Appendix K. Modernized grid action plan

K.1 Modernized grid action plan

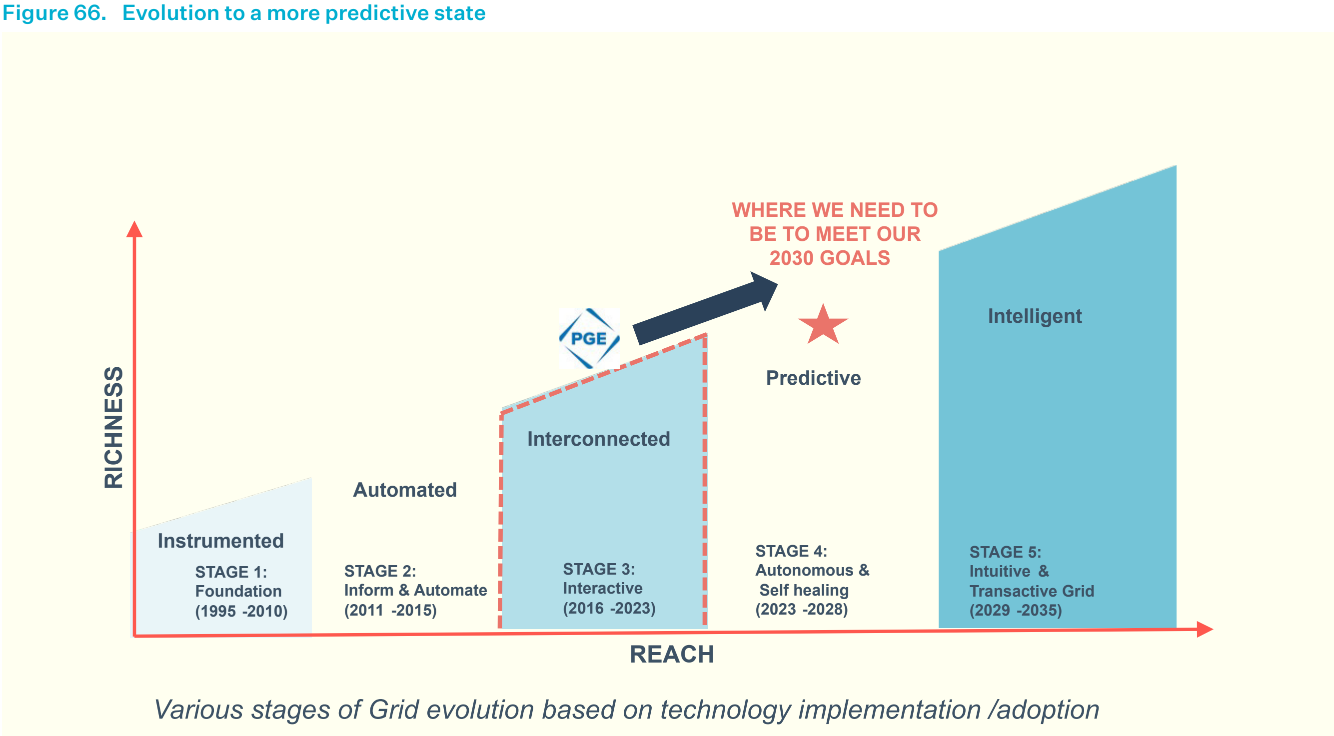
Our modernized grid initiative aims to enable an optimized grid platform that is safe, secure and reliable through current and future grid capabilities. The goal of a modernized grid is establishment of a system that can meet evolving customer needs while realizing the full value of DERs.

In order to meet the 2030 and 2045 goals, PGE's modernized grid needs to adopt a more predictive state and should evolve into an intelligent grid as shown in **Figure 66**.

PGE is currently working on realizing Stage 3 of the grid-evolution (Interconnected). Most IOU utilities in the US are at this stage of evolution. In order to meet Oregon's aggressive decarbonization requirements as set forth in HB 2021, it is imperative that PGE's grid should evolve to a state where systems predict the grid's next operational state and prepare customers and system operators to anticipate, rather than react.

PGE has been proactively modernizing the grid, integrating technologies such as smart meters and an advanced distribution management system (ADMS) to reduce outage response times and billing costs, among other benefits. Moving forward, this initiative will help align critical activities to enable and scale DER programs while addressing capability gaps in the company, such as performing locational net benefits analysis and optimized DER dispatch.

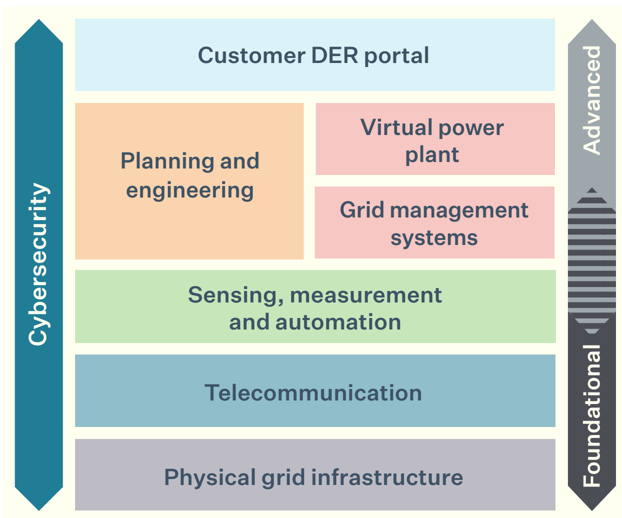
Figure 66. Evolution to a more predictive state



K.2 Modernized grid framework

PGE's latest iteration of its modernized grid framework is outlined in **Figure 67**. This iteration builds on the integrated grid concept outlined in PGE's 2019 Smart Grid Report and leverages the grid architecture outlined in DOE's DSPx to align with industry best practices.[89]

Figure 67. PGE's modernized grid framework



PGE's modernized grid framework can be broken down into three categories:

- Foundational capabilities refer to the set of core platform investments to enable visibility and control of the distribution system. These investments follow a least-cost, best-fit approach, usually through a request for proposal (RFP) or similar process.
- Advanced capabilities refer to investments that build on or, in some cases, supplement foundational investments to develop advanced, intelligent control of the grid. These investments, depending on their function, either go through a benefit-cost analysis or use a least-cost, best-fit approach.
- Overarching capabilities impact both foundational and advanced capabilities and are key considerations when making the investments after the primary need is addressed. These capabilities include cybersecurity, workforce implications and other compliance needs. This overarching nature requires the investment justification to mirror the base investments.

K.3 Currently planned capabilities investments

PGE has planned near-term investments with a direct impact on the outcomes of our vision for the distribution system. Each investment includes a forecasted timeline and costs over the short term. Where available, PGE also describes the expected long-term evolution of the specific investments.

K.3.1 CUSTOMER DER PORTAL

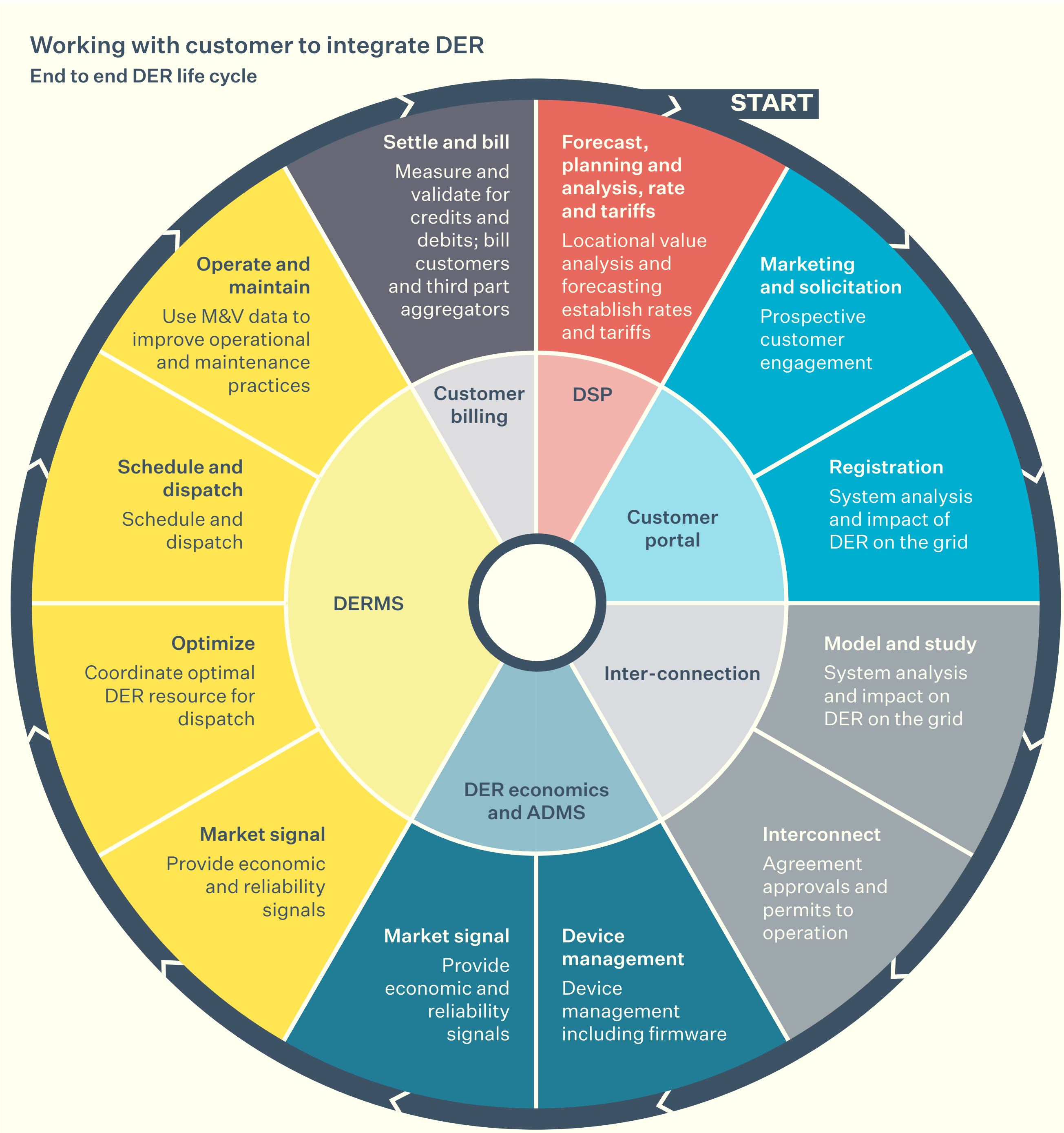
As part of the DER lifecycle, new functionalities and capabilities are being planned to improve customer interaction and experience. Customers need to be solicited and marketed with newer products and at the same time, they need to be recruited and registered to use the new product offerings from interconnection to various demand response and energy efficiency products. New products related to distributed energy resources are being devised and the customers' experiences of procuring and registering is critical. At the same time, PGE will have a responsibility to maintain the grid connectivity to those devices and manage the behavior of those devices including device management and cyber security.

The accuracy of the interconnected devices will allow the grid operations to have a detailed view through the distribution management system, as these devices will form the basis of the Virtual Power Plant which is described below.

89. US Department of Energy's Modern Distribution Grid Project is available at https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx More details can be found in DOE's DSPx guidance in Volume III, available at https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid-Volume-III.pdf

Customers are expected to be marketed, solicited, and sold various products through which measurement and verification along with billing/settlements can be performed. The complex life cycle of the DER is being studied and evaluated at PGE. PGE plans to slowly invest and improve the customer portal. Some of the major customer portal functions that PGE is thinking about and leading the way are Customer DER Device Management, Customer Billing and Settlements, Customer DER Interconnections and Customer Interconnection Communications. Some future functions are DER Marketplace portal, Transactive Energy Portal, Transportation Energy related functionalities, Building Electrification related functionalities that provide a low carbon future by prioritizing cost effective, clean energy upgrades. PGE is also planning to develop various modeling tools and data science-based insights to deliver customized customer energy insights.

Figure 68. DER lifecycle diagram



K.3.2 Virtual power plants

PGE is designing a new virtual power plant (VPP) business function enabled by a next-generation technology platform. The VPP function will operate at the nexus of Grid Operations, Customer Products and Programs, and Planning and Engineering.

For grid operators, the VPP function will act as a central hub for dispatching DERs and flexible load in large quantities. The VPP function will present operators with bundled DER portfolios that mimic the operational characteristics of traditional power plants, allowing operators to call on VPPs to provide various grid services without concern for the varying requirements of underlying customer programs.

For product developers, the VPP function will define standard business requirements for supplying various grid services. This will enable product developers to focus their attention on designing for customer value and customer experience within established constraints.

The VPP function will assume ownership of program dispatch from program operators. Centralizing operational dispatch will reduce workload at the level of individual programs, enabling program managers to focus on marketing, recruitment and program improvement. Centralizing dispatch will also position the VPP function to standardize operations and drive automation across programs.

The DER Forecast team will work with the VPP function to establish DER forecasts and planning assumptions. The VPP function will then be able to reserve and manage resources for non-wires solutions when deferring upgrades is the highest value usage of specific DERs.

The VPP function's scope will include any DERs and flexible loads on the distribution grid, including front-of-meter and behind-meter resources, PGE-owned resource, and resources owned and operated by customers. Depending on the size and nature of the individual resources they may be managed individually or aggregated at the program level — either by PGE or by a third-party aggregator.

The primary mission of the VPP function is to drive DERs and flexible loads to scale by maximizing the value of grid services delivered. To accomplish this, PGE will segment grid services into groups according to their scaling potential. Grid services that PGE is capable of scaling immediately will take priority, and the VPP function will actively pursue resource acquisition while eliminating obstacles to growth. For grid services where existing conditions do not enable scaling, the VPP function will work proactively with other functions to build enabling capabilities.

Bulk generation capacity, contingency reserves, frequency response, and hourly economic dispatch are expected to be the priority grid services for scaling as the VPP begins operating. Focus areas for capability building will likely include distribution locational benefits, volt/var control, and sub-hourly economic dispatch.

An ongoing VPP operating model project will produce business requirements, a five-year road map, and a detailed action plan for implementation by the end of Q3 2022. Development of the VPP technology platform will then occur in parallel with business implementation.

K.3.3 PLANNING AND ENGINEERING

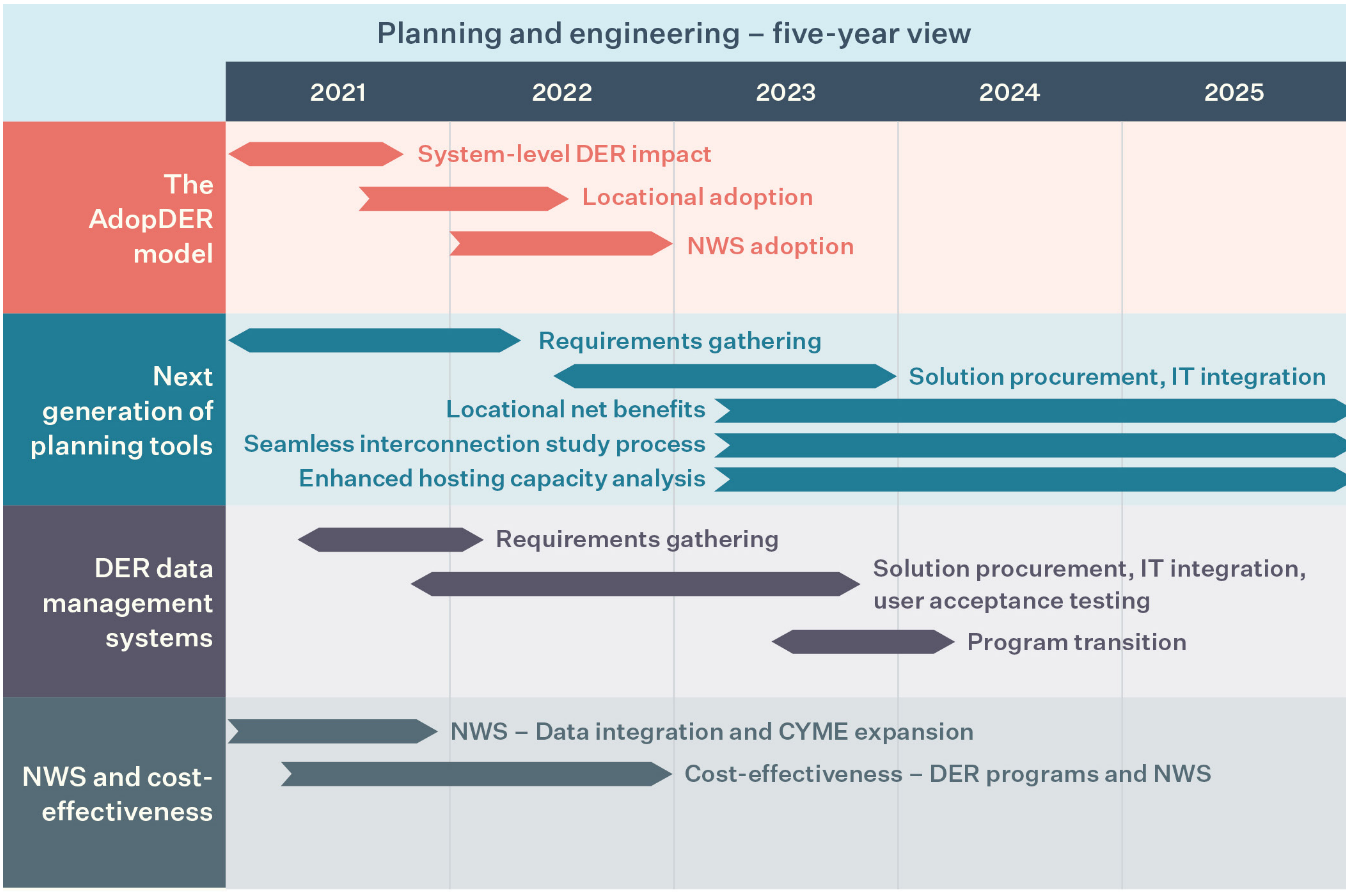
The planning and engineering capability refers to a suite of integrated, next-generation tools needed to perform distribution system planning functions. PGE's current approach to this capability builds on the functionalities outlined in the DOE's DSPx, as noted in **Figure 69**. This approach follows best practices and links investments directly to the goals outlined in our vision for the distribution system.

Figure 69. Planning functions as defined by DOE's DSPx

<table>
<tr><th colspan="3">Distribution planning</th></tr>
<tr><th>Functionality</th><th colspan="2">Technologies</th></tr>
<tr><td>Short and long-term demand and DER forecasting</td><td colspan="2">Demand forecast models
Load profile models
DER forecasting (customer DER adoption models, customer-EV adoption models)
Scenario analysis tools</td></tr>
<tr><td>Short-term distribution planning</td><td rowspan="2">Power flow analysis</td><td rowspan="2">Peak capacity analysis
Voltage drop analysis
Ampacity analysis
Contingency and restoration analysis
Balanced and unbalanced power
Flow analysis
Time series power flow analysis
Load profile analysis
Volt-var analysis</td></tr>
<tr><td rowspan="2">Long-term distribution planning</td></tr>
<tr><td rowspan="2">Fault analysis</td><td rowspan="2">Fault current analysis
Arc flash hazard analysis
Protection coordination analysis
Fault probability analysis</td></tr>
<tr><td rowspan="2">Hosting capacity</td></tr>
<tr><td rowspan="2">Power quality analysis</td><td rowspan="2">Voltage sag/swell analysis
Harmonics analysis</td></tr>
<tr><td>EV readiness</td></tr>
<tr><td>Planning analytics</td><td colspan="2">DER impact evaluation tool
Stochastic analysis tools</td></tr>
<tr><td>Reliability and resilience planning</td><td colspan="2">Realiability study tool
Value of lost load (VoLL) models
Resilience study models
Resilience benefit-cost models</td></tr>
<tr><td>Interconnection process</td><td colspan="2">Process management software and portals</td></tr>
<tr><td>Locational value analysis</td><td colspan="2">Cost estimating tools</td></tr>
<tr><td>Integrated resource, transmission and distribution planning</td><td colspan="2">Planning integration and analysis platform</td></tr>
<tr><td>Planning information sharing</td><td colspan="2">Web portals
Geospatial maps</td></tr>
</table>

PGE has planned the following key investments to enable the functions from **Figure 69**. These investments are considered foundational and aligned with DOE's DSPx. They are evaluated based on least-cost, best-fit and reasonableness. **Figure 70** provides a five-year overview of PGE's investments in planning and engineering.

Figure 70. PGE's planned investments in planning and engineering over next five years



Note: Includes future initiatives

K.3.3.1 Bottom-up DER forecasting and potential assessment – The AdopDER model

To meet the evolving needs of customers, we developed an in-house model, AdopDER, to conduct bottom-up DER forecasting and assess DER potential at the system- and locational-level. This model leverages an open modeling framework that integrates true bottom-up modeling of the building and vehicle stock with market-level adoption forecasts, creating a rich, integrated view of how different DER and electrification technologies complement and compete under different conditions. The AdopDER model represents a paradigm shift in how potentials are modeled and lays the foundation for continued evolution in planning processes across the energy system.

This project is being developed in two phases over a two- to three-year period. In Phase I, PGE estimated system-wide DER potential to inform the company's Integrated Resource Plan (IRP). In Phase II, PGE estimated locational adoption of DER resources and fine-tuned adoption models to account for different demographics, energy use patterns, built infrastructure and cluster effects that are known to impact the distribution of DERs on the system. Phase II results are discussed further in **Section 3.5**.

PGE expects to incorporate lessons learned and feedback to build on the existing functionality, enabling new features such as locational adoption for non-wire solutions (NWS), improved data and information technology (IT) integration and data quality.

K.3.3.2 Next-generation planning tools project

PGE is currently conducting an investigation to understand the current and required future planning capabilities needed to realize PGE's vision. This effort will also provide the required tools, data and IT infrastructure to perform planning analysis at the appropriate frequency, as well as the workforce changes to update our approach to distribution system planning and engineering.

We refer to this project as "next-generation planning tools." Through this investment, we expect to enable integrated distribution planning (IDP), acquiring additional technical analysis capabilities that will allow us to meet the future planning needs of the distribution system. The integrated distribution planning framework allows us to identify appropriate investments in the distribution system that deliver safety, reliability and security, while accommodating load and DER growth, as well as modernization of the grid through technology and aging asset replacements. Enabling IDP will also help us to enhance interconnection study processes to support rapid growth of DERs and improved processes for engaging community in addressing grid needs.

Some of the advanced technical analysis capabilities being considered include:

- Ability to perform time series analysis (8,760 hour analysis)
- Ability to consume profile-based forecast (8,760 hour forecast profiles)
- Ability to incorporate granular data in the analysis of the distribution system
- Enhancements and efficiencies to performing hosting capacity/integration capacity analysis
- Ability to perform integration of non-wires solutions (NWS) into the distribution grid
- Enhance and efficiencies in performing interconnection technical screenings and studies
- Distribution system optimization — Volt/Var, DER placement and dispatch, device placement (capacitor, regulator, DER)

Our next generation planning tools project will be a foundational investment designed to enhance PGE's current planning capabilities and enable improvements in various facets of distribution system planning.

As the initial phase of the next generation planning tools project, PGE evaluated the state and maturity of various planning tools and processes. An investigation into available planning engineering tools in the industry was also conducted to decide which vendor/tool provides the best flexibility and capability to meet the future needs.

An assessment of various commercially available planning tools was conducted to evaluate which vendor/tool could provide most of the capabilities that PGE is desiring to gain. Based on the assessment, a decision was made that CYME, through various analysis modules they offer, meets most of the capabilities that PGE needs.

CYME is currently engaged to work with PGE in developing a detailed road map for implementing an Advanced Distribution Planning System (ADPS) which would be foundational for enabling Integrated Distribution Planning capabilities.

Through this engagement, CYME and PGE will:

- Identify the current usage of CYME tools and modules at PGE
- Identify PGE pain points in the current planning engineering process
- Identify additional data and integration needs
- Identify specific analysis tools and capability maturity needs
- Explore various use cases of CYME tools and modules in planning engineering as well as operations planning
- Identify and document existing IT system and integration used by CYME
- Create a system architecture diagram to develop detailed IT system and integration design

Based on the discovery process, CYME and PGE will develop a high-level design for the ADPS. The design will include data integration needs with other systems and tools (e.g., GIS, AMI, SCADA, and Forecasting). The design will include automation of various processes needed in planning engineering such as — system model updates, power flow with profiles, integration capacity analysis, forecast profile creation, and grid needs summary output.

This high-level design will act as the foundation for the next steps to undertake a detailed design, develop and implement expanded and automated CYME capabilities (Advanced Distribution Planning System) that enables an Integrated Distribution Planning process. This will be a multi-year process that involves new IT equipment and integration as well as process changes in the planning engineering team.

K.3.3.3 DER cost-effectiveness update project

PGE has a strategy to develop a benefit-cost framework aligned with state policy and goals. This framework will be designed to account for the new and emerging value of DERs. The new comprehensive investment strategy presents many opportunities which come with challenges. DER investment strategy, with the growth forecasted, needs to be supported by an enhanced methodology to adequately value resources added to our grid. An improved cost-effectiveness analysis capability will help us look at broader impacts of DERs and open opportunities for expanding existing programs or creating new pilots. In return, it will help PGE reach our clean energy goals, while offering broader options for our customers to interact with the grid and contribute to greener future.

As part of this new methodology, PGE is developing a new cost-effectiveness tool, called Ben-Cost. It builds on PGE's previous work on the resource value of solar, flexible load and transportation electrification valuations. The new tool will enable DERs to be valued through multiple perspectives, accounting for energy system, host customer and societal impacts.

The Ben-Cost tool will enable PGE's product development teams to experiment with more nuanced program designs, especially as they pertain to impact on environmental justice communities.

In 2022, PGE will build on the Ben-Cost tool to enable economic analysis for NWS and perform studies to calculate other societal benefits. We expect to focus on refining the functions of the tool, performing IT integration of the model with AdopDER and the proposed Demand Side Management System (DSMS).

K.3.3.4 Systems of Record for DER Data

As DERs proliferate and become an increasing part of the physical infrastructure with which PGE interacts, PGE must maintain and organize new types of data related to generation, storage, and flexible load resources on the distribution grid. The availability of accurate and relevant data will determine how much value can be captured for the grid and for individual customers.

Examples of new or newly significant data include:

- **Nameplate characteristics, electrical and geographic location, configuration settings, and control functions of interconnected DERS:** Systems exist for storing relevant information about traditional, utility-owned resources, but these systems are not designed to manage all required information about new resource types, nor are they designed to manage information about resources owned by customers.

- **Characteristics of buildings and building loads that affect suitability and performance in flexible load programs:** Traditional utility systems have limited ability to represent and store information about what lies "behind the meter." Such data has typically been managed as a list of characteristics related to the service point. But emerging applications require richer multi-dimensional data.

- **Information necessary to gain insights from the operation of DERs and customer programs:** Site-level performance data — such as device telemetry — in association with customer insights and external variables like weather and market conditions enables more accurate forecasts and can generate ideas for innovation and improvement. And the benefits of applied data science compound over time as improved program performance drives lower rates and higher incentives for customer participation.

Identifying the source of data and which stakeholder team at PGE is responsible makes it easier to leverage data. Making effective use of DER data will enable key functions:

- **Planning and evaluation:** Support more accurate studies through awareness of each DER's capabilities and operational characteristics.
- **Operations:** Support real-time decisions through awareness of DER location, characteristics, and expected impact.
- **Products and programs:** Streamline program management, reporting, incentive processing, and cost-effectiveness calculations, and help improve program design.
- **Customer support:** Provide customers with improved information about the programs they participate in and the benefits available to them.
- **Field crews:** Ensure accurate information for maintenance assessment and crew safety.
- **Participation in organized markets:** Enable DERs to participate in the energy imbalance market and provide bulk system services.

In 2022 PGE has contracted with the Electric Power Research Institute (EPRI) as part of a collaborative R&D effort to help PGE remain abreast of emerging industry practices for managing DER data. Knowledge gained will be applied through various initiatives that implement or change PGE information systems. Primary near- and medium-term implementation efforts include:

- Efforts to further operational integration by automating the dispatch of flexible load resources and/or integrating dispatch into the processes and systems used to dispatch other resources.
- Efforts to rationalize and standardize technology implementation across programs through competitive procurement and improvement of the interfaces between systems.
- Efforts, such as the Customer 360 Project, that directly address the breadth, quality, and availability of data for analysis.

K.3.3.5 Demand Side Management System (DSMS)

PGE is in the early stages of developing an enterprise-wide central source of DER data and attributes. This project, also known as a DER measure database in energy efficiency, is a foundational requirement to record and house important DER details, such as:

- DER attribute data, telemetry data, locational data and customer information
- DER program performance data
- DER cost-effectiveness and evaluation results
- Energy efficiency and renewable energy integration with the ETO
- DER reporting and regulatory compliance

An analytical platform that works with this data will streamline core business functions, including interconnection and program application processes, incentive payments, demand response (DR) event performance reporting, standard reports for regulatory filings and data requests, integration with planning tools, improved visibility for operators, integration interconnection data, EV impacts and program opportunity analysis.

PGE is also in the process of contracting with Electric Power Research Institute (EPRI) as part of a new research and development (R&D) effort in which PGE will leverage EPRI's expertise and ensure best practices are implemented in the design of the DSMS.

The project is expected to affect the following business functions:

- **Planning and evaluation:** Accurate studies through awareness of each DER's capabilities and operational characteristics
- **Operations:** Real-time decisions supported by awareness of DER location, characteristics and expected impact
- **Product teams:** Streamlined program management, reporting, incentive processing, cost-effectiveness calculations and program design

- **DER customer support:** Utility staff and websites to provide DER customers with information
- **Field crews:** Accurate information for DER maintenance and assessment
- **Coordination with independent/transmission system operators (ISOs)/TSOs:** Support of requirements for DERs providing bulk system services

PGE has created a cross-functional team to develop requirements for procurement of a DSMS. We expect the project to take one to three years for completion.

K.3.4 GRID MANAGEMENT SYSTEMS

Grid management systems (GMS) are a collection of operational technology tools used by operators of electric utility grids to monitor, predict, analyze, control and optimize the performance of the distribution system.

The GMS communicates with field devices that sense, measure, protect and control the grid, via a telecommunications network. Investments across the GMS, field devices and telecommunication systems are interlinked and considered together to maximize customer benefit.

The following details describe key ongoing and planned investment activities within both the GMS and supporting infrastructure. Where available, PGE has provided long-term evolutions of these investments. The current set of planned investments in the following sections are foundational prerequisites for the modernized grid. PGE leverages the least-cost, best-fit approach to justify these investments. PGE has noted investments where future evolution will require investment justification through benefit-cost analysis.

PGE has developed a comprehensive grid modernization strategy that will facilitate cultural shifts, shorter development cycles and cohesive strategic alignment across PGE. These capabilities are needed to provide safe, secure, reliable and resilient power on the electric grid subject to high DER penetration. **Figure 71** illustrates the functions necessary from a comprehensive GMS.

Figure 72 illustrates PGE's five-year roadmap for GMS.

Figure 71. Grid management system functions

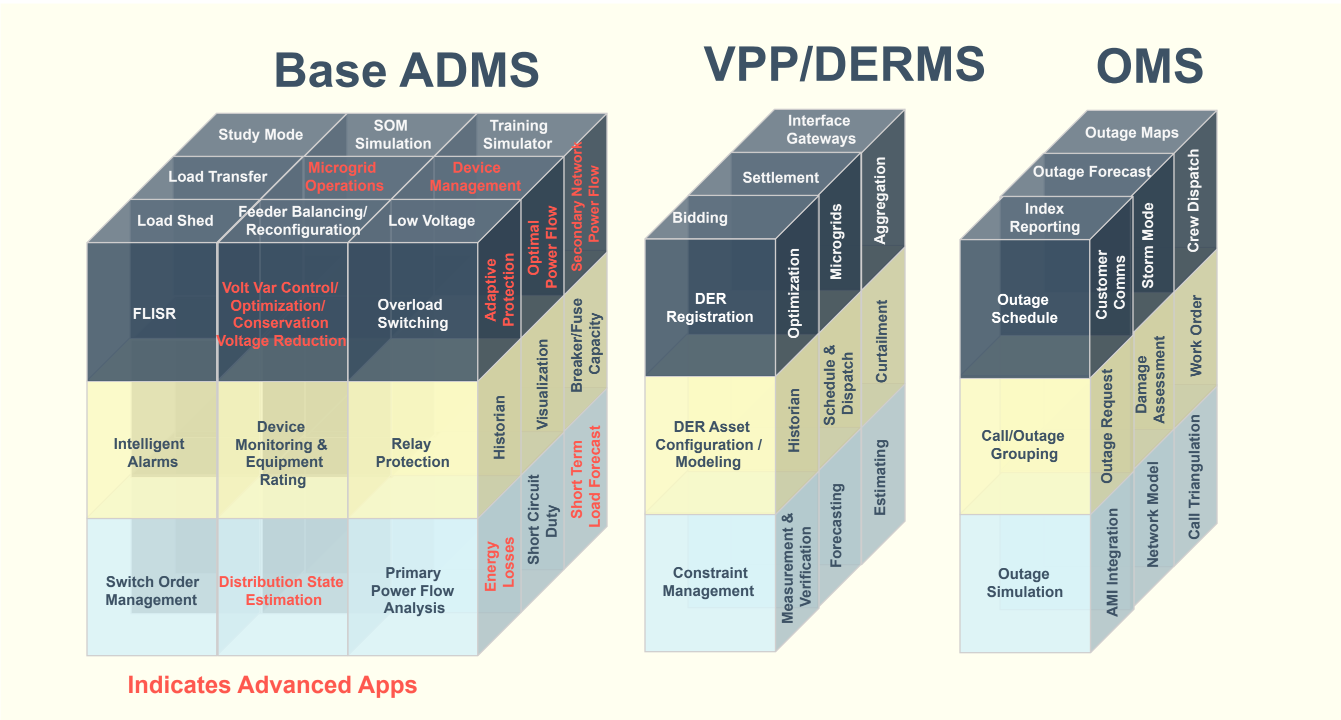
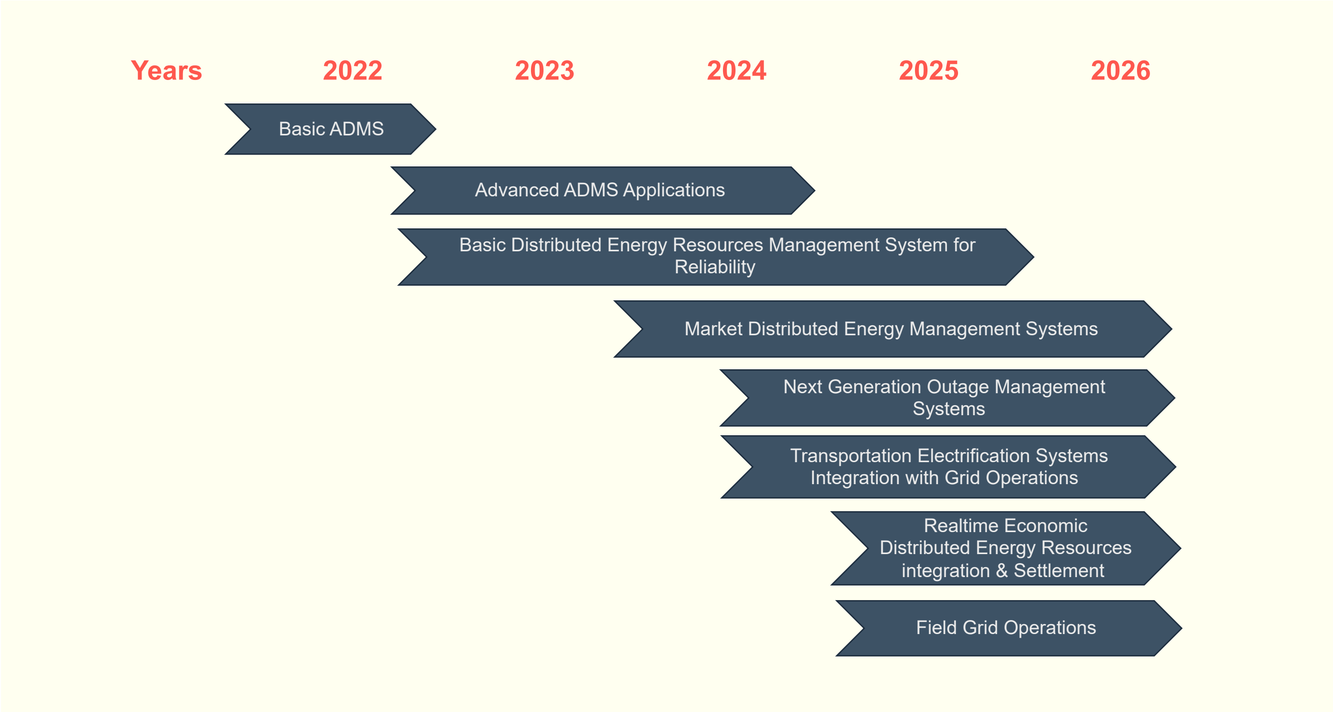


Figure 72. PGE's expected five-year roadmap for grid management systems



In 2022, completion of our Basic ADMS deployment included implementation of a distribution management system (DMS) with functions focused on monitoring, predicting and operating distribution devices on the distribution system. Additionally, PGE implemented fault location, isolation, and service restoration (FLISR) on several feeders to leverage the monitoring and operational capabilities of the DMS for direct reliability benefits. Finally, PGE's Basic ADMS implementation included management of electronic switching sheets, clearances, monitoring of integrated grid systems, and operation of equipment on the distribution system.

ADMS will collect real-time information from distribution substations and feeder and customer devices and integrate existing and future distribution automation schemes, which are defined in the following section.

While DER and DSG resources may not be classified as critical infrastructure protection assets, protective measures similar to the energy management system (EMS) are in place.

K.3.5 SENSING, MEASUREMENT AND AUTOMATION

Substations serve as the hub of energy transmission and delivery. State-of-the-art substations enable reliable and resilient operation of the grid. Substations need to be equipped with modern protection and automation (e.g., SCADA with device and data integration) to realize many of the capabilities needed to operate the modern grid.

K.3.5.1 Distribution automation (DA)

DA is the umbrella term for smart grid solutions that solve power system issues by integrating various equipment, devices and data into a centralized system (the ADMS). These solutions include FLISR, Volt-VAR optimization (VVO) and smart faulted circuit indicator (sFCI) integration. Each DA solution requires a unique set of integrated devices and systems to fully realize the benefits. Types of DA solutions are described below:

- **FLISR:** Normally open and normally closed supervisory control and data acquisition (SCADA)-integrated switching devices are strategically placed throughout the feeder to maximize the implementation's expected benefits. The preferred communications medium is PGE's FAN. When paired with a centralized controller (e.g., ADMS), the system will identify the location of sustained faults using sensor data, then will isolate the faulted section and restore service to customers outside of the isolation zone via automated, remote switching. The result is reduced frequency and duration of sustained outages for customers.
    - 2021 through 2024: For each year, install approximately 83 SCADA-integrated switching devices across approximately 20 feeders; perform upgrades at approximately 15 substations to enable ADMS integration.
    - 2025 and beyond: During the first four years of implementation, evaluate realized and forecasted FLISR cost-effectiveness to determine future implementations plans.
- **VVO:** Equipment that can manage voltage and optimize VAR flow and controlled via SCADA within ADMS, reducing system losses and contributing to peak reductions, is installed inside substations and along distribution feeders. Capacitor banks provide the principal source of VARs (a unit of reactive power) with smaller amounts of reactive power potentially being contributed by secondary VAR controllers or customer owned DERs. Similarly, load tap changers (LTC) and line voltage regulators provide direct voltage control for distribution feeders with supplemental voltage support provided by capacitor banks and some amount of local voltage support provided by inverter based DERs. Once integrated with an ADMS, this equipment is controlled to meet a variety of objectives, including implementing active or real-time conservation voltage reduction (CVR), minimizing power system losses, maintaining acceptable voltage for all customers and regulating the power factor (PF) for feeders and substation transformers.
    - Plan for initial active VVO implementation through PGE's across three LTCs and associated feeders
    - Pilot active VVO implementation.
    - Evaluate effectiveness of active pilot VVO implementation.
    - Scale VVO program commensurate with cost effectiveness.
- **Smart fault circuit indicator (sFCI):** Installation and integration of communicating line monitors, strategically placed throughout the distribution system, will help inform real-time operational decisions. Specifically, these monitors provide data that allows improved accuracy for FLISR as well as improved situational awareness, and reduced truck rolls and line patrols.
    - 2021: Select sFCI vendors for select feeders that are designated as having heightened wildfire risk.
    - 2022: Evaluate effectiveness of sFCI deployments and plan for future deployments throughout all identified wildfire feeders (if applicable).
    - 2023: Finalize an sFCI placement model to help strategically place sFCIs in areas that are forecasted to receive the greatest benefits. Consider other use cases for implementation (e.g., feeders without SCADA telemetry).
    - 2024 and beyond: Scale FCI program commensurate with cost effectiveness.

Execution of DA initiatives is paramount to transforming PGE's distribution system into a smarter, more integrated grid.

K.3.5.2 Substation automation and SCADA systems

- **Achieve efficient monitoring and operations:** 83% of PGE's substations have SCADA capability. This means the remaining 17% of substations do not have the same remote monitoring and control capabilities. Information about emerging equipment problems and loading issues at these substations is not readily known to grid operators and could lead to unintended events, affecting the reliability of the grid and customer experience. For emergency response operations at substations without SCADA, a person must be physically dispatched to the substation to validate the issue and take action. This reduces response efficiency and reliability and diminishes the customer experience.

- **Optimize the grid:** Optimizing the grid requires continuous measurement and control capabilities. Optimization can be achieved through VVO capabilities. This will help with reducing system losses, demand reduction and reduced energy consumption through CVR. An updated substation automation system with relay, metering and transformer load tap changer (LTC) control device integration through distributed network protocol 3.0 (DNP 3.0) and the ability to integrate with systems like ADMS is needed to achieve this.

- **Improve asset management and utilization:** With a modern substation automation and associated SCADA system, intelligent devices such as relays, controllers, meters and asset monitoring devices can be integrated and information can be bought back to the office (e.g., Reliability and Performance Monitoring Center) for additional analysis. This data allows for better management of substations and major assets, enables efficient operations, increases asset utilization, lowers maintenance costs, predicts failures and assists with fine-tuning of the grid for more reliable operations.

- **Secure the grid:** All connected devices should be configured, connected and managed in a secure manner.

- **Simplify design and construction:** Continue to explore newer methods of protection and automation construction (e.g., IEC61850).[90]

K.3.5.3 Modernize cost-effective communication-aided protection systems

- **Improve system reliability:** A protection system is fundamental to operating the grid. Modern digital relays are required to meet new operational objectives by providing multiple settings groups, supporting remote modification of settings and locally adaptive protection when enabled. They also provide more detailed data via connection to a substation automation gateway and centralized SCADA platforms.

- Many of PGE's distribution substations and feeders do not have protective devices that easily support integration of distributed generation (i.e., many require setting changes be made at the relay within the substation). Improved protection capabilities will support remote modification of protection settings to accommodate increasing levels of distributed generation.

PGE's approach to substation automation is to balance grid needs, budget priority, and budget availability. We expect this project to be an ongoing activity with investments made on an as-needed basis and usually coupled with other investments such as substation rebuilds and feeder upgrades.

PGE has standardized the integration of cybersecurity monitoring and management for protection/automation systems as part of constructing new substations or rebuilding older substations. PGE also establishes data integration between all substation automation systems/devices and the Reliability and Performance Monitoring Center in PGE's IOC.

PGE estimates consistent multi-year investments for automation and protection.

K.3.5.3.1 Substation automation

- PGE will add SCADA automation to remaining non-SCADA substations (i.e.,100% SCADA coverage for substations) based on need, priority, and budget.

- PGE will replace legacy SCADA with modern SCADA and substation automation platforms (e.g., DNP 3.0) based on need, priority, and budget.

90. IEC 61850 is an international standard defining communication protocols for intelligent electronic devices at electrical substations. It is a part of the International Electrotechnical Commission's (IEC) Technical Committee 57 reference architecture for electric power systems.

K.3.5.3.2 Substation protection

- 2021 through 2025: Prioritize replacement of all electro-mechanical relays in wildfire zone substations.
- Post 2025: PGE expects to put microprocessor-based relays on an 18-year replacement cycle. This will enable new functionality through new technology, which reduces failures within the protection system.

K.3.5.4 Field area network (FAN)

One of the communication options as part of the strategy is the Field Area Network. The FAN is a PGE-owned and operated wireless network that will cover PGE's service territory, enabling quick and reliable grid communications using the 1MHz of PGE owned spectrum. It is worth noting that the FAN provides speeds in the Kbps range. FAN's primary use case is providing the communications necessary to operate DA reclosers but can be extended to other devices with similar connection profiles.

The alternative to the FAN is cellular service and, though ubiquitous, it has disadvantages for certain critical systems:

- **Reliability:** We are at the mercy of wireless operators for outage resolution (and even throttling during major events). Past experience shows troubleshooting can get bogged down between companies.
- **Longevity:** Wireless operator's technology can be decommissioned and their spectrum is continuously being repurposed. Hence there is a potential that our field equipment could be made obsolete.
- **Security:** The FAN is part of the PGE network, so our data does not go out of the PGE network.
- **Cost:** Cellular service is an operational expense

The FAN project involves the design, procurement and installation of PGE-owned and operated base stations, currently at 90 sites to covers our service area, with the goal to have all sites constructed and online by the end of 2024. Today we have constructed 28 of the 90 sites and we are in the process of connecting our first end device. We are on track to complete this project by 2024.

K.3.5.5 Automated metering infrastructure (AMI) improvements

AMI is the technology that allows the bi-directional communication and control of utility meter assets at residential, commercial, industrial and generation service points. It includes meters that are embedded with a combination of network radios and network towers (collectors) that gather the transmissions from the meters and, ultimately, the software that stores, visualizes and integrates that data to various downstream systems and processes.

PGE was among the first utilities fully implementing AMI and has a fully operational system with 99.9% AMI penetration for more than 10 years. The technology has become more advanced over time and continues to evolve very quickly as AMI use cases broaden beyond the traditional "meter reading" to focus more on grid sensor and controller functions. The AMI system at PGE collects data from 920,000 meters, aggregating 50 million daily messages that contain usage, generation, reactive power, voltage and temperature. This system also has alarms indicating the relative health of the measurements and of the electrical service itself. The system is capable of bulk (over the air) transactions that monitor outage status and power quality, as well as keeping the meter and network software, programming and configuration up to date with the latest standards. On any given day, there are up to 2 million of these two-way transactions.

The original AMI design included only remote disconnect (RD) meters installed on non-owner-occupied single-phase homes. As of 2019, PGE's strategy has been to install RD meters for all new single-phase services and replace non-functioning single-phase meters with RD meters. In addition, the company started proactively replacing approximately 25,000 meters per year with RD meters. From a DER perspective, RD meters are a necessary backstop to prevent reliability issues if DER solutions do not perform as planned.

The core business case for AMI has generally been tied to the ability to remotely, quickly and accurately gather billing reads once a month, rather than sending a meter reader into the field. AMI has allowed for remote disconnection and reconnection of power, rather than sending a disconnect representative to the home. From there, AMI has been used to present hourly usage (interval data) to some customers to allow for greater insight into usage patterns, as well as enable variable rate structures such as Time of Use/Time of Day without the necessity of field visits in all cases.

In thinking about the future of AMI over the next five- to 10-year timeframe, PGE has completed an initial "AMI 2.0" assessment that built a list of requirements for a forward-looking AMI strategy. These requirements build on the initial capabilities for billing, collections and simple outage management, as well as what will be required to facilitate the dynamic, bi-directional smart grid of tomorrow.

K.3.6 TELECOMMUNICATION STRATEGY

PGE is planning to deploy various distribution automation devices and sensors to support the increased adoption of DERs. To operate a reliable and resilient grid, PGE needs to be able to monitor and react to the behavior of these DERs. In order to monitor their behavior, PGE needs to have a comprehensive telecommunication network to support the increased level of communication between devices and operators. The successful operation of the telecommunication network depends on the following major characteristics:

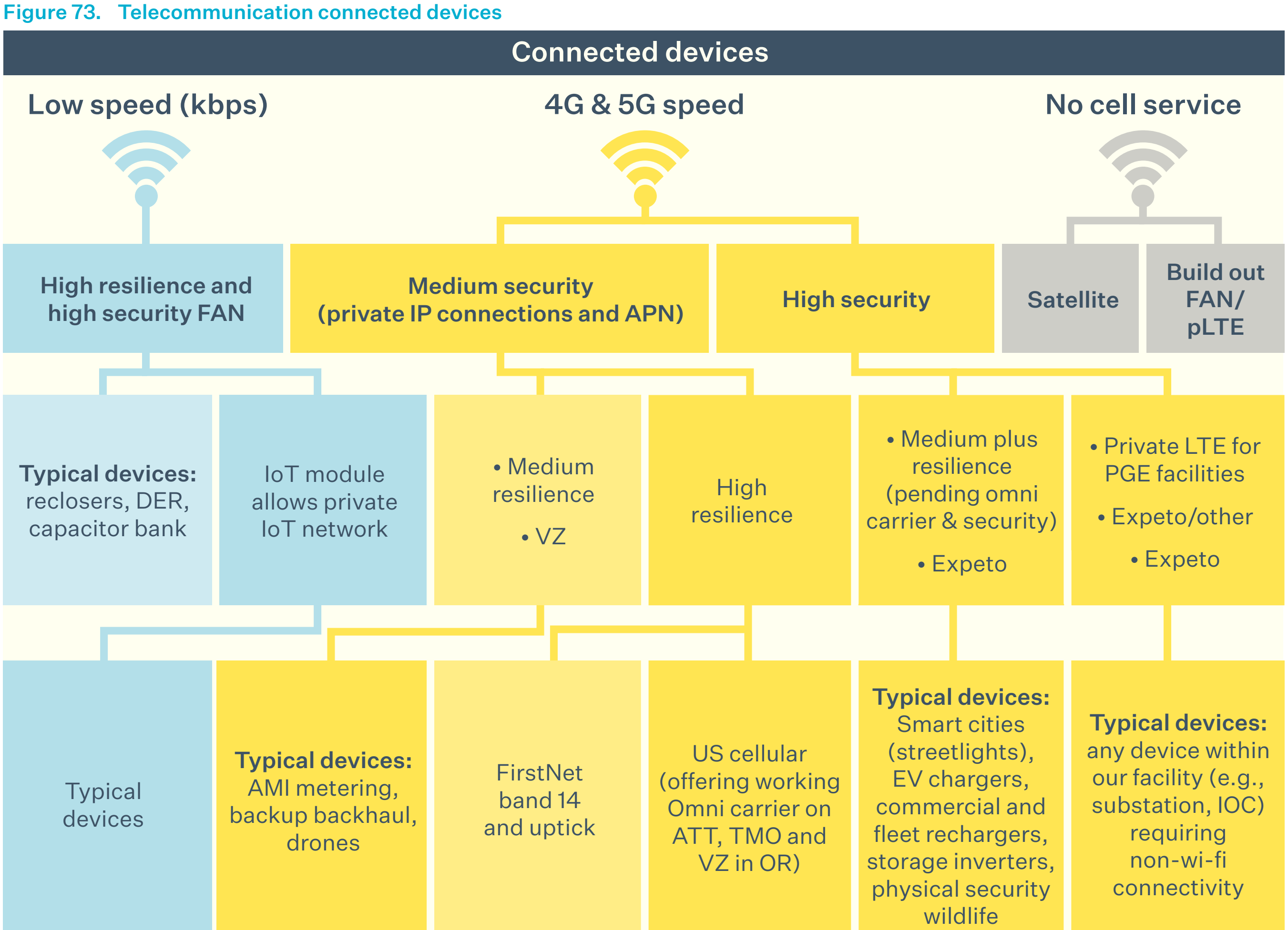
- Speed
- Bandwidth
- Latency (<40ms or >1s)
- Minimal service levels
- Security
- Availability
- Cost

The goal of the strategy is that the answers to the above points would drive the device to the network that best fulfills its needs.

Figure 73 shows the initial thoughts on how the different requirements translate into the connectivity options. At present, only the options highlighted in green are available for connectivity:

- Verizon data SIM
- PGE field area network (FAN)

Figure 73. Telecommunication connected devices



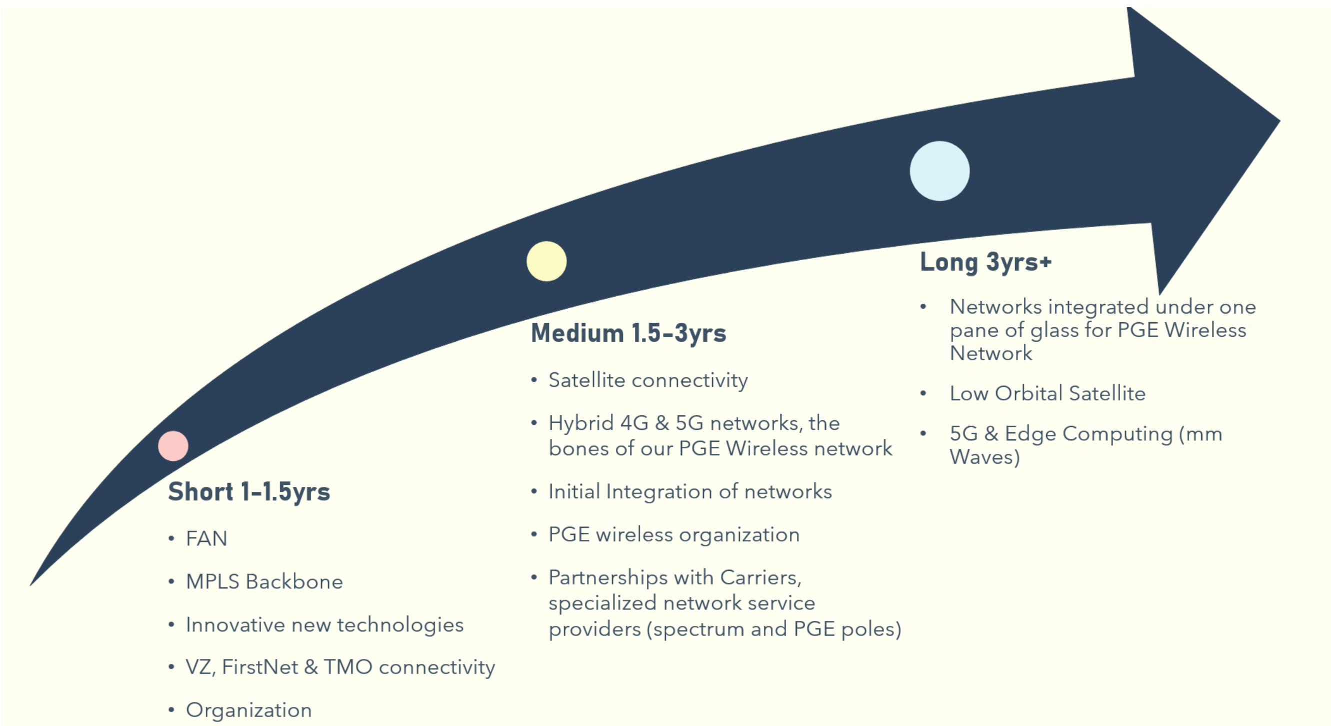
The other cellular options are in the process of being evaluated to see if they can meet our needs and to define their shortcomings. Some of the options being considered include:

- The concept of Omni carrier (the SIM will go on the "best" wireless provider), which both eXpeto, and now US Cellular, are proposing
- New FAN hardware, which would provide Internet-of-Things connectivity
- The security analysis for these different communication options

One of the challenges is how to get connectivity when there is no cell service from any operator (this is coming up more often when deploying sensors for wildfire mitigation)

Figure 74 depicts a high-level roadmap for advancing the telecommunication capability.

Figure 74. Telecommunication capability roadmap



K.3.6.5.1 Short term

There are a handful of short-term tasks that we can do to be in a better position for grid modernization:

- Integrate all operators — we currently have only one cellular wireless solution, Verizon. As such we are not able to leverage competitive prices from both T-Mobile and AT&T. To get the other operators added, we would need to set up the necessary connectivity between their networks and ours. We are researching the monthly costs to set this up.
- Organization — at present, we do not have a clear process to troubleshoot cellular network performance/outage issues. Our recent experience with Verizon and the AMI outages highlighted gaps in the process, such as:
  - Missing a troubleshooting step to confirm that the issues are not PGE's
  - The inability to track issues and open internal and external service requests with the wireless provider

There is an important area of focus regarding the organization required to manage all the different connection options and which team should be responsible.

K.3.6.5.2 Medium term

The noteworthy milestones are the deployment of a PGE wireless network and getting an initial platform in place to support that network. We anticipate narrowing down the technologies we want under the PGE wireless network and designing the organization that will be responsible for managing the network.

K.3.6.5.3 Long term

The PGE Wireless network will consist of different connection methods, such as:

- Hybrid 5G data network (Expeto)
- Satellite network
- Private LTE (5G)/edge computing for very low latency connectivity
- Private IoT network/mesh networks
- Commercial cellular (traditional voice)
- FAN

The challenge is integrating diverse technologies into one platform while being able to switch between the technologies at the end device to ensure we have diversity.

We expect to see the deployment of target, private LTE (5G) deployments together with edge computing to provide the necessary low latency that today's wireless signals struggle to achieve.

K.4 Resilience action plan

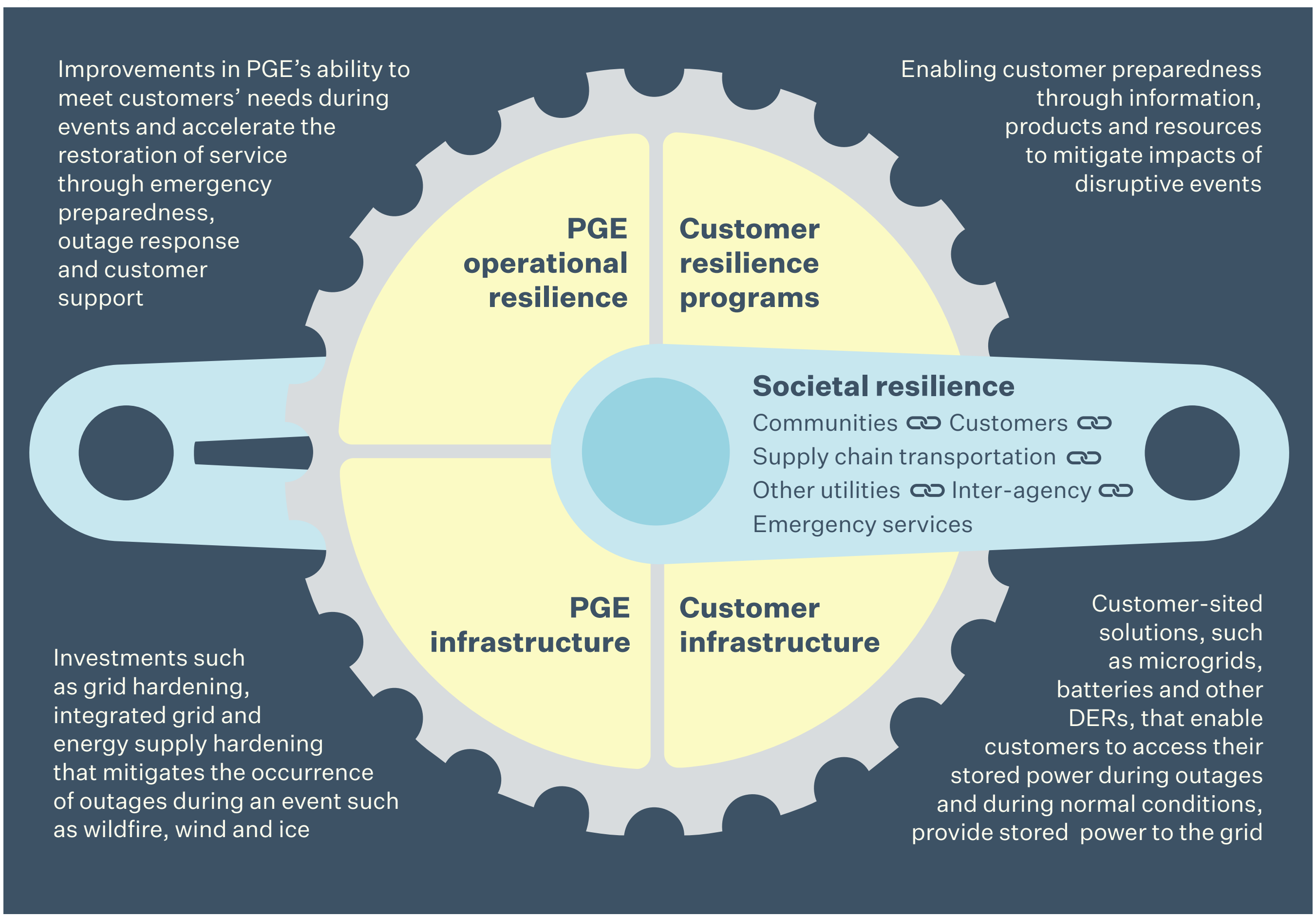
Resilience is defined as our ability to anticipate, adapt to, withstand, and quickly recover from disruptive events. Some customers are feeling the urgency to take action to prepare for the unexpected, and PGE does recognize this urgency. Our approach to resilience brings together leaders and teams from across the company to improve our ability to meet customer and community expectations for resilient power delivery. We align the efforts, investments, and plans across multiple functions and business lines to reduce the impacts of climate change, other natural disasters and human threats on our ability to serve customers.

PGE's approach focuses on four outcome-based capabilities:

- **Robustness:** the ability to absorb shocks and continue operating
- **Resourcefulness:** the ability to skillfully manage a crisis as it unfolds
- **Recovery:** the ability to get services back as quickly as possible
- **Adaptability:** the ability to incorporate new information and lessons learned from past events

PGE's resilience is highly dependent upon our broader societal resilience, including transportation, supply chain, and other agencies. Because energy system resilience is a critical component of societal resilience, PGE must take a community-centric approach to planning resilience investments. PGE's energy system resilience spans generation, transmission, distribution, and information technology operations with four areas of focus as shown in **Figure 75**.[91]

Figure 75. Resilience focus areas



91. Reliability – the availability of electric service
Hardening – a tool to create stronger infrastructure to protect customers from weather or other environmental impacts

Complementing the focus areas are PGE's resilience guiding principles:

Ahead of the game: PGE is monitoring changes in our environment and our community. We are proactively adjusting our plans to address your needs.

When we know, you know: PGE will communicate with you about the performance of your electric service. We will be transparent with our investment plans and resiliency challenges.

Meet you where you are: PGE delivers resilient electric service and programs to serve the diverse needs of all customers and communities.

Pushing the envelope: PGE is constantly exploring new solutions, customer programs, processes, and technologies to reinvent outage prevention and deliver value for you.

We'll help you prepare: PGE will partner with you and your community leaders to prepare for the future.

Affordable service: PGE is making prudent investments to improve the resilience of your electric service. We are considering both traditional and non-traditional solutions to new challenges.

K.4.1 RESILIENCY AS AN IMPERATIVE

Climate change brings increased risk of storms, power outages. In a survey conducted in 2016 among residential customers about battery energy storage, 63% of PGE residential customers indicate never experiencing a power outage is extremely important.[92] Working from home was cited as the main reason why consistent power was of utmost importance, and one can imagine that with record numbers of Oregonians working out of the home due to COVID-19 that importance has only increased.

Sixty-two percent of business customers say that an outage of five minutes or longer would have a moderate or significant impact on their business operations, with almost 40% saying the impact would be significant. The same survey showed that customers feel that reliable electric service without outages is the most important issue as a business customer of PGE, scoring one point higher than even "keep prices predictable and affordable."[93]

PGE must make the investments and help prepare our customers for both proactive, in the case of a public safety power shutoff (PSPS), and unplanned interruptions of power so that customers can withstand periods of utility power interruption and can have faith in our product. PGE customers are increasingly reliant upon electric service to power electric vehicles, medical equipment, internet access, appliances and more.

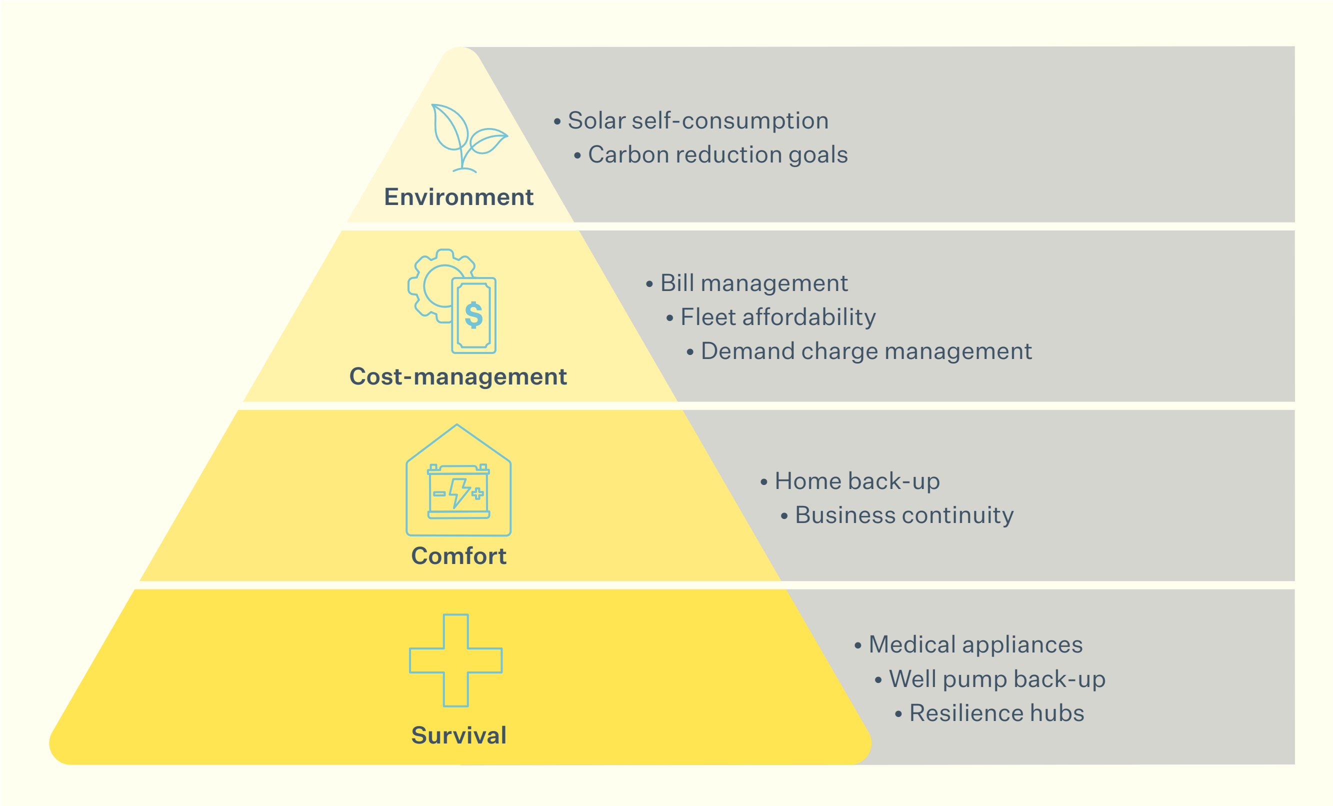
The following sections provide examples of the activities PGE is planning or undertaking to mitigate the effects of disruptive events.

K.4.2 CUSTOMER PREPAREDNESS AND CUSTOMER INFRASTRUCTURE

When considering customer resilience needs across all segments, we can categorize these needs into a few areas: survival, comfort, cost-management and environment. These customer needs can be arranged as a hierarchy, whereby a customer will focus on foundational needs such as survival before other use cases, such as carbon reduction. **Figure 76** illustrates this hierarchy with some examples of customer needs.

92. Residential Battery Storage Demand Assessment Research: Importance and Interest, January 2016
93. PGE Business Customer Segmentation Report, April 2019

Figure 76. Resilience use case hierarchy



This hierarchy for resilience is important because PGE may not have as many grid services that may be co-optimized with customers closer to the bottom of the hierarchy. For example, a battery that provides back-up power to a medical appliance would not be a technical or practical solution for participating in demand response or other grid services. PGE seeks to understand the resilience needs of all customers and understands that in order to support the most vulnerable needing resiliency for survival, customer programs may look different than traditional flexible load initiatives. Solutions may also involve societal solutions that are outside of PGE's control.

Our goal for how customers experience PGE's services is captured in the following vision statement:

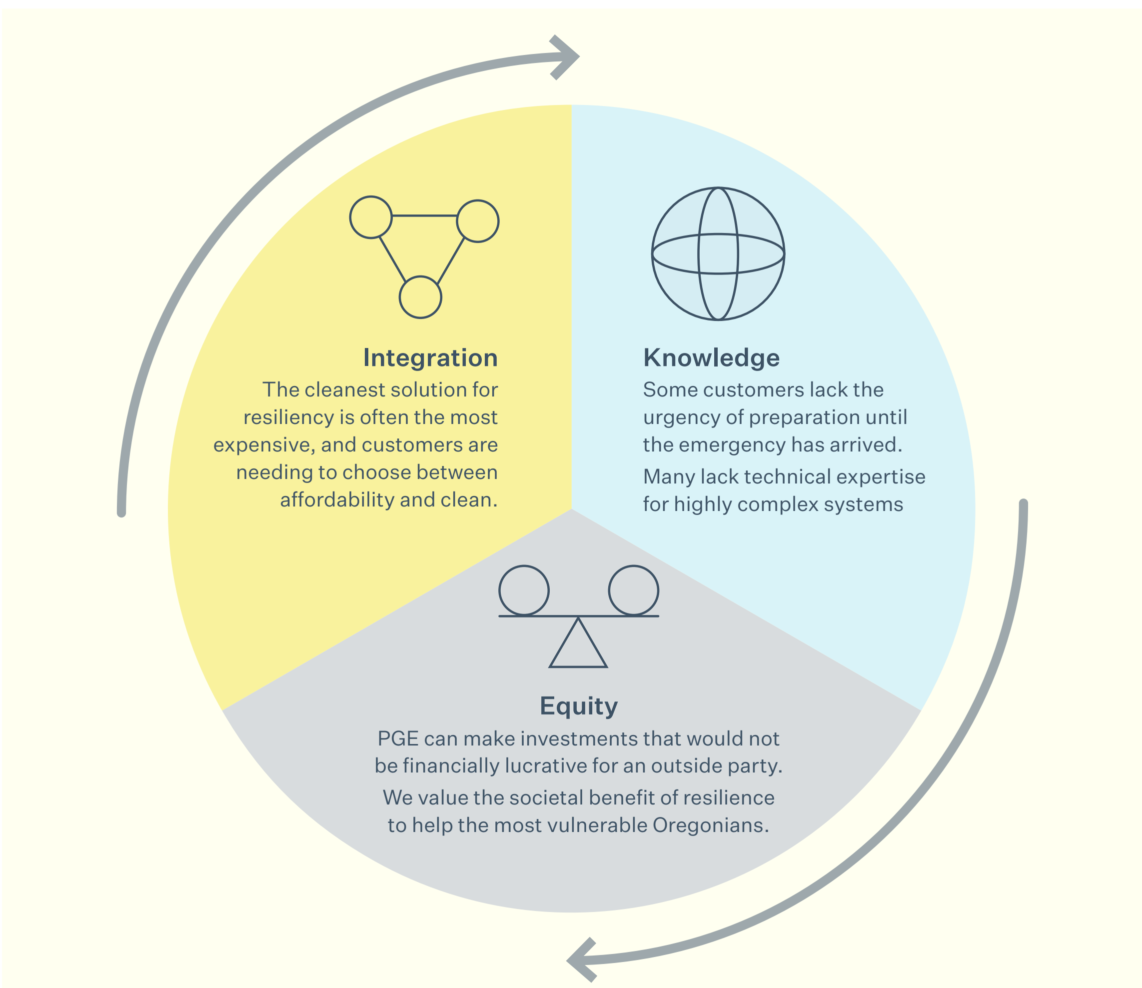
PGE provides my community with service that I can rely on. PGE understands our needs and is planning for the future, adapting and leading the way. I trust that my electric service will be safe, reliable and resilient.

I believe in PGE.

PGE's approach to customer resilience programs is:

1. Make **integrating** customers' resiliency assets with PGE as easy as possible
    - Full valuation of grid services, resilience, and locational benefits
    - Streamlined and cohesive programs
    - Give customers options to allow them to participate how they prefer
2. Serve as a **knowledge** partner so that customers know how to achieve their goals
    - Comprehensive consulting services
    - Vetted and specific recommendations for customers on how to prepare for the unexpected
3. **Equitable** access across all customer segments
    - Prioritize solutions for customers unlikely to be served via the competitive market
    - Overcome split incentives, economic obstacles
    - Partner with community, government, and non-profit agencies

Figure 77. Customer resilience programs ethos



K.4.3 EXISTING CUSTOMER RESILIENCE PROGRAMS

K.4.3.1 Smart Battery Pilot

PGE launched its 5-year Smart Battery pilot in 2020 that seeks to install and connect 525 residential energy storage batteries that will contribute up to four megawatts of energy to PGE's grid. Once installed, these distributed assets will create a virtual power plant that is made up of small units that can be operated individually or combined to serve the grid, adding flexibility that supports PGE's transition to a cleaner energy future. In addition, the energy storage batteries provide customers with a backup energy resource they can rely on in the event of a power outage.

PGE continues to learn from this pilot and is considering whether a tariff update is warranted to iterate and improve the pilot based on what has been learned thus far. For example, the current structure provides a single incentive level per customer, per month. Based on customer feedback, there is a desire to have more control and customization options for participation. PGE also has observed that the up-front rebates intended to encourage adoption on specific areas of the grid do not appear to be high enough.

Another consideration for energy storage is whether a new participation model is needed to allow customers to dispatch the battery themselves rather than by PGE direct dispatch. This will provide an option to engage with customers who are unwilling to allow PGE to have any control of their devices. Additionally, PGE has received numerous inquiries from customers that have an energy storage device that is not one of the five qualified products within the pilot. Limited product availability of approved brands means that PGE customers would benefit from a change in the pilot program that would allow for any battery brand to participate.

Historical information on this pilot can be found within the UM 1856 Energy Storage Docket. Should PGE file any revisions to Schedule 14 it will be within that docket as well, using the existing deferral.

K.4.3.2 Energy Partner

Energy Partner's Schedule 26 is a demand response (DR) program providing incentives to large nonresidential customers during seasonal peak time events for reducing their load. The program develops highly customized load curtailment plans that can work with a variety of unique types of businesses. In June 2022 the program received regulatory approval to expand upon the grid services that Energy Partner may provide PGE, as well as support customers' resiliency and clean energy goals by incorporating battery energy storage as a dispatchable resource.

K.4.3.3 Dispatchable Standby Generation

In 1999, the MacLaren Youth Correctional Facility became the first PGE customer to enroll their standby generator in the DSG program, a partnership with customers that interconnects generation resources providing electricity to PGE's grid when there is a critical need for power in the local region. Since then, the DSG program has grown to 59 sites with a cumulative nameplate generation capacity of 130 MW. While not fuel restrictive, the bulk of this capacity has historically consisted of internal combustion diesel generators, and PGE has undertaken a concerted effort to modernize and decarbonize the program.

With the increased commercialization of battery energy storage, as well as PGE's successful integration of customer-sited batteries for grid services as demonstrated by the Beaverton Public Safety Center and Anderson Readiness Center, PGE proposed to build upon those capabilities to expand the DSG program to include battery energy storage greater than 250 kW, receiving approval to do so in June 2022. In addition to contingency reserve and frequency response, customers with battery energy storage may opt to also participate in DR activities, a flexible load service not currently possible with fossil-fueled resources.

This program can now provide the same advanced resilience support to enrolled customers as the legacy DSG program, while also supporting customers', PGE's, and Oregon's decarbonization goals.

K.4.4 COMMUNITY MICROGRID DEMONSTRATIONS

PGE hopes to develop a programmatic approach to microgrid development that uses new front-of-the-meter renewable plus storage microgrids to access multiple value streams. Key benefits include generation capacity and energy, ancillary services, customer and societal resiliency value, local distribution grid benefits where applicable and local community benefits. Like the existing customer programs described above, development of these microgrid resources would support and benefit economically from the critical need for flexible capacity across the west, which is similarly motivating near-term storage development in California.

At scale, some microgrid projects may be deemed to be cost-effective for inclusion in general rates, especially if their upfront costs can be bought down through usage of external funding sources and incorporation of customer-owned generation and flex load resources. Other projects may depend on cost-sharing from benefiting local customers to pencil out economically through introduction of to-be-developed resiliency subscription rate option.

As a step toward this larger program, PGE has several planned and active initiatives that serve to create or enable more resilient customer infrastructure with a focus on critical community facilities. The following descriptions provide examples of the activities PGE is planning or undertaking to enable customers to mitigate the effects of disruptive events and get access to the services they need. We intend to use an evaluation of learnings and opportunities from these pilot activities to inform potential future expansion of distribution microgrid investments.

K.4.4.1 Salem Smart Power Center

At PGE's Salem Smart Power Center (SSPC), a 5 MW / 1.25 MWh battery is nearing the end of its 10-year life. Commissioned in May 2013, it has been showing signs of degradation and only maintains about 60 percent of its original capacity. Over the years, battery technology has advanced, and now most of the center's equipment is not supported; spare parts are unavailable. However, the SSPC remains critical in providing capacity to meet PGE's frequency response obligation.

With substation upgrades, the connection could support up to 15 MW of active power export. A repowered SSPC would provide support for fast frequency response, generating capacity, demand response, contingency reserve, and electric vehicle (EV) support.

At a nearby site, plans are underway for the future City of Salem Public Works Operations Center — a critical hub for responding to emergencies such as natural disasters or extended power outages. When the city reached out to PGE to inquire about a highly resilient power supply for the site, a utility-scale battery was proposed to support the customer's loads during events that disrupt infrastructure and public services. A repowered SSPC battery would be a possible solution.

PGE's recommendation is to isolate and automate the power grid in the vicinity of the new building, creating a distribution system microgrid — the first "community microgrid" of its kind in the Northwest. Our engineers helped the city design the innovative community microgrid infrastructure, including increased incremental power storage at the nearby SSPC.

To help fund the new operations center and microgrid, the City of Salem (partnering with Pacific Northwest National Labs) in June applied for an Oregon Department of Energy grant, established through HB 2021. It provides up to $1 million for planning and constructing community renewable energy and energy resilience projects. If awarded to the City of Salem, this grant would help meet its strategies for increased energy resilience in the new operations building constructed with renewable energy features, including solar panels and EV charging stations. Funds also could be used to support the new microgrid infrastructure and increased power storage at the SSPC.

During a power outage, the installed microgrid technologies and additional power storage would allow PGE to maintain power to the operations building. In turn, excess power from the city's solar panels would help to recharge the SSPC and extend the longevity of the microgrid. The microgrid also would serve an area of residences, including single family homes and an apartment complex, in a qualified low income and under-served community.

If the application is successful, ODOE will award the grant this year, and the city will contract with PGE for the proposed work.

By partnering with the City of Salem to create this microgrid, everyone will share the benefits from greater resiliency to the system. The SSPC will be repowered, and the City of Salem Public Works Operations Center will have a continuous power supply during emergencies.

K.4.4.2 Department of public safety standards and training (DPSST) Microgrid

PGE has been actively exploring the potential of custom-engineered microgrids at commercial and industrial customers' locations that can provide resilience to the customer, as well as flexible load for the power grid. This concept of creating a microgrid "island," disconnected from the main electrical grid and able to sustain itself for an extended period of time, has been implemented for single facilities in PGE's service area. However, creating a microgrid that serves a campus with multiple buildings is unique to the microgrid PGE is proposing for the Oregon Department of Public Safety Standards Training (DPSST) campus in Salem. As the State's key operational hub for emergency management, a microgrid at this site could be the solution for a reliable source of electricity during extended power outages.

The DPSST microgrid would use solar and battery storage to partially offset the need for fueled generation on the PGE distribution system. The solar resource will be generating and providing clean energy even when there is no grid outage. We will propose a generator hookup option in case the battery and solar output isn't sufficient for a more extended outage, especially in the winter. In that case, because of the generator, the microgrid will provide greater resiliency to the entire campus.

Although PGE began developing plans for the DPSST project several years ago, the effort was put on hold in 2020 when COVID-19 impacted Oregon state government activities. We have designed the structure and set of distribution upgrades needed to complete the campus microgrid, which could be operational by 2025 if funds are available.

PGE and the State would share the costs and benefits of this project. Our share of the project would include installing the battery and portable generator hookup. The State would install the solar resource and may be able to apply for grant funds to help support some of these expenses. Once funding details are agreed upon, the project will move forward.

K.5 PGE infrastructure resilience

PGE has several planned and active initiatives to strengthen infrastructure by mitigating the occurrence of outages during disruptive events such as wildfires and wind or ice storms. The following descriptions provide examples of the activities PGE is planning or undertaking to harden the grid against outage events.

K.5.1 WILLAMETTE VALLEY RESILIENCY PROJECT (WVRP)

PGE's sub-transmission (57 kV) and distribution system in the Willamette Valley is aging. Some of its unique equipment and assets have become non-standard or are nearing end-of-life; they weren't designed to withstand the ice storm of 2021. While PGE continues to maintain these assets to ensure reliability of the system, the increased demand, from new load growth to severe weather events, has jeopardized an already fragile system.

While the 57 kV system is not part of the Bulk Electric System, we strive to operate to the same criteria as required by the North American Electric Reliability Corporation (NERC) and the Reliability Coordinator (RC West), which states that there be no overload or voltage issue on our system for the next credible worst-case contingency. This means that if an outage is scheduled on the 57 kV system, we must be able to survive the next outage without any issues. The system in this area cannot reliably serve the distribution load if two lines are out of service during the summer or winter, meaning that the ability to perform maintenance is severely restricted.

To resolve deficiencies in the system, the WVRP will "future proof" the system to be resilient and reliable to withstand these events, minimizing restoration time and damage. A portfolio of projects is proposed for the 99E and I-5 corridor, from Oregon City to Salem. These projects; including transmission, sub-transmission, and distribution; will add capacity and resiliency to the system.

We will convert much of the Willamette Valley's 57 kV sub-transmission system to 115 kV. The project includes rebuilds of five substations and a significant portion of a sixth substation in the Willamette Valley with updated substation configurations for greater reliability. The transmission lines associated with these substations will be rebuilt and two new transmission lines will be constructed to improve reliability, resiliency, and capacity in the area. The distribution infrastructure at these substations will be upgraded for additional capacity and redundancy.

With these system improvements, we are supporting at least 50 MW of load growth for economic development in the valley, setting the foundation for adapting to future electrification of the I-5 corridor, reducing the impact of unpredictable outages and events, and providing for operational flexibility and compliance. The upgrades also will provide the infrastructure to bring more renewable generation resources onto the system, when needed.

Currently, we are engineering, scoping, and planning for these projects necessary to support the Willamette Valley system. These are the projects that comprise the WVRP:

- Monitor project
- St Louis project (included in 2023 Plan)
- Waconda project (included in 2023 Plan)
- North Marion project
- Woodburn project
- Bethel project
- WVRP Transmission project

By investing in these projects today, before an event occurs, PGE is avoiding the high costs of storm recovery and manual intervention in the future. For our customers, today and tomorrow, we are providing peace of mind with reliable and resilient energy services.

K.5.2 TELECOMMUNICATION SINGLE POINTS OF FAILURE PROGRAM

PGE designs and maintains a vast telecommunication transport network critical to the operation of our power system. We send critical information to substations, power plants and facilities over a network of microwave radios and fiber optics. The network also supports PGE phones, the internet, Customer Service, and other customer-facing technology. The better we can communicate, internally and externally, the more efficient we are.

Most importantly, when there is a failure on the telecommunication system, our power system is at risk. Information sent and received protects our critical infrastructure by supporting the relay systems in detecting faults on the lines. Real-time data from substations provide information about circuit breakers opening and closing and tell us why. By adding redundancy to the network, we increase its reliability and improve resiliency across multiple communication channels within one system.

When successful, the impact of this work has low visibility. If a communication path is lost, the redundant one allows us to operate the network from a different direction. Redundancy in the communication network provides resilience through un-interrupted service during disruptive events such as ice storms and fires in the service area. This ensures that there is minimal or no disruption to company voice, IT and control systems during such events.

PGE's goal is to strengthen our infrastructure by identifying vulnerabilities to the telecommunication network, including risks and consequences. Single points of failure, without redundancy, are given a high priority in that process. If we lose communication visibility at these points, an event could impact multiple lines and substations, requiring Dispatch to send line crews to investigate the issue. That can cause longer restoration time and dissatisfied customers.

We have identified numerous projects to add redundancy to our telecommunication network, as well as upgrades to new technology. In addition, as new generation resources come online, such as solar and battery storage, and new substations are built, the telecommunication network will expand to support system growth.

Over the next four years, the top ten Telecommunications vulnerability mitigation projects have been prioritized for completion to help harden the system.

- Bethel-Round Butte fiber; single fiber connection leased from Century Link.
- World Trade Center (WTC); lack of fiber route diversity
- Marquam Substation; lack of redundant, diversely-routed communications
- Corporate Network WAN; connections from WTC to outlying locations
- Integrated Operating Center (IOC), south fiber route
- Salem area; relies on single fiber route leased from CenturyLink to reach PGE Control Centers
- Corporate Readiness Center, lack of point-to-point wireless connection
- WTC to Healy Heights collapsed SONET ring section
- Monitor Substation; communications upgrade
- SONET Ring 9, collapsed section near Mt. Scott

Nearly half of these single point of failure projects include building diversity in the communication network.

K.5.3 CUSTOMER RELIABILITY IMPROVEMENT PROGRAM (CRIP)

The goal of the customer reliability improvement program (CRIP) is to improve the customer experience. Specifically, for customers that have experienced multiple, sustained interruptions year over year. The program uses a customer focused metric called CEMI (customers experiencing multiple interruptions) to identify areas of poor performance. The interruption causes for these areas are evaluated and solutions to mitigate reoccurring interruptions are recommended. Solutions typically leveraged for this program include, but are not limited to, additional protection/isolation devices and covered conductor.

The CRIP program is being launched in 2022 with the intent to learn how to best analyze and quickly deploy solutions that will reduce the re-occurrence of outages for customers. The initial focus of the program is on customers experiencing six or more interruptions per year from 2019 - 2021. Funding will be increased for this program in coming years as the mechanics of the program, and resulting benefit to customers, are better understood.

K.6 Operational resilience

PGE has several planned and active initiatives to accelerate and improve the response to outages during disruptive events such as wildfires and wind or ice storms. The following descriptions provide examples of the activities we are planning or undertaking to enhance outage response.

K.6.1 MOBILE COMMAND VEHICLES

Mobile Command is used and deployed to enhance or re-establish communication and coordination during emergency incidents and special security events. Mobile Command Units will allow PGE to enhance our capability to coordinate between utility management, crews, and first responders in the field, so they can restore power as quickly and safely as possible. Users of Mobile Command units include the Corporate Incident Management Team, Transmission & Distribution Operations Team, Corporate & Social Responsibility, and Customer Solutions.

Delivery of the first unit is scheduled for Q2 of 2023 and a second unit will begin build-out in late 2023 or early 2024.

K.6.2 IMT (INCIDENT MANAGEMENT TEAM) REFRESHER AND TRAINING

Business continuity and emergency management (BCEM) is planning and coordinating an exercise that will provide training and refresher to current and new IMT members. The exercise will work in conjunction with Grid Operations to have a real-world scenario for the IMT to facilitate restoration of power to customer. BCEM and Grid Ops are working to develop multiple scenarios that could challenge the IMT in complexity and develop muscle memory for the IMT members.

Objectives of IMT refresher and training include training new IMT members, providing refresher training for current team members, practice “right sizing” IMT to meet the outage complexity, establish communications lines, and build team through practice.

Qualified BCEM team members will schedule annually a minimum of one FEMA ICS300 and ICS400 courses for IMT members and other individuals interested in pursuing IMT roles.

K.6.3 BC (BUSINESS CONTINUITY) PARTNER ENGAGEMENT LIFECYCLE

BC will engage with Partners to develop/update plans for response to and recovery from disruptive events. The team will ensure plans are reviewed, tested, and exercised for accuracy by key stakeholders. Then they will finalize updates and approval by the business area director. This plan is distributed to all stakeholders, with each receiving training to instill an understanding of their role and required actions at the time of plan activation.

Plans will be housed in a location that BCEM, CIMT, and all key stakeholders can easily access before, during, and after an incident. Partners are empowered to initiate updates with BCEM if there are change conditions that require the plan to be revised to remain relevant.

K.7 Targeted interventions to reduce wildfire risk[94]

K.7.1 PUBLIC SAFETY POWER SHUTOFFS (PSPS)

Before and during fire season, PGE reviews regional National Weather Service forecasts, fire activity briefings, fire potential forecasts, and readings from PGE weather stations strategically located throughout the service territory daily. In 2022, PGE is deploying additional weather stations to increase situational and conditional awareness and provide visibility within the newly identify high-risk fire zones (HRFZs) on the west side of its service territory. PGE consulted with external meteorologists to identify locations that will provide the best overlap for wildfire risk coverage. PGE uses meteorological and outage data predictive analytics to better inform decisions regarding PSPS events, as well as outage/curtailment decisions related to transmission.

In 2022, PGE is developing the model architecture and sourcing the required data to implement a risk-based predictive analytical approach to meteorological modeling. The purpose of this project is to provide more granular and sophisticated inputs to PGE's PSPS decision analysis, as well as its system alarming.

K.7.2 VEGETATION MANAGEMENT

Primarily focused on inspection and maintenance activities in the high fire risk portions of PGE's service territory, as identified through PGE's HRFZ assessment process, PGE's Vegetation Management strategy includes both cyclical, routine inspections and maintenance of the entire PGE transmission system and Advanced Wildfire Risk Reduction (AWRR) activities driven by PGE's wildfire risk analytics. Specific, year-to-year vegetation management activities are guided by PGE's Risk Assessment Program, data from PGE's Remote Sensing Pilot Project (which uses LiDAR and hyperspectral imagery to precisely monitor vegetation density and proximity to PGE assets), and annual vegetation surveys. AWRR crews follow program trim specifications, which include increased removal rates and enhanced vegetation control techniques.

K.7.3 SYSTEM HARDENING FOR WILDFIRE

PGE continues to leverage its Strategic Asset Management (SAM) utility wildfire risk methodology and Wildfire Construction Standards to harden the transmission and distribution (T&D) system within its HRFZs. PGE's system hardening activities are designed to accomplish three goals:

- Reduce the risk of potential wildfire ignition caused by PGE facilities
- Reduce the impacts of a wildfire on PGE's assets by installing system hardening technologies (fire mesh, ductile iron poles, fiberglass crossarms)
- Protect utility infrastructure during potentially disruptive natural and human-caused disasters, supporting PGE's ability to maintain and restore reliable electrical service to support disaster relief and public safety.

In working towards these goals, PGE will deploy additional reliability improvements within the HRFZs. PGE is guided by its Wildfire Construction Standards in conducting equipment replacement in HRFZs. As outlined in PGE's Wildfire Construction Standards, the company will evaluate the following assets, with input from PGE subject matter experts, for replacement or implementation when warranted:

- Undersized/aging conductors in HRFZs
- Tree wire, an insulated overhead conductor designed to reduce service interruptions, which also reduces the potential for the conductor to become an ignition source
- Fuse replacement with non-expulsion fuses to eliminate a potential ignition source
- Viper reclosers and switching devices to increase operational flexibility and minimize customer impacts through the application of wildfire operational settings.

94. See PGE's Wildfire Mitigation Plan for a complete discussion of PGE's wildfire mitigation actions and investments, available at: https://assets.ctfassets.net/416ywc1laqmd/4w4NtrZtZZUpDeWoNC5vXn/e035ceb24ce56518afab817b0c0ffe6/2022_Wildfire_Mitigation_Plan_Final_Version_1.0_FINAL.pdf

K.7.4 Investment decisions

PGE is also revising its capital investment strategy to align with its ongoing analysis of risk velocity over time. The goal of this effort is to create a multi-year investment framework to implement these separate but interrelated mitigation strategies, based on a risk profile that incorporates all wildfire risk drivers (such as vegetation contact). This multi-year investment strategy will help PGE balance system hardening mitigation measures with speed of execution.

Figure 78 below shows the multiple system hardening and situational awareness investment programs currently included in PGE's multi-year wildfire risk mitigation investment strategy, through 2025.

PGE's multi-year investment strategy articulates a gradual increase in capital spending, distributed among multiple asset types. **Table 65** describes PGE's planned capital project investment types, together with estimated quantities. PGE will begin scoping these capital project investments in 2022. In addition to these asset replacements, PGE will begin scoping potential undergrounding areas. These investments (including undergrounding) will be prioritized in alignment with PGE's wildfire investment strategy, which ranks system hardening and situational awareness projects identified as the highest value risk mitigation projects per dollar of investment.

Figure 78. Planned wildfire system hardening and situational awareness investments

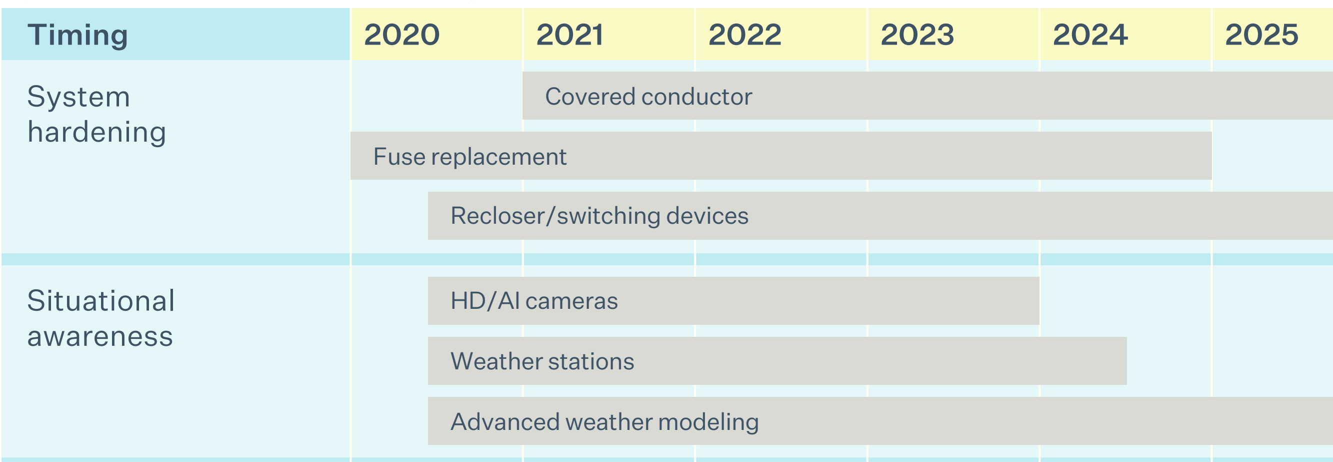


Table 65. Planned wildfire-related capital investments for 2022

Asset Category	Quantity
Wildfire cameras	10
Intelligent reclosers	40
Weather stations	23
Non-expulsion fuses	480
Aluminum-conductor steel reinforced cable (ACSR)/Tree wire	8 miles

The wildfire mitigation efforts will continue for multiple years. As such PGE is developing a multi-year mitigation investment effort which is based on risk reduction and providing enhanced value to our customers. The investment plan will be reflected in PGE's annual Wildfire Mitigation Plan which is filed with the OPUC.

K.8 Plug and play action plan

Our plug and play initiative addresses how we can improve access to grid edge investments needed to accelerate customers' clean energy transitions through such activities as hosting capacity analysis and developing the capability to connect dynamic devices (e.g., batteries).

With the ability to seamlessly interconnect a bi-directional flow, a modernized grid is a key enabler to improved access to DERs. Additionally, DERs have different effects on the grid under different conditions, including time, location, demand magnitude and system contingency. Today's grid is not designed to receive energy from customers at scale. Thus, some DERs today, specifically inverter-based systems and some types of EVs, such as mass transport electrification, may require complex studies.

The following project descriptions highlight the work PGE is doing to remove barriers to DER adoption.

K.8.1 SYSTEM PROTECTION FOR DISTRIBUTED ENERGY RESOURCE (DER) READINESS

PGE performed a full review of the distribution system to identify the upgrades required to make the system DER ready. DER Readiness in this context is defined in terms of system protection to accommodate distributed generation (i.e., the appropriate equipment is in place to enable the system to support bi-directional power flow).

The full cost of these upgrades is dependent on the specific project conditions associated with the upgrade and include considerations such as:

- Need for a mobile substation to provide continuity of service while the substation is taken offline
- Permitting requirements for the jurisdiction involved
- Telecommunication requirements
- Labor costs
- Additional upgrades that are required to support a specific DER implementation, such as upgrades to provide additional hosting capacity for load or generation

Performing these upgrades would address constraints such as PGE's generation-limited feeders. Some of these upgrades will occur in conjunction with projects that address grid needs. PGE currently does not have a cost recovery mechanism that enables proactive investment to perform these upgrades. This is discussed further in **Section 7.4**.

K.8.2 DISTRIBUTED GENERATION EVALUATION MAP UPDATES

PGE's response to the DSP guidelines for DSP Part 1 included augmentation of the Limited Generation Feeder map to show more distribution data and included demographic data sourced from the US Census. With the help of our DSP stakeholders the new map was named the Distributed Generation (DG) Evaluation map and serves as PGE's "phase 1" version of a hosting capacity analysis (HCA) map.[95]

Going forward, docket UM 2111: Staff Investigation into Interconnection Process and Policies is the forum for discussing utilities' plans for implementing HCA.[96] However, it was clear from stakeholder comments on DSP Part 1 that, regardless of whether we advance our HCA capability, there is value in providing more and different types of data to support stakeholders' decision-making processes.

95. EPRI's "Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State" study, available at: https://www.epri.com/research/products/000000003002008848, page 15, Table 1 and PGE's DG Evaluation Map, available at: https://pge.maps.arcgis.com/apps/webappviewer/index.html?id=959db1ae628845d09b348fbf340eff03
96. The OPUC's Docket UM2111, available at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=22475

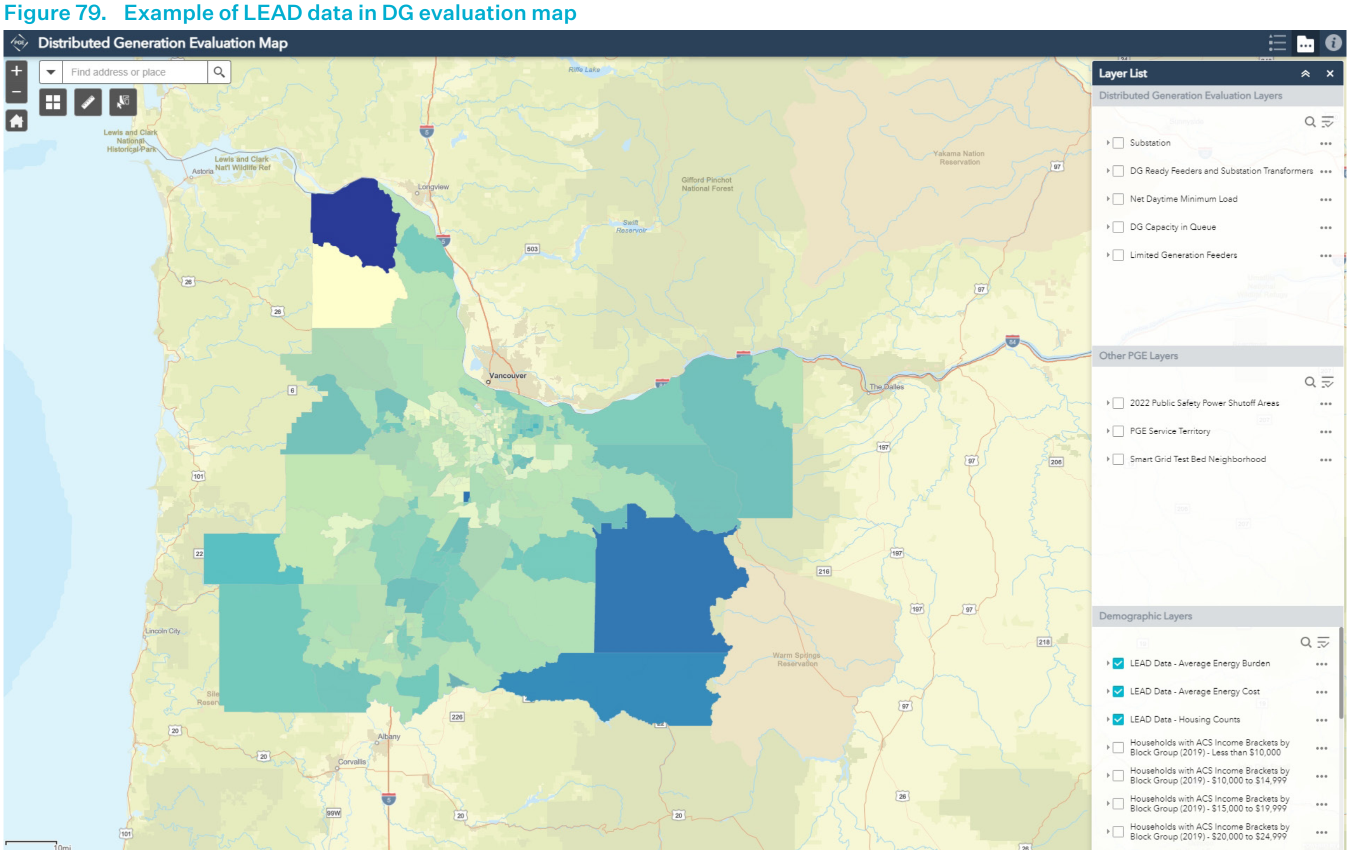
The DG Evaluation map is PGE's platform for sharing distribution system indicators and other datasets that enable developers, installers and customers to identify favorable locations for connecting distributed generation to the grid. A few key themes emerged from stakeholder's feedback on the map:

- Current viewer map needs to be refined to incorporate equity indicators;
- More distribution system data needs to be included; and
- The data needs to be downloadable, preferably in a mapping file format.

We understand that the provision of these data is the best approach to improving the value of our current DG Evaluation map. Based on the feedback and OPUC's guidance we received, we reviewed a number of different data sources and determined that data from the LEAD Tool, shown in **Figure 79**, as well as peak load data could readily be added to the map as a next step.

The Low-income Energy Affordability Data (LEAD) Tool is an online, interactive platform that allows users to build their own national, state, county, city, or census tract profiles. LEAD provides estimated low-income household energy data based on income, energy expenditures, fuel type, and housing type. Data from the LEAD tool is free to the public, and by incorporating it into our DG Evaluation map, will enable PGE and stakeholders to make data-driven decisions on energy goals and program planning by improving the understanding of low-income and moderate-income household energy characteristics. LEAD Tool data comes primarily from the U.S. Census Bureau's American Community Survey 2016 Public Use Microdata Samples (5-Year Average, 2012-2016) and are calibrated to the U.S. Energy Information Administration's electric utility (Survey Form-861) and natural gas utility (Survey Form-176) data.[97]

Figure 79. Example of LEAD data in DG evaluation map



97. LEAD tool, available at: https://www.energy.gov/eere/slsc/low-income-energy-affordability-data-lead-tool

PGE will continue to evaluate equity related indicators, such as those from the Greenlink Equity Map (GEM), for inclusion in the DG Evaluation map.[98] We have three goals as we consider which data should be incorporated into the DG Evaluation map:

- Publishing additional distribution system data – add more granular and more descriptive data, such as the data identified in IREC's comments on DSP Part 1, as well as enabling downloads in shapefile format or potentially through an Application Program Interface (API).[99]
- Collaboration on best-practices for maps – evaluate possibilities to add interconnection related data to help interconnection screening process; add reliability info including historic outage data – minutes of duration, outage frequency and customers affected; integration of DER forecasting and adoption results into map.
- Inclusion of equity metrics – consider adding more equity metrics such as health related indicators from Greenlink platform and others.

Figure 80 shows the equity related variables and data sources we are considering and analyzing.

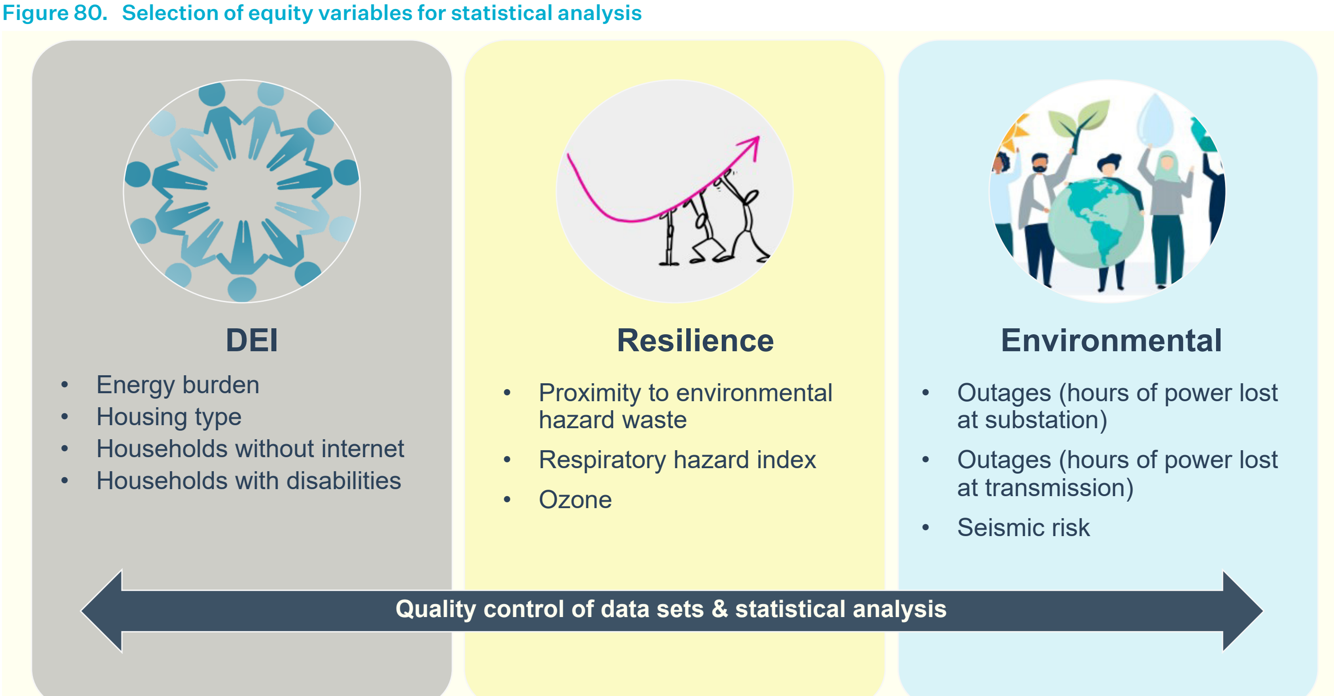
As described in **Chapter 2**, PGE is in the process of rolling out an Equity Index across use cases within the DSP. For the present analysis purposes, we applied this Equity Index to the location DER adoption results to identify any patterns.

Most data are free and from public sources such as the US census bureau, American Communities survey at census tract and census block level. We also are reviewing PGE customer information to determine whether this data would assist in needs identification or program planning.

K.8.3 SMART GRID TEST BED (SGTB) PHASE II INITIATIVES

For Phase II of the SGTB, PGE proposed a five year, roughly $11 million program that builds on successes achieved in Phase I.[100] This proposal will leverage the high levels of customer awareness and engagement achieved over the last two years to develop a portfolio of technology and market demonstration projects. These projects spread across several research areas and will help expand and enhance PGE's flexible load product portfolio while exploring the additional use cases and value streams of DERs.

Figure 80. Selection of equity variables for statistical analysis



98. Greenlink Equity Map GEM, available at: https://www.equitymap.org/equity-map
99. IREC Comments on DSP Part 1, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAC&FileName=um2197hac153720.pdf&DocketID=23043&numSequence=11
100. PGE Phase II Proposal and Phase 1 Report, available at: https://edocs.puc.state.or.us/efdocs/HAD/um1976had145212.pdf Adoption of Staff Recommendation: https://apps.puc.state.or.us/orders/2021ords/21-444.pdf

The goals of Phase II are threefold:

- Carry forward, and apply "at scale," the customer-centric strategies learned in Phase I
- Demonstrate enhanced value of flexible load/DER technologies as a grid resource, including planning and operations
- Support the development of the product portfolio through testing of new technologies and program design, including pricing strategies, gamification and direct control of DERs to address a grid need

PGE is not proposing a firm budget for Phase II, but rather providing a budget estimate and funding cap, with project level expenditures to be authorized during the review process agreed upon with stakeholders and the Commission. PGE estimates that the five-year effort will cost approximately $11 million and launch in January 2022. A brief description of the initiatives included in the Phase II scope is provided in Appendix G.

K.8.4 ADOPTION OF IEEE 1547-2018 (SMART INVERTER STANDARDS)

The modernization of the standard used for inverters, IEEE-1547, is set to occur in the first phase of current Commission docket UM 2111. In the first phase of UM 2111, several issues will be addressed. The current proposal is that a stand-alone workgroup will be established that will focus specifically on the implementation of the newest version of IEEE-1547. The workgroup will consist of Staff, utility representatives, and other stakeholders. It is intended that the workgroup will meet at least on a monthly basis and make decisions based on group consensus. Further discussion and documentation of IEEE 1547 will occur in the UM2111 proceedings.

K.8.5 TRANSPORTATION ELECTRIFICATION (TE) CONSIDERATIONS

PGE's investments in customer energy efficiency over the past several decades will enable us to make initial investments in transportation electrification without significant impacts on our distribution system. TE will, however, have a growing overall impact on energy and capacity needs. PGE must continue to make investments into our system to ensure that our service-level transformers, feeders, substation transformers, and substations will have enough capacity to provide EV drivers access to charging service throughout our service area.

This section introduces the expected distribution system impacts arising from TE for which PGE will need to plan. This section is not intended to present a thorough distribution planning exercise for EVs. Instead, we provide indicative examples of how various types of EVs can impact the distribution system, and strategies to efficiently manage the grid in light of these impacts.

For example, PGE did not conduct power flow analyses to determine EV hosting capacity or estimate locational value. Such analyses will be done in concert with other new loads coming to the system through the course of routine distribution planning.

The TE forecast is shown in **Table 66**. The forecast clearly indicates levels of load growth that require upgrades to the distribution system much in the same way a new residential development or manufacturing facility would require upgrades to serve new load. As we know from the grid needs analysis described in **Section 4.5**, the primary considerations for planning those upgrades are the size of load growth, timing and location.

Table 66. Transportation electrification forecast

Transportation Electrification Potential Forecasts (MWa)									
Scenario	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
High	13	21	30	40	53	68	86	109	135
Ref	12	19	26	35	45	57	72	90	111
Low	12	17	22	29	36	45	55	67	82

To accommodate EV adoption, we must make planful investments so that infrastructure is right-sized, future-proofed, and optimally located to minimize integration costs. Adoption of light duty EVs is less likely to trigger distribution system upgrades beyond service-level transformers that are typically paid for by customers. Large, spot-load additions, such as fleet electrification or development of charging hubs, are the types of TE-driven load growth that require system impact analyses from the distribution planning team.

When EV adoption starts to reflect the forecast, the associated load will show up as a need in PGE's grid needs analysis and, if prioritized at that time, we will develop solutions to meet those needs. Two examples of emerging needs, needs that might require a distribution infrastructure investment, are described in the following sections.

K.8.5.1 West Coast Clean Transit Corridor

The transportation sector is one of the largest contributors to greenhouse gas (GHG) emissions in the U.S. according to the EPA — 29 percent of the total GHG reported in 2019. Within that sector, medium- and heavy-duty trucks represent 24 percent of GHG emissions impacting our environment. The manufacturing industry relies upon this transportation to move more than 50 million tons of goods worth about $50 billion every day. On the West Coast, electric utilities are working together to find a solution for this growing problem.

By the year 2026, commercial freight and fleet electric vehicles will be able to transport their loads from southern California to the Canadian border — all within a corridor of charging sites along the Interstate-5 (I-5) highway system. That's the vision of the West Coast Clean Transit Corridor project, which can only be accomplished with the support of all electric utility companies on the route, including PGE.

There would be a phased approach for electrifying the I-5 corridor. Charging sites would be built about 50 miles apart, within a mile from I-5, to serve medium- and heavy-duty trucks. The next phase would be to upgrade every site to accommodate faster heavy-duty charging using the new Mega-Watt (MCS) standard. Additional sites may be built on arterial highways, as well.

Today, PGE does not have the charging infrastructure necessary for a customer to switch over to electric vehicles for long-haul trucking applications. A survey of fleet operators found that improved access to public charging would accelerate deployment of EVs if their trucks could use public charging sites. This project will help support our customers in that effort, as well as help reduce greenhouse gas emissions from freight transportation and eliminate health-harming diesel emissions from trucks in our service area.

PGE will be responsible for building two charging sites in the corridor — one near Salem and the other near Troutdale. Currently, we are conducting feasibility assessments of existing truck stops in each of the areas to determine the interest of the site host and what upgrades would be needed at the location, substation, and distribution system. With the costs of the chargers, customer construction, grid enhancements and added storage to the charging hub, the investment could be in excess of the cost of a new substation.

Both PGE charging sites could be built to support the initial scope of 3.5MW and operational by 2026, along with other utility partners' sites in the region — all with the ultimate goal to help complete the West Coast Clean Transit Corridor. For local EV commercial trucks transporting within our service area, just the completion of our two charging sites will help support their regional deliveries.

Electrifying commercial transportation on the I-5 corridor is one more step we can take to meet our long-term imperatives to decarbonize and electrify for a clean energy future.

K.8.5.2 Newberg School Bus Program – V2G Demonstration

As customer demand for electric vehicles (EVs) continues to grow, and electric vehicle equipment with its supporting infrastructure technology advances, many EVs will have the ability to power your home, as well as send electricity to the power grid as a dispatchable resource when it's needed. This vehicle-to-grid (V2G) technology also has potential with commercial vehicles. That's why, in 2020, PGE began a small-scale V2G demonstration project funded through our Electric School Bus grant program, awarded to the Newberg School District, contracting with their transportation provider, First Student, Inc.

In 2021, PGE began work at the school district bus yard, installing the V2G electrical infrastructure and switchgear. The utility infrastructure was completed in December 2021, and the electrical charger installed and energized in March 2022. By April, students and the school district were enjoying the benefits of the newly commissioned electric school bus — no carbon emissions, lower maintenance and fuel costs, and a quieter ride. The total cost of the project, including the bus, charger and infrastructure, was $395,155 .

The bus now is ready to support the new V2G technology as we enter the project's next phase.

Given the changing relationship with the school district, First Student is now in the process of moving the charger to another location within PGE's service territory. We will provide technical assistance as First Student selects a site and constructs the necessary infrastructure. It is anticipated that the V2G bus could begin operations at a new school district by fall 2023, where it will be among the first dispatchable V2G sources in Oregon.

Although the technology may not be fully commercialized at this time, we are preparing to modernize the grid beyond its current capabilities to support our customers who will be purchasing vehicles with V2G capability. As a "proof of concept" project, the school bus demonstration allows us to evaluate the technology and identify lessons learned so we may design scalable ways for our customers to use V2G in the future. We look forward to deploying this new V2G technology at additional electric bus sites and passenger vehicle sites, and to partnering with our customers to help them provide clean flexible resources for a flexible and reliable power grid.