Chapter 4.

Modernized grid: building a platform for participation

Chapter 4. Modernized grid: building a platform for participation

"The virtue of the intelligent grid is that your connection to it can choose, opportunistically and economically, what the cheapest way is to provide energy when you need it. Your connection might think, 'Oh, there's wind that blows during the evening hours in this county, let's tap that energy right now.' 'Okay, it's a bright sunny day, let's go to the solar panels and bring that energy in.'"

— Neil deGrasse Tyson, astrophysicist[74]

4.1 Reader's guide

PGE's Distribution System Plan (DSP) takes the first step toward outlining and developing a 21st century community-centered distribution system. This system primarily uses distributed energy resources (DERs) to accelerate decarbonization and electrification and provide direct benefits to communities, especially EJ communities.[75] It's designed to improve safety and reliability, ensure resilience and security, and apply an equity lens when considering fair and reasonable costs.

This chapter details PGE's capability roadmap over the next 10 years, along with planned investments. It discusses how the evolving grid has implications for workforce planning and cybersecurity. This chapter also provides research and development (R&D) activities undertaken by PGE.

Chapter 4, unlike other chapters, will address multiple requirements from Order 20-485[76] in each section. For this reason, we recommend revisions to the final DSP guidelines a s they pertain to the long-term plan investments, borrowing from national best practices outlined in the U.S. Department of Energy's (DOE) next-generation distribution system platform (DSPx) and DSP requirements from other jurisdictions.[77] Clearly addressing these requirements is essential to developing a DSP that communicates PGE's long-term direction and intent. We will work with partners and Oregon Public Utility Commission (OPUC) staff to more clearly frame and address these requirements in future DSPs.

74. "Astrophysicist Neil deGrasse Tyson tackles renewable energy's future," available at: renewableenergymagazine.com
75. PGE uses the definition of environmental communities under Oregon House Bill 2021, available at: oregonlegislature.gov
76. OPUC UM 2005, Order 20-485 was issued on December 23, 2020, and is available at: apps.puc.state.or.us
77. Department of Energy's Office of Electricity Delivery and Energy Reliability — Next-generation distribution system platform, available at: gridarchitecture.pnnl.gov

Table 16 illustrates how PGE has met OPUC's DSP guidelines under Docket UM 2005, Order 20-485.

Table 16. Modernized grid: guideline mapping

DSP guidelines	Chapter section
4.1.c.iv	Section 4.7
4.1.d	Section 4.7
4.4.b.i	Section 4.6.3, 4.8
4.4.b.ii	Section 4.6.1, 4.6.2
4.4.b.iii	Section 4.6.3
4.4.b.vi	Section 4.7
4.4.b.vii	Section 4.6.1, 4.6.2, 4.6.3
4.4.c	Section 4.6, 4.7
4.4.d	Section 4.3, 4.4, 4.5
4.4.e	Section 4.8
4.4.b.vii	Section 4.6.1, 4.6.2, 4.6.3
4.4.c	Section 4.6, 4.7
4.4.d	Section 4.3, 4.4, 4.5
4.4.e	Section 4.8

For more details on how PGE has complied with the requirements under UM 2005, Order 20-485, see **Appendix A: DSP plan guidelines compliance checklist**.

WHAT WE WILL COVER IN THIS CHAPTER

The benefits of a modernized grid

An overview of modernized grid architecture, systems and capabilities

PGE's roadmap and planned investments for modernizing the grid

4.2 Introduction

Through Order 20-485, the OPUC required investor-owned utilities (IOUs) to:

- Capture planned investments
- Invest in smart grid opportunities in the next five to ten years
- Report key opportunities for distribution system benefits
- Provide a five- to ten-year roadmap of distribution system investments that advance their vision
- Provide relative costs and benefits for each category of investment
- Provide assumptions and barriers to adoption needed to achieve their vision of the DSP
- Provide current R&D activity
- Detail other opportunistic investments that can benefit the distribution system's ability to deliver customer value

In PGE's 2019 Smart Grid Report, PGE shared its integrated grid conceptualization for the modernized distribution system.[78] In this chapter, PGE builds on the integrated grid concept, provides details on its capabilities and describes how these capabilities address the goals outlined in the vision in **Section 2.3.** PGE's approach to this chapter is to provide the required details at the capability level. For each capability, PGE:

- Highlights the description and need for the capability
- Provides a gap analysis for each capability, identifying desired future functionalities
- Discusses the relative costs, benefits, assumptions, maturity and timeline at the capability level

PGE's planned investments focus on capabilities that will directly advance PGE's vision as described in **Section 2.3** by accelerating DER adoption and scaling of DER programs. PGE will build on this topic in its DSP Part 2 Action Plan.[79]

Modernizing the grid is a key element of the transformation and enablement of large-scale DER integration. Specifically, modernization will ensure solar photovoltaic (PV) systems, storage capabilities and electric vehicles (EVs) can be integrated through DER programs. Modernizing the grid works to improve grid flexibility and asset utilization as well as reduce the need for long-term supply-side resources. This approach addresses the grid goals outlined in PGE's vision as described in **Section 2.3.** DERs and their associated programs can provide community benefits, accelerating environmental justice goals as outlined in **Section 2.3.** However, grid modernization is a complex undertaking requiring large investments focused on augmenting and improving the electrical grid. PGE is wary of the impact of these investments on customer prices. We will continue to take a pragmatic approach, balancing differing objectives. In this way, PGE can ensure investments provide significant customer value once in service.

78. PGE's 2019 Smart Grid Report is available at: apps.puc.state.or.us
79. Under UM 2005 Order 20-485, PGE is required to submit Part 2 of its initial DSP by August 15, 2022.

4.3 Modernized grid desired outcomes

Grid modernization refers to the evolution of the grid through the integration of new technologies and enhanced computing solutions. This transformation has been underway for several years, with its scope evolving over time. Early grid modernization efforts focused on improving the operator's awareness of the state of the distribution system, especially as it related to outages. This was soon followed by the need for improved planning and forecasting capabilities to ensure least-risk, least-cost planning. Today, grid modernization on the operations side involves not only operator awareness, but also operator control, specifically the interaction between DERs and the grid. On the planning side, needs have evolved to focus on the ability to holistically interconnect DERs to deliver maximum grid and community benefit. As technologies and computing solutions mature, it is likely that the scope of grid modernization will continue to evolve as well.

In line with this evolution, PGE continues to modernize the grid as reported in previous smart grid reports and the most recent General Rate Case.[80] While PGE's historical efforts have focused on improving operator awareness and distribution system resolution, current and future efforts will build on this work to enable seamless integration and control of DERs to deliver a vibrant, two-way grid that is safer, more secure, more reliable and more resilient, at fair and reasonable costs.

PGE shares examples of how the grid modernization capabilities broadly advance the vision described in **Section 2.3**.

- **Decarbonization:** By managing DERs connected to the grid, operators can co-optimize across available resources to ensure least cost and carbon intensity in resource dispatch.
- **Reliability:** Investments in sensors and communication devices to increase the amount of information received about the performance of the distribution grid can help operators better predict distribution system needs and take necessary steps to prevent system reliability issues.
- **Resilience:** Through investments in smart algorithms and sensing devices, feeder sections can be isolated to create microgrids that provide resilience during disruptive events.
- **Security:** While grid modernization investments increase the attack surface or number of access points for cybersecurity threats, PGE is taking proactive steps through investments in cybersecurity solutions and the integration of cyber-physical security in planned investments. This is highlighted in **Section 4.5**.
- **Assistance for EJ communities:** Through investments in analytics platforms that use smart meters, PGE can develop improved rate designs and DER programs to assist with energy burden relief in EJ communities. PGE has already started developing load-shaping solutions through its Time of Use programs.[81]

80. PGE's July 9, 2021, UE 394 filing is available at: ue394htb155528.pdf (state.or.us). Transmission and distribution expenditures are summarized in Exhibit 801.
81. More information on PGE's pricing programs is available at: portlandgeneral.com

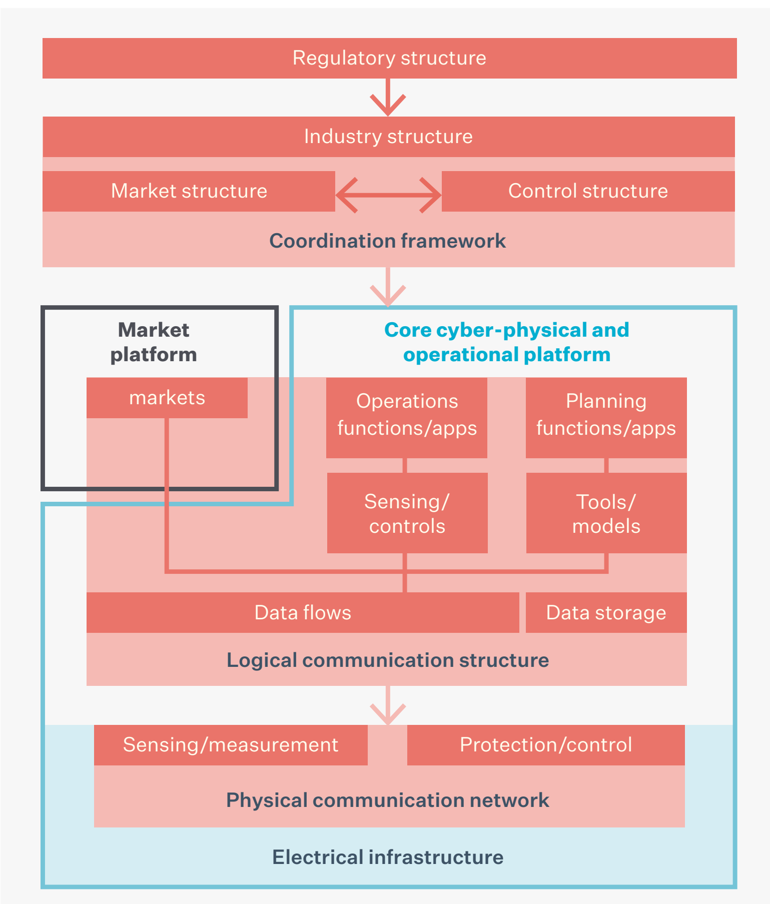
4.4 Modernized grid approach and architecture

The scope of grid modernization is likely to evolve with the maturity of different technologies. To ensure new technologies and capabilities can be integrated easily, a platform-based architecture with modular elements is the most promising approach. Certain central capabilities remain relatively stable throughout the platform's evolution over time. These are known as core platform capabilities, or foundational capabilities. Examples include planning for peak and daytime minimum load and transferring loads or isolating faults for system reliability. Other capabilities and layers are complementary to these core capabilities and work in an integrated manner to deliver customer value, such as a customer's digital experience through PGE's application on their smart phone.

PGE, just as most, if not all, utilities, has adopted a platform-based architecture. Additionally, there is consensus among most experts, including the U.S. DOE, on modernizing the grid using a platform architecture. In other words, a modernized grid is equivalent to a platform with layers of digital capabilities upon layers of physical assets that work together in various combinations to improve and enable system capabilities. Over time, as different technologies mature, capabilities and layers can be added or replaced as needed. A common example of this is in meter technology, where previous generations of automatic meter reading (AMR) have given way to advanced metering infrastructure (AMI) and smart meters, which can perform more computationally advanced functions.

In PGE's system, physical assets include grid infrastructure (such as poles and wires, smart sensors, meters and switches) and telecommunication assets (such as fiber optic cables and field area networks, or FANs). These components work together to send signals and receive actions from digital capabilities such as an advanced distribution management system (ADMS) or DER management system (DERMS). These digital capabilities use data from physical assets to feed algorithms that optimize system performance, delivering a more efficient and flexible electric system. The same data combined with ADMS and DERMS outputs is also used for planning purposes as part of a feedback loop. This interaction across the different layers of a modernized grid is shown in **Figure 18**.

Figure 18. Layers within a distribution system platform as described by DOE's DSPx



4.4.1 ALIGNMENT WITH DOE'S DSPX[82]

PGE's grid architecture is grounded in the DOE's DSPx approach. This architecture builds on PGE's work as described in prior smart grid reports and uses the same layered approach as the DOE's DSPx to build a cyber-physical grid platform.

We will continue to align as closely as possible, where reasonable and feasible, with the DOE's DSPx recommended method to justify grid modernization investments. This is operationalized through project assessment processes in PGE's Grid Modernization Business Service Group as described in **Section 2.5.2. Table 17** illustrates DOE guidance for grid modernization investments.[83]

Table 17. Grid modernization cost-effectiveness framework from DOE's DSPx Volume III

Expenditure need	Methodology	Examples
Grid expenditures to replace aging infrastructure, new customer service connections, relocation of infrastructures for roadwork or the like and storm damage repairs	Least-cost, best-fit or other traditional method recognizing the opportunity to avoid replacing like-for-like and instead incorporate new technology	Planning tools and models, physical infrastructure, sensing devices and telecommunication devices
Grid expenditures required to maintain reliable operations in a grid with much higher levels of distributed resources connected behind and in front of the customer meter that may be socialized across all customers	Least-cost, best-fit for core platform, or Traditional utility cost-customer benefit based on improvement derived from technology	Smart meters, volt-VAR management and optimization analytics
Grid expenditures proposed to enable public policy and/or incremental system and societal benefits to be paid by all customers	Integrated power system and societal benefit-cost (e.g., EPRI and NY REV BCA)	Non-wires solution analysis (NWS)
Grid expenditures that will be paid for directly by customers participating in DER programs via a self-supporting, margin-neutral opt-in DER tariff, or as part of project-specific incremental interconnection costs	These are "opt-in" or self-supporting costs, or costs that only benefit a customer's project and do not require regulatory benefit-cost justification	Customer portion of DER costs

4.5 Modernized grid framework

PGE's latest iteration of its modernized grid framework is outlined in **Figure 19**. 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 best practices. Because of the complexity of the DSPx graphic and the DSP's focus to appeal to both partners and communities (traditional and non-traditional stakeholders), we performed multiple iterations to create a consistent, capability-based, PGE-specific modernized grid framework.

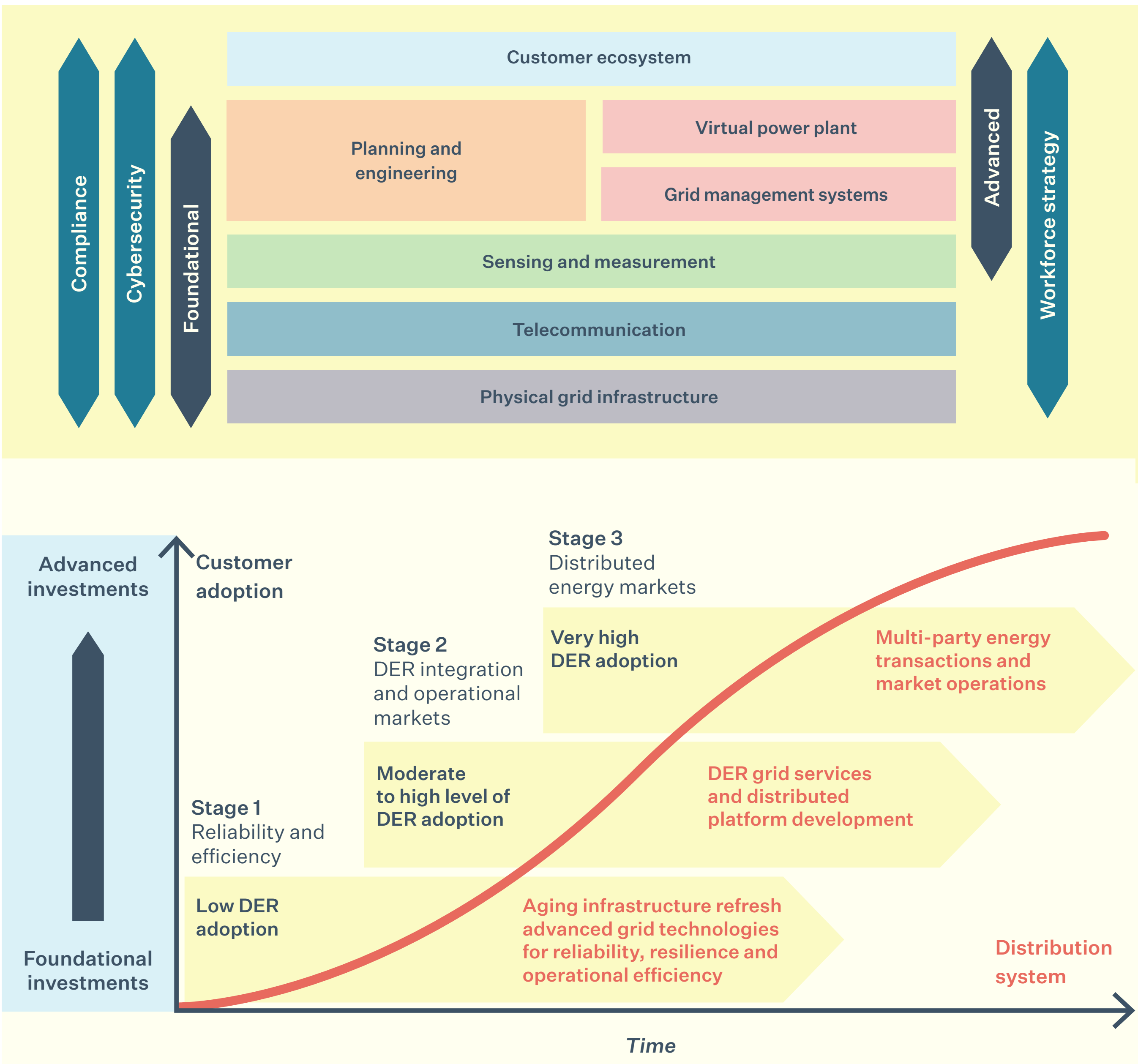
PGE's modernized grid framework can be broken down into three categories:

- **Foundational capabilities** refer to the set of core platform investments needed to improve monitoring and basic control of the distribution system. Based on **Table 17**, these investments follow a least-cost, best-fit approach, usually through a request for proposal (RFP) or similar process.

82. U.S. Department of Energy's Modern Distribution Grid Project is available at: gridarchitecture.pnnl.gov
83. More details can be found in DOE's DSPx guidance in Volume III, available at: gridarchitecture.pnnl.gov

- **Advanced capabilities** refer to investments that build on or, in some cases, supplement foundational investments to develop advanced controls 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 investments. They are key considerations when making the investments after the primary need is addressed. They include cybersecurity, workforce implications and other compliance needs. This overarching nature requires the investment justification to mirror the base investments (cybersecurity investments needed as part of foundational capabilities would be based on least-cost, best-fit, whereas cybersecurity investments as part of some advanced capabilities, such as a conservation voltage reduction program, would likely require a benefit-cost analysis).

Figure 19. PGE's modernized grid framework



We believe that compliance and workforce strategy are not capabilities by themselves but are key considerations in the development of each capability. Foundational and advanced capabilities will impact most areas of the company, so workforce gaps will need to be assessed and solutions prioritized at the functional level as well as at the organizational and enterprise level.

To be successful, PGE must develop a workforce plan that can help adapt to and evolve with changing conditions and the maturity of different technologies. Our workforce plan must be built on the foundation of recruiting, developing, retraining and retaining the talent required to help enable the grid's transformation. Hiring staff with skills relevant to new technologies while diversifying recruiting practices to broaden the range of skills and abilities will be important. However, as the market gets more constrained, workforce strategies must include more solutions than just recruiting.

New technologies with the requisite skillsets often outpace what the current workforce can provide. The ability to address key skill shortages will enable PGE to keep up with new technologies and progress through our capability maturity model. As such, reskilling, upskilling and implementing talent initiatives designed to redeploy staff to other parts of the business are essential components to PGE's workforce plan. Diversifying PGE's staffing strategies should include new ways of deploying talent to manage the transactional elements of its operations and the strategic and specialized elements of the grid. Augmenting the workforce with outside resources for various durations of time will allow us to more quickly move and pivot. Smart grid technologies and processes will require different levels of education and training, which has implications for how we invest in our training programs. There may be workforce segments where we hire more early-career professionals and train them to proficiency across a variety of technologies.

While it's important to build a flexible and dynamic workforce, we should ensure we are focusing on retention strategies that improve productivity and employee engagement. Keeping valuable employees will help PGE win in a competitive marketplace. All these elements are further strengthened by the right organizational structures that encourage alignment and cross-functional coordination to achieve modernized grid objectives.

Table 18 provides brief descriptions of each capability, including the needs they address and examples of the technologies and functions.

Table 18. Capabilities and their descriptions

Capability	Description of capability and needs statement
Customer ecosystem	Description: Providing customers access to relevant and timely usage, system infrastructure and operational data Needs statement: Enable customer choice and decision making. Example technologies: Customer analytic tools (e.g., calculators), green button (automated data transfer), smart meters/meter data management system Example functions: Remote meter data collection and verification, energy management and DER purchase/program performance analysis, advanced interactive voice response (IVR) systems
Virtual power plant (VPP)	Description: Multiple flexible loads and DERs, which in aggregate, supply grid services visible to and dispatchable by PGE power operations, characteristic of a traditional power plant facility. Needs statement: Distribution investment deferral, support for customer needs such as resiliency and resource adequacy Example technologies: DERs, DER programs, dynamic tariffs Example functions: Delivery of peak load electricity or load-following power generation on short notice, ancillary services including frequency regulation and providing operating reserve

Table 18. Capabilities and their descriptions (continued)

Capability	Description of capability and needs statement
Planning and engineering	Description: A suite of integrated tools to perform distribution system planning and engineering functions Needs statement: Improved planning enables optimal grid investments, including DER integration through information exchange and non-wires solutions. Example technologies: CYME/Synergi (power flow analysis), Envelio, cost-effectiveness tools, AdopDER (DER forecasting), OpusOne Example functions: Grid needs analysis, locational net benefit analysis, non-wires analysis, hosting capacity analysis, DER forecasting
Grid management systems	Description: A set of computer-aided tools used by operators of electric utility grids to monitor, control and optimize the performance of the distribution system Needs statement: Shifting from central management of one-way power flows supplied by relatively few bulk generators to coordinating large numbers of DERs, creating two-way power flows, may cause grid stability issues. As DER adoption grows, the number of possible control actions will increase and the time to execute those control actions will decrease beyond the capability of human grid operators to react to events. Safety and reliability issues will increase in both frequency and magnitude unless advanced technologies are used to stabilize the grid. Example technologies: Advanced distribution management system (ADMS), DER management system (DERMS), outage management system (OMS), demand response management system (DRMS) Example functions: Monitor grid operations, analyze the data collected, predict events and grid behavior through algorithms, issue commands to grid devices based on the analyzed information (fault location, isolation and service restoration/FLISR scheme and conservation voltage reduction/CVR control)
Sensing, measurement and automation	Description: Operating the distribution system requires continuous monitoring of the infrastructure that comprises the grid. Sensing, measurement and automation is accomplished through devices and algorithms that are installed at various points on the distribution system — such as at feeders, breakers and distribution power transformers. The sophistication of those devices determines the degree to which devices on the grid can be controlled by the grid management system. Needs statement: More advanced sensing, measurement and automation enables accurate information flow for rapid outage response and reduced outage durations; outage avoidance through real-time mitigation; enablement of DER integration and optimization. Example technologies: Supervisory control and data acquisition (SCADA), microprocessor relays, digital meters and power system monitoring devices Example functions: Detect emerging equipment and power system issues, automated circuit switching (e.g., Fault, location, isolation and service restoration (FLISR)), volt-VAR optimization (e.g., conservation voltage reduction (CVR))

Table 18. Capabilities and their descriptions (continued)

Capability	Description of capability and needs statement
Telecommunications	Description: The infrastructure that connects grid assets and the distribution system operators Needs statement: A reliable telecommunications network allows grid operators to communicate with grid assets and enable more grid services. Example technologies: Communication spectrum licensed from the Federal Communications Commission (FCC), owned and leased fiber, cellular communication equipment, AMI mesh network Example functions: Communication networks at different levels of granularity — field area networks (FANs) to enable communication between field devices and the Integrated Operations Center, neighborhood area networks (NANs) to enable communication between devices in a microgrid
Physical grid infrastructure	Description: The poles, wires, transformers, substations, operations control center and other distribution system equipment (e.g., reclosers, capacitors, regulators) that comprise the distribution system Needs statement: Enable the safe, reliable, bi-directional flow of power. Example technologies: See description Example functions: See needs statement
Cybersecurity	Description: The protection of computer systems and networks from information disclosure, theft of or damage to their hardware, software or electronic data and the disruption or misdirection of the services they provide Needs statement: The power grid is a highly connected system as described by the capabilities above. The ongoing modernization of the grid will create more connections and introduce more vulnerability to cyberattacks, efforts by rogue actors to threaten the operation of the grid Example technologies: Cyber-physical barriers to restrict access to critical assets, advanced physical security systems (e.g., intelligent badging), firewalls, data encryption and spyware/malware detection Example functions: Ensuring access is restricted to authorized personnel, insulating critical infrastructure networks from external threats and obscuring critical communication between devices and operators

4.6 Future capability roadmap with costs and benefits

4.6.1 ASSESSING COSTS AND BENEFITS

According to a recent study by U.S. DOE's Grid Modernization Laboratory Consortium, several public utility commissions have required electric utilities to prepare grid modernization plans demonstrating that grid modernization investments provide benefits to customers.[84] These plans typically include a benefit-cost analysis (BCA) to determine whether grid modernization investments' benefits will exceed costs. However, DOE's study found several challenges when determining the benefits of these investments. The challenges include:

- Multiple grid modernization components with interactive effects are difficult to analyze or justify separately.
- Many benefits are hard to monetize, making it difficult to compare them with costs using a single metric.
- Equity issues may arise when all customers pay for grid modernization projects, but benefits of a particular project may accrue more to some customers than others.
- Utilities seek some form of approval for grid modernization projects before making investments.

An earlier study conducted by the DOE's National Energy Technology Laboratory (NETL) estimated that grid modernization investments' benefits exceed the cost of those investments by a benefit-to-cost ratio of four-to-one.[85] The same study estimated that grid modernization investments deliver 20% savings per year relative to the cost (a $100 investment delivers $20 of savings each year).

The investments outlined in **Table 19** are in different stages of implementation, therefore the range of costs and benefits have not been fully developed. During the development of our DSP, we researched potential costs for modernizing the grid. Expected costs for grid modernization investments ranged widely depending on the type of investment and the goals of the project ($2.1 million to $275 million).[86] As we work to modernize the grid, we will balance customer costs with the need to modernize the grid, accelerate DER adoption and meet our customers' decarbonization goals.

4.6.2 ROADMAP

Table 19 provides a breakdown of each capability in the modernized grid framework and summarizes the relative costs and benefits of each over a 10-year planning horizon. Investments going through future action plans of the DSP will include the appropriate analysis to justify the investment. We expect to continue to use rate cases to provide detailed analysis and justification for specific grid modernization investments.

Investments, both within and across capabilities, are not mutually exclusive, so investments in one capability can affect future investments in other capabilities. Examples include:

- Investments in smart meters may impact telecommunication investments and virtual power plant needs under certain conditions and vice versa.
- Investments made in sensing, measurement and automation may offset field device and installation costs associated with developing hosting capacity analysis as noted in **Section 6.5** or operating a virtual power plant and vice versa.

84. U.S. DOE's Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations report is available at: eta-publications.lbl.gov
85. U.S. DOE's Modern Grid Benefits report is available at: netl.doe.gov
86. Sources for cost ranges are from GreenTech Media available at: greentechmedia.com

Table 19. Future relative potential costs and benefits by capability

Capability	Potential costs (0-10 years)	Potential benefits (0-10 years)
Customer ecosystem	Acquisition and provision of data Additional customer service IT infrastructure	Customer engagement Self-service analysis and decision-making 24/7 availability
Virtual power plant (VPP)	Development of rate structure to compensate participants Software to enable VPP Physical infrastructure to enable VPP (e.g., comms, controllers)	Distribution system efficiencies Optimized distribution system investments (NWS) Support for customer resilience and community benefits Support for decarbonization
Planning and engineering	Robust distribution planning tools Experienced planning engineers IT integrations	Distribution planning and engineering is how PGE accomplishes its goals for the distribution system and its customers, including safety, reliability, resilience, customer choice, decarbonization and electrification
Grid management systems	Grid management system hardware, software and infrastructure Cybersecurity infrastructure and protocols	Customer empowerment and decarbonization through DER enablement Improved workforce safety and productivity Improved grid efficiency and reliability Improved grid resilience
Sensing, measurement and automation	Cybersecurity infrastructure and protocols Shorter equipment lifecycles for digital vs. analog equipment Workforce requirements of a more digital grid	Improved situational awareness for line operations and distribution system operators Increased operational efficiency New and improved data for distribution planning and distribution operations Increased safety for line operations
Telecommunications	Cybersecurity infrastructure and protocols Shorter equipment lifecycles for digital vs. analog equipment Workforce requirements of a more digital grid	Enablement of benefits gained through grid management systems and sensing, measurement and automation
Physical grid	Undergrounding equipment Hardening equipment Replacement of old/failed assets Assets to support new growth	Safe, reliable and resilient delivery of power to customers
Cybersecurity	Included in grid management systems estimate	Operational technology (OT) visibility Ability to monitor and detect anomalous activity in operational systems Protection against threats to the safe, reliable operation of the grid Protection of customer information and, potentially, equipment

Table 21 provides additional detail on the state of PGE's current and planned capabilities based on Carnegie Mellon University's Smart Grid Maturity Model (**Table 20**).[87] This model is well suited to assist utilities in understanding the current and future state of their capabilities. PGE will utilize Carnegie Mellon University's Smart Grid Maturity Model to monitor and adapt our long-term roadmap over time. In addition to using this maturity model, we will also incorporate feedback we have received from our partners through our Community Engagement Plan.

Table 21 reveals a higher maturity level in grid management systems and the physical grid. This stems from investments in ADMS and PGE's Integrated Operations Center (IOC), which are some of the key drivers of PGE's 2021 General Rate Case.

Table 20. Carnegie Mellon University's Smart Grid Maturity Model

Maturity scale	Maturity type	Maturity description
5	Pioneering	Organization is breaking new ground and advancing the state of practice within a domain
4	Optimizing	Organization's smart grid implementation within a given domain is being tuned and used to further improve organizational performance
3	Integrating	Organization's smart grid deployment within a given domain is being integrated across the organization
2	Enabling	Organization is implementing features within a domain that will enable and sustain grid modernization
1	Initiating	Organization is taking the first implementation steps within a domain
0	Default	Default level of the maturity model

87. Available at: Carnegie Mellon University, Smart Grid Maturity Model Version 1.2

Table 21. PGE's capability gap analysis, assumptions and barriers

Capability	Current maturity	Desired maturity	Assumptions	Barriers
Customer ecosystem	2	4-5	Customer information can be protected. System vulnerabilities are not exposed.	Availability of data in sharable format Identification of valuable information to share
Virtual power plant (VPP)	1	4-5	ADMS is fully implemented. DER adoption continues/accelerates. Economic value is identified.	Technology not yet mature across all DERs Regulatory alignment of VPP
Planning and engineering	2	4-5	Sensing and measurement in place to collect better data. Advanced tools acquired.	Advanced planning capabilities not supported by current market VPP.
Grid management systems	3	4-5	Adoption curve of DER is similar to planned/forecasted. OPUC policies are consistent. Stakeholder demands and community demands are similar. Investments are made in parallel with sensing, measurement and automation and telecommunication capabilities.	Balancing spending with rate impacts Complex information and operational technology (IT/OT) integration
Sensing, measurement and automation	1-2	4	Adequate planning, engineering, design and construction resources. ADMS is fully implemented.	Balancing spending with rate impacts
Telecommunications	2	4	Adequate planning, engineering, design and construction resources. Adequate bandwidth and speeds are available at low costs.	Balancing spending with rate impacts
Physical grid	3	4	Adequate planning, engineering, design and construction resources.	Balancing spending with rate impacts
Cybersecurity	2	4-5	Current strategy and tools maintain effectiveness; no emergence of new types of threats or vulnerabilities.	Balancing spending with rate impacts

A modernized grid will help our customers and communities better manage and reduce their energy consumption and costs, while giving them greater access to their own energy data. Customers also benefit from a modernized grid with improved security, reduced peak load costs, increased integration of renewables and lower operational costs. As utilities upgrade grid infrastructure that is being pushed to do more than it was originally designed to do, investment analysis is critical. Modernizing the grid to make it smarter and more resilient through the use of cutting-edge technologies, equipment and communications controls that work together to deliver cleaner electricity more reliably and efficiently can greatly reduce the frequency and duration of power outages, reduce storm impacts and restore service faster when outages occur.

4.6.3 RECOMMENDATION FOR COST-BENEFIT ANALYSIS

We recommend a discussion with OPUC staff on potential cost-benefit analysis options using the U.S. DOE's "Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations" report as a starting point for discussion. **Table 22** illustrates DOE's options for addressing key BCA challenges.

Table 22. U.S. DOE's options for addressing key BCA challenges

Challenge	Potential approaches
Identifying objectives	Use long-term strategic planning to define objectives up front. Identify the amount and type of cost-effective DERs.
Documenting the purpose of each grid modernization component	Specify a standard taxonomy for grid modernization. Define purpose and driver of each grid modernization component.
Determining when to apply least-cost, best-fit approach	Consider grid modernization objectives. Consider purpose and driver of the component. Consider whether component is core or application.
Choosing BCA framework	Articulate the BCA framework up front. Focus on two tests: utility cost test and regulatory test.
Choosing discount rate(s)	Choose a discount rate that reflects state regulatory goals. Conduct sensitivities using different discount rates.
Accounting for interactive effects	Use the least-cost, best-fit approach, where warranted. Use scenario analysis with different combinations of components. Conduct BCA for grid modernization components in isolation.
Accounting for benefits that are hard to quantify or monetize	Use the least-cost, best-fit approach, where warranted. Establish metrics to assess the extent of benefits. Apply methodologies to make unmonetized benefits transparent.
Addressing uncertainty	Use approaches that include contingency costs, scenario and sensitivity analyses, and probabilistic and expected value modeling.
Putting BCA results in context	Estimate long-term bill impacts.
Prioritizing grid modernization investments	Identify least-regrets investments that balance cost, risk, functionality and value.
Encouraging follow-through	Encouraging follow-through.

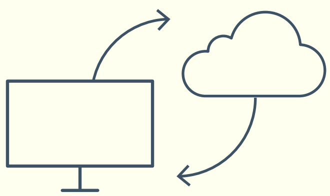
4.7 Currently planned capabilities investments

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. Investment justification is based on guidance provided in **Table 16**. Where available, PGE also describes the expected long-term evolution of the specific investments.

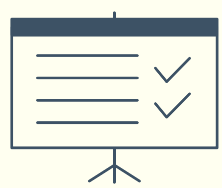
While investments are primarily driven by the needs within each capability, there are several considerations unique to each investment. **Figure 20** provides example considerations related to IT needs and impacts, business process changes and workforce implications.

Figure 20. Example considerations for investments in a modernized grid

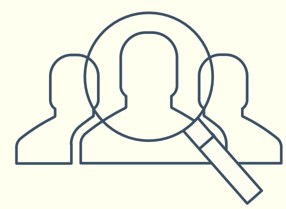
IT needs and impacts
- Data availability and analytics
- System integration
- Cybersecurity



Business process changes
- Work management
- Operational protocols
- Design standards
- Engineering procurement and construction



Workforce impacts
- New and evolving roles and responsibilities
- Skill gaps and training for reskilling and upskilling current employees
- Labor market competition for digital skills



4.7.1 VPP

There is no current industry consensus on the definition of a VPP and how it differs from certain DER programs. For the purposes of this DSP, PGE defines a VPP as follows:

> The VPP is a combination of DERs that work together to provide an array of grid services such as capacity, regulation, load following, contingency reserves and frequency response. Controlled through a central platform which integrates with DERMS, DRMS and ADMS, these bundles of DERs mimic the operational abilities of a traditional power plant.

PGE expects this definition to evolve both as the company learns and as the industry standardizes around the concept and application of VPPs. Over time, as PGE integrates foundational investments such as ADMS and DERMS, we will further the discussion around VPPs. PGE will continue to leverage the DSP to communicate its progress toward VPP integration.

Today, PGE has a variety of aggregation platforms (DRMS), each with a set of distinct energy services they can offer. Within the next five years, we intend to integrate these platforms into our real-time operations teams for a more streamlined dispatch, servicing the needs of PGE's energy portfolio using a DERMS software. We will be integrating these same DERMS platforms into our ADMS for enhanced distribution operational value.

Investments in VPP require that ADMS and DERMS projects are complete and functional across all use cases (see **Section 4.7.3** for details on ADMS and DERMS) and assume that PGE sees the forecasted penetration of customer-sited DERs that enable VPPs. The technology platforms available today do not offer critical support to PGE's energy needs or distribution reliability needs because our operations teams are not accustomed to managing behind-the-meter DERs and flexible loads. Customer impact is not yet fully understood for PGE's plan to migrate these resources to a full-fledged VPP.

Within the next five years, we intend to consolidate aggregation platforms and put in place the structure, people, processes, tools and training needed to support a full-fledged VPP operation. We will rely on the VPP to provide the flexibility needed in our energy portfolio to sustain reliable energy delivery at reasonable costs. This supports PGE's goal of operating a more carbon-free energy portfolio and assist Oregon in meeting its clean energy goals as specified in Oregon's House Bill 2021. VPP is an advanced capability where each portfolio of aggregated DERs is evaluated through a BCA that includes customer and societal values as detailed in **Section 4.7.1**.

4.7.2 PLANNING AND ENGINEERING

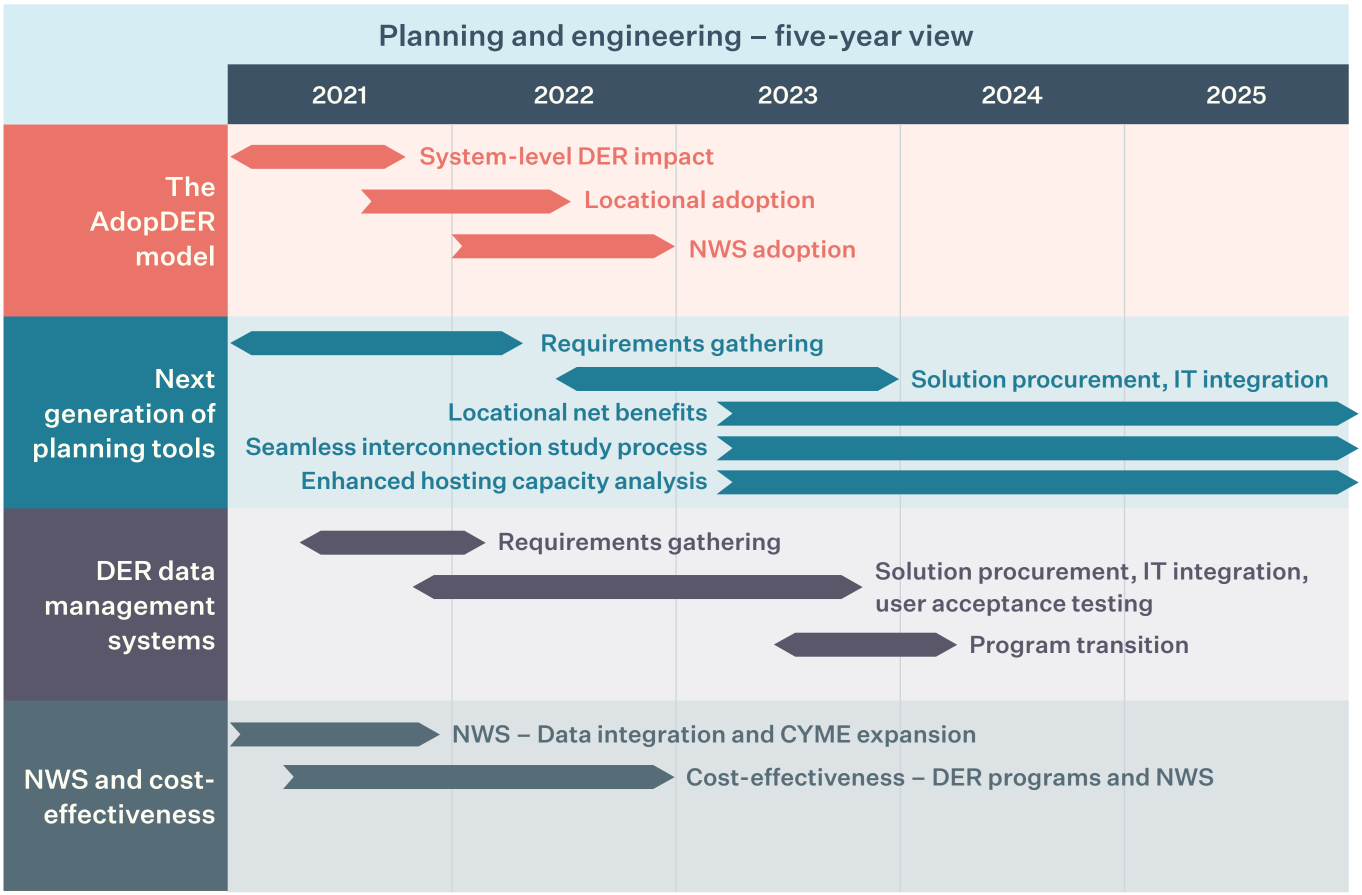
The planning and engineering capability refers to a suite of integrated, next-generation tools needed to perform distribution system planning functions. PGE's current approach to this capability builds on the functionalities outlined in the DOE's DSPx, as noted in **Table 23**. This approach ensures we are following best practices and can link investments directly to the goals outlined in our vision for the distribution system.

Table 23. Planning functions as defined by DOE's DSPx

Distribution planning		
Functionality	**Technologies**	
Short and long-term demand and DER forecasting	Demand forecast models Load profile models DER forecasting (customer DER adoption models, customer-EV adoption models) Scenario analysis tools	
Short-term distribution planning **Long-term distribution planning** **Hosting capacity** **EV readiness**	Power flow analysis	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
	Fault analysis	Fault current analysis Arc flash hazard analysis Protection coordination analysis Fault probability analysis
	Power quality analysis	Voltage sag/swell analysis Harmonics analysis
Planning analytics	DER impact evaluation tool Stochastic analysis tools	
Reliability and resilience planning	Realiability study tool Value of lost load (VoLL) models Resilience study models Resilience benefit-cost models	
Interconnection process	Process management software and portals	
Locational value analysis	Cost estimating tools	
Integrated resource, transmission and distribution planning	Planning integration and analysis platform	
Planning information sharing	Web portals Geospatial maps	

PGE has planned the following key investments to enable the functionalities from **Table 23**. These investments are considered foundational and aligned with DOE's DSPx. They are evaluated based on least-cost, best-fit and reasonableness as described in **Section 4.4.1**. **Figure 21** provides a five-year overview of PGE's planned investments in planning and engineering.

Figure 21. PGE's planned investments in planning and engineering over next five years



Note: Includes future initiatives

4.7.2.1 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.

4.7.2.1.1 Project details

- PGE, through a competitive-bidding process, selected three third-party consultants, Cadeo Group, The Brattle Group and Lighthouse Energy Consulting, to develop an open-source framework for DER forecasting and potential analysis.

- 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 will estimate locational adoption of DER resources and fine-tune 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 will inform PGE's DSP Part 2, as well as future DER program and distribution system planning efforts.

- PGE is expecting to invest approximately $500k over the two phases of the project (2020-2021).
- PGE expects model improvements in the next year (2022) to build on the existing functionality, enabling new features such as locational adoption for NWS, improved data and IT integration and data quality. PGE expects this cost to be approximately $400k.

4.7.2.2 Next-generation planning tools project

PGE is conducting an internal investigation to understand the current and required future planning capabilities needed to realize PGE's vision. This effort will also provide the required 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 see outcomes such as integrating NWS at scale instead of on a case-by-case basis, reducing operational uncertainty through probabilistic planning, streamlining interconnection study processes and ensuring safety and reliability in a dynamic grid. Our next-generation planning tools project will be a foundational investment designed to enhance PGE's current planning capabilities and enable improvements (**Figure 22**) in various facets of distribution system planning.

Figure 22. PGE's current distribution planning capabilities

- Enhanced power flow analysis
- Enhanced power quality analysis
- Resiliency analysis
- Hosting capacity analysis
- Streamlining interconnection studies
- Probabilistic planning
- Advanced fault analysis
- Dynamic analysis
- Safety analysis
- System optimization
- Locational value analysis
- Risk assessment

Each of these facets of planning have one or more elements, each with their own needs. **Table 24** gives an example of PGE's assessment for enhanced power flow analysis.

Table 24. Example of PGE's assessment for enhanced power flow analysis

Component	Study name	Current state	Future state	Current tool
Enhanced power flow analysis	**Full-sequence power flow analysis:** The ability to determine the flow of electric power in an interconnected system. A full-sequence power flow analysis comprises the analysis of positive, negative and zero sequence flows, which allows the capture of system unbalance conditions in three-phase circuits.	2	4	CYME
	Power flow on secondary circuits: The ability to determine the capacity and model the important components of any secondary network. A secondary system model includes model representations of all the components (e.g., lines, cables, switches) between the customer connection and the distribution transformer at the intersection of the secondary system and primary system, including a representation of the distribution transformer.	1	4	CYME
	Voltage analysis: The ability to determine the voltage profile along the feeder as a function of (1) distance from the substation and (2) time of day. Line and transformer impedances cause a voltage drop between the generation source and the point of consumption.	2	4	CYME

4.7.2.2.1 Project details

- PGE is evaluating the current state of its planning tools and analysis, as well as its desired future state. PGE will subsequently develop requirements needed to procure market solutions through a request for proposal (RFP) that can work in an integrated manner to achieve the functionalities outlined above.
- PGE will design the underlying IT architecture needed to improve computation speeds, reduce labor costs and ensure PGE can perform scalable calculations for an increasing number of interconnection applications, NWS and other distribution system analyses.
- Based on the IT infrastructure, PGE will determine any workforce implications. It is anticipated that PGE may see a need for engineers to perform analysis, such as hosting capacity and interconnection.
- PGE expects the project to span a one- to three-year timeline with an expected RFP in early 2022.
- PGE estimates the upfront project costs in 2022 of approximately $2 million with additional multi-year ongoing costs based on available market products, IT capabilities and workforce needs.

4.7.2.3 NWS data integration and CYME expansion

PGE will actively invest to improve data integration in current planning capabilities and expand capabilities by procuring new CYME modules, such as:

- Load relief DER optimization: This allows engineers to evaluate load relief projects using battery energy storage systems (BESS) as well as dispatchable and non-dispatchable generation. The module bundles two distinct algorithms, one for the optimization of BESS and dispatchable generation and one for the sizing of non-dispatchable generation.
- Microgrid modeling and analysis: This module enables modeling and simulation of grid-tied microgrids operating in either islanded or grid-connected mode, as well as isolated microgrids, such as those of remote communities far from any transmission and distribution infrastructure.
- Long-term dynamic load flow analysis: This module performs time series long-term dynamics load flow analysis (in the seconds to minutes range) of the variable phenomena introduced by DERs. Device controls are included in the analysis, including load tap changers, shunt capacitors and switchable shunt banks. This module also enables the time-domain simulation of smart inverters and battery energy storage systems.

By procuring these types of modules, PGE will have the ability to repeatably perform specific elements of an NWS analysis. We expect this project and next-generation planning tools to work together, with this project focusing on needs within the next year (2022) and next-generation planning tools focusing on needs post 2022, including IT and workforce implications.

4.7.2.3.1 Project details

- PGE is working with CYME to determine the necessary modules to perform NWS. We expect there will be incremental license costs of approximately $100k to obtain these modules.
- PGE is also working internally with the relevant IT teams to improve AMI integration, CYME gateway updates and other data integration to improve planning accuracy and resolution.
- We expect both elements of the project to be complete by mid-2022, with a focus on performing the analysis to identify NWS opportunities for our DSP Part 2.

4.7.2.4 DER cost-effectiveness update project

In alignment with direction from OPUC staff's comments to PGE's Flexible Load Plan, we are working to update DER cost-effectiveness.[88] We've started developing a new cost-effectiveness tool to perform robust analysis that is aligned with the National Standard Practice Manual and regional best practices. To ensure PGE takes advantage of best-in-class approaches from other leading national sources and jurisdictions, we are working with third-party consultants, Applied Energy Group and The Cadmus Group.

This cost-effectiveness tool, called Ben-Cost, builds on PGE's previous work on the resource value of solar, flexible load and transportation electrification valuations. The new tool will ensure DERs can be valued through multiple perspectives, accounting for energy system, host customer and societal impacts. Through this project, PGE will:

- Review current cost-effectiveness methodology and inputs.
- Perform gap analysis and valuation research.
- Refine and develop cost-effectiveness methodology and inputs that may include, but are not limited to:
  - Updating the proxy resource for the value of capacity to a non-emitting resource if available through an updated IRP analysis
  - Integrating system-level transmission and distribution impacts of DERs
  - Non-energy benefits and low-income benefits development with future iterations improving on these values
  - Improving EV benefit calculations, such as avoided gasoline car operations and maintenance, avoided gasoline and emission reduction

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.

88. PGE's Flexible Load Plan available at: apps.puc.state.or.us

4.7.2.4.1 Project details

- In 2021, PGE began review of existing cost-effectiveness methods to identify gaps compared to national best practices. This work is expected to be completed in early 2022. .
- In 2021, PGE is estimating a spend of approximately $100k to develop a new cost-effectiveness tool that includes development of low-income customer benefits.
- 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). Estimated costs for this project vary between $100k to $250k for 2022.

4.7.2.5 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 connection
- DER program performance data
- DER cost-effectiveness and evaluation results
- Energy efficiency and renewable energy integration with Energy Trust of Oregon (ETO)
- DER reporting and regulatory compliance

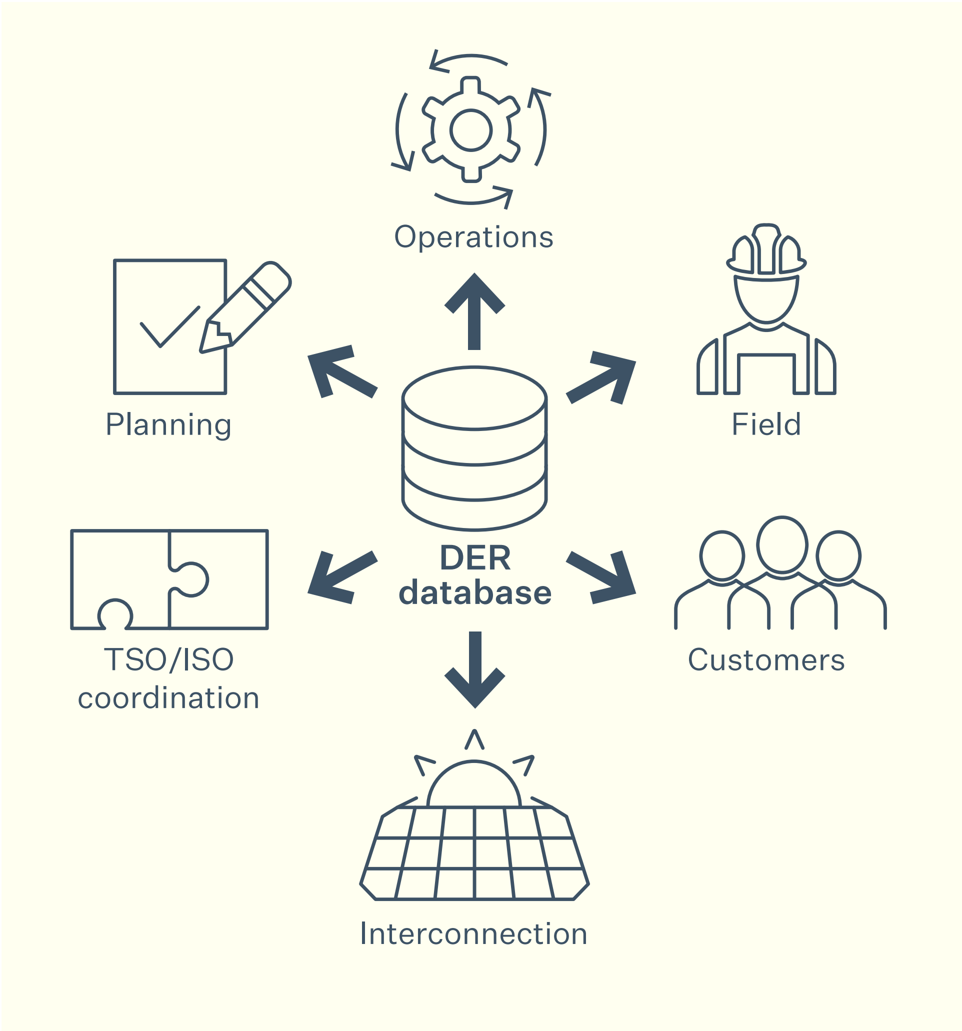
An analytical platform that works with this data will streamline core business functions, including interconnection and program application processes, incentive payments, demand response (DR) event performance reporting, standard reports for regulatory filings and data requests, integration with planning 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 R&D effort in which PGE will leverage EPRI's expertise and ensure best practices are implemented in the design of the DSMS. **Figure 23** represents the breadth and importance of an enterprise-wide single source of truth for DER data.

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

Figure 23. EPRI's illustration of a DER data management system



4.7.2.5.1 Project details

- 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.
- PGE estimates initial costs of approximately $1 million to include project scoping and customized software, with future costs contingent on the chosen solution.

4.7.3 GRID MANAGEMENT SYSTEMS

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

The GMS operates with a complex infrastructure of field devices that sense, measure, protect and control the grid, enabled by 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 highlighted below are foundational in nature and a requirement 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.

4.7.3.1 Grid management systems

We have developed a comprehensive grid modernization strategy that will facilitate cultural shifts, shorter development cycles and cohesive strategic alignment across PGE. These are needed to provide safe, secure, reliable and resilient power on the electric grid that will be dominated by DERs. We have determined that a comprehensive GMS that can perform the functions described in **Figure 24** is required. **Figure 25** illustrates PGE's five-year roadmap for GMS.

Figure 24. Grid management system functions

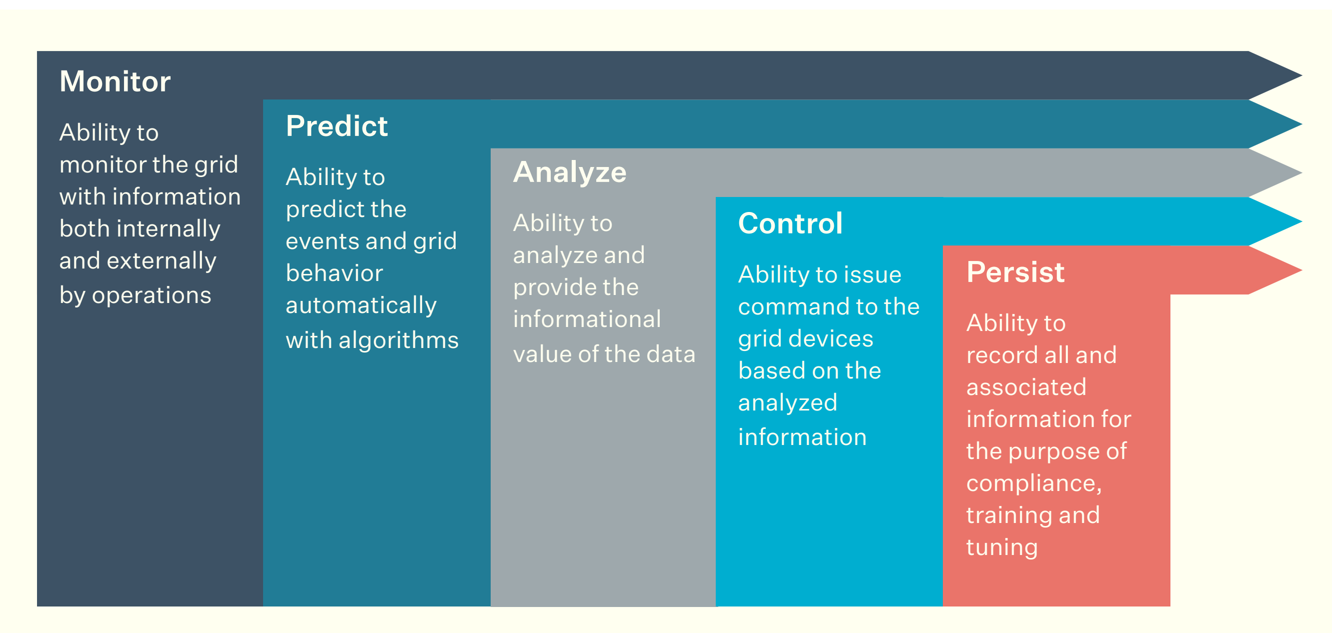
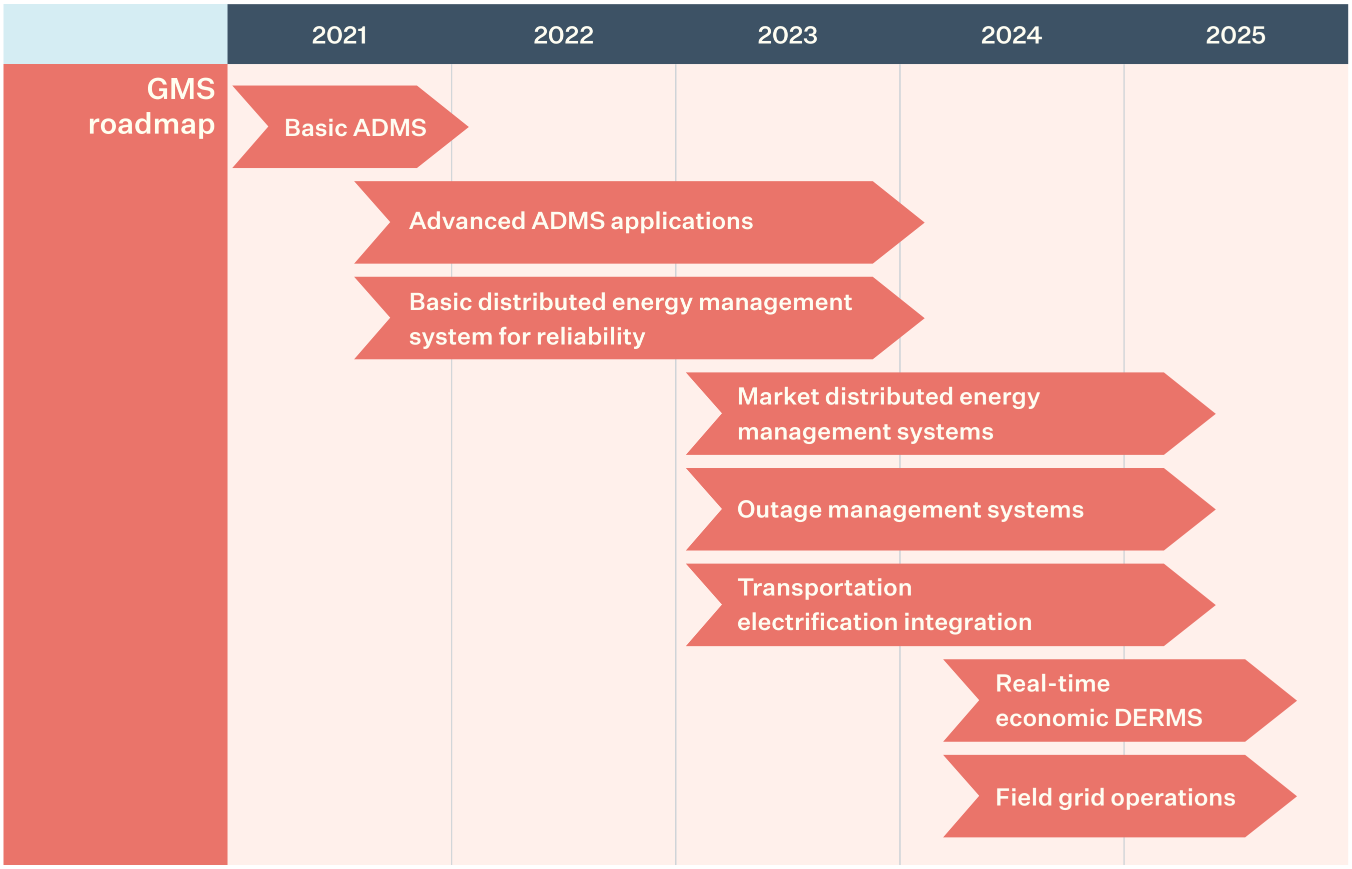


Figure 25. PGE's expected five-year roadmap for GMS



4.7.3.1.1 Project details

- In Phase I (basic ADMS), PGE plans to implement a distribution management system (DMS) with fault location, isolation and service restoration (FLISR) on a minimum of three circuits. The primary function of the DMS will focus on monitoring, predicting and operating distribution devices on the distribution system. PGE will then update the outage management system (OMS), manage electronic switching sheets, issue clearances, monitor integrated grid systems and operate equipment on load-serving distribution systems.
  - 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, they will require protective measures like the energy management system (EMS).
- PGE estimates $40 million in grid management systems investments for 2022.

4.7.3.2 Distribution automation (DA)

DA is the umbrella of smart grid solutions aimed at solving 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. Feeders targeted for DA implementation are those with a high exposure to non-asset failure risk. The addition of DA reclosers and substation upgrades will reduce the risk of mainline non-asset failure on these feeders, reduce the total number of customer outage minutes for a sustained mainline fault and minimize the consequence of sustained mainline faults. The following describes the types of DA solutions:

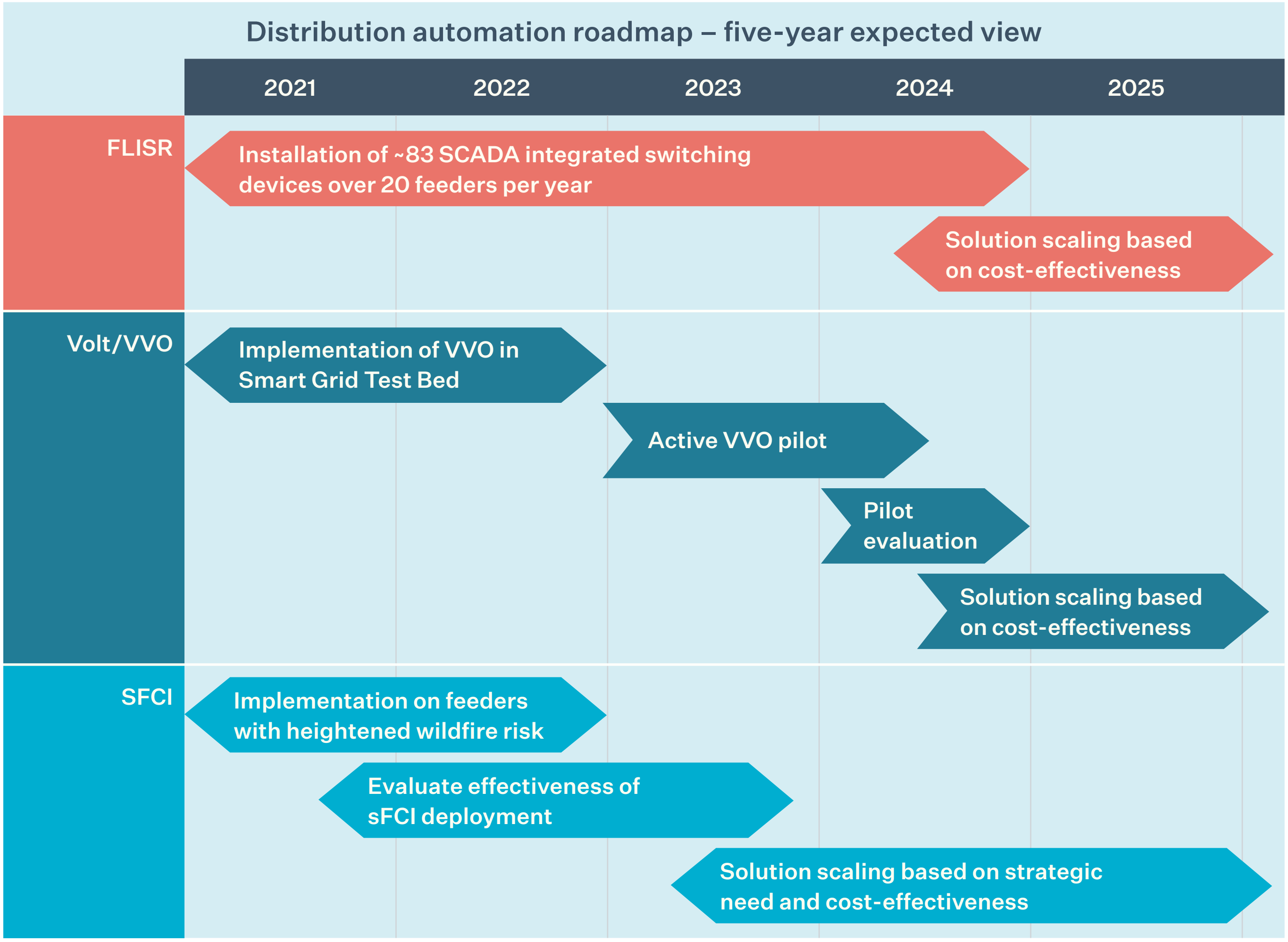
- **FLISR:** Normally open and normally closed supervisory control and data acquisition (SCADA)-integrated switching devices are strategically placed throughout the feeder to maximize the implementation's expected benefits. The preferred communications medium is PGE's FAN. When paired with a centralized 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.
- **VVO:** Equipment that can manage voltage and optimize VAR flow, which reduces system losses and improves efficiency in power distribution, is installed inside of substations and throughout the distribution feeder. VAR, a unit of reactive power, can be produced by inverter-based DERs. Other equipment to optimize voltage and VARs includes load tap changers (LTC), switched capacitor banks and line regulators. As with other smart grid solutions, harnessing the full benefits of this technology deployment requires integration into a control system (e.g., ADMS). Once fully integrated, 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 distribution power transformer's power factor.
- **sFCI:** Installation and integration of communicating line monitors, strategically placed throughout the distribution system, will help inform real-time operational decisions. Situational awareness is improved, and truck rolls and patrols are reduced. This results in reduced duration of sustained outages.

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

4.7.3.2.1 Project details

- PGE estimates $8 million of DA investments in 2022 with additional, annual investments through 2024.
- **Figure 26** shows PGE's expected roadmap for DA solutions.

Figure 26. PGE's expected five-year roadmap for distribution automation



Note: Includes future initiatives

FLISR

- 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

- 2021 through 2022: Plan for first active VVO implementation through PGE's Smart Grid Test Bed.
- 2023: Pilot active VVO implementation.
- 2024: Evaluate effectiveness of active pilot VVO implementation.
- 2025 and beyond: Scale VVO program commensurate with cost effectiveness.

sFCI

- 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 sFCI program commensurate with cost effectiveness.

4.7.3.3 Substation protection 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.

4.7.3.3.1 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 (TLTC) 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 SCADA system, intelligent devices such as relays, meters and asset monitoring devices can be integrated and information can be brought 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 and 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).[89]

4.7.3.3.2 Modernize cost-effective communication-aided protection systems

- **Improve system reliability**: A protection system is fundamental to operating the grid. Many of the distribution substations are still operated with 40- to 50-year-old electromechanical relays, providing bare minimum, inflexible protection. This often leads to mis-operations, failures that could cause major outages and equipment damage or even seriously affect the personal safety of employees working on the grid. Modern relays are required to meet new operational objectives. Modern relays also provide much more detailed information through integration with a substation automation system to analyze events, make settings modifications and fine-tune the grid to operate in a more stable, reliable fashion.

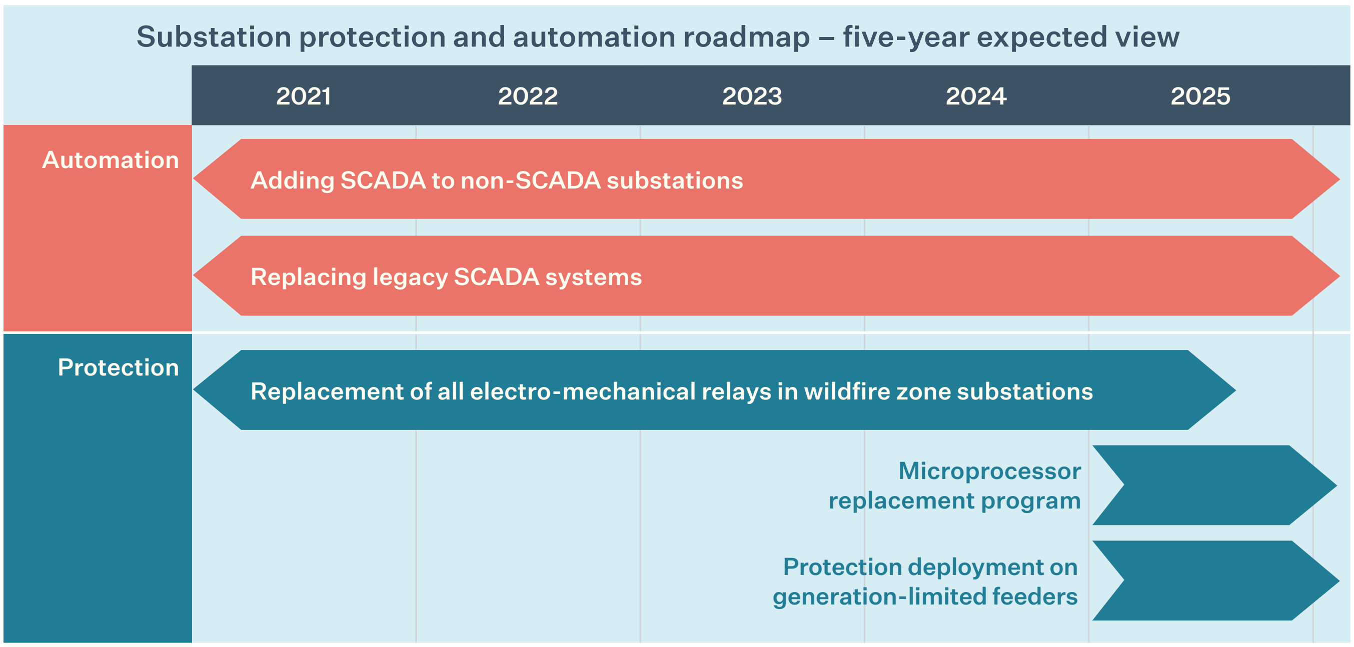
- **Enable the integration of DERs**: Many of PGE's distribution substations and feeders do not have sufficient protective devices to allow for easy integration of DERs. By building protection capabilities, PGE will better integrate inverter-based DERs (e.g., rooftop solar and batteries).

89. 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.

4.7.3.3.3 Project details

- 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 opportunistic investments such as substation rebuilds, feeder upgrades and the like.
- PGE has standardized the integration of cybersecurity monitoring and management for protection/automation systems as part of new substations or older substation rebuilds.
- PGE also ensures 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.
- **Figure 27** provides PGE's expected five-year roadmap for substation automation and protection investments.

Figure 27. PGE's expected five-year roadmap for substation automation and protection



Note: Includes future initiatives

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.

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 also ensures reduced failure of the protection system.
  - Update protection on generation-limited feeders or feeders nearing the load/generation threshold (e.g., modern relays with protection capabilities, hot line blocking capabilities, substation 3V0 protection).

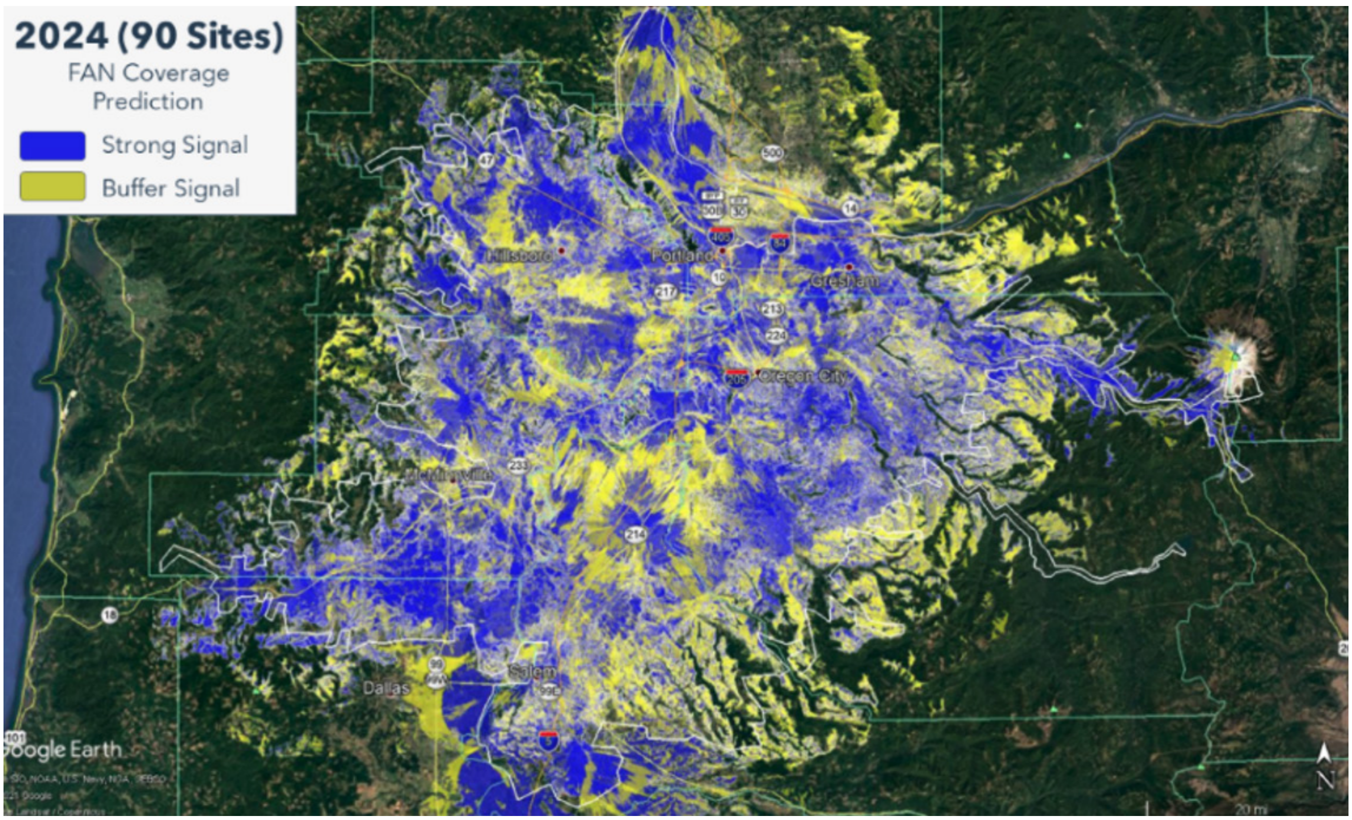
4.7.3.4 Field area network (FAN)

The FAN is a PGE-owned and operated wireless network that will cover PGE's service territory, enabling quick and reliable grid communications. FAN's primary use case is providing the communications necessary to operate DA reclosers. For this use case, the current alternative solution is Verizon cell modems, which have monthly operation and maintenance (O&M) costs in perpetuity, are less secure and do not guarantee reliability of service in a natural disaster scenario.

As PGE launches ADMS, the company is deploying more reclosers, meaning that the issues experienced with the current modems will exponentially increase. FAN mitigates this by building PGE's own private, secure and resilient network, which is scalable to accommodate future needs. It reduces the O&M costs of renting a network, provides control over reliability, security, latency and quality of service, and allows PGE to scale. As our grid becomes more sophisticated, we will have additional visibility into customer demand, empowering us to improve response.

The project scope is the design, procurement and installation of PGE-owned and operated base stations (estimated at 90 physical locations, with three sectors each for a total of 270 tier 1 base stations); coverage area shown in **Figure 28**.

Figure 28. PGE's estimated FAN coverage by 2024



These base stations will aggregate field traffic and transport it to the IOC. That transportation will occur over the multi-protocol label switching (MPLS) network and use fiberoptic cables, microwave or another radio path to connect to the final destinations. The FAN will use 700 MHz transceivers deployed on PGE's poles, towers and substation assets. These radios will utilize PGE-owned and licensed spectrum, providing coverage certainty, deployment flexibility, application prioritization, increased security and lowest possible latency.

4.7.3.4.1 Project details

- FAN is a new technology for PGE, requiring additional training to operate and maintain and collaboration between departments to ensure its continued viability. There is a component of customer education to promote awareness of the benefits and limitations of the network so that it can incorporate additional use cases. We will monitor this project to ensure all operational risks are mitigated.
- PGE considered and rejected the following alternatives to FAN:
  - An AMI network, which is a lower-quality, high-latency connection with limited bandwidth
  - Cellular networks, which also have a lower-quality, high-latency connection, are shared and are not PGE exclusive
  - Leased circuits to endpoints, which are more expensive and limited in bandwidth
- PGE expects multi-year investments to deploy FAN. PGE estimates $3 million in FAN investments in 2022.
- FAN investments are expected to continue through 2024, when the FAN tower build-up is expected to be complete.

4.7.3.5 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 wave of utilities fully implementing AMI and had 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.

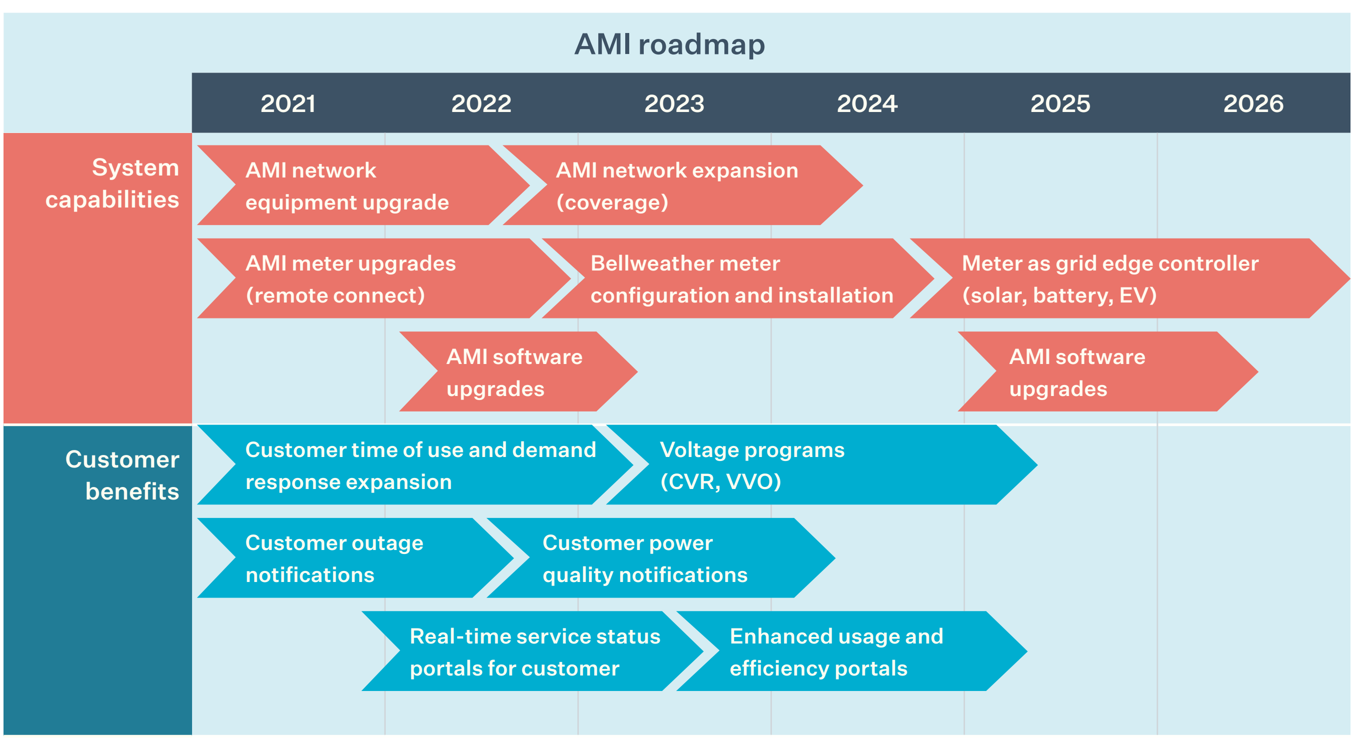
AMI is also used for operational outage processes focused on detection and restoration, as well as customer-facing use cases like notifications. In 2021, PGE started using the AMI system for more than just an outage restoration tool, but also to send proactive customer notifications (proactive outage text alerts). PGE is investing $2.7 million in AMI by the end of 2021, with the objective of improving reliability of two-way coverage. This will include meter replacement, modernizing backhaul at transceiver gateway base stations (TGBs), installing/sectorizing new TGBs and emergency generation make-ready work. TGBs are computational processing units that collect and process data, usually at the substation. Emergency generation make-ready refers to getting sites ready to be plugged in and powered by a generator, mostly during storms, when site service is down. This will allow PGE to have higher-quality data directly from the customer meter. It will also reduce the operational risks of additional truck rolls to replace failing batteries at a base station site and unnecessary dispatches when the repair has already been made.

Following this project completion, PGE will see the following outcomes:

- **Availability:** 99.9% of towers have the power, capacity and bandwidth to receive messages, even in a storm.
- **Resilience:** 98% of meters can talk to at least two towers.
- **Reliability:** 99% of meters respond when a ping is sent.
- **Completeness:** 92% of outage alarms reach their destination.

In thinking about the future of AMI over the next five- to ten-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. **Figure 29** visualizes PGE's expected roadmap for AMI functionalities.

Figure 29. PGE's expected five-year roadmap for AMI



4.7.4 PHYSICAL GRID

4.7.4.1 IOC

An IOC is a facility that centralizes all mission-critical operations that maintain the flow of power to customers. These operations include primary support functions, including the System Control Center (SCC), cybersecurity, physical security and network security. The IOC will be a critical part of PGE's strategy to deliver the reliable, resilient, affordable clean energy future customers need and expect. It will provide immediate and enduring value to customers through:

- Resource and system integration: weaving together clean energy resources and smart technologies into a seamless, reliable whole — renewable power, flexible load (demand response), distributed energy resources and storage, and regional resources (e.g., Energy Imbalance Market)
- Improved reliability: daily grid management of load/generation, transmission and distribution with advanced visibility and control for improved reliability and outage response (for both routine and extreme weather events and catastrophic events, such as wildfires)
- Increased resilience and security: strong physical and cybersecurity to meet critical infrastructure standards, seismic and other natural disaster readiness and extended off-grid operational capacity to facilitate recovery operations

By integrating the relevant people, functions and systems into a single facility, PGE will be able to maximize the effectiveness of this modernized grid initiative and provide a more reliable and resilient system for customers. In addition, an IOC will allow for the direct analytics and security support that is needed to effectively operate the future electrical grid, which cannot be achieved by simply rebuilding or replacing the control center. The IOC is critical to the successful transition to a more complex, smarter, more flexible power grid that can reliably integrate a diverse portfolio of renewable and distributed generating resources and load management systems.

The delivery of power to our customers during and after a disaster is critical for the safety of the communities PGE serves. A seismic evaluation performed on the current location of PGE's SCC and other grid-related functions at 3 World Trade Center (3WTC) determined that, although the 3WTC building is fit for general purpose activities, it has deficiencies for mission-critical activities that could result in localized hazards or partial or total collapse of the structure in a major seismic event. The nature of the 3WTC facility and its urban location have required additional security resources to address the trend of increasing encounters with protesters and individuals engaged in civil unrest. In addition to reliability and resilience risk mitigation, PGE's IOC will better allow the company to bring together grid control and cyber, physical and network security into one center. The needed space is not available at WTC, and simply providing the needed seismic upgrades for 3WTC was estimated to cost $350 million.

The IOC includes the implementation of an ADMS, enterprise data analytics and expansion of the Reliability Performance Monitoring Center. The IOC will provide value to customers through enhanced day-to-day functioning of a more efficient, cleaner and more flexible power grid. It will also provide improved resilience in the face of routine and extreme natural and human threats to physical, cybersecurity and network operations.

4.8 Research and development

PGE provides annual reports on R&D updates and spending pursuant to Order 15-356 under UE-294.[90] The latest annual report, a retrospective on 2020 R&D activity as reported in PGE's 2020 annual report, is available at portlandgeneral.com/DSP and will be available at apps.puc.state.or.us.

90. Order 15-356 within UE 294, available at: apps.puc.state.or.us