RFP's are conducted annually, 'RFP annually' is the least-cost because the model has the most freedom to match the timing of resource additions to capacity and energy needs. The 'RFP annually' scenario has higher variability than the scenarios in which RFPs are larger and occur less frequently because in some High Need Futures it has higher NPVRR. This is a result of having less ability to match the timing of larger needs with smaller and more frequent procurement. Additionally, adding resources early may increase costs but decreases procurement risk by obtaining resources when they are available, rather than waiting and risking not being able to procure resources when they are needed. As we approach a decarbonization target that is less than 7 years away, we continue to work with regulators and stakeholders to find ways to accelerate the acquisition timeline while retaining an emphasis on engagement and feedback throughout the process. PGE has proposed a streamlined framework for the 2023 RFP within docket UM 2274 and anticipates the need for frequent and nimble procurement throughout the remainder of the decade.[319] Procurement risk associated with supply chain constraints is explored further in **Section 11.7.2, Supply chain**.

11.7.2 Supply chain

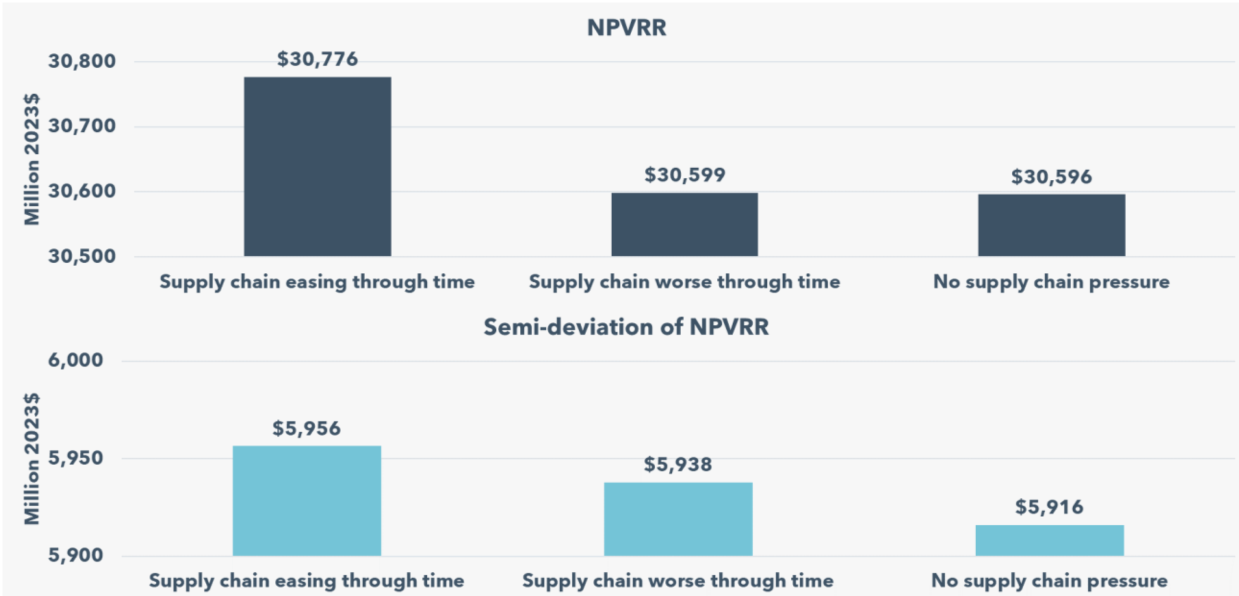
As described in **Section 3.3.3, Supply chain**, PGE's ability to procure new resources is subject to the ability of the complex global system of manufacturing, shipping and construction, known as supply chains, to produce, deliver and install the critical equipment (i.e., solar panels, wind turbines and batteries) used in energy generation facilities. PGE considered the potential impact of supply chain congestion on resource acquisition by imposing two different sets of procurement constraints. The first scenario (Supply chain pressure easing) simulates near-term supply congestions that eases through time, and the second simulates increasing congestion through time (Supply chain pressure increasing). Procurement constraints imposed for the two cases are shown in **Table 68**. The supply chain pressure cases are compared to a case with no procurement constraints, aside from the default set identified in **Section 11.1.6, Procurement constraints**.

Table 68. Procurement constraints of supply chain portfolios

Year	Maximum annual resource addition			
	Supply chain pressure easing		Supply chain pressure increasing	
	Renewables (MWa)	Storage (MW)	Renewables (MWa)	Storage (MW)
2026	150	38	400	228
2027	200	76	350	190
2028	250	114	300	152
2029	300	152	250	114
2030	350	190	200	76
2031	400	228	150	38

[319] *In the Matter of Portland General Electric Company, 2023 All-Source Request for Proposals, Request for Partial Waiver of Competitive Bidding Rules*, Docket No. UM 2274 (filed Jan 31, 2023), available at: https://edocs.puc.state.or.us/efdocs/HAA/um2274haa16364.pdf

Figure 108. Cost and risk of supply chain scenarios



Results of the analysis provide evidence suggesting that supply chain disruptions have the potential to increase the cost and risk associated with acquiring the resources needed for PGE to meet HB 2021 GHG emissions reduction requirements. As can be seen in the cost and risk metrics (**Figure 108**), both cases produce increased cost metrics compared to the unconstrained supply chain portfolio. Near-term supply chain disruptions have a larger impact on portfolio costs and risk than ones that occur further in the future. The larger magnitude of the impact on costs of near-term supply chain disruptions is due to the need to acquire resources earlier than would otherwise be necessary, when discounting has less of an effect and resources are more expensive. While the cost and risk metrics quantified in this analysis are lower if PGE waits to acquire resources, if resource acquisitions are delayed as much as possible, and supply chain disruptions occur closer to 2030, there are risks that the resources necessary to comply with HB 2021 GHG emissions reductions requirements will not be available. This suggests a tradeoff between cost-risk and compliance-risk that PGE must balance.