Chapter 4

Grid needs analysis

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"Prediction is very difficult, especially if it is about the future."

– Niels Bohr, Nobel prize winning physicist

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 environmental justice communities.[39] It's designed to improve safety, reliability, resilience and security, and apply an equity lens when considering fair and reasonable costs.

WHAT WE WILL COVER IN THIS CHAPTER

The analytical framework for identification of grid needs

A discussion of assessing risk within the distribution system

How grid needs are ranked and prioritized according to the Distribution Planning Ranking Matrix

Identifies 12 prioritized grid needs

This chapter provides an overview of PGE's current capabilities, distribution system analysis, the demands on that system, and how we prioritize grid needs. We describe the technical requirements needed to provide a safe, reliable and resilient system that provides adequate power quality to the customers it serves. We also discuss the process for identifying needs and constraints in the distribution system and include a review of our risk assessment framework.

Table 20 illustrates how PGE has met OPUC's DSP guidelines under Docket UM 2005, Order 20-485.[40]

Table 20. Distribution system overview: Guideline mapping

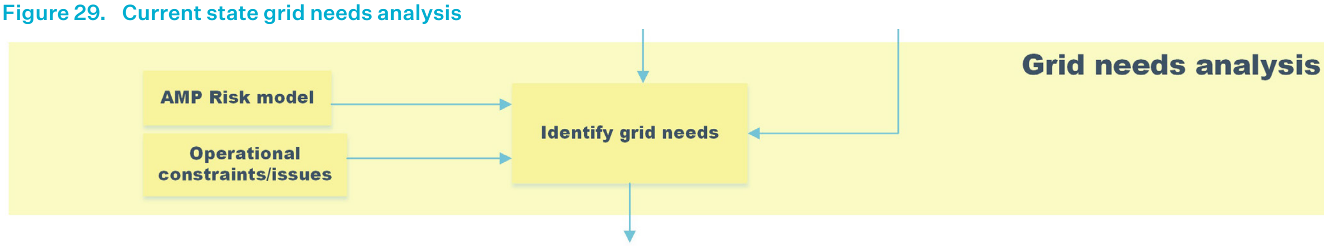
DSP guidelines	Chapter section
5.2.a	**Section 4.2, 4.3**
5.2.b	**Section 4.4**
5.2.c	**Section 4.5**
5.2.d	**Section 4.5**

39. PGE uses the definition of environmental justice communities under Oregon House Bill 2021, available at: https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB2021.
40. OPUC UM 2005, Order 20-485 was issued on December 23, 2020, available at: https://apps.puc.state.or.us/orders/2020ords/20-485.pdf.

4.2 Introduction

Distribution planning is informed by key drivers such as load growth forecasts, economic development, new large single loads, grid modernization, regulatory requirements, safety, reliability performance of the system, urban growth boundary expansion, and zoning changes. At PGE, we see the distribution grid as an evolving system that is at different stages of modernization. By responding to changes in the communities we serve, we can advance and improve distribution operations and customer service. Grid needs analysis is the process (depicted in **Figure 29**) by which we identify the impacts of these drivers on the distribution system.

Figure 29. Current state grid needs analysis



4.3 Assessing grid adequacy and identifying needs

Grid adequacy is assessed by determining existing system conditions, creating projections for future system conditions, and then determining mitigation strategies for system deficiencies. It requires existing system loading and performance conditions that are obtained from substation SCADA and metering sources, customer metering data, load projections from PGE's Corporate Planning team, Key Customer team, and Business Development team as well as directly from municipalities and customers.

Near-term studies are performed in the one- to five-year horizon for project development, and long-term studies, in the five- to ten-year horizon, are used to inform strategic substation and distribution infrastructure placement and land acquisition for future use. An example is a large swath of undeveloped industrial land. Studies would be performed on the anticipated customer load levels on the site. The existing electrical infrastructure in the area would be analyzed to determine how much load could be accommodated and what additional infrastructure, such as substations, would be required to serve the projected load. This information would be used to inform decisions on proactively purchasing property for a future substation site.

Existing conditions and future system conditions are evaluated by PGE's Distribution Planning team utilizing our engineering analysis software, CYME, to determine system deficiencies based on established criteria explained in the following sections. Using CYME, input from Distribution Operations engineers, and Distribution Planning engineers' technical knowledge of long-range plans for the system, multiple options to mitigate system deficiencies are developed.

4.3.1 CONTINGENCY ANALYSIS

Grid adequacy assessments are performed on worst-case system conditions. For most of PGE's system, this is during the summer, when system loading conditions are the highest and equipment and line thermal limits are at the lowest due to high temperatures. Two scenarios are evaluated, the system normal condition, referred to as N-0, and the system during a single outage, or contingency, referred to as N-1. N-0 refers to the system when all substation transformers and distribution feeders are in service and in their normal configuration. When a single substation transformer or a single distribution feeder is out of service, this is an N-1 condition. System loading information is obtained from PI Historian as well as customer metering data. This information is entered into CYME distribution analysis software, which is used to determine where system operating conditions are outside acceptable ranges.

PGE's system is designed to serve customers with adequate reserved capacity needed to allow timely restoration of service after an outage of one distribution power transformer or one distribution feeder (N-1 conditions). This is accomplished by limiting the peak loading of distribution transformers to 80% of capacity and limiting distribution feeders to 67% of capacity.

4.3.2 LOAD LIMITS

Loading limits are determined by ambient temperatures and industry standards for obtaining expected length of service before failure. Institute of Electrical and Electronics Engineers (IEEE) Standard C57.91 is applied for transformer loading.[41] Insulated Cable Engineers Association (ICEA) and IEEE standards are applied for feeder loading.[42] The system is also designed to maintain an acceptable voltage range, as defined by American National Standards Institute (ANSI) C84.1.[43] The primary voltage of the system is required to stay within +/- 5% from nominal.

4.3.3 SYSTEM MODELING

Once existing system deficiencies, if present, are determined, system loading conditions are modified in the CYME model to account for projected load growth. Data is collected from PGE's Corporate Planning team, Key Customer Management team, Business Development team, Design Project Manager team, the Distribution Operations Engineering team, as well as local and state agencies. This data is used to predict the amount and location of load growth that will occur in the one- to ten-year planning horizon. Loading and voltage conditions are then analyzed a second time to determine possible deficiencies that will likely occur during any known load ramp timeframe and five years out with potential, but not committed, load growth.[44] We modify the CYME model for the system until all existing and possible future deficiencies are corrected. Increasing the size of conductors, adding substation transformers, or adding new distribution feeders are examples of modifications to correct distribution system deficiencies in the CYME model.

4.4 Assessing reliability and risk

System reliability is determined by PGE's Distribution Planning team through two primary sources — historical outage information and existing and future system contingency analysis. Outage information is collected from our Outage Management System (OMS) and industry-specified indices are calculated according to IEEE Standard 1366 and IEEE Standard 1782 for every feeder by Asset Management Planning (AMP) team.[45]

Feeders showing poor performance based on these indices are evaluated for traditional wired solutions as well as modern techniques like distribution automation. In the future, non-wires solutions (NWS) may also be deployed to address reliability performance concerns. The PGE system is evaluated in CYME for the ability to continue to serve all customers during the outage of one transformer or one feeder. The existing system as well as the projected future state of the system are evaluated.

In addition to using industry standards and CYME, PGE uses the outputs of the economic life cycle models developed by the AMP team to identify concentrations of system risk. These models and outputs are discussed in **Section 4.4.1** and **Appendix H**. Reduction in system risk is primarily determined through analysis of PGE's assets with the Integrated Planning Tool (IPT) by the AMP group.

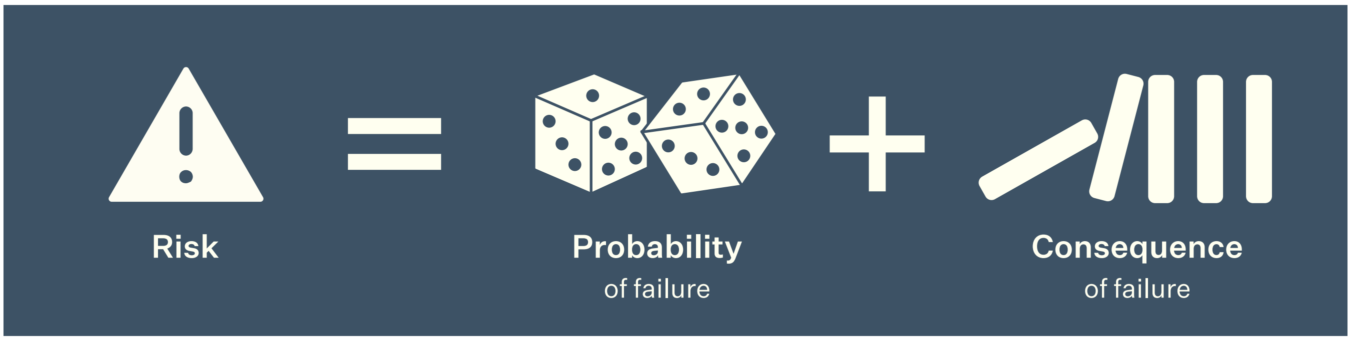
41. IEEE standards, available at: https://standards.ieee.org/.
42. ICEA standards, available at: https://www.icea.net/docs.
43. ANSI standards, available at: https://ansi.org/.
44. Historically, in most of PGE's system, the load growth has been relatively flat and any significant fluctuations in load have been due to weather, not actual new demand on the system. As a result, sometimes the forward-looking analysis has not been required.
45. IEEE Guide for Electric Power Distribution Reliability Indices," in IEEE Std 1366-2012 (Revision of IEEE Std 1366-2003), vol., no., pp.1-43, 31 May 2012, doi: 10.1109/IEEESTD.2012.6209381 and " in IEEE Std 1366-2012 (Revision of IEEE Std 1366-2003), vol., no., pp.1-43, 31 May 2012, doi: 10.1109/IEEESTD.2012.6209381.

4.4.1 RISK ASSESSMENT FRAMEWORK

PGE has an Asset Management program, which has a goal to cost effectively mitigate risk while achieving customer value. Our AMP team uses risk-based economic lifecycle models to prioritize long term capital investments. These models calculate the lowest cost of ownership. We determine the lowest cost of ownership as the optimal time to replacement of an asset which balances maintenance cost and the risk of owning and operating the existing asset compared to the cost of replacing the asset. Using the outputs of these models as a determinate for proactive asset replacement reduces risk of failure on the system, improves reliability, and improves the customer experience.

The approach PGE's AMP team takes to modeling assets is based on the fundamental concept of risk. Risk is defined as the product of annual probability of failure and consequence cost of failure (**Figure 30**). The cost includes reliability impacts to customers, load impacted from the failure, as well as environmental, safety and direct cost impacts to our company.

Figure 30. The risk equation



PGE's AMP team uses a suite of asset models combined with the IPT to assess projects on economic benefits and key risk and reliability metrics. The AMP team's asset models calculate annual probability of equipment failure and corresponding consequence costs of failure, resulting in annual risk cost streams. These risk cost streams are aggregated with annual maintenance and annualized capital costs to develop cost of ownership net present value (NPV) estimates for each asset.

The lifecycle cost values, combined with other key risk and reliability metrics, are used to evaluate projects. Risk, reliability, and lifecycle cost metrics are calculated for each asset using PGE's AMP team's asset risk models, which have been developed for multiple different transmission and distribution asset classes. Assets and their associated model outputs are combined to analyze potential projects using the IPT.

The annual failure probability is the likelihood an asset will have a repairable or non-repairable failure as a function of its age, condition and model.

Consequence cost of failure is the weighted average cost of repairable and non-repairable failure scenarios of the asset.

4.4.2 ASSET MODELS

PGE has developed 11 different transmission, sub-transmission, and distribution asset class models, identified in **Figure 31**. Within each model, PGE calculates risk using the definition from **Figure 30** for every individual asset on the system, which can then be aggregated to calculate the risk on the system at the asset class level.

Details of the calculation of both terms of the risk equation for these assets are discussed in **Appendix H**.

Figure 31. Existing asset models

Economic life cycle models

Substation assets	Distribution assets
✓ Transformer ✓ Circuit breaker ✓ Relay system ✓ SCADA system ✓ Switch	✓ UG cable ✓ Line transformer ✓ Recloser ✓ Regulator ✓ Switch ✓ Structures
Geographic risk	**Business case tools**
✓ Vegetation/ weather risk ✓ Wildfire risk ✓ Animal risk ✓ Public risk	✓ Risk register ✓ Integrated planning tool

4.5 Prioritized list of grid constraints

Currently, grid needs originating from PGE's Distribution Planning team are driven by loading on equipment. Substation transformers and distribution feeder lines that exceed planning criteria are identified as potential grid needs and prioritized using multiple factors into a same Distribution Planning Ranking Matrix. The ranking matrix is split into five different levels (**Figure 32**), with multipliers from five to one.

Each level of the Distribution Planning Ranking Matrix and the associated evaluation criteria is described in **Appendix I**.

Figure 32. Distribution planning ranking matrix

Level 5	Safety and customer commitment
Level 4	Impacts to other facilities
Level 3	Heavy loading, telemetry and substation risk
Level 2	Feeder risk, load growth, and redundancy
Level 1	System utilization and DG readiness

4.5.1 LIST OF GRID CONSTRAINTS

Utilizing the Distribution Planning Ranking Matrix, PGE prioritizes grid needs. The following distribution planning grid needs in **Table 21** were analyzed for solutions as part of the 2023 capital cycle, which began in 2021 and are based on 2020 loading information on equipment.

Table 21. List of prioritized grid needs

			Level score					
Priority	**PGE location**	**Grid need**	**5**	**4**	**3**	**2**	**1**	**Total**
1	Evergreen substation	Industrial load growth in North Hillsboro	75	40	18	14	2	**149**
2	St. Louis substation	Commercial load growth in Woodburn area and 57 kV system constraints	0	80	9	12	1	**102**
3	Silverton substation	Existing loading issues and industrial load growth in Silverton	75	0	9	12	0	**96**
4	Redland substation	Aging infrastructure, heavily loaded transformer and feeders, lack of telemetry east of Oregon City	0	20	36	26	2	**84**
5	Kaster substation	Substation with high arc flash concerns, commercial load growth in St Helens	75	0	0	8	0	**83**
6	Glisan substation	Industrial load growth in Gresham	75	0	0	6	0	**81**
7	Waconda substation	Commercial load growth south of Woodburn and 57 kV system constraints	0	60	3	14	1	**78**
8	Harrison substation	Capacity addition to implement other grid need mitigations, temporary equipment being used for support in inner SE Portland	0	60	3	10	0	**73**
9	Linneman substation	Residential load growth in the Happy Valley and Gresham areas, temporary equipment being used for support	0	20	18	20	0	**58**
10	Boring substation	Transformer failure resulting in capacity constraints, aging infrastructure in the Boring area	0	20	18	16	1	**55**
11	Glencullen substation	Capacity addition to implement other grid need mitigations in SW Portland, lack of SCADA telemetry, feeder reliability improvements	0	40	9	4	1	**54**
12	Scholls Ferry substation	Existing loading issues and residential development in the Murrayhill/Scholls areas resulting in capacity constraints	0	0	18	20	0	**38**

4.5.2 GRID NEEDS THAT WILL BE CONSIDERED IN FUTURE PLANNING CYCLES

PGE's Distribution Planning Ranking Matrix is continuously evolving to account for the changing planning environment. Based on the current ranking criteria, the grid needs listed below will be re-evaluated in future planning cycles. Typically, each planner will take on one to three grid needs depending on complexity. The prioritization framework and matriculation of grid needs will be re-evaluated as equity is incorporated into the ranking matrix.

Multiple grid needs from prior planning cycles already have solutions proposed and projects defined, but the projects were deferred for various reasons (most notably COVID-19-related challenges). These projects have been delayed long enough that the grid needs must be re-evaluated and re-prioritized in the 2024 capital planning cycle. These grid needs are listed in **Table 22**.

Table 22. Grid needs that need to be re-evaluated

PGE location	Need/constraint
Arleta substation	Heavily loaded transformer and feeders
Centennial substation	Heavily loaded transformer
Eastport substation	Heavily loaded feeder (currently under consideration for a non-wires solution)
Hogan South substation	Heavily loaded transformer and feeders
Mt Pleasant substation	Heavily loaded transformer and feeders

The grid needs in **Table 23** have been identified and will be included in the grid needs prioritization using the Distribution Planning Ranking Matrix for the 2024 capital planning cycle.

Table 23. Grid needs that are ready to be ranked

PGE location	Need/constraint
Bell substation	Heavily loaded feeder
Bethany substation	Heavily loaded transformer
Canby substation	Heavily loaded transformer and feeder
Carver substation	Heavily loaded transformer
Cedar Hills substation	Heavily loaded feeder
Clackamas substation	Heavily loaded feeder
Delaware substation	Heavily loaded feeder
Elma substation	Heavily loaded feeder
Fargo substation	Heavily loaded transformer
Glencoe substation	Heavily loaded feeder
Harmony substation	Heavily loaded transformer
Hillsboro substation	Heavily loaded feeders
Huber substation	Heavily loaded transformers and feeders
Indian substation	Heavily loaded transformer and feeders
Kelley Point substation	Heavily loaded feeder
Molalla substation	Heavily loaded feeders
Mt Angel substation	Heavily loaded feeder
North Plains substation	Heavily loaded feeder
Sandy substation	Heavily loaded transformer and feeders
Swan Island substation	TE growth
Sylvan substation	Heavily loaded transformer
Tabor substation	Heavily loaded transformer
Tualatin substation	TE growth
Twilight substation	Heavily loaded feeder

4.5.3 RISKS TO TIMELINE AND ADDRESSING GRID CONSTRAINTS

Grid needs or constraints may take many years to be addressed, depending on the solution identified to mitigate the constraint. Supply chain constraints have become a significant roadblock in implementing projects to address grid constraints in the desired timeframe. Other factors that could delay implementation of a project to address grid constraints are permitting, easement and/or land acquisition, labor shortages and capital budget constraints.

4.6 Evolution

PGE's AMP team is evolving their model to incorporate resiliency. As a customer centric utility, we need to address both the reliability and resiliency needs on our grid. We have outlined below the key milestones that need to be addressed or adapted.

> Resiliency is defined as being able to anticipate, adapt to, withstand, and quickly recover from disruptive events.

- **Risk Framework** — The risk methodology PGE has developed and utilized for reliability can be adapted to calculate risk mitigation for resiliency. The overall methodology is the same calculation, where risk equals probability of failure multiplied by consequence of failure; however, instead of using a reliability-focused consequence impact, "blue sky" event, we will update the consequence impact to a "dark sky" event. "Blue sky" events are traditional outage events that are less than 24 hours in duration, such as, cable failure, vegetation or animal related outage, or minor storm. "Dark sky" events are extreme events that result in outage duration greater than 24 hours, such as a wildfire event or significant ice storm. To properly reflect the customer experience in these "dark sky" events, we need to acquire updated outage duration assumptions and resiliency-based value of service (VOS) measures.
- **VOS** — As part of the risk-based methodology, PGE uses reliability-based VOS measures from a CPUC-approved PG&E study, which was developed in 2012. This study is out of date and does not capture resiliency-related events (such as outages greater than 24 hours). We plan to survey our own customer base to acquire resiliency VOS measures along with updated reliability VOS measures. Our goal for a new study is to have more current data that reflects our customer-base and captures value of service for both reliability and resiliency events. Conducting a survey of our customer base will enable our teams to better understand how customers value both reliability and resiliency and what we should take into account when making decisions.
- **Resiliency Metrics** — PGE has identified changes to Customer Experiencing Long Interruption Durations (CELID) as the primary resiliency metric. Our teams are working through various ways to leverage this and other metrics to evaluate resiliency.

As stated earlier, PGE's corporate load forecast first incorporated a DER forecast in March of 2022. We refreshed our DER forecast in April of 2022. This forecast will be used in the 2024 capital planning cycle to factor into the grid needs identification. In addition, an equity metric will be incorporated into the Distribution Planning Ranking Matrix. As the regulatory landscape changes with regards to generation investments by utilities and the planning process in general evolves, the ranking matrix discussed in **Section 4.5** will be re-evaluated.