Chapter 1

Distribution system planning overview

Chapter 1. Distribution system planning overview

"The journey of a thousand miles begins with one step."

— **Lao Tzu**, ancient Chinese philosopher and writer

1.1 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 environmental justice communities.[4] It's designed to improve safety and reliability, resilience and security and apply an equity lens when considering fair and reasonable costs.

This chapter provides an overview of PGE's distribution planning process. We describe the key factors we consider when analyzing the system and identifying the investments in the distribution system. We also discuss our advancements to innovate legacy distribution planning practices since our DSP Part 2 filing.

WHAT WE WILL COVER IN THIS CHAPTER

Existing and future distribution system analysis.

Distribution grid, analyzed during normal and abnormal conditions.

Distribution system conditions evaluated based on established near- and long-term guidelines.

4. PGE uses the definition of environmental communities under Oregon House Bill 2021, available at: https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB2021.

1.2 Introduction

Distribution system planning is the process of analyzing the electric distribution system to assess whether it is capable of serving existing and future power demand (sometimes called load) under normal conditions and when things go wrong (sometimes called contingencies), like equipment failure. This process allows us to provide reliable, safe and resilient energy to PGE's customers at a fair and reasonable cost.

Historically, PGE distribution system planners were primarily concerned about managing current and future power demand because power flowed in one direction; from the place it was created or generated to homes and businesses. This has changed as technologies, policies, and our capabilities continue to evolve. The grid has become more complex, which means PGE has to plan for more situations and predict new, possible scenarios for operating and maintaining the distribution system.

When conducting distribution system planning, PGE looks at how we will meet customer needs, improve safety, increase reliability and resiliency, meet new standards and requirements and reduce risk to the system and our customers. We also optimize the configuration of the distribution system to improve customer experiences and reliability. We are doing this work with detailed network models of the distribution grid using Eaton's power flow modeling software, CYME, that factors into most aspects of distribution system planning. CYME is used for the analysis of three-phase electric power networks and is equipped with powerful analytical options and alternative solution techniques. This model is our way of identifying and developing solutions for traditional grid needs on our system such as equipment overloads or voltage issues.

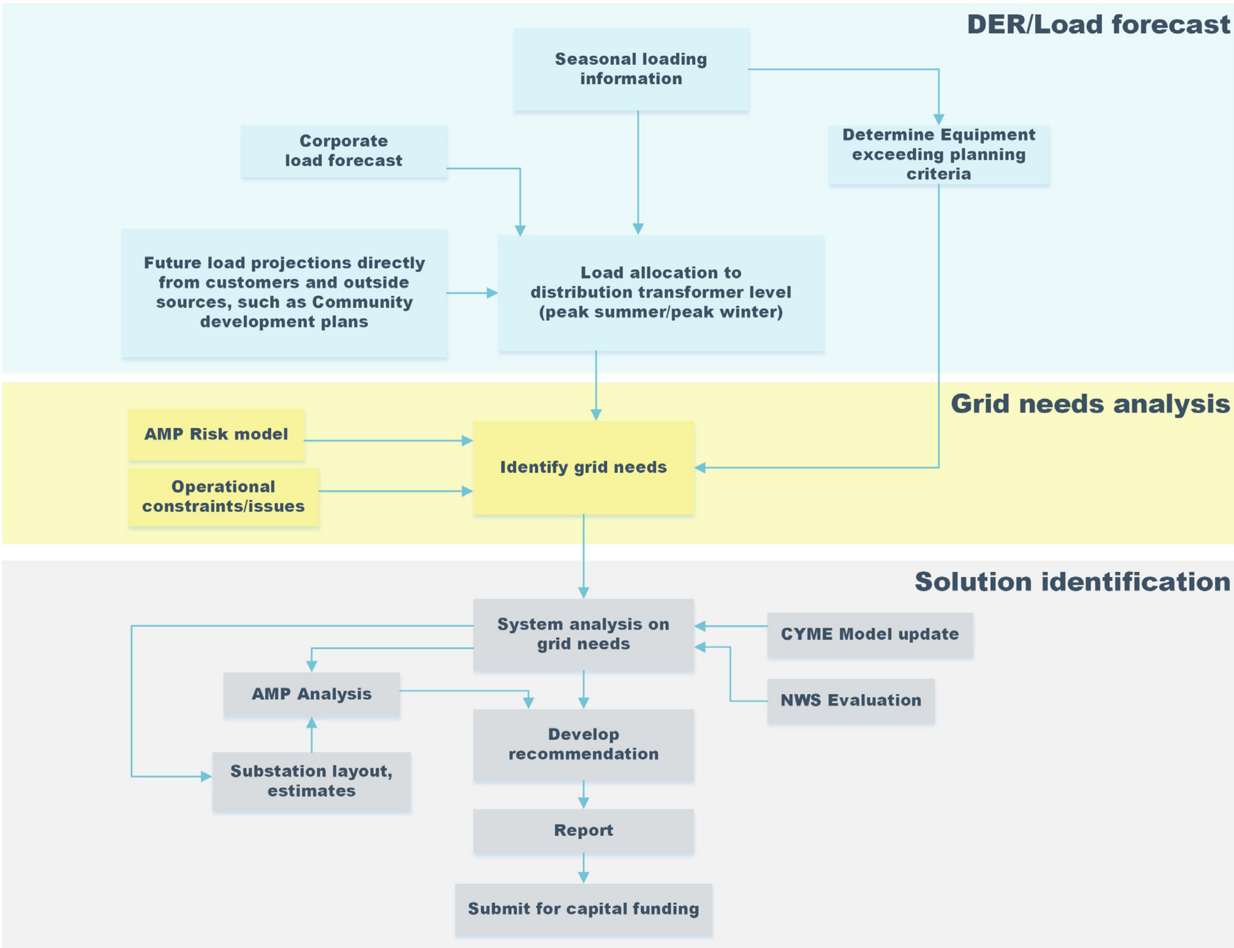
1.3 Current distribution planning process

A robust distribution planning process helps us make the best decisions to improve safety, increase reliability, meet customer needs, meet standards and requirements and reduce risk. PGE analyzes our distribution system on a continual basis, including analyses for scenarios such as new customer loads or changes in system conditions. Our distribution planning process has traditionally followed five major guiding principles:

- **Plan to peak** — PGE plans the distribution system to serve customers even during extreme temperatures, at the largest power demand at a given point during a year.
- **Plan for load capacity** — PGE's target loading is less than 67% for feeders and less than 80% for transformers. This gives us flexibility and spare capacity to move load around on the system, when needed, to meet the needs of our customers.
- **Target system flexibility** — All customers are served by switching load from one piece of equipment to another (at both the transformer and feeder level) during planned or unplanned outage events.
- **Prioritize customer load growth projects** — Large housing developments, manufacturing facilities and industrial parks that anticipate an increased need for power.
- **Planning at least 10 years out** — New infrastructure is built for the long-term load needs of an area, ensuring that the infrastructure provides adequate capacity and reliability for at least 10 years.

This planning process is a cyclical process that follows a series of steps shown in **Figure 3**. The planning process considers a wide array of variables, such as equipment loading and asset health, so that PGE continues to provide safe and reliable power to our customers.

Figure 3. Current distribution planning process



1.3.1 CAPITAL PLANNING PROCESS

In the spring of each year, PGE begins the capital planning process (described in **Appendix L**) in which we identify needs on the grid, develop projects (investments) to address those needs and request funding for projects that need to be prioritized to support reliability and safety.

PGE starts our capital planning process with the forecast of peak customer load and now the DER forecast (starting in 2022). We conclude our planning process with the design and construction of prioritized and funded projects. This process can be lengthy and sometimes takes years. As part of our annual distribution planning process for capital planning, we thoroughly review existing and historical conditions, as defined in **Table 3**.

Table 3. Planning considerations

Consideration	Description
Safety concerns	When equipment is obsolete or at end of life and failure is imminent, or equipment can no longer safely protect the transmission or distribution system.
Customer commitments	Includes signed agreements such as minimum load agreements (MLAs) or customer-provided estimates of future load needs that we identify as highly likely.
Feeder and substation loading, reliability, and resiliency performance	Covers historical loading and future load projections, compared to planning guidelines and thermal limits of substation equipment (reliability and resiliency performance is determined using IEEE standards metrics).
Dependencies between substations and feeders	Ensure that system upgrades leave room for system reconfiguration during planned or unplanned outages, so we can move customer load to other facilities when we need to take equipment out of service.
Temporary equipment use and system configurations	Allow the removal of temporary equipment that has been installed as a result of an outage.
Asset health	The condition of an asset, such as a substation transformer, and how much longer it can be used before it is at risk of failing.
Known and projected load growth	Increased load for new residential developments or large commercial customers, and growth of existing commercial/industrial customers in specific locations.
Quantity and types of DERs	Review of current and projected types of DERs on the distribution system.
Total system load forecasts	The corporate load growth forecast applied across the entire service territory, as well as DER forecasts.
Previous planning studies	May require updates to information, such as projected loading and large customer load additions.

Solutions identified as part of the distribution planning process may include, but are not limited to, a new feeder or substation, upsizing, or “reconductoring” distribution lines for more capacity, or upgrading substation transformers for more capacity. While PGE has relied on these traditional solutions in the past, we will evolve to explore non-wires solutions to resolve our grid needs. We develop cost estimates and perform cost-benefit analyses to determine the best options based on several factors, including operational requirements, technical feasibility and future needs.

Proposed projects are funded as part of an annual budgeting process. This is based on a portfolio-level ranking methodology that also funds other distribution investments and expenditures (including asset health, grid modernization, storm response and mandated projects to relocate utility infrastructure in public rights-of-way when required for public projects like road widening). This process is described in **Section 5.3**.

1.3.2 PLANNING CRITERIA

All distribution system equipment has thermal loading limits that must factor into PGE’s planning processes. Exceeding these limits stresses the system, causes premature equipment failure and can result in customer outages.

The thermal loading limit is the maximum amount of load that can be served by a piece of equipment before risking equipment failure.

PGE’s planning processes primarily focus on the substation distribution transformer and mainline feeder levels. We plan, measure and forecast distribution system load with the goal of ensuring we can serve all customer load under system normal (N-0) and single contingency (N-1) conditions (N-1 refers to conditions when ‘1’ system component fails, for example, a feeder or transformer). Our goal is always to keep electricity flowing to as many customers on the feeder as possible. Designing our system for adequate N-1 capacity allows for restoring power to all customers by reconfiguring the system using electrical switching when there is an outage of any single element. Planning criteria for our distribution feeders require associated feeder getaways, mainlines and voltage regulators not to exceed 67% of their seasonal thermal limits or 12 MVA, whichever is lower, under system normal, or N-0, conditions. For most standard feeders, this equates to two-thirds normal capacity of a standard feeder mainline. Under N-1 conditions, distribution feeders can load up to their seasonal thermal limits. For both N-0 and N-1 conditions, the distribution system is planned such that voltage at the customer meter is maintained within 5% of the customer's nominal service voltage, which for residential customers is typically 120 volts.

Underground feeder circuits are installed in a group of plastic pipes called a duct bank that is strengthened with concrete when required. When multiple feeder circuits are installed close to each other in the duct banks they heat up more quickly than a single underground feeder circuit would. PGE planning engineers use software tools to determine maximum N-0 and N-1 feeder circuit cable capacities for circuits installed in duct banks. When underground feeders fill existing duct banks, and there is no more room for additional duct banks from a substation to the distribution load, we have to construct facilities from a different area to serve this load.

In addition to examining distribution feeder demands, PGE looks at the loading levels compared to the capacity limits for the substation distribution transformers. A transformer loading limit study was performed on our system in July 2009 to determine the summer and winter transformer loading beyond nameplate ratings (LBNR). This study evaluated the transformer winding limits based on top oil temperature, hot spot temperature, and loss of life with derating factor considerations for individual transformers based on bushings, LTC, and/or auxiliary components on a case-by-case basis. The transformer loading limit study calculations used the Institute of Electrical and Electronic Engineers (IEEE) standard for transformer loading.[5] The distribution power transformer ratings were classified based on transformer capacity (MVA), manufacturer and cooling type to provide the loading capabilities that planning engineers use for transformer loading analysis.

The IEEE standard criteria used to determine the summer and winter LBNR is:

- Top-oil temperature not to exceed 110˚C
- Hottest-spot temperature not to exceed 130˚C
- Insulation loss of life not to exceed 0.0133% (per day)
- Hottest-spot temperature range from 120˚C to 130˚C not to exceed four hours

Transformer design life is determined by the longevity of all the transformer components. At a basic level, most substation transformers have a high voltage coil of conductor and a low voltage coil electrically insulated from each other and submerged in a tank of oil. Transformer loading generates heat; the more load transformed from one voltage to the other, the more heat; too much heat damages the insulation and connections inside the transformer. Hottest-spot temperatures refer to the places inside the transformer that have the greatest heat, and top-oil temperature limits refer to the maximum design limits of the material and components inside the transformer. The LBNR rating is the transformer thermal loading limit that must be maintained to avoid loss of life. Loss of life refers to the shortening of the equipment design life that leads to premature transformer degradation and failure.

To maximize the service life and the ability to reliably serve customers, PGE's loading objective for transformers is 80% of the distribution power transformer's LBNR. A robust distribution system keeps substation transformer utilization rates below 80%, with multiple restoration options in the event of a substation transformer becoming unavailable because of an equipment failure or required maintenance and construction. During emergency situations, such as N-1 contingencies, distribution power transformers are permitted to be loaded up to 100% of their LBNR rating.

5. IEEE Guide for Loading Mineral-Oil-Immersed Transformers - Corrigendum 1," in IEEE Std C57.91-1995/Cor 1-2002, vol., no., pp.1-16, 12 June 2003, doi: 10.1109/IEEESTD.2003.94283

All supervisory control and data acquisition (SCADA)-enabled substation feeders and transformers are equipped with metering equipment that can measure various power quantities (MW, MVAR, MVA, voltage and current) and these meters are polled by grid management systems (EMS and ADMS) every 10 seconds. These 10-second sample values are archived in a historian (PI system) which allows us to refer to historical peak demands for system planning needs. For non-SCADA stations, the feeders are equipped with meters, and they are polled hourly for interval data and demand values are then archived in the historian (PI system). Transformer loading in non-SCADA stations can be obtained by aggregating corresponding feeder loads.

Each transformer's peak in a multi-transformer substation is typically non-coincident, which means the transformers can each individually experience peak load at different times, and potentially on different days. This is because each transformer serves multiple feeder circuits, and each circuit serves different loads. Substation transformer peak load is proportional to, but usually less than, the sum of the feeder circuit peak loads served from that substation transformer, because typically the feeders also experience peak load at differing times. Using PGE's planning criteria, planning engineers evaluate the distribution system, assess transformer and feeder loading, and identify risks for normal and contingency operation of the system.

1.3.3 FEEDER AND SUBSTATION DESIGN

Distribution feeders for standard service to customers are designed as radial circuits (**Figure 4**). Therefore, the failure of any single critical element of the feeder causes a customer outage. PGE constructs ties between different feeders so that we can switch load from one feeder to another in the event of an outage. The distribution system is planned with enough capacity to minimize the number of switching operations that are required to restore power to customers after a single outage event. In the past few years, we have automated some of these feeder ties through distribution automation, which automatically moves the load from one feeder to another if there is an outage. This is an essential component of our grid modernization efforts and can reduce outage frequency and duration.

PGE plans and constructs distribution substations with a physical footprint sized for the ultimate substation design. This is based on anticipated load but can occasionally be limited by factors such as geography and available land (as seen in **Figure 5**, where the changes in the fence line required us to make the substation a polygon instead of the typical rectangle shape). Many substations are planned for a maximum ultimate design capacity of three transformers at the same distribution voltage, however, geography and land constraints for substations can limit capacity to two transformers, like the substation in **Figure 5**. This maximum size balances substation and feeder costs with customer service, customer load density

Figure 4. Typical radial distribution system one-line schematic

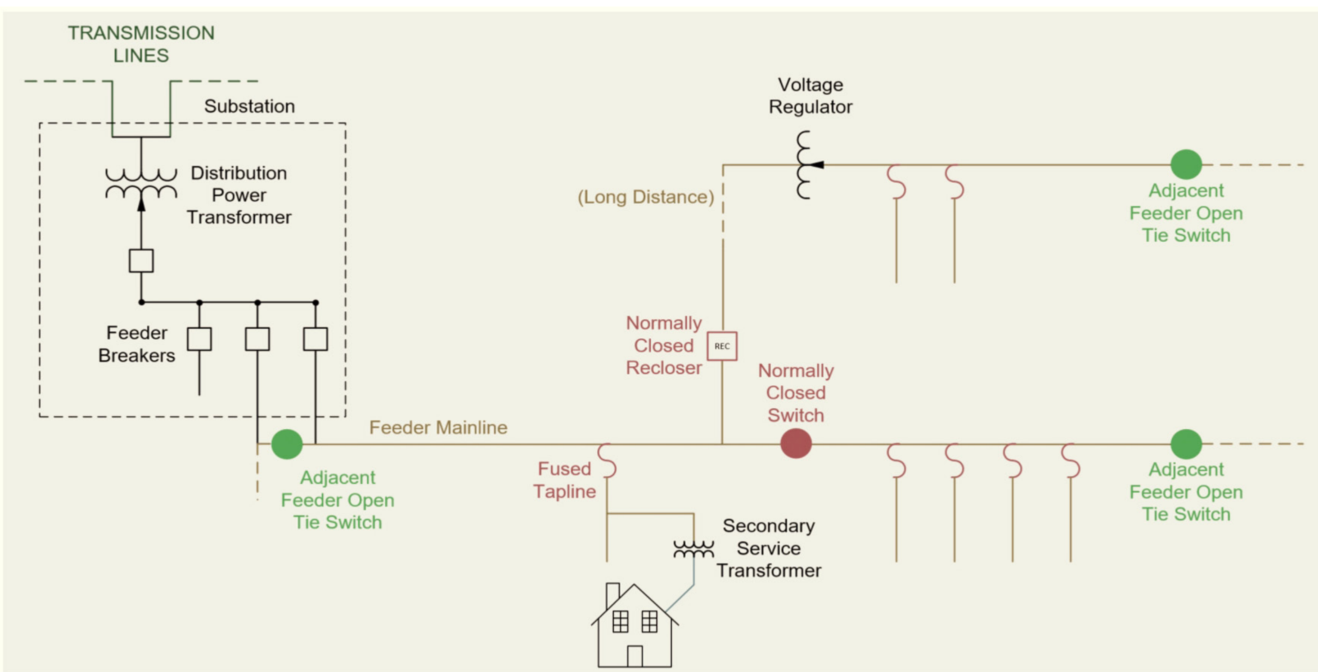


Figure 5. Distribution substation

and reliability considerations. Some substations serve very large industrial loads and require more than three transformers to provide enough power.

Planning includes cost, reliability and customer service considerations. Cost considerations include the transmission, sub-transmission, and distribution capital investment in the lines, land cost and space to accommodate growth. Customer service and reliability implications include line length and route, integration with the existing system, access and security. Over time, transformers and feeders are incrementally added within the established footprint until the substation is built to ultimate design capacity. Higher levels of DER will affect substation capacity, system protection and voltage regulation. Sometimes a large development will require the addition of a new substation because the area substations do not have enough capacity to serve the new development.

To best serve customers with reliable power, distribution feeders are sized to carry existing and planned customer load. PGE's distribution system is designed to serve existing customer loads with adequate reserved capacity to pick up load in the event of a failure. The maximum design ampacity on our standard feeders is 900 amps. Some distribution feeders are sized larger to serve large industrial load and minimize the amount of infrastructure in a constrained space.

A substation's size is limited not only by the physical space inside the fence, but also by the number of feeder circuits that can be physically routed to the surrounding area's loads. Overhead feeder construction is the most cost effective and standard overhead construction is one feeder circuit on a pole line. For more feeder density, two overhead feeder circuits per pole line can be constructed when conditions allow it. Underground feeder construction has a higher cost than overhead construction but is often mandated by the local jurisdiction, especially in urban areas. For this reason, underground feeder construction is becoming more common than overhead feeder construction for new feeders. Thermal limits of underground feeder cable require spacing between multiple feeder circuit main line cables. Thermal limits for primary distribution lines are defined in **Table 4** and **Table 5**.

Table 4. 13 kV Overhead feeder thermal limits

Conductor	Winter (MVA)	Summer (MVA)
795 kcmil[1] ACSR[2]	27.9	18.9
795 kcmil AAC[3]	27.1	17.8
556 kcmil ACSR	22.3	14.7
556 kcmil AAC	21.6	14.3
336 kcmil ACSR	16.3	10.7
336 kcmil AAC	15.8	10.4
4/0 AWG[4] AAC	11.7	7.8
4/0 AWG ACSR	11.1	7.3

1. kcmil: measure of conductor size representing one thousand circular mils
2. ACSR (aluminum conductor steel-reinforced): galvanized steel conductor or conductors surrounded by one or more concentric layers of 1350-grade aluminum conductors
3. AAC (all aluminum conductor): high-purity, corrosion-resistant, concentric lay of 1350-grade aluminum conductors
4. AWG (American Wire Gauge): measure of conductor size as defined by American Society for Testing and Materials (ASTM) standards

Table 5. 13 kV Underground feeder thermal limits

Cable	Winter (MVA)	Summer (MVA)
750 kcmil Cu[1] - Dual run	26.7	24.9
1,000 kcmil Al[2] - Dual run	23.3	20.9
750 kcmil Al - Dual run	20	18.4
750 kcmil Al - Single run	12.2	11

1. Cu: denotes copper conductor
2. Al: denotes aluminum conductor

1.4 Evolution

The following chapters provide a more detailed description of each phase of the Distribution Planning process. The chapters follow the order of the four groups of Part 2 requirements in the DSP guidelines, illustrated in **Figure 6**.

The description of forecasting, grid needs, and solution identification is delivered in two sections: current state and evolution. The current state description provides an explanation of current practices. The evolution section briefly discusses the plan to incorporate additional information and capabilities as described in the DSP Guideline's Stage 2 and Stage 3 requirements.

Figure 6. DSP requirements summary