Chapter 6. Resource needs

This chapter quantifies the drivers of system demand and their impact on energy, capacity and system flexibility need. Estimating these values is the first critical step in ensuring resource actions result in an adequate system that meets decarbonization and other policy objectives while minimizing long-term costs and risks.

Chapter highlights

- Load growth, expiring non-GHG emitting resource contracts and decreasing retail sales from existing thermal resources drive the need for more non-GHG emitting resources through the planning horizon.
- The load forecast has increased since the 2019 Integrated Resource Plan (IRP) Update due primarily to higher industrial load growth projections. In addition, the persistent impacts of COVID-19 have increased residential usage.
- Distributed energy resources (DERs), including transportation and building electrification, are having a more significant impact on total Portland General Electric (PGE) loads as compared to past IRPs.
- Capacity needs step upwards in 2026 and grow through the planning horizon due to expiring contracts, exiting resources and load growth. In the Reference Case, the 2028 capacity need is 624 megawatts (MW) in the summer and 614 MW in the winter.
- Flexibility needs in 2026 are estimated at 80 MW in the Reference Case, growing to 122 MW in 2030.
- Although capacity needs increase in both summer and winter throughout the planning horizon, climate change drives relatively more need in the summer and less need in the winter.

6.1 Load forecast

PGE's estimated demand for electricity is called its 'load forecast.'[116] Our load forecast has been influenced by rapidly evolving trends (such as those related to COVID-19 or extreme temperatures) and the slower-moving, longer-term trends in energy deliveries. Each is accounted for in different ways. The primary components of PGE's load forecast are:

- Top-down econometric load forecast: This model comprises two segments that capture business cycle impacts and long-term trends. **Section 6.1.1, Top-down econometric load forecasting**, describes the top-down econometric forecast mode and **Section 6.1.2, Load trends**, describes current load trends.[117]
- Incremental impacts associated with passive DERs: The impact of nascent and rapidly evolving end uses, including transportation electrification, rooftop solar and building electrification, is forecasted in PGE's Distribution System Planning process. The load impacts of DERs are accounted for in **Section 6.2, Distributed Energy Resource (DER) impact on load**.

6.1.1 Top-down econometric load forecasting

PGE's top-down forecasting models take an econometric approach by estimating the relationships between PGE service area historical load and exogenous drivers. These exogenous drivers include seasonal and weather variables and macroeconomic indicators (population, employment and income) used to describe regional economic trends.

Weather, specifically ambient temperature, is the most significant factor affecting customer electricity demand. PGE uses several weather variables in its energy and peak models, including heating and cooling degree days and wind speed. Energy use is also correlated with economic activity. PGE's econometric models forecast monthly energy deliveries by customer class and peak demand for the total PGE system. The primary model inputs are weather, population, employment, income, customer counts and historical loads. **Appendix**

[116] The Corporate Load Forecast is described in Section 3.3 of PGE's DSP, available at: https://assets.ctfassets.net/416ywc1laqmd/46I2n65SyTv3TUMMdq1l55/a993aebb7b7a84ebd3209d798454a33a/DSP_Part_2_-_Chapter03.pdf

[117] *In the Matter of Portland General Electric Company, 2019 Integrated Resource Plan*, Docket No. LC 73, Order No. 21-129 (May 3, 2021), Appendix A at 5 states: "Staff concurs with CUB that the impact of large customers in the industrial load forecast should be closely monitored. Staff supports PGE's plan on page 8 of its Reply Comments to 'review… peer electric utility industrial load forecasts and… summarize findings in an IRP roundtable participant discussion during the next IRP.'" PGE presented results of its benchmarking of economic drivers used in peer regional electric utilities' industrial load forecasts and performance of a broad range of economic drivers in PGE's industrial load forecast model at the July 22, 2021, public roundtable meeting to meet this commitment. Available at: https://apps.puc.state.or.us/orders/2021ords/21-129.pdf

H, 2023 IRP modeling details, provides additional details on the models that constitute this IRP top-down forecast and how those models were tested and selected.

Econometric models assume that certain structural relationships captured represent the future. In addition, PGE's Reference Case load forecast incorporates several key model input assumptions:

- **COVID Recovery:** An indicator variable is used in PGEs models to capture the impact of COVID-19 on energy deliveries. The input assumption for this variable implies how those impacts taper during the forecast period. While we expect this input to continue to evolve to reflect current expectations, this IRP forecast assumes the long-term equilibrium for residential customers was reached in mid-2022. This level is estimated to be approximately 30 percent of the impact seen in the early months of the COVID-19 lockdowns.
- **Weather:** PGE's load forecasts reflect normal or expected weather conditions throughout each year. For this IRP, the expected weather conditions are represented by a trended model for heating and cooling degree days to reflect the gradually warming regional climate. The forecasts do not attempt to predict, for example, an El Niño winter, a particularly hot summer or any weather event in any given year. A discussion of additional climate analysis is included in **Section 6.9, Climate adaptation**.
- **Direct access:** Customers with approximately 270-megawatt average (MWa) of combined commercial and industrial load in PGE's service area have opted out of PGE's cost-of-service (COS) supply rates and receive energy from electricity service suppliers (ESS).[118] In IRP Guideline 9, in Order No. 07-002, the Commission prohibits the inclusion of long-term direct access customer loads in long-term planning for both energy and capacity needs.[119] This IRP portfolio analysis excludes these customer loads. However, as discussed in **Section 3.1.6, Local climate action planning** nine counties and cities served by PGE have already established climate-related goals through community processes and plans, and at least four more are in the process of developing plans. These plans typically cover a variety of goals and objectives, including those concerning greenhouse gases, energy use, transportation, waste, land use, health and safety, and economic development. **Table 5** captures a list of local governments with existing plans (or in some phase of developing one) and some key electricity and emissions goals.

Several cities and counties have timelines for their decarbonization goals that align with our HB 2021 targets. For those local governments that want to decarbonize on a faster timeline, PGE's Green Future Enterprise and Green Future Impact are being used to support clean

[118] This includes 1-year direct access (STDA), long-term direct access (LTDA) and new load direct access (NLDA) schedules.
[119] *In the Matter of Public Utility Commission of Oregon, Investigation Into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 (Jan 8, 2007) at 19, available at: https://apps.puc.state.or.us/orders/2007ords/07-002.pdf

energy goals. Many of our large commercial and industrial customers also use these and other programs to meet their decarbonization goals.

PGE has been working with local governments since 2020 to develop a community-supported renewable program to support those local governments that have adopted community-wide climate goals. During the 2021 legislative session, PGE worked in partnership with several of our local governments to pass language within HB 2021. The program will allow local governments to work with PGE to accelerate the procurement of non-emitting energy to meet their climate goals. Since the bill's passage, PGE staff have been meeting regularly with local governments to solicit feedback on the design so that the program will meet their goals and desired approach. As PGE continues to engage with local governments, collectively we will determine the right time to file the tariff to support the program.

- Regulatory policy: Direct access, this interpretation presents reliability and cost risks to cost-of-service supply customers. Consistent with prior IRPs, PGE includes one-year direct access customers in its IRP planning because they may return to PGE's COS rates with little notice.

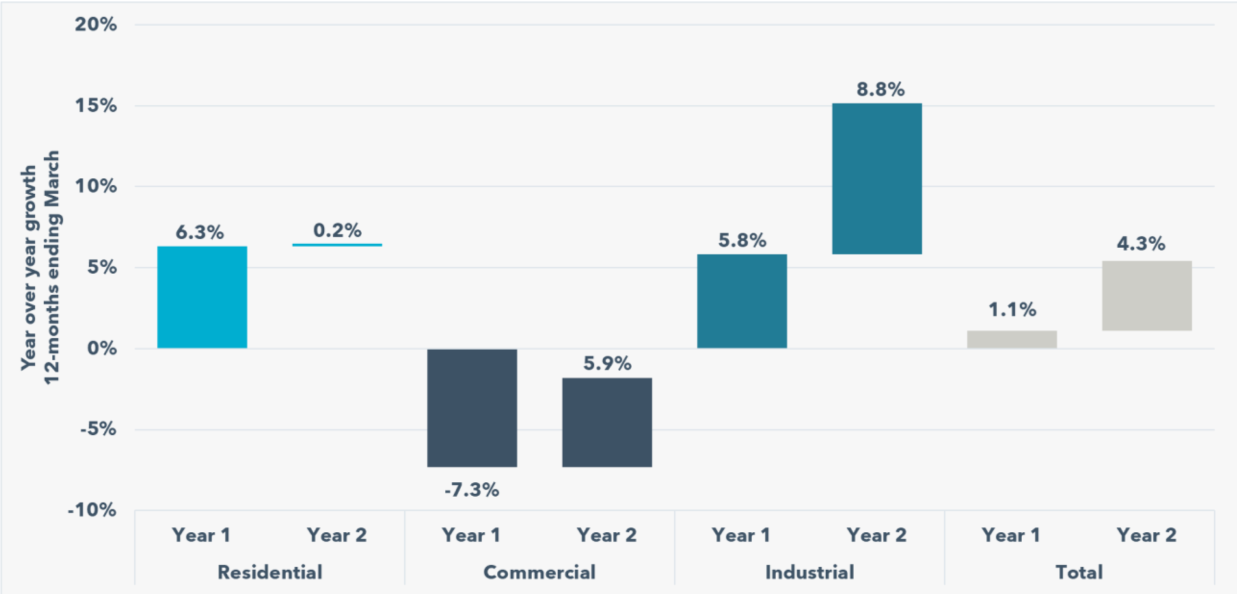
6.1.2 Load trends

6.1.2.1 Impact of COVID-19

Recent load trends (marked by the impact of COVID-19) have influenced how PGE's customers use electricity. The prevalence of work-from-home policies increased average residential usage, which remains high. As these changes to remote work will persist, we believe the impact of the last two years marks a longstanding change in average residential usage. In the commercial segment, initial shutdowns had a stark but short-lived impact on energy deliveries. We believe prior structural relationships, including long-term trends and relationships to macroeconomic indicators, hold true. PGE's industrial segment was impacted least by COVID-19 and has grown since the 2019 IRP.[120] **Figure 31** depicts changes in usage between customer classes since the March 2020 lockdowns.

[120] *In the Matter of Portland General Electric Company, 2019 Integrated Resource Plan*, Docket No. LC 73, filed July 19, 2019.

Figure 31. PGE's annual energy deliveries growth since the initial COVID-19 lockdown



Given the limited duration since the onset of COVID-19, PGE used out-of-model forecast adjustments to account for COVID-19 in its 2019 IRP Update load forecast.[121] Since the 2019 IRP Update load forecast was finalized, PGE developed a methodology to account for COVID-19 in its econometric models by using indicator variables to reflect various stages of closure and recovery. This method applies to most, but not all, of PGE's forecast segments and is discussed in further detail in **Appendix D, Load forecast methodology**. The evolution of the modeling approach was shared with stakeholders in IRP Roundtables, first on October 28, 2020, when out-of-model adjustments were used as a temporary approach, and then on July 22, 2021, where the indicator variable approach was presented.

6.1.2.2 Industrial growth

Energy deliveries to PGE's industrial segment have increased rapidly over the past few years. Industrial growth has been focused on the semiconductor manufacturing and data center segments. The construction of new customer facilities continues at a rapid pace as discussed in **Chapter 3, Planning environment**.

With respect to electric load, the number of projects and the average project size assessing sites in PGE's service area for new data center projects have increased. Additional projects may see investment opportunities associated with CHIPS and Science Act funding in coming years. The realization and timing of large projects present heightened uncertainty around

[121] Docket No. LC 73, PGE's Integrated Resource Plan Update, filed January 29, 2021.

PGE's load forecast. However, the rate at which the industrial sector incorporates energy efficiency also presents uncertainty in demand.[122]

6.1.2.3 Severe temperature

Since the 2019 IRP, PGE's service area experienced an unprecedented maximum temperature event, the "heat dome" of June 2021, and the warmest month on record in August 2022 based on average temperature.[123] Concurrent with these events came unprecedented hourly peak demands. PGE's net system peak on June 28, 2021, set a new system record at 4,453 MW. During the summer of 2022, PGE's net system exceeded 4,000 MW - a load level not seen in over 10 years prior to 2021 - on nine different days, including reaching 4,100 on five consecutive days in late July. These events, coupled with more time spent in the home due to work-from-home policies and national macroeconomic trends of strong consumer expenditures on home upgrades, will likely continue the long-term trend of increasing saturation of air conditioning in PGE's service area. Air conditioner saturation is included in PGE's peak demand forecast. Several sector-level energy delivery models have been modified to account for this additional cooling demand.

In addition to extreme heat events, winter weather continues to be a significant driver of PGE's peak loads. On December 22, 2022, PGE's service area set a record for its winter season net system peak at 4,113 MW. This event occurred during severe weather, with a daily average temperature of 23 degrees Fahrenheit at Portland International Airport and surpasses PGE's prior winter system peak set in 1998. This event highlights that while PGE has transitioned towards a summer peaking service area, the regional climate still faces the challenges of planning for a dual peaking system.[124]

6.1.3 Load uncertainty

All forecasts have inherent uncertainty. For example, uncertainty is associated with the model input data, the selection of the model itself and the relationships established within it, and factors external to the model. To reflect uncertainty in the model input data and the

[122] PGE and the ETO presented opportunities for energy efficiency at data centers at the February 2023 IRP roundtable; greater adoption by the industrial sector could mitigate demand growth.
[123] Mesh, Aaron. "August Was Portland's Hottest Month Ever: The key factor: warm nights." Willamette Week (Sept 2, 2022, 2:14 pm PDT), available at: https://www.wweek.com/news/environment/2022/09/02/august-was-portlands-hottest-month-ever/#:~:text=The%20key%20factor%3A%20warm%20nights.&text=This%20August%20was%20the%20hottest,record%3A%2074.1%20in%20July%201985. Accessed October 27, 2022.
[124] **Appendix I, C-level analysis**, provides discussion on how extreme temperature can impact system GHG emissions. These extreme weather trends were first discussed in the "Climate Change Projections in Portland General Electric Service Territory" that PGE commissioned Oregon State University's Oregon Climate Change Research Institute, Prepared by Meghan Dalton. The report is available in Docket No. LC 66, PGE's 2016 Integrated Resource Plan (filed Nov 15, 2016) at 391, available at: https://edocs.puc.state.or.us/efdocs/HAA/lc66haa144338.pdf

relationships estimated in the load forecast, PGE empirically develops high- and low-load growth scenarios. These scenarios focus on alternate futures for macroeconomic drivers and incorporate stochastic load risk analysis by adding or subtracting one standard deviation in model uncertainty. **Table 10** shows the inputs used to create the low, reference and high top-down load forecasts.

Table 10. Inputs to top-down econometric load forecast scenarios

Economic driver	Low load	Reference Case	High load
Population	0.0%	0.7%	1.5%
Employment	0.5%	1.3%	2.5%
Income	1.0%	2.1%	3.5%
Model uncertainty	-1 SD	None	+1 SD

Electrification is also a key area of load uncertainty. This is modeled outside PGE's top-down econometric forecast and discussed in **Section 6.2, Distributed Energy Resource (DER) impact on load**.

The resulting load scenarios are summarized in **Table 11**.

Table 11. Top-down econometric load forecast scenarios

	Low load	Reference Case	High load
Peak demand	0.4%	0.8%	1.1%
Total energy	0.5%	1.2%	1.7%
Residential	0.0%	0.5%	0.9%
Commercial	-0.4%	0.0%	0.3%
Industrial	2.3%	3.5%	4.3%

*Table reflects 20-year average annual growth rate for years 2023-2042, before the impacts of electrification, discussed in **Section 6.2, Distributed Energy Resource (DER) impact on load**.

6.2 Distributed Energy Resource (DER) impact on load

PGE's 2022 Distribution System Plan (DSP) Part 1 and 2 form the basis for DER actions within this IRP except for energy efficiency, which is sourced from Energy Trust of Oregon

(ETO).[125,126,127] The DSP leverages PGE's AdopDER model to perform bottom-up site-level adoption of over 60 DER technologies and technology combinations. The model accounts for key site-level factors such as access to garage parking, breaker space and equipment turnover to determine the technical, achievable and economic potential, as illustrated in **Figure 32**. The AdopDER model simulates the market adoption of passive DERs and the expected participation of customers in current and potential demand response programs. Within the DSP, we simulated the adoption across three scenarios with varying parameters such as cost and policy interpretation. Additional details on the DER forecast methodology, assumptions, and outputs can be found within the DSP filing. The Inflation Reduction Act (IRA) was signed into law after filing the DSP. Thus, its impact is not captured as it pertains to the market adoption of passive DERs such as rooftop solar, electric vehicles and building electrification. While this impact is not explicitly modeled, PGE has modeled both a high adoption case of these technologies and conducted a sensitivity to understanding how resource actions and system needs vary along the range of passive DER adoption. This is further described in **Section 4.2, Need** , and **Section 6.10.2, Accelerated load growth sensitivity**.

In this chapter, we first focus on the market adoption of passive DERs (rooftop solar, transportation electrification and building electrification). Then, we discuss the integration of cost-effective or economic potential of DR and EE through customer programs. The cost-effective potential is highlighted in yellow in **Figure 32**. The treatment of non-cost-effective or additional energy efficiency and demand response is described in **Section 8.2, Additional distributed energy resources**.

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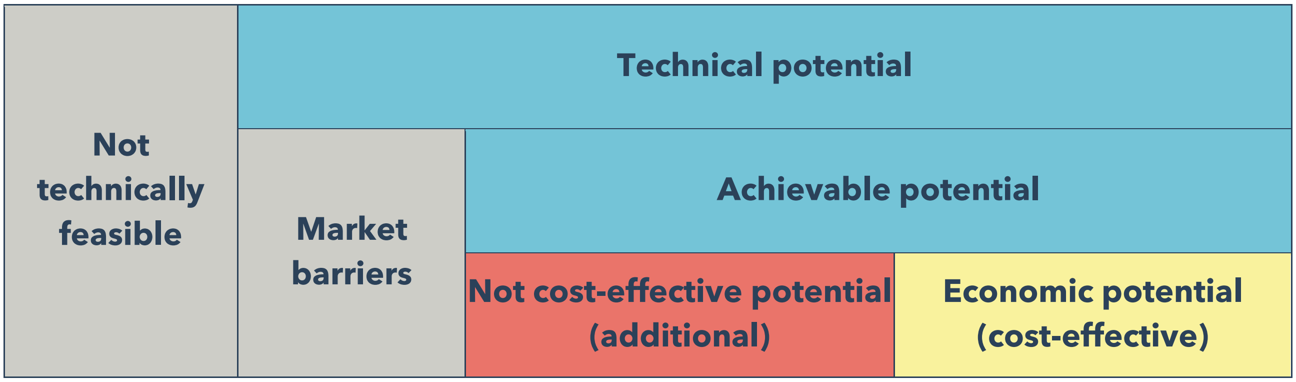
[125] PGE's DSP Part 1, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAA&FileName=um2197haa85326.pdf&DocketID=23043&numSequence=1

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

[127] For the purposes of PGE's IRP, we utilize the OPUC's definition of DERs which includes distributed generation resources, distributed energy storage, demand response, energy efficiency and electric vehicles that are connected to the electric distribution power grid. See *In the Matter of Public Utility Commission of Oregon, Investigation Into Distribution System Planning*, Docket No. UM 2005, Order No. 20-485 (Dec 23, 2020), Appendix A at 15, fn. 2.

Figure 32. The different potential assessments of DERs



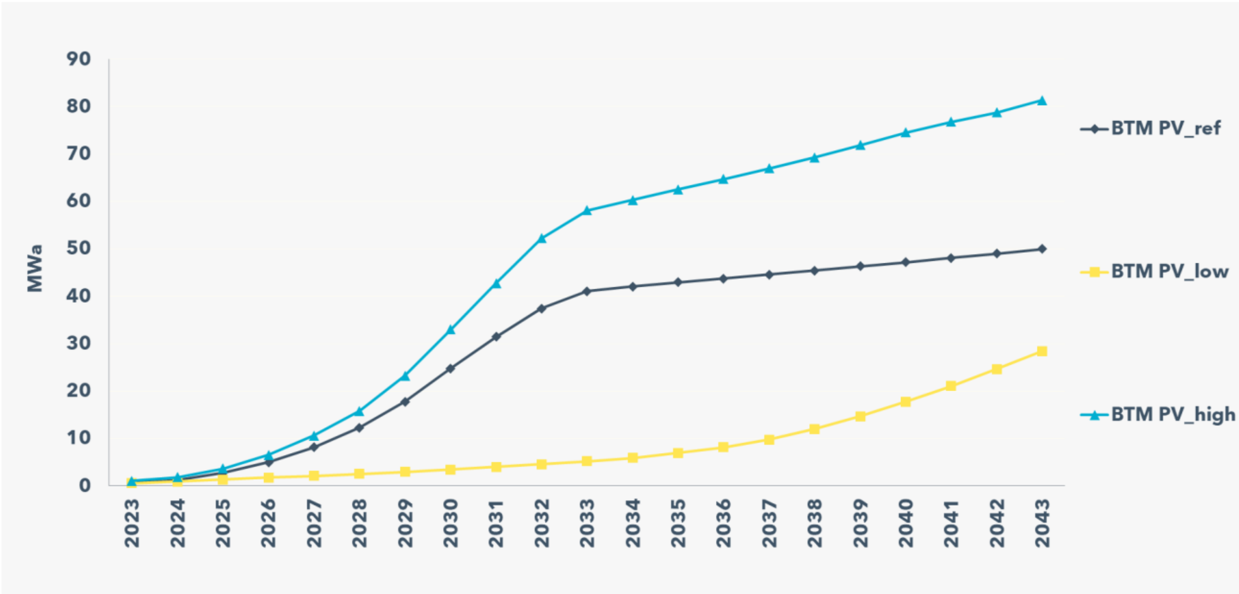
6.2.1 Passive DERs

Passive DERs are driven by direct customer adoption, such as distributed solar PV, electric vehicles and building electrification end uses. As identified in the DSP, distributed solar PV has a high technical potential of approximately seven gigawatts (GW) of nameplate capacity within the service area by 2050. Based on the adoption curves produced within the DSP, we expect annual customer adoption of solar to peak in the early 2030s because of declining solar PV costs, which will lead to favorable customer economics within the current policy environment. Thus, the incremental energy impact from 2023 of customer-adopted solar in the Reference Case is estimated at ~25MWa by 2030, as shown in **Figure 33**.[128] By the end of the planning horizon, this is expected to double. The incremental nature of **Figure 33** ensures that solar PV currently on the system is not double counted.[129] Residential customers drive the bulk of the solar adoption, given the economics between rates (Net Energy Metering (NEM) Incentives) and costs. However, NEM incentives do not require customers to comply with IEEE-1547, 2018 smart inverter standards. This prevents rooftop solar from being properly integrated and thus prevents PGE customers from realizing the full benefit of rooftop solar PV. Additionally, and especially with the IRA extending tax benefits on rooftop solar, the cost shift stemming from the current NEM policy will continue to increase inequities across customers and, consequently, energy burden, which was identified as a key measure by community partners in **Section 7.1.6, Informational community benefits indicators**.

[128] MWa and MW reporting of DERs may vary between the DSP and IRP, though the source data for the locational forecast is consistent between the DSP and IRP. The DSP outputs used for reporting purposes are simplified and do not account for intra-year ramping/adoption. IRP outputs shown here include intra-year ramping. This difference is larger in early years where intra-year ramping is significant and shrinks over time because each new year's incremental contribution decreases.

[129] In response to Docket LC 73, PGE 2019 Integrated Resource Plan, Order 20-152's requirement at 22, "In the next IRP, PGE is to report on trends of sales by customer class and DER installments for 2015 through 2019", PGE has provided this information within the DSP Part 1, Section 1.5 of Chapter 1, available at: https://assets.ctfassets.net/416ywc1laqmd/ELNdf17zyQvQiU9k71pIX/683cd2f7b3098517068c4594100a1025/DSP_2021_Report_Chapter1.pdf.

Figure 33. MWa generation impact of behind the meter (BTM) distributed solar PV over the planning horizon



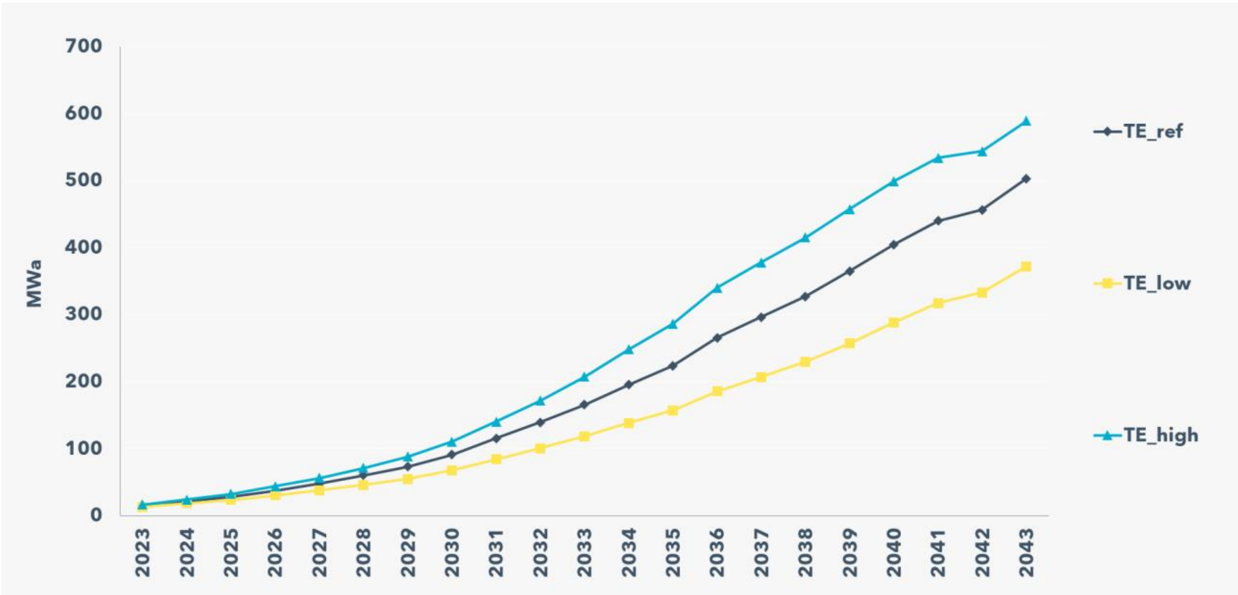
We forecast higher levels of adoption for electric vehicles than in the previous IRP, particularly in the light-duty segment. Based on the DSP, by 2030, we expect 341,280 light-duty electric vehicles on the road, with 298,244 vehicles in the residential sector and 9,817 medium and heavy-duty EVs in the Reference Case. Consequently, we expect the transportation electrification load to be ~91 MWa by 2030, with a fivefold increase by 2043 to ~503 MWa.

Policy assumptions in the DSP do not include the impact of the Advanced Clean Cars II rule passed on December 19, 2022, which requires auto manufacturers to deliver 100 percent new zero-emission battery electric and plug-in hybrid electric vehicles by 2035.[130] **Section 6.10.2, Accelerated load growth sensitivity**, details a demand growth sensitivity analysis that is more aggressive than the Advanced Clean Cars II rule.

Figure 34 represents the gross transportation electrification load across varying adoption scenarios, not accounting for the potential impact of associated demand response programs such as time-of-use or managed charging programs. These demand response programs are represented within the demand response potential in **Section 6.2.2, Demand response**.

[130] The Advanced Clean Cars II, Administrative Order No. DEQ-23-2022, effective 12/19/2022, available at: https://www.oregon.gov/deq/rulemaking/Documents/DEQ232022.pdf

Figure 34. MWa impact of transportation electrification (TE) over the planning horizon

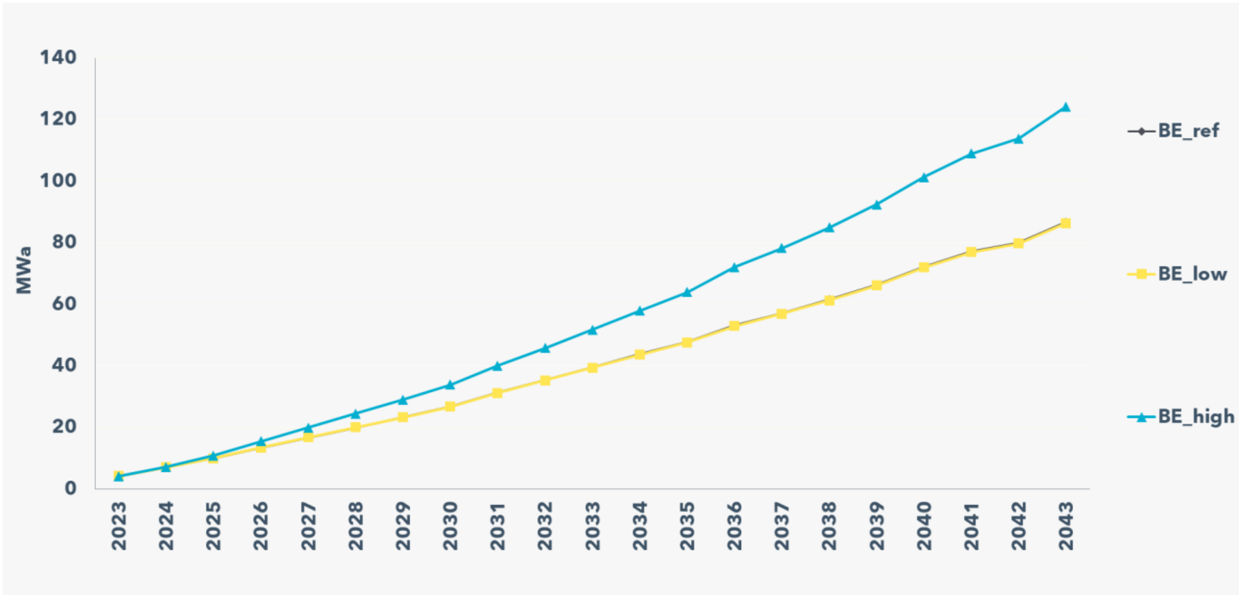


Building electrification has significant potential to decarbonize the economy further. The adoption of electric space heating, water heating and cooking technologies within the new construction sector and fuel switching within existing buildings drives the building electrification forecasts. For this IRP, we leveraged the DSP outputs and associated assumptions. By 2030, we expect a ~27MWa impact from building electrification. While this impact increases both summer and winter resource adequacy needs, the winter needs are impacted more prominently because of the space heating end use, which coincides with the winter peak.

Like transportation electrification, **Figure 35** represents the gross building electrification load across varying adoption scenarios, not accounting for the potential impact of associated demand response programs such as time-of-use or managed charging programs. These demand response programs are represented within the demand response potential in **Section 6.2.2, Demand response**.

In addition to the building electrification scenarios modeled in the DSP, we have also modeled an electrification sensitivity to understand the impact of electrification, assuming the Climate Protection Program's compliance is achieved only through increased electrification. This is further described in **Section 6.10.2, Accelerated load growth sensitivity**.

Figure 35. MWa impact of building electrification (BE) over the planning horizon



6.2.2 Demand response

As noted earlier in the section, the DSP informs DER[131] implications within the IRP, including demand response. PGE's DSP modeled current and potential demand response programs, including technologies (storage, smart thermostats, electric vehicles and water heaters) and strategies (peak time rebates and time of use pricing programs) across all customer classes. Three adoption cases, which are the inputs to the IRP, are produced based on industry trends, such as technology cost, heuristics of customer adoption from other utility territories, and policy. **Table 12** and **Table 13** detail the achievable potential by season through the Action Plan period, with the cost-effective potential broken out. The cost-effective potential is integrated within the Need Futures and the Action Plan as the procurement target. The difference between achievable and cost-effective potential is the non-cost-effective potential, included within the IRP as potential resource options and further described in **Section 8.2, Additional distributed energy resources**.

[131] For the purposes of PGE's IRP, we utilize the OPUC's definition of DERs which includes distributed generation resources, distributed energy storage, demand response, energy efficiency and electric vehicles that are connected to the electric distribution power grid. See, UM 2005, Order No. 20-485, Appendix A at 15, fn. 2.

Table 12. Summer demand response/flex load peak impacts

Summer MW peak impacts, achievable potential							
Scenario	2024	2025	2026	2027	2028	2029	2030
High	271	298	310	326	343	359	385
Ref	146	183	211	236	257	274	294
Low	98	118	137	155	173	187	201
Cost-effective, achievable potential (TRC >=1)[132]							
Scenario	2024	2025	2026	2027	2028	2029	2030
High	256	273	278	282	287	287	294
Ref	133	162	183	199	211	218	228
Low	93	110	126	141	155	166	177

Table 13. Winter demand response/flex load peak impacts

Winter MW peak impacts, achievable potential							
Scenario	2024	2025	2026	2027	2028	2029	2030
High	174	191	204	219	234	259	282
Ref	106	134	158	177	194	213	231
Low	68	83	99	113	127	141	152
Cost-effective achievable potential (TRC >=1)							
Scenario	2024	2025	2026	2027	2028	2029	2030
High	165	176	183	188	192	199	205
Ref	98	119	137	149	158	167	174
Low	66	79	92	104	115	126	134

As noted in the DSP Part 2, we expect approximately 228 MW of summer and 174 MW of winter economic achievable demand response (including behind-the-meter storage enrolled

[132] The Total Resource Cost (TRC) test compares the costs and benefits of a resource and determines if the benefits are equal to or outweigh the costs, *i.e.*, TRC >=1, or if the resource is not cost-effective, *i.e.*, the projected costs are not greater than the expected benefits. The TRC test is the primary determinant in the implementation of a demand response and energy efficiency program in Oregon.

in a program) by 2030.[133] The demand response portfolio will likely be dominated by Peak Time Rebates, Energy Partner and Thermostat programs in the near-term. In the latter years of the planning horizon, post 2030, the adoption of building and transportation electrification end-uses increase the demand response potential, especially for programs such as Time of Use when combined with technologies such as smart thermostats, batteries or EVs. Details on the procurement targets across these programs can be found in the DSP Part 1 and Part 2, the 2021 Flexible load Multi-year Plan (MYP) and the 2019 Transportation Electrification Plan (TEP).[134,135,136]

Figure 36 describes the Commission-filed resource plans that help PGE move from planning to procurement for demand response. This process will evolve as PGE's virtual power plant (VPP) capabilities mature. Presently, the DSP forms the basis for all DER forecasts. Demand response forecasts go through the IRP process, where they may be layered with additional demand response previously deemed not cost-effective. Thus, the IRP Action Plan sets a target that combines both the cost-effective and currently non-cost-effective resources. The MYP is where PGE details the programs and procurement strategies for those programs to meet this DR target. The MYP will also highlight any operational concerns that may prevent achievement of the target, which may result in increasing the current targets for the supply side Request for Proposals (RFP) or undertaking a new RFP.

[133] PGE Distribution System Plan (DSP) Part 2 (August 15, 2022), available at: https://downloads.ctfassets.net/416ywc1laqmd/2Fr2nVc4FKONetiVZ8aLWM/b209013acfedf1125ceb7ba2940bac71/DSP_Part_2_-_Full_report.pdf

[134] PGE Distribution System Plan (DSP) Part 1 (October 2021), available at: https://assets.ctfassets.net/416ywc1laqmd/i9dxBweWPkS2CtZQ2lSVg/b9472bf8bdab44cc95bbb39938200859/DSP_2021_Report_Full.pdf

[135] PGE Distribution System Plan (DSP) Part 2 (August 15, 2022), available at: https://downloads.ctfassets.net/416ywc1laqmd/2Fr2nVc4FKONetiVZ8aLWM/b209013acfedf1125ceb7ba2940bac71/DSP_Part_2_-_Full_report.pdf

[136] *In the Matter of Portland General Electric Company, Flexible Load Plan*, UM Docket No. 2141 (filed Nov 3, 2021), the 2021 Flexible Load Multi-Year Plan, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAD&FileName=um2141had16243.pdf&DocketID=22696&numSequence=19;

Figure 36. Planning to procurement Demand Response

6.2.3 Energy efficiency

This IRP incorporates the ETO's most recent long-term cost-effective EE savings forecast from May 2022. Additional details on ETO's forecast are provided in **Ext. Study-II, EE methodology**. ETO is working to understand how IRA tax credits might reduce costs. This work is in its infancy and is not captured directly in the IRP. However, the different Need Futures account for how cost changes impact the EE forecast, as described in **Section 4.2, Need Futures**.

From 2026 through 2030, ETO projects that cost-effective energy efficiency will provide ~156 MWa of energy savings averaging about ~31 MWa each year. **Table 14** provides the breakdown of the annual energy efficiency savings by sector and program from 2024 through 2030.

Table 14. Energy efficiency MWa savings breakdown by year, sector and program

Sector	Program	2024	2025	2026	2027	2028	2029	2030
Commercial	New buildings	3.5	3.8	3.8	3.9	3.6	3.5	3.4
Commercial	Existing buildings	9.4	9.2	9.0	9.0	9.1	9.2	9.1
Commercial	Multifamily	1.1	1.0	1.0	1.2	1.5	1.9	2.2
Commercial Total		14.0	14.0	13.8	14.1	14.1	14.6	14.8
Industrial Total		11.0	10.0	9.9	10.0	10.0	10.2	10.2
Residential	Existing homes	3.6	3.9	4.1	4.0	4.5	5.5	6.0
Residential	New homes	1.6	1.8	1.8	2.2	2.0	2.4	2.3
Residential Total		5.2	5.7	6.0	6.2	6.5	7.9	8.4
Yearly Total		30.2	29.7	29.6	30.2	30.6	32.7	33.3

Figure 37 highlights the annual EE forecast or cost-effective potential in MWa that is considered within the Need Futures, as noted in **Chapter 4, Futures and uncertainties**. **Figure 38** provides the same data in a cumulative approach to highlight the aggregate impact of the cost-effective EE. **Ext. Study-II, EE methodology,** also includes details on the annual energy efficiency trends. **Section 8.2.1, Additional energy efficiency**, provides more information on the additional energy efficiency evaluated within this IRP.

Figure 37. Annual EE forecast by adoption scenarios in MWa

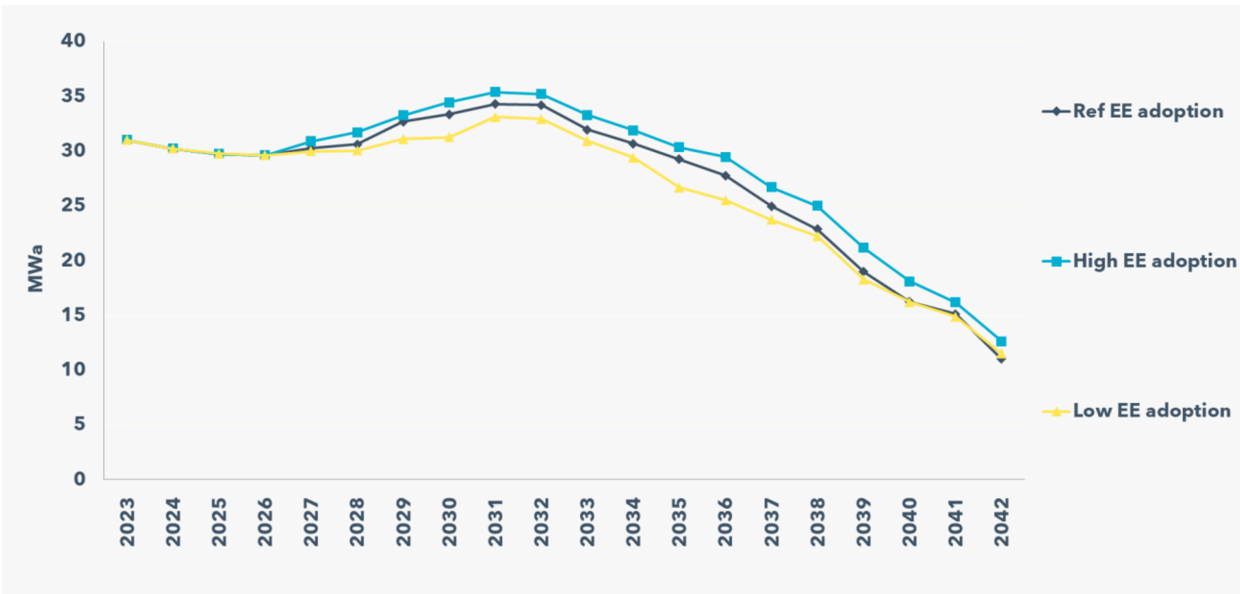
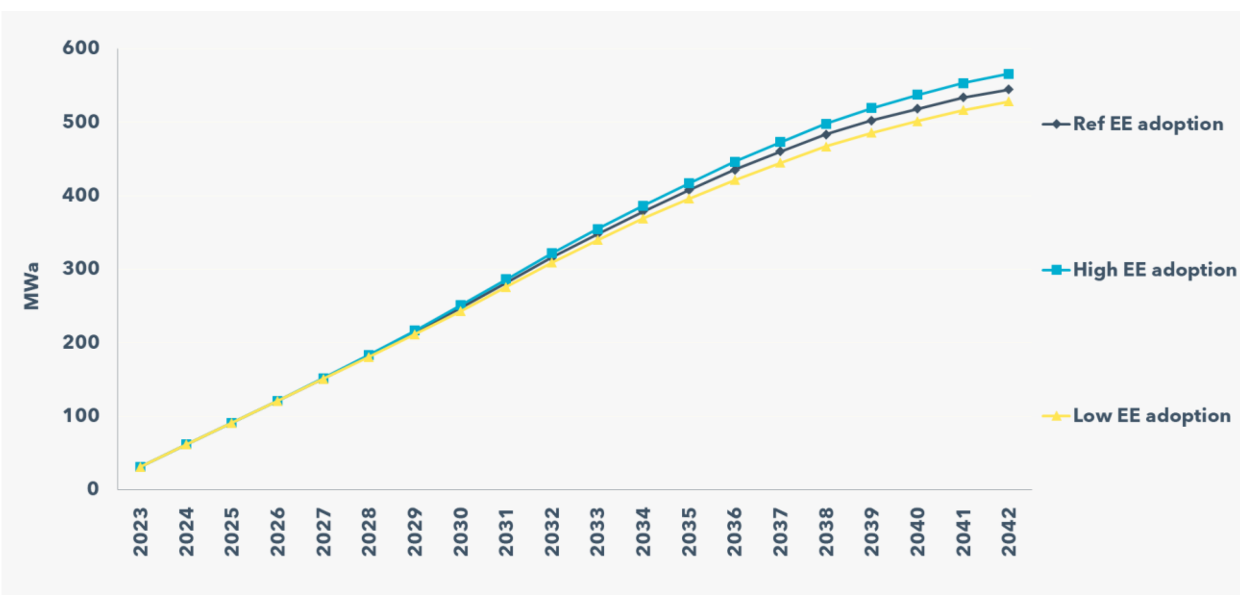


Figure 38. Cumulative EE impact over the planning horizon

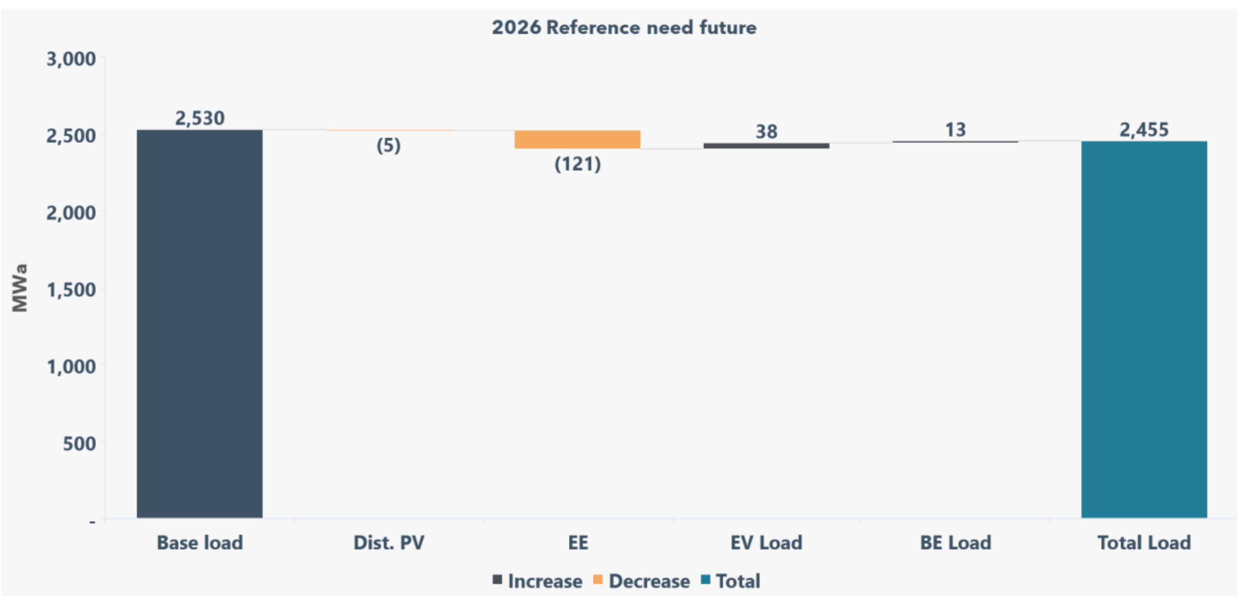


6.3 Load scenarios

The aggregate impact of energy efficiency, other passive DERs and the top-down economic forecast (or Base load forecast) yield the total load used within the IRP. In this section, we graphically present this information. **Figure 39** shows the energy impact of EE savings, distributed PV generation, building electrification and transportation electrification load in the Reference Case for 2026 and 2040. As mentioned earlier, key data considerations for **Figure 39** include the following:

- The base load forecast includes all DER impacts through 2022. The DER impacts highlighted here are the forecasted incremental impacts from 2023 to the year in question.
- The transportation and building electrification loads are gross loads, meaning they do not include the impact of associated demand response programs such as managed charging or time of use, which could increase or decrease loads based on the program design.

Figure 39. Aggregate impact of DERs on base load in 2026 and 2040



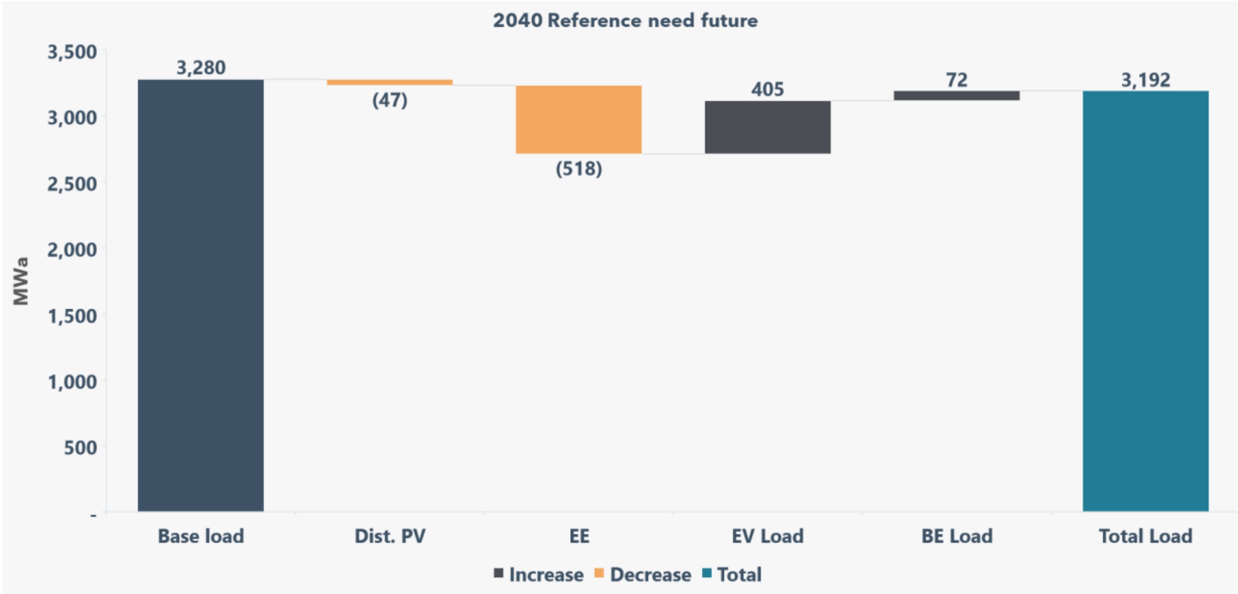
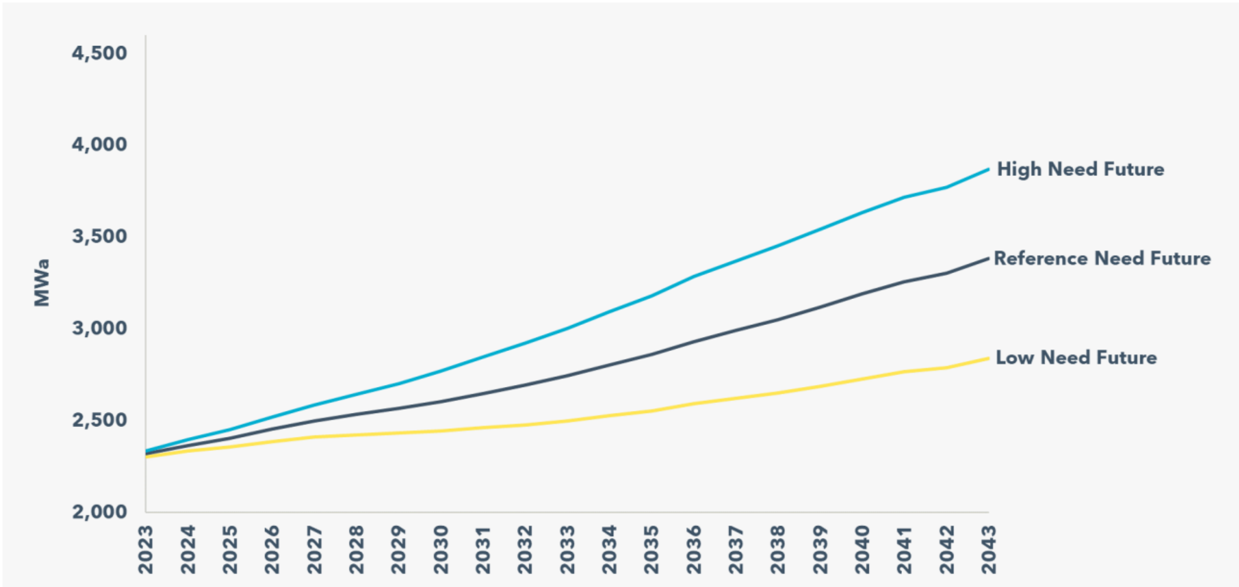


Figure 40 describes the expected total load of each Need Future over the planning horizon showing the divergence between the Need Future over time. By 2030, we expect the total load to be ~2604MWa, growing to just under ~3192MWa by 2040. This represents a 2.1 percent growth between 2030 and 2040. By 2040, the impact of building and transportation electrification is forecast to be ~13 percent of the total load of the system.

Figure 40. Total load for each Need Future over the planning horizon[137]



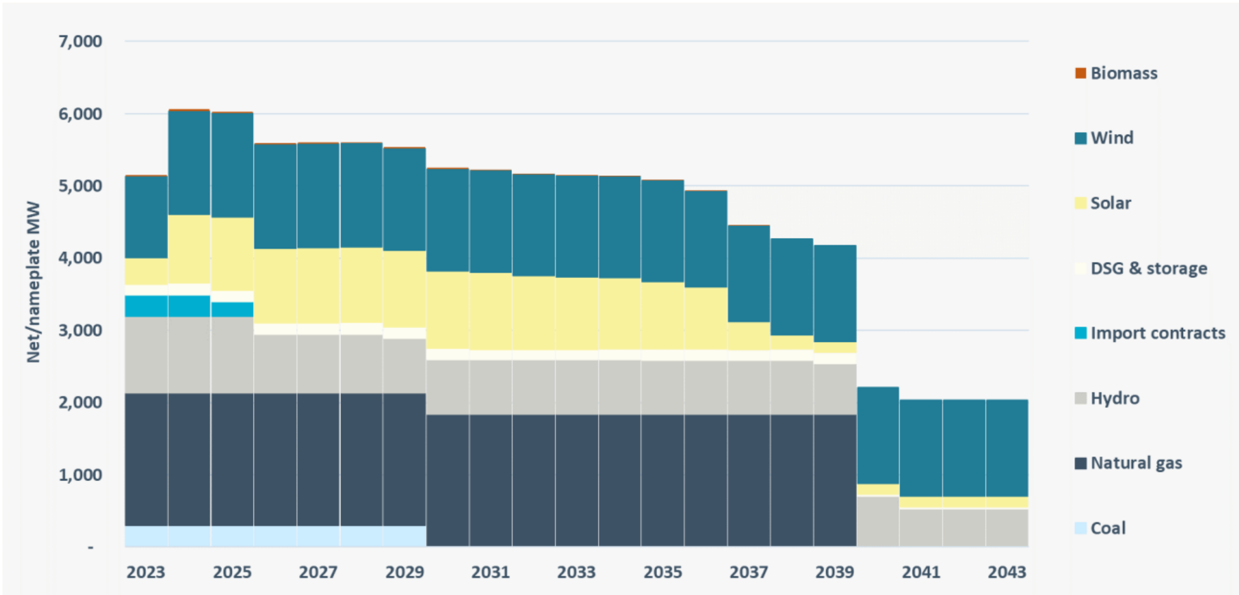
6.4 Existing and contracted resources

PGE owns and contracts a diverse set of resources to meet customer needs. Driven by state policy and company sustainability goals, PGE has been accelerating its transformation to a non-emitting power provider in recent years. This involves acquiring new non-emitting resources, like the Wheatridge Renewable Energy Facility, extending hydroelectric contracts like the Pelton and Round Butte projects, and moving away from coal resources, like the Boardman power plant, which was retired in 2020.

Figure 41 shows the net/nameplate MW of PGE-owned and contracted generating resources, including committed but not yet online resources (like the Clearwater wind project).[138] It does not show future resources from the IRP Preferred Portfolio and assumes no renewals of existing contracts. In 2023, 52 percent of capacity comes from PGE-owned resources, 31 percent from contracted resources and 17 percent from co-ownership and community resources. Net/nameplate MW indicates resource size but is not a good indicator of how much energy or capacity resources can contribute to the system. For a view of PGE's energy position, see **Section 6.5, Energy need**. For a view of PGE's capacity adequacy, see **Section 6.6, Capacity need**.

[137] The figure shows annual energy load forecasts, not peak load forecasts. Peak loads may grow at a different pace due to changing load shapes, demand response programs and other factors.
[138] The figure does not include demand-side resources other than distributed system generation. Net MW may differ from nameplate. Values are approximate.

Figure 41. PGE owned & contracted resources



The forecasted amount of solar on the system grows through 2025 due to bilateral contracts and qualifying facilities coming online.[139] In 2025 and 2026, there is a reduction in resources from the loss of the Avangrid capacity contract (100 MW), the BPA capacity contract (200 MW) and a contract with Douglas PUD. Later in the decade, additional hydro contracts expire, and Colstrip exits the portfolio at the end of 2029. In the mid/late 2030s, the quantity of solar resources on the PGE system declines due to contract expirations.

The IRP only assumes existing contracts will renew if there is a high degree of confidence that the specific contract (or something closely resembling it) will be executed. Contract uncertainty affects IRP resource adequacy and energy needs. PGE would, upon an extension of a contract or entering a new bilateral contract, update the resource need picture (and adjust RFP procurement levels if applicable). **Section 6.10.3, Contract extension sensitivity,** includes additional discussion on the impact of contracts on resource needs.

6.5 Energy need

After detailing forecasts of system demand (in **Sections 6.1-6.3**) and existing supply (**Section 6.4, Existing and contracted resources**), estimates of resource needs in terms of energy and capacity can be derived. This section describes PGE's resource needs through the lens of energy, which represents the amount of electricity demanded and supplied each year and is

[139] These solar projects are largely schedule 202 qualifying facilities and GFI resources.

discussed in terms of megawatt average (MWa) or megawatt hours (MWh).[140,141] **Section 6.6, Capacity need**, describes PGE's needs for capacity, which is discussed in terms of MW, referring to the ability to generate electricity when needed.

6.5.1 Energy-load resource balance

An energy-load resource balance estimates the difference between PGE's forecast customer load (demand) and the expected energy forecasted to be available to serve load (supply). The forecasted amount of energy available annually (in MWa) from owned and contracted non-dispatchable and non-emitting sources is calculated by multiplying the nameplate of each facility by the forecast capacity factor in each year.

The calculation of energy available annually from sources with associated GHG emissions requires a different methodology than was employed in the past due to the GHG emissions regulation created by House Bill (HB) 2021. Prior to the existence of GHG emissions targets, the availability of energy from thermal resources was calculated assuming the availability of the total capacity of PGE's thermal resources to serve load, with adjustments for expected maintenance and outages.

As described in **Section 5.3, Components of IRP emissions reporting**, the total generation levels from PGE's dispatchable thermal plants are determined through economic dispatch from the PZM simulation. To comply with HB 2021 emissions targets, only a portion of the total energy produced by those plants through economic dispatch can be retained to serve Oregon retail load. The amount of energy retained to serve Oregon retail load is determined using PGE's Intermediary GHG model. The amount of energy that can be retained from market purchases and contracts with associated GHG emissions intensity is also accounted for in the Intermediary GHG model.

When combined, the energy retained from GHG-emitting sources and the total energy from non-emitting sources determines the amount of energy allowed to serve Oregon retail load. The forecast of Oregon retail load and the amount of allowed energy that can be used to serve that load are shown in **Figure 42**. The quantity of allowed energy does not include new supply-side resources outside of those from the 2021 RFP and the continued acquisition of energy efficiency, demand response and other demand-side resources.[142] Before any additional incremental resource additions, the Oregon retail load is expected to surpass the

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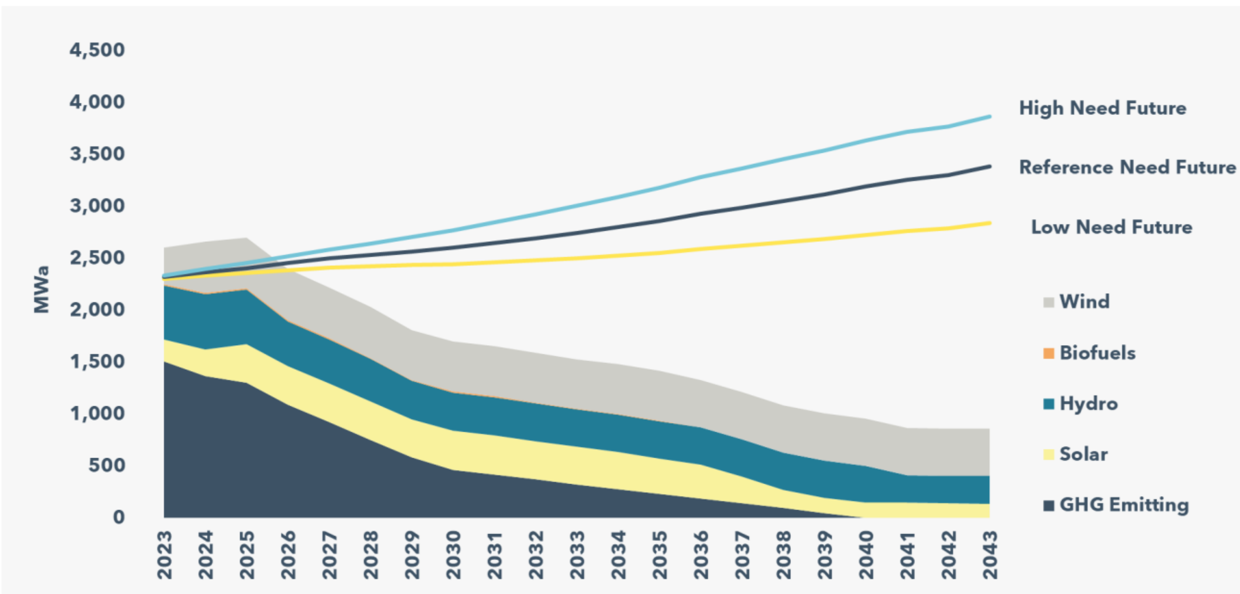
[140] One megawatt is 1 million watts. One megawatt delivered continuously 24 hours a day for a year (8,760 hours) is called an average megawatt.
[141] A megawatt hour (MWh) is equal to 1,000 kilowatts of electricity used continuously for one hour.
[142] As described in **Section 6.2, Distributed Energy Resource (DER) impact on load**, cost-effective EE and DERs are incorporated into PGE's load forecast as a reduction in future loads. Forecast of cost-effective EE and DERs used in this IRP are consistent with what was used in PGE's 2022 Distribution System Plan. Available at: https://portlandgeneral.com/about/who-we-are/resource-planning/distribution-system-planning

allowed energy on PGE's system starting in 2027, with the gap growing through the end of the 20-year planning horizon. The gap between Oregon retail load and allowed energy grows through time because of reductions in the amount of energy retained to serve retail load from GHG-emitting sources, expiration of certain contracts and growth in Oregon retail load through time. Because the entirety of PGE's GHG emissions budget is allocated through the dispatch of owned thermals and energy from contracts and purchases with associated GHG emissions, the future gap between load and allowed energy must be bridged with new non-emitting resources or specified-source non-emitting market purchases.[143]

Figure 42. Energy-load resource balance in linear GHG glidepath in Reference Case future



6.6 Capacity need

Capacity needs describe the effective capacity required to achieve a resource-adequate power system. For example, in 2026, the PGE system has a forecasted capacity need of 506 MW in the summer. This implies that the system needs additional resources that, in the aggregate, provide 506 MW of power during key summer hours.[144] These estimates come out of the PGE resource adequacy model, Sequoia.

[143] Assuming no change in the emissions rate used to account for GHG emissions associated with market purchases from unspecified sources.

[144] An effective load-carrying capability study (ELCC), described in **Chapter 10, Resource economics**, determines how much power different resources can effectively provide. In most cases, a resource's effective capacity is lower than the resource nameplate.

The IRP uses the Sequoia model to calculate the capacity needed to maintain resource adequacy in future years. Sequoia is an hourly model that simulates tens of thousands of weekly combinations of loads and resources to assess power system adequacy under a wide range of conditions.[145] Loads in the model represent all retail customers. Resources include owned and long-term contracted facilities (including Green Future Impact (GFI) resources), the recently signed Clearwater Wind project plus proxy resources that provide capacity and energy expected via the 2021 RFP, cost-effective levels of demand-side resources, and spot power market assumptions (see **Chapter 4, Futures and uncertainties**, for a discussion on the changing region and power market assumptions).[146] The capacity need assessment is performed before the portfolio model is run. As a result, the capacity need assessment does not include new resources identified by the IRP portfolio model. A list of major changes made to the Sequoia model between the 2019 IRP Update and the 2023 IRP is available in **Appendix H, 2023 IRP modeling details**.

GHG-emitting resources are available for use in Sequoia through the year 2039. There may be multiday periods with high GHG-emitting resource utilization to maintain resource adequacy (for example, a period of cold, non-windy weather in the winter). To support this assumption and meet HB 2021 GHG targets, the IRP must select sufficient non-emitting resources to offset GHG-emitting generation usage annually.[147]

For the IRP, a resource-adequate system must average 2.4 hours of lost load or fewer per season (2.4 LOLH), an interpretation of one outage every 10 years. This standard is for supply and demand-caused outages, not outages due to transmission and distribution system issues (like a downed power line). Additionally, the capacity needs assessment does not examine flexibility needs, like having quick-to-react resources to balance variable energy resources and mitigate forecast errors. See **Section 6.8, Flexibility adequacy**, of this chapter for a discussion on system flexibility needs.

The IRP examines power system capacity needs on a seasonal, summer and winter basis. **Figure 43** shows system capacity needs for summer and winter from 2024 through 2043 in the Reference Case in the solid lines.[148] The dashed lines show capacity needs with a 200 MW hydro-based contract renewing from 2026 through 2030.

[145] PGE developed Sequoia following the 2019 IRP. It was developed to better model energy limited resources and to incorporate process efficiency improvements. Sequoia was used in the 2019 IRP Update and in the PGE 2021 RFP. More information on Sequoia is in **Appendix H, 2023 IRP modeling details.**
[146] The GFI projects in Sequoia are Bakeoven Solar, Daybreak Solar and Pachwáywit Fields solar.
[147] The selection of sufficient non-emitting resources is done in ROSE-E, the capacity expansion model.
[148] Winter is defined as October through March; summer is defined as April through September.

Figure 43. Seasonal capacity need

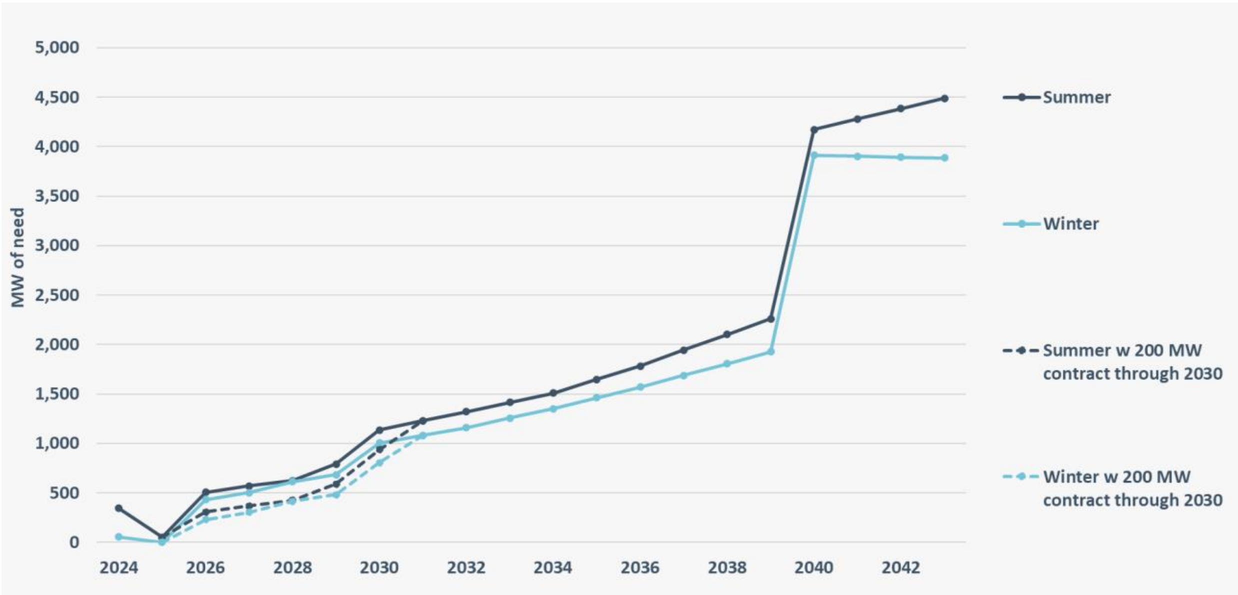
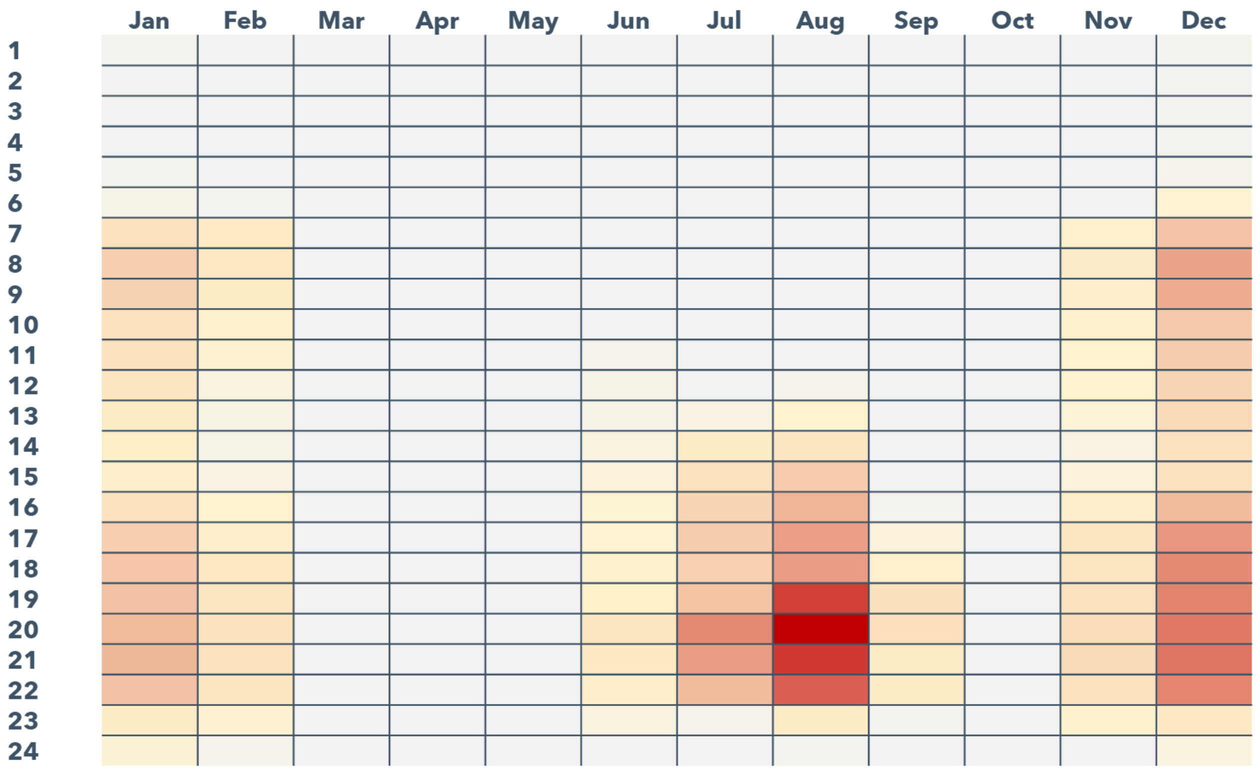


Figure 43 demonstrates larger capacity needs emerging in 2026 (lower levels of needs exist prior to 2026 as well). The increased 2026 need is due to various capacity contracts expiring in 2024 and 2025.[149] A second upward step in capacity need occurs in 2030 when Colstrip exits the portfolio. After 2030, the need for power will grow via two primary drivers. First, steady forecasted load growth for the core system and quickening electrified end-use growth projections push the need up. Second, resource reductions, like the loss of solar contracts in the mid/late 2030s, add to the need. In 2040, the need steps upward when existing GHG emitting resources, like natural gas power plants, can no longer serve retail load (the 2040 need increase could be reduced if existing gas plants are able to convert to a non-emitting fuel).

Figure 44 presents a 12x24 (monthly by hourly) look at 2026 capacity needs. The graph gradients from gray (zero/minimal outages) to red (higher levels of outages). PGE's system sees adequacy challenges in the winter and summer evening hours and the morning in the winter (hours in the heatmap are all Pacific standard time). In 2026, under the Reference Case assumptions, there is a need for 430 MW of effective capacity in the winter and 506 MW in the summer to achieve an adequate system (2.4 LOLH per season).

[149] Contracts may fail to renew for many reasons. These include actions by the seller, like keeping the power to serve local load and/or selling to another entity. The seller may also price the contract higher than other resource/contract options, causing PGE to pursue other options.

Figure 44. 2026 Reference Case capacity need heatmap

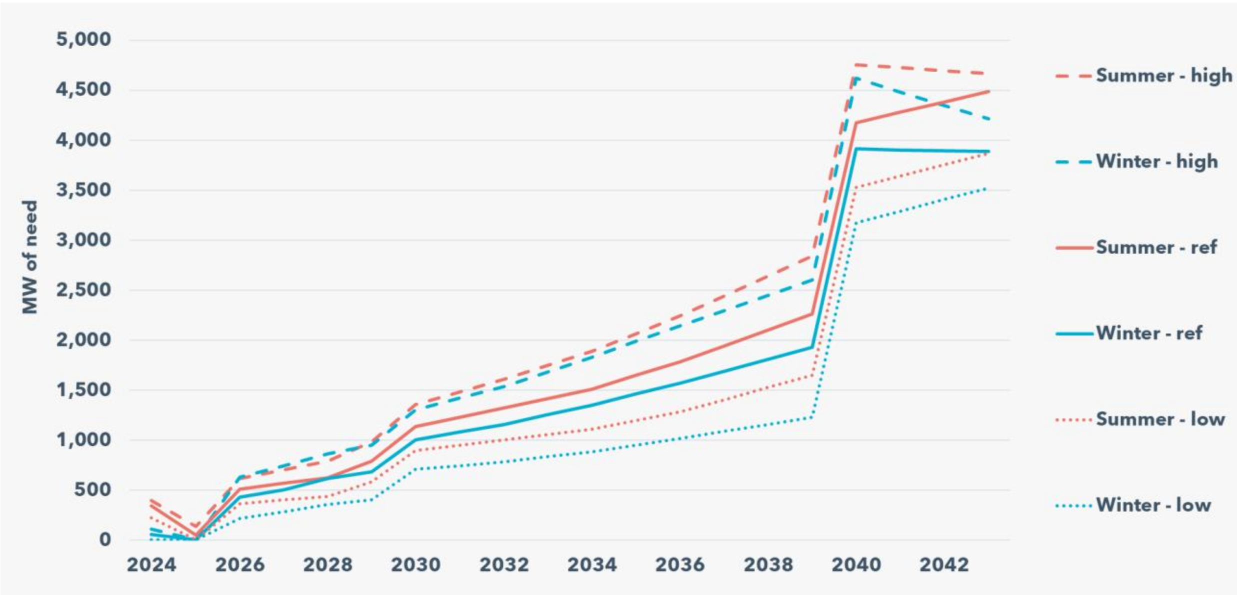


6.6.1 Capacity under different Need Futures

There is capacity need uncertainty in the next decade. The uncertainty is due to many factors, including:

- Load growth uncertainty, both from the core forecast and electrification
- Uncertainty regarding the level of demand-side resources PGE will acquire
- Existing contract renegotiation uncertainty
- This IRP examines low and High Need Futures to test uncertainty associated with loads and demand-side resources. See **Chapter 4, Futures and uncertainties**, for more information on Need Futures. **Figure 45** shows the capacity needs of the low and high-needs futures and the Reference Case. In 2026, summer need ranges from 364 MW in the low case to 617 MW in the high case. **Section 6.10, Need sensitivities**, examines how different qualifying facility forecasts, electrification projections, contracts and Colstrip impact capacity needs.

Figure 45. Capacity need under different futures



6.7 RPS need

The Renewable Portfolio Standard (RPS) was established as a law in Oregon in 2007. In 2016, Senate Bill (SB) 1547 escalated the RPS requirements for electric utilities to meet customer energy needs with 50 percent of electricity from renewable resources by 2040 (see **Table 15**).[150]

Table 15. RPS obligations per SB 1547

Year	RPS requirement (% of retail sales)	RPS requirement MWa (reference need)
2025	27%	491
2030	35%	691
2035	45%	975
2040	50%	1207

[150] SB 1547 (2016), available at:
https://olis.oregonlegislature.gov/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled

In conjunction with meeting HB 2021 requirements, PGE projects that without incremental renewable resource actions, RPS obligations will exceed the quantities of Renewable Energy Certificates (RECs) available from generation from existing RPS-eligible resources in the Low, Reference and High Cases beginning in 2030 when RPS requirements increase from 27 percent to 35 percent of the retail load. PGE's forecasted physical RPS shortage[151] in 2030 is illustrated in **Figure 46** and **Table 16**. For details regarding PGE's expected compliance with the RPS requirements, see **Section 11.5.2, Resulting RPS position**, which compares the RPS requirements with PGE's corresponding RPS position within its Preferred Portfolio.

Figure 46. PGE's physical RPS shortage across Need Futures

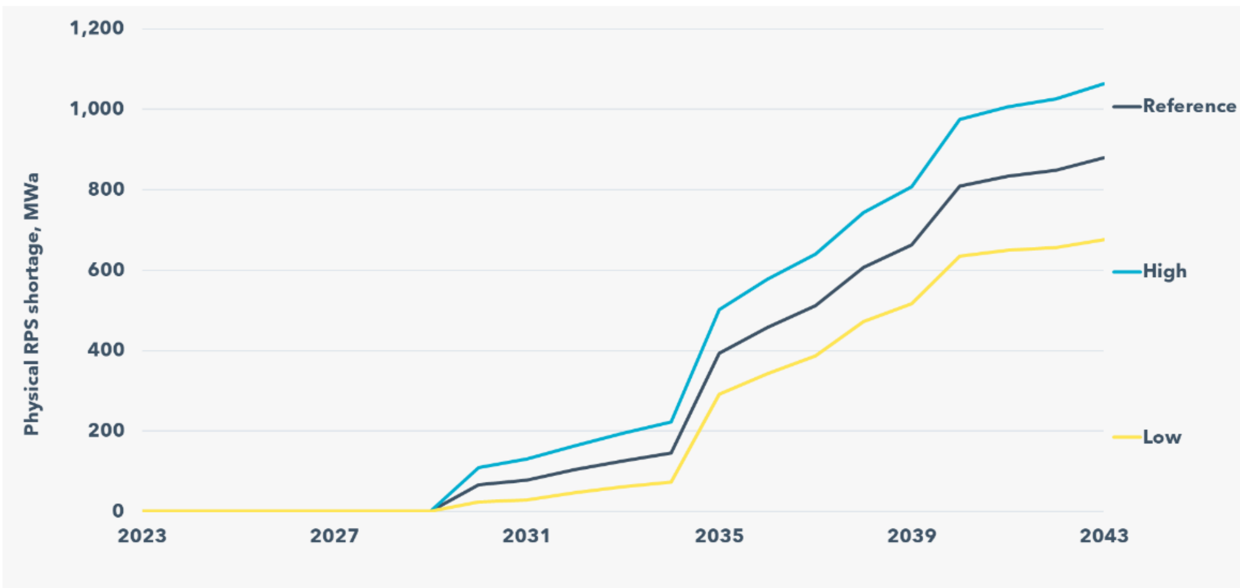


Table 16. Physical RPS shortage in 2030

Need future	2030 physical RPS shortage (MWa)
Reference Case	53
Low Need Future	11
High Need Future	97

[151] A physical RPS shortage is forecasted when RPS obligations exceed PGE's physical RPS position. Physical RPS position is the comparison of forecast-generated Renewable Energy Credit (REC) to the forecast RPS obligation over time. PGE includes information about physical RPS compliance as informational only and does not include any resource additions based on physical compliance. For more detail, see **Section 11.4.6, Targeted policy portfolios**.

6.8 Flexibility adequacy

Resource adequacy need is a vital part of the IRP process to ensure resource actions result in a reliable system. An element of this assessment is understanding operational challenges associated with the need for operating reserves, operational constraints of power plants and errors in supply forecasts and commitments. Unserved energy from these sources can be attributed to a deficit in the system's operational flexibility. Accordingly, flexibility adequacy is an element of resource adequacy that highlights the deficit in a system's operational capabilities hourly and is denoted by a MW flexible adequacy target.

In addition to the hourly flexibility adequacy, the importance of more granular flexibility analyses, from hourly to sub-hourly, is growing as more Variable Energy Resources (VERs) are integrated across the Western Interconnection. Sub-hourly resource integration impacts are a growing body of research across the industry. PGE is still in the learning phase on this topic, focusing on how it can be assessed, understanding its connection with other elements of resource adequacy and hourly flexibility adequacy, and its impact on resource selection.

As part of the flexibility assessment in this IRP, three key critical concepts are analyzed:

- **Flexibility adequacy.** A MW number that represents the magnitude of fast-acting dispatchable resources needed to meet the operational flexibility needs of the system and ensure system reliability. This metric is incorporated within our capacity expansion model, ROSE-E, to address this need by selecting an adequate amount of fast-acting dispatchable resources within the portfolio, such as batteries, pumped storage hydro and other dispatchable resources.
- **Flexibility value.** Represents a benefit value stream that fast-acting dispatchable resources such as batteries and certain DERs should receive for addressing flexibility adequacy. This benefit is integrated into resource economics and is described further in **Section 10.3, Flexibility value and integration cost**.
- **Integration cost.** Represents a cost value stream for VERs such as wind and solar that increase the need for flexibility adequacy due to their variability. This cost is integrated into resource economics and is described further in **Section 10.3, Flexibility value and integration cost**.

For this IRP, PGE worked with Blue Marble Analytics, a third-party consultant, to model all three elements. Blue Marble Analytics used its Grid Path Model to perform the analysis, calibrating the model to the 2019 IRP's flexible adequacy analysis. The findings of the Flexibility Adequacy Study are summarized in the following section, and the entire Blue Marble Analytics study is included in **Ext. Study-IV, Flexibility study**.

6.8.1 Study takeaways and implications

From **Ext. Study-IV, Flexibility study**, we gathered the following findings on flexibility adequacy (**Table 17**):

- **Flexibility challenges in the near- and mid-term are driven by forecast error**. In both the 2026 and 2030 test years, the system experiences inadequate flexibility driven by forecast error. This is where the system, after adjusting hydropower and gas generation, does not have sufficient capacity intra-day to address the magnitude of forecast error during the hours with the highest net load.
- **Flexibility adequacy grows in magnitude and frequency from near- to mid-term.** The study results indicate that in 2026, the system will require an additional 80 MW and 158 MWh of flexible resources to meet the needs of the system, which occur about 0.1 percent of the time. This inadequacy grows to 122 MW and 501 MWh by 2030, with the frequency increasing to 0.3 percent of the time.

Table 17. Flexibility adequacy in 2026 and 2030

	2026	2030
% Timepoints	0.1%	0.3%
Total MWh	158	501
Max MW	80	122

- **Flexibility adequacy challenges are experienced in both summer and winter seasons.** In 2026, the model sees that winter outages are most common in the evenings. In summer, outages are later in the evening, with most outages during hours with the highest net load, usually in the evenings from 6-10 PM. By 2030, as the magnitude and frequency of these outages increase, the outages also occur in the spring and fall seasons. However, the largest outages still occur during evening peaks in summer and winter.
- **System headroom is constrained during summer and winter.** Headroom is defined as how close the system is to experiencing a flexibility-related event. Blue Marble Analytics also assessed the system headroom and found that on a seasonal basis, the system is most constrained in the winter. System headroom is 300 MW or less 25 percent of the time in December and reaches zero in all three winter months as well as in November. Headroom is also frequently constrained in the summer and falls to zero in July, August and September.

- **Diverse resources can help mitigate the increasing flexibility adequacy issues of the system.** Blue Marble found that fast-responding battery storage is required to address flexibility adequacy issues caused by forecast errors. The magnitude of storage required can be reduced when the portfolio includes more diverse VERs. Thus, resource actions that maximize the diversity benefits of VERs that reduce the magnitude of storage needed to address flexibility adequacy issues is one of the more cost-effective methods to address the increasing flexibility challenges. However, given PGE's growing transmission constraints, the costs associated with new transmission for VERs may offset their diversity benefits for flexibility adequacy.

6.8.2 Future improvements/limitations of current data and analysis

As noted, performing a flexibility assessment at the hourly granularity is a critical step in ensuring the reliability of a VERs-dependent system. There is a growing need to understand flexibility needs at the sub-hourly level. Sub-hourly flexibility assessments ensure the system has adequate operational capabilities to balance real-time generation changes of VERs. Assessing the sub-hourly flexibility needs is not only an extremely data and computationally intensive exercise but also raises several questions such as:

- Is there sufficiently granular data of a future system to perform this analysis within resource planning?
- Is there an industry standard or accepted modeling practices to perform such an assessment?
- How do we apply annual reliability targets and standards to a sub-hourly analysis?
- How do we account for the interaction between the different adequacy analyses, ensuring that the needs are not under or over-represented?

PGE is committed to exploring these questions, among others, to ensure we are accurately assessing the system's needs and are developing resource plans to deliver clean energy to customers reliably.

6.9 Climate adaptation

As the climate warms, PGE is adapting its planning process to reflect future temperature and hydrologic conditions. Generally, continued warming in the Northwest will lead to higher temperatures and reduced snowpack (as more precipitation falls as rain rather than snow). Higher temperatures will increase summer electric demand (more AC) and decrease winter demand (less heating). Less snowpack but similar precipitation levels will result in more hydropower in the winter (more rain increases stream flows) but less hydropower in the summer (due to less snowpack and an earlier melt).[152] The impact of these changes will result in relatively higher capacity needs in the summer (due to more demand and less hydropower) and relatively lower capacity needs in the winter (due to less demand and more hydropower).

6.9.1 Climate change in the 2023 IRP Reference Case

PGE incorporates some elements of climate change into the IRP Reference Case scenario and is studying other aspects of climate change via sensitivities. PGE also engaged a consultancy, Creative Renewable Solutions, to review climate change incorporation in the IRP and to provide recommendations for future improvements. The consultancy's work is in the **Ext. Study-III, Climate adaptation**.

The IRP Reference Case incorporates climate change by:

- Including a warming assumption based on historical temperature trends in the load forecast. See **Section 6.1, Load forecast**, of this chapter for more information on the load forecast.
- Using a reduced number of historical years (30) for both temperature and hydropower sampling in the adequacy model to better reflect climate trends.
- Using climate change model data in the market capacity study.[153] This study dictates how much market power is available to the PGE resource adequacy model, Sequoia. Switching to climate change model data played a role in allowing market power access in the winter and restricting power market access in the summer.

Information on how historical temperature trends align with climate change model data are in **Appendix D, Load forecast methodology**. **Appendix G, Market capacity study**, discusses how climate change data impacted that analysis.

6.9.2 Temperature years in the 2023 IRP adequacy model

The IRP uses the Sequoia model to examine resource adequacy and determine capacity need in future years. The IRP uses the corporate load forecast and historical weather years to create the hourly load profile used in Sequoia and provide load variations based on weather. In past planning work, Sequoia used temperature data from 1980 through the most current year

[152] There is some ability to store/move water from month to month at select Northwest hydroelectric projects, but the overall trend is towards more water/hydro generation in the winter, and less in the summer.
[153] The market capacity study uses data from the Northwest Power & Conservation Council. Their switch to climate change data for the 2021 Power Plan led to the switch in the study.

available. For the 2023 IRP, the model uses the most recent 30 years (1992-2021). The rationale for the switch is that more recent temperature data should better reflect the changing climate.

To test the impact of switching to the 30-year record, Sequoia ran with two sets of temperature years:

- 1980-2021, a 42-year temperature record
- 1992-2021, a 30-year temperature record (created by shortening the 42-year record)

Table 18 shows how the seasonal capacity need in the year 2026 varies depending on the number of temperature years used in the model. In both summer and winter, the capacity need is higher in the 30-year record than in the 42-year record.

Table 18. Seasonal capacity needs in year 2026 under different weather years (MW)[154]

	42 load years	30 load years
Summer	452 MW	506 MW
Winter	417 MW	430 MW

6.9.3 Hydropower climate change data sensitivities

Resource adequacy needs can vary due to hydro conditions. Some years have relatively high levels of hydropower generation due to high levels of snow and rainfall. Due to the higher levels of hydropower generation, those years may have fewer adequacy issues than average. Other years have low levels of hydropower generation due to decreased rain/snow and may face more adequacy challenges than average.

Incorporating a wide and realistic array of hydro conditions in resource adequacy modeling is important to provide an accurate picture of system needs. In past planning work, Sequoia used a 79-year (1929-2007) hydro record. For the 2023 IRP, the model uses the most recent 30-year record (1989-2018). The rationale for the switch is that more recent hydrological records should better reflect the changing climate.

[154] These tests use the 30-year hydro record from the 2023 IRP.

The IRP tests how six different hydro generation records impact resource adequacy needs. [155] The first test uses the historical 1929-2007 record. The second test uses the 30-year historical hydro record (1989-2018). The third through sixth tests use climate change model forecasts for 2020-2048.[156]

Table 19 shows how summer and winter capacity needs in the year 2026 differ by the hydro record. Compared to the 79-year record, all other hydro records result in equal or increased summer capacity needs and decreased winter capacity needs. Going forward, PGE will continue to explore using climate change hydro data in planning work.

Table 19. Year 2026 capacity need (MW)

	79-year record	30-year record	CanESM2	MICRO5	HadGEM2	GFDL
Summer	506 MW	506 MW	514 MW	508 MW	507 MW	506 MW
Winter	432 MW	430 MW	423 MW	426 MW	423 MW	431 MW

6.10 Need sensitivities

For the 2023 IRP, PGE examined the capacity and energy need impacts of different qualifying facility success rates, accelerated load growth beyond the high Need Future, contract renewals, market emissions rates and Colstrip exiting the portfolio four years early.

6.10.1 Qualifying facility sensitivities

PGE ran two qualifying facility (QF) success rate sensitivities focusing on years 2026 and 2030. These sensitivities primarily impact the amount of solar energy on the PGE system. The Reference Case QF assumptions and the two sensitivities follow. In all cases, the IRP assumes that QF contracts do not renew after they end.

[155] For all of the tests, the data which are changing are for the larger PGE owned/contracted projects which are Mid-C contracts associated with specific dams and the Pelton Round Butte projects. The impact of changing the hydro record for smaller hydro projects is not assessed in the IRP.
[156] The 30-year hydro record and climate change hydro data are from BPA/US Army Corps of Engineers and processed by the consultancy Creative Renewable Solutions. More information on the climate models is available in **Ext. Study-III, Climate adaptation**.

- Reference Case: All QFs that are currently online plus 50 percent of executed Schedule 201 projects and 100 percent of executed Schedule 202 projects are included.[157]
- Low QF sensitivity: All QFs that are currently online plus 50 percent of executed Schedule 201 projects and 50 percent of executed Schedule 202 projects are included.
- High QF sensitivity: All QFs that are currently online plus 100 percent of executed Schedule 201 projects and 100 percent of executed Schedule 202 are included.

Table 20 shows capacity needs for winter and summer under the Reference Case and high/low QF case assumptions. With fewer QFs on the system, capacity needs increase; with more QFs on the system, capacity needs decrease or stay the same.

Table 20. Qualifying facility sensitivity Capacity need (MW)

Capacity impact	2026 summer	2026 winter	2030 summer	2030 winter
Low QF	537	431	1,156	1,008
Reference	506	430	1,136	1,004
High QF	505	430	1,136	1,004

On an energy basis, in 2026, the Low QF sensitivity results in a 36MWa decrease in energy, increasing PGE's energy shortage and requiring additional resources. The High QF sensitivity results in a 1MWa increase in energy, reducing the need for new resources.

This analysis shows that delays or terminations of executed QF projects have an impact on capacity and energy needs. To minimize these risks, PGE will continue to monitor the status of QF projects and provide updates within the docket if changes materially impact the Action Plan (**Chapter 12**). PGE continues to advocate in OPUC policy and rulemaking dockets for changes in the power purchase agreements and the contracting process for QFs that would reduce speculative contracting and increase the success rate of QFs that sign power purchase agreements.

[157] Schedule 201 resources are 10 MW nameplate in size or fewer; Schedule 202 resources are greater than 10 MW, not to exceed 80 MW.

6.10.2 Accelerated load growth sensitivity

In addition to the High Need Future which includes the high building and transportation electrification adoption cases from the DSP, the IRP includes an electrification and load sensitivity to understand the combined impact of the following possibilities:

1. Increased building electrification from building-related Climate Protection Program compliance being achieved through electrification only (this results in higher building electrification than the high Need Future).[158]
2. Transportation electrification growth that is more aggressive than the Advanced Clean Cars II policy (this results in higher transportation electrification than the high Need Future).[159]
3. A base load forecast with higher load growth in part due to increased industrial growth.

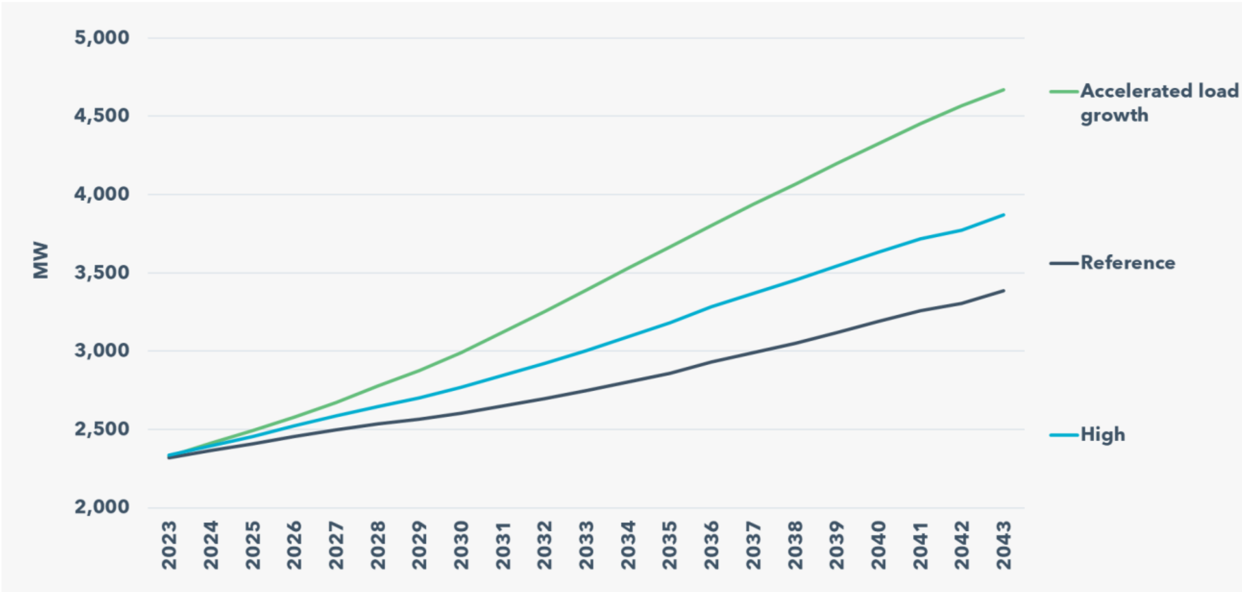
PGE created this sensitivity to test the capacity need and load impact of these possibilities in aggregate. **Table 21** compares the capacity need of this accelerated load growth sensitivity against the IRP's reference Need Future and high Need Future for years 2026 and 2030. **Figure 47** provides the same comparison on an annual energy load basis.

Table 21. Capacity need (MW), high electrification & load sensitivity

Case	2026 summer	2026 winter	2030 summer	2030 winter
Reference	506	430	1,136	1,004
Accelerated load growth	788	870	2,020	2,036
High Need Future	617	628	1,357	1,302

[158] The Climate Protection Program reduces GHG emissions from multiple sources, including space heating, available at: https://www.oregon.gov/deq/ghgp/cpp/pages/default.aspx
[159] Advanced Clean Cars II puts Oregon on a trajectory to 100 percent EV sales for passenger cars, SUVs and light-duty trucks by 2035, available at: https://www.oregon.gov/deq/rulemaking/Pages/CleanCarsII.aspx

Figure 47. Comparison of the accelerated load growth sensitivity with the IRP reference and high Need Future



6.10.3 Contract extension sensitivity

Table 22 estimates how the IRP's capacity and energy needs change based on existing contract renewal. The contracts included in the table are:

- A 100 MW capacity contract to Avangrid that expires in 2024
- A 200 MW capacity contract to BPA that expires in 2025
- Contracts with Douglas PUD that expire in 2025 and 2028

In the following table, all contracts extend through the year 2030. Contract extension reduces both energy and capacity need in all impacted years.

Table 22. Energy and capacity needs with and without select contract extensions

Year	Ref. case energy need (MWa)	Energy need with extensions (MWa)	Ref case summer capacity (MW)	Summer cap with extensions (MW)	Ref case winter capacity (MW)	Winter cap with extensions (MW)
2024	0	0	344	252	55	2
2025	0	0	51	-	-	-
2026	58	0	506	-	430	-
2027	277	167	568	48	502	-

Year	Ref. case energy need (MWa)	Energy need with extensions (MWa)	Ref case summer capacity (MW)	Summer cap with extensions (MW)	Ref case winter capacity (MW)	Winter cap with extensions (MW)
2028	504	388	624	104	614	28
2029	757	603	791	164	683	96
2030	905	756	1,136	540	1,004	458

6.10.4 Market emissions rate sensitivity

PGE buys unspecified power on the market. **Table 23** estimates how energy needs would change in 2030 if half of the recent quantity of unspecified market power purchased by PGE were instead specified as non-emitting. As existing thermal resources are considered always available for resource adequacy purposes, this change in purchases would have no effect on estimated capacity needs. However, such a change would significantly reduce PGE's yearly energy needs, which in turn would reduce the quantity of non-emitting generation and customer price increases. These results suggest that determining the appropriate emission factor of market purchases will be critical going forward to accurately determine resource needs.

Table 23. 2030 energy need with 50 percent of unspecified market purchases designated as non-emitting

2030 Energy Need	MWa
Low Need Future	746
Reference Need Future	905
High Need Future	1,071
Reference Need Future with 50% of unspecified market purchases designated as specified/non-emitting	686

6.10.5 Colstrip sensitivity

Table 24 estimates how capacity and energy needs change in years 2026 through 2029 if Colstrip no longer provides power to retail customers starting in 2026. This differs from the Reference Case assumption of Colstrip providing power to retail customers through the end of 2029. Capacity needs increase when Colstrip no longer provides retail power starting in 2026, but energy needs decrease. The decrease in energy needs is due to Colstrip having a higher GHG intensity than other resources in the portfolio. Its higher GHG intensity results in higher GHG emissions per MWh in the portfolio; thus, fewer MWhs from GHG-emitting sources are kept for retail load service. This accounting happens in the Intermediary GHG model (see **Chapter 5, GHG emissions forecasting**, for details on that model).

Table 24. Energy and capacity needs with and without Colstrip

Year	Ref. case energy need (MWa)	Energy need w/o Colstrip (MWa)	Ref case summer capacity (MW)	Summer cap w/o Colstrip (MW)	Ref case winter capacity (MW)	Winter cap w/o Colstrip (MW)
2024	0	0	344	344	55	55
2025	0	0	51	51	-	-
2026	58	0	506	799	430	726
2027	277	138	568	858	502	797
2028	504	406	624	917	614	902
2029	757	683	791	1,083	683	974
2030	905	905	1,136	1,136	1,004	1,004