Chapter 8. Resource options

In this Integrated Resource Plan (IRP), we evaluate a broad set of resources to meet the needs identified in **Chapter 6, Resource needs**. To meet these system needs while reaching the emissions targets established in House Bill (HB) 2021, we focus on analyzing only commercially available technologies applicable through 2030. These resources include both distributed energy resources (DER) and supply-side options. This chapter begins with a discussion of technology trends and an exploration of candidate supply-side options tested in portfolio analysis, including energy storage and renewables. We then describe DER programs and technologies deemed non-cost-effective under prior estimates of cost-effectiveness. We conclude with discussions of how resources are expected to be integrated via Portland General Electric's (PGE's) virtual power plant (VPP), transmission, emerging technologies and the advantages and disadvantages of utility and third-party ownership of resources.

Chapter highlights

- PGE discusses utility-scale supply-side options available for meeting portfolio needs, including wind, solar photovoltaic (solar PV) and energy storage resources, among others.
- The costs and megawatt (MW) potential of additional energy efficiency and demand response are included as resource options in this IRP.
- An analysis showing the adequacy challenges of a decarbonized system based on current resource options, followed by potential long-term resource options and strategies that can help address the challenges.
- A discussion of the benefits and risks of different resource ownership structures for customers is included.

8.1 Utility-scale energy resources

8.1.1 Summary of technologies

The supply-side resources considered in this section represent technically and economically feasible options that are plausible options to meet PGE's needs through 2030. These resources are generally categorized as non-emitting renewable or storage resources. Additionally, natural gas-fueled resources are included for continuity with prior IRPs and in the event that data related to these resources are required for other regulatory proceedings. PGE relies on publicly available information to inform supply-side resource options' cost and performance parameters.[206]

8.1.2 Sources of information

8.1.2.1 Cost and performance parameters

Resource cost and performance parameters form the basis for the economic analysis of generic proxy resources in the IRP. In this IRP, PGE is generally using supply-side resource information from two sources:

- The National Renewable Energy Laboratory produces the Annual Technology Baseline (NREL ATB) to "develop and document transparent, normalized technology cost and performance assumptions" for typical generating resources in the United States.[207]
- The U.S. Energy Information Administration (EIA) commissioned Sargent & Lundy to "evaluate the overnight capital cost and performance characteristics for 25 electric generator types" to reflect these generators in the Annual Energy Outlook 2020 (EIA AEO).[208]
- Resource operating parameters are sourced from the ATB and AEO when possible. Where information needed for PGE's models is not provided in the ATB or AEO, PGE relies on information from other publicly available sources, including past IRPs. Overnight capital costs presented in this chapter are inclusive of interconnection costs. Historical inflation rates were applied to escalate from the EIA and NREL study values. Cost estimates do not explicitly account for supply chain-related disruptions experienced post-

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[206] In PGE's recent IRPs, supply-side resource cost and operating parameter information was generally developed by third-party consultants.
[207] NREL. 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/about.
[208] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy, available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/

2019.[209] These estimates do not reflect the impacts of the US Department of Commerce's investigation into the potential circumvention of tariffs on certain imported solar panels.

8.1.3 Renewable energy generation

The generation of wind and solar resources in PGE's models is based on input shapes simulated for each resource. PGE simulates hourly renewable generation using NREL's System Advisor Model (SAM). SAM is free software provided by NREL for modeling the performance and economics of renewable energy projects.[210]

8.1.4 Wind and solar weather data

Weather data for wind and solar resources are inputs to SAM (e.g., wind speed and solar irradiance). Onshore wind weather data are sourced from the NREL Wind Integration National Database (WIND) Toolkit for 2007–2014.[211] Offshore wind weather data rely on NREL's Offshore NW Pacific Dataset. The dataset comprises 20 years of weather data covering 2000–2019.[212] NREL's National Solar Radiation Database (NSRDB) is the source of weather data for solar PV simulations.[213] PGE uses NSRDB data for 1998–2020. PGE uses data available from these sources at the time of the analyses.

8.1.5 Methodology for average year Capacity Factor

As discussed in **Appendix H, 2023 IRP modeling details** PGE's energy valuation modeling (PZM simulation, conducted in Aurora) in this IRP uses a representative 8760 hourly shape of energy generation for each renewable resource.[214] These representative shapes are developed from the hourly simulations for each year of available data mentioned in this section, using the following steps:

1. Simulate 8760 hourly shapes for each year with available weather data (e.g., for 10 years of weather data, create 10 simulated 8760 hourly shapes).

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[209] This implicitly assumes that the supply chain issues are temporary.
[210] NREL SAM information, available at: https://sam.nrel.gov/.
[211] NREL WIND Toolkit information, available at: https://www.nrel.gov/grid/wind-toolkit.html and https://developer.nrel.gov/docs/wind/wind-toolkit/.
[212] NREL Offshore NW Pacific dataset information, available at: https://developer.nrel.gov/docs/wind/wind-toolkit/offshore-nw-pacific-download/.
[213] NREL's National Solar Radiation Database information, available at: https://nsrdb.nrel.gov/ and https://developer.nrel.gov/docs/solar/.
[214] In years past, the IRP utilized month-hour average energy shapes for wind and solar resources, specifically. In doing so, resource variability was potentially reduced.

2. Compute the monthly average capacity factors across the data from step #1 (average across 10 years each month).
3. For each month, choose the hourly data from the year that most closely matches the monthly average capacity factor computed in step #2 (if in January, for example, the year five capacity factor is nearest to the average from step #2, the representative shape will use the year five hourly data for January).
4. Use the hourly data from each month selected in step #3 to create the representative shape.

This process results in shapes that closely match the annual capacity factors averaged across the available weather data while maintaining the variability of the underlying hourly data. Using publicly available data from NREL is an attempt to enable transparent and comparable analysis across resources in the IRP. The resulting energy shapes and capacity factors from this analysis will differ from those experienced by resources constructed in the future. Resource developers participating in a competitive procurement process will perform detailed analyses of specific projects to optimize resource economics (cost and performance) with respect to geographic location and resource configuration, among other factors.

8.1.6 Treatment of tax credits

As discussed in **Section 2.1, Federal support for energy transition**, the Inflation Reduction Act (IRA) brought several changes to the tax credit landscape. These changes are expected to have material effects on the economic values of various generation and storage resources. When modeling resources in the IRP, the following assumptions are made:

- Tax credits will phase out over three years beginning in latter 2032, or the year in which the US electricity sector emits 75 percent less CO2 than in 2022. For modeling purposes, all tax credits are assumed to be extended through 2043 (the end of PGE's analysis time horizon). This assumption removes the possibility of tax credit expiration influencing the portfolio optimization process.
- Non-emitting generating resources qualify for 100 percent of the production- or investment-based tax credits.

- Standalone storage resources qualify for 100 percent of the investment-based tax credit without the need for normalization.[215]
- Carbon capture and hydrogen production resources qualify for specific credits outlined in the IRA.
- Tax credits are assumed to be fully monetized in the year they are generated.
- Numerous additional changes within the IRA and the IIJA are not currently built into modeling assumptions. Some of these are:
  - The EE forecast, as noted in **Section 6.2.3, Energy efficiency**, does not contemplate the IRA's tax credits, which include the Residential Energy Efficient Home Improvement Credit, that likely will increase the savings forecasted.
  - The DER forecast, as noted in **Section 6.2, Distributed Energy Resource (DER) impact on load**, also does not capture the impacts of the IRA tax credits, which include rooftop solar, electric vehicles and building electrification, that likely will result in faster adoption of these technologies.
  - The IIJA provides significant funding, which PGE is pursuing as appropriate, for the following areas of interest:
  - $23B to enhance the resiliency of the power infrastructure and investment in renewable energy.
  - $21.5B to develop clean energy demonstrations and research hubs.
  - $5B to boost energy efficiency and clean energy creation.
  - $18B to support electric vehicle (EV) charging deployment, clean transit and school buses, and other transportation electrification funding.

8.1.7 Renewable generation resources

8.1.7.1 Onshore wind

PGE analyzes proxy onshore wind resources at four locations in this IRP: Oregon Columbia River Gorge, Central Montana, Southeastern Washington and east of Casper, Wyoming. The

[215] To achieve 100 percent of the available credits, PGE's analysis assumes that prevailing wage and apprenticeship requirements are met, and that no additional tax credit adders apply, such as the those associated with domestic content, Energy Community or low-income community considerations. The adders, as noted in **Section 2.1.1, Inflation Reduction Act**, disproportionately benefit the ITC over the PTC. PGE will explore different options, including a wholly-owned affiliate, to work around the ITC normalization issue in order to promote a level playing field in future renewable solicitations, which will deliver least cost resources for customers.

Wyoming wind resource is available in PGE's analysis with an assumption of incremental transmission action.[216] For more detail on the costs and benefits associated with the incremental transmission, see **Section 9.4.1, Proxy transmission options identify transmission need**.

The resource configuration is common across the four locations, comprising 3.5 MW turbines with 136-meter rotor diameters and 105-meter hub heights. Standard resource configurations are used to focus the analysis on differences arising from locational characteristics rather than an optimized resource design. Resource cost information is based on EIA AEO data. Capital cost estimates are adjusted by geographic location based on EIA's location-based adjustment factors. Characteristics for the four onshore wind resources are summarized in **Table 28**.

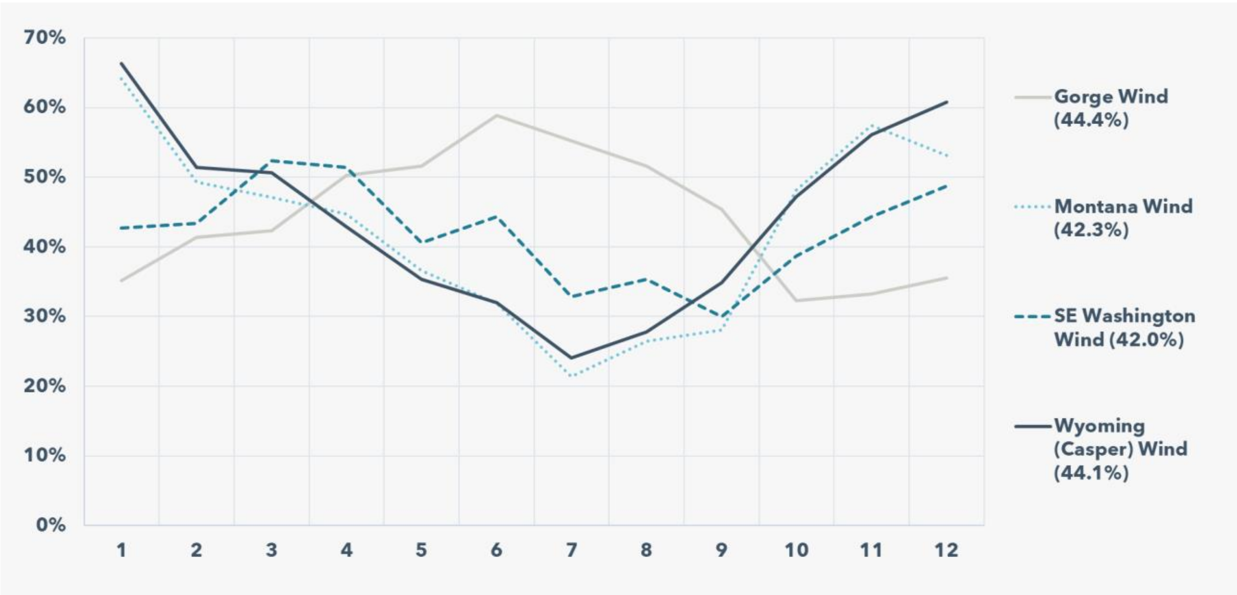
Table 28. 2026 COD onshore wind[217]

	Oregon Columbia Gorge	Central Montana	SE Washington	Casper, Wyoming
Location (Lat., Long.)	45.65, -120.63	46.35, -110.34	46.41, -117.84	43.04, -105.56
Capacity (MW)	300	300	300	300
Capacity Factor (%)	44.4%	42.3%	42.0%	44.1%
O/N Capital Cost ($/kW)	$1,503	$1,457	$1,491	$1,457

Figure 56 summarizes the shape of monthly capacity factors for the various wind resources used for energy valuation in this IRP.

[216] PGE's 2019 IRP included two Oregon-sited proxy wind resources; for purposes of streamlining the resources being analyzed, the Oregon wind site with the superior capacity factor is included in this IRP.
[217] Wind project capacity factor data are from NREL. They do not necessarily comport with historical generation values from these locations from existing projects.

Figure 56. Wind resources monthly capacity factor shapes



8.1.7.2 Solar photovoltaic (PV)

Three Oregon locations are used to represent solar photovoltaic (PV) resources in the IRP: one central Oregon (east of Cascades) location near Christmas Valley, one location with a similar longitude (east of Cascades) but farther north near Wasco and one location with a similar latitude as Wasco but in the Willamette Valley (west of the Cascades) near McMinnville. A solar PV resource near Mead, Nevada, that will be accessed via incremental transmission action is also included in PGE's analysis. Each location is modeled using identical underlying parameter assumptions, so any difference in simulated energy production is attributable to the solar resource. Resource cost and parameter information is based on NREL ATB. Capital cost estimates are adjusted by geographic location based on EIA's location-based adjustment factors. All solar PV resources use single-axis tracking. The inverter loading ratio (ILR) describes the ratio of solar array direct current (DC) capacity to inverter alternating current (AC) rating.[218] The 1.34 ILR modeled in the IRP is consistent with the NREL ATB. ILRs are also discussed further in the context of co-located, or hybrid, solar and battery energy storage resources. A selection of solar PV parameter assumptions is summarized in **Table 29**.

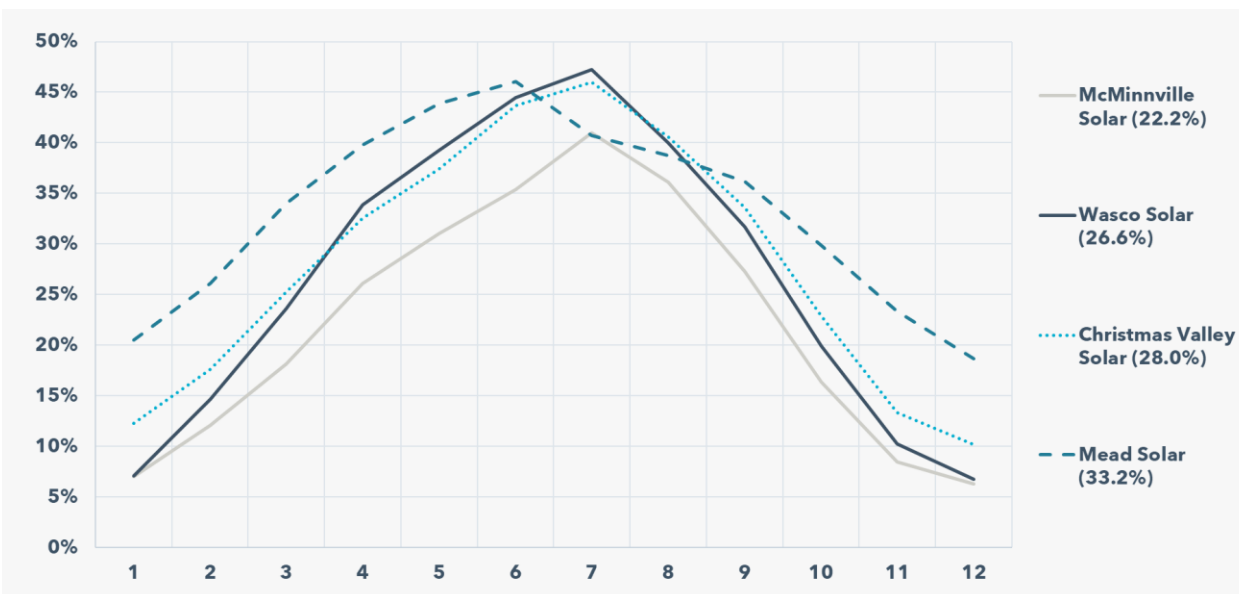
[218] An ILR greater than 1.0 means that the DC capacity of the solar array is greater than the AC capacity of the inverter. In such a configuration it is possible for the energy generation from the solar array to exceed the inverter rating resulting in the system output being limited to the inverter AC rating. This situation is referred to as "inverter clipping". The energy in excess of the inverter rating is lost and not delivered to load. All else being equal, as the ILR increases the quantity of clipped energy will increase.

Table 29. 2026 commercial operation date solar PV

	Christmas Valley, Oregon	Wasco, Oregon	McMinnville, Oregon	Mead, Nevada
Location (Lat., Long.)	43.25, -120.62	45.61, -120.7	45.21, -123.18	35.89, -114.98
Capacity (MWac)	75	75	75	75
Capacity Factor (%)	26.7%	25.3%	21.1%	31.6%
Inverter Loading Ratio	1.34	1.34	1.34	1.34
O/N Capital Cost ($/kW)	$1,297	$1,297	$1, 354	$1,297

Figure 57 summarizes the representative monthly average capacity factor for the three solar locations modeled:

Figure 57. Solar resources monthly capacity factor shapes



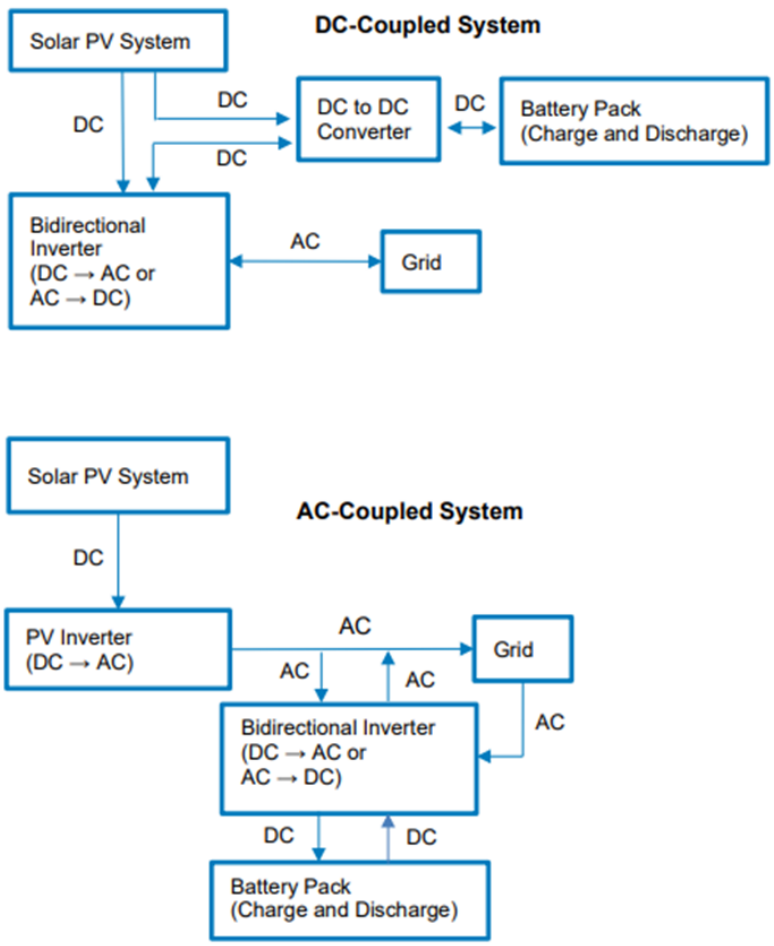
8.1.7.3 Hybrid: Solar + Storage

"Hybrid" resources pair renewable and storage resources behind a single interconnection. Hybrid resources could include solar PV with energy storage, wind with energy storage, and wind and solar PV with energy storage (such as PGE's Wheatridge Renewable Energy Facility), among others. In this 2023 IRP, PGE models solar PV with battery energy storage hybrid resources. Multiple elements are required when describing a solar + storage resource, including resource coupling (AC- or DC-coupled), solar-to-storage ratio, solar-to-inverter ratio ("inverter loading ratio" as previously described) and storage duration. Given the large number of hybrid resource permutations that would arise from investigating sensitivities around each of these elements, the IRP simplifies the analysis to include two representative solar and battery energy storage system (BESS) hybrid resources. These two hybrid resources:

- Employ a DC-coupled configuration. The solar and storage components could be coupled on the AC side of the inverters (AC-coupled) or the DC side of the inverter (DC-coupled). When AC-coupled, the battery and solar resources use separate inverters. The IRP assumption of DC coupling is consistent with the NREL ATB. **Figure 58** illustrates the essential elements of these two configurations:[219]

[219] Feldman, David, Vignesh Ramasamy, Ran Fu, Ashwin Ramdas, Jal Desai and Robert Margolis. 2021. US Solar Photovoltaic System Cost Benchmark: Q1 2020. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-77324. Available at: https://www.nrel.gov/docs/fy21osti/77324.pdf.

Figure 58. Illustrative DC- and AC-coupled solar + storage



- Differ in the ratio of solar-to-storage capacity. Similar to using ILR to summarize the solar array and inverter relationship, the solar-to-storage capacity relationship is defined in the IRP as the ratio of the storage resource capacity to the inverter rating. The two representative hybrid resources tested in this IRP are differentiated by this ratio, with one resource featuring a storage power capacity equivalent to the inverter rating (1.0) and one with a storage power capacity equal to one-half of the inverter rating (0.5).
- Use the Christmas Valley and McMinnville solar locations as discussed; however, the solar resources differ regarding the inverter loading ratio. While the standalone solar resource is modeled with an ILR of 1.34, the hybrid solar resource has an ILR of 1.50. A potential benefit of DC-coupled hybrid solar PV and BESS, since both resources are on the DC side of the inverter, is the ability of the battery to capture energy from the solar PV resource that would otherwise be “clipped” by the inverter.
- Use storage resources with a four-hour storage duration, consistent with NREL modeling assumptions.

The optimal configuration of hybrid or co-located resources will likely depend on the cost and performance characteristics of the specific resource components. This includes both the generating (wind, solar, etc.) and storage resource technologies. Prior to the passage of the IRA, energy storage resources could qualify for the investment tax credit (ITC) only when paired with a solar generating resource (and sourcing at least a minimum amount of the charge energy from that resource). As mentioned, the IRA introduced an ITC for standalone energy storage resources, removing one of the primary benefits associated with this resource configuration. However, the prevalent regional transmission constraints suggest that important benefits of co-locating renewables and storage remain.

A summary of the NREL ATB-sourced costs and parameters for the hybrid solar PV and BESS resources modeled in the IRP is provided in **Table 30**. Capital cost estimates are adjusted by geographic location based on EIA's location-based adjustment factors.

Table 30. 2026 COD solar PV and battery energy storage

	Christmas Valley Solar w/ 4 Hour Li-Ion (0.5)	Christmas Valley Solar w/ 4 Hour Li-Ion (1.0)	McMinnville Solar w/ 4 Hour Li-Ion (0.5)	McMinnville Solar w/ 4 Hour Li-Ion (1.0)
Location (Lat., Long.)	43.25, -120.62	43.25, -120.62	45.21, -123.18	45.21, -123.18
Duration (hours)	4	4	4	4
Solar ILR	1.50	1.50	1.50	1.50
Solar capacity (MWdc)	112.5	112.5	112.5	112.5
Solar capacity (MWac)	75	75	75	75
Storage capacity (MW)	37.5	75	37.5	75
Overnight (O/N) capital cost ($/kW)	$1,796	$2,297	$1,848	$2,348
O/N capital cost ($/kWh)	$449	$574	$462	$587

8.1.7.4 Offshore wind

NREL Oregon offshore wind studies are the basis for PGE's modeling of offshore wind in this IRP.[220] The NREL studies present five proxy resources distributed across the Oregon coast. For this IRP, PGE uses the southernmost of these proxy resource locations. This southern location provides the highest expected capacity factor from NREL's and PGE's modeling. This site also closely aligns with the Brookings wind energy Call Area identified for potential lease by the federal Bureau of Ocean Energy Management (BOEM).[221]

Consistent with NREL study assumptions for a 2032 commercial operation date, IRP modeling reflects 15 MW turbines with 248-meter rotor diameter and 150-meter hub height. Other modeled characteristics are summarized in **Table 31**.

Table 31. 2032 COD offshore wind

Southern Oregon	
Location (Lat., Long.)	42.69, -124.84
Capacity (MW)	960
Capacity Factor (%)	55.2%
O/N Capital Cost ($/kW)	$3,546

8.1.7.5 Geothermal

The representative geothermal resource in the IRP is modeled based on hydrothermal flash technology, as provided in the NREL ATB (Annual Technology Baseline). Given the site-specific nature of geothermal resources, the representative resource assumes a typical temperature and depth. NREL notes that costs heavily depend on these factors, requiring site-specific studies to improve accuracy.[222] These costs are summarized in **Table 32**.

[220] Musial, Walter, Patrick Duffy, Donna Heimiller and Philipp Beiter. 2021. Updated Oregon Floating Offshore Wind Cost Modeling, available at: nrel.gov/docs/fy22osti/80908.pdf.
[221] BOEM. Oregon Call Areas, available at: https://www.boem.gov/sites/default/files/images/or_callareas_april2022.jpg
[222] NREL. 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/geothermal

While hydrothermal technology is relatively mature, future resource opportunities may include developing so-called enhanced geothermal systems (EGS). EGS resources differ from hydrothermal resources as they require engineering to promote the flow of underground fluids. See the additional discussion related to geothermal resources in **Section 8.5, Post-2030 resource options**.

Table 32. 2026 COD geothermal

Geothermal	
Capacity (MW)	40
O/N Capital Cost ($/kW)	$5,123

8.1.8 Energy storage resources

Two energy storage resources are included in the IRP and discussed in the following sections:

- Battery Energy Storage Systems
- Pumped-Hydro Storage

8.1.8.1 Battery Energy Storage System (NREL)

The representative battery energy storage systems (BESS) costs and performance characteristics are based on lithium-ion technology. These data are sourced from the NREL ATB for durations up to eight hours; IRP cost assumptions for longer durations apply the NREL ATB methodology of scaling the energy component costs and are derived from the same energy and power cost estimates.[223] By maintaining a representative technology assumption across durations, any analytical results between these resources are driven by the costs and benefits of the duration changes alone, not the details of their operating parameters. Costs and characteristics for the BESS resources are summarized in **Table 33**.

[223] NREL. Utility-Scale Battery Storage, available at: https://atb.nrel.gov/electricity/2021/utility-scale_battery_storage

Table 33. 2026 COD battery energy storage

	2 Hour Li-Ion	4 Hour Li-Ion	6 Hour Li-Ion	8 Hour Li-Ion	16 Hour Li-Ion	24 Hour Li-Ion
Capacity (MW)	50	50	50	50	50	50
Duration (hours)	2	4	6	8	16	24
Round-Trip Efficiency	86%	86%	86%	86%	86%	86%
O/N Capital Cost ($/kW)	$773	$1,189	$1,606	$2,022	$3,687	$5,353
O/N Capital Cost ($/kWh)	$386	$297	$268	$253	$230	$223

8.1.8.2 Pumped-Storage Hydro

The pumped-storage hydro resource is a 600 MW closed-loop system. The availability of this resource is geographically limited. Costs and performance attributes of this representative resource are based on an average of proposed regional closed-loop projects gathered from information published by the Northwest Power and Conservation Council; a summary of that information is provided in **Table 34**.[224]

Table 34. 2026 COD pumped-storage hydro

Pumped-storage hydro	
Capacity (MW)	600
Duration (hours)	10
Round-trip efficiency	80%
O/N capital cost ($/kW)	$2,912
O/N capital cost ($/kWh)	$291

[224] NW Power and Conservation Council Generating Resource Reference Plants, available at: https://www.nwcouncil.org/2021powerplan_pumped-storage_generating-resource-reference-plants/

8.1.9 GHG emitting resources

Three natural gas-fired generators are included in this IRP:

- F Class simple-cycle combustion turbine unit
- H Class combined-cycle com combustion turbine unit
- H Class combined-cycle combustion turbine unit with CO2 capture and storage
- Closed-loop biomass

Each resource is modeled with fuel supplied at a price assumed for AECO-delivered natural gas.[225] See **Section 4.5, Uncertainties in price forecasts**.

8.1.9.1 Simple-cycle combustion turbine and combined-cycle combustion turbine

The simple-cycle combustion turbine (SCCT) and combined-cycle combustion turbine (CCCT) are based on EIA's cost and performance parameter estimates. The SCCT is representative of an F-class unit. The combined-cycle combustion turbine (CCCT) resource is based on EIA's representation of a 1 x 1 H-class unit. Lifetime net capacity and heat rate are summarized in **Table 35**.

Table 35. 2026 COD SCCT and CCCT

	Simple-cycle CT	Combined-cycle CT (1 x 1)
Capacity (MW)	227	407
Heat rate	10,042	6,564
O/N capital cost ($/kW)	$830	$1,325

[225] Wood Mackenzie. "North American Power & Renewables H1 2022 Long-Term Outlook."

8.1.9.2 Combined-cycle combustion turbine with CO2 capture system

The cost and parameters for CCCT with CO2 capture system (CCS) resources are based on those produced by EIA.[226] The H-class combined-cycle unit is similar in configuration and specification to the traditional resource described previously. In addition to the CCCT, the resource includes an amine-based CO2 capture system designed to remove 90 percent of the CO2 from exhaust gases. The costs of CO2 storage are not included in the EIA cost estimates; as such, these costs are derived from Hunter to represent an estimate of the total resource cost.[227]

The configuration and auxiliary power requirements for the CO2 capture system operation result in an approximately 40 MW decrease in the net capacity of this resource relative to the CCCT without the CO2 capture previously described. Similarly, the resource is less efficient, resulting in a higher heat rate than the CCCT without CO2 capture (**Table 36**).

Table 36. 2026 COD CCCT with CO2 capture

CCCT w/ CO2 capture system	
Capacity (MW)	367
Heat rate	7,271
O/N capital cost ($/kW)	$2,720

8.1.9.3 Biomass

The biomass-fueled resource uses bubbling fluidized bed boiler technology to drive a steam turbine. Emissions controls include overfire air in the combustion process, with selective catalytic reduction and a baghouse post-combustion. The EIA AEO is the basis for resource cost and operating parameter data. Wood chips serve as the fuel in this closed-loop system. Biomass fuel prices are based on Wood Mackenzie forecasts (**Table 37**).[228]

[226] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy. 93–98.
[227] Hunter *et al.*, "Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high variable renewable energy grids." Available at: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3720769
[228] Wood Mackenzie. "North American Power & Renewables H2 2020 Long-Term Outlook."

Table 37. 2026 COD closed-loop biomass

	Biomass
Capacity (MW)	50
Heat rate	13,300
O/N capital cost ($/kW)	$7,186

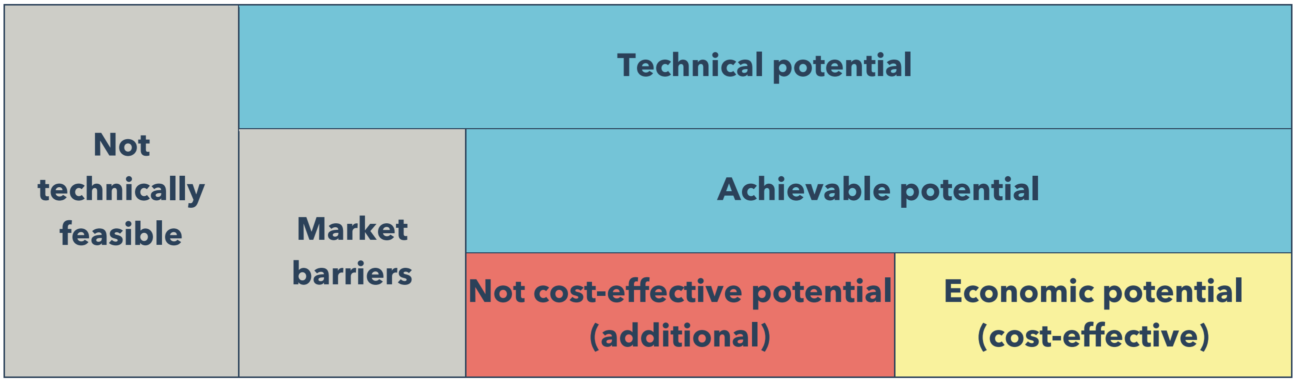
8.2 Additional distributed energy resources

In **Section 6.2, Distributed Energy Resource (DER) impact on load**, we focus on the market adoption of passive DERs (rooftop solar, transportation electrification and building electrification) and the cost-effective or economic potential, as highlighted in yellow in **Figure 59**. This IRP, like prior IRPs, includes the entire market adoption and cost-effective DERs forecast upfront when determining total load, as shown in **Section 6.3, Load scenarios**. While this process has been sufficient in the past to estimate DER impact in the IRP, the processing time between the IRP and developing the next DER potential could lead to suboptimal planning, especially in a rapidly evolving planning environment. The need to evaluate additional EE beyond cost-effective levels was also noted in Order 20-152.[229] PGE has taken steps to address this lag within resource planning by evaluating additional energy efficiency and demand response opportunities within the IRP, highlighted in red in **Figure 59**.

Additional DER or non-cost-effective DERs refer to energy efficiency and demand response technologies, measures or programs included in the Achievable Potential but were deemed non-cost-effective under the previous set of avoided costs developed for UM 1893 in 2021 and the DSP in 2022. Thus, additional DERs represent the difference between the Achievable potential and Economic potential for that DER. This is illustrated in **Figure 59**, which also highlights the relationship between the different DER potentials evaluated.

[229] *In the Matter of Portland General Electric, 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

Figure 59. The different potential assessments of DERs



In this IRP, we have developed a process to analyze these additional DERs previously deemed non-cost-effective through portfolio analysis. Traditionally, this is done outside of portfolio analysis using IRP inputs described in **Chapter 10, Resource economics Energy value, Capacity value, Cost of clean energy**, and **Section 10.8, Resource net cost**. Introducing the non-cost effective DERs within the portfolio has the following analytical differences:

- The IRP ELCC's method to determine capacity contribution ensures resource interactions between the DER and other resources are captured. Based on the resource's operational characteristics, this may lead to a higher or lower capacity contribution.
- The impact of transmission quality and availability significantly affects the capacity contribution and economics of supply-side options. Potential economic tradeoffs between higher fixed-cost resources, such as DERs, and avoiding additional transmission buildout, are captured within portfolio analysis.

If selected through portfolio analysis, it would provide early indications of the expected changes to upcoming avoided costs of demand response and energy efficiency, which are procured across different channels including the Energy Trust of Oregon (ETO) and PGE's demand response programs. The following sections describe the additional energy efficiency and demand response potential.

8.2.1 Additional energy efficiency

PGE worked with ETO to develop non-cost-effective or additional energy efficiency resources, leveraging the 2021 energy efficiency potential assessment to determine which list of measures did not pass the cost-effectiveness screen based on the 2021 values in UM 1893 and their associated characteristics, such as load shape, cost and expected life.

ETO provided 67 unique energy efficiency measures over the planning horizon. To optimize the modeling approach, PGE adopted a similar process as the Northwest Power and Conservation Council and aggregated energy efficiency measures into discrete bundles (or 'bins') based on the measures' levelized cost. The levelized costs are used to determine the bin size, which is the MW potential of the resources within that bin by year. Costs and design life for each bundle or bin is based on a weighted average of the measures within weighted by their megawatt average (MWa) potential. PGE also included benefits based on the UM 1893 filing,[230] by including a commensurate reduction in the fixed costs resulting from a distribution deferral credit, a regional Power Act credit of 10 percent and a risk reduction value.

Table 38 summarizes each bin for 2026, highlighting fixed costs, MWa potential and associated end uses. As the bins are developed based on levelized cost, the number and proportion of end use in each bin evolves with each year. End uses represent an aggregated set of unique measures referencing different market opportunities. For example, if we examine weatherization end uses in bins 3 and 4, we see that they contain different weatherization measures that apply to different types of buildings with different heating fuels:

- Weatherization in Bin 3 includes opportunities such as residential floor insulation, new construction manufactured housing space heating, retrofit opportunities for attic insulation and residential windows for homes heated with electricity.
- Weatherization in Bin 4 includes opportunities for residential wall insulation for homes heated with electric space heat and residential wall insulation and double pane windows in existing homes with gas heating and electric air distribution systems.

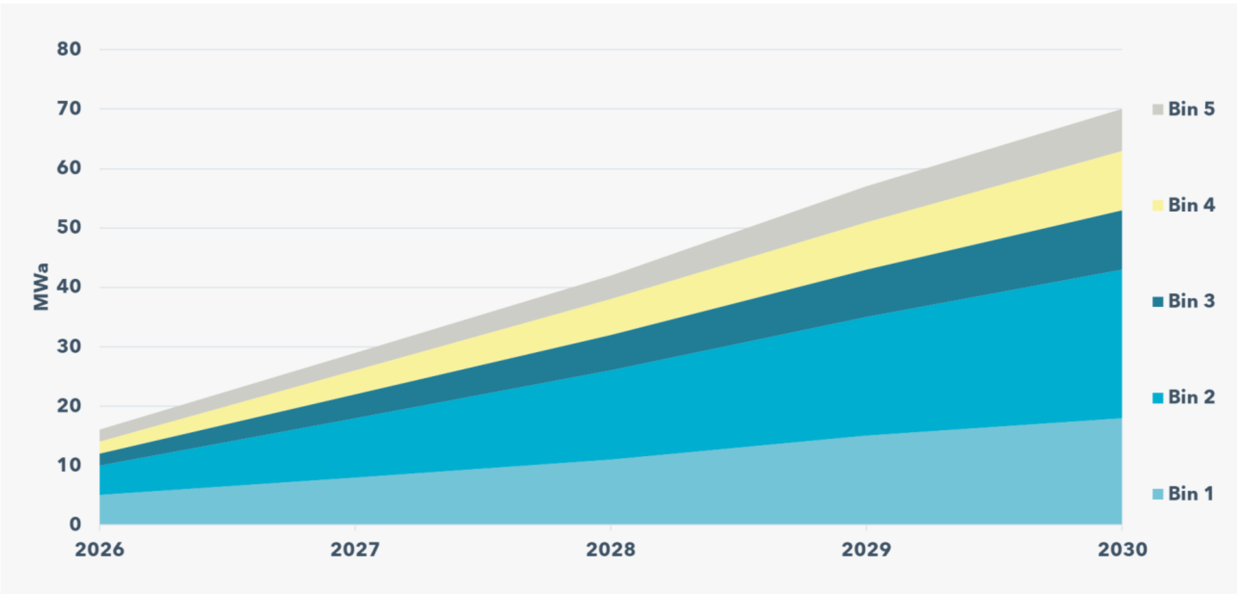
Table 38. The costs and additional potential of each EE bin in 2026

Bin	Fixed costs ($/kW-yr.)	MWa potential	End uses
1	687	5	Ventilation, lighting
2	1,486	5	Heating, weatherization, refrigeration
3	1,369	2	Lighting, weatherization
4	2,771	2	Cooling, weatherization
5	10,884	2	Weatherization

[230] PGE's updated UM 1893 avoided costs are available in ETO's presentation at the October 3, 2022 workshop, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAH&FileName=um1893hah161441.pdf&DocketID=20999&numSequence=45

Figure 60 describes the cumulative potential by bin from 2026 through 2030. While each bin has a combination of residential and commercial measures, commercial measures represent ~58 percent of the savings over the same period and residential represent the remaining ~42 percent.

Figure 60. Cumulative additional EE MWa potential through 2030



8.2.2 Additional demand response

Leveraging a similar approach for demand response as with energy efficiency, we have bundled the additional or non-cost-effective demand response programs identified by the DSP into four bundles or bins based on their dispatch characteristics and costs. **Table 39** summarizes each bin for 2026, followed by a brief description of the measures included in that bin for the year 2026.

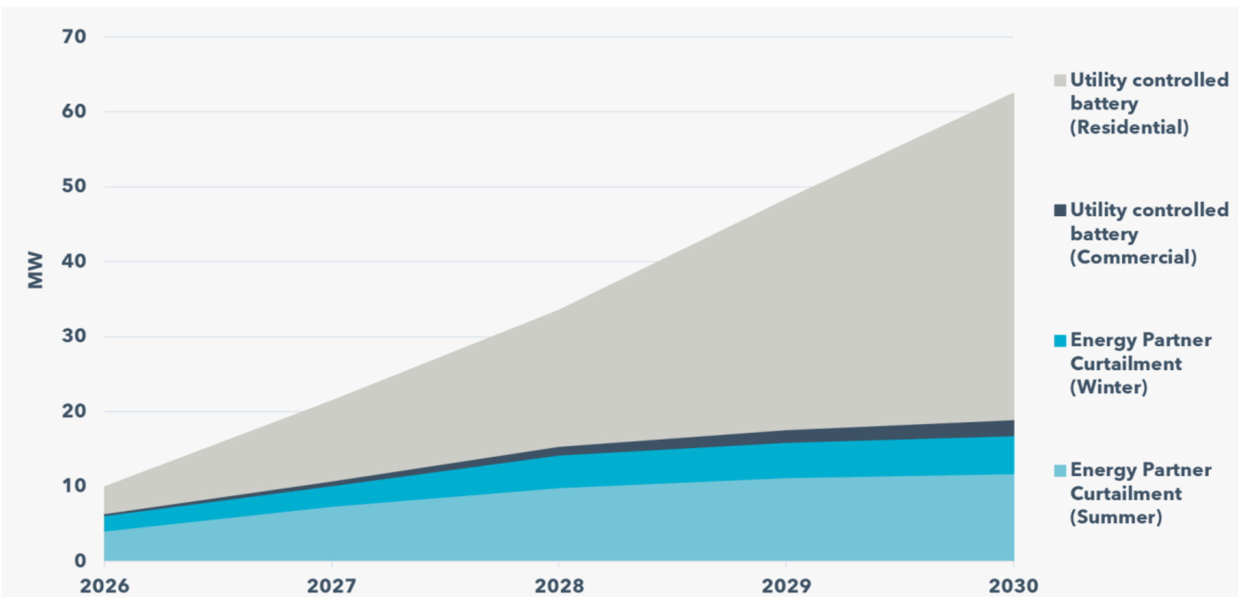
Table 39. Costs and potential of additional demand response opportunities in 2026

Measure	Fixed costs ($/kW-yr.)	MW
Energy Partner Curtailment (summer)	$499	4.1
Energy Partner Curtailment (winter)	$1,177	2.0
Utility controlled battery (commercial)	$453	0.3
Utility controlled battery (residential)	$660	3.6

- **Energy Partner Curtailment (summer and winter).** Represent the group of technologies that can deliver value within PGE's Energy Partner program, which dispatches seasonally during peak periods during weekdays and weekends.
- **Utility controlled batteries (commercial and residential).** Represents the batteries installed in partnership with customers and controlled by PGE for optimal dispatch. Optimal dispatch by PGE can offset variable power costs reducing costs for customers or can be used for reliability purposes, reducing potential market exposure risk during higher prices. PGE will conduct optimal dispatch through its VPP as described in **Section 8.4, Virtual Power Plant (VPP)**.

Figure 61 describes the cumulative potential through 2030. Residential batteries represent ~25 percent of the total MW potential.

Figure 61. Cumulative additional DR potential through 2030



8.3 Community-based renewable energy resources

Section 7.2, Community-based renewable energy (CBRE), describes the overall process PGE followed under the Community Lens Potential study. PGE identified three proxy resources for CBRE for inclusion in portfolio analysis:

- Community-scale standalone solar
- Community resiliency microgrid
- In-conduit hydropower

8.3.1 Community-scale standalone solar

PGE modeled the community-scale standalone solar proxy resource from a combination of sources. Cost assumptions were taken from the Oregon Community Solar program filing and include additional program administration and marketing costs typically associated with these resources.[231] PGE used the cost data for the "community-based carve out projects" to inform resource modeling, with an assumed efficiency factor of 20 percent cost savings from the historical baseline to account for expected economies of scale from a broader-based procurement effort.[232]

Performance features (such as capacity factor and resource shape) of the community-scale standalone solar proxy resource were modeled after a solar resource located in Boring, OR. A selection of solar PV parameter assumptions is summarized in **Table 40**.

Table 40. Performance and cost parameters of community-scale solar CBRE

Community-scale standalone solar	
Location (Lat., Long.)	45.45, -122.38
Capacity (MWac)	50
Capacity factor (%)	18.30%
Inverter loading ratio	1.2
O/N capital cost ($/kW)	$1,992

8.3.2 Community resiliency microgrid

The community resiliency microgrid CBRE proxy resource was modeled after the hybrid resources described in **Section 8.1.7.3, Hybrid: Solar + Storage**, with the solar resource component of the microgrid being the same as assumed for community-scale standalone solar described in **Section 8.3.1, Community-scale standalone solar.** Cost components, including advanced controls and islanding costs associated with the microgrid design, were used from PGE's Distribution System Plan (DSP).

The proxy microgrid resource was assumed to have a fixed ratio of solar and storage in a 2:1 ratio, such that 1 MW of storage resource was added for every 2 MW of solar PV. However, in

[231] See *In the Matter of Public Utility of Commission of Oregon, Community Solar Program Implementation*, Docket No. 1930, Staff Report for the September 21, 2021, Special Public Meeting, available here: https://edocs.puc.state.or.us/efdocs/HAU/um1930hau175534.pdf.
[232] *Id.*, Table 5 at 17, includes the upfront costs in $/kW for the carveout projects that PGE used as a starting point for analysis.

practice, the microgrid sizing and design will be location-specific and heavily dependent on the goals of the local community. For instance, system sizing decisions will differ depending on the amount and type of critical loads the microgrid supports, as well as the community preference for longer- or shorter-duration support during an outage.

PGE expects that certain projects that fall under this resource type will be eligible for federal funding opportunities under the IIJA, but because these are project-specific opportunities (as opposed to generic tax credits like the ITC), they are not reflected as a cost-reduction in IRP modeling.

8.3.3 In-conduit hydropower

The capacity factor for in-conduit hydropower resource in the IRP is modeled based on a study conducted by Oak Ridge National Lab.[233] PGE reviewed the capacity factor and other performance assumptions of the in-conduit hydropower resource and determined that it closely approximates the resource characteristics of the biomass resource described in **Section 8.1.9.3, Biomass.**

8.4 Virtual Power Plant (VPP)

Through both the DER adoption forecasts discussed in **Section 6.2, Distributed Energy Resource (DER) impact on load** and the resource options listed in **Section 8.2, Additional distributed energy resources**, and **Section 8.3, Community-based renewable energy resources**, PGE is preparing for significant growth of distributed resources. In resource adequacy calculations and portfolio analysis (discussed in **Chapter 11, Portfolio analysis**), PGE assumes that all resource types can be integrated into PGE's system and orchestrated to deliver their full potential system value. However, extending this assumption to smaller and/or behind-the-meter resources requires advancement of PGE's ability to monitor, schedule and dispatch resources in an optimized manner. To ensure realization of the full value of these resources, PGE is coordinating resource deployment and operation through a VPP.

PGE's VPP comprises DERs and flexible loads managed through a technology platform to provide grid and power operations services. The VPP will incorporate and optimize the operation of DERs and flexible loads by connecting them through the VPP platform to provide services they would not be able to provide in isolation. The VPP will be an important

[233] Oak Ridge National Lab, "An Assessment of Hydropower Potential at National Conduits" October 2022. Available at: https://info.ornl.gov/sites/publications/Files/Pub176069.pdf. Capacity factor assumptions are on page 30.

tool for identifying and extending DER and flexible load benefits to customers and communities seeking local clean energy investments.

The progression of the VPP will allow us to activate the full value of DER capabilities assumed in IRP modeling. Over time, the number of VPP operations will grow from 139 events in 2022 to many thousands and eventually millions as we go from discrete event operation to real-time energy management. Resource orchestration will be managed by a VPP technology platform, which will provide real-time visibility and control of generation, flexible loads and batteries residing within the distribution network.

VPP implementation will provide analytics that can support improved accuracy of DER and flexible load modeling in IRP analysis, as well as program cost-effectiveness evaluation and DER acquisition actions.

8.5 Post-2030 resource options

In **Chapter 6, Resource needs**, the IRP discusses future resource adequacy needs. In 2040 there is a roughly 2,000 MW increase in need due to natural gas fueled power plants no longer being available to meet retail load.[234] As a result of this need, and earlier capacity and renewable needs, most portfolios require over 3,000 MW of transmission expansion and/or generic GHG free dispatchable resources.

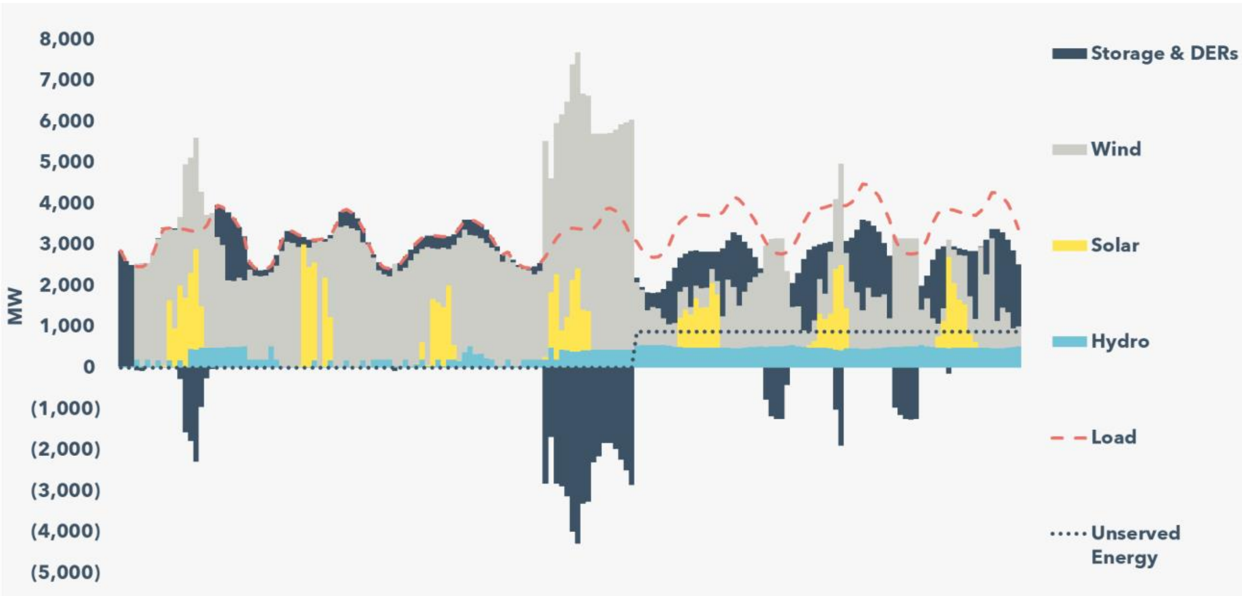
To test what happens if the assumed transmission expansion options and generic non-emitting resource are not available after 2030, PGE simulated an example power system in year 2040 with existing supply-side options available. In this example system, 6,000 MW nameplate of Northwest located wind, 6,000 MW of Northwest located solar and 6,000 MW of storage are added to the system in addition to existing resources (GHG emitting resources, like natural gas power plants, are not available in 2040 for meeting Oregon retail load). Despite adding 18,000 MW of new resource, the system still has adequacy challenges, particularly during winter days of low wind and solar generation.

A one-week example of these adequacy challenges is shown in **Figure 62**. [235] In this example, the model starts the week resource adequate, but in the last three days no longer has enough energy to meet load. Energy stored in the batteries is exhausted and there is not enough wind and solar generation available to recharge the storage and/or meet load (storage recharging is shown in the graph in negative values). The lack of energy is due to a multiday period in which both wind and solar locations in the Northwest are unproductive

[234] In 2040, per HB 2021, PGE must serve retail load with 100 percent non-emitting power. This 2040 increase in capacity needs could be reduced if the existing natural gas plants were converted to use an alternate GHG fuel source.
[235] This study was run with an earlier (spring 2022) version of Sequoia.

due to a lack of wind (reducing wind generation) and shorter winter daylight hours combined with cloud cover (reducing solar generation).

Figure 62. Example week in 2040 with only Northwest resources



As discussed earlier, the Northwest located resources provide insufficient diversity to always ensure power generation. This highlights the need for alternative resources and/or expanded transmission networks, from a geographic and/or technological perspective, to achieve longer-term GHG emission reductions while maintaining reliability. This section provides a summary of potential future resource options that PGE has considered in the 2023 IRP beyond transmission expansion to other regions.[236]

8.5.1 Hydrogen and ammonia

Hydrogen's high energy content makes it useful as an energy carrier and fuel source. On Earth, hydrogen exists naturally only in compound form with other elements, the most common being water (H_2O). Hydrogen and oxygen molecules in H_2O can be separated from one another using a process called electrolysis.[237] Hydrogen gas is combustible and it releases no CO2 when burned, which means it can provide an emissions-free fuel source.[238]

[236] While many of these resources are not included in IRP portfolio modeling, PGE may explore them in greater depth in future planning work. PGE may also explore other resource options not discussed in this section/IRP.
[237] Hydrogen production via electrolysis is done using equipment called an electrolyzer.
[238] When produced in an emissions-free manner.

One of the biggest challenges of achieving a fully decarbonized electricity system is the need for generating resources that are dispatchable, flexible and available for long durations. This is a role that is currently filled primarily with natural gas plants in today's system. Similar to natural gas, hydrogen can be used as fuel in combustion-based dispatchable electricity generating facilities, making it well-suited to providing these types of services in a decarbonized system. Hydrogen gas can be stored for long durations and used to generate power when needed, making it a complementary technology on a system with large buildouts of VERs. In such a system, electrolyzers could be powered by excess renewable energy in times of oversupply, producing hydrogen than can be stored for long durations and used to generate power when needed.

Hydrogen fuel can be used in power plants built specifically to run on hydrogen or in existing natural gas generating facilities with turbines that have been retrofitted with combustors designed to handle hydrogen fuel. Depending on the combustor technology used, appropriately equipped plants can use a fuel blend ranging from 0 percent to 100 percent hydrogen. PGE has over 1,800 MW of existing natural gas plants that could continue to provide dispatchable capacity in a fully decarbonized system if retrofitted to run on 100 percent hydrogen fuel. This represents substantial amounts of emission-free dispatchable capacity, with larger amounts possible through purpose-built facilities. Electricity generation in combustion-based power plants is far from a novel technology and while there are costs associated with retrofit, this part of the hydrogen electricity pathway is unlikely to present substantial development challenges or to be the main driver of development costs of this technology.

The largest costs and development challenges associated with this potential option for decarbonizing PGE's system are likely to be associated with development of hydrogen production, transportation and storage infrastructure. Transportation and storage infrastructure are likely to have large costs and long project lead-times, with hydrogen's low energy content by volume presenting storage and transportation challenges because of the large volumes required relative to natural gas. However, issues caused by hydrogen's low energy content by volume can be mitigated by conversion into ammonia, which has higher energy density and can be used as fuel in a similar manner as hydrogen. The production of hydrogen also has substantial capital costs associated with electrolyzers and variable costs of power used to drive the energy-intensive electrolysis process. Declines in these costs through technological innovation and economies of scale in manufacturing of electrolyzers and high penetration of VERs on the grid that lower power costs will be important developments needed to lower the barriers to hydrogen development.

Opportunities for government funding aimed at supporting the development of hydrogen production and transportation infrastructure could substantially lower the barriers to hydrogen playing a role in decarbonizing PGE's system. For example, in June of 2022, the US Department of Energy (US DOE) announced an $8 billion program associated with the

Bipartisan Infrastructure Law to fund the development of regional clean hydrogen hubs.[239] Additionally, the Inflation Reduction Act of 2022 (IRA) created clean energy tax credits, similar to those that have contributed to unprecedented development of wind and solar over the past decade, that apply to clean hydrogen production.[240]

8.5.2 Nuclear

Nuclear power is a mature technology, with the first commercial power generating reactors coming online in the 1950s, and hundreds of operating reactors around the world. Nuclear power provides both baseload capacity and non-emitting energy to the power system.

Although nuclear power has many positive characteristics, like non-emitting baseload generation, traditional large nuclear reactors also have hurdles to overcome. Nuclear power safety accidents, while rare, can be catastrophic and are often followed by public and political pushback on the technology. Recent large reactor nuclear builds in the US, like Vogtle units 3 & 4, have seen construction cost overruns and timeline delays (both units are currently in testing, with Unit 3 recently achieving criticality and expected in-service in Q2 2023).[241] Additionally, in Oregon, Measure 7 prohibits the construction of a new nuclear power plant in Oregon without a federal long-term nuclear waste repository and a statewide popular vote. Public dislike of nuclear power, largely due to safety concerns, led to multiple ballot measures in Oregon aimed at closing Trojan, a nuclear power plant operated by PGE that closed in 1992.[242] Oregon law does not prohibit PGE from purchasing nuclear power produced in a nearby state, subject to standard prudency review.

There is optimism that new generation nuclear plants will be competitive in the electric power landscape and reduce safety and political concerns of more traditional designs. UAMPS, a collective of smaller utilities in the US West, is planning to build a small modular reactor nuclear power plant. The project reactor design recently received US Nuclear Regulatory Commission certification (a first for Small Modular Reactor designs).[243] The reactor design has passive safety features, including being able to shut down and cool without operator action or power.[244] In their 2021 IRP, PacifiCorp identified a 500 MW sodium cooled fast reactor nuclear power plant with molten salt storage to come online in 2028.

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[239] Available at: https://www.energy.gov/articles/doe-launches-bipartisan-infrastructure-laws-8-billion-program-clean-hydrogen-hubs-across
[240] Available at: https://www.energy.gov/eere/fuelcells/financial-incentives-hydrogen-and-fuel-cell-projects
[241] Vogtle 3 & 4 were initially estimated to cost around 14 billion, more recent estimates are over 30 billion.
[242] The ballot measures failed; Trojan closed early in 1992 due to repair costs following a maintenance check.
[243] Available at: https://www.energy.gov/ne/articles/nrc-certifies-first-us-small-modular-reactor-design.
[244] Available at: https://www.nuscalepower.com/en/products/voygr-smr-plants.

Both the UAMPS and PacifiCorp nuclear projects have not begun construction. It remains to be seen if next generation nuclear technology can lower the cost, safety and political hurdles faced by traditional nuclear power. If it can, nuclear power could play a role in replacing existing dispatchable GHG emitting generation with non-emitting power that has similar characteristics.

8.5.3 Geothermal

Geothermal energy is the heat contained in the Earth's interior. Electricity generation from geothermal resources is generally achieved by the recovery of heat in the form of hot water or steam accessed via injection and production wells drilled into the Earth. Resources are broadly categorized as either hydrothermal or enhanced geothermal systems (EGS) depending on the characteristics of the groundwater and subsurface rock structure.[245] Geothermal resources are non-emitting and are expected to operate at an 80-90 percent capacity factor.

The US Geological Survey estimates nine gigawatts (GW) of electrical generation capacity are available from identified hydrothermal resources in the US.[246,247] Of this, approximately 3.5 GW have been developed, all in the WECC (except for the Puna plant in Hawaii).[248] An additional 30 GW may be present in favorable, yet undiscovered, hydrothermal resources. Over 95 percent of regional geothermal capacity is in California and Nevada. Roughly 30 percent of California's geothermal capacity is at Calpine's nearly 700 MW The Geysers project north of Santa Rosa.

The hydrothermal potential (discovered and undiscovered) in Oregon is estimated to be 2.4 GW. EGS development in Oregon could support electrical generation capacity of more than 60 GW. The only commercial geothermal project currently operating in Oregon is the Neal Hot Springs plant near Vale in eastern Oregon. The nearly 30 MW project, which began operation in 2012, is jointly owned by Ormat and Enbridge with Idaho Power as the off taker.[249]

[245] Hydrothermal resources are those where the naturally occurring rock structure and groundwater flow are sufficient to support energy recovery. EGS resources have sufficient heat but lack either the groundwater or rock structure to allow for efficient energy recovery, thus requiring the use of engineering techniques to introduce liquid or allow for the flow of liquid within the rock structure.
[246] USGS. "Assessment of Moderate- and High-Temperature Geothermal Resources of the United States." Menlo Park, CA: US Geological Survey, 2008. Available at: https://pubs.usgs.gov/fs/2008/3082/pdf/fs2008-3082.pdf.
[247] NREL. 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/geothermal.
[248] S&P Global Market Intelligence.
[249] S&P Global Market Intelligence.

An EGS demonstration project at Newberry Volcano (southeast of Bend, Oregon) is being developed.[250] The developer reports that commercial deployment of EGS technology at this site may be possible by 2030.[251] The approximately 3 MW Paisley Geothermal plant in Lake County, Oregon, is out of service per EIA reporting.

Factors that may restrict the development of geothermal resources include:[252]

- Difficulties in locating new resources (undiscovered);
- Technological challenges related to the development of and production from EGS resources over relatively long periods of time;
- Issues surrounding permitting, land access and environmental reviews may extend project development timelines;
- The general constraints to availability of transmission capacity discussed elsewhere in this IRP may apply to this resource site.

Future improvements in drilling technologies will result in reduced development time and costs. Developments in EGS stimulation technology and higher success rates will also reduce costs and development timelines.[253]

8.5.4 Renewable natural gas

Renewable natural gas (RNG) is a fuel derived from biogenic and other renewable sources that offers the potential of use within existing natural gas pipelines. Today RNG is commonly produced from waste streams found in landfills, wastewater treatment plants and animal manure. The American Gas Foundation estimates that under a high resource potential scenario the US could produce more than 4,500 trillion British thermal units (BTU) of renewable natural gas by 2040, which can serve 93 percent of current average residential gas usage nationally (the low resource potential study found roughly 60 percent less RNG available by 2040).[254] Oregon's DOE found nearly 50 billion cubic feet of potential renewable natural gas sources in Oregon, enough to replace around 20 percent of the state's current

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[250] Available at: https://www.energy.gov/eere/geothermal/enhanced-geothermal-systems-demonstration-projects
[251] Available at: https://www.businesswire.com/news/home/20210923005253/en/AltaRock-Energy-Initiates-Development-of-First-SuperHot-Rock-Geothermal-Resource
[252] USGS. "Assessment of Moderate- and High-Temperature Geothermal Resources of the United States." Menlo Park, CA: US Geological Survey, 2008. Available at: https://pubs.usgs.gov/fs/2008/3082/pdf/fs2008-3082.pdf.
[253] NREL. 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/geothermal
[254] American Gas Foundation, "Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment," 2019.

gas usage (this represents 10 billion cubic feet from biogenic sources and an additional 40 billion from thermal gasification, which currently faces technical obstacles).[255]

The integration of RNG into PGE's existing plants could potentially provide PGE a means to retain thermal generation at lower or zero GHG emissions. This would provide dispatchable capacity for periods of low renewable generation and/or elevated demand. However, there is uncertainty around if RNG will be considered GHG emissions free.[256] If GHG emissions are attributed to RNG usage it then becomes a bridge solution that could reduce emissions between 2023-2039.

RNG is not currently a scalable option for PGE due to its limited supply. While the ODOE has estimated that biogas could offset roughly 20 percent of the state's current natural gas use, there currently are only a few facilities that generate RNG. An economic push due to higher natural gas prices and the effect of directed state, local and federal policies could potentially increase both the number of RNG facilities and the quantities they produce.

8.5.5 Long-duration energy storage

Long-duration energy storage (LDES) is defined as any electricity storage with greater than six hours of duration. These storage options perform the same function as those described earlier in **Sections 9.1.8, Energy storage resources,** however their extended durations allow them to provide supply over longer times of need. This provides a better ability to maintain resource adequacy in larger times of system stress, and IRP modeling has demonstrated a more effective capacity per MW than shorter duration storage.[257] This section describes the wide variety of long duration storage technologies being developed.

Chemical energy storage resources convert electrical energy into an intermediate state and back using a chemical process. Currently lithium-ion batteries are the most common storage options on the market and are discussed in detail in **Chapter 11, Resource Economics**. Other chemical storage options include flow batteries. Longer duration batteries may soon be more widely available. For example, Great River Energy, a Minnesota Utility, is working to develop a multiday iron air battery.[258] Hydrogen storage is another long duration chemical storage option (discussed earlier in this section). Power can also be stored by converting electricity into potential energy with physical work, then reversing that process to discharge

[255] Oregon Department of Energy, Biogas and Renewable Natural Gas Inventory SB 334 (2017) – 2018 Report to the Oregon Legislature, available at: https://www.oregon.gov/energy/Data-and-Reports/Documents/2018-RNG-Inventory-Report.pdf
[256] The California Air Resources Board (CARB) shows the Carbon Intensity Values of Certified Pathways of Bio-CNG (RNG) as being significantly less than LNG and CNG (geological natural gas). The Carbon Intensity Values of Certified Pathways table was last updated on December 30, 2022. LCFS Pathway Certified Carbon Intensities | California Air Resources Board.
[257] See **Appendix J, ELCC sensitivities** for more detail
[258] https://greatriverenergy.com/company-news/battery-project-includes-minnesota-flair/

back to the grid. This process of mechanical energy storage includes pumped storage hydro, compressed air storage and other storage technologies.

Thermal energy storage converts electricity into heat, stores the heat in a medium and then converts it back into electricity. For example, concentrating solar power often uses molten salt for energy storage.[259]

As more variable energy resources are expected to arrive on both the PGE system and the greater Western Interconnection, there may be increased opportunities to use storage to shift energy from oversupply hours to hours of greater need/value. Forecasted oversupply trends are discussed in IRP **Appendix N, Renewable curtailment**. PGE will continue to track trends in long duration storage and evaluate how new products can potentially bring value to the power system.

8.5.6 Carbon capture, utilization and storage

Carbon capture, utilization and storage (CCUS) is the process of capturing CO2 emissions produced by the combustion of fossil fuels so it can be stored or used in downstream processes. CO2 emissions can be captured through a process in which CO2 is separated from other gases by chemical absorption or physical separation during the power generation process. This is done using equipment that employs chemical “scrubbers” that bind to CO2 molecules, capturing them before they are released into the atmosphere. Such equipment can be installed on existing or new power plants. Once captured, the CO2 can be compressed and then stored or sequestered in underground geologic formations or utilized as a feedstock in downstream industrial applications.

CCUS could help PGE achieve a reliable decarbonized system by allowing existing or new natural gas plants to serve as non-emitting dispatchable resources. As noted previously with regards to hydrogen, PGE’s over 1,800 MW of existing natural gas fired power plants represent a substantial amount of dispatchable capacity if retrofitted to become non-emitting resources.

The most substantial barriers to the use of CCUS as a tool for decarbonizing PGE’s system are costs and technological maturity. CCUS costs are high relative to other technologies and globally there is currently only one operational commercial power plant equipped with CCUS (Boundary Dam coal plant, Canada)[260] after the other that existed was shut down due to persistent mechanical failures.[261] The ability of CCUS systems to convert fossil fuel plants to

[259] https://www.energy.gov/sites/default/files/2018/09/f55/Concentrating-Solar-Thermal-Power-FactSheet.pdf
[260] Boundary Dam Carbon Capture Project (saskpower.com)
[261] https://www.reuters.com/article/us-usa-energy-carbon-capture/problems-plagued-u-s-co2-capture-project-before-shutdown-document-idUSKCN2523K8

completely non-emitting is unproven and most CCUS projects today target 90 percent capture of emissions.[262] In order for CCUS to play a role on PGE's system beyond 2040, the technology would need to be able to capture 100 percent of emissions.

Substantial opportunities for government funding have the potential to both advance the technological development and reduce costs of CCUS. There is a federal tax credit for \$50/MT of captured CO2 that is geologically stored and \$35/MT if the CO2 is used as opposed to stored.[263] Additionally, the Bipartisan Infrastructure Bill appropriates significant funding for the development of CCUS, including: \$3.5 billion for a Carbon Capture Technology program and CCUS large-scale projects over the next five years; \$3.5 billion for four regional direct air capture (DAC) hubs. \$2.5 billion for a ODOE carbon storage program; and establishment of a new Carbon Dioxide Transportation Infrastructure Finance and Innovation (CIFIA) program to provide \$2.1 billion in low-interest loans to large CO2 pipeline projects (up to 80 percent of costs).[264]

8.5.7 Regional integration

A regional market administered through a Regional Transmission Organization (RTO), or an Independent System Operator (ISO) provides several key functions that can yield regional benefits. Key regional benefits that can help address the adequacy needs of 2040 include:

- **Common resource adequacy standards** across the region enable the opportunity to share capacity and capture regional diversity across a larger geographical footprint enabling reduction in planning reserve margins which reduce overall resource need.
- **Shared transmission planning** allows resource planning to inform transmission planning and vice versa. This broadens the set of capacity expansion alternatives that can reduce the overall size (nameplate MW) of the system needed to meet system needs. Additionally, shared transmission planning through an organized market yields governance benefits that can assist with cost and benefit allocation conflicts. This in turn increases the likelihood of successful construction and commissioning of a transmission project. Lastly, with shared transmission planning spanning a larger footprint of customers, the risk per customer is lowered.
- **A single market operator** can dispatch resources more efficiently and at lower production costs while optimizing use of transmission capacity, a key constraint within the region.

262 https://climate.mit.edu/ask-mit/how-efficient-carbon-capture-and-storage#:~:text=CCUS%20projects%20typically%20target%2090,will%20be%20captured%20and%20stored.
263 The Tax Credit for Carbon Sequestration (Section 45Q) (fas.org)
264 Bipartisan Infrastructure Bill Invests Billions in CCUS | Holland & Hart LLP - JDSupra

Today, PGE is part of or interested in multiple voluntary regional programs ranging from short-term capacity or resource adequacy programs such as the Western Resource Adequacy Program (WRAP) to real-time or energy imbalance programs such as the Western Energy Imbalance Market (EIM). These programs are focused on short-term market operations and are commonly designed to unlock key operational benefits such as price arbitrage, load diversity, improved visibility, reduced area control error etc. While these benefits are critical, they are usually unable to support long-term reliability planning needs. Consequently, these programs, given their current structure, are unable to address the 2040 needs highlighted earlier.

For this IRP, PGE described the Western Resource Adequacy Program (WRAP) in **Section 11.1.2, Resource adequacy**, including program details, benefits and its applicability in this and future IRPs. Additionally, PGE has also modeled a portfolio that explores the benefits of participating in an organized market by 2030. This is further detailed in **Section 11.4.7, Emerging technology portfolios.**

8.5.8 Coastal generation

There are several coastal energy technologies that could become commercially available inside the IRP planning horizon. In Oregon the PacWave South test bed is under development to evaluate different wave energy technologies and eyeing a 2025 online date.[265] The test bed will allow for various types of wave energy technologies to be evaluated. PGE will continue to follow the development of wave and other coastal technologies as they mature. Offshore wind, another coastal energy technology, is discussed in **Section 8.1, Utility-scale energy resources**.

8.6 Utility versus third-party ownership

The following section addresses the requirements outlined in IRP Guideline 13 of the Public Utility Commission of Oregon (OPUC or the Commission) Order No. 07-002 by providing a high-level discussion of the advantages and disadvantages of owning a resource instead of purchasing power from another party. This discussion, however, is not intended as specific recommendations for the IRP portfolio modeling or Action Plan process.

In this IRP, procurement action plans are designed to use technology-neutral procurement processes to allow PGE to pursue resources with the key attributes identified in the Preferred Portfolio. However, PGE does not procure the specific resource types in amounts set forth in the Preferred Portfolio. Instead, PGE preserves the flexibility to pursue various technologies

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[265] https://today.oregonstate.edu/news/osu-led-wave-energy-testing-facility-reaches-key-construction-milestones

and resource locations that may deliver maximum value to customers. With dynamic technology development and pricing changes, we continue to be open to opportunities that would secure lower cost from projects bid into a Request for Proposals (RFP) that may diverge from the modeled technologies in the IRP Preferred Portfolio.

8.6.1 Benefits of utility resource ownership

Utility-owned resources provide multifaceted advantages to customers, including resource control, long-term access, fleet efficiency, physical and digital security integration, cost-of-service rate making benefits and reduced exposure to counterparty performance.

8.6.1.1 Operational autonomy

Customers benefit from utility-owned resources when utilities elect to change operations, determine maintenance practices, implement system upgrades or make any other decision that advances customers' best interests. When resources are under contract with a third-party, a utility's ability to make changes to third-party owned resources are generally restricted. Therefore, a utility is generally prevented from making any operational change at a third-party owned resource, regardless of the customer benefit associated with such a change.

8.6.1.2 Long-term access

Customers also benefit from reduced customer costs and risks when a utility decides to extend the operating life of a utility-owned asset. Direct ownership of a utility-owned resource provides long-term access to the asset and associated resource potential since the utility has prioritized rights to the site in addition to the holding of necessary permits, transmission rights and interconnection rights.

8.6.1.3 Alignment among owned resources

Operating utility-owned resources also provides utilities with the ability to design co-location resources to fit customer needs. Port Westward Unit 2 is an example of a co-location design decision where PGE was able to augment existing resource locations to cost save for customers while adding capacity to meet needs. Port Westward Unit 2 was put in the existing Port Westward site, where operations and maintenance are shared among resources. In doing so, the usable life of the site was extended, and fixed cost was reduced.

8.6.2 Risks of utility resource ownership

Utility resource ownership may come with the risk of production underperformance. Another risk of utility resource ownership is the significant increase in revenue requirement at the beginning of the resource's useful life and having this substantial cost increase impact customer prices.

Owning a resource also imposes on the utility the responsibility to deliver and integrate the resource to the power grid.

8.6.3 Benefits of third-party ownership

When a utility enters a contract with a power producing third-party, the project risk of the power plant is shared by both parties. In general, the terms of the agreement allocate some of the risks associated with construction of the project to the power producing third party. The reduced risk for the utility reduces the risk passed onto customers.

8.6.4 Risks of third-party ownership

There are contractual and operational risks associated with third party-owned resources. A utility is locked into specific contract arrangements for the duration of the contract, usually twenty to thirty years. Such long-duration commitments can introduce operational, market or regulatory compliance risks.

8.6.5 Resource ownership considerations

In general, PGE intends to engage in RFP processes that adhere to the competitive bidding rules to assess the resource ownership structure that will best serve customers from a delivery, cost and environmental standpoint. In the upcoming RFP, PGE is contemplating submitting a benchmark to encourage competitive bidding and solicitations from a wide range of resource technologies and structures that will provide the best value for customers. PGE is evolving the RFP process to objectively weigh the benefits and risks of the various ownership structures during the RFP process to make the best decisions about resource ownership for customers.

Note that in evaluating projects from an RFP process, each project is assessed using project-specific characteristics such as project development maturity, resource performance, resource pricing and counterparty capability. This level of detail is unique to the RFP selection process and does not apply to proxy resources included in the IRP evaluation. Proxy resources are designed to represent technology options rather than specific projects.