Chapter 5. Virtual Power Plant (VPP)



This chapter details PGE's Virtual Power Plant (VPP) strategy and benefit-cost analysis, focusing on three main elements:

VPP Components & Strategy

- Definition and purpose of VPP
- Core resources: Flexible load, distributed supply (solar + storage), distributed thermal
- Technology platforms and integration
- Grid services and capability stages
- Strategic alignment with customer needs

Resource Development

- Flexible load programs targeting 211MW summer/158MW winter by 2028
- Distributed solar and storage forecasts and implementation
- Dispatchable Standby Generation (DSG) program expansion
- Technology platform integration requirements

Benefit-Cost Analysis

- Overall benefit-to-cost ratio of over one
- Detailed analysis of costs and benefits across VPP components
- Quantitative and qualitative impact assessment
- Conservative preliminary analysis showing positive economic returns

The chapter establishes how these elements work together to create a comprehensive VPP strategy while demonstrating its economic viability and customer benefits.

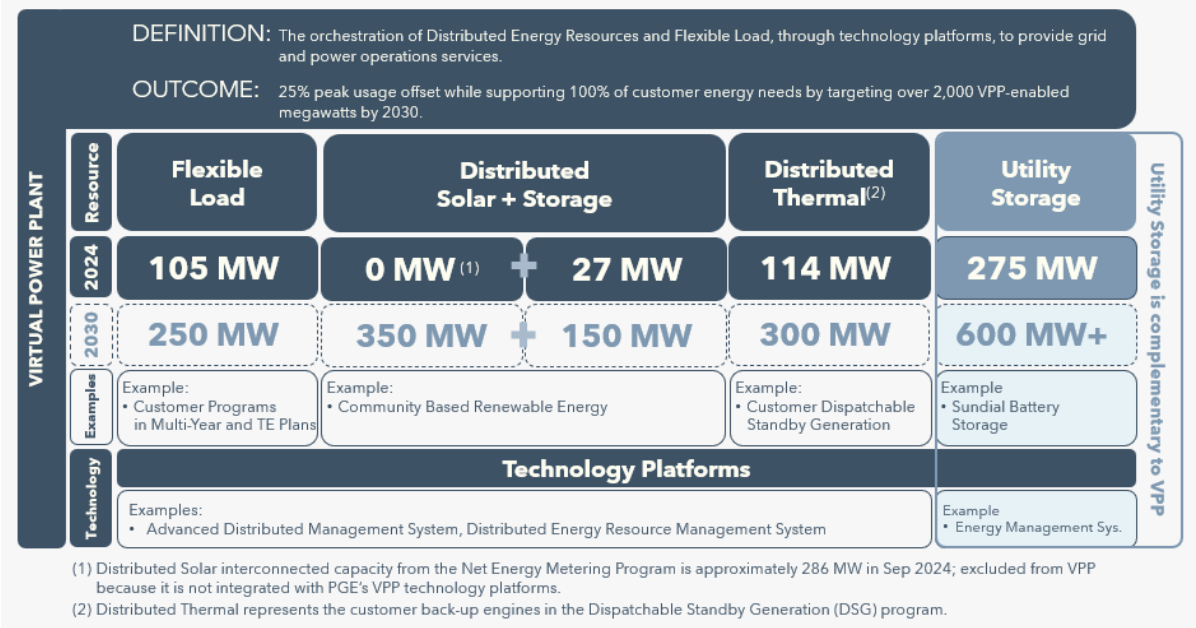
5.1 Virtual Power Plant

5.1.1 What is the VPP

The term "VPP" is used across the industry with disparate and potentially conflicting definitions. PGE's VPP is a combination of resources, technologies, infrastructure, and operations. To clearly articulate these discrete components and describe how they are integrated to scale the size and capabilities of the VPP, PGE defines its VPP as "the orchestration of Distributed Energy Resources (DERs) and Flexible Load, through technology platforms, to provide grid and operations services." The VPP is *how* PGE integrates and operates the distribution system with increasingly distributed resources, flexible loads, and technology in an optimized manner to deliver value to customers.

A visual representation of this definition is provided below. Further description of the resources, quantities targeted, technology platforms, and the how they are orchestrated is provided in **Figure 19** and the sections that follow.

Figure 19. Visualization of virtual power plant definition

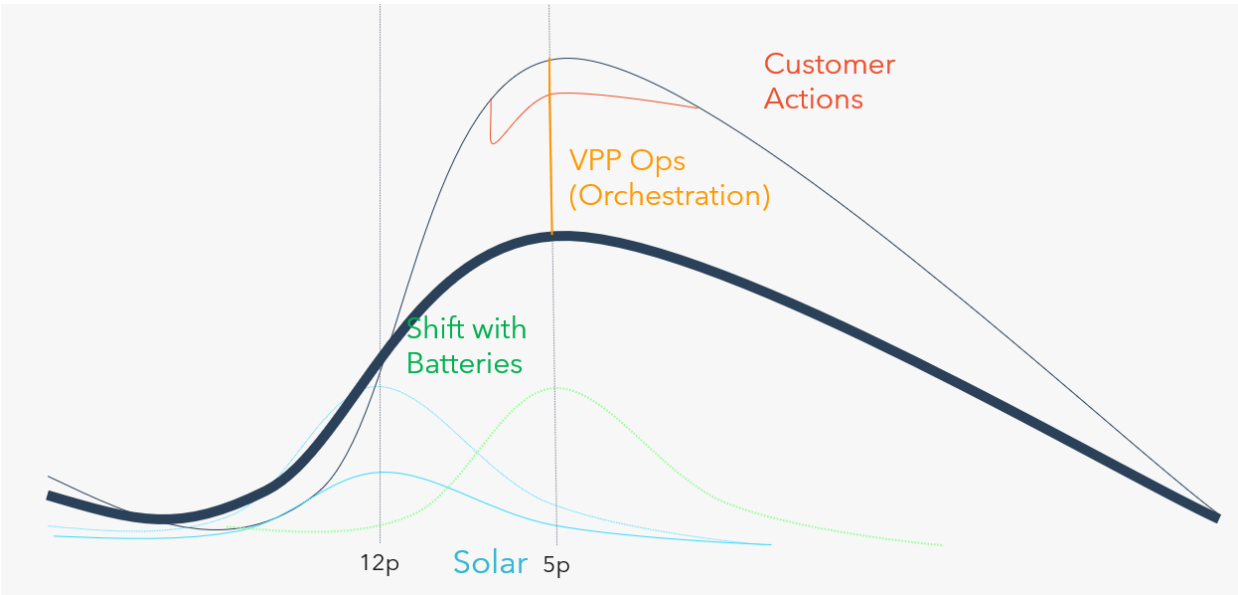


5.1.2 Why develop a Virtual Power Plant

There are several reasons to develop a virtual power plant (VPP), each integrally contributing to a more reliable and resilient grid that scales electrification to serve customer energy needs and enables efficient decarbonization as affordably as possible.

As a sophisticated aggregation, integration, and optimization platform through orchestration of DERs and flexible loads to deliver grid and operations services, PGE's VPP enables active customer participation in controlling their energy usage and costs. The VPP provides agility to meet the needs of customers through a reliable distribution grid, delivering a range of services by reshaping demand curves (**Figure 20**), accelerating decarbonization, helping customer affordability, and to bridge the time for new transmission and clean energy capacity to come online.

Figure 20. Illustration of shifting energy generation and usage via VPP Orchestration



5.1.2.1 Customer growth in energy use

PGE's strategy continues to reflect the needs of our customers and meets their growth with clean, reliable, and affordable energy. Customers share a common need for energy but their drivers for when, how, and how much energy they use vary.

The residential growth forecast is driven by electrification and adoption of customer products like electric vehicles, heat pumps, and smart devices. Customers expect seamless interoperability of their devices and a digital interface to see and manage their energy use.[32] PGE's VPP strategy integrates programs through customers' preferred channels while ensuring affordability options for all residential customer segments (**Section 8.5.1 MYP programs)**.

The largest acceleration in customer growth is occurring in the industrial segment. Driven by national policy to strengthen U.S. economic competitiveness and enhance national security through domestic manufacturing (particularly semiconductors)[33] along with the growing computational demands of emerging technologies like generative artificial intelligence (AI), we are experiencing a global increase in demand for energy that has not been seen since post-World War II industrialization.[34] PGE's service territory is a key location for these customers. The geographic location of the international fiber terminus, high-tech workforce

[32] Reference Section 5.2.7 Sensing, Measurement, & Automation and Section 5.2.8 Telecommunications.
[33] CHIPS and Science Act. Available at: https://www.congress.gov/bill/117th-congress/house-bill/4346
[34] A New Surge in Power Use Is Threatening U.S. Climate Goals. Available at: https://www.nytimes.com/interactive/2024/03/13/climate/electric-power-climate-change.html

capabilities, reliable and affordable power, and a clean energy ethos all converge here and are stimulating industrial growth.[35,36] This creates opportunity to engage with these customers to integrate VPP capabilities and bring innovative solutions to meeting their growing needs while benefiting all customers and the community.

Commercial growth of small and medium businesses and the municipalities within which they operate is also incorporated in PGE's load forecast. Subsegments such as builders, developers and fleet managers are incorporating sustainability more directly into their operations. In some cases, subdivisions are now being designed with fully electric homes and electric vehicle charging in every garage, and trucking and logistics companies are building charging depots with the capability to charge electric vehicle fleets quickly. Key to enabling growth in this segment are the municipalities where these businesses operate as they are focused on growing the economy and making more goods and services available to their residents. For example, in Portland the Electric Vehicle (EV) Ready Code Project amends the Portland Zoning Code (Title 33) to require all new multi-dwelling and mixed-use development with five or more units – that include onsite parking – to provide EV-ready charging infrastructure at higher rates than required by State rules.[37]

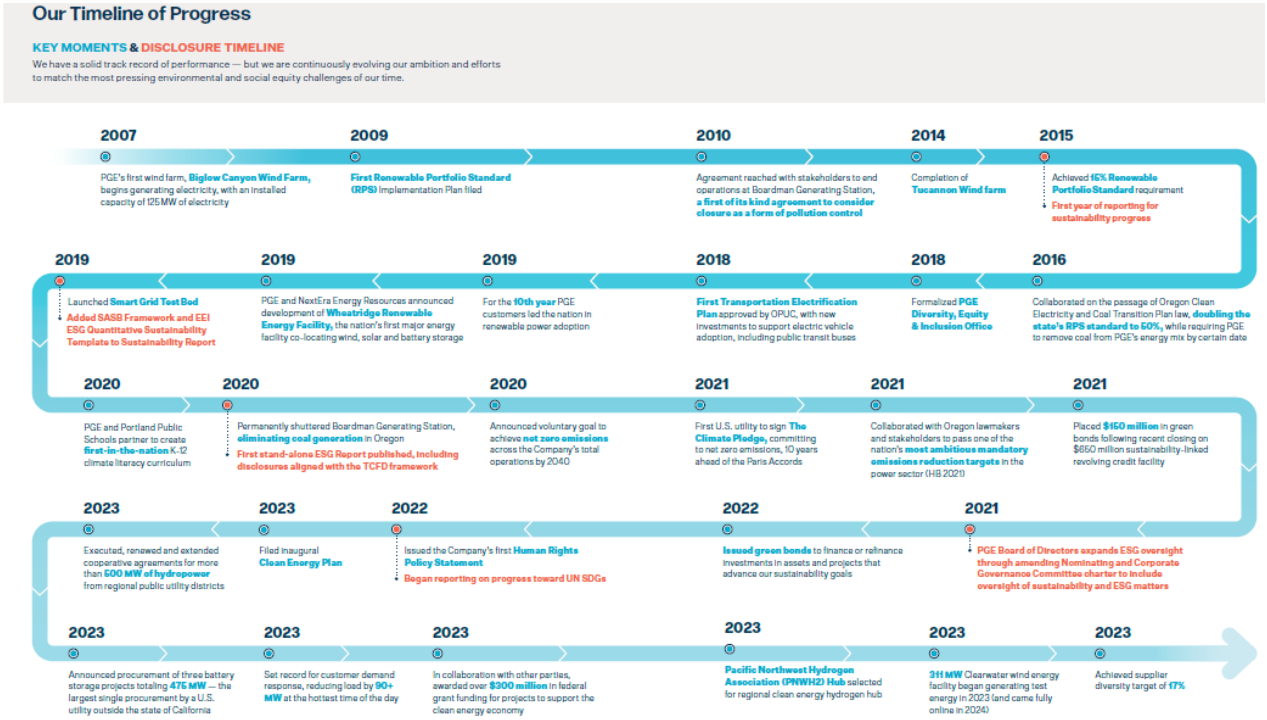
5.1.2.2 Decarbonization through electrification

PGE began the transition to clean energy many years ago. Milestones along that journey are shown in in **Figure 21** below. We have long been advocates for energy efficiency, and have been integrating wind and solar generation since the early 2000's. We closed Oregon's only coal fired plant at Boardman. We are exploring different ways to operate our existing thermal fleet, which includes some of the highest efficiency natural gas plants in the nation. We are also exploring novel cleaner fuels, such as hydrogen, to replace natural gas combustion in existing plants. In the future, other non-emitting technologies like long-duration storage, off-shore wind, advanced geothermal, and nuclear may prove cost-effective for serving customers in our region, but today they have long development timeframes.

With the increased dependence on weather-driven resources, like wind, solar, and hydro, a reliable clean energy grid requires distributed energy resources and flexible loads, orchestrated through technology platforms, to provide grid and operations services. It requires the VPP.

[35] Daimler Truck North America Expands Portland, Oregon, Operations. Available at: https://www.opb.org/article/2024/03/20/intel-investment-oregon-federal-funding/
[36] Intel announces $36B Hillsboro investment following federal funding commitments. Available at: https://www.areadevelopment.com/newsitems/5-16-2024/daimler-truck-north-america-swan-island-oregon.shtml#:~:text=Daimler%20Truck%20North%20America%2C%20an,expected%20to%20create%20150%20jobs .
[37] Portland Zoning Code (Title 33). Available at: https://efiles.portlandoregon.gov/record/16627527

Figure 21. Timeline of progress toward clean energy transformation[38]



5.1.2.3 Customer energy management

The rapid customer adoption of distributed energy resources (DERs) and technology that enable flexible load provides both tremendous opportunities to utilize resources already on the system, as well as necessitates an evolution in how PGE operates its distribution system. Technology and resources must be integrated with the grid to unlock the value of energy supply and load flexibility. [39]

Through our smart grid connected appliance programs for water heaters and thermostats customers can automatically adjust their energy use. Our customer offerings aim to benefit both participating and nonparticipating customers, support grid reliability and increase portfolio flexibility and resource diversity. We continue to partner with customers, in collaboration with ETO, on energy efficiency programs (e.g., rooftop solar, battery storage and electric vehicle chargers).

[38] PGE 2023 ESG report, pages 8-9. Available at: https://downloads.ctfassets.net/416ywc1laqmd/FMJv3RPASD70GLZFvHx3g/6fe4b31c4eba6669557f5c97ac8c3584/Printer-friendly_ESG_Report_2023.pdf

[39] PGE CEP & IRP portfolio analysis refresh addendum. Available at: https://assets.ctfassets.net/416ywc1laqmd/E074bPlYZi0LF129vutf7/a6766ab7ba78c9cf28a51a2a0441a7c9/2023_CEP-IRP_Portfolio_Analysis_Refresh_Addendum.pdf

5.1.2.4 Increase resilience and bridge infrastructure development

To serve our communities with reliable energy, we continue to actively plan and invest in transmission, distribution, and generation to support the growth of existing and new load from our customers.

The long development timeframes noted above to bring new transmission and off-system clean energy to our customers necessitate orchestrating two-way energy flows on the distribution grid. This provides capability to utilize DERs and Flexible Load to improve distribution utilization and serve as a bridge until new central resources and transmission capacity are available.

We continue to innovate with the local community on smart grid technology learning programs, including the Smart Grid Test Bed (SGTB) and Smart Grid Advanced Load Management & Optimized Neighborhoods (SALMON) projects. We are using wireless smart sensors and centrally controlled automated switches to help isolate disruptions and more quickly reroute power, preventing or shortening disruptions. During outages, these technologies help us to share timely, accurate information with customers – notifying them when their power goes out and providing updates through digital and mobile channels.

We have been working with municipalities to pair energy storage batteries with rooftop solar and advance equitable electric vehicle charging needs through a municipal charging program, placing Level 2 chargers on utility poles or in the right-of-way. We are also working with transit providers and school districts on bus charging on-route and at the depot.

5.1.3 Examples of the services that will be provided by the VPP

Today, the VPP provides essential grid services when they are most needed such as load reduction during peak load events and contingency and frequency reserves for grid disruptions. Further capabilities to provide locational value, voltage regulation, microgrid support, and other grid services are unlocked with the implementation and integration of technology platforms, such as the Enterprise DERMS, for resource dispatch.

5.1.3.1 Grid services

Grid Services (**Table 5**) describe the list of grid and operations services that can be individually or jointly provided by a Resource or combination of Resources via the VPP. The PGE Balancing Authority schedules services for reliable and compliant operations. Grid Services include:

Table 5. Example grid services that a VPP can provide[40]

Service Category	Grid Service [X]	Duration [Y]	Response Time [Z]
Energy Schedule	Capacity	3 hours	Scheduled
	Energy	1 hour	< 5 minutes
Reserve	Contingency	1 hour	< 10 minutes

[40] NOTE: Program and Resource Capabilities vary by Grid Service. Support for each Grid Services varies based on Program and Resource parameters for operation.

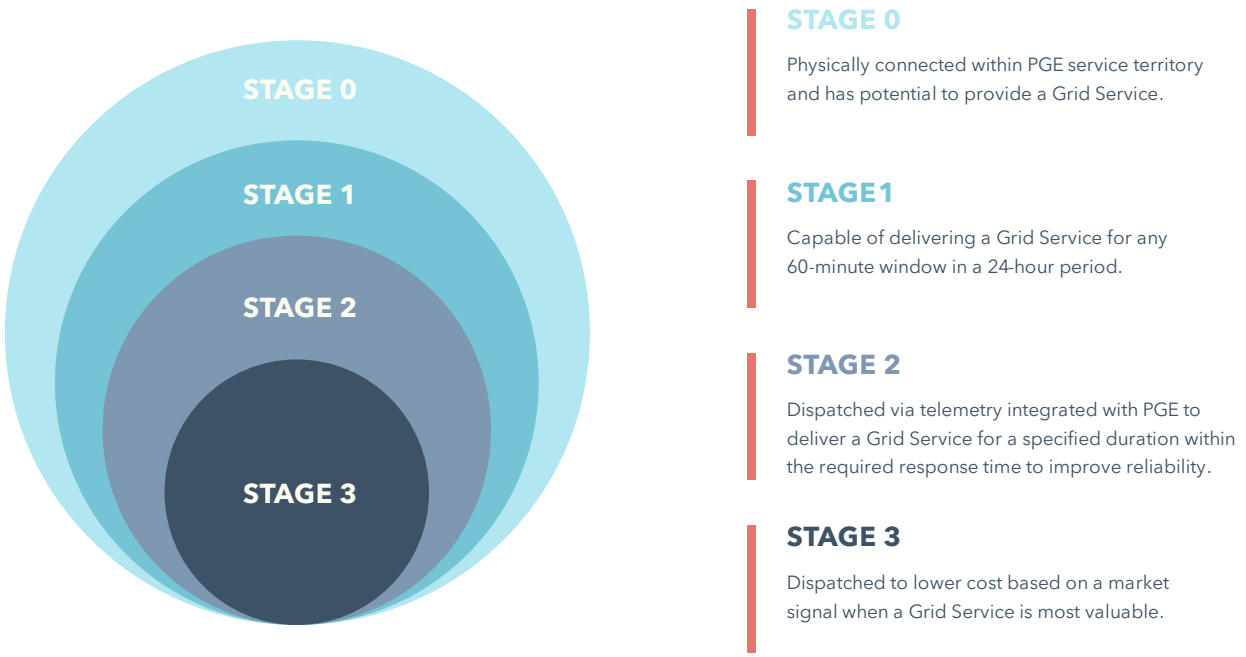
Service Category	Grid Service [X]	Duration [Y]	Response Time [Z]
	Frequency	1 hour	< 2 seconds (20-52 seconds for compliance)
Regulation	Regulation	1 hour	< 4 seconds
Voltage	Voltage	Seconds to minutes	< 10 minutes
	Volt-VAR Control	Seconds to minutes	60 cycles < Z < 90 seconds

Other Grid Services are not considered to be provided by the VPP at this time. For example, Black-start Service is not a service currently provided by the VPP.

5.1.3.2 Capability stages

Capability Stages (**Figure 22**) encourage cross-functional coordination and create the visibility necessary to inform the sequence of execution that optimizes development of the VPP. Capability Stages include:

Figure 22. Capability stage definitions[41]



5.1.3.2.1 CAPABILITY STAGE 0

Capability Stage 0 is the foundational qualification for VPP. At this Stage, the intent is to identify the devices and resources connected within PGE's service territory which have the potential to provide Grid Services in the future.

[41] NOTE: Program and Resource Capabilities vary by Grid Service

A resource/program at this stage is not required to provide the specified Grid Service [X] for a minimum Duration [Y], within a specified Response Time [Z], or for a quantifiable value at this stage.

For Programs, the requirement to qualify at Stage 0 is that the device exists in PGE's Service Territory, but the device doesn't need to be participating. For example, a customer may have a smart thermostat, but may not be participating in PGE's Peak Time Rebate Program.

For Resources, the requirement to qualify at Stage 0 is that the resource has an approved or waived interconnection agreement to PGE's system. For example, a customer may be building a rooftop solar panel system, but it may not be operational, may not have a smart invertor, nor be connected to a battery. As long as that system is approved in the interconnection queue it qualifies for Stage 0. The purpose of including an interconnection waiver is to reflect the process by which resources connected through the Dispatchable Standby Generation (DSG) Program (Schedule 200) are connected.

In contrast, an interconnection that has been requested but is not approved/waived, does not qualify for Stage 0. This is to reduce the risk of overestimating the potential to provide Grid Services from resources that don't get approved or projects that are cancelled.

5.1.3.2.2 CAPABILITY STAGE 1

Capability Stage 1 requires a program or device to have the ability to provide a Grid Service during any hour within a 24-hour period. At this stage, the intent is to require the devices and resources to have the ability to be scheduled to provide a Grid Service when needed.

A resource/program is not required to provide the specified Grid Service [X] repeatedly in the same 24-hour period, nor is activation required within a specified Response Time [Z] at this stage.

This provides additional value over Stage 0 due to the ability to shift when energy is used or store energy for later use. For example, a customer with a solar panel system coupled with a battery will have the ability to charge the battery when the sun is shining and use that energy in the middle of the night. In contrast, a stand-alone solar panel system may have to be curtailed when it could otherwise be generating, thereby foregoing the utilization of that clean energy.

For Programs, the requirement to qualify at Stage 1 is that the device is registered to participate in a PGE Program, but the customer doesn't need to respond when called. For example, a customer participating in PGE's Peak Time Rebate Program may elect to opt out during an event.

For Resources, the requirement to qualify at Stage 1 is that the resource be coupled with a source that enables its energy to be utilized in any hour as described in the examples above.

5.1.3.2.3 CAPABILITY STAGE 2

Capability Stage 2 requires a program or device to have the ability to provide the specified Grid Service [X] for a minimum Duration [Y], within a specified Response Time [Z]. At this stage, the intent is to require the devices and resources to have the ability to dispatch in concert with the conditions of the grid to maintain or improve reliability.

A resource/program is not required to have a direct compensation mechanism at this stage.

This provides additional value over Stage 1 due to the ability to respond to dynamic grid conditions with confidence that system reliability will be maintained. For example, if there is a forced outage of a generation facility which impacts grid frequency, a device or resource at Capability Stage 2 specified for Frequency Reserve Service can be activated within 2 seconds to help mitigate the event. As another example, if a feeder is experiencing high load conditions, the device or resource can be scheduled within 5 minutes to reduce the load along the line by activating customers to reduce usage or utilize their distributed energy resources to reduce loading on the line.

For Programs and Resources, the requirement to qualify at Stage 2 is to be monitored and dispatched via telemetry integrated with PGE's Enterprise DERMS system. Until operational go-live of Enterprise DERMS, resources connected to GenOnSys will qualify for Stage 2. After operational go-live of the Enterprise DERMS, GenOnSys will become an Edge DERMS and resource dispatch will be required via the Enterprise DERMS to qualify for Stage 2.

5.1.3.2.4 CAPABILITY STAGE 3

Capability Stage 3 requires a program or device to have the ability to be dispatched to lower system cost, based on a market signal. At this stage, the intent is to require the devices and resources to have the ability to dispatch when they are most valuable.

This requires the existence of valuation and allocation mechanisms.

This provides additional value over Stage 2 due to the ability to dispatch programs and resources based on the dynamic grid conditions with confidence that the lowest cost portfolio is being utilized. For example, if there is congestion on a feeder, the options to ask customers to reduce their load or to utilize (charge or discharge) their distributed energy resources will be dispatched based on the highest value option.

5.1.3.3 Capability stage qualification thresholds

Qualification Thresholds (**Table 6**) provide the requirements for each program or resource type to qualify for each Capability Stage. The Qualification Thresholds are:

Table 6. Qualification thresholds for each VPP capability stage[42]

Capability Stage	Threshold Qualification	Customer Programs	Distributed Solar	Distributed Thermal	Distributed Storage	Utility Storage
Stage 0 - connection	Base qualification					
Connected to PGE's system and has potential to	Physically connected within PGE service territory	Device connected within PGE Service Territory	Interconnection to PGE's system approved	Interconnection to PGE's system approved/accepted	Interconnection to PGE's system	Interconnection to PGE's system approved

[42] NOTE: Program and Resource Capabilities vary by Grid Service

Capability Stage	Threshold Qualification	Customer Programs	Distributed Solar	Distributed Thermal	Distributed Storage	Utility Storage
provide Grid Service [X]					approved/accepted	
Stage 1 - delivery	Stage 0 plus					
Customer/ Resource delivers Grid Service [X] for Duration [Y]	Capable of delivering in any 60-minute window in a 24 hour period	Customer enrolled in a PGE Program	Solar coupled with battery storage	Thermal fuel source available	Storage coupled with a charging source	Storage coupled with a charging source
Stage 2 - utilization	Stage 1 plus					
Customer/ Resource responds in Timeframe [Z] to committed Grid Service [X] for Duration [Y]	Monitored and dispatched via telemetry integrated with PGE	Connected to PGE Enterprise DERMS	Connected to PGE Enterprise DERMS	Connected to PGE Enterprise DERMS (GenOnSys for 2024)	Connected to PGE Enterprise DERMS (GenOnSys for 2024)	Connected to PGE EMS
Stage 3 - price	Stage 2 plus					
Customer/ Resource deployed when Grid Service [X] is most valuable	Dispatched to lower cost based on a market signal	Signal via PGE DERMS	Signal via PGE DERMS	Signal via PGE DERMS	Signal via PGE DERMS	Signal via PGE EMS

5.1.4 VPP resources: Flexible load programs

The Flex Load activities described herein are in service to the acquisition goals of 211 MW Summer and 158 MW winter demand response by 2028. These goals were laid out in PGE's 2019 & 2023 CEP & IRP, and associated Addenda.

Since 2021, existing pilot and program capacity has grown +20 percent, adding 22.8 summer MW and 13.6 winter MW, forecasted to end 2024 with an additional 10.8 summer MW and 4.3 winter MW. PGE seeks to continue to grow existing pilot and program capacity with an additional 22.7 summer MW and 8.5 winter MW by the end of 2026. This performance represents both growth and retention of the portfolio.

Flex Load customers served are summarized in **Table 7**, below, with detail for the underlying offerings in the subsections thereunder.

Table 7. Flex Load portfolio: Customers enrolled

Customers Served	2023 (actual)	2024 (forecast)	2025 (forecast)	2026 (forecast)
Residential Offerings	188,187	204,629	229,847	253,430
Commercial Offerings	13,162	15,602	17,512	19,578

PGE is working to increase the value and utilization of Flexible Load locally and regionally.

Requirements of state and regional entities regarding demand response participation in markets and resource adequacy programs such as the California Independent System Operator Energy Imbalance Market and Extended Day-Ahead Market (CAISO EIM and EDAM) and the Western Resource Adequacy Program (WRAP) need to be aligned to maximize the value of Flexible Load.

PGE has advocated for demand response to receive credit for its capacity contribution through WRAP's resource adequacy participants committee (RAPC) process. This resource adequacy credit is another source of valuation or benefit that can be ascribed to PGE's demand response and Flex Load investments. Within WRAP, demand response programs can receive credit in one of two ways: submitted as a 'Qualifying Resource' or as a load shaving capability in the forward showing demonstration.

To date, PGE has submitted demand response as load shaving capability. In doing so, PGE's peak load demonstration + Planning Reserve Margin is lowered by the amount claimed in the forward showing. This delivers real benefits to customers, because filling PGE's Planning Reserve Margin with supply-side resources creates opportunity costs that are borne by customers.

Additionally, PGE is pursuing opportunities for co-deployment with Energy Trust, with the goal to leverage synergies between offerings and capabilities of both organizations to more effectively and economically deploy products to customers. PGE is also funding NEEA market transformation along with other regional utilities.

Table 8. Prospective co-deployment measures PGE is pursuing

Measure	Objective	ETO-Exception	ETO-Pilot	RTF-Flex[43]	Public Sector Braiding[44]
All Insulation/ Weatherization	Affordability, DERs Activation	Expires March 2028		2025-2029	IRA HEAR, 25C
Low-Income Insulation/ Weatherization	Affordability	Expires March 2028		2025-2029	IRA HEAR, 25C
Ducted Heat Pumps	Affordability, DERs Activation	Expires Dec 2026 (Fixed Promotion)	No-Cost Program Delivery Pilot (PDP)	2025-2029 upgrades/ conversions	IRA HEAR, 25C
Ductless Heat Pumps	Affordability, DERs Activation	Expires March 2025	No-Cost Program Delivery Pilot (PDP)	2025-2029 + Small Commercial	IRA HEAR, 25C
Extended Capacity Heat Pump	DERs Activation	Expires Jan 2026			IRA HEAR, 25C
Manufactured Home Replacement	Affordability	Expires March 2025			
New Buildings	DERs Activation	Expires March 2024			
Heat Pump Water Heater	Affordability, DERs Activation		No-Cost Program Delivery Pilot (PDP)	2025-2029 + Commercial	IRA HEAR, 25C
Connected Thermostat	DERs Activation	Equity Metrics < $500		2025-2029 + Commercial	
Line Voltage Thermostat	DERs Activation			2025-2029	

[43] The Regional Technical Forum (RTF) is a technical advisory committee to the Northwest Power and Conservation Council established in 1999 to develop standards to verify and evaluate energy efficiency savings. In the 2025-2029 Funding Levels the RTF has included in its business plan priority energy efficiency and demand response technologies.

[44] The Inflation Reduction Act (IRA) includes the Home Electrification Appliance Rebate (HEAR) program which provides funding for incentives to flow state energy offices. In addition, there exists IRS sections 25C and 25D for energy-efficient home improvements and residential clean energy credits.

Measure	Objective	ETO-Exception	ETO-Pilot	RTF-Flex[43]	Public Sector Braiding[44]
Level 2 Electric Vehicle Service Equipment	DERs Activation			2025-2029	25D
Irrigation Pump Controls	DERs Activation			2025-2029	
Battery	DERs Activation				ODOE, 25D
Inverter	DERs Activation				ODOE, 25D

5.1.4.1 Capabilities and customer benefit

PGE's comprehensive Flexible Load portfolio includes the following key pilots and programs:

- Energy Partner on Demand Schedule 26: This program targets large commercial and industrial customers, providing incentives for custom load curtailment strategies and event-based energy shifts. The offering is technology agonistic and flexible, with a mix of behavioral/manual participants and other customers who opt for direct load control.
- Residential Smart Thermostat: A direct load control offering aimed at residential HVAC systems, utilizing smart thermostats to manage and optimize energy usage.
- Peak Time Rebates (PTR): A behavioral/manual DR offering which incentivizes residential customers to reduce energy consumption during peak times without the need for up-front equipment investment.
- Time of Day (TOD): A residential time-varying rate offering designed to encourage customers to shift their energy use to off-peak times, reducing overall demand during peak periods.
- Energy Partner Commercial Thermostats Schedule 25: A direct load control offering which targets small and medium-sized businesses, using smart thermostats to manage HVAC loads.
- Multi-family Water Heater (MFWH): An offering targeting multi-family residences to control water heater loads, providing significant demand response potential in an underserved market segment.

5.1.4.2 Flexible load program MW forecast and funding

Table 9. Schedule for increasing summer capacity (MW)

Large-scale Pilots and Programs	2025	2026	2027	2028	2029
Energy Partner Sch 26	41.3	43.8	45.8	47.8	49.6
Energy Partner Thermostats	2.1	2.8	6.3	7.6	8.8

Large-scale Pilots and Programs	2025	2026	2027	2028	2029
MFWH	2	2.3	2.7	3.0	3.4
Peak Time Rebates	16.1	16.6	17.1	17.6	18.1
Res EV Smart Charging	2.6	3.3	4.1	4.8	5.6
Res Smart Thermostat	48.1	52.5	57.2	61.8	66.7
Time of Day	4.1	5.6	7.1	8.7	10.2
Grand Total	**116.3**	**126.9**	**140.3**	**151.3**	**162.3**

Table 10. Schedule for increasing winter capacity (MW)

Large-scale Pilots and Programs	2025	2026	2027	2028	2029
Energy Partner Sch 26	33.5	35.5	37.3	38.8	40.3
Energy Partner Thermostats	0.6	0.7	0.4	0.5	0.6
MFWH	2.5	2.8	3.2	3.7	4.1
Peak Time Rebates	12.0	12.4	12.8	13.1	13.5
Res EV Smart Charging	2.7	3.5	4.3	5.0	5.8
Res Smart Thermostat	9.9	10.8	11.9	12.9	13.9
Grand Total	**61.2**	**65.7**	**69.8**	**74.0**	**78.2**

Table 11. Summary of Flex Load funding

Activity	2025 (proposed)	2026 (proposed)	2025-2026 (proposed)
Residential Smart Thermostats	$3,756,000	$4,044,000	$7,800,000
Peak Time Rebates	$2,913,610	$2,967,105	$5,880,715
Time of Day	$666,500	$535,150	$1,201,650
Energy Partner on Demand	$6,087,977	$6,055,727	$12,143,704
Multi-family Water Heating	$1,170,250	$2,771,080	$3,941,330
Energy Partner Smart Thermostat	$1,422,000	$1,573,460	$2,995,460
NEEA Market Transformation[45]	$ 357,500	TBD	$ 357,500
Funding	**$16,373,837**	**$17,946,522**	**$34,320,359**
Smart Grid Test Bed[46]	*$ 2,030,214*	*$ 1,254,288*	*$ 3,284,502*
Residential EV Charging[47]	*$ 2,130,409*	*TBD*	*$ 2,130,409*
Holistic Flex Load Spending[48]	*$20,534,460*	*$19,200,810*	*$39,735,270*

5.1.5 VPP resources: Distributed supply (solar + storage)

The integration and optimization of distributed supply-side resources (likely primarily comprised of solar and storage) is a central goal of PGE's VPP.

PGE's intent is to continue progressing toward HB 2021's decarbonization targets and small-scale resource targets, while doing so in a way that prioritizes reliable energy supply and keeping prices as low as possible for customers. Currently, PGE's system has >460 MW of rooftop and distributed solar installed[49] that is being sub-optimized due to lack of

[45] While PGE expects NEEA's Market Transformation activity to continue past 2025, the scope and cost of that work remains to be determined. PGE will reengage with the Commission once PGE and other utilities have aligned on the scope and costs of that additional work and cost.
[46] Smart Grid Test Bed figures are subject to change; those funding proposals and related filings can be found in UM 1976. Available at: https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=21662.
[47] Residential Smart Charging pilot is funded separately under UM 2033 and has yet to propose funding for 2026. The 2025 funding for this pilot reflects the most recent available: that filed with PGE's 2023 Final Transportation Electrification Plan under UM 2033. Available at: https://edocs.puc.state.or.us/efdocs/HAH/um2033hah15818.pdf.
[48] As noted in the prior footnotes, Smart Grid Test Bed and Residential EV Charging activities are funded via separate dockets (UM 1976 and UM 2033, respectively) and are included for informational purposes only.
[49] Largely as a result of longstanding programs such as feed-in tariff, net energy metering, qualifying facilities and Oregon Community Solar Program

aggregation and widespread pairing with battery storage. While these resources add energy to the grid, they provide little flexibility to the grid as defined in the Capability Stages above and point to the need for continued action by PGE and customers.

As PGE seeks to grow the number of renewables connected to our grid, the company is also seeking new builds by partnering with customers and communities to bring forward new projects via Community Based Renewable Energy (CBRE) and other opportunities to add small-scale resources in a way that provides best value for customers. The availability of subsidies, including those from the Energy Trust of Oregon (ETO) via solar and battery incentives, the EPA's Solar 4 All Funding, potential partnership with the Portland Clean Energy Community Benefits Fund (PCEF), and the Federal Investment Tax Credit (ITC), provide a unique opportunity to increase grid stability and flexibility as energy infrastructure (transmission) is built and technology advances in preparation for Oregon's 2040 target of zero carbon.

5.1.5.1 Key outcomes

Combining distributed solar with distributed storage and the technology platforms included in the VPP is advantageous for several reasons. First and foremost is that it provides customers energy independence and resilience. Doing so puts control into customers' hands to drive cost savings and help mitigate the increase in outages caused by extreme weather events. Second, pairing solar and storage increases grid stability while reducing reliance on emitting resources. PGE proposes to act swiftly while there are considerable subsidies available now that will help buy down the cost of this investment on behalf of customers.

Included in **Table 12** below is a summary of the targets PGE has established for both distributed solar and storage and incorporate time required to navigate global supply chain constraints, need for updated/amended permits, and construction timelines. Critical to success is active participation from customers with standalone rooftop solar, counterparties (QF, CSP), and communities (CBRE) as PGE looks to partner in delivering the clean, reliable, affordable grid of the future.

5.1.5.1.1 SCHEDULE AND IMPLEMENTATION

Each program contributing to the distributed solar and storage planned outcomes requires planning, design, regulatory engagement, and ultimately deployment. Some programs are more mature than others today and require less planning and design, while others are new or in their infancy.

5.1.5.1.2 NEW STANDALONE DISTRIBUTED STORAGE

As PGE adds new VPP resources and as demand growth is realized, PGE anticipates that adding new standalone distributed storage on the grid can help alleviate distribution, transmission, or power flow constraints. The deployment of standalone grid-sited storage may allow for investments in new infrastructure to be deferred and/or to help mitigate the operational risk of transmission constraints.

The combination of PGE's Integrated Resource Plan (IRP)/Clean Energy Plan (CEP) and Distribution System Plan (DSP) processes will help identify forecasted opportunities for the

deployment of storage. PGE is actively working on identifying potential sites for battery storage projects within our distribution system. Our team is currently analyzing grid needs across all distribution substation transformers, focusing on both summer and winter peak loading values. This assessment is based on our established substation transformer planning guidelines.

The ongoing analysis aims to determine the peak demand reduction required at various locations to optimize transformer loading. Additionally, we are evaluating the maximum energy requirements over a 24-hour period for each site. It's important to note that this initial assessment primarily considers loading conditions and serves as a starting point for further investigation.

As we progress, we will conduct more comprehensive evaluations that take into account site suitability and other relevant factors to determine the viability of battery storage systems at specific substation transformers. This thorough approach will help us make informed decisions about potential battery storage implementations across our distribution network.

5.1.5.1.3 CUSTOMER-SITED ROOFTOP SOLAR

PGE is forecasting 299,545 kW (i.e. almost 300 MW but not greater) of nameplate capacity of solar by the end of 2024 and growing to at least 672 MW of nameplate capacity of solar by the end of 2030. The battery storage market is nascent and has been piloted through PGE's Smart Battery pilot for residential, and Energy Partner On-Demand and DSG for non-residential efforts. However, because uptake is low in the early stages of this market, the majority of Customer-sited rooftop solar remains at Capability Stage 0.

For customers who are interested in adding battery storage to their solar, PGE will continue to support the Smart Battery pilot, including the evolution to Phase 2 as outlined in the Multi-Year Plan. The Company will evaluate customer needs and methods to accelerate market adoption to increase the attachment rate of solar with storage and transition existing solar from Stage 0 to a more VPP-ready state. PGE will continue collaboration with the Energy Trust of Oregon (ETO) to deploy available subsidies to customers.

PGE intends to target 150 MW of distributed storage to add to the grid in a way that leverages the output of distributed solar by the end of 2027. If successful, these resources, that are capability stage 2 or 3, can defer the need to acquire additional resources to otherwise maintain a reliable system. As these resources achieve a more mature grid value status, PGE believes such resources should qualify for satisfying the Small-Scale Renewable mandate.

5.1.5.1.4 QUALIFYING FACILITY (QF)/COMMUNITY SOLAR PROGRAM (CSP)

PGE has existing contracts for greater than 300 MW of distribution system connected solar projects with QF and CSP developers sold to PGE pursuant to standard Power Purchase Agreements (PPA). Pairing such resources with distributed storage, either through actual co-location or through the addition of batteries to the grid that roughly approximates the amount of renewable generation, can meaningfully improve the contribution to grid reliability and flexibility.

Adding distributed storage to QF and CSP projects requires collaboration between PGE and project owners to identify which projects are best positioned to add distributed storage and provide the greatest benefit to the grid, including addressing transmission and distribution system constraints. Most QF/CSP projects are sized between 2 and 3 MW and depending on land configuration could be ideal candidates to add up to 1 MW of distributed storage for every MW of distributed solar.

Based on the total volume of installed QF and CSP projects in PGE's service area, combined with PGE's sense of battery energy storage supply chains via engagement as part of the Smart Battery pilot, PGE currently forecasts that adding more than 100 MW of storage to take renewable resources from capability stage 0 to capability stage 2 or 3 is possible.

PGE issued its inaugural CBRE acquisition process to the market in November 2024 and will be accepting bids through October of 2025. This inaugural process, working in collaboration with various communities, will seek to acquire at least 65 MW of distributed solar paired with distributed storage, or just distributed storage, and will be followed in the future with additional CBRE RFP windows to procure an additional 90 MW bringing the total forecast to 155 MW by 2030 as demonstrated in the 2023 IRP.[50] Should CBRE RFP windows result in a greater number of mature resources, PGE will evaluate the cost effectiveness of such resources and may procure additional MWs.

Bids submitted in each review window (multiple windows are anticipated each year) will be reviewed for project maturity with a focus on key development activities (e.g., site control, interconnection, permitting). To the extent projects lack maturity, PGE will work with bidders/communities to identify plans to mature the projects to achieve readiness in a future review window.

The CBRE RFP includes technical specifications designed consistent with PGE's VPP capability stages. Therefore, all resources acquired would provide meaningful grid value to customers and operate at capability stage 2 or 3.

Table 12. Distributed solar and storage forecast

	YE 2025	YE 2026	YE 2027	YE 2028	YE 2029
Current Storage	28	0	0	0	0
CBRE Solar	0	0	36	6	8
CBRE Hybrid (Solar and Storage)[1]	0	0	71	14	15
QF Solar	0	0	100	0	0
QF Storage[2]	0	0	50	0	0

[50] PGE's 2023 CEP/IRP. Available at: https://downloads.ctfassets.net/416ywc1laqmd/6B6HLox3jBzYLXOBgskor5/63f5c6a615c6f2bc9e5df78ca27472bd/PGE_2023_CEP-IRP_REVISED_2023-06-30.pdf

	YE 2025	YE 2026	YE 2027	YE 2028	YE 2029
NEM Solar	0	0	150	30	30
NEM Storage[3]	0	0	15	3	3
Total VPP Resources	**28**	**28**	**450**	**503**	**559**

1 Assumes CBRE resources are required to pair solar resources with battery storage
2 Assumes 50 percent of QF solar resources will be paired with battery storage
3 Assumes 10 percent of NEM solar resources will be paired with battery storage

5.1.5.2 Strategic alignment

5.1.5.2.1 CUSTOMER GROWTH IN ENERGY USE

Availability of economic incentives, such as tax credits, rebates, grants, and subsidies can make it economically viable for customers to expand their energy use while adopting distributed solar and storage. Customers can be credited for excess energy sent back to the grid and distributed solar and storage assets can then be orchestrated by PGE through participation in energy markets further optimizing portfolio benefits for all customers.

Distributed solar and storage similarly support community climate action plans by providing a shared resource that benefits multiple customers, including low-income customers, that may not otherwise have opportunities to participate in the clean energy transition. Additionally, by reducing peak demand on the local grid, solar paired with storage can help prevent grid overloads as energy consumption grows from extreme weather conditions, electrification, semiconductors, or data centers, supporting broader community and regional growth enhancing Oregon's economic development objectives and bringing value to customers.

5.1.5.3 Capabilities and customer benefit

Distributed solar and storage in the VPP play a crucial role in enhancing the efficiency, sustainability, and resilience of the power grid. Here are the intended benefits:

Table 13. Benefits of solar and storage

	Existing Rooftop	CBRE	New batteries	Battery-paired QF/CSP	Existing standalone batteries
Energy production	+++	++	N/A	++	N/A
Integration	N/A	++	+++	++	+++
Grid flexibility	+	+++	+++	++	+++
Peak needs	+	++	+++	++	+++
Scalability	+++	+	+	+	+

+ = relative measure of benefits

5.1.5.4 Roles and responsibilities

As the orchestrator of the VPP, PGE's role within the distributed solar and storage program is to collaborate with customers, counterparties, and stakeholders to convert approximately 460 MW of distributed solar providing minimal grid value into 460+ MW of distributed solar and storage contributing to grid value with the VPP platform and operating at capability stage 1, 2, or 3 by 2030.

PGE will work collaboratively with existing and future rooftop solar customers to deploy battery storage systems to move participating MWs from Stage 0 to Stage 1 (or further) while simultaneously furthering PGE's advancement of its Small-Scale Renewable target. The cost effectiveness of adding storage to existing distributed solar customer assets benefits greatly from ETO and PCEF (where applicable) subsidies to drive down up-front cost for customers. Where applicable, PGE will look to connect customers with third-party financing to further reduce the barrier of up-front costs to customers, as outlined in PGE Schedule 342.

QF and Community Solar developers are uniquely situated to coordinate with PGE by adding distributed storage. These currently operational resources have already completed the difficult development activities including obtaining land/site control and permits. Today, land within PGE's service territory is increasingly sparse as economic development from the semiconductor and technology industries look to grow in Oregon. By working collaboratively with the owners of the QF and CSP projects and regulatory stakeholders including the OPUC, identifying a structure to add distributed storage at an appropriate avoided cost price can be achieved and convert a significant number of distributed solar MWs into MWs not contributing to Stage 2 or 3 withing PGE's grid value capability framework.

Lastly, PGE's Community Based Renewable Energy (CBRE) RFP process has initiated and is seeking new distributed solar/storage resources providing value to various communities within PGE's service territory, all of which will be designed to contribute to the VPP portfolio operating at Stage 2 or 3 of the capability gates. PGE is planning for the CBRE RFP framework to be repeated through at least the end of the current decade, creating multiple opportunities for customers and communities to participate in the clean energy journey and contribute to building a more flexible and resilient grid.

5.1.5.5 PGE cross functional coordination

Integrating distributed solar and storage into the VPP requires extensive cross-functional coordination among various internal PGE teams and stakeholders to achieve technical viability, regulatory compliance, financial optimization, and customer satisfaction.

5.1.5.5.1 TECHNICAL/ENGINEERING

PGE and third-party engineers will be required to work on the design, installation, and optimization of distributed solar and storage systems to ensure proper connection capable of feeding into the VPP. To monitor, control, and dispatch the assets through the Enterprise DERMS, software and hardware infrastructure design and management will be necessary to integrate into the VPP.

Integration of distributed solar and storage with the grid will also be necessary to ensure that power generated is compatible with grid requirements and that any grid stability issues are addressed. This function in essence delivers on the grid value associated with each capability stage. These teams must coordinate with IT and cybersecurity teams to maintain secure and reliable communication between distributed solar and the VPP platform while also handling data management, storage, and cybersecurity protocols.

5.1.5.5.2 OPERATIONS AND MAINTENANCE

Asset management functions, whether PGE or customer owned, are essential to monitor the performance of the distributed solar and storage assets to achieve optimal operation within the VPP. This team will coordinate with the technical teams to manage maintenance schedules and address any performance issues that may arise. Field technicians will be responsible for the on-ground maintenance and repair of installations and must work closely with the remote monitoring team to respond to alerts and faults.

5.1.5.5.3 POWER OPERATIONS

Analyzing market trends and forecasts of energy prices to optimize the dispatch of distributed solar and storage assets within the VPP combined with managing the sale of excess solar generation or ancillary services in energy markets enable the VPP's solar contributions to maximize economic and financial benefits for customers.

5.1.5.5.4 REGULATORY/COMPLIANCE

Design and integration of distributed solar and storage into the VPP must comply with local, regional, and national regulations. This includes interconnection standards and any incentives for renewable energy. Similarly, PGE and our customers must understand how the VPP satisfies environmental standards and sustainability goals including Oregon's HB 2021 emission reduction targets and the Small-Scale Renewable requirements.

PGE must also coordinate with the OPUC and stakeholders to navigate establishing the VPP from inception/strategy through development and ultimately operations to deliver on the value proposition for customers.

5.1.5.5.5 PROGRAM OPERATIONS

Achieving participation in the VPP requires engagement with potential customers to enroll their assets into the appropriate flexible load program. The program teams continue to support customer questions and needs as they look to invest in distributed solar and storage, but also provides ongoing support to customers whose assets are integrated into the VPP, ensuring they understand how their systems are being used and compensated.

5.1.5.5.6 COMMUNITIES

Working and coordinating with local communities to address any concerns or questions regarding the integration of distributed solar and storage into the VPP, including how their respective community can participate, will be critical to drive adoption but more importantly providing the opportunity for all customers to actively participate in the clean energy transition.

Communities will be key partners to PGE in identifying land or buildings, accelerating permitting, and helping define success measures within their respective goals and climate action plans.

5.1.6 VPP resources: Distributed thermal

PGE began the Dispatchable Standby Generation (DSG) program as a pilot program in 2000. The program has grown, 2024 enrollment is 130 MW of capacity provided from 79 generators at 45 different sites with 38 customers.

The DSG program partners PGE with commercial and industrial customers who have emergency, standby generation or batteries greater than 250 kW. Reciprocating diesel engines normally power these standby generators. The program helps to fulfill PGE's NERC requirement for reserves to respond to local region reliability impacts. Through deployment of communications and our dispatch via Genonsys an Edge DERMs control technology, PGE can remotely start the generators to supply capacity to the grid when the region has a reliability need.

Under the DSG program, PGE is responsible for communication, metering, control equipment, generator maintenance, and fuel costs. The typical DSG agreement is for a term of 10 years, and PGE uses the DSG capacity to help meet its reserve requirements, NERC BAL-002 for meeting Contingency Reserve Obligation (CRO) and NERC BAL-003 for Fast Frequency Response (FFR). This is beneficial as the generators are located throughout the service territory. DSG benefits the customer through financial and technical support described by Schedule 200.

5.1.6.1 Capabilities and customer benefit

The DSG program offers a low-cost distributed generation resource, which PGE uses to help satisfy required reserves.

Customers that have a DSG generator system partner with PGE to obtain a more reliable and versatile generator system. PGE's program covers some of the O&M costs of the generator system for the customer. Because each customer system is an integral part of PGE's DSG program, the Company also provides customers enhanced monitoring and metering. PGE monitors the system on a 24/7 basis, before the implementation of DSG (Distribution System Generators), some customers lacked this capability, while for others, it provided enhanced monitoring of their electrical systems.

PGE manages maintenance for the generators participating in the program. The company has also developed a high level of expertise in troubleshooting, analyzing problems, and finding solutions to issues with the generator systems. In addition, the DSG control system has data logging and reporting capabilities that are often lacking in less sophisticated generator systems – thus, PGE can easily understand and quickly resolve problems for customers within the program.

Finally, DSG customers can transition from generator to the grid without load interruption, enabling smooth and efficient outage recovery for customers. This is attributable to the inherent nature of a paralleling generator system, which allows the generator output

connected to the utility grid to perform "closed transitions" into and out of the parallel mode.

The DSG program currently helps fulfill some of PGE's reserve requirements and PGE uses the generators when the local region has experienced a critical reliability event such as generation tripping offline, local transmission constraint, or Frequency deviation events associated with overall system and generation constraints. These requirements vary based upon the amount of generation that PGE is operating, system load, and how much reserves are available. PGE estimates that the DSG program could grow to meet the majority of the Company's required reserve capacity need.

In summary, the customer benefits are significant and largely quantifiable, lasting throughout the life of the partnership. Ongoing maintenance and monitoring add extra value for existing DSG customers, who report lower labor requirements and peace of mind from entrusting these functions to PGE. Customers with smaller facility teams can focus on other critical items due to participation in the program.

5.1.6.2 Schedule and implementation

The DSG customer engagement and operational cycle ranges between 16 and 30 months, depending on customer and site complexity. A customer with existing qualified backup power will present shorter timelines for program activation. Customers leveraging the DSG incentives to invest in backup power will have a longer sales cycle due to acquisition times for new generation, which can vary widely by capacity. PGE is compressing our project schedule of customer education, site engineering assessments and planning, local grid enhancements, and environmental permitting requirements to acquire program capacity. **Table 14** represents PGE's estimated project growth over the next five years.

Table 14. Distributed thermal forecast

	2024	2025	2026	2027	2028	2029
Yearly Incremental DSG Online		26	40	40	40	40
Cumulative DSG Online	114	140	180	220	260	300

Increasing total program capacity to 300 MW within the next five years will require strategic investment, process improvement, and modernization of the Schedule 200 incentives to enroll more customers in the program. Customer outreach and program marketing can support the program at existing staffing levels with prioritization adjustments. Additional full-time employee (FTE) will be required on the program team to meet the increased requirements for sales support, project management, customer site assessments and engineering, and program oversight.

The DSG project plan and project schedule has been rebuilt in 2024 to match the current landscape, as the last kW enrolled occurred in 2018 before an idle period. This updated process will serve as a guide for customers and the allocation of internal resources. Regular

updates and continuous improvement to our processes will be necessary as customers enroll and become operational.

DSG growth will require regular engagement from PGE's environmental compliance, partially due to diesel emissions criteria at the Oregon Department of Environmental Quality (ODEQ). Per ODEQ, customers with a General Permit for Electric Power Generation (GP-18) must install a Diesel Particulate Filter (DPF) on any Tier 2 diesel generators prior to program participation. Customers using Tier 4 generators do not need a DPF. A Tier 2 diesel generator is the near universal choice for customers seeking cost effective backup power. Customers with larger sets of generators may require an individual Air Contaminant Discharge Permit (ACDP) and may be required to conduct environmental modeling to determine if they meet federal and state requirements. For each individual engagement, PGE may need to assist customers with the program capacity and run hour specification needed for the air modeling processes.

Finally, the economics of standby generation are evolving as PGE navigates a changing environment around capacity, congestion, and decarbonization. Over this 5-year period of aggressive program growth, the shifting economics may influence the structure of the DSG program and require changes to our tariff. Under the shared value model of the virtual power plant, any increase in financial support for customer-sited backup generation will directly benefit local organizations and communities.

5.1.7 Technology platform

PGE's VPP leverages the components of the modernized grid platform by integrating and optimizing a diverse array of distributed energy resources (DERs) and flexible loads through advanced technology platforms. By orchestrating distributed resources, the VPP enables PGE to operate a dynamic two-way system, unlocking additional grid services and increasing overall system flexibility and reliability. This approach not only reduces the need for new infrastructure but also aligns with PGE's 2023 Clean Energy Plan and Integrated Resource Plan, with potential to scale to 2,000 MW by 2030.[51]

5.2 Benefit cost analysis

The preceding sections have outlined the key benefits of a VPP:

- Increased Resilience: VPPs can enhance grid reliability by integrating backup power and eliminating single points of failure.
- Decarbonization: They support the integration of renewable energy, reduce reliance on fossil fuels, and lower greenhouse gas emissions.
- Cost Savings: VPPs can defer grid capital expenditures, avoid fuel costs, and offer compensation to consumers and businesses.
- Enhanced Efficiency: By smoothing demand peaks and alleviating congestion, VPPs improve the overall efficiency of the transmission and distribution (T&D) infrastructure.

[51] 2023 Annual Report. Available at: https://investors.portlandgeneral.com/static-files/2457aa2d-263c-4933-a33b-8fc6b53ca9bb

- Community Empowerment: VPPs enable consumers to optimize their energy usage and costs, fostering greater engagement and creating local jobs.
- Versatility: The adaptable nature of VPPs allows them to meet evolving grid needs.

PGE intends to be more concrete in its understanding and demonstration of the types and extent of benefits of the Modernized Grid platform in combination with the VPP resources. This understanding can only be gained by quantifying the costs incurred towards the development and operation of the VPP, identifying the various streams of benefits that can be obtained through its utilization, and performing an initial computation of those benefits. Such an assessment would be the first essential step towards demonstrating the net benefits of VPP and justifying the VPP-related investments to our different stakeholders. Although this analysis is preliminary in nature, this exercise would provide important insights towards determining which VPP resources are economically more effective, and what benefit streams should be harnessed in a targeted manner to achieve maximization of net benefits.

Benefit-costs analysis (BCA) is a systematic approach for assessing the cost-effectiveness of investments by quantifying the benefits and the costs. The analysis entails precise identification of the possible streams of financial impacts (benefits and costs), computation of those benefits and costs in monetary terms, and then determining whether overall the benefits exceed the costs over the considered lifetime of the program or not. In this Section, we have described the assumptions, high-level methodology and results of a preliminary BCA for the VPP effort.

It is important to note that all the use cases and operational characteristics of the different resources and enabling technologies considered as part of this VPP are not known. In this BCA, reasonable assumptions have been made based on their technical specifications of relevance, and their direct benefits that are PGE's priorities. Over time as VPP is operationalized, we would obtain more accurate data regarding the costs and benefits which would be utilized to update this analysis.

This analysis is prepared consistent with the National Standards Practice Manual (NSPM) BCA Principles as follows[52]:

1. The VPP resources under consideration should be compared to other energy resources including other DERs using a consistent approach to avoid any kind of bias.
2. Benefits and costs should be treated symmetrically.
3. The analyses should be forward-looking, long-term and incremental to what would have happened in the absence of the VPP components being assessed.
4. All impacts should be clearly defined to avoid double counting.
5. Assessment should be based on transparent assumptions and methodologies.
6. In this section we have kept BCA separate from rate impact analysis and focused on only the BCA portion.

[52] NSPM-DERs. Available at: https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf.

The net benefits analysis model is an Excel-based tool developed to calculate quantitative benefits associated with the proposed portfolio of VPP investments and compare these benefits to the costs of investments. This section explains the analysis context, approach, findings, and detailed methodology in support of the pre-filed testimony for net benefits.

5.2.1 Scope of analysis

Safely managing and integrating additions of electric loads (e.g., electric vehicles), other distributed energy resources (e.g., energy storage, rooftop solar), industrial load (e.g., manufacturing, data centers), and renewable generation at the bulk scale requires a larger grid with greater capacity and more flexibility. VPP resources and the integrated grid platform with supportive grid solutions can provide that added capacity and flexibility utilizing the DERs that are existing or are planned to be added in the distribution system.

VPP components considered individually or as a whole can help strategically relieve to a great extent the generation, transmission and distribution constraints in the distribution system, thereby deferring or avoiding the need for infrastructure upgrades in the short or long term. Therefore, within the portfolio of VPP considered here, we have included those projects which provide resources or supporting capabilities of dispatching distributed resources or coordinating edge devices. **Figure 23** includes the list of projects/resources that have been included within the scope of this first iteration of the BCA.

Figure 23. Items included in benefit cost analysis

Strategic storage	•Front of meter (Coffee Creek, Salem Smart Power Center, Dispatchable Standby Generation) •Behind the meter (Beaverton Public Safety Center, ARC, Integrated Operating Center, Daimler Electric Island)
Generic storage	•Feeder storage •Substation storage
Demand response / flex load	•PTR, TOD, MFWH, smart thermostat, Energy Partners - Schedule 25, Energy Partner - Schedule 26
Distribution automation	•FLISR
Transportation electrification	•Biz EV charging, biz make ready - multifamily, clean fuels program, fleet partners, HDV pilot, muni charging, residential EV charging
VPP grid integration	•Platform •Desk

5.2.1.1 Strategic storage projects

The strategic storage projects include those specific energy storage projects that are developed/operated at specific locations on the distribution system of PGE. Batteries can provide capacity and reliability benefits that reduce risk on key substation or feeder assets, extending economic life and deferring capital investments needed for replacement.

- **Front-of-meter storage projects**: There are some front of meter storage projects where PGE is the owner and operator. Therefore, there are no separate customer costs in this category of projects. PGE may be able to control these resources more readily and more often. To minimize costs of purchasing costly bulk generation, arbitrage would be a good future strategy. Arbitrage may be performed to charge those batteries during off-peak times and discharge them during on-peak times.
- **Behind-the-meter storage projects**: There are behind-the-meter storage projects where PGE is not the owner or operator. PGE did not have extensive information about additional costs that customers may have incurred for these projects. We included all the available information on costs.

Table 15 lists the various strategic storage projects that PGE has considered in its VPP portfolio along with the high-level specifications for the associated battery resources.

Table 15. High level specifications of strategic storage projects included in the analysis

	Coffee Creek	Beaverton Public Safety Center (BPSC)	Anderson Readiness Center (ARC)	Integrated Operating Center (IOC)	Daimler Electric Island	Salem Smart Power
Type of resource	Lithium-Ion Battery Energy Storage System	Lithium-Ion Battery Energy Storage System				
Capacity	17 MW	250 kW	500 kW	2 MW	750 kW	3.9 MW
Energy	34 MWh	1,000 kWh	1,000 kWh	4 MWh	1,000 kWh	7.8 MWh

5.2.1.2 Generic storage projects

Feeder and substation storage are generic storage projects which consist of front of meter storage resources that are located at the utility's feeders in order to serve the loads downstream in a strategic manner. Such storage could be used to supply stored energy during times of higher-than-normal level of load or when bulk generation cost is high, when there are constraints in the transmission and distribution system, or provide critical power when recovering from faults.

5.2.1.2.1 FEEDER STORAGE

The battery size assumed for feeder storage is 5.5 MW/11 MWh which is typically sufficient to supply entire feeder load so that it can either reduce or eliminate customer outages, depending on duration. A conservative effective load-carrying capabilities (ELCC) with average annual values of 38 percent (average of summer and winter seasons) has been assumed for these 2-hour batteries; for more details on ELCC calculation method please refer to 2023 CEP/IRP. [53] In the absence of any operational feeder storage projects, we have utilized data from the Dayton Non-Wires Solution pilot project as proxy for the relevant costs (like reconductor costs) and benefits. For feeder-sited storage, the outage risk reduction analyzed the benefit of avoiding an outage for customers on the feeder due to either asset failures or failure caused from vegetation/weather. Assets like distribution switches, transformers, and underground cable are considered in the analysis. The benefit timeline of each of these projects is assumed to be 10 years to align with the battery depreciation schedule.

5.2.1.2.2 SUBSTATION STORAGE

The battery size assumed for substation storage is 14.5 MW/5.8 MWh which allows for supplying energy to the load downstream on the substation transformer after accounting for a conservative ELCC with annual average value of 57 percent[53]. In the absence of any operational substation storage projects, we have developed a proxy project using real-world data from the Eastport Substation project. For substation storage, the transformer is used to measure benefits, since it is the primary beneficiary of a low side bus-connected battery. Outage mitigation benefits include avoidance of a 4-hour outage. The benefit timeline of each of these projects is assumed to be 10 years to align with the battery depreciation schedule.

5.2.1.3 Demand Response / Flex Load

Demand response programs are considered part of VPP since they play an important role by enabling coordination of the edge devices and therefore managing the net load. Leveraging demand-side resources can defer and/or avoid some of the cost of rebuilding or adding new transmission and distribution infrastructure. PGE's mature pilots and programs for DR are some of the first DERs to be enrolled in our Virtual Power Plant (VPP) and used for delivering grid services.

5.2.1.4 VPP platform and desk

The integrated VPP platform, which allows the monitoring and orchestration of the various DER and VPP resources, consists of an Enterprise DERMS (EDERMS) platform built on the same code-base as ADMS and EMS. EDERMS is integrated seamlessly with ADMS and eMAP, the topological view of PGE's system. This integration allows PGE to dynamically aggregate and disaggregate DERs and flexible loads, through edge DERMS, to provide essential grid services. ADMS includes applications like FLISR and switch order management

[53] PGE, Clean Energy Plan and Integrated Resource Plan 2023, Chapter 10 – Resource Economics, June 2023, Available at: 2023_CEP-IRP_Ch_10.pdf (ctfassets.net)

which may benefit VPP with more efficient fault handling, optimized switching operations, and improved overall reliability. The cost estimates of the VPP Platform beyond 2025 would be refined as the system requirements and use cases are finalized; in this initial BCA they are rough estimates based on reasonable assumptions and information available thus far.

Within VPP, a plan for establishing a VPP desk is also considered, and costs for staffing the desk with personnel of appropriate skills has been included in the BCA.

5.2.1.5 Transportation electrification

VPP includes TE activities that require participating customers to partner with PGE to manage load. Investments in the Integrated Operations Center and Advanced Distribution Management System will pair with managed load programs to use TE load as a resource thereby enhancing our capability to reliably serve at least cost. VPP resources can be expanded by integrating and managing TE load using for example DR-capable chargers, vehicle telematics, vehicle-to-building, or through rates specific to TE load types.

5.2.1.6 Distribution Automation (DA)

In the future, DA would play an important role in enhancing VPP operations. DA includes umbrella of smart grid solutions like SCADA-enabled/automatic switch management, FLISR etc. These are aimed at solving power system issues by integrating various equipment, devices and data into a centralized system (e.g. ADMS). These would therefore add essential pre-emptive actions to enable the provision of various grid services from DERs while mitigating potential issues. Feeders targeted for DA implementation are those with a high exposure to vegetation/weather risk (see **Appendix F** for a discussion of ADMS and Distribution Automation capabilities).

Half of the feeders in the system are currently planned to be FLISR enabled in the system by 2035 which will lead to deployment of remote/SCADA enabled switch management capabilities in those feeders. This advanced switch management capability which would be crucial for optimal routing of energy from the VPP resources in the system. Since VPP relies on high number of customer-owned resources it is important to reduce the frequency and duration of outages for customers. By rerouting of power around faults using FLISR, energy from DERs (or VPP resources) would be utilized more efficiently thereby maximizing benefits from DERs.

In this BCA, DA benefits have focused on the probabilistic reactive outage mitigation benefits for faster fault isolation and service restoration utilizing FLISR. The benefits of using SCADA-enabled or automatic switch management for optimal VPP dispatch by reconfiguring feeders have not been quantified and therefore not included.

Approximately 300 feeders could be FLISR-enabled, which is about 50 percent of feeders on the system. Thirty-five feeders have already been enabled in 2024. We have identified the next batch of 57 feeders, which is a good average representation for the remaining 300 feeders. To quantify the benefits, we took the average profile of those identified 57 feeders.

- For outages originating at cable section or breaker, the assumption is that an outage affecting the entire feeder (all three sections) will immediately be isolated down to one section. The reliability benefit of the DA system is that only 1/3 the customers will

be impacted by a sustained outage. This is modeled as each outage having 1/3 the duration as normal to all customers impacted.

- For outages originating at recloser, the assumption is that an outage affecting the customers downstream of a recloser will impact at least 2 of the switchable sections (the first switchable section from breaker to recloser is unaffected). The reliability benefit of the DA system is that only 1/2 the customers will be impacted by a sustained outage.

After a few years of the schemes being in-service, the actual benefits vs. modeled benefits of the FLISR schemes would be compared to refine the estimates. Actual benefits may be higher or lower depending on if/where the feeders experienced an outage.

The timeline we used for realizing benefits is 18 years. This aligns with the other DSP benefit streams ending in 2041. Given the fact that benefits are curtailed in 2041, only 35 feeders are getting 18 years of benefits due to feeders being added incrementally each year. All other feeders are getting less than 18 years of benefits but reflecting the full cost. As such this is a conservative benefit estimation. The total benefits received over the lifetime of the DA capability is not included but the entirety of the estimated costs are included.

5.2.2 Benefit-costs tests

The Total Resource Cost (TRC) test has been employed which includes the benefits and costs experienced by the utility system, plus benefits and costs to host customers. The TRC has been typically adopted for cost-effectiveness testing by PGE and various other utilities, and it is acceptable to OPUC. Here utility system benefits typically include all the utility system costs that would be avoided or deferred by implementing VPP. These avoided costs are one of the more important and sometimes challenging inputs to any BCA and can significantly affect the results of the analyses. Therefore, it is important that the assumptions are clearly articulated, methodology is informed and aligned with other internal stakeholders, and ultimately the analysis is shared with regulators. Costs typically include a portion of the VPP resources paid by the utility, other financial or technical support provided to host customers, and interconnection costs and distribution upgrades not paid by customers who may own certain VPP resources. The costs also generally include administration, marketing, measurement and evaluation.

Engineers, analysts and economists worked collaboratively to consider how PGE intends to use the technology and systems it will put in place as part of the VPP. The specific functions of the VPP components determine the impacts that arise, which in turn determine the benefits. For example, FLISR automatically restores (with reduction of manual intervention) power to as many customers as possible, as quickly as possible, in the event of a sustained fault. Therefore, it will help to direct truck rolls to fault locations which is a significant positive impact. One of the quantified economic benefits related to this impact is the cost savings due to more efficient truck rolls. Next step was to ascertain which impacts could be reasonably quantified for their economic impacts using methodologies known to be accepted by the stakeholder community. However, the benefits which could not be quantified in this version of the analysis have been qualitatively described in the later part of this section. Where possible, PGE utilized data regarding actual costs incurred and benefits

realized through projects as direct inputs into the model and to refine forward-looking assumptions.

This BCA presents two perspectives:

- Primary conservative analysis without DA/FLISR benefits
- Prospective analysis which looks into 10-15 years in the future and includes FLISR benefits anticipated and needed for SCADA-enabled switch management to achieve reactive outage mitigation benefits. The second perspective illustrates how the planned DA capabilities in the later years will enhance benefits during the lifetime of the projects included in the BCA.

It is axiomatic that PGE will actively manage the topology of the distribution system to orchestrate and optimize DERs in the long-term. If this assumption was used in the development of the BCA the score would be higher. However, we took a conservative approach and thus only accounted for the reliability benefits of reactive switching presently employed by FLISR.

5.2.3 Costs

Costs include capital for internal and external labor, equipment, software, hardware, and vendor-provided services. Costs also include the Operation and Maintenance (O&M) expenses to sustain the investments. Recent historical and actual cost data have been collected and leveraged to develop the cost inputs, if available and as applicable.

5.2.4 Quantitative impacts

The National Standard Practice Manual provides a comprehensive list of the potential benefits and costs of DERs that should be considered when computing TRC. Since DERs are the building blocks of VPP, therefore this list is applicable for performing BCA of VPP portfolio. Below in **Table 16** is a subset of those quantifiable impact streams from NSPM that are directly applicable in our analysis.

Table 16. National standard practice manual impact categories

Type	Utility system impact	Summary
Generation	Energy generation (includes energy arbitrage)	The production or procurement of energy (kWh) from generation resources on behalf of customers
	Capacity	The generation capacity (kW) required to meet the forecasted system peak load
	Ancillary Services	Services required for providing flexibility to the grid
	Risk reduction	Benefit due to decrease in the likelihood of negative impacts on a system, such as reduced risk of power outages due to increased grid resilience or decreased exposure to volatile fuel prices

Type	Utility system impact	Summary
Transmission	Transmission capacity	Maintaining the availability of the transmission system to transport electricity safely and reliably; Congestion relief and upgrade deferral
Distribution	Distribution capacity	Maintaining the availability of the distribution system to transport electricity safely and reliably; Congestion relief and upgrade deferral
	Distribution capital cost Deferral	Distribution capital cost deferral
Other	Program administration	Utility outreach to trade allies, technical training, marketing, and administration and management of DERs
	Reliability, or outage risk reduction benefit	Maintaining generation, transmission and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components; ability to prevent or reduce the duration of customer outages
	Host portion of costs (DER/ transaction/ interconnection)	Cost incurred to install and operate DERs Other costs incurred to install and operate DERs Costs paid by host customer to interconnect DERs to the electricity grid
	Tax incentives	Federal, state, and local tax incentives provided to host customers to defray the costs of some DERs

A number of these impact streams have been included in plans of other utilities as well like AES Ohio and Eversource.[54, 55]

5.2.5 Qualitative impacts

The CBA encompasses the identification and enumeration of benefits that are quantitative and economic in nature as well as benefits that are strictly qualitative in nature, or that would be difficult to quantify. Qualitative benefits are important estimates of impacts and outcomes arising from VPP, and incremental to the quantitative benefits included in the principal CBA model result. To account for those benefits, PGE's community benefit indicator (CBI) study is in the process of cataloguing and valuing indicators that reflect broader societal and community benefits, such as increased access to clean energy, economic development, and

[54] The Dayton Power and Light Company D/B/A AE Ohio, Case no. 24-10112-EL-GRD. Available at: dis.puc.state.oh.us/DocumentRecord.aspx?DocID=e9f48179-b76b-4d01-bf1b-d30e067a9256

[55] Petition of NSTAR Electric Company d/b/a Eversource Energy, pursuant to G.L. c. 164, § 92B, for approval by the Department of Public Utilities of its Electric Sector Modernization Plan. Available at: 18550448 (comacloud.net)

improved public health outcomes. This work supports a more holistic approach to resource planning, moving beyond traditional cost measures to include impacts on underserved communities and other non-monetized benefits. The draft list of CBIs and approach to the study were presented to stakeholders for discussion and feedback.[56] In August and September of 2023, Cadeo presented to OPUC staff, PGE's IRP Roundtable group, and led a facilitated discussion with community-based organizations participating as part of the Community Benefits and Impacts Advisory Group (CBIAG).

Below is a list of some the key examples of other benefits which have not been quantified in this round are as follows:

- **Safety:** Increased worker safety via proposed investments in DA will reduce trips to resolve outages, particularly during dangerous conditions (i.e., storm response).
- **Minimization or Mitigation of Impacts on Ratepayers:** Reduce future utility spend through reduced storm costs and optimized grid planning; create opportunities for customers to reduce their bill by deploying distributed resources. The VPP investments aim to minimize or mitigate impacts to ratepayers in the long-term by reducing utility costs (and thereby reducing passthrough to customers) through expansion of access to DG, optimized grid planning, deployment, and operations – all of which reduce the need for infrastructure upgrades and break/fix.
- **Reduced emissions of Greenhouse Gas (GHG) and air pollutants:** Carbon dioxide emission reductions quantified are assumed to be related to one of two impacts: 1) reduced electricity generation; and/or 2) reduced internal combustion engine vehicle usage. The VPP components that reduce the consumption of electricity, result in reduced electricity generation and resulting greenhouse gas emissions. For example, transportation electrification enables reduction in gas usage which leads to reduction in CO2 emissions. The plan includes targeted projects to reduce environmental burdens in underserved communities. Development of VPP will enable the interconnection of DERs (like solar, EV) while optimizing system demand at all times of the year, and therefore improve air quality and reduce pollution-related health issues. In the next version of this analysis, we intend to include quantified estimates of benefits from reduction of GHG and air pollutants. Limiting pollutants such as nitrous oxide (NOx) and particulate matter (PM2.5) result in improved health outcomes for all communities.
- **Economic and workforce development:** Over a 20-year period, consistent with the considered timeframe of analysis, the Bureau of Economic Analysis (BEA) 13 RIMS II Model suggests that direct and indirect yearly jobs will be created. Direct jobs are expected to be higher-paying, technology-oriented positions that will support

[56] September 4, 2024 CEP/IRP Roundtable, CBI Study presentation, Available at: https://assets.ctfassets.net/416ywc1laqmd/2KYZToHzDEUncfQrvJfCNS/f6c4eeef494dcfc85975515f53d1ea5a/IRP_Roundtable_September_24-5.pdf.

economic growth and stability, while providing rewarding and developmental opportunities to a growing workforce. Additionally, there will be creation of indirect jobs, such those associated with restaurants, hotels, and construction support activity. The development of projects related to VPP will stimulate the regional economy.

- **DER proliferation:** For example, should FERC Order 2222 become applicable to PGE, investment in a VPP platform enables the Company to comply and to see, forecast, and respond to DER generation on their grid, thus making it easier for customers to adopt DERs.
- **Customer satisfaction:** Detect problems before they impact a customer, thereby improving the overall customer experience,
- **Commercial investments:** For example, the Company has heard from manufacturing and commercial customers that reliable electric service is important to their selection of Portland and the surrounding area for additional investment, thus demonstrating how the reliability of the local grid can directly contribute to regional economic growth.
- **Facilitation of the electrification of buildings and transportation:** Increased feeder and substation capacity to support growing EV and electric heating adoption.
- **Avoided Land Use Impacts:** Reduce requirement for build or expansion of traditional generation infrastructure.

The significant qualitative benefits further support the reasonableness of VPP.

5.2.6 Assumptions

Evaluation of costs and benefits is a complex undertaking which needs to consider many factors, some of which may be easier to quantify than others. It is important to understand the base financial and framework assumptions that go into the assessment, including forecasting to estimate the future benefits and costs, and cumulative impacts of changes to systems over time. Below are some of the key assumptions that have shaped the analysis.

Benefits are captured from an investment's in-service dates to either 2041 or to the end of their asset lives, whichever comes first. This analysis only recognizes benefits for assets that go in service after 2021. In order to quantify the different benefit streams, it is necessary to assume certain avoided cost elements and they are shown in **Table 17**. The widely accepted or approved sources from which their values have been obtained are also mentioned. The annual ELCC values for 2-hour and 4-hour batteries are assumed to be 38 percent and 57 percent respectively, by averaging over the time the numbers reported for summer and winter in Table 50 of 2023 IRP[57]. **Table 18** provides the financial parameter values that have been utilized for the computation of the costs and the benefits. **Table 19** presents the

[57] PGE, Clean Energy Plan and Integrated Resource Plan 2023, Chapter 10 – Resource Economics, June 2023. Available at: 2023_CEP-IRP_Ch_10.pdf (ctfassets.net)

annualized energy and flexibility benefits for 4-hour battery resources in $/kW-yr that have been leveraged.

Table 17. Avoided cost elements utilized in the BCA and their values

Avoided cost element	Units	Value	Source
Transmission Loss Factor (Summer)	Percent	2.09%	BPA Open Access Transmission Tariff, Effective Date: October 1, 2023
Transmission Loss Factor (Winter)	Percent	2.04%	BPA Open Access Transmission Tariff, Effective Date: October 1, 2023
Risk Reduction Value	$/MWh	$3.00	2019 IRP (not updated in 2023 IRP)
Transmission Deferral Credit	$/kW-yr	$87.34	2024 General Rate Case (GRC UE 416) Transmission Marginal Cost Study
Distribution Deferral Credit	$/kW-yr	$17. 21	2024 GRC
Generation Capacity Credit	$/kW-yr	$175	2023 IRP Update - New Resource Economics

Table 18. Financial parameters from - June 2024

Parameters	Assumed Values
Inflation Rate	2.04%
Pre-Tax Cost of Capital	7.64%
After-Tax Nominal Cost of Capital	6.85%
After-Tax Real Cost of Capital	4.71%

Table 19. Annualized benefits for 4-hour battery resources in $/kW-yr[58]

Years	Energy value	Flexibility value
2026	9	10
2027	9	12
2028	9	14

5.2.7 Approach

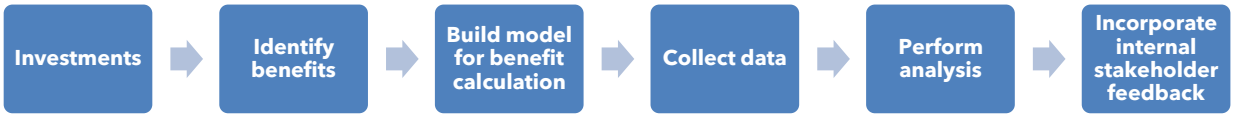
Benefits and costs for projects, programs and portfolios depend on the assets/technologies developed; each with specific benefits delivered and costs associated to do so. Careful consideration of the project, program and portfolio must be given to properly parse out these details, on both the benefit and cost side, to allow determination of inputs without co-inflating, overlapping or discounting benefits or costs in error. Quantifying the impacts of a technology within the project, program or portfolio is an important initial step; assignment of valuation and monetizing the benefits, as well as identification of the associated costs follows the initial quantification.

The net benefits analysis relies on industry best practices, nationally recognized methodologies used to evaluate similar types of electric utility investments, and assumptions that may have been previously considered. The widely accepted principles outlined in National Standard Practice Manual ("NSPM")[59] and the United State Department of Energy's ("DOE") Modern Distribution Grid documents have been adopted; these state that net benefits should account for state regulatory and policy goals as well as all relevant costs and benefits and assess investments as bundles and portfolios instead of separate measures. Once the key impacts that need to be assessed were identified, the framework was developed for each resource category complete with the specific method of cost and benefit quantification implemented in an excel tool. Source data needed for the CBA model was identified and gathered from stakeholders including actual data where available and appropriate. This source input data was then applied within the CBA model to compute the outputs. A simplified process flowchart has been provided in **Figure 24**.

[58] IRP/CEP 2023. Available at: https://downloads.ctfassets.net/416ywc1laqmd/6B6HLox3jBzYLXOBgskor5/63f5c6a615c6f2bc9e5df78ca27472bd/PGE_2023_CEP-IRP_REVISED_2023-06-30.pdf

[59] NSPM-DERs. nationalenergyscreeningproject.org. Available at: https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf

Figure 24. Benefit cost analysis steps



Finally, iterative review and adjustments were performed to firstly validate that model inputs are correctly stated and applied, secondly confirm calculation accuracy under the applied methodologies, thirdly maintain consistency in net benefits approach across the EDCs, and lastly confirm comprehensive benefits included. These efforts have resulted in a set of reasonable cost and benefit estimates as part of this initial BCA.

5.2.7.1 Generation energy

In general, VPP resources will create energy generation benefits when they reduce the amount of electricity utilities need to produce or procure in order to meet load and will create costs if they require higher levels of energy generation[60]. For energy generation we calculated the amount of energy (i.e. in kWh) produced by the DERs and the corresponding reduction in energy that needs to be purchased from the grid. A conservative estimate of benefits related to 100 days of arbitrage each year has been included.

5.2.7.2 Generation capacity

The amount of generation (i.e. in kW) required to meet the forecasted peak load. With load growth if over time the utility does not have sufficient generation capacity then it may either need to build generation capacity or procure it (through bilateral contracts or wholesale market). DERs spread geographically over the system can provide additional capacity which can help. For example, curtailment through demand response, injections from storage and solar PVs during the system peak can result in a net decrease in load, and therefore PGE can derive a benefit in the form of lower capacity needs.

The generation capacity benefit provided by VPP resources can be calculated by determining the avoided costs of building new generation capacity or upgrading existing infrastructure. This includes capital costs, operation and maintenance costs, and any other costs associated with new capacity. Since the VPP resources are essentially DERs, therefore for measuring their contribution to meeting peak demand we have considered the Effective Load Carrying Capability (ELCC) values which are highly conservative in values. A monetary value to the capacity benefits is provided by comparing the costs of VPP resources to the costs of traditional capacity solutions.

[60] Available at: https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf.

5.2.7.3 Ancillary services

Ancillary Services are those services that are required to maintain grid stability and enhance flexibility. The extent of ancillary service benefits from any resource depends on how the DER operates and what are expected to be the system conditions during its time of operation. VPP resources like storage, especially if they are front of the meter, may be actively dispatched to increase grid flexibility. We have calculated how much each VPP resource contributes to the ancillary services which involves measuring the capacity of DERs to provide these services and their performance during grid events.

5.2.7.4 Transmission capacity

Transmission capacity refers to the availability of transmission infrastructure to transfer bulk energy from generation to the loads in a reliable manner. Since DERs like solar PV can generate electricity in the distribution system, storage can shift load by charging during off-peaks and discharging during peak load times, and demand response can reduce the system load, so these resources can essentially defer the need for new transmission infrastructure. We calculated the potential capacity constraints that the VPP resources can alleviate and calculated the costs that are avoided by deferring transmission upgrades. This includes capital costs, operation and maintenance costs, and any other costs associated with new transmission capacity.

5.2.7.5 Distribution capacity

Distribution capacity refers to the substation and distribution line infrastructure necessary to meet customer electric demand. By reducing net load during peak period, DERs can help defer distribution capacity upgrade needs either actively or passively, and therefore eliminate deferral costs. We calculated the costs that are avoided by potentially deferring distribution upgrades through the development of the considered VPP resources.

5.2.7.6 Distribution capital cost deferral

Utilities face ongoing O&M and capital expenses to achieve safe and reliable operation of distribution facilities. VPP resources, particularly batteries, can help defer both capacity-driven investments and reliability-driven asset replacements, especially for aging infrastructure. We evaluated various investment types that VPP-related initiatives could potentially avoid or postpone, including equipment, distribution infrastructure, and other assets. The implementation of VPP resources is expected to lead to a reduction in future capital expenses within the considered timeframe, which would likely continue into the future without VPP adoption.

VPP resources offer two primary reliability benefits to customers: reducing the impact of outages and potentially deferring aging infrastructure investments. Both of these benefits effectively mitigate risk while delivering customer value. To calculate these reliability benefit streams, risk-based economic lifecycle models are employed. These models determine the optimal time to replace an asset by balancing maintenance costs and the risk associated with owning and operating the existing asset against the cost of replacement. Utilizing the outputs of these models to justify proactive asset replacement reduces the risk of system

failures and customer outages, efficiently allocates capital to improve reliability, and enhances the overall customer experience.

This asset modeling approach is founded on the fundamental concept of risk, defined as the product of annual failure probability and the consequence cost of failure. The annual failure probability represents the likelihood of an asset experiencing a repairable or non-repairable failure, based on its age, condition, and/or vintage. The consequence cost of failure is the weighted average cost of various failure scenarios for the asset. To calculate this weighted average, subject matter experts identify different failure scenarios, ranging from minor to catastrophic, and assign their relative likelihoods, informed by historical data when available. The failure scenario costs encompass the reliability impact on customers, the load affected by the failure, and direct cost impacts to the company. This risk modeling approach effectively enables the quantification of both outage risk reduction for customers and the deferral of aging infrastructure investments.

5.2.7.7 Reliability, or outage risk reduction benefit

This benefit focuses on calculating the reliability improvement estimates based on the proposed scope of work. The analysis provides estimates avoidance of customers interrupted ("CI") and customer minutes of interruption ("CMI") and the number of customers directly impacted by the failure. Since the analysis focused on VPP components in the system, the actual number and type of customers that would see a direct benefit was identified. We then leveraged PG&E's 2012 Value of Service (VOS) study that was approved by the California Public Utility Commission to calculate the economic impact of avoiding an outage, referred to as Customer Outage Impact. Annual Outage Risk Reduction ($) is the reduction in outage risk for customers from asset and geographic factors by having each of the VPP components versus in their absence. For example, in case of DA, reduction in outage risk for customers by having a 2/3 or half of customers on respective feeder no longer experiencing outage due to automated switching. Benefits are comparing manual switching to automated switching resulting from the installation of distribution automation.

5.2.8 Discussion of results

The model computes costs and quantified economic benefits of these two perspectives (with and without FLISR-based reliability benefits) based on a utility cash flow cost basis over the 20-year CBA timeframe. For each of these results, a net present value calculation is performed. We assigned the appropriate benefits to the appropriate VPP resources and based on that we derived the calculation.

Table 20. Benefit cost analysis results

Types	Categories	Benefits ('000s)	Costs ('000s)	B/C Ratio
Storage	Front of meter storage	$974,429	$734,129	1.33
	Behind the meter storage	$57,387	$20,655	2.78
	TOTAL (Storage)	$1,031,815	$754,784	1.37
Demand response / flex load (excluding storage)	EP Schedule 26	$44,093	$10,775	4.09
	Tstat	$73,294	$16,456	4.45
	EP Schedule 25	$2,795	$4,350	0.64
	PTR	$14,266	$7,652	1.86
	TOD	$11,035	$3,858	2.86
	MFWH	$4,394	$7,609	0.58
	DR-portfolio level reliability benefits	$90,000		
	TOTAL (DR/Flex Load)	$239,877	$50,701	4.73
VPP Desk & Platform			$64,566	
TE		$40,942	$20,881	1.96
FLISR		$635,252	$90,184	7.04
VPP (Perspective 1 – without DA/FLISR)		1,276,374	880,810	1.45
VPP (Perspective 2 – with FLISR)		1,911,626	970,995	1.97

The NPV method has been used to compare the present value of benefits to the present value of costs over the time horizon considered in this analysis. This involves discounting future benefits and costs to their present value using an appropriate discount rate. The accompanying workbook shows the quantified economic benefits, costs, net present value ("NPV"), and benefit-to-cost ratio result.

This is a conservative preliminary BCA which has considered only the quantifiable direct customer benefits, although there are several indirect customer benefits which are accrued over time. While direct customer benefits represent the economic value that is expected to accrue directly to the company and its customers, indirect benefits represent those which are more difficult to quantify due to lack of standardized computation methodology. However, some of these indirect benefits hold major significance since they enable PGE to advance towards Oregon state's clean energy targets. For example, part of the rationale for investing in clean energy focused resources is to meet state energy goals, which can be

difficult to quantify in the absence of carbon tax in the state, and therefore not included in the direct benefits that have been calculated for VPP. In spite of quantifying a subset of the benefits the overall quantified economic benefits for the portfolio exceeds the costs giving a benefit-to-cost ratio that is over one then it provides solid justification for pursuing the investment and going ahead with the effort.

All the use cases and operational characteristics of the different resources are not yet known. In this analysis, assumptions have been made based on technical specifications of these resources and their direct benefits that are PGE's priorities. As the resources will be developed, interconnected, energized and operated, we would obtain more accurate data regarding the costs and benefits over time. The analysis performed here helps determine the benefits of the planned investments; what use cases for each type of resource would be beneficial to the utility and/or customers, and what type of resources may be relatively more cost-effective. This analysis serves to provide direction to the utility internally and is a first step towards demonstrating the benefits of VPP to the external stakeholders.

It is important to note that this BCA is only applicable to the scope of the projects that have been mentioned and only as part of the Distribution System Plan. Because this analysis is preliminary and not complete it is not applicable elsewhere and should not be used by stakeholders in any other context.