BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PCN 6

Petition for a Certificate of Public Convenience and Necessity

PORTLAND GENERAL ELECTRIC COMPANY

REDACTED Direct Testimony of

Dr. Ian Beil

Apri1 17, 2024

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I. Introduction

Q. Please state your name, business address, and present position with Portland General Electric Company (PGE or the Company).

A. My name is Dr. Ian Beil. My business address is 121 SW Salmon Street, Portland, OR 97204. My current position at PGE is Manager, Transmission Planning.

Q. Briefly describe your educational background and relevant licenses or certificates.

A. I have a PhD in Electrical Engineering from the University of Michigan, Ann Arbor.

Q. Please describe your work experience.

A. I have nine years' experience in the power system industry, first as a consultant, and then with PGE. I joined PGE in 2018 as a Transmission Planning engineer, then spent time working on the Grid Edge Solutions team, and now serve as Manager of the Transmission Planning team at the Company. Prior to my time at PGE, I worked in power systems research at the university level as well as at Los Alamos National Laboratory. I have also served as an adjunct faculty member at Portland State University's Maseeh College of Engineering for the past five years, teaching graduate level courses on power system planning and design.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the need for the Rosemont-Wilsonville Transmission Line (the Rosemont-Wilsonville Line), which is an overhead, 115-kilovolt (kV) transmission line totaling 7.4 miles in length located within Clackamas and Washington Counties, with the line's termini being the existing Rosemont and Wilsonville Substations. The Rosemont-Wilsonville Line is a critical component of the Tonquin Project, which will include significant upgrades to PGE's distribution and transmission systems, including the new Tonquin substation in Washington County. The Rosemont-Wilsonville Line is the only portion of the Tonquin Project for which PGE requires a Certificate of Public Convenience and Necessity (CPCN). However, the need for the Rosemont-Wilsonville Line is driven by the same factors as the larger project as a whole and all components of the Tonquin Project, including the distribution and transmission upgrades, are designed as an integrated solution. Therefore, while my testimony will focus on the Rosemont-Wilsonville Line, I will address the need for the entire Tonquin Project. In particular, my testimony will demonstrate that the Tonquin Project, including the Rosemont-Wilsonville Line, is necessary to PGE's provision of adequate, safe and reliable service in Portland's south metropolitan area, including Tualatin, Sherwood, Wilsonville, West Linn, Lake Oswego, and unincorporated areas of Clackamas County and Washington County (hereinafter, South Metro area).[1]

Q. Why is PGE constructing the Tonquin Project, including the Rosemont-Wilsonville Line?

A. The Tonquin Project, including the Rosemont-Wilsonville Line, is critical for the Company's ability and obligation to provide adequate, safe and reliable energy services to its customers in the rapidly growing South Metro area. In particular, the project is needed to accommodate existing and anticipated load growth in the area due to semiconductor manufacturing, general commercial and residential growth, and expected public infrastructure.

[1] Technically, the area described above refers to the southern portions of PGE's western and eastern service regions.

Most immediately, the Tonquin Project will accommodate new load from essential public infrastructure. The growing populations in Beaverton, Tualatin, and Hillsboro have increased the need for drinking water supplied to the area; in response, the Willamette Water Supply System (WWSS) Commission is in the process of building a new water treatment plant near SW Tualatin-Sherwood Road on property that is in the City of Sherwood. As of July of 2025, operation of this water treatment plant will require 11.8 megavolt-amperes (MVA)[2] of electricity. The new plant will be located between PGE's Tualatin and Six Corners Substations, both of which are already nearing their seasonal thermal limits. Because of these constraints, the existing substations cannot support the additional 11.8 MVA load.

As I will explain in more detail below, PGE performed a comprehensive distribution and transmission analysis that was memorialized in a white paper published in January 2020 (January 2020 Study), which determined the impact the new load would have on the existing distribution and transmission systems in the area (attached as Highly Protected Exhibit PGE/101). Due to existing load conditions on the feeders and transformers adjacent to the proposed water treatment plant, the January 2020 Study showed that accommodation of the new load would require construction of a new substation, upgrades to the distribution feeders and transformers associated with the new substation, as well as upgrades to the transmission system (including building

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[2] MVA represents the apparent power in an electrical system. It is the combination of real power (in megawatts or MW) and reactive power (in megavolt-amperes reactive or MVAR) and represents the total power in an AC circuit. Note that in the initial load request, the predecessor of the WWSS Commission, the Willamette Water Supply Program (WWSP), indicated that operations of the water treatment plant would require approximately 11 MVA of electricity. The WWSS Commission has since revised this figure to 11.8 MVA.

approximately 5.0 miles of new 115-kV overhead transmission lines along the Rosemont-Wilsonville segment).

With respect to PGE's transmission system in particular, the January 2020 Study showed that the addition of the new load from the water treatment plant would result in **Begin Highly Protected/**[redacted]**/End Highly Protected** contingency event scenarios that could cause overloads (i.e., greater than 100 percent of the facility rating) on two 115-kV lines: **Begin Highly Protected/**[redacted]**/End Highly Protected**.

PGE performed an updated transmission power flow analysis in 2024 (2024 Study) (attached as Highly Protected Exhibit PGE/106) and the results now indicate several more N-1-1 contingency combinations that may cause an overload (i.e., over 100 percent of the facility rating). Specifically, during peak summer conditions, there are now **Begin Highly Protected/**[redacted]**/End Highly Protected** contingency event scenarios that may cause overloads (i.e., greater than 100 percent of the facility rating) on various 115-kV transmission lines in the area, as well as **Begin Highly Protected/**[redacted]**/End Highly Protected** contingency events where near overloads (i.e., 95-100 percent of the facility rating) are likely. The increase in the number of observed overloads between the studies conducted in 2020 and those conducted in 2024 is due to an increase in the projected load in the South Metro area. These load projections incorporate the latest available information for the area, including increased expectations for industrial load such as semiconductor manufacturing, increased commercial activity, and residential load growth from increasing population and greater prevalence of air conditioning and electric vehicles.

In both the original January 2020 Study and the updated 2024 Study, the models showed that ameliorative actions such as switching substations to alternate sources or adjusting generation patterns would not be sufficient to protect against overload; only direct shedding or curtailing of customer loads would bring the transmission facilities within rated limits. Construction of the Tonquin Project, including the **Begin Highly Protected/**[redacted]**/End Highly Protected**. Accordingly, based on the January 2020 Study and updated analysis in the 2024 Study, the Tonquin Project, including the Rosemont-Wilsonville Line, is urgently needed to resolve and reduce these potential overloads and near-overloads.

II. Description of the Tonquin Project

Q. Please summarize the Tonquin Project components.

A. The Tonquin Project components include the construction of the new Tonquin Substation, building and upgrading associated distribution feeders and transformers, and upgrades to the transmission system, including the Rosemont-Wilsonville Line.

Q. Does PGE require a CPCN for all components of the Tonquin Project?

A, No. Under ORS 758.015, PGE requires a CPCN only for the new construction transmission line components of the Tonquin Project "which will necessitate a condemnation of land or an interest therein."[3] However, as noted above, I will discuss

[3] ORS 758.015(1) ("When any person, as defined in ORS 758.400, providing electric utility service, as defined in ORS 758.400, or any transmission company, ***proposes to construct an overhead transmission line which will necessitate a condemnation of land or an interest therein***, it shall petition the Public Utility Commission for a certificate of public convenience and necessity….") (internal emphasis added).

all the Tonquin Project components in my testimony to provide necessary context for PGE's transmission analysis supporting the Rosemont-Wilsonville Line.

A. <u>Tonquin Substation</u>

Q. Please describe the new Tonquin Substation.

A. The Tonquin Substation is currently under construction on the southwest corner of the PGE-owned Integrated Operations Center (IOC) property (shown in Figure 1 below), a relatively short distance from the water treatment plant. The substation is designed as a 115-kV five-position ring bus with three 115-kV line positions and two transformer positions. Building the Tonquin Substation will help accommodate the new load addition that the water treatment plant will introduce.

Highly Protected Figure 1: Tonquin Substation Location on IOC Property

Begin Highly Protected/

[redacted]

/End Highly Protected

B. Distribution System Feeders and Transformers

Q. Please describe the Tonquin Project upgrades to the distribution system feeders and transformers associated with Tonquin Substation.

The Tonquin Project includes construction of four new distribution feeders Tonquin-Hoodview, Tonquin-Driver, Tonquin-Crystal, Tonquin-Springs, and a feeder improvement on Six Corners-13359.

The Tonquin Project also includes construction of two new transformers associated with the Tonquin Substation. The two new transformer positions will be installed as **Begin Highly Protected/**[redacted]**/End Highly Protected**, but the substation will be built to accommodate a future upgrade **Begin Highly Protected/**[redacted]**/End Highly Protected**.

C. Transmission System

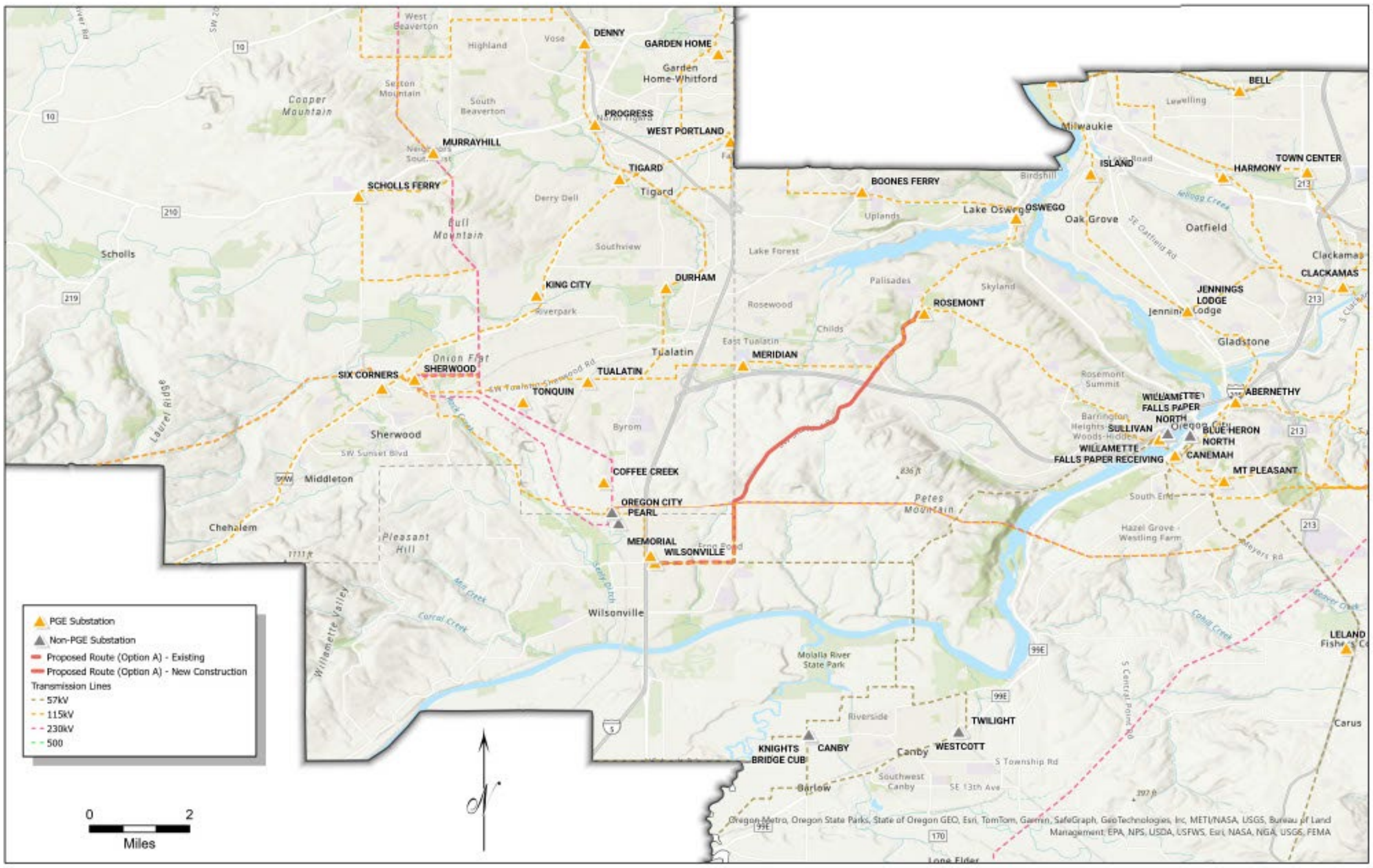
Q. Please describe the Tonquin Project upgrades to the transmission system.

A. For ease of understanding, I will separate the transmission upgrades included in the Tonquin Project into three broad categories.

First, PGE will repurpose the existing McLoughlin-Wilsonville 115-kV line into the Rosemont-Wilsonville Line and the McLoughlin-Tonquin 115-kV line.

The Rosemont-Wilsonville Line connects the existing Rosemont and Wilsonville Substations, providing a **Begin Highly Protected/**[redacted]**/End Highly Protected** source of power into the Rosemont Substation and replacing two sources of power into the Wilsonville Substation for system reliability. The line will have a total length of 7.4 miles, approximately 5.0 miles of which will be new construction. The new construction portion of the line starts at Rosemont Substation and double-circuits with the existing Meridian-Rosemont 115-kV line until the roundabout at Borland Road, which is a distance of approximately 1.4 miles. From Borland Road the new construction portion of the line then transitions to the installation of new 115-kV structures along the existing Rosemont-Mossy Brae 13-kV distribution feeder right-of-way for approximately 0.3 miles. New structures will be constructed for the next 0.3 miles along the Interstate 205 Freeway crossing where there are not currently any electrical lines. Next, new 115-kV structures will again utilize the existing Meridian-Meridian-13 and Wilsonville-Boeckman 13-kV distribution rights-of-way for approximately 3.0 miles. Finally, the line will tie into the repurposed, existing McLoughlin-Wilsonville 115-kV line for 2.4 miles until it connects to the Wilsonville Substation. Because it is possible that PGE will need to initiate condemnation proceedings to acquire easements for certain parcels along the new construction portion of this segment, a CPCN is required for the Rosemont-Wilsonville Line.

Figure 2: Map of Rosemont-Wilsonville 115-kV Transmission Line



The McLoughlin-Tonquin 115-kV transmission line will connect the McLoughlin Substation to the proposed Tonquin Substation by passing through the existing Coffee Creek Substation. By reconfiguring the existing McLoughlin-Wilsonville transmission line into the proposed McLoughlin-Tonquin line, PGE is able to provide additional power sources into the Rosemont, Wilsonville, Coffee Creek, and Tonquin Substations. The McLoughlin-Tonquin line will start at McLoughlin and use the existing 115-kV line until Pole **Begin Highly Protected/**[redacted]**/End Highly Protected**. The line will then continue on the idle tap (starting with Pole **Begin Highly Protected/**[redacted]**/End Highly Protected**) and continue near the end of the idle tap at

Pole **Begin Highly Protected/**[redacted]**/End Highly Protected** (crossing over Interstate 5 and avoiding having to build another transmission line over the freeway). The first new portion of the McLoughlin-Tonquin line will be built from Pole **Begin Highly Protected/**[redacted]**/End Highly Protected** to the Coffee Creek Substation. The second new portion of the line will go from the Coffee Creek Substation to the Tonquin Substation. The existing Coffee Creek alternative tap northwest of Pole **Begin Highly Protected/**[redacted]**/End Highly Protected** will be idled up to the connection with the Meridian-Sherwood 115-kV line. In total, there are approximately 3.0 miles of new overhead transmission along the McLoughlin-Tonquin line. Construction of this line is scheduled to begin in July 2024, and it will be complete in December of 2025.

Second, PGE is constructing the new Meridian-Tonquin and Sherwood-Tonquin 115-kV transmission lines, each requiring approximately 0.3 miles of new transmission line. These two lines provide the first two sources required to energize the proposed Tonquin Substation. PGE began construction on these lines in October 2023, and they are expected to be completed in May 2024.

Finally, PGE is rebuilding portions of the existing Sherwood-Wilsonville 115-kV transmission line, which is approximately 6.3 miles in total length and is required for various aspects of the Tonquin Project. Specifically, the line construction will provide space for the McLoughlin-Tonquin and Bonneville Power Administration (BPA) Pearl-Sherwood transmission lines near the BPA Oregon City Substation. In addition, the line will continue to provide a second source of power to the Coffee Creek Substation. Finally, once the proposed Memorial Substation is built, the Sherwood-Wilsonville line will be split to create the Memorial-Sherwood and Memorial-

Wilsonville 115-kV transmission lines, respectively. Construction work on these rebuilds is scheduled to begin in October 2024 and to be completed by December 2025.

Q. Please explain why PGE is not seeking a CPCN for all of the new transmission line segments described above.

A. PGE already has all land rights needed for construction of all other transmission segments associated with the Tonquin Project and therefore will not need condemnation authority for any segment ***except*** the Rosemont-Wilsonville Line. Therefore, PGE is seeking a CPCN for the Rosemont-Wilsonville Line only.

III. Identified Need for the Tonquin Project and Rosemont-Wilsonville Line

Q. When did PGE first identify a need for the Tonquin Project?

A. In 2017, the Willamette Water Supply Program (WWSP) submitted a load request to PGE informing the Company of its intention to construct a new water treatment plant near SW Tualatin-Sherwood Road on property that is now in the City of Sherwood. The load request indicated that operation of the water treatment plant would require PGE to accommodate approximately 11 MVA of load.[4]

Over the following several years, PGE continued discussions with the WWSP and its successor, the Willamette Water Supply System (WWSS) Commission. Because it was self-evident that the addition of the new load would require a new substation, PGE worked to locate an appropriate site for the substation. Subsequently, PGE began work in earnest to identify any upgrades that would be required to serve the new load. In particular, PGE performed a robust transmission and distribution

[4] The WWSS Commission has since revised this load figure to 11.8 MVA.

analysis, which was memorialized in a white paper published in January 2020.[5] It was in this analysis that PGE first determined the need for the Tonquin Project and the Rosemont-Wilsonville Line.

A. Applicable Standards, Guidelines, and Methodologies for Distribution and Transmission Planning Analyses

1. Loading Guidelines for Distribution System

Q. Please describe the applicable standards for assessing capacity limitations on PGE's distribution system.

A. While there are no external standards for assessing capacity limitations on electric utility distribution systems, PGE has developed internal loading guidelines for distribution feeders and transformers. These guidelines are designed to ensure that PGE's system operates efficiently and reliably.

Q. What are PGE's loading guidelines for distribution feeders and transformers under normal operating conditions?

A. The loading guideline for a distribution feeder under normal operating conditions is **Begin Highly Protected/**[redacted]**/End Highly Protected** percent of their seasonal (summer/winter) thermal rating, which allows for load shifting in the event of planned outages for construction, equipment failures, unplanned outages, and other emergencies. The loading guideline for substation distribution power transformers is **Begin Highly Protected/**[redacted]**/End Highly Protected** percent of their Loading Beyond Nameplate Rating.

[5] Highly Protected PGE/101.

2. Requirements for Transmission System Reliability

Q. Please describe PGE's responsibility for maintaining reliability on its transmission system.

A. In 2005, Congress directed the Federal Energy Regulatory Commission (FERC) to establish reliability standards to ensure the safe and reliable operation of the Nation's Bulk Electric System (BES).[6] The following year, FERC adopted rules to implement the statute,[7] and delegated these responsibilities to the North American Electric Reliability Corporation (NERC).[8]

NERC established various reliability standards, including transmission system planning (TPL) performance requirements (Reliability Standards). NERC's Reliability Standards establish, among other things, "Transmission system planning performance requirements within the planning horizon to develop a [BES] that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies."[9] These Reliability Standards, along with regional planning criteria (i.e., regional planning criteria established by the Western Electricity Coordinating Council (WECC)) and utility-specific planning criteria, define the minimum transmission system requirements to safely and reliably serve customers.

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[6] 16 U.S.C. § 824o.

[7] *In re Electric Reliability Standards Rulemaking*, 71 FR 8662-01, Docket RM05-30-000; Order No. 672 (Feb. 3, 2006).

[8] *In re NERC Certification*, 116 FERC ¶ 61,062 (July 20, 2006), *aff'd Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[9] *See* NERC Reliability Standard TPL-001-5.1 – Transmission System Planning Performance Requirements , Section A(3) at 1, *available at* https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.1.pdf (PGE/102, Beil/1) [hereinafter, "NERC Reliability Standard TPL-001-5.1"].

Q. Please describe the relevant NERC Reliability Standards for PGE transmission planning purposes.

A. NERC Reliability Standard TPL-001 is relevant to PGE's transmission planning, and in particular, NERC Reliability Standard TPL-001-5.1. NERC Reliability Standard TPL-001-5.1 defines a number of credible contingencies that must be studied for planning purposes, including: (1) single element outages of transmission lines, transformers, generators and shunt devices (N-1 or P1); (2) bus outages and breaker failure outages (P2); (3) double outages of one transmission element followed by a subsequent loss of a second element (N-1-1 or P6); and (4) simultaneous outages of common-corridor transmission elements (N-2 or P7).[10] The standard specifies acceptable post-contingency states and allowable transmission operator actions.[11]

Q. Please describe an N-1-1 contingency event in more detail.

A. An N-1-1 contingency event describes two transmission system elements out of service at the same time, but due to independent causes. An example of an N-1-1 contingency event would be a planned outage of one 115-kV transmission line followed by an unplanned outage of any additional element in the system being used to continue service with the initial element out. Category P6 outages, as defined in NERC Reliability Standard TPL-001-5.1, are equivalent to N-1-1 contingencies.

Q. What is the relevant WECC Regional Criterion for PGE's transmission planning purposes?

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[10] *See* NERC Reliability Standard TPL-001-5.1, Table 1 – Steady State & Stability Performance Planning Events at 21-25 (PGE/102, Beil/21-25).
[11] *See* PGE/102, Beil/21-25.

A. PGE's transmission system must meet or exceed WECC Regional Criterion TPL-001-WECC-CRT-3.2. This criterion applies to all transmission planning studies conducted within the Interconnection of WECC and is intended to "facilitate coordinated near-term and long-term transmission planning within the Interconnection of [WECC], and to facilitate the exchange of the associated planning information for normal and abnormal conditions."[12] This criterion specifies voltage stability requirements, including requirements for steady-state voltages at all applicable BES buses, allowed post-contingency steady-state voltage deviation, allowed voltage recovery parameters and timing after fault clearing, and allowed voltage dips for contingencies without a fault.[13]

Q. How does PGE ensure compliance with NERC Reliability Standards and WECC Regional Criteria?

A. PGE plans, designs, and operates its transmission system to meet or exceed NERC Reliability Standards for BES and WECC regional standards and criteria. To ensure compliance with applicable Reliability Standards, PGE conducts an annual system assessment to evaluate the performance of the Company's transmission system and to identify system deficiencies (TPL Assessment).[14]

The annual system assessment is comprised of steady state, stability, and short circuit analyses to evaluate peak and off-peak load seasons in the near-term (years one through five) and long-term (years six through 10) planning horizons.[15] PGE maintains

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[12] *See* WECC Regional Criterion TPL-001-WECC-CRT-3.2 – Transmission System Planning Performance, Section 3 at 1 (effective June 18, 2019), *available at* https://www.wecc.org/Reliability/TPL-001-WECC-CRT-3.2.pdf. (PGE/103, Beil/1) [hereinafter, "WECC Regional Criterion TPL-001-WECC-CRT-3.2"].
[13] PGE/103, Beil/3.
[14] 2023 PGE Transmission Planning Study Methodology at 1 (June 26, 2023), *available at* http://www.oasis.oati.com/woa/docs/PGE/PGEdocs/Study_Methodology_2023.pdf (PGE/104, Beil/1).
[15] *See* PGE/104, Beil/1.

system models within its planning area for performing the studies required to complete the system assessment.[16] The system assessment is performed using power flow base cases maintained by WECC in accordance with the MOD-032 Reliability Standard and developed in coordination among all transmission planning entities in the Western Interconnection.[17] These base cases include load and resource forecasts along with planned transmission system changes for each of the future year cases and are intended to identify future system deficiencies to be mitigated.

The load model used in the studies is obtained from PGE's corporate forecast, and reflects demand level for peak summer, peak winter, and off-peak spring conditions.[18] Known outages of generation or transmission facilities with durations of at least six months are appropriately represented in the system models.[19]

As part of the annual system assessment, corrective action plans are developed to mitigate identified deficiencies, and may prescribe construction of transmission system reinforcement projects or, as applicable, adoption of new operating procedures to achieve the required system performance throughout the planning horizon.[20] In certain instances, operating procedures prescribing action to change the configuration of the transmission system can prevent deficiencies from occurring when there are two back-to-back (N-1-1) (or concurrent) transmission system events with allowed system adjustments between two events in the form of an operating procedure. For general

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[16] *See* PGE/104, Beil/1.
[17] *See* PGE/104, Beil/1. Electrical facilities modeled in the base cases have established ratings, as defined in PGE's "Facility Ratings Methodology" document and in accordance with the FAC-008 Reliability Standard. *See id.* A facility rating is determined based on the most limiting component in each transmission facility, in accordance with the FAC-008 Reliability Standard. *See id.*
[18] PGE/104, Beil/1.
[19] PGE/104, Beil/1.
[20] PGE/104, Beil/2.

planning purposes, PGE Transmission Planning attempts to mitigate all observed transmission element overloads (i.e., any loading that is greater than 100 percent of the designating planning rating of the transmission element) for all contingencies specified in NERC Reliability Standard TPL-001-5.1.

Q. What standard controls the facility rating and system operating limits?

A. NERC Reliability Standard FAC-008-5 is applicable to Transmission Owners (TO) and Generator Owners (GO), which are required to determine facility ratings (normal and emergency) with respect the most limiting piece of applicable equipment.[21] The purpose of NERC Reliability Standard FAC-008-5 is to ensure that facility ratings used in the reliable planning and operation of the BES are determined based on technically sound principles.[22] A facility rating is essential for the determination of system operating limits.[23]

B. <u>Analysis of Distribution System</u>

Q. Why are you discussing PGE's distribution system analysis in this testimony?

A. We designed the Tonquin Project as an integrated solution that would address both transmission and distribution constraints caused by projected load growth in the South Metro area. Importantly, PGE's distribution system analysis and chosen upgrades informed both the Company's transmission analysis and transmission configuration option that ultimately became the Tonquin Project transmission facilities, including the Rosemont-Wilsonville Line. Accordingly, discussion of the Company's distribution system analysis and chosen distribution system upgrades provides necessary context

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[21] NERC Reliability Standard FAC-008-5 – Facility Ratings at 1, *available at* https://www.nerc.com/pa/Stand/Reliability%20Standards/FAC-008-5.pdf (PGE/105, Beil/1).
[22] *See* PGE/105, Beil/1.
[23] *See* PGE/105, Beil/1.

for the need of the Tonquin Project transmission facilities, including the Rosemont-Wilsonville Line.

Q. Did PGE's January 2020 Study find that upgrades to the Company's distribution system were necessary?

A. Yes, and as discussed above, these necessary distribution system upgrades are also considered Tonquin Project components. A CPCN is not required for non-transmission line components of a project.

Q. Please describe the existing distribution feeders adjacent to the planned water treatment plant.

A. The feeders that serve the general area of the planned water treatment plant include the Tualatin-Cipole feeder from the Tualatin Substation and the Six Corners-Six Corners 13 feeder from the Six Corners Substation.

Q. Based on the January 2020 Study, what was the existing loading status of the Tualatin-Cipole and Six Corners-Six Corners 13 feeders, along with their respective substation transformers?

A. **Begin Highly Protected/**[redacted]**/End Highly Protected**

Highly Protected Table 1: Loading Status of Transformers and Feeders Adjacent to WWSP Load

Begin Highly Protected/

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]

/End Highly Protected

Importantly, Table 1 shows the status of the distribution system ***prior to the addition of the anticipated new load associated with the water treatment plant***. Adding the estimated load of 11.8 MVA from the water treatment plant to each of these feeders and associated transformers would push them well beyond the loading guidelines for the distribution feeders and substation transformers during peak summer conditions.

Q. Please describe PGE's methodology for its distribution system analysis.

A. PGE primarily assessed the Tualatin Substation and Six Corners Substation, along with all of their 13-kV feeders. The surrounding substations and feeders were also considered in the study for N-1 outage scenarios. The distribution studies were performed using EATON's CYME Power Engineering Software CYMDIST with the most current database assembled in March 2019 for system equipment and configuration.

For the load allocation used in the studies, the 2018 summer peaks for megawatts (MW) and megavolt-amperes reactive (MVAR) were found at each substation transformer and each feeder was loaded to its respective transformer peak date and time. In addition to these coincidental feeder loads, each load was scaled using a 1-in-3 peak summer loading condition factor, which corresponds to a daily average temperature of 81 degrees Fahrenheit. In this case the 1-in-3 peak summer loading factor for summer 2018 was 0.96. This indicates that the summer 2018 daily average temperatures during the summer peak load days were higher than an average of 81 degrees Fahrenheit, and thus the summer 2018 peak load values were multiplied by the factor of 0.96 to reduce the loading to that of a 1-in-3 event.

In addition, to account for load growth in the area, PGE applied a load growth scaling factor to the loads. The scaling factor of 1.05 was derived from the PGE system-wide load forecast and the predicted 2024 PGE system summer peak, which was 5 percent higher than 2018 summer peak load. Lastly, a load addition of 11 MVA with a lagging power factor of 95 percent was added to simulate the future load from the water treatment plant.

Q. Did PGE assess multiple distribution system scenarios in the January 2020 Study?

A. Yes. PGE performed a base case study without the new Tonquin Substation; a study with the new Tonquin Substation but without any feeder additions or improvements (Option A); and two studies with the new Tonquin Substation along with two options of area feeder additions and improvements—Option B (Tonquin Substation with Baseline Feeder Improvements) and Option C (Tonquin Substation with All Feeder Improvements).

Q. How did PGE assess these distribution system scenarios?

A. For each proposed distribution option, the cost of the project was weighed against the estimated benefit of that option. Some examples of estimated benefits include decreased outage probability, decreased outage duration, decreased asset failure probability, and decreased asset failure impact.

Q. Please describe the distribution system configuration option that PGE chose.

A. PGE chose the Option B distribution system configuration because it provided the most benefits in relation to cost. Option B includes the construction of the new Tonquin Substation, distribution feeders Tonquin-Hoodview, Tonquin-Driver, Tonquin-Crystal, Tonquin-Springs, and a feeder improvement on Six Corners-13359. Tonquin Substation will be constructed as a 115-kV five-position ring bus with three 115-kV line positions and two transformer positions. These two transformer positions will start out as **Begin Highly Protected/**[redacted]**/End Highly Protected**, but the substation will be built to accommodate **Begin Highly Protected/**[redacted]**/End Highly Protected** such that these transformers can be upgraded in the future.

Q. What are the benefits of the Option B distribution system configuration?

A. There are several reliability benefits. First, with the addition of new general-purpose feeders to the Tonquin Substation, heavy loading of the surrounding area feeders and transformers will be reduced by up to 14 MVA during peak loading. Decreased loads allow for faster and more comprehensive switching in outage situations, which will improve system functionality. These new feeders will also increase system reliability by an estimated 1,500 customer interruptions and an estimated 438,000 customer minutes interrupted the first year after the feeders and upgrades are completed. Each year after implementation these estimated benefits will increase compared to doing no distribution upgrades as the existing distribution system would have aged more.

Second, this proposed configuration will offload portions of the **Begin Highly Protected/**[redacted]**/End Highly Protected**. Additionally, the **Begin Highly Protected/**[redacted]**/End Highly Protected** will also be partially offloaded as a result of these load transfers.

Third, the Tonquin-Driver and Tonquin-Hoodview distribution feeders will lighten the load on many of the heavily loaded feeders and transformers. Although not analyzed as part of PGE's January 2020 Study, the additional capacity that the two new Tonquin feeders provide creates an opportunity for load balancing to be done at Tualatin Substation to relieve the remaining heavily loaded feeders and transformers.

Fourth, the new feeders provided in Option B also help decrease N-1 contingencies. As compared to the base case study (Option A), which has no additional Tonquin feeders, the number of customers that would experience low voltage is lower for every feeder outage and also in normal configuration. Additionally, while Option A has overloaded cable/conductor for two of the feeder outages, Option B shows that no feeder outage caused overload conditions when restoring load with the surrounding feeders.

C. <u>Transmission Analysis</u>

Q. Please describe the existing 115-kV transmission system in the South Metro area.

A. The existing 115-kV transmission system in the South Metro area that was studied in PGE's January 2020 Study is shown in Figure 3 below, which provides a one-line diagram of the existing 115-kV infrastructure in the area (before construction of the Tonquin Substation).

Highly Protected Figure 3: Existing 115-kV Transmission System in South Metro Area
Begin Highly Protected/

[redacted]

/End Highly Protected

Q. Please describe the methodology used by PGE for its January 2020 Study.

A. In order to assess the impacts of the new load associated with the new water treatment plant, PGE Transmission Planning employed the typical study methodologies outlined above with respect to NERC Reliability Standard TPL-001. PGE Transmission Planning also considered voltage requirements as specified by WECC.[24]

As noted above, PGE initially understood that the new water treatment plant would require roughly 11 MVA of capacity. The WWSP and WWSS Commission have

[24] No excessively high or low voltages were observed in the local area for any of the configurations considered in the January 2020 Study.

also mentioned potential long-term additions to the facility, which would increase the loading at the substation. Moreover, additional feeders sourced from Tonquin Substation are expected to serve existing load and eventual new load growth in the surrounding areas. Accordingly, for planning purposes, a 25 MW, 12 MVAR (0.90 power factor) load was used in all simulations as a conservative assumption.

PGE Transmission Planning performed all analyses using the PowerWorld load flow software program. Three cases were considered for each configuration: 2-year light spring, 5-year heavy winter, and 5-year heavy summer. The heavy summer and heavy winter cases utilized 1-in-10 loading profiles, while the light spring case utilized loading levels adjusted to 70 percent of the 1-in-3 peak loading at non-industrial loads. These load profiles are consistent with those used in other PGE transmission planning studies, and generally capture the behavior of the system on stressed summer and winter days, as well as less stressed spring days in which different generation patterns can cause different flows across the system. Generation dispatch and transmission path flows were set in accordance with case descriptions as described in the WECC 2018 Base Case Compilation Schedule.

Q. What were the base case studies for the January 2020 Study?

A. There were two base case studies assessed in the January 2020 transmission analysis: (1) an examination of existing system constraints without the addition of the Tonquin Substation load (referred to as the Base Case); and (2) a study of the transmission system impacts from adding the Tonquin Substation necessary to accommodate the new load from the water treatment plant and splitting the existing Meridian-Sherwood 115-kV transmission line—creating new Sherwood-Tonquin 115-kV and Meridian-

Tonquin 115-kV lines, providing two sources to the Tonquin Substation (referred to as Transmission Configuration Option 1). Transmission Configuration Option 1 assumed the distribution system upgrades and construction of the Tonquin Substation discussed above.

Q. Please summarize the results of the Base Case.

A. The Base Case, which represents existing system constraints, showed one transmission overload concern in the Tualatin Sherwood area. **Begin Highly Protected/**[redacted]**/End Highly Protected** PGE's current mitigation plan for this contingency event, which is allowed under NERC Reliability Standard TPL-001-5.1, is to shed load at the Boones Ferry Substation (although as discussed below, the proposed Tonquin Project will alleviate this issue as well as other observed double outage contingency scenarios).

Highly Protected Table 3: Base Case Contingency Results

Begin Highly Protected/

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

/End Highly Protected

Q. Please summarize the results of Transmission Configuration Option 1—i.e., the addition of Tonquin Substation to address new load.

A. By adding the Tonquin Substation necessary to accommodate the new load from the water treatment plant and splitting the existing Meridian-Sherwood 115--kV transmission line (creating new Sherwood-Tonquin 115-kV and Meridian-Tonquin 115-kV lines, providing two sources to the Tonquin Substation), the January 2020 transmission analysis determined that there are **Begin Highly Protected/** [redacted] **/End Highly Protected** as shown in Table 4 below.

Highly Protected Table 4: Transmission Configuration Option 1 - Tonquin Substation Loop-In Configuration Contingency Results
Begin Highly Protected/

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
			[redacted]	[redacted]	[redacted]	[redacted]
			[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]	[redacted]

/End Highly Protected

Q. What were the alternative transmission configurations that PGE analyzed in the January 2020 transmission analysis to address the potential outages identified in the Base Case and Transmission Configuration Option 1?

A. Using the methodology described above, PGE Transmission Planning developed five alternative options to address the N-1-1 contingency event outages identified in the Base Case (i.e., existing system constraints without the Tonquin Substation for new load) and resulting from the additional load from the water treatment facility (i.e., Option 1 – Addition of Tonquin Substation for new load and splitting of existing Meridian-Sherwood 115-kV transmission line into a two-source loop-in configuration):

- **Transmission Configuration Option 2**: Build Tonquin Substation in a ring bus configuration, with a third transmission source connecting from the nearby Coffee Creek Substation. Part of the existing Coffee Creek Tap-

Sherwood 115-kV line section would be idled in this scenario, and a short 115-kV line section would be constructed to Tonquin Substation. In order to provide a third source, Coffee Creek Substation would also be rebuilt as a five-position ring bus.

- **<u>Transmission Configuration Option 3</u>**: Build Tonquin Substation in a ring bus configuration and offload 14 MW from Tualatin Substation onto Tonquin Substation. In this case, circuit switchers at Coffee Creek Substation would be replaced with breakers, but the substation would not need to be rebuilt. The addition of breakers at Coffee Creek Substation creates a three-terminal line, Coffee Creek-Sherwood-Wilsonville 115-kV.
- **<u>Transmission Configuration Option 4</u>**: Build Tonquin Substation in a two-source loop-in configuration and rebuild Tualatin Substation to a gas-insulated (due to space constraints) five-position ring bus and Coffee Creek Substation to an air-insulated five-position ring bus. Construct a new Coffee Creek-Tualatin 115-kV line in all new right-of-way, and reconfigure the existing Coffee Creek tap off Sherwood-Wilsonville 115-kV line into new Coffee Creek-Sherwood 115-kV and Coffee Creek-Wilsonville 115-kV lines. Reconductor the Coffee Creek tap section and an existing section of the Meridian-Tualatin 115-kV lines.
- **<u>Transmission Configuration Option 5</u>**: Build Tonquin Substation in a ring bus configuration and reconfigure the surrounding 115-kV transmission system in order to avoid rebuilding the Coffee Creek and Tualatin Substations. This option involves idling a small section of the McLoughlin-

Wilsonville 115-kV line, building a small 115-kV section off of the Coffee Creek tap to Tonquin Substation, constructing a new portion of line from McLoughlin Substation to Rosemont Substation, and creating a Tonquin-Wilsonville 115-kV line (with alternate tap to Coffee Creek Substation) and a McLoughlin-Rosemont 115-kV line.

- **Transmission Configuration Option 6**: Build Tonquin Substation in a ring bus configuration and repurpose the McLoughlin-Wilsonville 115-kV transmission line, creating the new McLoughlin-Tonquin 115-kV line and Rosemont-Wilsonville Line. Like Transmission Configuration Option 5, this reconfiguration avoids having to rebuild the Coffee Creek and Tualatin Substations and requires a similar amount of new transmission construction.

Q. How did PGE Transmission Planning assess each transmission configuration option?

A. Each Option 1-6 was assessed based on several factors: (1) whether the configuration would eliminate and/or reduce the overloads caused by the addition of the Tonquin Substation load (as identified in Transmission Configuration Option 1 discussed in more detail below) and the overloads observed in the Base Case; (2) whether the configuration was cost-effective (e.g., by avoiding rebuilding other substations in the area); and (3) whether the configuration was impractical/not viable for other reasons (e.g., there was no space to rebuild other substations as proposed in the configuration or the configuration would prevent future load growth at other substations).

Q. Which transmission configuration options, if any, resolved the potential outages identified in the Base Case and resulting from the addition of the Tonquin Substation load?

A. Transmission Configuration Option 3, Option 4, and Option 6 resolved the potential outages identified in the Base Case and resulting from the addition of the Tonquin Substation load.

Q. Which transmission configuration did PGE choose and why?

A. PGE chose Transmission Configuration Option 6, i.e., the Tonquin Project transmission facilities, including the Rosemont-Wilsonville Line, as the most cost-effective and practical solution that addressed the identified outages. This configuration eliminated the overloads caused by the addition of Tonquin Substation load (as identified in Transmission Configuration Option 1), and eliminated the overloads observed in the Base Case. Furthermore, this option avoided having to rebuild any other substations in the area, which may be impractical due to space limitations and significant costs. Please see the transmission configuration for Option 6 in Figure 4 below.

Highly Protected Figure 4: Transmission Configuration Option 6
Begin Highly Protected/

[redacted]

/End Highly Protected

Q. Please explain why PGE did not choose Transmission Configuration Option 3.

A. PGE did not choose Transmission Configuration Option 3 as it created a three-terminal line (which can cause protection and reliability issues as compared with a two-terminal line) and required 14 MW to be offloaded from Tualatin Substation to Tonquin Substation in order to mitigate the observed Base Case overload. PGE determined that this scenario was impractical because it would require shifting load to the **Begin Highly Protected/** [redacted] **/End Highly Protected**. Additionally, Transmission Configuration Option 3 would create a three-terminal transmission line and PGE policy does not allow for the construction of new three-terminal transmission lines due to the challenges they introduce from a system protection standpoint. For these reasons, PGE determined that Transmission Configuration Option 3 was not a viable option. Please see the transmission configuration for Option 3 in Figure 5 below.

Highly Protected Figure 5: Transmission Configuration Option 3 Configuration
Begin Highly Protected/

[redacted]

/End Highly Protected

Q. Please explain why PGE did not choose Transmission Configuration Option 4.

A. Transmission Configuration Option 4, which would build the Tonquin Substation in a two-source loop-in configuration, was modeled to alleviate all observed 115-kV overloads in the area. However, PGE did not choose Transmission Configuration Option 4 as it would require rebuilding both the Coffee Creek and Tualatin Substations. Rebuilding these two substations would be both impractical and extremely expensive.

Specifically, due to space limitations and lack of available land for expansion at Tualatin Substation, rebuilding the substation as a ring bus would require gas-insulated switchgear (GIS) equipment, which would add significant cost. GIS equipment is necessary when substations need to expand but are space-constrained by an inability to expand substation fence lines. GIS equipment is inherently much more expensive than equivalent air-insulated switchgear equipment. In fact, PGE estimated that selection of Transmission Configuration Option 4 would result in direct costs for all project components (not including loadings and Allowance for Funds Used During Construction) of approximately $86 million, as compared to $59 million under Transmission Configuration Option 6. Please see the transmission configuration for Option 4 in Figure 6 below.

Highly Protected Figure 6: Transmission Configuration Option 4
Begin Highly Protected/

[redacted]

/End Highly Protected

Q. Have additional transmission planning studies and annual TPL Assessments found a continued need for the Tonquin Project, including the Rosemont-Wilsonville Line?

A. Yes. In 2024, PGE updated its modeling of potential outage events in the case of the Tonquin Substation addition necessary to accommodate the new load from the water treatment plant and initial load additions (without the construction of Rosemont-Wilsonville Line and McLoughlin-Tonquin 115-kV transmission line), i.e., Transmission Configuration Option 1 (Highly Protected Exhibit PGE/106). The results now indicate several more N-1-1 contingency combinations that may cause an overload (i.e., over 100 percent of the facility rating). Specifically, during peak summer conditions, there are now **Begin Highly Protected/**[redacted]**/End Highly Protected** separate N-1-1 contingencies that may cause an overload (i.e., over 100 percent of the facility rating), with the worst contingency resulting in a **Begin Highly Protected/**[redacted]**/End Highly Protected** contingencies that may result in near overloads (i.e., 95-100 percent of the facility rating). In these cases, the models show that ameliorative actions such as switching substations to alternate sources or adjusting generation patterns are not sufficient to protect against overloads. Instead, only direct shedding or curtailing of customer loads will bring the transmission facilities within rated limits. Indeed, without the Tonquin Project, including the Rosemont-Wilsonville Line, in a **Begin Highly Protected/**[redacted]**/End Highly Protected** percent overload contingency scenario, PGE will need to shed 35 MW of load, which equates to 21,000 residential customers losing power. Construction of the Tonquin Project, including the Rosemont-Wilsonville Line, alleviates all **Begin Highly**

Protected/[redacted]**/End Highly Protected** scenarios as well as **Begin Highly Protected/**[redacted]**/End Highly Protected** scenarios. Accordingly, since 2020, the Tonquin Project and Rosemont-Wilsonville Line have become even more urgently needed.

In addition, since 2020, PGE has repeatedly identified the Tonquin Project, including the Rosemont-Wilsonville Line, in the Company's annual TPL Assessments as a transmission project that will be needed to maintain reliability on PGE's BES. In the Company's 2020-2021 Near Term Local TPL Assessment, the Company identified the Tonquin Project as a necessary project to address new customer load and loading concerns on the Oswego-West Portland 115-kV line.[25] PGE similarly indicated a need to construct the Tonquin Project to maintain reliability on its system in the Company's 2022-2023 Near Term Local TPL Assessment[26] and 2023-2024 Long Term Local TPL Assessment.[27]

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[25] PGE, Near Term Local Transmission Plan For the 2020-2021 Planning Cycle at 26 (Dec. 23, 2020), *available at* http://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Near_Term_LTP_2020_Final.pdf (PGE/107, Beil/29).

[26] PGE, Near Term Local Transmission Plan For the 2022-2023 Planning Cycle at 20 (Dec. 28, 2022), *available at* http://www.oasis.oati.com/woa/docs/PGE/PGEdocs/Final_Near_Term_LTP_2022_12-28-22.pdf (PGE/108, Beil/23).

[27] PGE, Longer Term Local Transmission Plan For the 2023-2024 Planning Cycle at 39 (Dec. 26, 2023), *available at* http://www.oasis.oati.com/woa/docs/PGE/PGEdocs/2023_Local_Transmission_Plan.pdf (PGE/109, Beil/39). Note that the PGE Long Term Local Transmission Plan For the 2021-2022 Planning Cycle document covered the 6-10 year planning horizon and did not mention any near term (1-5 year) projects, including the Tonquin Project. *See generally* PGE, Longer Term Local Transmission Plan For the 2021-2022 Planning Cycle (Dec. 30, 2021), *available at* https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_Longer_Term_LTP_2021_FINAL.pdf (PGE/110). PGE Transmission Planning has since changed this practice, and now describes all projects identified in a 1–10-year timeframe in all Local Transmission Plans (both the Near and Long term versions).

Q. Does the Company's 10-year load and sales forecasts also support the need for the Rosemont-Wilsonville Transmission Line?

A. Yes. The Sherwood, Tualatin, and Wilsonville areas are experiencing load growth from a variety of sources, including new residential developments, increasing commercial activity in the area, and industrial load growth stemming from many sources, including advanced semiconductor manufacturing and technology customers, and utility water service providers. The Tonquin Project, including the Rosemont-Wilsonville Line, will provide additional transmission capacity needed to serve these communities and the surrounding areas as they continue to expand and increase their power requirements over time. In particular, the table attached as Highly Protected Exhibit PGE/111 documents the projected load growth between 2023 and 2034 for the nine substations that will be at risk of a load shedding event until the Rosemont-Wilsonville Line is completed. **Begin Highly Protected/**[redacted]**/End Highly Protected**

Q. Please identify what benefits the Tonquin Project transmission facilities provide, if any, to other transmission already in service in terms of line ratings and congestion.

A. Constructing the Rosemont-Wilsonville Line and the McLoughlin-Tonquin 115-kV Line will alleviate identified congestion under N-1-1 transmission outage conditions on the following transmission facilities:

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[redacted]

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The construction of these lines is also expected to increase the loading on the **Begin Highly Protected/** [redacted] **/End Highly Protected** percent under certain outage conditions. A long-term (5+ years out) plan is being developed to add a **Begin Highly Protected/** [redacted] **/End Highly Protected**. This plan would need to be pursued regardless of whether the third Tonquin Project transmission source is added and is required for general load growth in the area.

Q. How did PGE determine the appropriate size for the Rosemont-Wilsonville Line?

A. PGE studied modeled load growth over a ten-year outlook in its 2024 Study and determined that a 115-kV line would meet the expected growth over this time period. PGE's 2024 Study indicates that once the Rosemont-Wilsonville Line and the McLoughlin-Tonquin 115-kV line are constructed, there will be sufficient capacity on both of these lines to avoid any further reconductors through 2034.[28]

Q. Please describe the expected capacity utilization along the Rosemont-Wilsonville Line.

[28] Highly Protected PGE/106, Beil/1-2.

A. Assuming the Rosemont-Wilsonville Line is energized by the end of 2025, given forecasted substation loading in the area at that time, it will experience contingency loading during double outage (N-1-1) system conditions of up to **Begin Highly Protected/**[redacted]**/End Highly Protected**, as discussed in the direct testimony of Kevin Putnam, Dan Nuñez, and Matt Gordanier.[29] In 2034, as substation loads in the area are forecasted to grow, contingency loading during N-1-1 system conditions will cause flows on the line of **Begin Highly Protected/**[redacted]**/End Highly Protected** percent of the line's rated capacity.

Q. Does this conclude your testimony?

A. Yes.

[29] PGE/300, Putnam-Nuñez-Gordanier/7.

List of Exhibits

PGE Exhibit	Description
PGE/101 **HP**	Banks and Beil, Tonquin Substation Project (Jan. 22, 2020)
PGE/102	NERC Reliability Standard TPL-001-5.1
PGE/103	WECC Criterion TPL-001-WECC-CRT-3.2
PGE/104	2023 PGE Transmission Planning Study Methodology
PGE/105	NERC Reliability Standard FAC-008-5
PGE/106 **HP**	Tonquin Power Flow Results Update
PGE/107	PGE, Near Term Local Transmission Plan For the 2020-2021 Planning Cycle (Dec. 23, 2020)
PGE/108	PGE, Near Term Local Transmission Plan For the 2022-2023 Planning Cycle (Dec. 28, 2022)
PGE/109	PGE, Longer Term Local Transmission Plan For the 2023-2024 Planning Cycle (Dec. 26, 2023)
PGE/110	PGE, Longer Term Local Transmission Plan For the 2021-2022 Planning Cycle (Dec. 30, 2021)
PGE/111 **HP**	Ten-Year Load Forecast Supporting Need for Line

HP - Highly Protected Information

PGE/101

Banks and Beil, Tonquin Substation Project (Jan. 22, 2020)

Exhibit 101 contains highly protected information

and is subject to

Modified Protective Order No. 24-087

(Redacted Copy)

Tonquin Substation Project

Prepared by Transmission & Distribution Planning
Aaron Banks
Ian Beil
January 22, 2020

Table of Contents

Executive Summary

The growing population in Hillsboro has caused the need for additional drinking water to be supplied to the area. In response, the Willamette Water Supply Program (WWSP) plans to build a new raw water treatment facility off of SW Tualatin-Sherwood Road at SW 124th Avenue. This water treatment plant represents a large load addition of approximately 11 MVA to PGE's transmission and distribution system. The new plant will be located between the existing Tualatin and Six Corners substations, which are already nearing their seasonal thermal limits. These substations cannot support an additional 11 MVA load. In addition to the WWSP water treatment facility, the area along SW 124th Avenue to the southwest of the City of Tualatin is anticipating future load growth with the extension of SW 124th south to SW Grahams Ferry Rd.

A study was performed to determine the impact the new 11 MVA load would have on the existing distribution system in 2024 during 1-in-3 summer peak conditions. This study work was performed using CYME power flow software. Due to the heavy loading on the Tualatin-Cipole feeder along with transformers Tualatin WR2 and Six Corners WR2, the large load addition by the water treatment facility will result in overloads of Tualatin WR2, Six Corners WR2, and mainline feeder cable on the Tualatin-Cipole feeder. In addition to the overloading, PGE will not be able to provide WWSP with alternate service under the current conditions.

For this project, three construction options were analyzed with the recommended distribution option that includes the addition of a new substation with dedicated feeders to support the new load, two additional feeders to support local area distribution, and upgrades to existing Six Corner feeders. The second option included constructing a new substation to only serve the WWSP loads, and a third option involved constructing a new substation with four new general purpose feeders.

Further transmission analysis was performed to determine the proper reconfiguration of the local transmission system to accommodate a new substation at the specified location. The existing Meridian-Sherwood 115kV line, which runs just north of the WWSP location along SW Tualatin-Sherwood Road, can be split to provide two separate transmission sources to the potential new substation.

However, studies using the PowerWorld program show that looping in the Meridian-Sherwood 115kV line would result in unacceptable overloads to the Oswego-West Portland 115kV and Canemah-Rosemont 115kV transmission lines during certain contingencies. To mitigate these observed transmission overloads, several additional configurations are presented.

The recommended transmission system solution is to build the new Tonquin substation as a five-position ring bus with three 115kV transmission sources and reconfigure several of the existing transmission lines in the area (McLoughlin-Wilsonville 115kV and the Coffee Creek alternate tap off of Meridian-Sherwood 115kV) into new McLoughlin-Tonquin 115kV (with alternate tap to Coffee Creek) and Rosemont-Wilsonville 115kV lines. This would require building new transmission for approximately 5 miles, to be overbuilt with existing PGE distribution right-of-way (for 3.7 miles) and double circuited with existing PGE transmission (for 1.3 miles).

Introduction

Feeders that serve the general area that the WWSP will reside include the Tualatin-Cipole feeder from Tualatin substation and the Six Corners-Six Corners 13 feeder from Six Corners substation.

[redacted]

Figure 1: WWSP water treatment facility location and surrounding PGE substations and 13 kV feeders

The loading guideline for a distribution feeder under normal operating conditions [redacted] of its thermal rating to allow for load shifting in the event of planned outages for construction, equipment failures, unplanned outages, and other emergencies. Similarly, the loading guideline for a substation power transformer [redacted] The Tualatin-Cipole and Six Corners-Six Corners 13 feeders, along with their respective substation transformers, are considered [redacted] as of summer 2018.

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Table 1: Existing loading of transformers and feeders adjacent to WWSPload

Table 1 shows that the feeders and transformers adjacent to the WWSP facility site are near or exceeding the loading guideline with existing load. Adding the estimated WWSP load of 11 MVA to each of these feeders would push them well beyond the loading guideline for the distribution feeders and the substation transformers during peak summer conditions.

This report will provide the methodology and results from several different distribution and transmission options considered to provide the PGE system the needed capacity for the addition of the WWSP load. Both the distribution and transmission analysis will start with looking at the base case, or existing sytem constraints, and then will move onto the project options to be analyzed. Once the project options have been presented, the distribution and transmission recommendations will be presented. The recommended project options will consider project cost, system resiliency, and system reliability.

Distribution Study Methodology

The physical boundaries of the Six Corners and Tualatin substations area are shown in Figure 2. Tualatin substation and Six Corners substation, along with all of their 13 kV feeders, were the primary substations considered. The surrounding substations and feeders were also considered in the study for N-1 outage scenarios. The distribution studies were performed using CYME Power Engineering Software with the most current database assembled in March, 2019 for system equipment and configuration.

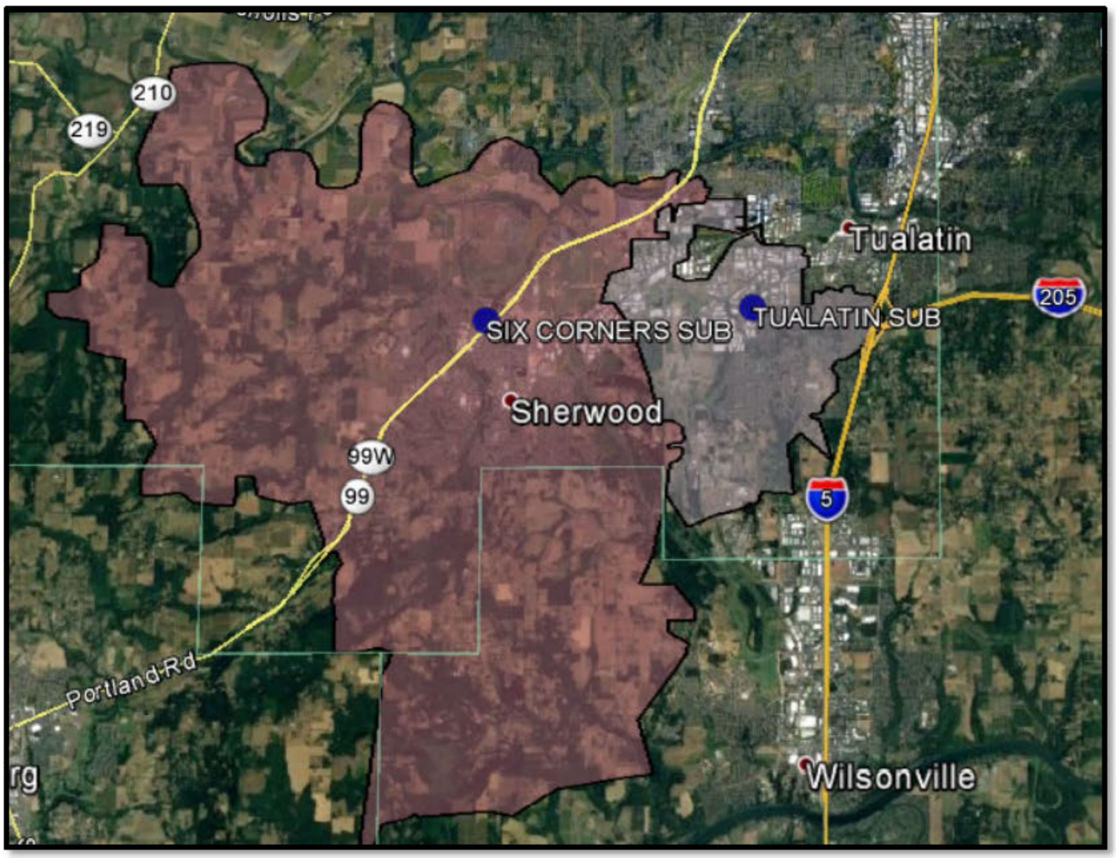


Figure 2: Project study area

For the load allocation used in the studies, the 2018 summer peaks for MW and MVAR were found at each substation transformer and each feeder was loaded to its respective transformer peak date and time. In addition to these coincidental feeder loads, each load was scaled a 1-in-3 peak summer loading condition factor, which corresponds to a daily average temperature of 81 degrees F. In this case the factor was 0.96. A factor of 0.96 indicates that the summer 2018 temperatures were higher than an average of 81 degrees for a span of time causing the summer peaks used to be higher than a 1-in-3 event; thus the downscale. To account for load growth in the area a load growth scaling factor was also applied to the loads. The scaling factor of 1.05 was derived from the PGE system wide load forecast and the predicted 2024 PGE system summer peak which was 5% higher than 2018 summer peak load. Lastly, a load addition of 11 MVA with a lagging power factor of 95% was added to simulate the future water treatment load.

A base case study without the new Tonquin substation, a study with the new Tonquin substation but without any feeder additions or improvements, and two studies with the new Tonquin substation along with two options of area feeder additions and improvements were performed. The loading of underground cables, overhead conductors, substation transformers, and steady state voltages will be analyzed for each option presented. Feeder and substation transformer contingencies will also be analyzed for each option.

Distribution Analysis

Base Case – Do Nothing Option

The two feeders that will have to carry the 11 MVA load from the WWSP water treatment facility will be Tualatin-Cipole and Six Corners-Six Corners 13 as these are the only feeders near the facility's location. Figure 3 shows the percentage of normal summer rating of the feeders based on 2018 summer peak loading for the Tualatin and Six Corners substations. The loading percentage after half (or 6.5 MVA) of the WWSP water treatment plant load is introduced for Tualatin-Cipole and Six Corners-Six Corners 13 is also shown.

[redacted]

Figure 3: Feeder loading percentage before and after WWSP load addition

As shown in Figure 3, there are several feeders served by the Six Corners and Tualatin substations that are already near the [redacted] feeder loading guideline with the existing load. One of these feeders is Tualatin-Cipole which is adjacent to the WWSP facility location. Adding half of the predicted WWSP load of 11 MVA to Tualatin-Cipole and Six Corners-Six Corners 13 puts both feeders well above the feeder loading guidance of [redacted]

[redacted]

Figure 4: Cable and conductor loading on Tualatin-Cipole

Figure 5 shows the substation transformer loading percentages based on the 2018 summer peak load of Six Corners and Tualatin substations before the addition of the WWSP load addition and after.

[redacted]

Figure 5: Transformer loading percentage before and after WWSP addition

Three of the four transformers in the Six Corners and Tualatin substations are [redacted] loading beyond nameplate rating). When accounting for the added load that WWSP will introduce, the transformers associated with the new load will be [redacted] of the summer LBNR rating.

In summary, [redacted] The overloaded cables and conductors are already the PGE standard largest sizes and upgrading these would require larger nonstandard materials. In addition to the overloads on Tualatin-Cipole, operating with feeders above [redacted] and transformers above [redacted] loading greatly limits system flexibility. This flexibility is needed to adjust and shift load for unplanned outages, equipment failures, and necessary planned outages for construction. [redacted] Finally, if no new substation is built it will not be feasible to provide the WWSP water treatment facility with alternate service if they choose to contractually reserve capacity on the distribution system. Due to this, the following options were analyzed.

Option A – Tonquin Substation Alone

Building the Tonquin substation will accommodate the new load addition that the WWSP will introduce. The proposed location for the substation is on the SW corner of the PGE owned IOC property and will be a relatively short distance from the water treatment facility. If the Tonquin substation is built without any surrounding feeder improvements, the Six Corners and Tualatin substations will remain in their current state. [redacted]

To show the area's need for more capacity, N-1 contingencies were examined for this option with no additional Tonquin feeders. N-1 contingencies are scenarios where an entire feeder or transformer is taken out of service, creating the need for adjacent facilities to pick up the de-energized load. To ensure that all lost load can be restored even during peak conditions, the N-1 contingencies were simulated for summer peak loading. Table 2 shows the area's system conditions with each feeder modeled offline one at a time. The emergency switching sheets for each N-1 contingency were used to determine which feeder switches to open and which ones to close to pick up the lost load onto the remaining distribution system.

Feeder Outage	Low Voltage Count (Customers)	Overloaded Cable/Conductor (feet)
[redacted]	[redacted]	[redacted]

Table 2: Feeder conditions for N-1 contingencies, Option A

PGE's voltage standard is no more than +/- 5% of nominal voltage. The above conditions show that even with no feeder outages there are 151 customers who experience low voltage during a 1-in-3 peak summer event. The number of customers experiencing low voltage increased with five of the feeder outages and with two of the feeder outages, cable and/or conductor were overloaded. Table 3 shows the system conditions with each transformer at Six Corners and Tualatin substations modeled offline with the system restored according to the emergency switching sheets.

Transformer Outage	Low Voltage Count (Customers)	Overloaded Cable/Conductor (feet)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Table 3: Transformer conditions for N-1 contingencies, Option A

As Table 3 shows, the number of customers experiencing low voltage in a transformer outage is higher than the baseline of 151 customers for all four transformer outages. [redacted]. Figure 6 shows the overloaded adjacent transformers for each corresponding transformer outage.

[redacted]

Figure 6: Transformer outages and corresponding adjacent transformer overloads

[redacted] Because transformers beyond their summer LBNR rating will result in significant loss of life for the asset, the choice will have to be made to leave sections of the feeder de-energized in these scenarios. [redacted]

While building the new Tonquin substation provides the needed capacity for the new WWSP loads, the new addition does not help the area with the existing feeders and transformers that are nearing their recommended loading maximums.. Loading at these facilities can become much more severe when considering N-1 conditions during summer peaks at both the feeder and the transformer levels.

Option B – Tonquin Substation with Baseline Feeder Improvements

As discussed in the do nothing option, the Six Corners and Tualatin substations already have multiple feeders and transformers with loads nearing their recommended maximums. If the Tonquin substation includes the addition of new general purpose feeders to both serve the WWSP facility as well as PGE general load, heavy loading of the surrounding area feeders and transformers will be reduced by up to 14 MVA during peak loading. Decreased loads allow for faster and more comprehensive switching in outage situations which will improve system functionality. These new feeders will also increase system reliability by an estimated 1500 customer interruptions and an estimated 438,000 customer minutes interrupted the first year after the feeders and upgrades are completed. Each year after implementation these estimated benefits will increase compared to doing no distrubition upgrades as the existing distribution system would have aged more. Figure 7 shows the two baseline feeder improvements proposed in this project option.

[redacted]

Figure 7: New Tonquin feeders configuration

[redacted] As shown in Figure 7, two new feeders Tonquin-Hoodview and Tonquin-Driver will be constructed from Tonquin substation. To construct the Tonquin-Hoodview feeder as shown, a reconductor of approximately 0.80 miles along SW Murdock Road is required. Additionally, another 0.33 mile reconductor/cable replacement along SW Washington Street in Sherwood will further optimize the load sharing between the new Tonquin-Hoodview feeder and the existing Six Corners-Chapman feeder by establishing a strong tie between the two feeders. Figure 8 provides more details of these feeder improvements.

[redacted]

Figure 8: Feeder improvement reconductors and cable replacements

Figure 9 shows the Six Corners and Tualatin feeders existing load in percent of summer rating versus the new load percentage with this proposed configuration. [redacted]

[redacted]

Figure 9: Existing feeder load percentage versus Option B feeder load percentage

Figure 10 shows the Six Corners and Tualatin transformers loading percentage with the new proposed Tonquin feeders.

[redacted]

Figure 10: Existing transformer load percentage versus Option B substation load percentage

Tonquin-Driver and Tonquin-Hoodview will lighten the load on many of the heavily loaded feeders and transformers. Although not completed as part of this study, this additional capacity that the two new Tonquin feeders provide an opportunity for load balancing to be done at Tualatin substation to relieve the remaining heavily loaded feeders and transformers.

Figure 9 and Figure 10 show that these two new Tonquin feeders will benefit the Tualatin and Sherwood areas when the feeders are in their normal configurations. When considering N-1 contingencies, the area will also benefit. Table 4 shows the number of customers experiencing low voltage and overloaded cables and conductors for each feeder outage.

Feeder Outage	Low Voltage Count (Customers)	Overloaded Cable/Conductor (feet)
[redacted]	[redacted]	[redacted]

Table 4: Feeder conditions for N-1 contingencies, Option B

The N-1 contingency numbers in Table 4 were determined from the emergency switching sheets that for study purposes were modified to include the new feeders presented in option B. In comparison to option A, which has no additional Tonquin feeders, the number of customers with low voltage in Table 4 is lower for every feeder outage and also in normal configuration. Option A had overloaded cable/conductor for two of the feeder outages while Table 4 shows that no feeder outage caused overload conditions when restoring load with the surrounding feeders. Table 5 shows the low voltage count and that there is no overloaded cable/conductor for N-1 transformer contingencies.

Transformer Outage	Low Voltage Count (Customers)	Overloaded Cable/Conductor (feet)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Table 5: Transformer conditions for N-1 contingencies, Option B

Compared to the Option A low voltages and overload conditions, the new feeders provided in Option B help decrease the low voltage and overload conditions for every transformer outage. Additionally, in Option B all transformer outages are able to have the load restored without overloading any of the adjacent substation transformers.

The additional capacity of the two new Tonquin feeders and their associated transformers will require new emergency switching sheets to be written. With the new emergency switching sheets it can be expected that fewer customers will experience low voltage and that overloaded conductors, cables, and transformers will be able to be avoided even in N-1 scenarios. Less low voltage and overloaded equipment during outages improves customer experience and reliability and will also increase the operational flexibility in the region, allowing for future PGE construction projects to be more easily and cost effectively be carried out. Finally with the addition of new feeder ties and more transformer capacity, the opportunity for distribution automation increases.

Option C – Tonquin Substation with All Feeder Improvements

In addition to the two proposed feeders in Option B, two more feeders are proposed in Option C to further benefit the Tualatin Sherwood region. Figure 11 shows these two new feeders.

[redacted]

Figure 11: Tonquin-Basalt Creek and Tonquin-Blake feeders

As opposed to Tonquin-Driver and Tonquin-Hoodview in Option B which are immediately picking up load from other existing feeders; Tonquin-Blake and Tonquin-Basalt Creek are feeders to prepare for future load growth. SW Tualatin is growing, and the City of Tualatin has two long range planning areas in the region; one along the new SW 124th Avenue[1] and one further south along SW Tonquin Rd[2]. Figure 12 shows these planning areas.

[1] The SW Tualatin Concept Planning Area
[2] Basalt Creek Planning Area

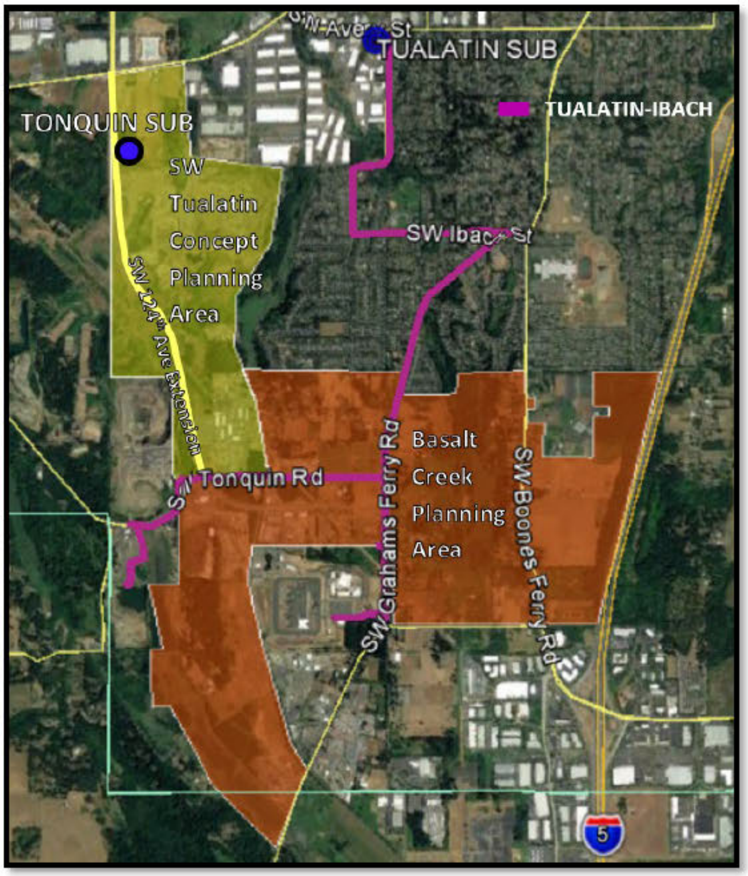


Figure 12: Areas to experience load growth in the region

Currently, there are no concrete timelines regarding implementation of these projects, but with the two additional feeders, PGE will be well prepared for future load growth in these areas. These two new feeders will better utilize the new Tonquin substation to pick up future load growth as well as prevent the Tualatin-Ibach feeder, which is already loaded to a moderate level, from incorporating additional load.

Beyond preparing for future load growth, these two new feeders provide strong ties from Tonquin substation to the Tualatin-Ibach feeder. Table 4 and Table 5 show that for Option B there are minimal overload conditions for N-1 feeder and transformer outages. The Option C feeders do not have the opportunity to further remedy N-1 overload conditions if the Option B feeders are already in place. However, these two new feeders will help with future N-1 conditions as the region experiences load growth and there is more load to shift during N-1 scenarios.

Transmission Study Methodology

The addition of a new Tonquin substation has the potential to introduce a substantial amount of new load on the local transmission system. In order to assess the effects this new load will have, PGE Transmission Planning employs typical practices, as outlined in the NERC TPL-001 standard. This standard defines a number of credible contingencies that must be studied, including single element (N-1) outages of transmission lines, transformers, generators, and shunt devices; bus outages and breaker failure outages; double outages (N-1-1) of one transmission element followed by the subsequent loss of second; and simultaneous outages of common-corridor transmission elements (N-2).

TPL-001 specifies acceptable post-contingency states and allowable transmission operator actions. For general planning purposes, PGE Transmission Planning attempts to mitigate all observed transmission element overloads (i.e. any loading ≥ 100% of the designated planning rating of the transmission element) for all contingencies specified in TPL-001. Voltage requirements (as specified by WECC) are also considered; however, no excessively high or low voltages were observed in the local area for any of the configurations considered in this study.

As noted above, it is expected that the new WWSP water treatment plant served from Tonquin will require roughly 11 MVA of capacity. WWSP has also mentioned potential long-term additions to the facility which would increase the loading at the substation. Additional feeders sourced from Tonquin are expected to serve existing load and eventual new load growth in the region. For planning purposes, a 25 MW, 12 MVAR (0.90 power factor) load was used in all simulations.

All analyses were performed using the PowerWorld load flow software program. Three cases were considered for each configuration: 2-year light spring, 5-year heavy winter, and 5-year heavy summer. The heavy summer and heavy winter cases utilized 1-in-10 loading profiles, while the light spring case utilized loading levels adjusted to 70% of the 1-in-3 peak loading at non-industrial loads. Generation dispatch and transmission path flows were set in accordance with case descriptions as described in the WECC 2018 Base Case Compilation Schedule.

Transmission Analysis

Base Case: Existing system constraints

There is one existing transmission overload concern in the Tualatin/Sherwood area that is relevant to the Tonquin substation addition. [redacted] specifically, the section between West Portland and Boones Ferry substations).

[redacted]

Figure 13: Existing 115kV transmission system in the Tualatin/Sherwood area

The current mitigation plan for this contingency is to shed load at Boones Ferry substation. While it is undesirable to shed load anywhere, the alternative of reconductoring the Oswego-West Portland 115kV is not considered feasible because access to the line is very limited (the line routes through a number of back lots) and the cost would be prohibitively expensive.

Category	Outage	Voltage	Element	Voltage	Base Case
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 6: Base Case contingency summary

Option 1: Two source loop-in configuration

A map of the local transmission system is shown in Figure 14 below. The existing Meridian-Sherwood 115kV transmission line runs just north of the proposed Tonquin substation location along Tualatin-Sherwood Road. This line can be split and routed along SW 124th Avenue, creating new Sherwood-Tonquin 115kV and Meridian-Tonquin 115kV lines, providing two sources to Tonquin substation.

Figure 14: Tonquin substation location and surrounding transmission lines

This potential two source loop-in configuration for Tonquin substation is shown in below.

[redacted]

Figure 15: Tonquin loop-in configuration one-line

While this would be the simplest and most cost effective available option, reconfiguring the 115kV system in this manner significantly exacerbates the overloading in the previously identified Base Case contingency, and creates several new contingency overload scenarios.

Category	Outage	Voltage	Element	Voltage	Base Case	Tonquin loop-in
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 7: Tonquin loop-in contingency summary

Option 2: Tonquin and Coffee Creek ring bus configuration

Another option is to build Tonquin substation in a ring bus configuration, with a third transmission source connecting from the nearby Coffee Creek substation. Part of the existing Coffee Creek Tap-Sherwood 115kV line section would be idled in this scenario, and a short 115kV line section would be constructed to Tonquin substation. In order to provide a third source, Coffee Creek substation would also be rebuilt as a five-position ring bus.

[redacted]

Figure 16: Tonquin and Coffee Creek ring bus configuration one-line

The Option 2 configuration would eliminate the additional overloads observed in Option 1. However, it would not eliminate the Base Case N-1-1 overload for Oswego-West Portland 115kV. It would also require building one substation and rebuilding a second, which would be an expensive approach.

Category	Outage	Voltage	Element	Voltage	Base Case	Tonquin ring + Coffee Creek ring
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 8: Tonquin and Coffee Creek ring bus contingency summary

Option 3: Move load from Tualatin

One potential way to mitigate the observed overload in the base case, while avoiding rebuilding other substations, would be to offload Tualatin substation loading onto Tonquin. In this case, circuit switchers at Coffee Creek would be replaced with breakers, but the substation would not need to be rebuilt. The addition of breakers at Coffee Creek creates a three-terminal line, Coffee Creek-Sherwood-Wilsonville 115kV. Protection impacts would need to be evaluated due to this new system configuration.

[redacted]

Figure 17: Moving load from Tualatin one-line

This approach would require 14 MW to be offloaded from Tualatin substation to Tonquin substation in order to mitigate the observed Base Case overload. Furthermore, this would prevent any future load growth at Boones Ferry, Oswego, Rosemont, Meridian, and Tualatin substations. As outlined in the distribution analysis section above, [redacted] and shifting load to mitigate the observed transmission contingency overloads is not considered a viable option.

Category	Outage	Voltage	Element	Voltage	Base Case	Move 14MW of load from Tualatin to Tonquin
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 9: Moving load from Tualatin contingency summary

Option 4: Tualatin and Coffee Creek ring bus configuration

Another possibility would be to rebuild Tualatin and Coffee Creek substations as ring buses, leaving Tonquin substation in a two source loop-in configuration.

[redacted]

Figure 18: Tualatin ring bus configuration one-line

This configuration would alleviate all observed 115kV overloads in the area. However, it would require the construction of a new substation (Tonquin) as well as the rebuilding of two others (Coffee Creek and Tualatin). Due to space limitations at Tualatin substation, rebuilding the substation as a ring bus would likely require GIS equipment, which would add significant cost. While this configuration solves the local overloading issues, it is not expected to be the most cost-effective approach.

Outage	Voltage	Element	Voltage	Base Case	Tualatin + Coffee Creek ring
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 10: Tualatin ring bus contingency summary

Option 5: Tonquin ring bus + McLoughlin/Wilsonville 115kV reconfiguration #1

In order to avoid rebuilding either/both of Coffee Creek and Tualatin substations, reconfiguring the surrounding 115kV transmission system is also a possibility. One approach, referred to as Option 5, is shown below. This would involve idling a small section of the McLoughlin-Wilsonville 115kV line, building a small 115kV section off of Coffee Creek tap to Tonquin substation, and constructing a new portion of line from McLoughlin substation to Rosemont substation, creating a Tonquin-Wilsonville 115kV line (with alternate tap to Coffee Creek substation) and a McLoughlin-Rosemont 115kV line.

[redacted]

Figure 19: Tonquin ring bus + McLoughlin/Wilsonville 115kV reconfiguration one-line

This approach would eliminate the overloads observed in the Base Case and in Option 1 (the loop-in configuration). [redacted] This would result in a number of new contingency overloads on the transmission lines terminating at Six Corners substation. These significant new overloads are not acceptable from a Transmission Planning perspective.

Category	Outage	Voltage	Element	Voltage	Base Case	Tonquin ring + Wilsonville/ McLoughlin redesign #1
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 11: Tonquin ring bus + McLoughlin/Wilsonville reconfiguration contingency summary

Option 6: Tonquin ring bus + McLoughlin/Wilsonville redesign #2

Another possible transmission reconfiguration is shown below in Figure 20. Similarly to Option 5, this reconfiguration avoids having to rebuild Coffee Creek and Tualatin substations. Again, the McLoughlin-Wilsonville 115kV repurposed, but this time new McLoughlin-Tonquin 115kV and Rosemont-Wilsonville 115kV lines are created. The amount of new transmission construction required for Option 6 is very similar to Option 5.

[redacted]

Figure 20: Tonquin ring bus + McLoughlin/Wilsonville reconfiguration #2 one-line

This configuration eliminates the overloads caused by the addition of Tonquin substation load (as identified in Option 1), and eliminates the overloads observed in the Base Case. Furthermore, by avoiding having to rebuild any other substations in the area, Option 6 is considered the most cost-effective solution, and is the recommended approach to mitigating local transmission constraints.

Category	Outage	Voltage	Element	Voltage	Base Case	Tonquin ring + Wilsonville/ McLoughlin redesign #2
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 12: Tonquin ring bus + McLoughlin-Wilsonville 115kV reconfiguration #2 contingency summary

Recommended Options

Distribution Recommendation

For each proposed distribution option, the cost of the project was weighed against the estimated benefit of that option. Some examples of estimated benefits are decreased outage probability, decreased outage duration, decreased asset failure probability, and decreased asset failure impact.

Project Option	Benefit Cost Ratio
Option A	0.59
Option B	0.60
Option C	0.53

Table 13: Distribution option benefit cost ratios

The various project options provided similar cost benefit ratios, but the option with the highest ratio by a slight margin was Option B. It is important to note that these cost benefit ratios are considering the conservative 50% estimates for project cost. Any future estimate updates will affect these ratios. The full cost benefit analysis prepared by Strategic Asset Management is available upon request.

The recommended distribution option for this project is Option B. This includes the construction of the new Tonquin Substation, distribution feeders Tonquin-Hoodview, Tonquin-Driver, Tonquin-Crystal, Tonquin-Springs, and a feeder improvement on Six Corners-13359.

The Tonquin Substation will be a 115 kV five position ring bus with three 115 kV line positions and two transformer positions. [redacted]

The new Tonquin feeders will be routed as shown in Figure 21.

[redacted]

Figure 21: Map of new 13kV feeders

Tonquin-Hoodview will consist of approximately 6,000 feet of new underground 750 Al cable to get the the point of connection with the existing feeder Six Corners-Six Corners 13 and approximately 6,000 feet of 795 overhead reconductor to pick up the southeastern portion of Six Corners-13359. The solid orange coloring indicates new underground cable or overhead conductor and the shaded orange coloring indicates areas of existing feeders that Tonquin-Hoodview will acquire. Tonquin-Driver will consist of approximately 4,000 feet of 750 Al underground cable to get to the point of connection with the existing feeder Tualatin-Cipole. The solid blue coloring indicates new underground cable and the shaded blue indicates the area that Tonquin-Driver will aquire from the existing feeder. Both feeders to the WWSP water treatment plan will be entirely new construction; they will each include approximately 1500' of new 750 Al underground cable. The feeder improvement on Six Corners-13359 will provide a strong tie to Six Corners-Chapman and also allow load from the [redacted] Six Corners-Chapman to be shifted to Six Corners-13359. Figure 22 shows a preliminary scope of work for the Six Corners-13359 feeder improvement. This scope of work will include approximately 2000 feet of new underground 750 Al cable and two spans of new 795 Al overhead conductor along NW 3rd Street.

[redacted]

Figure 22: Six Corners - 13359 Improvement

The WWSP group is planning to go live with the water treatment plant beginning in April of 2024. With their startup date in mind, the proposed timeline of the project is shown below.

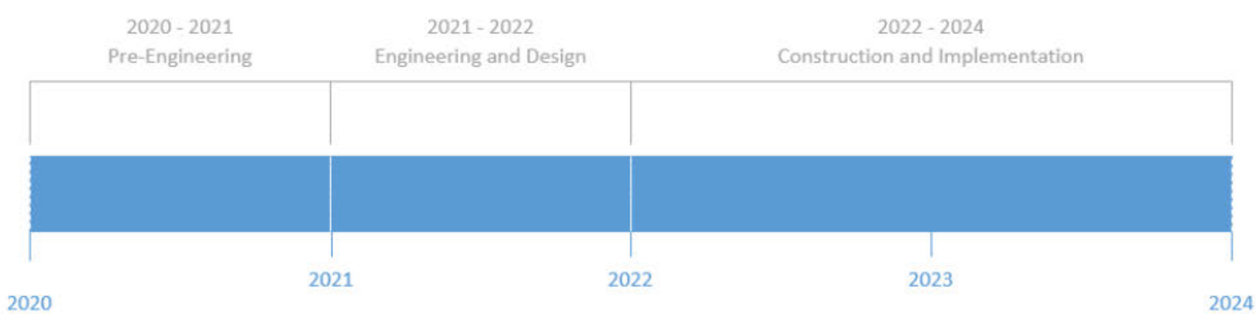


Figure 23: Proposed timeline for Tonquin Project

Transmission Recommendation

As detailed in the Transmission Analysis section, the preferred arrangement of the transmission system is provided in Option 6, which involves building a five-position ring bus at Tonquin and repurposing the existing McLoughlin-Wilsonville 115kV line into a Rosemont-Wilsonville 115kV line and a McLoughlin-Tonquin 115kV line.

The Rosemont-Wilsonville line would start at Wilsonville and use the existing 115kV line until [redacted]. It would then involve routing new 115kV structures along the existing Meridian-Meridian 13kV distribution feeder right-of-way to Rosemont (approx. 3.7 miles) and then double-circuit with Meridian- Rosemont 115kV line (approx. 1.3 miles). This route would involve crossing I-205 and the Tualatin River.

The McLoughlin-Tonquin line would start at McLoughlin and use the existing 115kV line unti [redacted]. It would then continue on the idle tap [redacted] and continue near the end of the idle tap at Pole [redacted] (crossing over I-5 and avoiding having to build another line over the freeway here). The first new portion of the line would be built from Pole [redacted] to the Coffee Creek alternative tap location (Pole [redacted] in the diagram). The existing Coffee Creek alternative tap would then be used up until (Pole [redacted]). The second new portion of the line would then go from this pole to the Tonquin substation. The existing Coffee Creek alternative tap northwest of (Pole [redacted] would be idled up to the connection with the Meridian-Sherwood 115kV line.

A one-line diagram of the proposed configuration is shown in Figure 20. Maps of the proposed transmission line arrangements are shown below in Figures 24 and 25.

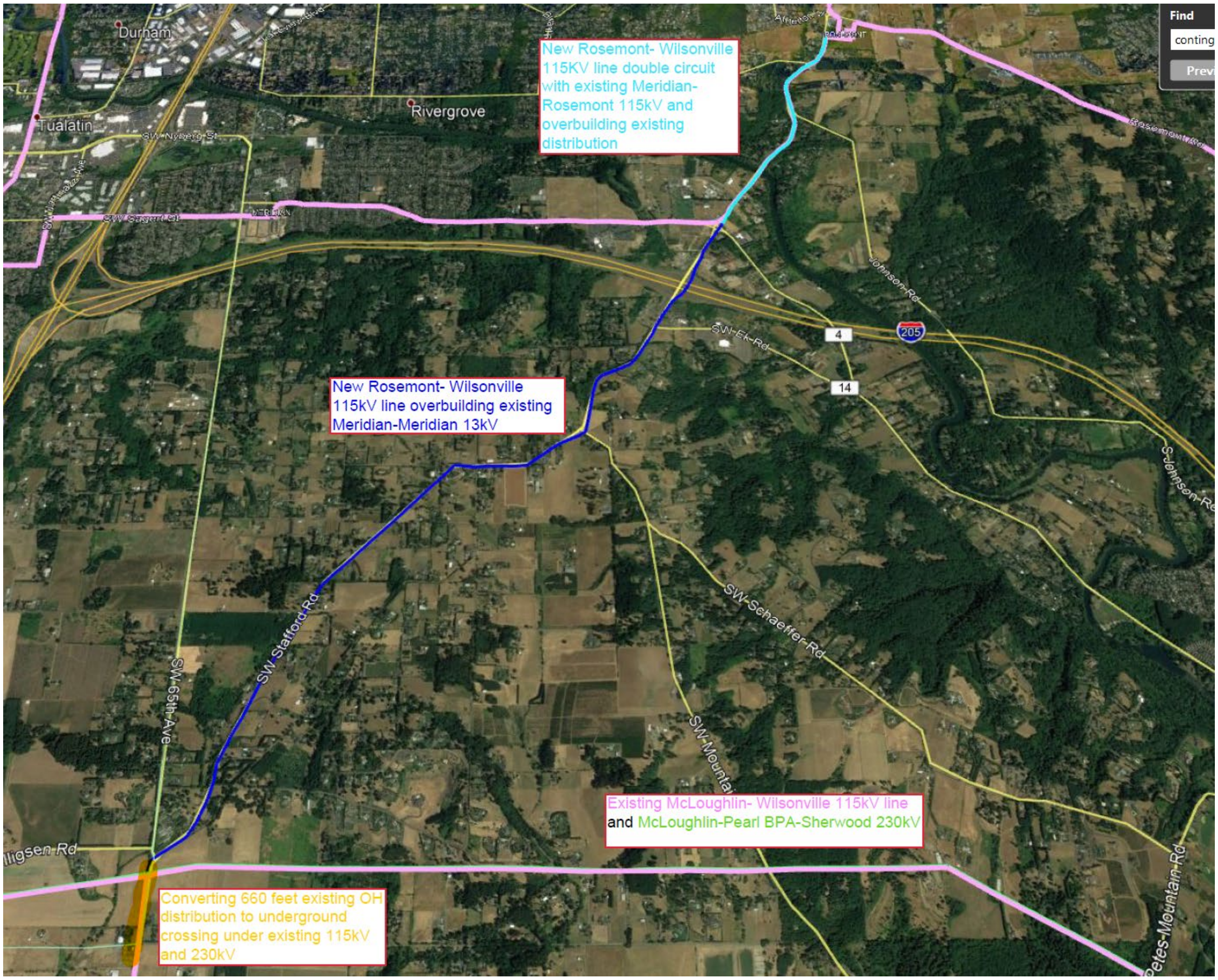


Figure 24: Recommended new Rosemont-Wilsonville 115kV line construction

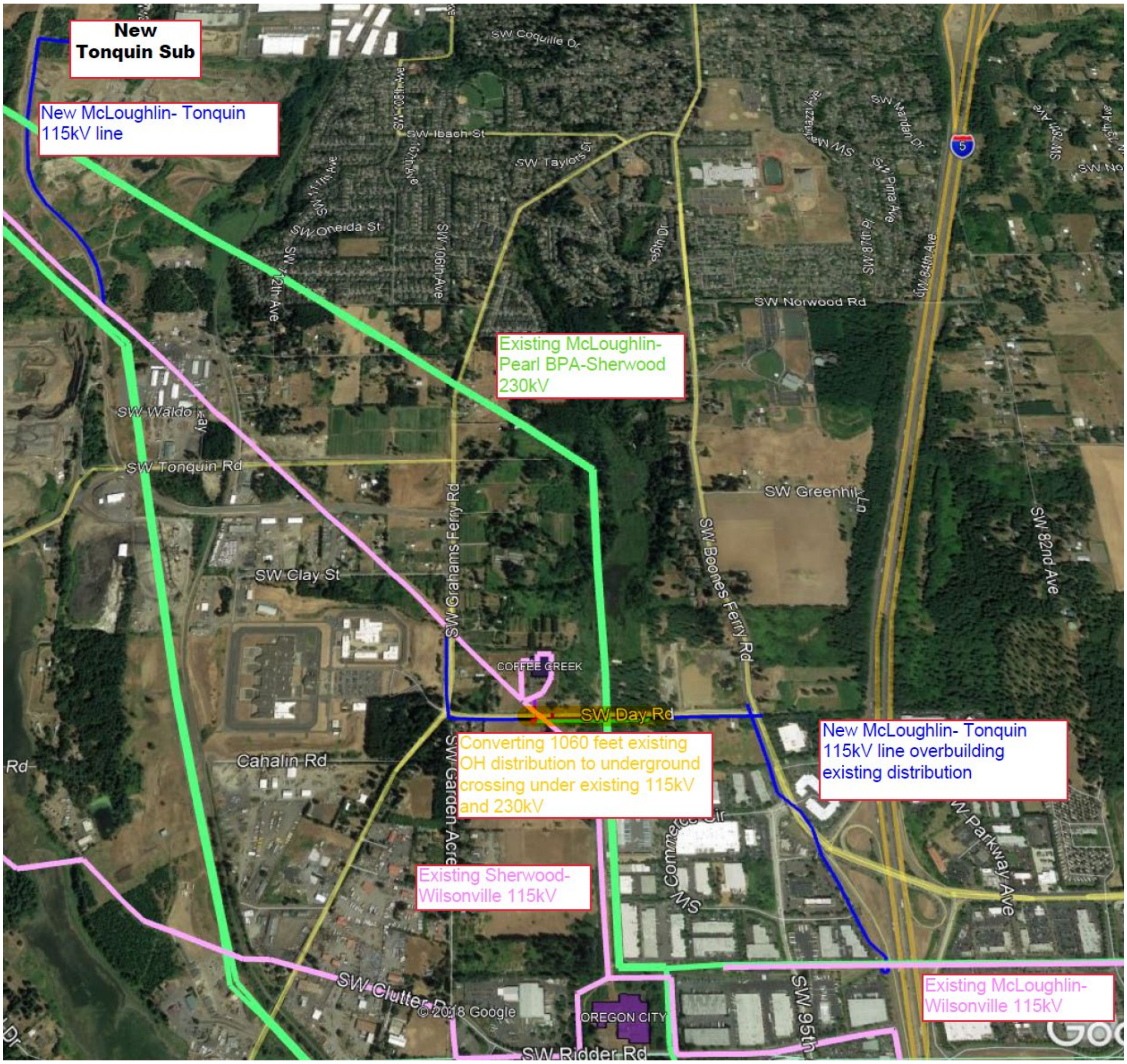


Figure 25: Recommended new McLoughlin-Tonquin 115kV line construction

This arrangement provides the most cost-effective solution that both mitigates existing overloads and prevents new overloads to the surrounding transmission system.

Project Costs

Distribution Costs

The total estimated cost for the distribution portion of this project is $7,945,705. These are early estimates and are subject to change as the project develops and more uknown factors are considered.

- $2,008,334 for the construction of the Tonquin-Driver feeder
- $3,370,273 for the construction of the Tonquin-Hoodview feeder
- $1,013,439 for the upgrades to the Six Corners-13359 feeder
- $742,431 for the construction of the Tonquin-Crystal feeder
- $811,228 for the construction of the Tonquin-Springs feeder

These feeder estimates each have a 15% contingency, labor and material escalations, and store room material loading costs factored into them. The full broken down estimate, prepared by the T&D Line Design group, can be provided upon request.

WWSP will share in the cost of one of the distribution feeders that directly feeds their water treatment plant. This will bring the cost of the distribution portion of the project to $7,203,274 assuming WWSP covers the cost of the Tonquin-Crystal.

Substation Costs

The total estimated cost to build the Tonquin substation is $20,519,639. The estimated cost will be for a 115 kV open air substation configured as a five-position ring bus with three 115 kV transmission line positions and two 13 kV distribution transformer positions. This estimate has a 25% contingency adder as well as a material cost escalation built into it. A detailed estimate provided by substation design can be provided upon request.

As with the distribution estimate, the substation estimate is an preliminary estimate and is not to be used as a final project cost. A noted risk for the substation construction is that the land that the substation is to be built on is currently covered with large trees and has been noted to have very rocky soil, making site development challenging and costly. The current estimate claims that the costs to prepare the area for the building of the substation are large unknowns that should be considered when discussing this preliminary estimate.

WWSP will share in the cost of the Tonquin Substation cost as they are the large load addition triggering the need for the new substation. With their estimated demand of 11 MVA and the substation's future N-1 capacity of 50 MVA they will share in approximately 20% of the total substation cost. [redacted]

Transmission Costs

The total estimated cost for the transmission portion of this project is $13,070,865.

This includes:

- $6,115,386 for the construction of Rosemont-Wilsonville 115kV
- $4,579,742 for the construction of McLoughlin-Tonquin 115kV
- $1,604,269 in contingency costs (15%)
- $568,148 in labor and sub escalation

- $125,503 in material escalation
- $77,817 in store room material loading costs

This total should be considered an initial feasibility estimate only. The full estimate report, prepared by Transmission Engineering, can be provided upon request.

Communications Costs

The total estimated cost to bring communications to the new Tonquin substation will be $205,000. This is an early estimate from the communications engineering department and should not be used as a final project cost.

- $105,000 to provide communications to the substation (materials, engineering, and operations time)
- $100,000 for connectivity from existing PGE communications to new substation

Total Cost Summary

The total cost summary of the project can be seen in Table 14.

	PGE Responsibility	WWSP Responsibility	Total Cost
Distribution	[redacted]	[redacted]	[redacted]
[redacted]			

Table 14: Cost summary of entire project

Conclusion

The addition of the new Tonquin substation will allow for the WWSP water treatment facility to be served reliably. Without a new substation the existing distribution system will not be adequate to serve the WWSP facility. In addition to serving the WWSP water treatment facility with the new Tonquin substation, additional feeders will offload some heavily loaded equipment served by Tualatin and Six Corners substations. This will increase the operational flexibility in the area, improving reliability for the whole region and preparing the area for further load growth in the coming years.

The added WWSP load will introduce further challenges on the transmission system. The proposed project will address potential compliance related issues, and will allow the area to be reliably served by the transmission system.

Appendix A

Substation Scope

The Tonquin Substation will be a 115 kV five position ring bus with three 115 kV line positions and two transformer positions. [redacted] The long lead items involved with the substation portion of the project are as follows:

- [redacted]

The following pages include figures 26-30 which are preliminary substation layout drawings and operating one line diagrams. PDF files of these drawings can be provided upon request.

[redacted]

Figure 26: Tonquin Substation Location on IOC property

[redacted]

Figure 27: Tonquin Substation Layout

REDACTED

[redacted]

Figure 28: Operating One Line Diagram Page 1

REDACTED

[redacted]

Figure 29: Operating One Line Diagram Page 2

[redacted]

Figure 30: Operating One Line Diagram Page 3

Appendix B

Distribution Scope

The distribution scope of this project is four new feeders and one feeder improvement on an existing feeder served by Six Corners Substation. Figure 31 on the next page shows the four new feeders that will be served by the new Tonquin Substation.

The Tonquin-Hoodview feeder will consist of approximately 6,000 feet of new underground 2-750 AL TX cable to get the the point of connection with the existing Six Corners-Six Corners 13 feeder, and approximately 6,000 feet of 795 overhead reconductor to offload the southeastern portion of the Six Corners-13359 feeder. The solid orange coloring indicates new underground cable or overhead conductor and the shaded orange coloring indicates areas of existing feeders that Tonquin-Hoodview will acquire.

The Tonquin-Driver feeder will consist of approximately 4,000 feet of 2-750 AL TX underground cable to get to the point of connection with the existing Tualatin-Cipole feeder. The solid blue coloring indicates new underground cable and the shaded blue indicates the area that Tonquin-Driver will aquire from the existing feeder.

Both feeders to the WWSP water treatment plant will be entirely new construction; they will each include approximately 1500' of new 750 Al underground cable. Both of these feeders will require crossing under SW 124th Avenue.

The feeder improvement on Six Corners-13359 will provide a strong tie to Six Corners-Chapman and also allow load from the heavily loaded Six Corners-Chapman to be shifted to Six Corners-13359. Figure 32 shows a preliminary scope of work for the Six Corners-13359 feeder improvement. This scope of work will include approximately 2000 feet of new underground 2-750 AL TX cable and two spans of new 795 Al overhead conductor along NW 3rd Street.

[redacted]

Figure 31: New Tonquin Feeders

[redacted]

Figure 32: Six Corners Feeder Improvement

Appendix C

Transmission Scope

The transmission scope of this project involves two stages.

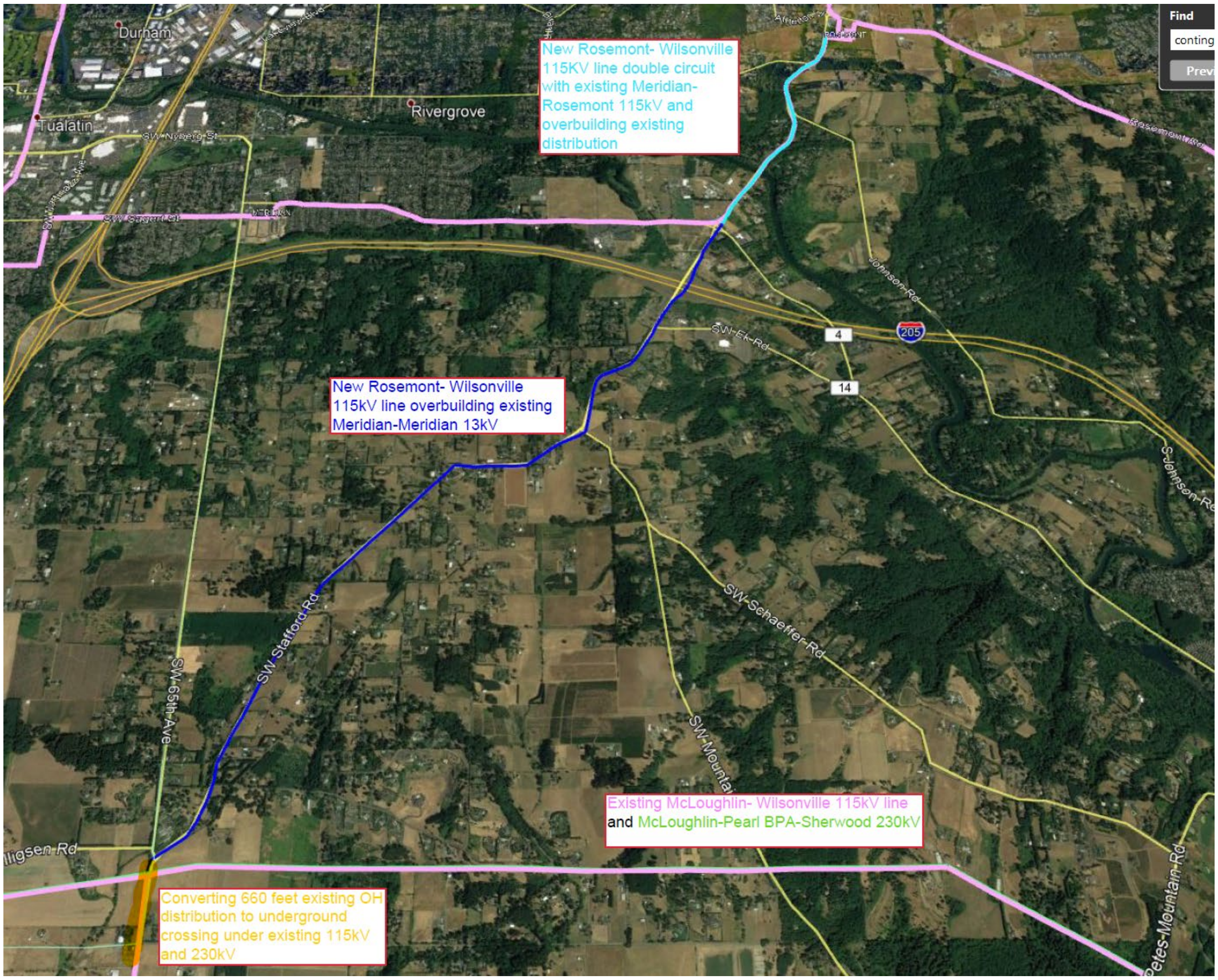
The first stage of the project splits the existing Meridian-Sherwood 115kV line at the intersection of 124^{th} Ave and Tualatin-Sherwood Rd, and constructs two parallel transmission lines south from this point into the Tonquin substation. This creates new Meridian-Tonquin 115kV and Sherwood-Tonquin 115kV lines, providing two sources initially to Tonquin substation.

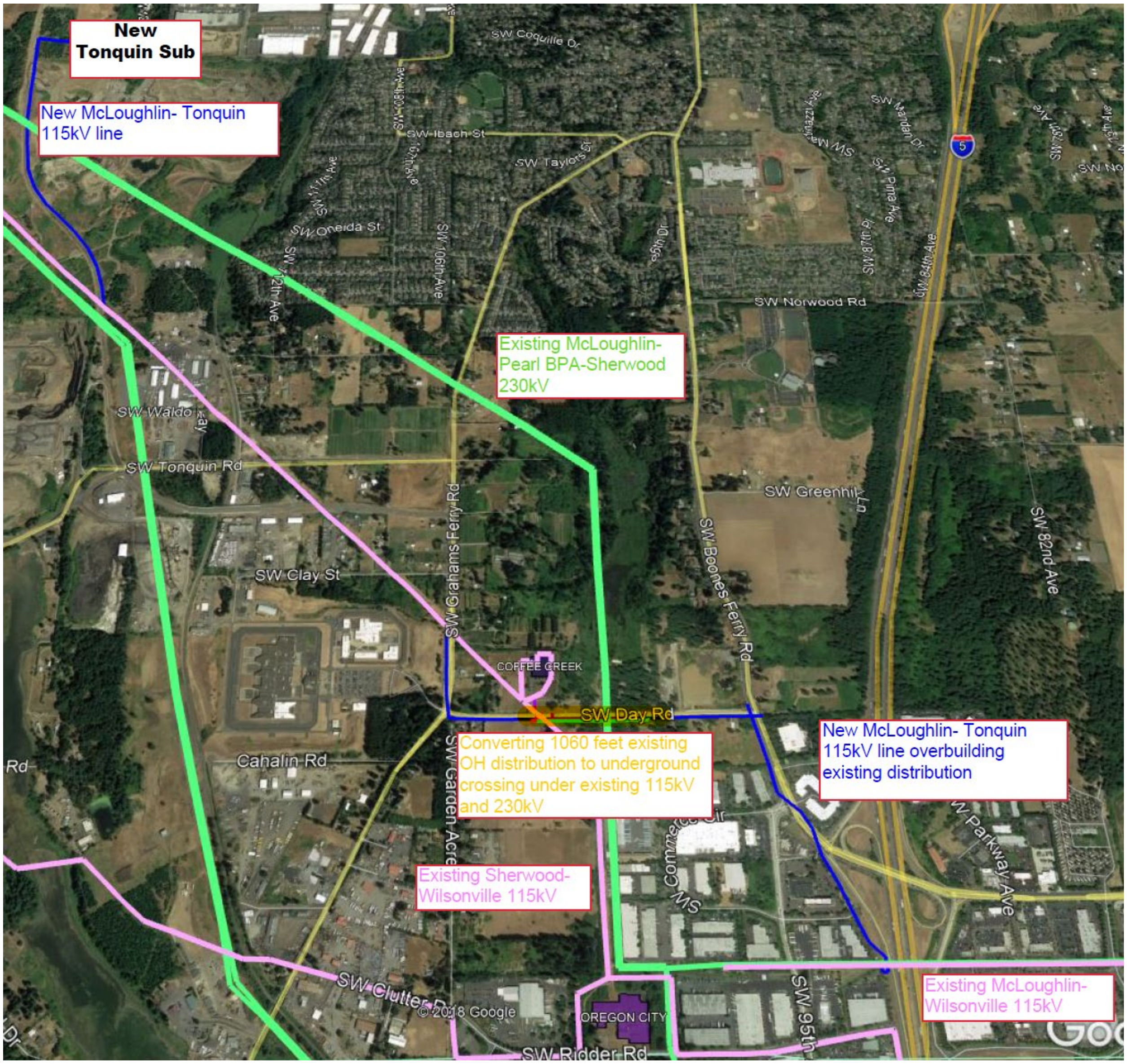
The second stage of the project involves several components. One component is the construction of a new Rosemont-Wilsonville 115kV line, which would start at Wilsonville substation and use the existing McLoughlin-Wilsonville 115kV line until Pole [redacted] It would then involve routing new 115kV structures along the existing Meridian-Meridian 13kV distribution feeder right-of-way to Rosemont (approx. 3.7 miles) and then double-circuit with Meridian- Rosemont 115kV line (approx. 1.3 miles). This route would involve crossing I-205 and the Tualatin River.

The other component is the construction of the McLoughlin-Tonquin line, which would start at McLoughlin substation and use the existing McLoughlin-Wilsonville 115kV line until Pole [redacted] It would then continue on the idle tap (starting with Pole [redacted] and continue near the end of the idle tap at Pole [redacted] (crossing over I-5 and avoiding having to build another line over the freeway here). The first new portion of the line would be built from Pole [redacted] to the Coffee Creek alternative tap location [redacted] in the diagram). The existing Coffee Creek alternative tap would then be used up until [redacted]). The second new portion of the line would then go from this pole to the Tonquin substation. The existing Coffee Creek alternative tap northwest of [redacted] would be idled up to the connection with the Sherwood-Tonquin 115kV line.

The completion of the second stage of the project results in a third source into Tonquin substation.

Maps of the proposed transmission line arrangements are shown in the figures below.


New Rosemont- Wilsonville 115KV line double circuit with existing Meridian-Rosemont 115kV and overbuilding existing distribution
New Rosemont- Wilsonville 115kV line overbuilding existing Meridian-Meridian 13kV
Existing McLoughlin- Wilsonville 115kV line and McLoughlin-Pearl BPA-Sherwood 230kV
Converting 660 feet existing OH distribution to underground crossing under existing 115kV and 230kV
Durham
Tualatin
Rivergrove
SW Stafford Rd
SW 65th Ave
SW Schaeffer Rd
SW Ek Rd
Johnson Rd
S Johnson Rd
Petes Mountain Rd
205
4
14


New Tonquin Sub
New McLoughlin- Tonquin 115kV line
Existing McLoughlin-Pearl BPA-Sherwood 230kV
Converting 1060 feet existing OH distribution to underground crossing under existing 115kV and 230kV
New McLoughlin- Tonquin 115kV line overbuilding existing distribution
Existing Sherwood-Wilsonville 115kV
Existing McLoughlin-Wilsonville 115kV
SW Day Rd
SW Tonquin Rd
SW Clay St
SW Grahams Ferry Rd
SW Boones Ferry Rd
SW Norwood Rd
SW Ridder Rd
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PGE/102

NERC Reliability Standard TPL-001-5.1

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-5.1**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   - Planning Coordinator.
   - Transmission Planner.

5. **Effective Date: See Implementation Plan.**

B. Requirements and Measures

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities.

1.1.2. New planned Facilities and changes to existing Facilities.

1.1.3. Real and reactive Load forecasts.

1.1.4. Known commitments for Firm Transmission Service and Interchange.

1.1.5. Resources (supply or demand side) required for Load.

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using data consistent with MOD-032, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. Based upon this assessment, an analysis shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.4.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner’s portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

2.4.5. When an entity’s spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments, but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.3 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

3.3. Contingency analyses for Requirement R3, Parts 3.1 and 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Remedial Action Scheme is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event (s) shall be conducted.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data identified in Measures M1 through M8 or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Compliance Monitoring Period and Reset Timeframe:

Not applicable.

1.5. Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checks
- Compliance Violation Investigations
- Self-Report
- Complaints

1.6. Additional Compliance Information

None.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.5.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.5.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.5.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.5. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-032 standard and other sources, including items represented in the Corrective Action Plan.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1,	The responsible entity failed to comply with two or more of the following Parts of

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3.	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4.	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				deviations, or the transient voltage response for its System.
R6.	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.
R7.	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees.	

Version	Date	Action	Change Tracking
		TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	November 7, 2018	Adopted by the NERC Board of Trustees.	Revised to address reliability issues as identified in FERC Order No. 754 and Order No. 786 directives and update the references to the MOD Reliability Standards in TPL-001.
5.	January 23, 2020	FERC Order issued approving TPL-001-5. Docket No. RM19-10-000.	
5.1	June 10, 2020	FERC Order issued approving TPL-001-5.1. Docket No. RD20-8-000.	Errata

Version	Date	Action	Change Tracking
5.1	July 29,2020	Effective Date	7/1/2023

Table 1 – Steady State & Stability Performance Planning Events
Steady State & Stability: a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur. b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0. c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. d. Simulate Normal Clearing unless otherwise specified. e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Steady State Only**: f. Applicable Facility Ratings shall not be exceeded. g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner. h. Planning event P0 is applicable to steady state only. i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements. **Stability Only:** j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker[10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events	
Steady State & Stability For all extreme events evaluated: a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency. b. Simulate Normal Clearing unless otherwise specified.	
Steady State 1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. 2. Local area events affecting the Transmission System such as: a. Loss of a tower line with three or more circuits.[11] b. Loss of all Transmission lines on a common Right-of-Way[11]. c. Loss of a switching station or substation (loss of one voltage level plus transformers). d. Loss of all generating units at a generating station. e. Loss of a large Load or major Load center. 3. Wide area events affecting the Transmission System based on System topology such as: a. Loss of two generating stations resulting from conditions such as: i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.	**Stability** 1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. 2. Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker[10] resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing. e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. i. 3Ø internal breaker fault. j. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. For purposes of this standard, non-redundant components of a Protection System to consider are as follows: a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times; b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center); c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit); d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level

   b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency

2. Amount of Non-Consequential Load Loss with:
   a. The estimated number and type of customers affected
   b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)

2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

PGE/103

WECC Criterion TPL-001-WECC-CRT-3.2

Electric Reliability and Security for the West

WECC Criterion
TPL-001-WECC-CRT-3.2

Introduction

1. **Title**: **Transmission System Planning Performance**
2. **Number**: TPL-001-WECC-CRT-3.2
3. **Purpose**: To facilitate coordinated near-term and long-term transmission planning within the Interconnection of the Western Electricity Coordinating Council (WECC), and to facilitate the exchange of the associated planning information for normal and abnormal conditions.

   This document applies to all transmission planning studies conducted within the Interconnection of the Western Electricity Coordinating Council (WECC).

   This is a planning criterion. This document does not designate the entity responsible for system remediation.

4. **Applicability**:

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Transmission Planner

   4.2. Facilities

   4.2.1. This document applies to Bulk Electric System (BES) Facilities.

   4.2.2. The following buses are specifically excluded from this WECC Criterion:

   4.2.2.1. Non-BES buses,

   4.2.2.2. Line side series capacitor buses,

   4.2.2.3. Line side series reactor buses,

   4.2.2.4. Dedicated shunt capacitor buses,

   4.2.2.5. Dedicated shunt reactor buses,

   4.2.2.6. Metering buses, fictitious buses, or other buses that model point of interconnection solely for measuring electrical quantities; and

4.2.2.7. Other buses specifically excluded by each Planning Coordinator or Transmission Planner internal to its system.

5. **Effective Date**: June 18, 2019

Requirements and Measures

WR1. Each Transmission Planner and Planning Coordinator shall use the following default base planning criteria, unless otherwise specified in accordance with Requirements WR2 and WR3:

1.1. Steady-state voltages at all applicable Bulk-Electric System (BES) buses shall stay within each of the following limits:

1.1.1. 95 percent to 105 percent of nominal for P0[1] event (system normal pre-contingency event powerflow);

1.1.2. 90 percent to 110 percent of nominal for P1-P7[2] events (post-contingency event powerflow).

1.2. Post-Contingency steady-state voltage deviation at each applicable BES bus serving load shall not exceed 8 percent for P1 events.

1.3. Following fault clearing, the voltage shall recover to 80 percent of the pre-contingency voltage within 20 seconds of the initiating event for all P1 through P7 events, for each applicable BES bus serving load.

1.4. Following fault clearing and voltage recovery above 80 percent, voltage at each applicable BES bus serving load shall neither dip below 70 percent of pre-contingency voltage for more than 30 cycles nor remain below 80 percent of pre-contingency voltage for more than two seconds, for all P1 through P7 events.

1.5. For Contingencies without a fault (P2.1 category event), voltage dips at each applicable BES bus serving load shall neither dip below 70 percent of pre-contingency voltage for more than 30 cycles nor remain below 80 percent of pre-contingency voltage for more than two seconds.

1.6. All oscillations that do not show positive damping within 30-seconds after the start of the studied event shall be deemed unstable.

WM1. Each Transmission Planner and Planning Coordinator will have evidence that it used the base criteria in its Planning Assessment specified in Requirement WR1, unless otherwise allowed in accordance with Requirements WR2 and WR3.

WR2. Each Transmission Planner and Planning Coordinator that uses a more stringent criterion than that stated in Requirement WR1 shall apply that criterion only to its own system, except

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[1] P0 through P7 refers to the categories of contingencies identified in Table 1 of NERC Standard TPL-001-4, Transmission System Planning Performance Requirements.

[2] Previously cited

where otherwise agreed upon by all other planning entities to which the more stringent criterion was applied.

WM2. Each Transmission Planner and Planning Coordinator that uses a more stringent criterion in its planning assessment than that stated in Requirement WR1 and applied that criterion to other systems will have evidence of agreement from all other planning entities to which the more stringent criterion was applied.

WR3. Each Transmission Planner and Planning Coordinator that uses a less stringent criterion than that stated in Requirement WR1 shall allow other Transmission Planners and Planner Coordinators to have the same impact on that part of the system for the same category of planning events (e.g., P1, P2).

WM3. Each Transmission Planner and Planning Coordinator that uses a less stringent criterion than that stated in Requirement WR1 will have evidenced that it allowed other Transmission Planners and Planner Coordinators to have the same impact on that part of the system for the same category of planning events (e.g., P1, P2).

WR4. Each Transmission Planner and Planning Coordinator shall use the following threshold criteria to identify the potential for Cascading or uncontrolled islanding. An entity can use these criteria to identify instability due to Cascading or uncontrolled islanding if it does not impose it on others:

- When a post contingency analysis results in steady-state facility loading that is either more than a known BES facility trip setting, or exceeds 125 percent of the highest seasonal facility rating for the BES facility studied. If the trip setting is known to be different than the 125 percent threshold, the known setting should be used.
- When transient stability voltage response occurs at any applicable BES bus outside of the criteria stated in Requirement WR1.3 of this document.
- When either unrestrained successive load loss occurs or unrestrained successive generation loss occurs.

WM4. Each Transmission Planner and Planning Coordinator will have evidence that it used the indicators of Requirement WR4 to identify the potential for Cascading or uncontrolled islanding.

WR5. Each Transmission Planner and Planning Coordinator shall use the following minimum criteria when identifying voltage stability:

5.1. For transfer paths, all P0-P1 events shall demonstrate a positive reactive power margin at a minimum of 105 percent of transfer path flow.

5.2. For transfer paths, all P2-P7 events shall demonstrate a positive reactive power margin at a minimum of 102.5 percent of transfer path flow.

5.3. For load areas, all P0-P1 events shall demonstrate a positive reactive power margin at a minimum of 105 percent of forecasted peak load.

5.4. For load areas, all P2-P7 events shall demonstrate a positive reactive power margin at a minimum of 102.5 percent of forecasted peak load.

WM5. Each Transmission Planner and Planning Coordinator will have evidenced that it used the minimum criteria identified in Requirement WR5 to identify voltage stability.

WR6. Each Transmission Planner and Planning Coordinator that uses study criteria different from the base criteria in Requirement WR1 shall make its criteria available upon request within 30 days.

WM6. Each Transmission Planner and Planning Coordinator that uses study criteria different from the base criteria in Requirement WR1 will have evidence that it made its criteria available upon request, as required in Requirement WR6.

Version History

Version	Date	Action	Change Tracking
1	March 6, 2008	WECC Planning Coordination Committee (PCC) approved TPL-(001 thru 004)-WECC-1-CR.	Reliability Subcommittee translates existing WECC components of NERC/WECC Planning Standards into a CRT.
1	April 16, 2008	WECC Board of Directors (Board) approved	No substantive changes
2	October 13, 2011	PCC approves	Clarifies "corridor"
2	December 1, 2011	Board approved	No substantive change
2	September 5, 2012	Board changed designation	Approved a nomenclature change from "CRT" to "RBP"
2.1	August 6, 2013	Errata	WM2 Measure moved to WM3. WM3 Measure moved to WM4. WM4 Measure moved to WM2.
2.1	December 5, 2013	Board approved	Developed as WECC-0100, on October 8, 2013, the Ballot Pool retired WR1, WR2, WR4 and WR5 of TPL-(012 through 014)-WECC-RBP-2 coincident with the October 17, 2015 Effective Date of NERC TPL-001-4, Transmission System Planning Performance requirements. (See 18 CFR Part 40, Docket RM-12-1-000 and RM13-9-000, FERC Order 786, issued October 17, 2013.) Table W-1, WECC Disturbance-Performance Table of Allowable Effects on Other Systems, Table W-1 Notes, Figure W-1, and Footnotes 1-3 were also retired along with their supporting WECC Requirements, WR1, WR2, and WR5. On December 5, 2013, the Board ratified that decision.
2.1	June 25, 2014	Board changed designation	Changed from regional Business Practice (RBP) to Criterion (CRT). No other changes.
2.2	January 14, 2016	Errata	Retired WECC Requirements WR1, WR2, WR4, and WR5 and their subsets were removed from the document. WR3 was renumbered to WR1.
2.3	September 20, 2016	Errata	Sub-parts of the 4.2 Facilities section impacted by the retirement of WR1, WR2, WR4 and WR5 of TPL-(012 through 014)-WECC-RBP-2 were removed.
3	September 21, 2016	Board approved	This document addresses: 1) the substance of its preceding versions, 2) requirements imposed by NERC TPL-001-4, Transmission System Planning Performance Requirements, Requirements R5 and R6, and 3) the substance of Table W-1 retired from Version 2.1. The Effective Date was approved as "the later of January 1, 2016 or the Effective Date of TPL-001-4, Transmission System Planning Performance, Requirements R2-R6 and R8, subject to approvals." Because the effective date of the NERC requirements has already been triggered the document was effective immediately on approval by the Board.

3.1	December 6, 2016	Errata	The spelling error in Section 4.2.2.6 "quantizies" was corrected to read "quantities." In WM2, the phrase "the criteria was applied" was replaced with "the criterion was applied."
3.2	June 18, 2019	Errata	Converted to newest template. In Version 3.2: 1) bulleting in 4.2 Facilities was corrected, 2) at 4.2.2.7, "their" was replaced with "its", 3) use of "X%" was changed to "X percent" throughout, 4) use of "are/is allowed" was changed to "can" throughout, 5) WR4, "as long as" was replaced with "if", "in excess" was replaced with "more than", 6) Version History syntax was corrected, 7) Rationale section, "with the exception of the 500 kilo-volt class" changed to "except the 500 kilo-volt class", Rationale section (last page) "don't" was changed to "do not", 8) Rationale section at WR4, second bullet "Prepared" replaced with "prepared" and at the next to the last paragraph, "time frame" was replaced with "period".

Attachments

Not used.

Rationale

A Rationale section is optional. If Rationale Boxes were used during the development of this project, the content of those boxes appears below.

Rationale for Requirement WR1

This is a planning criterion.

WR1 addresses NERC TPL R5 and R6.

WR1 is designed to state the base planning criteria the system must meet—unless an individual entity or group of entities has different criteria. WECC Requirements WR2 and WR3 allow for entities to have different criteria.

Neither WR2 nor WR3 changes the WR1 default; rather, WR2 and WR3 allow for deviation from the WR1 default. WR2 allows for a more stringent approach without changing the WR1 default. A more stringent approach may be used in accordance with WR2 so long as all the affected parties agree. Similarly, WR3 allows deviation from the default with the additional protection that when used, other Transmission Planners and Planning Coordinators can use the same criteria on that part of the system for the same category of planning events (e.g., P1 and P2).

In the context of Requirement WR1, the word “nominal” carries its common definition and could be, for example, either the base voltage or the operating voltage as established in the entity’s Planning Assessment. This means that nominal may have a varying definition or use from one entity to the next. If an entity does not specify what is nominal, the default use of the term nominal defaults to the kilo-volt class that is specified in the WECC Base Case, except the 500 kilovolt class, in which case the default nominal would be specified as 525 kilovolt.

Requirement WR1.1.2 refers to the post automatic equipment adjustment effect prior to manual adjustment.

Rationale for Requirement WR1.2

For purposes of this document, a BES bus that is serving load is the bus with direct transformation from BES-level voltage to distribution-level voltage that serves load.

In developing WR1.2, the drafting team was aware that eight percent is not the only practical percentage for use. Historically, stakeholders reported successfully using percentages between five and ten whereas others reported being under a regulatory mandate to use eight percent. To accommodate both positions the team selected the eight percent.

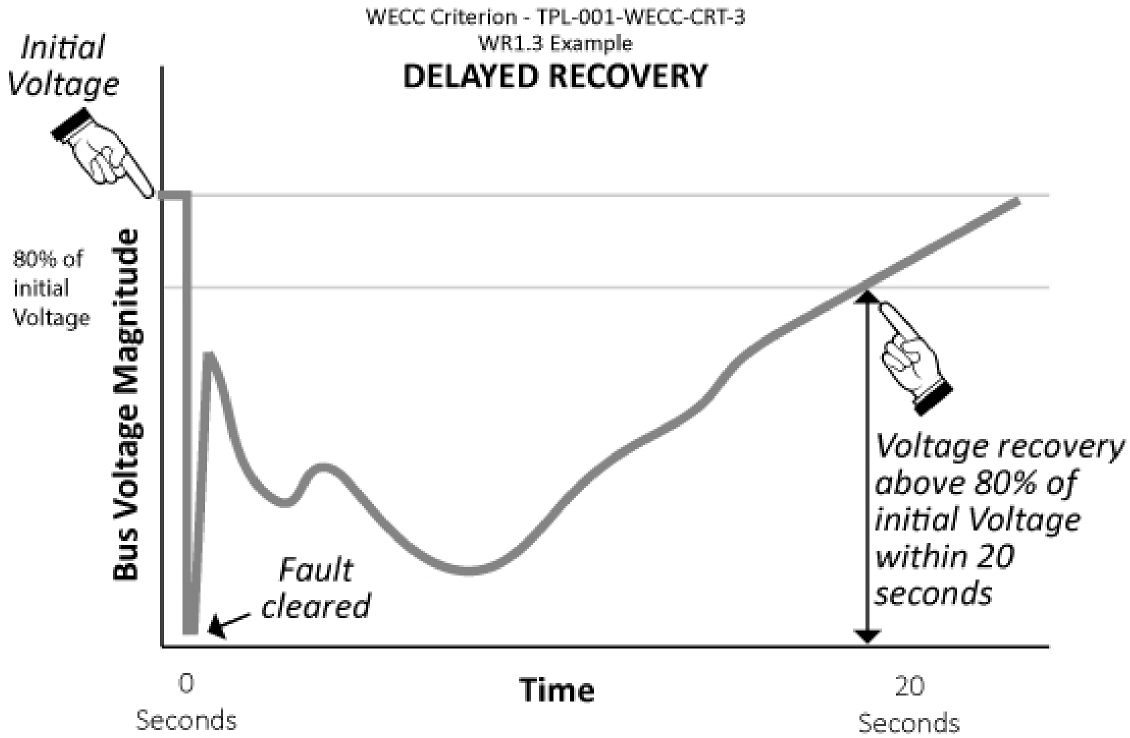
By default, only automatic post-contingency actions occurring in the studied timeframe are considered when calculating voltage deviation. This would include, among other things, capacitor or reactor switching. For purposes of WR1.2, automatic generally means a programmed response not manually initiated.

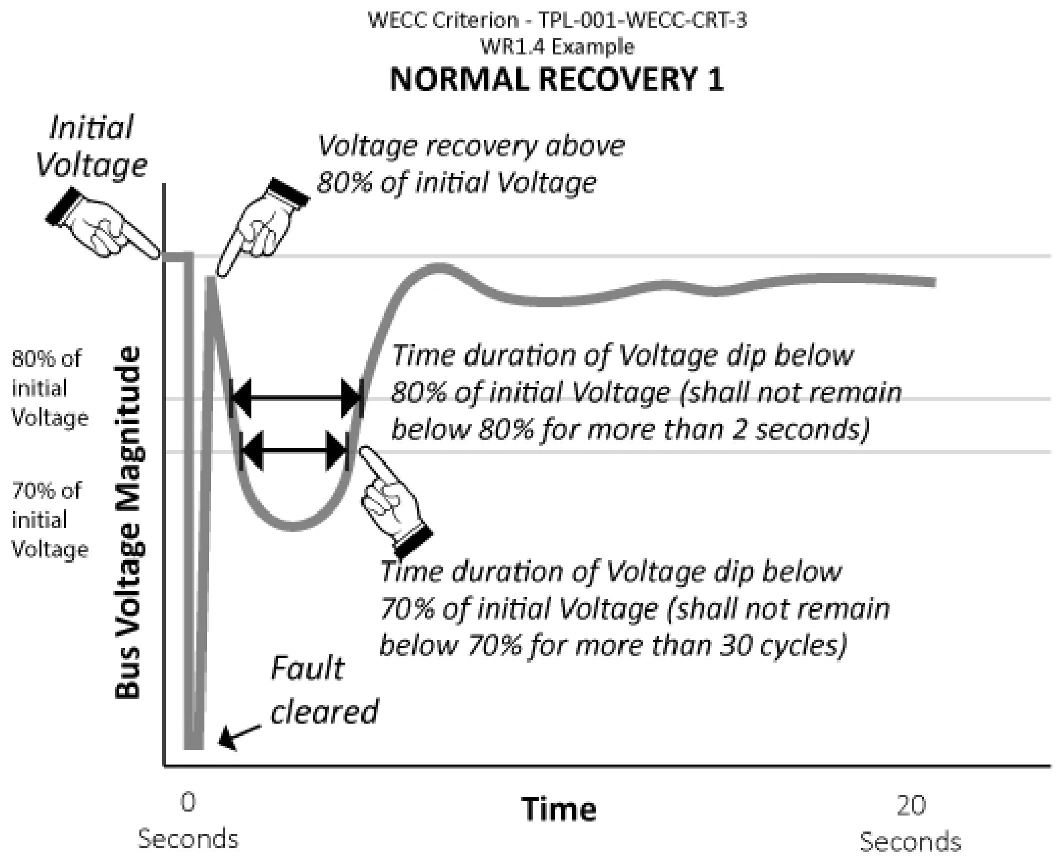
For P1 there is no high voltage deviation requirement. For P2-P7, there is no low or high voltage deviation requirement. It is implied that P2 through P7 events do not require a voltage deviation beyond meeting the requirements in WR1.1.2.

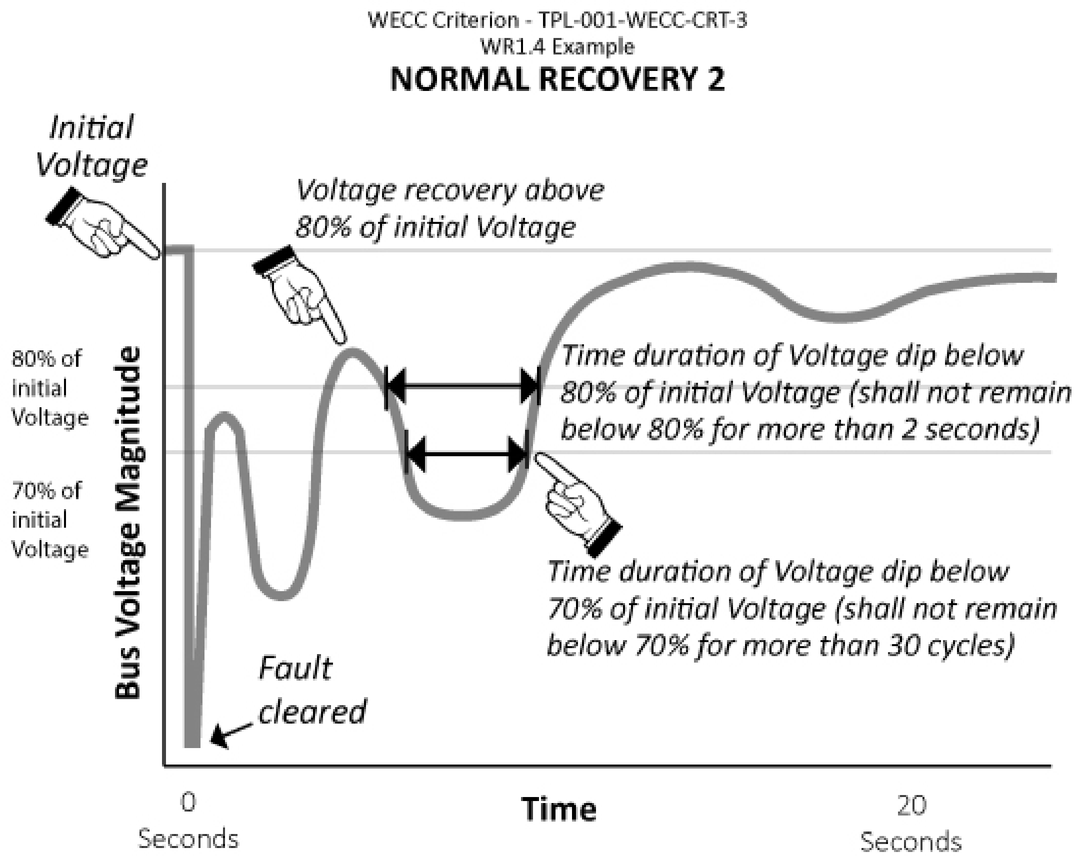
For purposes of this document, a BES bus that is serving load is the bus with direct transformation from BES-level voltage to distribution-level voltage that serves load.

The following illustrations apply to WR1.3 and WR1.4, and not WR1.2.

The following diagrams are offered for illustrative purposes. They are not designed to depict all possible voltage trajectories.


WECC Criterion - TPL-001-WECC-CRT-3
WR1.3 Example
DELAYED RECOVERY
Initial Voltage
80% of initial Voltage
Bus Voltage Magnitude
Fault cleared
Voltage recovery above 80% of initial Voltage within 20 seconds
0 Seconds
Time
20 Seconds


WECC Criterion - TPL-001-WECC-CRT-3
WR1.4 Example
NORMAL RECOVERY 1
Initial Voltage
Voltage recovery above 80% of initial Voltage
80% of initial Voltage
70% of initial Voltage
Bus Voltage Magnitude
Time duration of Voltage dip below 80% of initial Voltage (shall not remain below 80% for more than 2 seconds)
Time duration of Voltage dip below 70% of initial Voltage (shall not remain below 70% for more than 30 cycles)
Fault cleared
0 Seconds
Time
20 Seconds


WECC Criterion - TPL-001-WECC-CRT-3
WR1.4 Example
NORMAL RECOVERY 2
Initial Voltage
Voltage recovery above 80% of initial Voltage
80% of initial Voltage
70% of initial Voltage
Bus Voltage Magnitude
Time duration of Voltage dip below 80% of initial Voltage (shall not remain below 80% for more than 2 seconds)
Time duration of Voltage dip below 70% of initial Voltage (shall not remain below 70% for more than 30 cycles)
Fault cleared
0 Seconds
Time
20 Seconds

Rationale for Requirement WR4

Requirement WR4 is designed to establish screening criteria that when exceeded may require further investigation of instability. The Requirement is not intended to show the presence of Cascading or instability. An entity can use these criteria for instability if they choose without imposing it on others.

The term Cascading in WR4 is the NERC defined term.

In WR4, Bullet 1, the 125 percent threshold is imported from the Peak RC System Operating Limits Methodology. The 125 percent threshold should only be used for facilities where the trip setting is not known. If the trip setting is known that known setting should be used. For example, if the known trip setting is 150 percent of the continuous rating, this should take precedence over the 125 percent of the highest rating.

The specific amounts of unrestrained load loss addressed in WR4, Bullet three, are not specified in this document. Because of the breadth of the possible permutations, the amount should be left to the sound engineering judgment of the planning entity.

Rationale for Requirement WR5

Requirement WR5 addresses "what" must be achieved and does not address "how" to do it.

For a review of "how" to achieve the goals, please refer to:

- The WECC Voltage Stability Assessment Methodology
- WECC Guide to WECC/NERC Planning Standards 1.D: *Voltage Support and Reactive Power*, prepared by: Reactive Reserve Working Group (RRWG), Under the auspices of Technical Studies Subcommittee (TSS); Approved by TSS, March 30, 2006
- Additional guidance is contained in Section 2.2 Voltage Stability of the Guide to WECC/NERC Planning Standards 1.D, Voltage Support and reactive Power, March 30, 2006.

The intent of Requirement WR5 is to ensure the voltage stability of transfer paths as well as the system as a whole during peak load or peak transfer conditions. A margin on real power flow is used as a test for voltage stability. A positive reactive power margin can be demonstrated by a valid steady state power flow solution.

Power flow solutions refer to post contingency conditions where the actions of reactive devices and load tap changers should be modeled for the appropriate period being studied.

There is a higher likelihood of occurrence of a P0 to P1 category event; therefore, a higher margin (105%) is used. For P2–P7, there is a lower likelihood of occurrence; therefore, the lower margin (102.5%) is used.

Rationale for Requirement WR6

Requirement WR6 ensures the free flow of information between entities.

PGE/104

2023 PGE Transmission Planning Study Methodology

Study Methodology

PGE's Transmission System is designed to reliably supply projected customer demand and projected Firm Transmission Service. Studies are performed annually to evaluate where Transmission upgrades may be needed to meet the performance requirements established in the NERC TPL-001-5 Reliability Standard and the WECC TPL-001-WECC-CRT-3.2 Regional Criteria.

The summer (June 1st through October 31st) and winter (November 1st through March 31st) load seasons are considered the most critical study seasons due to heavier peak loads and high power transfers over PGE's Transmission and Distribution System to its customers. However, the off-peak seasons have different regional flow patterns that can result in issues not seen during peak load times. PGE defines the seasons to align with Attachment I of the RC West "RC Guidelines for Seasonal Assessment and Coordination Process."

Summer and Winter loading conditions and the corresponding daily averaged temperatures are as follows:

Summer	
1-in-2	81.9°F
1-in-3	83.4°F
1-in-5	84.6°F
1-in-10	86.1°F
1-in-20	87.3°F

Winter	
1-in-2	28.6°F
1-in-3	26.8°F
1-in-5	25.1°F
1-in-10	23.2°F
1-in-20	21.7°F

PGE maintains System models within its planning area for performing the studies required to complete the System Assessment. These models use data that is provided in WECC Base Cases in accordance with the MOD-032 reliability standard. Electrical facilities modeled in the cases have established ratings, as defined in PGE's Facility Ratings Methodology document. A Facility Rating is determined based on the most limiting component in a given Transmission path, in accordance with the FAC-008 reliability standard.

Reactive power resources are modeled as made available in the WECC base cases. For PGE, reactive power resources include shunt capacitor banks available on the 115 kV Transmission System and on the 57 kV distribution System.

Studies are evaluated for the Near Term Planning Horizon (years 1 through 5) and the Long Term Planning Horizon (years 6 through 10) to ensure adequate capacity is available on PGE's Transmission System. The load model used in the studies is obtained from PGE's corporate forecast, reflecting a 1-in-3[1] demand level for peak summer and peak winter conditions. Known outages of generation or Transmission Facilities with durations of at least six months are appropriately represented in the System models. Transmission equipment is assumed to be out of service in the Base Case System models if there is no spare equipment or mitigation strategy for the loss of the equipment.

Studies in the Near Term – Two Year Planning Horizon and the Near Term – Five Year Planning Horizon are performed for peak summer, peak winter, and off-peak spring conditions. Sensitivity studies are performed for each of these cases by varying the study parameters to stress the System within a range of credible conditions that demonstrate a measurable change in performance. PGE adjusts the real and reactive forecasted load and the transfers on the paths into the Portland area on all sensitivity studies. For peak System sensitivity cases, the 1-in-10[2] load forecast is used.

[1] The 1-in-3 conditions correlate to a Net System Load that PGE expects to reach once every three years. The 1-in-3 forecast takes the Corporate Load Forecast and adds large industrial load growth that is planned but does not have a firm load commitment (therefore not included in the Corporate Load Forecast).

[2] The 1-in-10 conditions correlate to a Net System Load that PGE expects to reach once every ten years. The 1-in-10 forecast takes the Corporate Load Forecast and adds large industrial load growth that is planned but does not have a firm load commitment (therefore not included in the Corporate Load Forecast).

Studies are evaluated at peak summer and peak winter 1-in-3 load conditions for one of the years in the Long Term Planning Horizon. Year Ten is chosen for the Long Term Planning Horizon studies because it aligns with the WECC Long Term Planning base cases and represents all projects in the Long Term Planning Horizon.

The Bulk Electric System (BES) is evaluated for steady state and transient stability performance for planning events described in Table 1 of the NERC TPL-001-5 reliability standard. When System simulations indicate an inability of the Systems to respond as prescribed in the NERC TPL-001-5 standard, PGE identifies projects and/or Corrective Action Plans which are needed to achieve the required System performance throughout the Planning Horizon.

Steady-State Studies

PGE performs steady-state studies for the Near-Term and Long-Term Transmission Planning Horizons. The studies consider all Contingency scenarios identified in Table 1 of the NERC TPL-001-5 reliability standard (Categories P0-P7) to determine if the BES meets performance requirements. PGE uses the criteria defined in the WECC TPL-001-WECC-CRT-3.2 document to establish acceptable System steady state voltage limits and post-Contingency voltage deviations. The WECC System Performance Criteria requires that the change in bus voltage percentage not exceed 8% for N-1 contingencies. Additionally, internal PGE performance criteria require that the change in bus voltage percentage not exceed 10% for N-2 and N-1-1 contingencies. These studies also assess the impact of Extreme Events on the System expected to produce severe System impacts.

The Contingency analyses simulate the removal of all Elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without Operator intervention. The analyses include the impact of the subsequent tripping of generators due to voltage limitations and tripping of Transmission Elements where relay loadability limits are exceeded. Automatic controls simulated include phase-shifting transformers, load tap changing transformers, and switched capacitors and reactors.

Cascading, or the uncontrolled successive loss of System Elements triggered by a Disturbance that results in the inability of the Elements of the BES to regain a state of operating equilibrium is defined as a System instability. Cascading is not allowed to occur for any Contingency analysis. If the analysis of an Extreme Event concludes there is Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is completed.

The following process is used to test for Cascading:

1. Single Contingencies and credible multiple Contingencies that result in excess of the lower of:
    a. The Facility(ies)'s trip setting, or
    b. 125% of the highest Facility Emergency Rating (Note: if the trip setting is known to be different than the 125% threshold, the known trip setting should be used).
2. For each flagged Contingency, open the original Contingency Elements and the Elements flagged in step 1. Run steady state analysis without any manual System adjustments.
3. Repeat step 2 for any newly overloaded Facilities in excess of step 1 criteria. Continue repeating step 2 until no more Facilities are removed from service or until the powerflow solution diverges.
4. If the process of tripping Elements in steps 2 and 3 stops prior to divergence, then it can be concluded that the area of impact is predetermined by studies, and Cascading does not occur. If the powerflow solution diverges during the test described above utilizing the 125% of the highest Facility Emergency Rating threshold, further investigation into post-Contingency loading may be warranted prior to declaring that Cascading occurs.

Uncontrolled islanding is defined as a System instability that occurs when Transmission operating actions, such as tripping for loading a given percentage above the highest Facility emergency rating, result in the separation and loss of synchronism of a portion of the Bulk Power System that includes generation or load. Generators disconnected from the System by fault clearing action or by a RAS are not considered out of synchronism. Similarly, islands formed by disconnection from the System by fault clearing action or by a RAS are considered a sub-network island and not an uncontrolled island.

Characteristics of a sub-network island include:

- The presence of both generation and load to support the continuation of the island.
- A clear disconnect between formed sub-networks.

Characteristics of uncontrolled islanding include:

- Out-of-step generators.
- Off-nominal frequency disturbances.
- Eventual collapse of formed islands due to frequency or voltage instability caused by generation-load unbalance.

Capacity addition projects are developed when simulations indicate the System's inability to meet the steady-state performance requirements for P0 (System Normal), P1, or P2-1 events. For P2-2 through P7 events, PGE may develop projects to mitigate overload or voltage issues; however, manual post-Contingency load-shedding may be identified as a mitigation to ensure that the BES remains within the defined operating limits, which is permissible (except for some categories of faults on equipment 300 kV and above) per TPL-001-4 for P2-2 through P7 events.

Short Circuit Studies

Short circuit studies are performed annually addressing the Near Term Planning Horizon. If the short circuit current interrupting duty on a circuit breaker exceeds 97% of its equipment rating, PGE identifies projects and/or Corrective Action Plans which are needed to achieve the required System performance throughout the Near Term Planning Horizon.

Voltage Stability Studies

PGE's Transmission System is evaluated for voltage stability in accordance with the WECC established procedures and criteria[3]. These performance criteria are summarized in the table below. Any voltage stability result that violates the criteria listed below is defined as a System instability. Contingencies to PGE and adjacent utility equipment at 500 kV and 230 kV are evaluated.

WECC Performance Level	TPL-001-4 Category	Disturbance	MW Margin (PV Method)	MVAR Margin (QV Method)
A	P0	No Contingency	≥5%	Positive Reactive Power Margin
B	P1[4]	A Single Element	≥5%	Positive Reactive Power Margin
C	P2-P7[5]	Any Two Elements	≥2.5%	Positive Reactive Power Margin
D	N/A	Extreme Events	>0	Positive Reactive Power Margin

For PGE's Real Power Margin assessment, the "transfer path" studied is identified by the Northwest (Area 40) generation as the (source) and PGE generation and load as the sink. Load internal to PGE's local Transmission System is scaled up to increase the "path" flow until a voltage stability limit is identified.

[3] "Guide to WECC/NERC Planning Standards I.D: Voltage Support and Reactive Power," prepared by the Reactive Reserve Working Group (RRWG) and approved by the Technical Studies Subcommittee (TSS) on March 30, 2006. https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/Voltage%20Stability%20Guide.pdf&action=default&DefaultItemOpen=1

[4] Not all NERC TPL-001-5 Categorical outages are specifically identified in the WECC Performance Criteria.

[5] TPL-001-5 P6 is not included in the WECC Performance Criteria.

Transient Stability Studies

PGE evaluates the transient stability performance of the BES for select Contingencies to PGE and adjacent utility equipment at 500 kV, 230 kV, and 115 kV. The studies evaluate single line-to-ground and three-phase faults to these facilities, including generators, bus sections, breaker failure, and loss of a double-circuit Transmission line. Extreme events are studied for three-phase faults with Delayed Fault Clearing.

For all 500 kV and 230 kV breaker positions, PGE implements high-speed protection through two independent relay systems utilizing separate current transformers for each set of relays. For a fault directly affecting these facilities, normal clearing is achieved when the Protection System operates as designed and faults are cleared within four to six cycles.

PGE implements breaker-failure protection schemes for its 500 kV and 230 kV facilities, and the majority of 115 kV facilities. Delayed clearing occurs when a breaker fails to operate, and the breaker-failure scheme clears the fault. Facilities without delayed clearing are modeled as such in the Contingency definition.

The transient stability results are evaluated for compliance with the following NERC and WECC System performance requirements. The simulation durations are run to 20 seconds. All oscillations that do not show positive damping within 20 seconds after the start of the studied event shall be deemed unstable.

1. Rotor Angle Stability
   Generators must maintain synchronism with PGE's Transmission System and the rest of the Transmission System in the Northwest through the transient period and rotor angle oscillations must exhibit positive damping for the loss of either one or two System Elements.

2. Frequency Stability[6]
   System frequency at any load bus must not fall below:
   - 59.6 Hz for 6 cycles or more following the loss of a single System Element.
   - 59.0 Hz for 6 cycles or more following the loss of two System Elements.

3. Voltage Stability
   Following fault clearing, the voltage shall recover to 80% of the pre-Contingency voltage within 20 seconds of the initiating event for all P1 through P7 events, for each applicable BES bus serving load.

   Following fault clearing and voltage recovery above 80%, voltage at each applicable BES bus serving load shall neither dip below 70% of pre-Contingency voltage for more than 30 cycles nor remain below 80% of pre-Contingency voltage for more than two seconds, for all P1 through P7 events.

   For Contingencies without a fault (P2-1 category event), voltage dips at each applicable BES bus serving load shall neither dip below 70% of pre-Contingency voltage for more than 30 cycles nor remain below 80% of pre-Contingency voltage for more than two seconds.

Failure to meet the above performance requirements for any transient stability simulation is defined as a System instability and will necessitate some form of mitigation.

Contingency analyses simulate the removal of all Elements that the Protection System and other automatic controls expected to disconnect for each Contingency without Operator intervention. The analyses include the impact of the subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized

[6] Although the WECC criterion is retired, PGE still adheres to the frequency dip criterion.

- Tripping of generators due to voltage limitations
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models

Automatic controls simulated include generator exciter and governor controls, generator power system stabilizers, static var compensators, power flow controllers, DC Transmission controllers, remedial action schemes (RAS) and under frequency load shedding (UFLS). Fault protection or automatic controls that result in unintended islanding as defined in the steady state section above is considered a System instability.

Corrective Action Plans are developed if the stability studies indicate that the System cannot meet the TPL-001-5 and WECC performance requirements.

- P1: No generating unit pulls out of synchronism
- P2-P7: When a generator pulls out of synchronism, the resulting apparent impedance swings do not result in the tripping of any BES Elements other than the generating unit and its directly connected facilities
- P1-P7: Power oscillations exhibit acceptable damping

PGE/105

NERC Reliability Standard FAC-008-5

A. Introduction

1. **Title:** Facility Ratings
2. **Number:** FAC-008-5
3. **Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on technically sound principles. A Facility Rating is essential for the determination of System Operating Limits.
4. **Applicability:**
   - **4.1.** Transmission Owner
   - **4.2.** Generator Owner
5. **Effective Date:** See Implementation Plan.

B. Requirements and Measures

R1. Each Generator Owner shall have documentation for determining the Facility Ratings of its solely and jointly owned generator Facility(ies) up to the low side terminals of the main step up transformer if the Generator Owner does not own the main step up transformer and the high side terminals of the main step up transformer if the Generator Owner owns the main step up transformer. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The documentation shall contain assumptions used to rate the generator and at least one of the following:

- Design or construction information such as design criteria, ratings provided by equipment manufacturers, equipment drawings and/or specifications, engineering analyses, method(s) consistent with industry standards (e.g. ANSI and IEEE), or an established engineering practice that has been verified by testing or engineering analysis.
- Operational information such as commissioning test results, performance testing or historical performance records, any of which may be supplemented by engineering analyses.

1.2. The documentation shall be consistent with the principle that the Facility Ratings do not exceed the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

M1. Each Generator Owner shall have documentation that shows how its Facility Ratings were determined as identified in Requirement 1.

R2. Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of interconnection with the Transmission Owner that contains all of the following. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. The methodology used to establish the Ratings of the equipment that comprises the Facility(ies) shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
- One or more industry standards developed through an open process such as Institute of Electrical and Electronic Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
- A practice that has been verified by testing, performance history or engineering analysis.

2.2. The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R2, Part 2.1 including identification of how each of the following were considered:

2.2.1. Equipment Rating standard(s) used in development of this methodology.

2.2.2. Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.

2.2.3. Ambient conditions (for particular or average conditions or as they vary in real-time).

2.2.4. Operating limitations.[1]

2.3. A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

2.4. The process by which the Rating of equipment that comprises a Facility is determined.

2.4.1. The scope of equipment addressed shall include, but not be limited to, conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

2.4.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

M2. Each Generator Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 2, Parts 2.1 through 2.4.

R3. Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The methodology used to establish the Ratings of the equipment that comprises the Facility shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
- One or more industry standards developed through an open process such as Institute of Electrical and Electronics Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
- A practice that has been verified by testing, performance history or engineering analysis.

[1] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

3.2. The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R3, Part 3.1 including identification of how each of the following were considered:

3.2.1. Equipment Rating standard(s) used in development of this methodology.

3.2.2. Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.

3.2.3. Ambient conditions (for particular or average conditions or as they vary in real-time).

3.2.4. Operating limitations.[2]

3.3. A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

3.4. The process by which the Rating of equipment that comprises a Facility is determined.

3.4.1. The scope of equipment addressed shall include, but not be limited to, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

3.4.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

M3. Each Transmission Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 3, Parts 3.1 through 3.4.

R4. Reserved.

M4. Reserved.

R5. Reserved.

M5. Reserved.

R6. Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Owner and Generator Owner shall have evidence to show that its Facility Ratings are consistent with the documentation for determining its Facility Ratings as specified in Requirement R1 or consistent with its Facility Ratings methodology as specified in Requirements R2 and R3 (Requirement R6).

R7. Reserved.

M7. Reserved.

[2] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

R8. Each Transmission Owner (and each Generator Owner subject to Requirement R2) shall provide requested information as specified below (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s): *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

8.1. As scheduled by the requesting entities:

8.1.1. Facility Ratings

8.1.2. Identity of the most limiting equipment of the Facilities

8.2. Within 30 calendar days (or a later date if specified by the requester), for any requested Facility with a Thermal Rating that limits the use of Facilities under the requester's authority by causing any of the following: 1) An Interconnection Reliability Operating Limit, 2) A limitation of Total Transfer Capability, 3) An impediment to generator deliverability, or 4) An impediment to service to a major load center:

8.2.1. Identity of the existing next most limiting equipment of the Facility

8.2.2. The Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1.

M8. Each Transmission Owner (and Generator Owner subject to Requirement R2) shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it provided its Facility Ratings and identity of limiting equipment to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Compliance Monitoring and Enforcement Processes:

- Self-Certifications
- Spot Checking
- Compliance Audits
- Self-Reporting

- Compliance Violation Investigations
- Complaints

1.3. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Generator Owner shall keep its current documentation (for R1) and any modifications to the documentation that were in force since last compliance audit period for Measure M1 and Measure M6.
- The Generator Owner shall keep its current, in force Facility Ratings methodology (for R2) and any modifications to the methodology that were in force since last compliance audit period for Measure M2 and Measure M6.
- The Transmission Owner shall keep its current, in force Facility Ratings methodology (for R3) and any modifications to the methodology that were in force since the last compliance audit for Measure M3 and Measure M6.
- The Transmission Owner and Generator Owner shall keep its current, in force Facility Ratings and any changes to those ratings for three calendar years for Measure M6.
- The Transmission Owner (and Generator Owner that is subject to Requirement R2) shall keep evidence for Measure M8 for three calendar years.
- If a Generator Owner or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit and all subsequent compliance records.

1.4. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The Generator Owner's Facility Rating documentation did not address Requirement R1, Part 1.1.	The Generator Owner's Facility Rating documentation did not address Requirement R1, Part 1.2.	The Generator Owner failed to provide documentation for determining its Facility Ratings.
R2.	The Generator Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R2: • 2.1. • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R2: • 2.1 • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner's Facility Rating methodology did not address all the components of Requirement R2, Part 2.4. OR The Generator Owner failed to include in its Facility Rating Methodology, three of the following Parts of Requirement R2: • 2.1. • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner's Facility Rating methodology failed to recognize a facility's rating based on the most limiting component rating as required in Requirement R2, Part 2.3 OR The Generator Owner failed to include in its Facility Rating Methodology four or more of the following Parts of Requirement R2: • 2.1 • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Transmission Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner's Facility Rating methodology did not address either of the following Parts of Requirement R3: • 3.4.1 • 3.4.2 OR The Transmission Owner failed to include in its Facility Rating methodology three of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner's Facility Rating methodology failed to recognize a Facility's rating based on the most limiting component rating as required in Requirement R3, Part 3.3 OR The Transmission Owner failed to include in its Facility Rating methodology four or more of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4
R4. Reserved.				
R5. Reserved.				

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for 5% or less of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 5% or more, but less than up to (and including) 10% of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 10% up to (and including) 15% of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than15% of its solely owned and jointly owned Facilities. (R6)
R7. Reserved.				
R8.	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by up to and including 15 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 100%,	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 15 calendar days but less than or equal to 25 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 95%, but	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 25 calendar days but less than or equal to 35 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 90%, but	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 35 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 85% of the required Rating information to all of the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	but not less than or equal to 95% of the required Rating information to all of the requesting entities. (R8, Part 8.1) OR The responsible entity provided the required Rating information to the requesting entity, but the information was provided up to and including 15 calendar days late. (R8, Part 8.2) OR The responsible entity provided less than 100%, but not less than or equal to 95% of the required Rating information to the requesting entity. (R8, Part 8.2)	not less than or equal to 90% of the required Rating information to all of the requesting entities. (R8, Part 8.1) OR The responsible entity provided the required Rating information to the requesting entity, but did so more 15 calendar days but less than or equal to 25 calendar days late. (R8, Part 8.2) OR The responsible entity provided less than 95%, but not less than or equal to 90% of the required Rating information to the requesting entity. (R8, Part 8.2)	not less than or equal to 85% of the required Rating information to all of the requesting entities. (R8, Part 8.1) OR The responsible entity provided the required Rating information to the requesting entity, but did so more than 25 calendar days but less than or equal to 35 calendar days late. (R8, Part 8.2) OR The responsible entity provided less than 90%, but no less than or equal to 85% of the required Rating information to the requesting entity. (R8, Part 8.2)	requesting entities. (R8, Part 8.1) OR The responsible entity provided the required Rating information to the requesting entity, but did so more than 35 calendar days late. (R8, Part 8.2) OR The responsible entity provided less than 85 % of the required Rating information to the requesting entity. (R8, Part 8.2) OR The responsible entity failed to provide its Rating information to the requesting entity. (R8, Part 8.1)

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	Feb 7, 2006	Approved by Board of Trustees	New
1	Mar 16, 2007	Approved by FERC	New
2	May 12, 2010	Approved by Board of Trustees	Complete Revision, merging FAC_008-1 and FAC-009-1 under Project 2009-06 and address directives from Order 693
3	May 24, 2011	Addition of Requirement R8	Project 2009-06 Expansion to address third directive from Order 693
3	May 24, 2011	Adopted by NERC Board of Trustees	
3	November 17, 2011	FERC Order issued approving FAC-008-3	
3	May 17, 2012	FERC Order issued directing the VRF for Requirement R2 be changed from "Lower" to "Medium"	
3	February 7, 2013	R4 and R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
3	November 21, 2013	R4 and R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
4	May 9, 2020	R7 and R8 and associated elements adopted by NERC Board of Trustees for retirement as part of Project 2018-03 Standards Efficiency Review Retirements.	
4	September 17, 2020	Remanded by FERC (Order No. 873).	Withdrawn
5	February 4, 2021	Adopted by NERC Board of Trustees	Requirement R8 and associated elements restored in response

Version	Date	Action	Change Tracking
			to FERC Order No. 873.

PGE/106

Tonquin Power Flow Results Update

Exhibit 106 contains highly protected information

and is subject to

Modified Protective Order No. 24-087

(Redacted Copy)

REDACTED

COMPARISON OF POWER FLOW RESULTS IN 2025 WITH AND WITHOUT THE MCLOUGHLIN-TONQUIN AND ROSEMONT-WILSONVILLE 115KV LINES

Contingency			Overloaded Element		2025: Tonquin two-source configuration (no McLoughlin Tonquin 115kV, no Rosemont-Wilsonville 115kV)	2025: Tonquin three-source configuration (with McLoughlin-Tonquin 115kV and Rosemont-Wilsonville 115kV)	
Category	Outage	Voltage	Element	Voltage	Percent Loading	Percent Loading	Operator Action (for overloads with Tonquin in a two-source configuration)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] provide additional source to Tonquin to alleviate this overload.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] provide additional source to Tonquin to alleviate these overloads.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] provide additional source to Tonquin to alleviate this overload.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] will provide additional source to alleviate Sherwood-Tonquin overload. Eventual [redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] provide additional source to Tonquin to alleviate this overload.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] provide additional source to Tonquin to alleviate this overload.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] provide additional source to Tonquin to alleviate this overload
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] provide additional source to Tonquin to alleviate this overload.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed amongst [redacted] provide additional source to Tonquin to alleviate this overload.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed amongst [redacted] provide additional source to Tonquin to alleviate this overload.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] provide additional source to Tonquin to alleviate this overload.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] provide additional source to Tonquin to alleviate this overload.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load in the Gresham and Sherwood areas. [redacted] source is added to Tonquin substation. Consider project to reconductor Hogan North-McGill 115kV line if this overload increases in future study years.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted].
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Plan project to upgrade Hogan South-McGill 115kV line. Shed load in the Gresham area.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] provide additional source to Tonquin to alleviate this overload.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] will provide additional source to alleviate Sherwood-Tonquin overload.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] will provide additional source to alleviate Sherwood-Tonquin overload

REDACTED

COMPARISON OF POWER FLOW RESULTS IN 2025 WITH AND WITHOUT THE MCLOUGHLIN-TONQUIN AND ROSEMONT-WILSONVILLE 115KV LINES

Contingency			Overloaded Element		2025: Tonquin two-source configuration (no McLoughlin Tonquin 115kV, no Rosemont-Wilsonville 115kV)	2025: Tonquin three-source configuration (with McLoughlin-Tonquin 115kV and Rosemont-Wilsonville 115kV)	
Category	Outage	Voltage	Element	Voltage	Percent Loading	Percent Loading	Operator Action (for overloads with Tonquin in a two-source configuration)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] will provide additional source to alleviate Sherwood-Tonquin overload.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] will provide additional source to reduce Canemah-Carver loading.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] will provide additional source to reduce Canemah-Carver loading.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] will provide additional source to reduce Canemah-Carver loading.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] will provide additional source to alleviate Sherwood-Tonquin overload.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Shed load amongst [redacted] will provide additional source to reduce Canemah-Carver loading.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted].
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted].

PGE/107

Near Term Local Transmission Plan for the 2020-2021 Planning Cycle

Portland General Electric Company's Near Term Local Transmission Plan For the 2020-2021 Planning Cycle

December 23, 2020

Contents

1. Introduction

This 2020 Near Term Local Transmission Plan reflects Quarters 1 through 4 of the local transmission planning process as described in PGE's Open Access Transmission Tariff (OATT) Attachment K. The plan includes all transmission system facility improvements identified through this planning process. A power flow reliability assessment of the plan was performed which demonstrated that the planned facility additions will meet NERC and WECC reliability standards.

PGE's OATT is located on its Open Access Same-time Information System (OASIS) at http://oasis.oati.com/PGE. Additional information regarding Transmission Planning is located in the *Transmission Planning* folder on PGE's OASIS. Unless otherwise specified, capitalized terms used herein are defined in PGE's OATT.

1.1. Local Planning

This Local Transmission Plan (LTP) has been prepared within the two-year process as defined in PGE's OATT Attachment K. The LTP identifies the Transmission System facility additions required to reliably interconnect forecasted generation resources and serve the forecasted Network Customers' load, Native Load Customers' load, and Point-to-Point Transmission Customers' requirements, including both grandfathered, non-OATT agreements and rollover rights, over a ten (10) year planning horizon. Additionally, the LTP typically incorporates the results of any stakeholder-requested economic congestion studies results that were performed. However, none were requested or incorporated during this particular cycle.

1.2. Regional and Interregional Coordination

PGE coordinates its planning processes with other transmission providers through membership in NorthernGrid, Northwest Power Pool (NWPP) and the Western Electric Coordinating Council (WECC). PGE uses the NorthernGrid process for regional planning, coordination with adjacent regional groups and other planning entities for interregional planning, and development of proposals to WECC. Additional information is located in PGE's OATT Attachment K, in our Transmission Planning Business Practice on OASIS, and on NorthernGrid's website at www.northerngrid.net.

2. Planning Process and Timeline

This plan is for the 2020-2021 planning cycle. PGE's OATT Attachment K describes an eight (8) quarter study and planning cycle. The planning cycle schedule is shown below in Figure 1.

Figure 1: PGE OATT Attachment K Eight Quarter Planning Cycle

		Quarter	Tasks
Near Term	Even Years	1	Select Near Term base cases and gather load data
		2	Post Near Term methodology on OASIS, select one Economic Study for evaluation
		3 & 4	Select Longer Term base cases, post draft Near Term Plan on OASIS, hold public meeting to solicit stakeholder comment
		4	Incorporate stakeholder comments and post final Near Term plan on OASIS
Longer Term	Odd Years	5	Gather load data and accept Economic Study requests
		6	Select one Economic Study for evaluation
		7 & 8	Post draft Longer Term plan on OASIS, hold public meeting to solicit stakeholder comment
		8	Post final Longer Term plan on OASIS, submit final Longer Term Plan to stakeholders and owners of neighboring systems

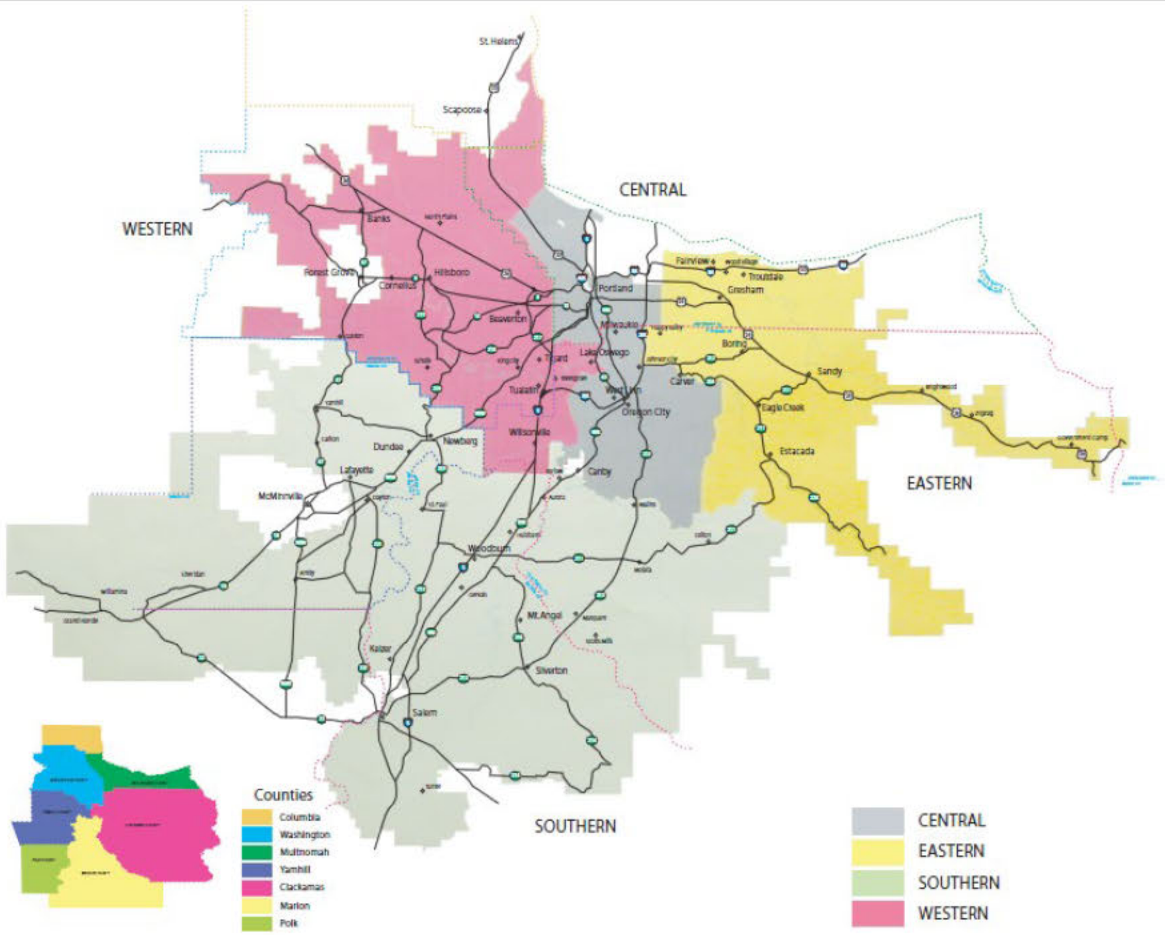
PGE updates its Transmission Customers about activities and/or progress made under the Attachment K planning process, during regularly scheduled customer meetings. Meeting announcements, agendas, and notes are posted in the *Customer Meetings* folder on PGE's OASIS. Meeting dates are also posted on PGE's OASIS.

3. Transmission System Plan Inputs and Components

3.1. PGE's Transmission System

Portland General Electric's (PGE) service territory covers 4,000 square miles and provides service to over 880,000 customers. PGE's service territory is confined within Multnomah, Washington, Clackamas, Yamhill, Marion, and Polk counties in northwest Oregon, as shown in Figure 2.

Figure 2: Map of PGE's Service Territory



PGE's Transmission System is designed to reliably distribute power throughout the Portland and Salem regions for the purpose of serving native load and integrating transmission and generation resources on the Bulk Electric System. The following PGE-owned 500 kV and 230 kV lines are essential elements of regional transmission paths:

> The Grizzly BPA-Malin BPA #2 500 kV line and the Grizzly BPA-Round Butte 500 kV line contribute to the reliability of the Northwest AC Intertie (NWACI); outages to these lines could result in a restriction on the path limit to move resources from the northwest to California.

PGE has 15% ownership in the Colstrip-Townsend #1 and #2 500kV lines. These 500 kV lines are part of the Colstrip Transmission System (CTS) that moves resources from Montana to the Northwest.

The Bethel-Round Butte 230 kV line is part of the West of Cascades South (WOCS) Path. WOCS is a WECC Major Path and experiences heavy east-to-west flows in the winter, with generation resources on the east side of the Cascades serving the Willamette Valley.

The Horizon-St Marys-Trojan 230 kV and Rivergate-Trojan 230 kV lines are part of the South of Allston (SOA) Path. The SOA Path experiences heavy north-to-south flows in the summer, with generation resources in the I-5 Corridor and Canada serving the Willamette Valley. For off-peak conditions in the northwest, these flows can reverse, serving the northwest from the south (southern Oregon or California) instead of the north. Both conditions can stress PGE's Transmission System; a Remedial Action Scheme (RAS) is in place to address north-to-south conditions. This RAS drops generation in the I-5 Corridor (including PGE's Port Westward 2 and Beaver plants) to mitigate overloads on the underlying 230 kV and 115 kV system and is triggered for the loss of the Allston BPA-Keeler BPA 500 kV or Keeler BPA-Pearl BPA 500 kV lines.

In total, PGE owns 1,625 circuit miles of sub-transmission/transmission at voltages ranging from 57 kV to 500 kV (See Figure 3).

Figure 3: PGE Circuit Miles Owned (By Voltage Level)

Voltage Level	Pole Miles	Circuit Miles
500 kV	268	268
230 kV	285	329
115 kV	514	565
57 kV	441	463

3.2. Load Forecast

For load forecasting purposes, PGE's transmission system is evaluated for a 1-in-3 peak load condition during the summer and winter seasons for Near Term (years 1 through 5) and Longer Term (years 6 through 10) studies.

The 1-in-3 peak system load is calculated based on weather conditions that PGE can anticipate experiencing once every three years. The summer (June 1st through October 31st) and winter (November 1st through March 31st) load seasons are considered the most critical study seasons due to heavier peak loads and high power transfers over PGE's T&D System to its customers. PGE defines the seasons to align with the seasons set by the Reliability Coordinator's seasonal planning process.

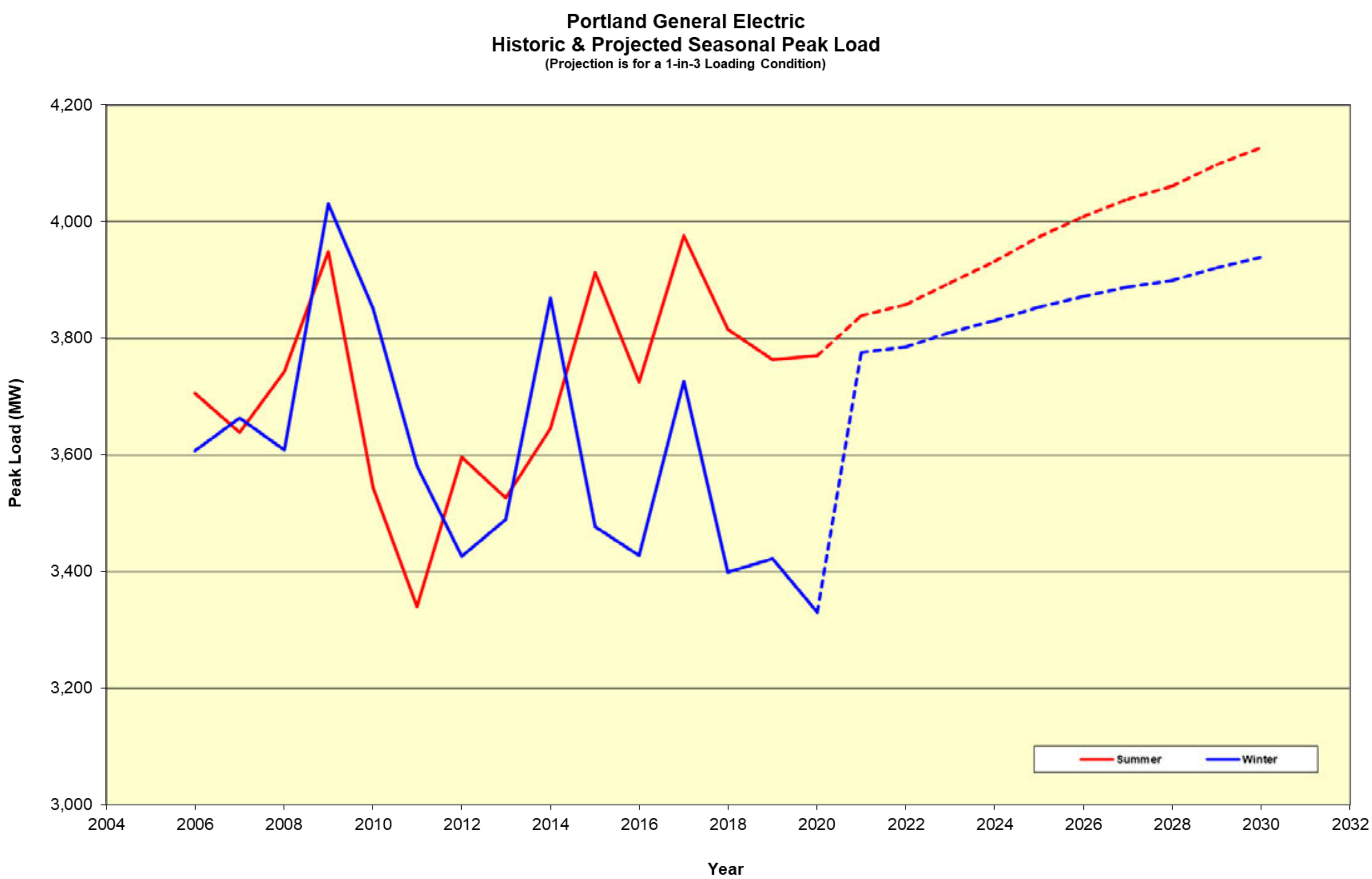
Figure 4: Summer/Winter Loading Conditions and Corresponding Daily-Averaged Temperatures

Summer	
1-in-2	81.9°F
1-in-3	83.4°F
1-in-5	84.6°F
1-in-10	86.1°F
1-in-20	87.3°F

Winter	
1-in-2	28.6°F
1-in-3	26.8°F
1-in-5	25.1°F
1-in-10	23.2°F
1-in-20	21.7°F

Figure 5: Portland General Electric's Historic & Projected Seasonal Peak Load

(Projection is for a 1-in-3 Loading Condition)



PGE's all-time peak load occurred on December 21, 1998, with the Net System Load[1] reaching 4073 MW. PGE's all time summer peak occurred on August 3, 2017 with the Net System Load reaching 3974 MW.

[1] The Net System Load is the total load served by PGEM, including losses. This includes PGE load in all control areas, plus ESS load, minus net borderlines.

3.3. Forecasted Resources

The forecasted resources are comprised of generators, identified by network customers as designated network resources, that are integrated into the wider regional forecasts of expected resources committed to meet seasonal peak loads.

3.4. Economic Studies

Eligible customers or stakeholders may submit economic congestion study requests during either Quarter 1 or Quarter 5 of the planning cycle. However, PGE did not receive any study requests during the 2020-2021 planning cycle.

3.5 Stakeholder Submissions

Any stakeholder may submit data to be evaluated as part of the preparation of the draft Near Term Local Transmission Plan and/or the development of sensitivity analyses, including alternative solutions to the identified needs set out in prior Local Transmission Plans, Public Policy Considerations and Requirements, and transmission needs driven by Public Policy Considerations and Requirements. However, PGE did not receive any such data submissions during the 2020-2021 planning cycle.

4. Methodology

PGE’s transmission system is designed to reliably supply projected customer demands and projected Firm Transmission Services over the range of forecast system demands. Studies are performed annually to evaluate where transmission upgrades may be needed to meet the performance requirements established in the NERC TPL-001-4 Reliability Standard and the WECC TPL-001-WECC-CRT-3.2 Regional Criteria.

PGE maintains system models within its planning area for performing the studies required to complete the System Assessment. These models use data that is provided in WECC Base Cases in accordance with the MOD-032 reliability standard. Electrical facilities modeled in the cases have established normal and emergency ratings, as defined in PGE’s Facility Ratings Methodology document. A facility rating is determined based on the most limiting component in a given transmission path, in accordance with the FAC-008-3 reliability standard.

Reactive power resources are modeled as made available in the WECC base cases. For PGE, reactive power resources include shunt capacitor banks available on the 115 kV transmission system and on the 57 kV distribution system.

Studies are evaluated for the Near Term Planning Horizon (years 1 through 5) and the Longer Term Planning Horizon (years 6 through 10) to ensure adequate capacity is available on PGE’s transmission system. The load model used in the studies is based on PGE’s corporate forecast, reflecting a 1-in-3 demand level for peak summer and peak winter conditions with additions of large customer loads. Known outages of generation or transmission facilities with durations of at least six months are appropriately represented in the system models. Transmission equipment is studied as out of service in

Base Case system models if there is no spare equipment or mitigation strategy for the loss of the equipment.

In the Near Term, studies are performed for the following:

- System Peak Load for either Year One or Year Two
- System Peak Load for Year Five
- System Off-Peak Load for either Year One or Year Two
- System Off-Peak Load for Year Five

Sensitivity studies are performed for each of these cases by varying the study parameters to stress the system within a range of credible conditions that demonstrate a measurable change in performance. PGE alters the real and reactive forecasted load and the transfers on the paths into the Portland area on all sensitivity studies. For peak summer and winter sensitivity cases, the 1-in-10 load forecast is used.

Studies are evaluated at peak summer and peak winter load conditions for one of the years in the Longer Term Planning Horizon.

Figure 6: Powerflow Base Cases Used in 2020 Assessment

		Study Year	Origin WECC Base Case	PGE Case Name	PGE System Load (MW)
SUMMER	Year One/Two Case	2022	2020 HS3	22 HS PLANNING	4113
	Year Five Case	2025	2025 HS2	25 HS PLANNING	4484
	Year One/Two Sensitivity	2022	2020 HS3	22 HS SENSITIVITY	4275
	Year Five Sensitivity	2025	2025 HS2	25 HS SENSITIVITY	4634
	Long Term Case	2030	2030 HS1	30 HS PLANNING	4711
WINTER	Year One/Two Case	2022-23	2020-21 HW2	22-23 HW PLANNING	4019
	Year Five Case	2025-26	2024-25 HW2	25-26 HW PLANNING	4394
	Year One/Two Sensitivity	2022-23	2020-21 HW2	22-23 HW SENSITIVITY	4230
	Year Five Sensitivity	2025-26	2024-25 HW2	25-26 HW SENSITIVITY	4535
	Long Term Case	2030-31	2029-30 HW1	30-31 HW PLANNING	4595
SPRING	Year One/Two Off Peak Case	2022	2020 LSP1	22 LSP PLANNING	2249
	Year Five Off Peak Case	2022	2020 LSP1	25 LSP PLANNING	2558
	Year One/Two Off Peak Sensitivity	2022	2020 LSP1	22 LSP SENSITIVITY	2249
	Year Five Off Peak Sensitivity	2022	2020 LSP1	25 LSP SENSITIVITY	2558

The Bulk Electric System is evaluated for steady state and transient stability performance for planning events described in Table 1 of the NERC TPL-001-4 reliability standard. When system simulations indicate an inability of the systems to respond as prescribed in the NERC TPL-001-4 standard, PGE identifies projects and/or Corrective Action Plans which are needed to achieve the required system performance throughout the Planning Horizon.

4.1. Steady State Studies

PGE performs steady-state studies for the Near Term and Longer Term Transmission Planning Horizons. The studies consider all contingency scenarios identified in Table 1 of the NERC TPL-001-4 reliability standard to determine if the Transmission System meets performance requirements. These studies also assess the impact of Extreme Events on the system expected to produce severe system impacts.

The contingency analyses simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each contingency without Operator intervention. The analyses include the impact of the subsequent tripping of generators due to voltage limitations and tripping of transmission elements where relay loadability limits are exceeded. Automatic controls simulated include phase-shifting transformers, load tap changing transformers, and switched capacitors and reactors.

Cascading is not allowed to occur for any contingency analysis. If the analysis of an Extreme Event concludes there is Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is completed.

Capacity addition projects are developed when simulations indicate the system's inability to meet the steady-state performance requirements for P0 (System Normal) or P1 events. For P2-P7 events, PGE identifies distribution substations where manual post-contingency "load-shedding" may be required to ensure that the Transmission System remains within the defined operating limits.

4.2. Voltage Stability Studies

PGE's transmission system is evaluated for voltage stability in accordance with the WECC established procedures and criteria[2]. These performance criteria are summarized in the table below. Contingencies to PGE and adjacent utility equipment at 500 kV and 230 kV are evaluated.

Figure 7. Voltage Stability Performance Criteria

WECC Performance Level	TPL-001-4 Category	Disturbance	MW Margin (PV Method)	MVAR Margin (QV Method)
A	P0	No Contingency	≥ 5%	Positive Reactive Power Margin
B	P1[3]	A Single Element	≥ 5%	Positive Reactive Power Margin
C	P2-P7[4]	Any Two Elements	≥ 2.5%	Positive Reactive Power Margin
D	N/A	Extreme Events	> 0	Positive Reactive Power Margin

For PGE's Real Power Margin assessment, the "transfer path" studied is identified by the Northwest (Area 40) generation as the (source) and PGE generation and load as the sink. Load internal to PGE's local transmission system is scaled up to increase the "path" flow until a voltage stability limit is identified.

[2] "Guide to WECC/NERC Planning Standards I.D: Voltage Support and Reactive Power," prepared by the Reactive Reserve Working Group (RRWG) and approved by the Technical Studies Subcommittee (TSS) on March 30, 2006.
https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/Voltage%20Stability%20Guide.pdf&action=default&DefaultItemOpen=1

[3] Not all NERC TPL-001-4 Categorical outages are specifically identified in the WECC Performance Criteria.

[4] TPL-001-4 P6 is not included in the WECC Performance Criteria.

4.3 Transient Stability Studies

PGE evaluates the voltage and transient stability performance of the Transmission System for contingencies to PGE and adjacent utility equipment at 500 kV, 230 kV, and 115 kV. The studies evaluate single line-to-ground and 3φ faults to these facilities, including generators, bus sections, breaker failure, and loss of a double-circuit transmission line. Extreme events are studied for 3φ faults with Delayed Fault Clearing.

For all 500 kV and 230 kV breaker positions, PGE implements high-speed protection through two independent relay systems utilizing separate current transformers for each set of relays. For a fault directly affecting these facilities, normal clearing is achieved when the protection system operates as designed and faults are cleared within four to six cycles.

PGE implements breaker-failure protection schemes for its 500 kV and 230 kV facilities; and the majority of 115 kV facilities. Delayed clearing occurs when a breaker fails to operate and the breaker-failure scheme clears the fault. Facilities without delayed clearing are modeled as such in the contingency definition.

The transient stability results are evaluated for compliance with the following NERC and WECC system performance requirements. The simulation durations are run to 20 seconds. All oscillations that do not show positive damping within 20 seconds after the start of the studied event shall be deemed unstable.

1. Rotor Angle Stability
   Generators must maintain synchronism with PGE's transmission system and the rest of the transmission system in the Northwest through the transient period and rotor angle oscillations must exhibit positive damping for the loss of either one or two system elements.

2. Frequency Stability
   System frequency at any load bus must not fall below:

   - 59.6 Hz for 6 cycles or more following the loss of a single system element.
   - 59.0 Hz for 6 cycles or more following the loss of two system elements.

3. Voltage Stability

   Following fault clearing, the voltage shall recover to 80% of the pre-contingency voltage within 20 seconds of the initiating event for all P1 through P7 events, for each applicable BES bus serving load.

   Following fault clearing and voltage recovery above 80%, voltage at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds, for all P1 through P7 events.

> For Contingencies without a fault (P2-1 category event), voltage dips at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds.

Failure to meet the above performance requirements for any transient stability simulation will necessitate some form of mitigation.

Contingency analyses simulate the removal of all elements that the Protection System and other automatic controls expected to disconnect for each contingency without Operator intervention. The analyses include the impact of the subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized
- Tripping of generators due to voltage limitations
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models

Automatic controls simulated include generator exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

Cascading is not allowed to occur for any contingency analysis. If the analysis of an Extreme Event concludes there is Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is completed.

Corrective Action Plans are developed if the stability studies indicate that the system cannot meet the TPL-001-4 and WECC performance requirements.

- P1: No generating unit pulls out of synchronism
- P2-P7: When a generator pulls out of synchronism, the resulting apparent impedance swings do not result in the tripping of any Transmission system elements other than the generating unit and its directly connected facilities
- P1-P7: Power oscillations exhibit acceptable damping

5. Results

5.1. Steady State Results – Near Term Evaluation

Contingency loading concerns identified on PGE's system for the Near Term Planning Horizon due to the loss of either the Allston BPA-Keeler BPA 500 kV line or the Keeler BPA-Pearl BPA 500 kV line are mitigated by implementing BPA's DSO 309, addressing the South of Allston Path RAS.

Contingency loading concerns on the Redmond BPA-Round Butte 230 kV line due to the loss of both Ponderosa BPA 500/230 kV transformers are mitigated by implementing the Ponderosa RAS.

Contingency loading concerns in the North Portland area are mitigated by Phase 2 of the Harborton Reliability Project and PACW's Project to construct a new Albina PACW-Knott PACW-St Johns BPA 115 kV line.

Contingency loading concerns in the Beaverton area are mitigated by the second Horizon-Keeler BPA 230 kV line, the Harborton-Wacker 115 kV line (part of the Harborton Reliability Project), and the Canyon-Urban 115 kV Reconductor Project.

There are no additional contingency loading or voltage concerns in the Near Term Planning Horizon on PGE's system for NERC TPL-001-4 Categories P1, P2, P3, P4, P5, and P7. NERC TPL-001-4 Category P6 contingency overloads and voltage concerns are addressed with load shedding, as permitted, on PGE's local distribution system. None of the contingencies evaluated will result in cascading from PGE's Control Area to another Control Area.

5.2. Near Term Voltage Stability

There are no voltage stability concerns identified on PGE's system in the Near Term Planning Horizon.

5.3. Near Term Transient Stability

The Near Term transient stability studies indicate that PGE's system exhibits adequate transient stability throughout the 500 kV and 230 kV transmission systems. The minimum frequency response recorded did not dip below 59.5 Hz for any of the contingency events studied on PGE's system. Underfrequency Load Shedding ("UFLS") relays are not affected because the set point for UFLS relays is 59.3 Hz. The transient voltage dip did not exceed 25% at any load bus or 30% at any non-load bus for any of the contingency events studied on PGE's system.

5.4. Near Term Short Circuit Analysis

The Near Term short circuit analysis identified three overdutied breakers; one at St Marys, one at Sherwood and one at Sunset. The St Marys breaker will be replaced as a part of the St Marys Battery Project. Projects will be evaluated to replace the Sherwood and Sunset overdutied breakers.

5.5. Projects Currently Included in the Near Term Plan

There are 15 projects currently planned for implementation in the Near Term Planning Horizon. The timing for completion of these projects is subject to change. These projects are described in detail in Appendix A.

Appendix A: Near Term Project List

Projects currently included in the Near Term Plan are:

- Harborton Reliability Project
- Horizon VWR3 Project
- Helvetia Substation Project
- Kelley Point Reconfiguration Project
- St Marys Battery Project
- Northern 115 kV Conversion
- Butler Substation Project
- Murrayhill-St Marys 230 kV Reconductor Project
- Century Substation Project
- Canyon-Urban 115 kV Reconductor Project
- Sherwood Breaker Project
- Sunset Breaker Project
- Tonquin Substation Project
- Horizon-Keeler BPA #2 230 kV Project
- Arrowhead Substation Project

These projects are described in more detail on the following pages.

Harborton Reliability Project

- **Project Purpose**
    - Address transmission operations flexibility for the loss of the Rivergate bulk power transformer.
    - Reconfigure the system to reduce exposure and provide a stronger source to the Northwest Portland 115 kV system.
- **Project Scope**
    - Rebuild the Harborton 115 kV yard to a breaker and one half configuration.
    - Build a new 230 kV breaker and one half yard at Harborton substation.
    - Route five 230 kV lines to Harborton.
    - Install a new bulk power transformer at Harborton.
    - Reconductor the 115 kV lines from Harborton to Canyon.
    - Reconfigure the 115 kV system to provide a source to Northwest Portland from Harborton substation.
- **Project Status**
    - Under Construction.
- **Project Requirement Date**
    - The initial Phase 1 of this project includes the 115 kV yard rebuild, the Harborton-Rivergate 115 kV circuit and Harborton-St Helens 115 kV circuit. This phase was completed in April 2020.
    - The remaining Phase 1 of this project includes the 230 kV yard, the Harborton-Rivergate 230 kV circuit, the Harborton-Trojan #1 230 kV circuit and the new bulk power transformer. This phase is scheduled for completion by Q2 2021.
    - Phase 2 of this project first reconductors the E-Wacker 115 kV line to 1272 ACSS. Next, the 115 kV system is reconfigured to create a Harborton-Wacker 115 kV circuit, which will also be reconductored to 1272 ACSS. The 115 kV line idled for this reconfiguration will be utilized for the fifth 230 kV source into Harborton. The Horizon-St Marys-Trojan 230 kV circuit will be looped into Harborton, creating the Harborton-Horizon 230 kV, Harborton-St Marys 230 kV, and Harborton-Trojan #2 230 kV circuits. This phase is scheduled to begin after the Canyon-Urban 115 kV Reconductor and is scheduled for completion by 2025.

Horizon VWR3 Project

- **Project Purpose**
  - Provide an additional 115 kV source to the Hillsboro area.
- **Project Scope**
  - Install a third bulk power transformer at Horizon substation.
  - Create a Rock Creek-Shute-Sunset 115 kV circuit by tying the Rock Creek-Sunset 115 kV line and Shute-Sunset #2 115 kV line outside of Sunset substation (temporary configuration).
  - Build a new Horizon-Sunset #3 115 kV line.
- **Project Status**
  - Under Construction.
- **Project Requirement Date**
  - The project is currently projected for completion by Q2 2021.

Helvetia Substation Project

- **Project Purpose**
    - Address new customer load with full N-1 distribution transformer redundancy.
- **Project Scope**
    - Construct a new 115 kV breaker and one half substation with two 115 kV line and two distribution transformer positions.
    - Loop the existing Shute-West Union 115 kV circuit into the substation, creating a Helvetia-Shute 115 kV line and a Helvetia-West Union 115 kV line.
- **Project Status**
    - Under Construction.
- **Project Requirement Date**
    - The project is currently projected for completion by Q2 2021.

Kelley Point Reconfiguration Project

- **Project Purpose**
  - Mitigate the loss of the Kelley Point substation for the loss of the Rivergate 115 kV bus.
- **Project Scope**
  - Reconfigure the Harborton-Rivergate 115 kV, the Rivergate-Kelley Point 115 kV, and the Rivergate-Hayden Island 115 kV lines to provide sources to Kelley Point substation from two different substations.
- **Project Status**
  - Project approved for preliminary engineering.
- **Project Requirement Date**
  - The project is currently projected for completion by Q3 2021.

St Marys Battery Project

- **Project Purpose**
  - Address a single point of failure at St Marys substation.
  - Replace antiquated 230 kV relays at St Marys substation.
  - Mitigate the St Marys V286 overdutied breaker.
- **Project Scope**
  - Install a second control enclosure with all new 230 kV relaying.
  - Install a second station battery to eliminate a single point of failure.
  - Replace the St Marys V286 230 kV breaker with a 50 kA breaker.
- **Project Status**
  - Design complete Q4 2019, construction scheduled to start Q1 2021.
- **Project Requirement Date**
  - The project is currently projected for completion by Q4 2021.

Northern 115kV Conversion

- **Project Purpose**
  - Address loading concerns on the Knott PACW-St Johns SS PACW 115 kV line.
  - Address aging infrastructure at Northern substation
- **Project Scope**
  - Rebuild the Northern substation to a 115 kV breaker station
  - Loop the Curtis-Rivergate #2 115 kV line into Northern substation creating the Curtis-Northern 115 kV line and the Northern-Rivergate 115 kV line.
- **Project Status**
  - Design in progress.
- **Project Requirement Date**
  - The project is currently projected for completion by Q2 2022.

Butler Substation Project

- **Project Purpose**
  - Address new customer load with full N-1 distribution transformer redundancy.
- **Project Scope**
  - Construct a new 115 kV breaker and one half substation with four 115 kV line and two distribution transformer positions (future third position).
  - Loop the existing Orenco-Sunset 115 kV circuit and the St Marys-Sunset 115 kV circuit into Butler substation, creating the Butler-Orenco 115 kV, Butler-St Marys 115 kV, Butler-Sunset #1 115 kV, and Butler-Sunset #2 115 kV circuits.
  - Install two 115 kV, 24 MVAR cap banks for voltage support.
- **Project Status**
  - Under Construction.
- **Project Requirement Date**
  - Phase 1 of this project will include the substation work and looping in all of the lines into the substation and is scheduled for completion by Q4 2020.
  - Phase 2 of this project will reconductor the existing St Marys-Sunset 115 kV line to 795 ACSS and is scheduled for completion by Q2 2022.

Murrayhill-St Marys 230 kV Reconductor

- **Project Purpose**
  - Address loading concerns on the Murrayhill-St Marys 230 kV line.
- **Project Scope**
  - Reconductor the Murrayhill-St Marys 230 kV line to 1272 ACSS.
- **Project Status**
  - Design in progress.
- **Project Requirement Date**
  - The project is currently projected for completion by Q2 2022.

Century Substation Project

- **Project Purpose**
  - Address new customer load with full N-1 distribution transformer redundancy.
- **Project Scope**
  - Construct a new 115 kV breaker and one half substation with three 115 kV line and four distribution transformer positions (initial buildout will be two transformers).
  - Loop the Helvetia-West Union 115 kV circuit into the substation, creating a Century-Helvetia 115 kV line and a Century-West Union 115 kV line.
  - Relocate the spare 115/57 kV transformer to Century and purchase a new spare.
  - Rebuild the existing Banks-Orenco 57 kV line between Century and Orenco to 115 kV, creating the Century-Orenco 115 kV circuit.
  - Terminate the Banks-Orenco 57 kV line at Century, creating the Banks-Century 57 kV circuit.
- **Project Status**
  - Design in progress.
- **Project Requirement Date**
  - Phase 1 of this project will build out the substation, loop in the Helvetia-West Union 115 kV circuit, and install two distribution transformers. This phase is scheduled for completion by Q2 2022.
  - Phase 2 of this project will re-terminate the Orenco end of the Banks-Orenco 57 kV line at Century, install a 115/57 kV transformer at Century, and rebuild the idled 57 kV line to create the Century-Orenco 115 kV circuit. This phase is scheduled for completion by Q2 2023.

Canyon-Urban 115 kV Reconductor

- **Project Purpose**
    - Address loading concerns on the Canyon-Urban 115 kV line.
- **Project Scope**
    - Reconductor the Canyon-Urban 115 kV line to 795 ACSS.
- **Project Status**
    - Design in progress.
- **Project Requirement Date**
    - The project is currently projected for completion by Q3 2022.

Sherwood Breaker Project

- **Project Purpose**
  - Mitigate the Sherwood V274 overdutied breaker.
- **Project Scope**
  - Replace the Sherwood V274 230 kV breaker with a 50 kA rated breaker.
- **Project Status**
  - This project will be developed in 2021 for implementation in 2022.
- **Project Requirement Date**
  - The project is currently projected for completion by Q4 2022.

Sunset Breaker Project

- **Project Purpose**
  - Mitigate the Sunset W196 overdutied breaker.
- **Project Scope**
  - Replace the Sunset W196 115 kV breaker with a 63 kA rated breaker.
- **Project Status**
  - This project will be developed in 2021 for implementation in 2022.
- **Project Requirement Date**
  - The project is currently projected for completion by Q4 2022.

Tonquin Substation Project

- **Project Purpose**
  - Address new customer load.
  - Address loading concerns on the Oswego-West Portland 115 kV line.
- **Project Scope**
  - Construct a new 115 kV, 5-position ring bus with three 115 kV line and two distribution transformer positions (one transformer position will be for future use).
  - Loop the existing Meridian-Sherwood 115 kV circuit into the substation, creating a Meridian-Tonquin 115 kV line and a Sherwood-Tonquin 115 kV line.
  - Reconfigure the McLoughlin-Wilsonville 115 kV circuit and install a new breaker position at Rosemont substation, creating the McLoughlin-Tonquin 115 kV circuit and the Rosemont-Wilsonville 115 kV circuit.
- **Project Status**
  - This project is in initial development stages.
- **Project Requirement Date**
  - Phase 1 of this project will build out the substation, loop in the Meridian-Sherwood 115 kV circuit, and install two distribution transformers. This phase is scheduled for completion by Q4 2023.
  - Phase 2 of this project will reconfigure the McLoughlin-Wilsonville 115 kV circuit and install a new breaker position at Rosemont substation, creating the McLoughlin-Tonquin 115 kV circuit and the Rosemont-Wilsonville 115 kV circuit. This phase is scheduled for completion by Q4 2024.

Horizon-Keeler BPA #2 230 kV Project

- **Project Purpose**
  - Address loading concerns on the 230 kV and 115 kV system in the Hillsboro area.
- **Project Scope**
  - Construct a second 230 kV line between PGE's Horizon Substation and BPA's Keeler Substation.
- **Project Status**
  - Project identified in current TPL process.
- **Project Requirement Date**
  - The project is currently projected for completion by Q2 2025.

Arrowhead Substation Project

- **Project Purpose**
  - Address new customer load.
- **Project Scope**
  - Construct a new 115 kV breaker substation with two 115 kV line and two distribution transformer positions (one to be installed initially).
  - Loop the existing Sherwood-Wilsonville 115 kV circuit into the substation, creating an Arrowhead-Sherwood 115 kV line and an Arrowhead-Wilsonville 115 kV line.
- **Project Status**
  - This project is in initial development stages.
- **Project Requirement Date**
  - The project is currently projected for completion by Q2 2025.

PGE/108

Near Term Local Transmission Plan for the 2022-2023 Planning Cycle

Portland General Electric Company's Near Term Local Transmission Plan For the 2022-2023 Planning Cycle

FINAL – December 28, 2022

Contents

1. Introduction

This 2022 Near Term Local Transmission Plan reflects Quarters 1 through 4 of the local transmission planning process as described in PGE's Open Access Transmission Tariff (OATT) Attachment K. The plan includes all transmission system facility improvements identified through this planning process. A power flow reliability assessment of the plan was performed which demonstrated that the planned facility additions will meet NERC and WECC reliability standards.

PGE's OATT is located on its Open Access Same-time Information System (OASIS) at http://oasis.oati.com/PGE. Additional information regarding Transmission Planning is located in the *Transmission Planning* folder on PGE's OASIS. Unless otherwise specified, capitalized terms used herein are defined in PGE's OATT.

1.1. Local Planning

This Local Transmission Plan (LTP) has been prepared within the two-year process as defined in PGE's OATT Attachment K. The LTP identifies the Transmission System facility additions required to reliably interconnect forecasted generation resources and serve the forecasted Network Customers' load, Native Load Customers' load, and Point-to-Point Transmission Customers' requirements, including both grandfathered, non-OATT agreements and rollover rights, over a ten (10) year planning horizon. Additionally, the LTP typically incorporates the results of any stakeholder-requested economic congestion studies results that were performed. However, none were requested or incorporated during this particular cycle.

1.2. Regional and Interregional Coordination

PGE coordinates its planning processes with other transmission providers through membership in NorthernGrid and the Western Electric Coordinating Council (WECC). PGE uses the NorthernGrid process for regional planning, coordination with adjacent regional groups and other planning entities for interregional planning, and development of proposals to WECC. Additional information is located in PGE's OATT Attachment K, in our Transmission Planning Business Practice on OASIS, and on NorthernGrid's website at www.northerngrid.net.

2. Planning Process and Timeline

This plan is for the 2022-2023 planning cycle. PGE's OATT Attachment K describes an eight (8) quarter study and planning cycle. The planning cycle schedule is shown below in Figure 1.

Figure 1: PGE OATT Attachment K Eight Quarter Planning Cycle

		Quarter	Tasks
Near Term	Even Years	1	Select Near Term base cases and gather load data
		2	Post Near Term methodology on OASIS, select one Economic Study for evaluation
		3 & 4	Select Longer Term base cases, post draft Near Term Plan on OASIS, hold public meeting to solicit stakeholder comment
		4	Incorporate stakeholder comments and post final Near Term plan on OASIS
Longer Term	Odd Years	5	Gather load data and accept Economic Study requests
		6	Select one Economic Study for evaluation
		7 & 8	Post draft Longer Term plan on OASIS, hold public meeting to solicit stakeholder comment
		8	Post final Longer Term plan on OASIS, submit final Longer Term Plan to stakeholders and owners of neighboring systems

PGE updates its Transmission Customers about activities and/or progress made under the Attachment K planning process, during regularly scheduled customer meetings. Meeting announcements, agendas, and notes are posted in the *Customer Meetings* folder on PGE's OASIS.

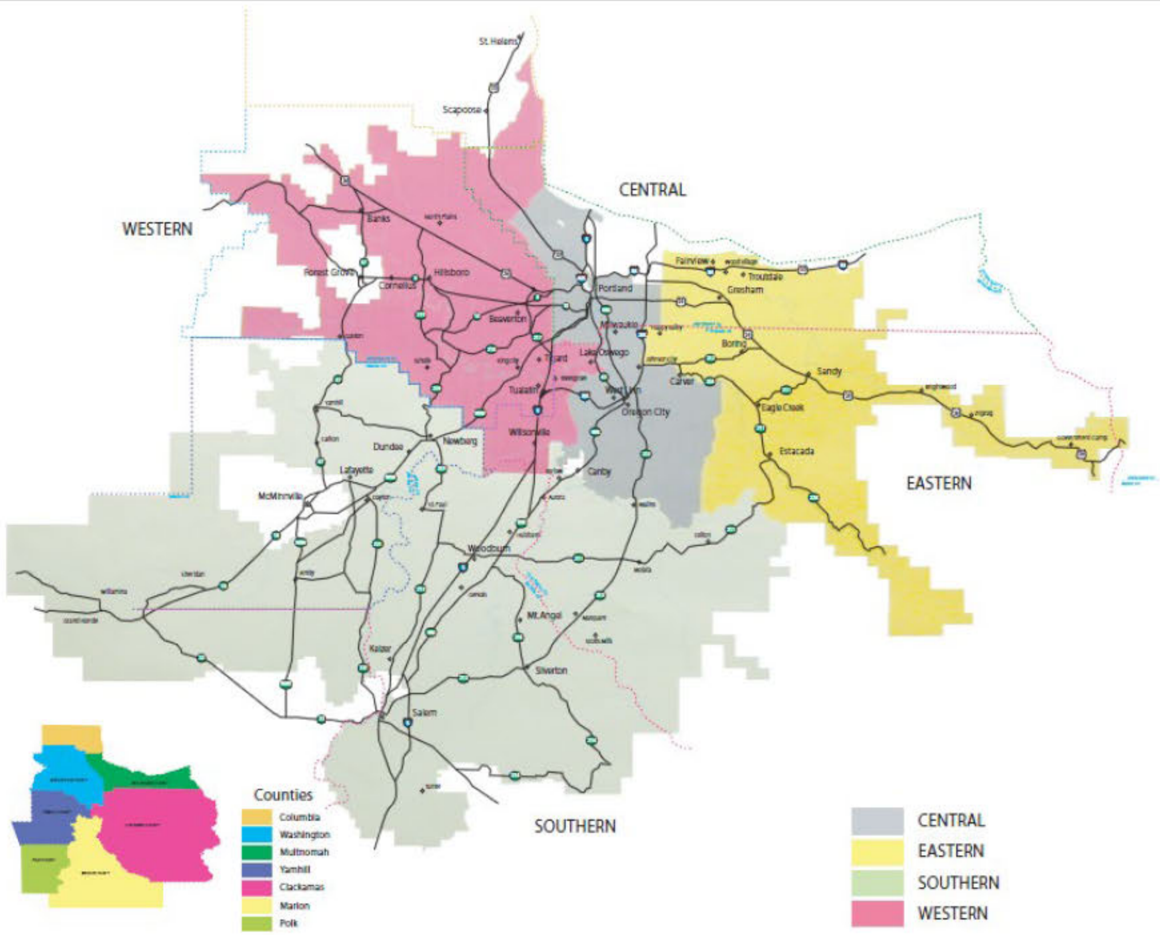
Meeting dates are posted on PGE's OASIS.

3. Transmission System Plan Inputs and Components

3.1. PGE's Transmission System

Portland General Electric's (PGE) service territory covers 4,000 square miles and provides service to over 880,000 customers. PGE's service territory is confined within Multnomah, Washington, Clackamas, Yamhill, Marion, and Polk counties in northwest Oregon, as shown in Figure 2.

Figure 2: Map of PGE's Service Territory



PGE's Transmission System is designed to reliably distribute power throughout the Portland and Salem regions for the purpose of serving native load and integrating transmission and generation resources on the Bulk Electric System. The following PGE-owned 500 kV and 230 kV lines are essential elements of regional transmission paths:

> The Grizzly BPA-Malin BPA #2 500 kV line and the Grizzly BPA-Round Butte 500 kV line contribute to the reliability of the Northwest AC Intertie (NWACI); outages to these lines could result in a restriction on the path limit to move resources from the northwest to California.

PGE has 15% ownership in the Colstrip-Townsend #1 and #2 500kV lines. These 500 kV lines are part of the Colstrip Transmission System (CTS) that moves resources from Montana to the Northwest.

The Bethel-Round Butte 230 kV line is part of the West of Cascades South (WOCS) Path. WOCS is a WECC Major Path and experiences heavy east-to-west flows in the winter, with generation resources on the east side of the Cascades serving the Willamette Valley.

The Horizon-St Marys-Trojan 230 kV and Harborton-Trojan #1 230 kV lines are part of the South of Allston (SOA) Path. The SOA Path experiences heavy north-to-south flows in the summer, with generation resources in the I-5 Corridor and Canada serving the Willamette Valley. For off-peak conditions in the northwest, these flows can reverse, serving the northwest from the south (southern Oregon or California) instead of the north. Both conditions can stress PGE's Transmission System; a Remedial Action Scheme (RAS) is in place to address north-to-south conditions. This RAS drops generation in the I-5 Corridor (including PGE's Port Westward 2 and Beaver plants) to mitigate overloads on the underlying 230 kV and 115 kV system and is triggered for the loss of the Allston BPA-Keeler BPA 500 kV or Keeler BPA-Pearl BPA 500 kV lines.

In total, PGE owns 1,630 circuit miles of sub-transmission/transmission at voltages ranging from 57 kV to 500 kV (See Figure 3).

Figure 3: PGE Circuit Miles Owned (By Voltage Level)

Voltage Level	Pole Miles	Circuit Miles
500 kV	268	268
230 kV	285	329
115 kV	531	570
57 kV	429	463

3.2. Load Forecast

For load forecasting purposes, PGE's transmission system is evaluated for a 1-in-3 peak load condition during the summer and winter seasons for Near Term (years 1 through 5) and Longer Term (years 6 through 10) studies.

The 1-in-3 peak system load is calculated based on weather conditions that PGE can anticipate experiencing once every three years. The summer (June 1st through October 31st) and winter (November 1st through March 31st) load seasons are considered the most critical study seasons due to heavier peak loads and high power transfers over PGE's T&D System to its customers. PGE defines the seasons to align with the seasons set by the Reliability Coordinator's seasonal planning process.

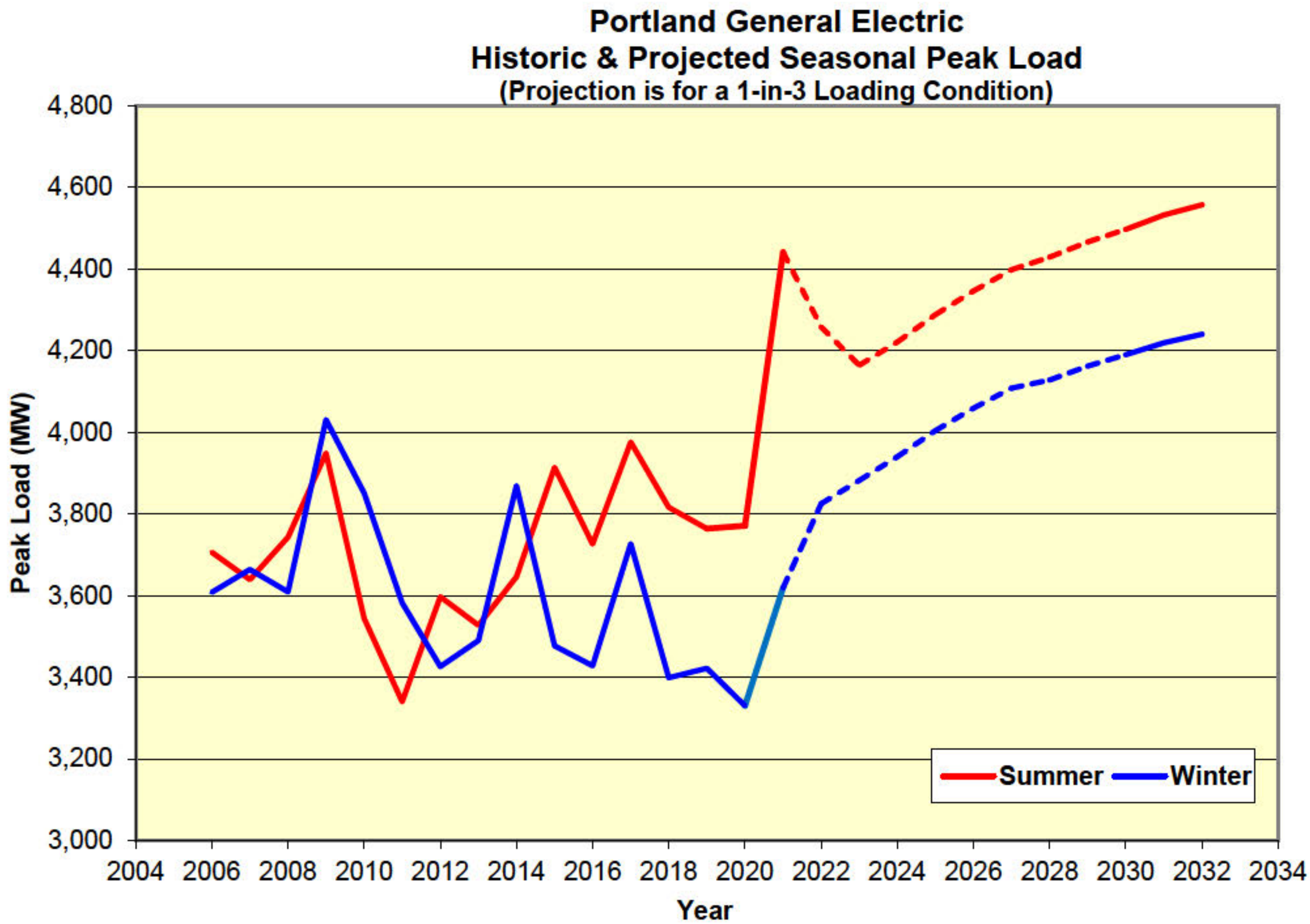
Figure 4: Summer/Winter Loading Conditions and Corresponding Daily-Averaged Temperatures

Summer	
1-in-2	83.1°F
1-in-3	85.1°F
1-in-5	87°F
1-in-10	89.1°F
1-in-20	90.9°F

Winter	
1-in-2	28.7°F
1-in-3	26.8°F
1-in-5	25.1°F
1-in-10	23.2°F
1-in-20	21.6°F

Figure 5: Portland General Electric's Historic & Projected Seasonal Peak Load

(Projection is for a 1-in-3 Loading Condition)



PGE's all-time peak winter load occurred on December 21, 1998, with the Net System Load[1] reaching 4073 MW. PGE's all time summer peak occurred on June 28, 2021 with the Net System Load reaching 4441 MW.

3.3. Forecasted Resources

The forecasted resources are comprised of generators, identified by network customers as designated network resources, that are integrated into the wider regional forecasts of expected resources committed to meet seasonal peak loads.

[1] The Net System Load is the total load served by PGEM, including losses. This includes PGE load in all control areas, plus ESS load, minus net borderlines.

3.4. Economic Studies

Eligible customers or stakeholders may submit economic congestion study requests during either Quarter 1 or Quarter 5 of the planning cycle. However, PGE did not receive any study requests during the 2022-2023 planning cycle.

3.5 Stakeholder Submissions

Any stakeholder may submit data to be evaluated as part of the preparation of the draft Near Term Local Transmission Plan and/or the development of sensitivity analyses, including alternative solutions to the identified needs set out in prior Local Transmission Plans, Public Policy Considerations and Requirements, and transmission needs driven by Public Policy Considerations and Requirements. However, PGE did not receive any such data submissions during the 2022-2023 planning cycle.

4. Methodology

PGE's transmission system is designed to reliably supply projected customer demands and projected Firm Transmission Services over the range of forecast system demands. Studies are performed annually to evaluate where transmission upgrades may be needed to meet the performance requirements established in the NERC TPL-001-4 Reliability Standard and the WECC TPL-001-WECC-CRT-3.1 Regional Criteria.

PGE maintains system models within its planning area for performing the studies required to complete the System Assessment. These models use data that is provided in WECC Base Cases in accordance with the MOD-032 reliability standard. Electrical facilities modeled in the cases have established normal and emergency ratings, as defined in PGE's Facility Ratings Methodology document. A facility rating is determined based on the most limiting component in a given transmission path, in accordance with the FAC-008-5 reliability standard.

Reactive power resources are modeled as made available in the WECC base cases. For PGE, reactive power resources include shunt capacitor banks available on the 115 kV transmission system (primarily auto mode - time-clock; one auto mode - voltage control) and on the 57 kV transmission system (auto mode - voltage control).

Studies are evaluated for the Near Term Planning Horizon (years 1 through 5) and the Longer Term Planning Horizon (years 6 through 10) to ensure adequate capacity is available on PGE's transmission system. The load model used in the studies is based on PGE's corporate forecast, reflecting a 1-in-3 demand level for peak summer and peak winter conditions with additions of large customer loads. Known outages of generation or transmission facilities with durations of at least six months are appropriately represented in the system models. Particularly sensitive outages of varying duration may be studied per TPL-001-5, an upcoming version of the current standard TPL-001-4. Transmission equipment is studied as out of service in Base Case system models if there is no spare equipment or mitigation strategy for the loss of the equipment.

In the Near Term, studies are performed for the following:

- System Peak Load for either Year One or Year Two
- System Peak Load for Year Five
- System Off-Peak Load for either Year One or Year Two
- System Off-Peak Load for Year Five

Sensitivity studies are performed for each of these cases by varying the study parameters to stress the system within a range of credible conditions that demonstrate a measurable change in performance. PGE alters the real and reactive forecasted load and the transfers on the paths into the Portland area on all sensitivity studies. For peak summer and winter sensitivity cases, the 1-in-10 load forecast is used.

Studies are evaluated at peak summer and peak winter load conditions for one of the years in the Longer Term Planning Horizon.

Figure 6: Powerflow Base Cases Used in 2022 Assessment

		Study Year	Origin WECC Base Case	PGE Case Name	PGE System Load (MW)
SUMMER	Year One/Two Case	2024	2022 HS3	24 HS PLANNING	4735
	Year Five Case	2027	2027 HS2	27 HS PLANNING	5157
	Year One/Two Sensitivity	2024	2022 HS3	24 HS SENSITIVITY	5104
	Year Five Sensitivity	2027	2027 HS2	27 HS SENSITIVITY	5685
	Long Term Case	2032	2032 HS1	32 HS PLANNING	5554
WINTER	Year One/Two Case	2024-25	2022-23 HW2	24-25 HW PLANNING	4563
	Year Five Case	2027-28	2026-27 HW2	27-28 HW PLANNING	4841
	Year One/Two Sensitivity	2024-25	2022-23 HW2	24-25 HW SENSITIVITY	5022
	Year Five Sensitivity	2027-28	2026-27 HW2	27-28 HW SENSITIVITY	5505
	Long Term Case	2032-33	2031-32 HW1	32-33 HW PLANNING	5296
SPRING	Year One/Two Off Peak Case	2024	2022 LSP1	24 LSP PLANNING	2696
	Year Five Off Peak Case	2027	2027 HS2	27 LSP PLANNING	3147
	Year One/Two Off Peak Sensitivity	2024	2022 LSP1	24 LSP SENSITIVITY	2696
	Year Five Off Peak Sensitivity	2027	2027 HS2	27 LSP SENSITIVITY	3147

The Bulk Electric System is evaluated for steady state and transient stability performance for planning events described in Table 1 of the NERC TPL-001-4 reliability standard. When system simulations indicate an inability of the systems to respond as prescribed in the NERC TPL-001-4 standard, PGE identifies projects and/or Corrective Action Plans which are needed to achieve the required system performance throughout the Planning Horizon.

4.1. Steady State Studies

PGE performs steady-state studies for the Near-Term and Long-Term Transmission Planning Horizons. The studies consider all contingency scenarios identified in Table 1 of the NERC TPL-001-4 reliability standard to determine if the Transmission System meets performance requirements. These studies also assess the impact of Extreme Events on the system expected to produce severe system impacts.

The contingency analyses simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each contingency without Operator intervention. The analyses include the impact of the subsequent tripping of generators due to voltage limitations and tripping of transmission elements where relay loadability limits are exceeded. Automatic controls simulated include phase-shifting transformers, load tap changing transformers, and switched capacitors and reactors.

Cascading is not allowed to occur for any contingency analysis. If the analysis of an Extreme Event concludes there is Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is completed.

Capacity addition projects are developed when simulations indicate the system's inability to meet the steady-state performance requirements for P0 (System Normal) or P1 events. For P2-P7 events, PGE identifies mitigations, including system topology changes (circuit breaker switching), moving selective transfer substations to alternate feeds, re-dispatching generation, and the implementation of committed transmission system upgrades, in order to eliminate identified overloads. Load shedding is also considered as on option to eliminate identified transmission overloads, but only as a last resort.

4.2. Voltage Stability Studies

PGE's transmission system is evaluated for voltage stability in accordance with the WECC established procedures and criteria[2]. These performance criteria are summarized in the table below. Contingencies to PGE and adjacent utility equipment at 500 kV and 230 kV are evaluated.

[2] "Guide to WECC/NERC Planning Standards I.D: Voltage Support and Reactive Power," prepared by the Reactive Reserve Working Group (RRWG) and approved by the Technical Studies Subcommittee (TSS) on March 30, 2006.
https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/Voltage%20Stability%20Guide.pdf&action=default&DefaultItemOpen=1

Figure 7. Voltage Stability Performance Criteria

WECC Performance Level	TPL-001-4 Category	Disturbance	MW Margin (PV Method)	MVAR Margin (QV Method)
A	P0	No Contingency	≥ 5%	Positive Reactive Power Margin
B	P1[3]	A Single Element	≥ 5%	Positive Reactive Power Margin
C	P2-P7[4]	Any Two Elements	≥ 2.5%	Positive Reactive Power Margin
D	N/A	Extreme Events	> 0	Positive Reactive Power Margin

For PGE's Real Power Margin assessment, the "transfer path" studied is identified by the Northwest (Area 40) generation as the (source) and PGE generation and load as the sink. Load internal to PGE's local transmission system is scaled up to increase the "path" flow until a voltage stability limit is identified.

4.3 Transient Stability Studies

PGE evaluates the voltage and transient stability performance of the Transmission System for contingencies to PGE and adjacent utility equipment at 500 kV, 230 kV, and 115 kV. The studies evaluate single line-to-ground and 3φ faults to these facilities, including generators, bus sections, breaker failure, and loss of a double-circuit transmission line. Extreme events are studied for 3φ faults with Delayed Fault Clearing.

For all 500 kV and 230 kV breaker positions, PGE implements high-speed protection through two independent relay systems utilizing separate current transformers for each set of relays. For a fault directly affecting these facilities, normal clearing is achieved when the protection system operates as designed and faults are cleared within four to six cycles.

PGE implements breaker-failure protection schemes for its 500 kV and 230 kV facilities; and the majority of 115 kV facilities. Delayed clearing occurs when a breaker fails to operate and the breaker-failure scheme clears the fault. Facilities without delayed clearing are modeled as such in the contingency definition.

The transient stability results are evaluated for compliance with the following NERC and WECC system performance requirements. The simulation durations are run to 20 seconds. All oscillations that do not show positive damping within 20 seconds after the start of the studied event shall be deemed unstable.

1. Rotor Angle Stability
   Generators must maintain synchronism with PGE's transmission system and the rest of the transmission system in the Northwest through the transient period and rotor angle oscillations must exhibit positive damping for the loss of either one or two system elements.

[3] Not all NERC TPL-001-4 Categorical outages are specifically identified in the WECC Performance Criteria.
[4] TPL-001-4 P6 is not included in the WECC Performance Criteria.

2. Frequency Stability
   System frequency at any load bus must not fall below:

   - 59.6 Hz for 6 cycles or more following the loss of a single system element.
   - 59.0 Hz for 6 cycles or more following the loss of two system elements.

3. Voltage Stability

   Following fault clearing, the voltage shall recover to 80% of the pre-contingency voltage within 20 seconds of the initiating event for all P1 through P7 events, for each applicable BES bus serving load.

   Following fault clearing and voltage recovery above 80%, voltage at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds, for all P1 through P7 events.

   For Contingencies without a fault (P2-1 category event), voltage dips at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds.

Failure to meet the above performance requirements for any transient stability simulation will necessitate some form of mitigation.

Contingency analyses simulate the removal of all elements that the Protection System and other automatic controls expected to disconnect for each contingency without Operator intervention. The analyses include the impact of the subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized
- Tripping of generators due to voltage limitations
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models

Automatic controls simulated include generator exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

Cascading is not allowed to occur for any contingency analysis. If the analysis of an Extreme Event concludes there is Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is completed.

Corrective Action Plans are developed if the stability studies indicate that the system cannot meet the TPL-001-4 and WECC performance requirements.

- P1: No generating unit pulls out of synchronism

- P2-P7: When a generator pulls out of synchronism, the resulting apparent impedance swings do not result in the tripping of any Transmission system elements other than the generating unit and its directly connected facilities
- P1-P7: Power oscillations exhibit acceptable damping

5. Results

5.1. Steady State Results – Near Term Evaluation

The majority of the contingency loading concerns identified on PGE's system for the Near Term Planning Horizon are mitigated by implementing BPA's DSO 309, addressing the South of Allston Path RAS. However, increased load in the Near Term Planning Horizon has caused a number of new overloads to appear as well as push existing contingencies that were previously being monitored, to worsen.

The majority of new overloads seen in the 2022 TPL results are driven by large increases in projected loads across the system – prompting new facilities and upgrading existing facilities as more load requests come in. These load requests across the region have increased the general number the projects identified in the 2022 TPL results, compared to previous years.

The following lines are being planned for reconductoring and/or new construction to address future overloads found in the Near Term TPL cases:

- Shute-Sunset #1 115 kV
- Horizon-Keeler BPA #1 230 kV
- Murrayhill-Sherwood #1 230 kV
- Murrayhill-Sherwood #2 230 kV
- Murrayhill-St Marys #2 230 kV
- Hogan South – McGill 115 kV
- Pearl/Sherwood reinforcement project (Pearl BPA-Sherwood 230kV and McLoughlin-Pearl BPA-Sherwood 230 kV)

Several BPA projects have also been identified as critical to meeting load increases within PGE service territory. These include:

- Rivergate-Ross BPA 230kV
- Keeler 230kV bus sectionalizing breaker
- A second Keeler 500/230kV transformer

There are no additional contingency loading or voltage concerns in the Near Term Planning Horizon on PGE's system for NERC TPL-001-4 Categories P1, P2, P3, P4, P5, and P7. NERC TPL-001-4 Category P6 contingency overloads and voltage concerns are addressed with load shedding, as permitted, on PGE's local distribution system. None of the contingencies evaluated will result in cascading from PGE's Control Area to another Control Area.

5.2. Near Term Voltage Stability

There are no voltage stability concerns identified on PGE's system in the Near Term Planning Horizon.

5.3. Near Term Transient Stability

The Near Term transient stability studies indicate that PGE's system exhibits adequate transient stability throughout the 500 kV and 230 kV transmission systems. The minimum frequency response recorded did not dip below 59.5 Hz for any of the contingency events studied on PGE's system. Underfrequency Load Shedding ("UFLS") relays are not affected because the set point for UFLS relays is 59.3 Hz. Simulations have identified the possibility of voltage dips on several 115 kV load buses for a multiple-element outage related to the McLoughlin 230 kV substation. These voltage dips would result in loss of load at three local 115kV substations; however, no malignant impacts to the 230kV system, nor any cascading outages at adjacent substations, have been observed.

5.4. Near Term Short Circuit Analysis

The Near Term short circuit analysis identified two overdutied breakers:

- Sherwood circuit breaker V274
- Sunset circuit breaker W196

Both breakers are scheduled for replacement.

5.5. Projects Currently Included in the Near Term Plan

There are 18 projects currently planned for implementation in the Near Term Planning Horizon. The timing for completion of these projects is subject to change. These projects are described in detail in Appendix A.

Appendix A: Near Term Project List

Projects currently included in the Near Term Plan are:

- Harborton Reliability Project
- Horizon-Keeler BPA #2 230 kV Project
- Reedville Substation Rebuild
- Memorial Substation Project
- Tonquin Substation Project
- Kaster Substation Project
- Redland Substation Project
- Scholls Ferry Substation Project
- Pearl BPA-Sherwood 230 kV Project
- Groveland Substation Project
- Glencullen Rebuild & Cedar Hills Breakers
- Willamette Valley Resiliency Project (4 parts)
- SE Portland Conversion Project – Holgate Substation Conversion
- Hillsboro Reliability Project
- Mt Pleasant Substation Project
- Horizon-Keeler BPA #1 230 kV Reconductor
- Murrayhill-St Marys #2 230 kV
- Murrayhill-Sherwood #1 and #2 230 kV Reconductor

These projects are described in more detail on the following pages.

Harborton Reliability Project

- **Project Purpose**
  - Address transmission operations flexibility for the loss of the Rivergate bulk power transformer.
  - Reconfigure the system to reduce exposure and provide a stronger source to the Northwest Portland 115 kV system.
- **Project Scope**
  - Rebuild the Harborton 115 kV yard to a breaker and one half configuration.
  - Build a new 230 kV breaker and one half yard at Harborton substation.
  - Route five 230 kV lines to Harborton.
  - Install a new bulk power transformer at Harborton.
  - Reconductor the 115 kV lines from Harborton to Canyon.
  - Reconfigure the 115 kV system to provide a source to Northwest Portland from Harborton substation.
- **Project Status**
  - Under Construction.
- **Project Requirement Date**
  - The initial Phase 1 of this project includes the 115 kV yard rebuild, the Harborton-Rivergate 115 kV circuit and Harborton-St Helens 115 kV circuit. This phase was completed in April 2020.
  - The remaining Phase 1 of this project includes the 230 kV yard, the Harborton-Rivergate 230 kV circuit, the Harborton-Trojan #1 230 kV circuit and the new bulk power transformer. This phase is scheduled for completion by Q2 2021.
  - Phase 2 of this project first reconductors the E-Wacker 115 kV line to 1272 ACSS. Next, the 115 kV system is reconfigured to create a Harborton-Wacker 115 kV circuit, which will also be reconductored to 1272 ACSS. The 115 kV line idled for this reconfiguration will be utilized for the fifth 230 kV source into Harborton. The Horizon-St Marys-Trojan 230 kV circuit will be looped into Harborton, creating the Harborton-Horizon 230 kV, Harborton-St Marys 230 kV, and Harborton-Trojan #2 230 kV circuits. This phase is scheduled to begin after the Canyon-Urban 115 kV Reconductor and is scheduled for completion by Q3 2026.

Horizon-Keeler BPA #2 230 kV Project

- **Project Purpose**
  - Significant load growth in the Hillsboro area has accelerated the need for another 230 kV source in the Near Term Planning Horizon. Studies indicate that the loss of the Keeler BPA-St Marys 230 kV line can cause the Horizon-Keeler BPA 230 kV line to approach its thermal rating during peak summer conditions. Conversely, the loss of the Horizon-Keeler BPA 230 kV line can cause the Keeler BPA-St Marys 230 kV line to approach its thermal rating during peak summer conditions. The loss of both the Horizon-Keeler BPA 230 kV line and the Horizon-St Marys-Trojan 230 kV line results in significant overloads on the underlying 115 kV system that can occur during all loading conditions.
- **Project Scope**
  - Construct a Horizon-Keeler BPA #2 230 kV line with 2156 ACSS conductor. A new bay will be installed on the east 230 kV bus at BPA's Keeler substation to accommodate the new line position. At Horizon substation, the remainder of the bay installed for the Horizon VWR3 transformer will be constructed. The existing lines at Horizon will both move one bay west, and the new line will terminate in the east-most bay.
- **Project Status**
  - Design Complete. Construction Sequencing in progress.
- **Project Requirement Date**
  - Project projected for completion Q2 2024.

Reedville Substation Rebuild

- **Project Purpose**
  - Address antiquated equipment and improve resiliency at the Reedville substation following an extended unplanned outage.
- **Project Scope**
  - Rebuild the Reedville substation to a 115 kV GIS ring bus configuration with three 115 kV lines and three 50 MVA distribution transformers. Construct a new Reedville-St Marys 115 kV line using the existing St Marys-Huber 115 kV line and part of the existing Murrayhill-Reedville 115 kV line. Construct a new 795 ACSS line section to create a new Murrayhill-Reedville 115 kV line.
- **Project Status**
  - Design Complete. Acquiring permits and materials.
- **Project Requirement Date**
  - Project projected for completion Q3 2024.

Memorial Substation Project

- **Project Purpose**
  - Address load growth in the Wilsonville region from multiple different customers, including new water treatment facilities.
- **Project Scope**
  - Construct a new 4-position ring bus 115 kV substation with two 115 kV line and two distribution transformer positions (one to be installed initially).
  - Loop the existing Sherwood-Wilsonville 115 kV circuit into the substation, creating an Memorial-Sherwood 115 kV line and an Memorial-Wilsonville 115 kV line.
- **Project Status**
  - Design Complete. Construction Sequencing in progress.
- **Project Requirement Date**
  - The project is currently projected for completion by Q4 2024.

Tonquin Substation Project

- **Project Purpose**
  - Address upcoming load growth, including new water treatment facilities.
  - Address loading concerns on the Oswego-West Portland 115 kV line.
- **Project Scope**
  - Construct a new 115 kV, 5-position ring bus with three 115 kV line and two distribution transformer positions (one transformer position will be for future use).
  - Loop the existing Meridian-Sherwood 115 kV circuit into the substation, creating a Meridian-Tonquin 115 kV line and a Sherwood-Tonquin 115 kV line.
  - Reconfigure the McLoughlin-Wilsonville 115 kV circuit and install a new breaker position at Rosemont substation, creating the McLoughlin-Tonquin 115 kV circuit and the Rosemont-Wilsonville 115 kV circuit.
- **Project Status**
  - Design Complete. Construction Sequencing in progress.
- **Project Requirement Date**
  - Phase 1 of this project will build out the substation, loop in the Meridian-Sherwood 115 kV circuit, and install two distribution transformers. This phase is scheduled for completion by Q4 2023.
  - Phase 2 of this project will reconfigure the McLoughlin-Wilsonville 115 kV circuit and install a new breaker position at Rosemont substation, creating the McLoughlin-Tonquin 115 kV circuit and the Rosemont-Wilsonville 115 kV circuit. This phase is scheduled for completion by Q4 2024.

Kaster Substation Project

- **Project Purpose**
  - Load growth in the St Helens area dictates the need to construct a new substation for distribution capacity. The new substation will also serve the existing Cascade substation load, which will enable the decommissioning of the antiquated Cascade substation.
- **Project Scope**
  - Construct a new 115 kV, 6-position ring bus substation with two 115 kV lines, two distribution transformers, and a 115 kV cap bank. Disconnect the Harborton-St Helens 115 kV line from St Helens and route the line to the new Kaster substation, creating the Harborton-Kaster 115 kV line. Reconductor the existing St Helens-Cascade 115 kV line to 795 ACSS, disconnect the line from the Cascade substation, and terminate the line at the Kaster substation, creating the Kaster-St Helens 115 kV line
- **Project Status**
  - Awaiting City of St Helens land use decision
- **Project Requirement Date**
  - The project schedule is dependent on land availability. It will require minimum 3 years from the time of any land procurement.

Redland Substation Project

- **Project Purpose**
  - Load in the Redland and Leland areas has increased, resulting in the Redland substation becoming heavily loaded and in need of additional capacity. Additionally, Redland substation has many assets aged past their useful life span including antiquated communication systems, necessitating the need for a substation rebuild.
- **Project Scope**
  - Completely rebuild Redland substation with two 28 MVA transformers.
- **Project Status**
  - Being scoped for construction
- **Project Requirement Date**
  - The project is currently scheduled for completion by June 2025

Scholls Ferry Substation Project

- **Project Purpose**
  - Address increased load in the Scholls Ferry region with an updated substation, converted to a 4 position ring bus, and a new additional distribution transformer.
- **Project Scope**
  - Construct a 4-position ring bus at Scholls Ferry 115 kV substation
  - Add an additional 50 MVA distribution transformer to the newly created position
- **Project Status**
  - Awaiting funding approval
- **Project Requirement Date**
  - The project is currently projected for completion by Q4 2025.

Pearl/Sherwood 230 kV Reinforcement Project

- **Project Purpose**
    - Mitigate the overloading of the McLoughlin-Pearl BPA-Sherwood 230 kV line caused by the P1-2 contingent loss of the Pearl BPA-Sherwood 230 kV line.
- **Project Scope**
    - Bifurcate the Pearl BPA-Sherwood 230 kV line into Pearl BPA-Sherwood #1 and #2 230 kV lines.
    - Bifurcate the McLoughlin-Pearl BPA-Sherwood 230 kV line into the Pearl BPA-Sherwood #3 and McLoughlin-Pearl BPA-Sherwood 230 kV lines.
    - Reconductor Pearl BPA-Sherwood #3 and the Pearl BPA to Sherwood sections of the McLoughlin-Pearl BPA-Sherwood 230 kV line with 2165 ACSS.
- **Project Status**
    - Initial scoping and ongoing coordination with BPA.
- **Project Requirement Date**
    - Q2 2026

Groveland Substation Project

- **Project Purpose**
  - Address new customer load with full N-1 distribution transformer redundancy.
- **Project Scope**
  - Construct a new 115 kV breaker-and-a-half substation with three 115 kV line and two distribution transformer positions.
  - Loop the Helvetia-West Union 115 kV circuit into the substation, creating a Groveland-Helvetia 115 kV line and a Groveland-West Union 115 kV line.
  - Relocate the spare 115/57 kV transformer to Groveland and purchase a new spare.
  - Rebuild the existing Banks-Orenco 57 kV line between Groveland and Orenco to 115 kV, creating the Groveland-Orenco 115 kV circuit.
  - Terminate the Banks-Orenco 57 kV line at Groveland, creating the Banks-Groveland 57 kV circuit.
- **Project Status**
  - Initial scoping
- **Project Requirement Date**
  - Phase 1 of this project will build out the substation, loop in the Helvetia-West Union 115 kV circuit, and install two distribution transformers. This phase is scheduled for completion by Q2 2025.
  - Phase 2 of this project will re-terminate the Orenco end of the Banks-Orenco 57 kV line at Groveland, install a 115/57 kV transformer at Groveland, and rebuild the idled 57 kV line to create the Groveland-Orenco 115 kV circuit. This phase schedule is still being determined.

Glencullen Rebuild & Cedar Hills Breakers

- **Project Purpose**
  - Excessive outage durations to perform planned and unplanned maintenance drove a need to reconfigure Glencullen substation as well as upgrade nearby the Cedar Hills substation breakers. This project also reduces some overloads seen on the surrounding 115 kV system during certain P6 events. This project also helps improve reliability to critical infrastructure, such as St. Vincent Hospital, by converting the substation from a selective transfer station, to a breaker station.
- **Project Scope**
  - Construct a 5-position ring bus at Glencullen with three 115 kV sources
  - Upgrade existing Circuit Switchers at Cedar Hills to Circuit Breakers.
- **Project Status**
  - Initial scoping
- **Project Requirement Date**
  - The project is currently projected for completion by Q4 2026.

Willamette Valley Resiliency Project – Monitor 115 and 230 kV Substation Project

- **Project Purpose**
  - Part of the Willamette Valley Resilience Project. The intent of the project is to strengthen and increase the resiliency of PGEs system in the Central portion of PGE's territory, North of the Salem region. Monitor is being converted from a 57/230 kV simple substation, to a 57/115/230 kV Ring Bus substation.
- **Project Scope**
  - Construct 115 and 230 kV Ring Bus for Monitor Substation. In the long term planning horizon, five 57 kV substations in the central region of PGEs service territory will be converted to 115 kV, with additional upgrades to existing 115 kV and 230 kV substations such as Bethel and Monitor.
  - Monitor 115 kV will be built to a 5 position ring bus with two transformers (57/115 kV and 115/230 kV).
  - Monitor 115 kV will also include a capacitor bank.
  - Monitor 230 kV will be built as a 4 position ring bus
- **Project Status**
  - Approved project with funding. Construction will be done in phases over an 8 year period with Monitor being the first portion of the work to be completed in an estimated 3 years.
- **Project Requirement Date**
  - Construction to be done in phases over an 8 year period. Monitor 115 and 230 kV substation expected to be complete in Q4 2025. Rebuilt substations will be energized at 57kV until Q4 2028, when all WVRP substation are re-energized at 115kV.

Willamette Valley Resiliency Project – St Louis 115 kV Project

- **Project Purpose**
  - Part of the Willamette Valley Resilience Project. The intent of the project is to strengthen and increase the resiliency of PGEs system in the Central portion of PGE's territory, North of the Salem region. St Louis substation is being converted from a 57 kV simple substation, to a 115 kV ring bus.
- **Project Scope**
  - Construct 4 position 115 kV Ring Bus St Louis substation.
  - Two distribution 28.0 MVA transformers to be included.
  - Two 115 kV sources
    - Waconda-St Louis
    - North Marion-St Loius
- **Project Status**
  - Approved project with funding. Construction will be done in phases over an 8 year period with St Louis being the first portion of the work to be completed in an estimated 3 years.
- **Project Requirement Date**
  - Construction to be done in phases over an 8 year period. St Louis substation expected to be complete in Q4 2025. Rebuilt substation will be energized at 57kV until Q4 2028, when all WVRP substations are re-energized at 115kV.

Willamette Valley Resiliency Project – North Marion 115 kV Project

- **Project Purpose**
  - Part of the Willamette Valley Resilience Project. The intent of the project is to strengthen and increase the resiliency of PGEs system in the Central portion of PGE's territory, North of the Salem region. North Marion substation is being converted from a 57 kV substation, to a 115 kV ring bus.
- **Project Scope**
  - Construct 6 position 115 kV Ring Bus North Marion substation.
  - Two distribution 28.0 MVA transformers to be included.
  - Three 115 kV Transmission Sources
    - North Marion-Twilight
    - North Marion-St Louis
    - North Marion-Woodburn
- **Project Status**
  - Approved project with funding. Construction will be done in phases over an 8 year period with the North Marion portion of the work to be completed in an estimated 5 years.
- **Project Requirement Date**
  - Construction to be done in phases over an 8 year period. North Marion 115 kV substation expected to be complete in Q4 2027. Rebuilt substation will be energized at 57kV until Q4 2028, when all WVRP substations are re-energized at 115kV.

Willamette Valley Resiliency Project – Woodburn 115 kV Project

- **Project Purpose**
    - Part of the Willamette Valley Resilience Project. The intent of the project is to strengthen and increase the resiliency of PGEs system in the Central portion of PGE’s territory, North of the Salem region. Woodburn substation is being converted from a 57 kV substation, to a 115 kV ring bus.
- **Project Scope**
    - Construct a 4-position 115 kV Ring Bus Woodburn substation.
    - Two distribution 28.0 MVA transformers to be included.
    - Two 115 kV Sources
        - North Marion-Woodburn
        - Monitor-Woodburn
- **Project Status**
    - Approved project with funding. Construction will be done in phases over an 8 year period with the Woodburn portion of the work to be completed in an estimated 5 years.
- **Project Requirement Date**
    - Construction to be done in phases over an 8 year period. Woodburn 115 kV substation expected to be complete in Q4 2027. Rebuilt substation will be energized at 57kV until Q4 2028, when all substations are re-energized at 115kV.

SE Portland Conversion Project – Holgate Substation Conversions

- **Project Purpose**
  - The SE Portland Conversion Project addresses antiquated equipment and resiliency in the SE Portland area. The project will be completed in multiple phases; the Holgate Substation Conversion is scheduled for completion in the Near Term Planning Horizon.
- **Project Scope**
  - The Holgate substation will be rebuilt to a 115 kV breaker station. The Gresham-Harrison PACW 115 kV line will be looped into the substation, creating the Gresham-Holgate 115 kV line and the Harrison PACW-Holgate 115 kV line. The existing distribution transformers will be replaced with two 28 MVA transformers and two metalclad switchgear will be installed.
- **Project Status**
  - Design in progress.
- **Project Requirement Date**
  - This project is projected for completion in Q2 2026.

Hillsboro Reliability Project

- **Project Purpose**

The Hillsboro Reliability Project constructs additional bulk power transformer capacity to serve the North Hillsboro area. In addition, the conversion of Brookwood substation and Main substation provides loading relief to the Hillsboro area 57 kV System while providing additional distribution transformer capacity. The Orenco substation rebuild provides improved reliability and additional distribution capacity, as well as mitigates breakers at Orenco that will become overdutied upon the energization of Evergreen substation.

- **Project Scope**

The new Evergreen bulk power substation will be constructed in Q2 2024. The 230 kV yard will be two bays of breaker and one half, with two lines and two bulk power transformers. The Harborton-Horizon 230 kV line will be looped into Evergreen, creating the Evergreen-Harborton 230 kV and Evergreen-Horizon 230 kV lines. The 115 kV yard will also be breaker and one half with five 115 kV line positions and two bulk power transformer positions. Two 115 kV cap banks will be installed for voltage support. The Helvetia-Shute 115 kV line will be looped into Evergreen, creating the Evergreen-Helvetia 115 kV and Evergreen-Shute 115 kV lines. The Rock Creek-Shute-Sunset 115 kV line will be unbundled to create the Evergreen-Rock Creek 115 kV line and the Evergreen-Sunset 115 kV line. The Evergreen-Shute 115 kV line will be reconductored to 1272 ACSS and a second Evergreen-Shute 115 kV line will also be constructed. Two 120/34.5 kV, 150 MVA distribution transformers will also be installed to serve new load growth in the area.

The Brookwood and Main substations will be converted to 115 kV with gas-insulated switchgear (GIS) ring bus configurations. Four new 115 kV lines will be constructed: Brookwood-Shute 115 kV, Brookwood-St Marys 115 kV, Brookwood-Main 115 kV, and Main-Roseway 115 kV. Both substations will have increased distribution capacity.

The Orenco substation 115 kV yard will be rebuilt to a breaker and one half configuration in 2023, using 63 kA breakers to mitigate fault duty concerns created by the energization of the Evergreen substation. The existing distribution yard will be eliminated, moving the distribution transformers to the main bus.

- **Project Status**
  - Project currently in various stages of design and construction.
- **Project Requirement Date**
  - The project is currently projected for complete completion by Q2 2027.

Mt Pleasant Substation Project

- **Project Purpose**
  - Upgrade Mt Pleasant 115 kV substation to a breaker station to address local load growth in the area.
- **Project Scope**
  - Upgrade Mt Pleasant 115 kV substation from a tapped manual switch substation off of the Canemah-McLoughlin 115 kV line to a breaker station with two sources:
    - Canemah-Mt Pleasant 115 kV
    - Carver-Mt Pleasant 115k V
  - Upgrade the existing 16.8 MVA transformer to a 28 MVA transformer.
- **Project Status**
  - Project in initial scoping phase
- **Project Requirement Date**
  - Q4 2027

Horizon-Keeler BPA #1 230 kV Reconductor

- **Project Purpose**
  - Mitigate overloads seen on the Horizon-Keeler BPA #1 230 kV line due to Hillsboro-area load growth.
- **Project Scope**
  - Reconductor the Horizon-Keeler BPA #1 230 kV line from 1272 ACSS to a larger conductor size.
- **Project Status**
  - Project in initial study phase.
- **Project Requirement Date**
  - Anticipated in-service date of Q2 2026

Murrayhill-Sherwood #1 and #2 230 kV Reconductor

- **Project Purpose**
  - Mitigate overloads caused by the loss of other 500 and 230kV sources during south-to-north flow conditions in the Beaverton/Hillsboro area. These flow conditions are the result of changing generation dispatch (increased solar from California), the addition of 500 and 230 kV infrastructure landing in the Sherwood area, and load growth within PGE service territory.
- **Project Scope**
  - Reconductor the Murrayhill-Sherwood #1 and #2 230 kV transmission lines from 1272 AAC to 2156 ACSS
  - Replace the remaining 230kV circuit breakers at Sherwood with higher fault duty equipment
- **Project Status**
  - Pre-scoping and initial study phase.
- **Project Requirement Date**
  - No firm date currently available. Targeting 2026.

Murrayhill-St Marys #2

- **Project Purpose**
  - Mitigate overloads caused by the loss of other 500 and 230kV sources during south-to-north flow conditions in the Beaverton/Hillsboro area. These flow conditions are the result of changing generation dispatch (increased solar from California), the addition of 500 and 230 kV infrastructure landing in the Sherwood area, and load growth within PGE service territory.
- **Project Scope**
  - Construct a second Murrayhill-St Marys 230 kV line using existing right of way.
  - Rebuild Murrayhill 230kV yard as a 3-bay, six position, breaker-and-a-half configuration
  - Rebuild Murrayhill 115kV as a GIS substation. Relocate the load service within the 115kV yard
- **Project Status**
  - Pre-scoping and initial study phase.
- **Project Requirement Date**
  - No firm date currently available. Targeting 2027.

PGE/109

Longer Term Local Transmission Plan for the 2023-2024 Planning Cycle

PGE Long Term Local Transmission Plan For the 2023-2024 Planning Cycle

December 26th, 2023

Prepared by
PGE Transmission Planning

Table of Contents

Revision Log

Date	Version	Revision Description	Author
11/10/2023	DRAFT	2023-2024 Local Transmission Plan	Christopher Brem
12/22/2023	1.0	2023-2024 Local Transmission Plan	Christopher Brem

Introduction

This 2023 Longer Term Local Transmission Plan reflects Quarters 5 through 8 of the local transmission planning process as described in PGE's Open Access Transmission Tariff (OATT) Attachment K. The plan includes all transmission system facility improvements identified through this planning process. A power flow reliability assessment of the plan was performed which demonstrated that the planned facility additions will meet NERC and WECC reliability standards.

PGE's OATT is posted on its Open Access Same-time Information System (OASIS) at http://oasis.oati.com/PGE. Additional information regarding Transmission Planning is located in the Transmission Planning folder on PGE's OASIS. Unless otherwise specified, capitalized terms used herein are defined in PGE's OATT.

1.1 Local Planning

This Local Transmission Plan (LTP) has been prepared within the two-year process as defined in PGE's OATT Attachment K. The LTP identifies the Transmission System facility additions required to reliably interconnect and transmit forecasted generation resources and serve the forecasted Network Customers' load, Native Load Customers' load, and Point-to-Point Transmission Customers' requirements, and also includes legacy, non-OATT agreements and rollover rights over a ten-year planning horizon. Additionally, the LTP typically incorporates the results of any stakeholder-requested economic congestion studies results that were performed. However, none were requested during this cycle.

1.2 Regional and Inter-regional Coordination

PGE coordinates its planning processes with other transmission providers through membership in NorthernGrid and the Western Electric Coordinating Council (WECC). PGE uses the NorthernGrid process for regional planning, coordination with adjacent regional groups and other planning entities for interregional planning, and development of proposals to WECC. Additional information is included in PGE's OATT Attachment K, in our Transmission Planning Business Practice on OASIS, and on NorthernGrid's website at www.northerngrid.net.

Planning Process and Timelines

This plan is for the 2023-2024 planning cycle. PGE's OATT Attachment K describes an eight (8) quarter study and planning cycle. The planning cycle schedule is shown below in Table 1.

Table 1: PGE OATT Attachment K Eight Quarter Planning Cycle

		Quarter	Tasks
Near Term	Even Years	1	Select Near Term base cases and gather load data
		2	Post Study Methodology on OASIS, select one Economic Study for evaluation
		3 & 4	Select Longer Term base cases, post draft Near Term Plan on OASIS, hold public meeting to solicit stakeholder comment
		4	Incorporate stakeholder comments and post final Near Term plan on OASIS
Longer Term	Odd Years	5	Gather load data and accept Economic Study requests
		6	Select one Economic Study for evaluation
		7 & 8	Post draft Longer Term plan on OASIS, hold public meeting to solicit stakeholder comment
		8	Post final Longer Term plan on OASIS, submit final Longer Term Plan to stakeholders and owners of neighboring systems

PGE updates its Transmission Customers about activities and progress made under the Attachment K planning process during regularly scheduled customer meetings. Meeting announcements, agendas, and notes are posted in the Customer Meetings folder on PGE's OASIS.

Meeting dates are posted on PGE's OASIS.

Transmission System Plan Inputs and Components

3.1 PGE Service Territory & Topology

PGE's service territory covers more than 4,000 square miles and provides service to over 900,000 customers. PGE's service territory is confined within Multnomah, Washington, Clackamas, Yamhill, Marion, and Polk counties in northwest Oregon. Transmission utilities directly connected to PGE's Transmission System include Bonneville Power Administration (BPA) and PacifiCorp (PACW).

PGE's Transmission System is designed to reliably distribute power to and then throughout the Portland and Salem regions for the purpose of serving native load and integrating transmission and generation resources on the Bulk Electric System. The following PGE-owned 500 kV and 230 kV lines are essential elements of regional transmission paths:

- The Grizzly BPA-Malin BPA #2 500 kV line and the Grizzly BPA-Round Butte 500 kV line contribute to the reliability of the Northwest AC Intertie (NWACI); outages to these lines could result in a restriction on the path limit to move resources from the Northwest to California. Traditionally, the NWACI experienced heavy north-to-south flows in the summer; however, during recent heat wave events, the Northwest has been observed to import energy from California, resulting in south-to-north flows on the NWACI during peak summer conditions that were historically unprecedented.

- PGE has approximately 15% ownership in the Colstrip-Townsend #1 and #2 500 kV lines. These 500 kV lines are part of the Colstrip Transmission System (CTS) that moves resources from Montana to the Northwest.

- The Bethel-Round Butte 230 kV line is part of the West of Cascades South (WOCS) Path. WOCS is a WECC Major Path and experiences heavy east-to-west flows in the winter, with generation resources on the east side of the Cascades serving the Willamette Valley.

- The Harborton-Trojan #1 230 kV and Horizon-St Marys-Trojan 230 kV lines are part of the South of Allston (SOA) Path.
    - The SOA Path historically experiences heavy north-to-south flows in the summer, with generation resources in the I-5 Corridor and Canada serving the Willamette Valley. Recent trends during extreme heat waves (greater than 1-in-3 loading conditions) indicate that transfers from the Northwest to California will be cut to be able to utilize the Northwest generation to serve the growing Northwest load. Resource retirements in the Northwest have also contributed to the changes in flow; there is no longer excess generation to deliver to other areas of the WECC.
    - During the heat event in June 2021, the SOA Path, while still flowing north-to-south, did not load heavily. PGE's system experienced flows never seen before during peak

summer conditions, at least partially due to the importing of generation from California. The PGE Transmission System experienced heavy south-to-north flow from the Sherwood area to the Beaverton/Hillsboro area, as well as a north-to-south flow from BPA's 500 kV system into the Beaverton/Hillsboro area. This flow pattern resulted in PGE Transmission System concerns in the Operations Horizon that were not previously identified in planning studies. As a result, PGE's summer sensitivity studies evaluate this flow pattern. Subsequent summers have experienced this flow pattern with increasing intensity, and the Hillsboro area continues to see increased load demands, necessitating a continued focus on studying power flow into the area that was first experienced in the previously mentioned 2021 heat event.

- For off-peak conditions in the Northwest, the SOA Path will often flow in the south-to-north direction. Ratings for the SOA path in the south-to-north direction will be retired in 2023 with the implementation of the North of Pearl (NOPE) BPA path. The NOPE path experiences heavy south-to-north flows in Spring and Summer from generation in California. PGE is currently working with BPA to increase the total transfer capability of the NOPE path, specifically by coordinating on the Pearl-Sherwood project discussed in the Corrective Action Plans segment.

- A Remedial Action Scheme (RAS) is in place to address north-to-south conditions. This RAS drops generation in the I-5 Corridor (including PGE's Port Westward 2 and Beaver plants) to mitigate overloads on the underlying 230 kV and 115 kV System and is triggered for the loss of the Allston BPA-Keeler BPA 500 kV or other elements of the South of Allston Path.

In total, PGE owns 1,613 circuit miles of sub-transmission/Transmission at voltages ranging from 57 kV to 500 kV. A breakdown of line miles owned, by voltage level, is as follows:

Voltage Level	Pole Miles	Circuit Miles
500 kV	268	268
230 kV	281	330
115 kV	513	552
57 kV	429	463

3.2 Load Forecast

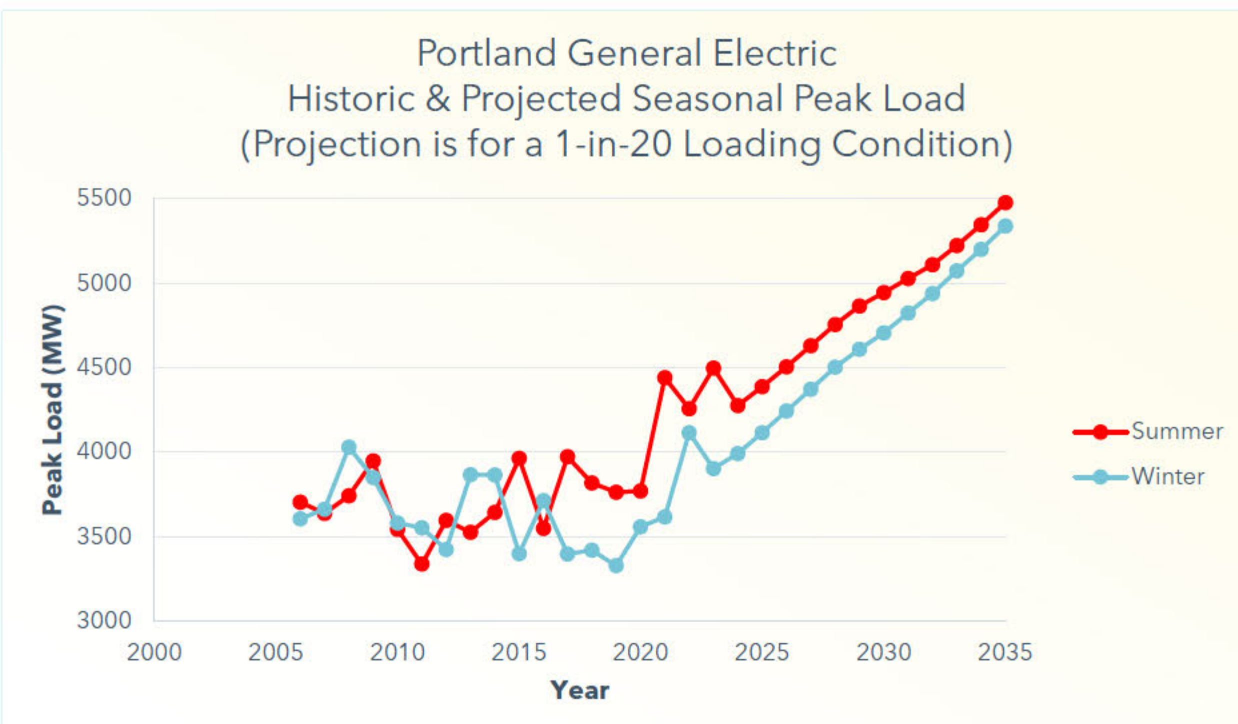
For load forecasting purposes, PGE's transmission system is evaluated for a 1-in-20 peak load condition during the summer and winter seasons for Near Term (years 1 through 5) and Longer Term (years 6 through 10) studies.

The 1-in-20 peak system load is calculated based on weather conditions that PGE can anticipate experiencing once every three years. The summer (June 1st through October 31st) and winter (November 1st through March 31st) load seasons are considered the most critical study seasons due to heavier peak loads and high-power transfers over PGE's T&D System to its customers. PGE defines the seasons to align with the seasons set by the Reliability Coordinator's seasonal planning process.

Summer and Winter loading conditions and the corresponding daily averaged temperatures are as follows:

Summer	
1-in-3	85.4
1-in-5	87.3
1-in-10	89.3
1-in-20	91.1

Winter	
1-in-3	26.3
1-in-5	24.5
1-in-10	22.5
1-in-20	20.8



As depicted in the figure above, PGE's all-time peak load occurred on August 16, 2023, with the Net System Load[1] reaching 4498 MW. PGE's all-time winter peak load occurred on December 22, 2022, with the Net System Load reaching 4116 MW.

3.3 Forecasted Resources

The forecasted resources are comprised of generators, identified by network customers as designated network resources, that are integrated into the wider regional forecasts of expected resources committed to meet seasonal peak loads.

3.4 Economic Studies

Eligible customers or stakeholders may submit economic congestion study requests during either Quarter 1 or Quarter 5 of the planning cycle. However, PGE did not receive any study requests during the 2022-2023 planning cycle.

3.5 Stakeholder Submissions

Any stakeholder may submit data to be evaluated as part of the preparation of the draft Near Term Local Transmission Plan and/or the development of sensitivity analyses, including alternative solutions to the identified needs set out in prior Local Transmission Plans, Public Policy Considerations and Requirements, and transmission needs driven by Public Policy Considerations and Requirements. However, PGE did not receive any such data submissions during the 2022-2023 planning cycle.

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[1] The Net System Load is the total load served by PGE Merchant (PGEM), including losses. This includes PGE load in all control areas, plus ESS load, minus net borderlines.

Methodology

PGE's Transmission System is designed to reliably supply projected customer demand and projected Firm Transmission Service. Studies are performed annually to evaluate where Transmission upgrades may be needed to meet the performance requirements established in the NERC TPL-001-5 Reliability Standard and the WECC TPL-001-WECC-CRT-3.2 Regional Criteria.

The summer (June 1st through October 31st) and winter (November 1st through March 31st) load seasons are considered the most critical study seasons due to heavier peak loads and high-power transfers over PGE's Transmission and Distribution System to its customers. However, the off-peak seasons have different regional flow patterns that can result in issues not seen during peak load times. PGE defines the seasons to align with Attachment I of the RC West "RC Guidelines for Seasonal Assessment and Coordination Process."

PGE maintains system models within its planning area for performing the studies required to complete the system assessment. These models use data that is provided in WECC base cases in accordance with the MOD-032 reliability standard. Electrical facilities modeled in the cases have established ratings, as defined in PGE's "Facility Ratings Methodology" document and in accordance with the FAC-014 reliability standard. A facility rating is determined based on the most limiting component in each transmission facility, in accordance with the FAC-008 reliability standard.

Reactive power resources are modeled as made available in the WECC base cases. For PGE, reactive power resources include shunt capacitor banks available on the 230 kV, 115 kV, and 57 kV systems.

Studies are evaluated for the Near-Term Planning Horizon (years 1 through 5) and the Longer Term Planning Horizon (years 6 through 10) to ensure adequate capacity is available on PGE's transmission system. The load modeled in the studies is obtained from PGE's corporate forecast, reflecting a 1-in-20 demand level for peak summer and peak winter conditions. Known outages of generation or transmission facilities with durations of at least six months are appropriately represented in the system models. However, any significant outage is studied as a result of an N-1-1 contingency and is therefore analyzed for every major season and year that PGE studies as part of the TPL process. Transmission equipment is assumed to be out of service in the base case system models if there is no spare equipment or mitigation strategy for the loss of the equipment.

Studies in the Near Term – Two Year Planning Horizon and the Near Term – Five Year Planning Horizon are performed for peak summer, peak winter, and off-peak spring conditions. Sensitivity studies are performed for each of these cases by varying the study parameters to stress the system within a range of credible conditions that demonstrate a measurable change in performance. PGE adjusts the real and reactive forecasted load and the transfers on the paths into the Portland area on all sensitivity studies. For peak system sensitivity cases, the 1-in-20 load forecast is used, and non-industrial loads are scaled by an additional +5%.

Studies are evaluated at peak summer and peak winter 1-in-20 load conditions for one of the years in the Longer Term Planning Horizon. Year Ten is chosen for the Longer Term Planning Horizon studies because it aligns with the WECC Longer Term Planning base cases and represents all projects in the Longer Term Planning Horizon.

The powerflow cases used in this year's assessment are described below. Topology, generation, and load changes are implemented to modify the cases as needed.

		Study Year	Origin WECC Base Case	PGE Case Name	PGE System Load (MW)
SUMMER	Year One/Two Case	2025	2023 HS4	25 HS PLANNING	4761
	Year Five Case	2028	2028 HS2	28 HS PLANNING	5094
	Year One/Two Sensitivity	2025	2023 HS4	25 HS SENSITIVITY	4953
	Year Five Sensitivity	2028	2028 HS2	28 HS SENSITIVITY	5299
	Longer Term Case	2033	2033 HS1	33 HS PLANNING	5527
WINTER	Year One/Two Case	2025-26	2022-23 HW3	25-26 HW PLANNING	4643
	Year Five Case	2028-29	2027-28 HW2	28-29 HW PLANNING	4967
	Year One/Two Sensitivity	2025-26	2022-23 HW3	25-26 HW SENSITIVITY	4831
	Year Five Sensitivity	2028-29	2027-28 HW2	28-29 HW SENSITIVITY	5151
	Longer Term Case	2033-34	2032-33 HW1	33-34 HW PLANNING	5597
SPRING	Year One/Two Off Peak Case	2025	2024 LSP2	25 LSP PLANNING	2818
	Year Five Off Peak Case	2028	2024 LSP2	28 LSP PLANNING	3122
	Year One/Two Off Peak Sensitivity	2025	2024 LSP2	25 LSP SENSITIVITY	2818
	Year Five Off Peak Sensitivity	2028	2024 LSP2	28 LSP SENSITIVITY	3122

The Bulk Electric System (BES) is evaluated for steady state and transient stability performance for planning events described in Table 1 of the NERC TPL-001-5 reliability standard. When system simulations indicate an inability of the systems to respond as prescribed in the NERC TPL-001-5 standard, PGE identifies projects and/or Corrective Action Plans which are needed to achieve the required system performance throughout the Planning Horizon.

4.1 Steady-State Studies

PGE performs steady-state studies for the Near Term and Longer Term Transmission Planning Horizons. The studies consider all Contingency scenarios identified in Table 1 of the NERC TPL-001-5 reliability standard (Categories P0-P7) to determine if the BES meets performance requirements. PGE uses the criteria defined in the WECC TPL-001-WECC-CRT-3.2 document to establish acceptable System steady state voltage limits and post-Contingency voltage deviations. The WECC System Performance Criteria requires that the change in bus voltage percentage not exceed 8% for N-1 contingencies. Additionally, internal PGE performance criteria require that the change in bus voltage percentage not exceed 10% for N-2 and N-1-1 contingencies. These studies also assess the impact of Extreme Events on the System expected to produce severe System impacts.

The Contingency Analyses simulate the removal of all Elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without Operator intervention. The analyses include the impact of the subsequent tripping of generators due to voltage limitations and tripping of Transmission Elements where relay loadability limits are exceeded. Automatic controls simulated include phase-shifting transformers, load tap changing transformers, and switched capacitors and reactors.

Cascading, or the uncontrolled successive loss of System Elements triggered by a Disturbance that results in the inability of the Elements of the BES to regain a state of operating equilibrium, is defined as a System instability. Cascading is not allowed to occur for any Contingency analysis. If the analysis of an Extreme Event concludes there is Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is completed.

The following process is used to test for Cascading:

1. Single Contingencies and credible multiple Contingencies that result in excess of the lower of:
    a. The Facility(ies)'s trip setting, or
    b. 125% of the highest Facility Emergency Rating (Note: if the trip setting is known to be different than the 125% threshold, the known trip setting should be used.)
2. For each flagged Contingency, open the original Contingency Elements and the Elements flagged in step 1. Run steady state analysis without any manual System adjustments.

3. Repeat step 2 for any newly overloaded Facilities in excess of step 1 criteria. Continue repeating step 2 until no more Facilities are removed from service or until the powerflow solution diverges.
4. If the process of tripping Elements in steps 2 and 3 stops prior to divergence, then it can be concluded that the area of impact is predetermined by studies, and Cascading does not occur. If the powerflow solution diverges during the test described above utilizing the 125% of the highest Facility Emergency Rating threshold, further investigation into post-Contingency loading may be warranted prior to declaring that Cascading occurs.

Uncontrolled islanding is defined as a System instability that occurs when Transmission operating actions, such as tripping for loading a given percentage above the highest Facility emergency rating, result in the separation and loss of synchronism of a portion of the Bulk Power System that includes generation or load. Generators disconnected from the System by fault clearing action or by a RAS are not considered out of synchronism. Similarly, islands formed by disconnection from the System by fault clearing action or by a RAS are considered a sub-network island and not an uncontrolled island.

Characteristics of a sub-network island include:

- The presence of both generation and load to support the continuation of the island.
- A clear disconnect between formed sub-networks.

Characteristics of uncontrolled islanding include:

- Out-of-step generators.
- Off-nominal frequency disturbances.
- Eventual collapse of formed islands due to frequency or voltage instability caused by generation-load unbalance.

Capacity addition projects are developed when simulations indicate the System’s inability to meet the steady-state performance requirements for P0 (System Normal), P1, or P2-1 events. For P2-2 through P7 events, PGE may develop projects to mitigate overload or voltage issues; however, manual post-Contingency load-shedding may be identified as a mitigation to ensure that the BES remains within the defined operating limits, which is permissible (except for some categories of faults on equipment 300 kV and above) per TPL-001-5 for P2-2 through P7 events.

4.2 Short Circuit Studies

Short circuit studies are performed annually addressing the Near Term Planning Horizon. If the short circuit current interrupting duty on a circuit breaker exceeds 97% of its equipment rating, PGE identifies projects and/or Corrective Action Plans which are needed to achieve the required System performance throughout the Near Term and Longer Term Planning Horizons.

4.3 Reactive Margin (Voltage Stability) Studies

PGE's Transmission System is evaluated for voltage stability in accordance with the WECC established criteria.[2] These performance criteria are summarized in the table below. Any voltage stability result that violates the criteria listed below is defined as a System instability. Contingencies to PGE and adjacent utility equipment at 500 kV and 230 kV are evaluated. All planning events were screened or reviewed for voltage stability requirement per WECC Criterion WR5 by simulating P0 and P1 events at 105% of forecasted peak load and simulating P2-P7 events at 102.5% of forecasted peak load. This screening indicated all planning events met the reactive margin requirement with the implementation of their associated operating procedures, RAS, or corrective action plans.

WECC Performance Level	TPL-001-5 Category	Disturbance	MW Margin (PV Method)	MVAR Margin (QV Method)
A	P0	No Contingency	≥5%	Positive Reactive Power Margin
B	P1[3]	A Single Element	≥5%	Positive Reactive Power Margin
C	P2-P7[4]	Any Two Elements	≥2.5%	Positive Reactive Power Margin
D	N/A	Extreme Events	>0	Positive Reactive Power Margin

For PGE's Real Power Margin assessment, the "transfer path" studied is identified by the Northwest (Area 40) generation as the (source) and PGE generation and load as the sink. Load internal to PGE's local Transmission System is scaled up to increase the "path" flow until a voltage stability limit is identified.

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[2] "Guide to WECC/NERC Planning Standards I.D: Voltage Support and Reactive Power," prepared by the Reactive Reserve Working Group (RRWG) and approved by the Technical Studies Subcommittee (TSS) on March 30, 2006. https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/Voltage%20Stability%20Guide.pdf&action=default&DefaultItemOpen=1

[3] Not all NERC TPL-001-5 Categorical outages are specifically identified in the WECC Performance Criteria.

[4] TPL-001-5 P6 is not included in the WECC Performance Criteria.

4.4 Transient Stability Studies

PGE evaluates the transient stability performance of the BES for select Contingencies to PGE and adjacent utility equipment at 500 kV, 230 kV, and 115 kV. The studies evaluate single line-to-ground and three-phase faults to these facilities, including generators, bus sections, breaker failure, and loss of a double-circuit Transmission line. Extreme events are studied for three-phase faults with Delayed Fault Clearing.

For all 500 kV and 230 kV breaker positions, PGE implements high-speed protection through two independent relay systems utilizing separate current transformers for each set of relays. For a fault directly affecting these facilities, normal clearing is achieved when the Protection System operates as designed and faults are cleared within four to six cycles.

PGE implements breaker-failure protection schemes for its 500 kV and 230 kV facilities, and the majority of 115 kV facilities. Delayed clearing occurs when a breaker fails to operate, and the breaker-failure scheme clears the fault. Facilities without delayed clearing are modeled as such in the Contingency definition.

The transient stability results are evaluated for compliance with the following NERC and WECC System performance requirements. The simulation durations are run to 20 seconds. All oscillations that do not show positive damping within 20 seconds after the start of the studied event shall be deemed unstable.

1. Rotor Angle Stability
   Generators must maintain synchronism with PGE's Transmission System and the rest of the Transmission System in the Northwest through the transient period and rotor angle oscillations must exhibit positive damping for the loss of either one or two System Elements.

2. Frequency Stability[5]
   System frequency at any load bus must not fall below:
   - 59.6 Hz for 6 cycles or more following the loss of a single System Element.
   - 59.0 Hz for 6 cycles or more following the loss of two System Elements.

3. Voltage Stability

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[5] Although the WECC criterion is retired, PGE still adheres to the frequency dip criterion.

Following fault clearing, the voltage shall recover to 80% of the pre-Contingency voltage within 20 seconds of the initiating event for all P1 through P7 events, for each applicable BES bus serving load.

Following fault clearing and voltage recovery above 80%, voltage at each applicable BES bus serving load shall neither dip below 70% of pre-Contingency voltage for more than 30 cycles nor remain below 80% of pre-Contingency voltage for more than two seconds, for all P1 through P7 events.

For Contingencies without a fault (P2-1 category event), voltage dips at each applicable BES bus serving load shall neither dip below 70% of pre-Contingency voltage for more than 30 cycles nor remain below 80% of pre-Contingency voltage for more than two seconds.

Failure to meet the above performance requirements for any transient stability simulation is defined as a System instability and will necessitate some form of mitigation.

Contingency analyses simulate the removal of all Elements that the Protection System and other automatic controls expected to disconnect for each Contingency without Operator intervention. The analyses include the impact of the subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized
- Tripping of generators due to voltage limitations
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models

Automatic controls simulated include generator exciter and governor controls, generator power system stabilizers, static var compensators, power flow controllers, DC Transmission controllers, remedial action schemes (RAS) and under frequency load shedding (UFLS). Fault protection or automatic controls that result in unintended islanding as defined in the steady state section above is considered a System instability.

Corrective Action Plans are developed if the stability studies indicate that the System cannot meet the TPL-001-5 and WECC performance requirements.

- P1: No generating unit pulls out of synchronism
- P2-P7: When a generator pulls out of synchronism, the resulting apparent impedance swings do not result in the tripping of any BES Elements other than the generating unit and its directly connected facilities
- P1-P7: Power oscillations exhibit acceptable damping

Results

5.1 Steady State

Steady state results are available in the 2023 PGE TPL-001 annual report.

There are no additional contingency loading or voltage concerns in the Near-Term and Long-Term Planning Horizon on PGE's system for NERC TPL-001-5 Categories P1, P2, P3, P4, P5, and P7. NERC TPL-001-5 Category P6 contingency overloads are addressed by a combination of planned transmission projects, system adjustments, and load shedding, when no other alternative is present. None of the contingencies evaluated will result in cascading from PGE's Control Area to another Control Area.

5.2 Short Circuit Analysis

The Near-Term short circuit analysis identified two overdutied breakers:

- Sherwood circuit breaker V274
- Sunset circuit breaker W196

Both breakers are scheduled for replacement.

The 5 Year Near-Term and 10 Year Longer-Term short circuit analysis identified the following overdutied breakers:

- St Marys W204 (5 Year Short Circuit)
- St Marys W238 (5 Year Short Circuit)
- St Marys W244 (5 Year Short Circuit)
- St Marys W272 (5 Year Short Circuit)
- St Marys W276 (5 Year Short Circuit)
- St Marys W386 (5 Year Short Circuit)
- St Marys W296 (5 Year Short Circuit)
- Bethel V208 Bus Tie (10 Year Short Circuit)
- Bethel V212 (10 Year Short Circuit)
- Bethel V230 (10 Year Short Circuit)
- St Marys W170 (10 Year Short Circuit)
- St Marys W174 (10 Year Short Circuit)
- St Marys W394 (10 Year Short Circuit)
- Trojan V592 (10 Year Short Circuit)
- Trojan V820 (10 Year Short Circuit)
- Trojan V832 (10 Year Short Circuit)
- Trojan V862 (10 Year Short Circuit)
- Trojan V884 (10 Year Short Circuit)

The Longer-Term short circuit analysis identified additional breakers to be replaced and these projects are going to be further investigated for an appropriate timeline or mitigation to resolve the fault current issues.

5.3 Reactive Margin Analysis (PV/QV Analysis)

There are no voltage stability concerns identified on PGE's system in the Longer-Term Planning Horizon.

5.4 Transient Stability

The transient stability studies indicate that PGE's system exhibits adequate transient stability throughout the 500 kV and 230 kV transmission systems. Underfrequency Load Shedding ("UFLS") relays are not affected with their set point for UFLS relays at 59.3 Hz. Simulations have identified the possibility of voltage dips on several BES load busses for a multiple-element outage related to the studied events during heavily loaded summer scenarios. PGE is looking into the results and will further process a plan for mitigation.

Corrective Action Plans (Planned Projects)

For the Near-Term and Long-Term Planning Horizon, PGE has identified 18 transmission projects which will be needed to maintain compliance with the NERC TPL-001-5 standard. Each project has identified a project completion date and any long lead time items that are required as a part of the project. Any construction phases which need to be scheduled are also identified and assessed to ensure that the reliability to the Bulk Electric System is not compromised during each phase of a project.

The Near- and Long-Term projects required to address steady-state overload concerns, aging infrastructure, or overdutied breakers on PGE's system are as follows:

Project Name	Project Completion Date
Boring 57kV rebuild	June 2026
Glencullen Rebuild & Cedar Hills Breakers	November 2026
Groveland Substation Project	April 2027
Harborton Reliability Project	November 2026
Horizon-Keeler #1 230kV Reconductor Project	December 2026
Horizon-Keeler BPA #2 230 kV Project	May 2024

Linneman Project	June 2026
Main 57kV to 115kV Project	November 2027
Memorial Substation Project	December 2024
North of Sherwood 230kV Project	May 2026
Pearl BPA-Sherwood 230 kV Project	May 2025
Redland Substation Project	June 2025
Reedville Substation Rebuild	September 2024
Scholls Ferry Substation Project	November 2025
Shute and Sunset Facility Upgrades Project	April 2026
Sunset 115kV Bus Split Project	April 2027
Tonquin Substation Project	April 2025
Willamette Valley Resiliency Project (4 parts)	May 2029

Boring 57kV substation Rebuild Project

Justification: The Boring 57kV substation rebuild will address antiquated equipment at the substation and reliability improvements.

Scope: The Boring 57kV substation will become a six-position ring bus station.

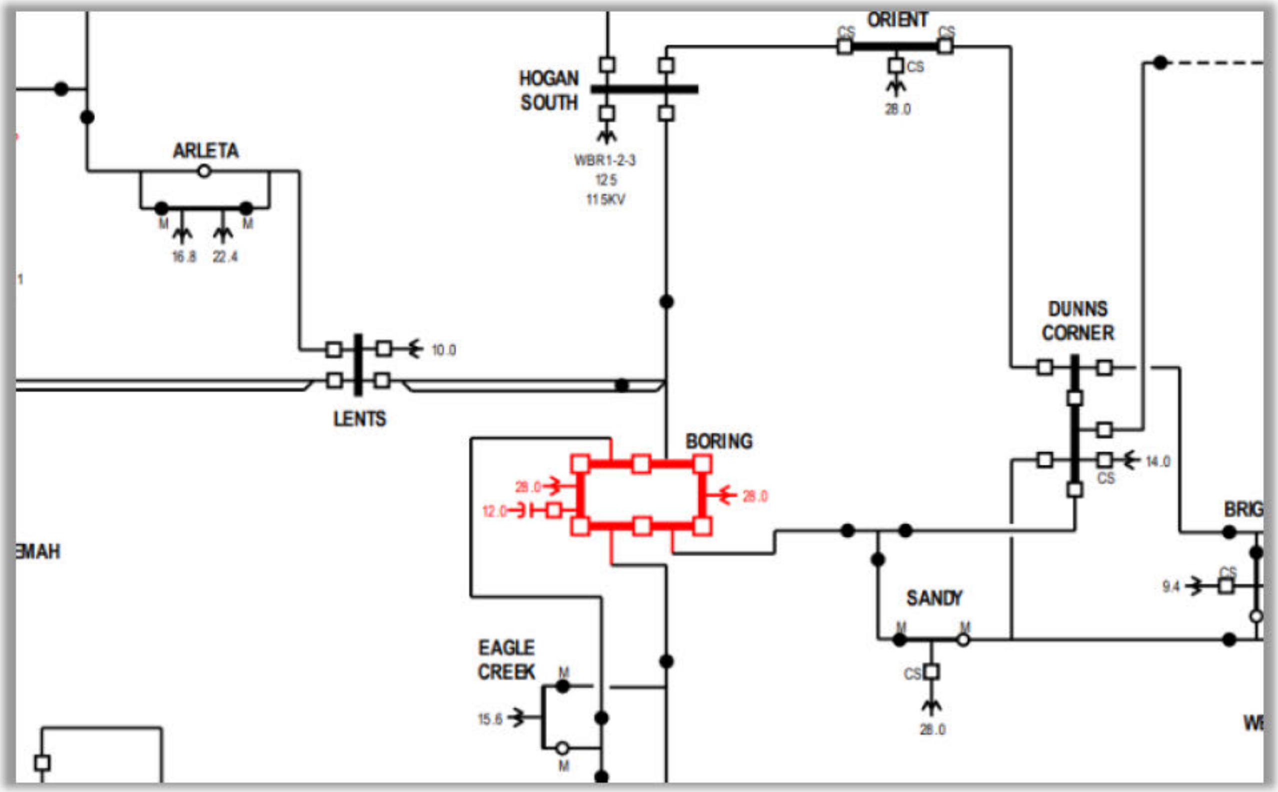


Figure 1: Boring 57kV substation plan to rebuild the station to a six-position, 57kV ring bus

Glencullen Rebuild & Cedar Hills Breakers

Justification: Excessive outage durations to perform planned and unplanned maintenance drove a need to reconfigure the Glencullen and Cedar Hills substations. This project also reduces some overloads seen on the surrounding 115 kV system during certain P6 events. This project also helps improve reliability to critical infrastructure, including a hospital, by converting the Cedar Hills substation from a selective transfer station to a breaker station.

Scope:

- Construct a 5-position ring bus at Glencullen with three 115 kV sources.
- Upgrade existing Circuit Switchers at Cedar Hills to Circuit Breakers.
- Line reconfiguration work in the immediate vicinity.

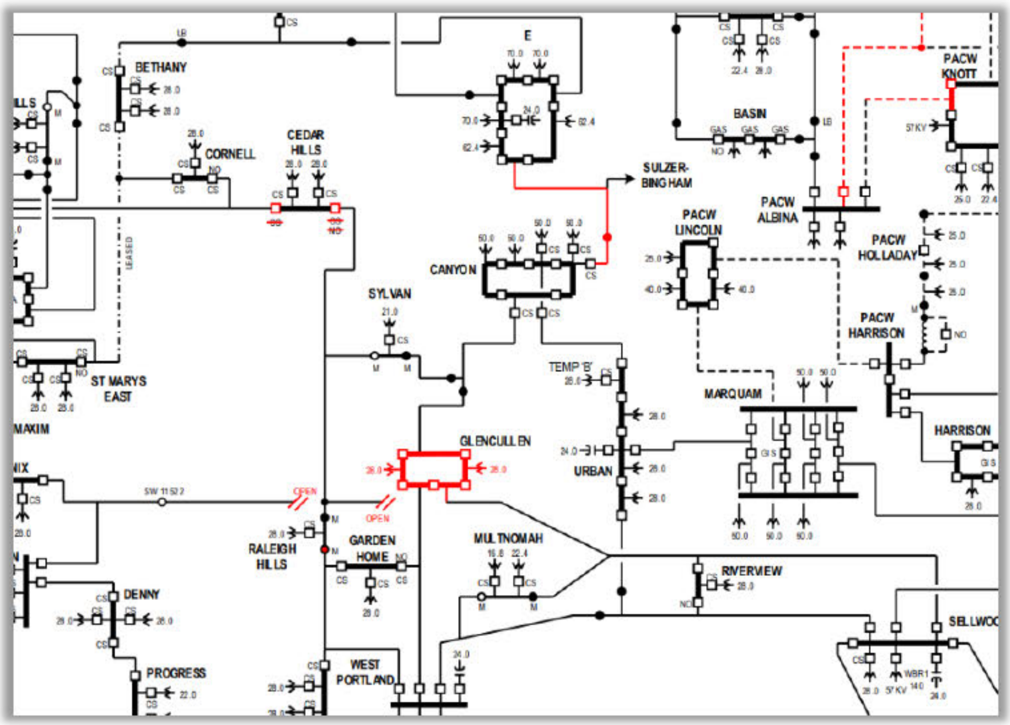
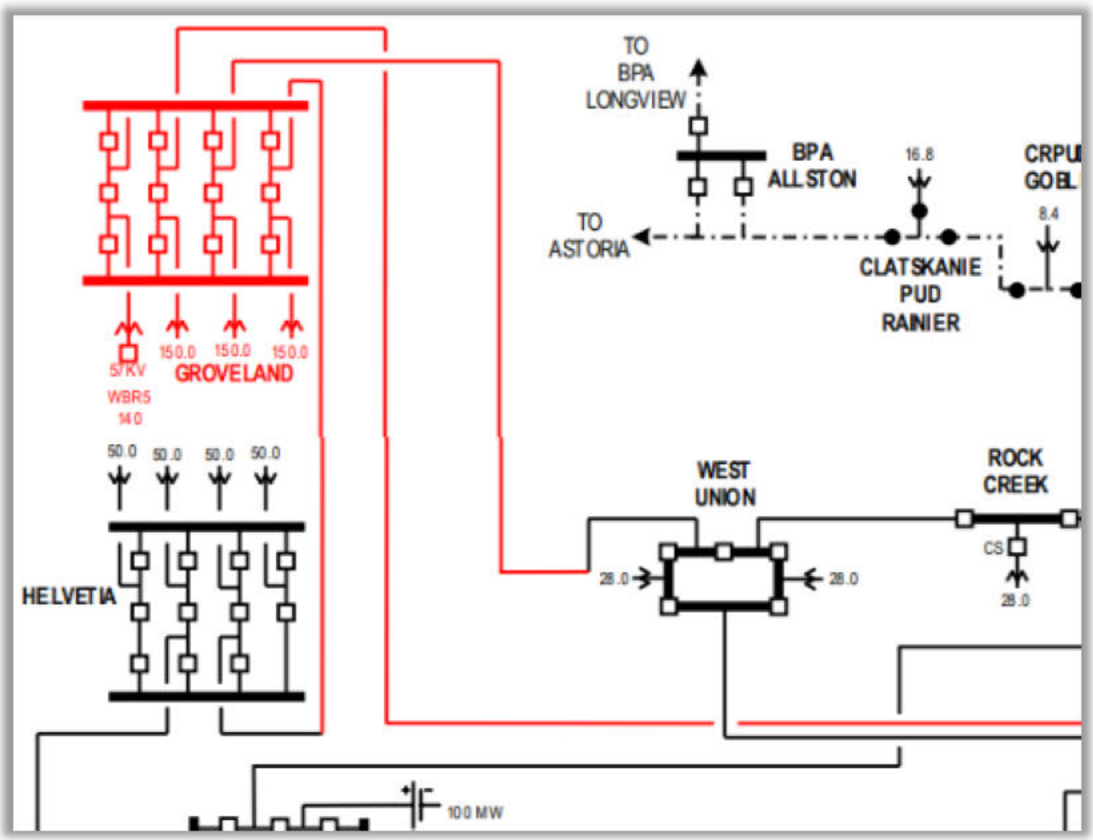


Figure 2: Glencullen 5-position, 115kV ring bus. Cedar Hills addition of 115kV breakers. Raleigh Hills transitioning from selective transfer station to auto-sectionalizing station

Groveland Substation Project

Justification: Address new customer load with full N-1 distribution transformer redundancy.

Scope: The substation project will be a 4-bay breaker and a half substation that will intersect the existing Helvetia-West Union 115kV line for two of its 115kV sources. A 57kV line from Orenco (Orenco-North Plains 57kV) that passes adjacent to the substation location will be converted to 115kV to create a Groveland-Orenco 115kV line. A new 115/57kV transformer at Groveland will provide a replacement for the 57kV source that Orenco was providing to North Plains, creating a Groveland-North Plains 57kV line. There is room for three 150 MVA distribution transformers to provide 34.5kV distribution to customers.



Harborton Reliability Project

Justification: The Harborton reliability project reconfigures the system to increase 230kV transmission capacity into the Portland area and provide a stronger source to the Northwest Portland 115kV system. One key purpose of this project is that it addresses transmission operations flexibility for the loss of the Rivergate bulk power transformer. The Harborton 115kV and 230kV yards will be constructed in a breaker and a half configuration with five 230kV lines into Harborton and three 115kV lines. One bulk 230/115kV transformer at Harborton is also installed. The Canyon-E 115kV line will be reconductored during the project.

Scope: Currently underway for this project is a reconductor to the E-Wacker 115 kV line to 1272 ACSS. Next, the 115 kV system will be reconfigured to create a Harborton-Wacker 115 kV circuit, which will also be reconductored to 1272 ACSS. The 115 kV line idled for this reconfiguration will be utilized for the fifth 230 kV source into Harborton. The Horizon-St Marys-Trojan 230 kV circuit will be looped into Harborton, creating the Harborton-Horizon 230 kV, Harborton-St Marys 230 kV, and Harborton-Trojan #2 230 kV circuits.

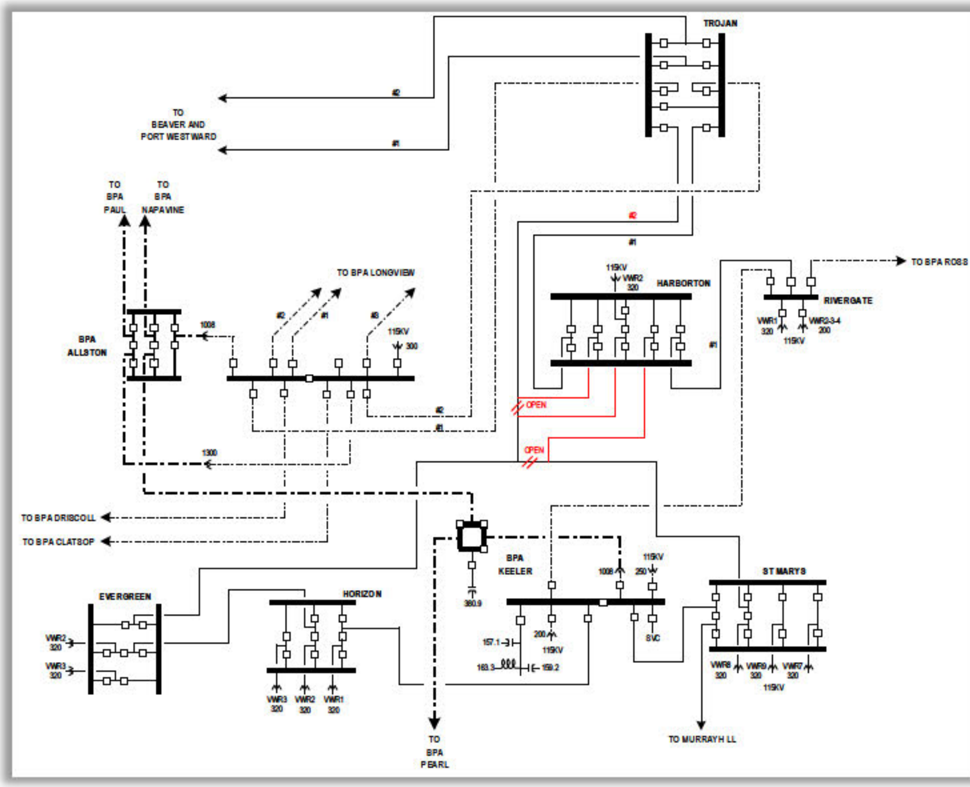


Figure 3: Harborton Reliability Project 230kV

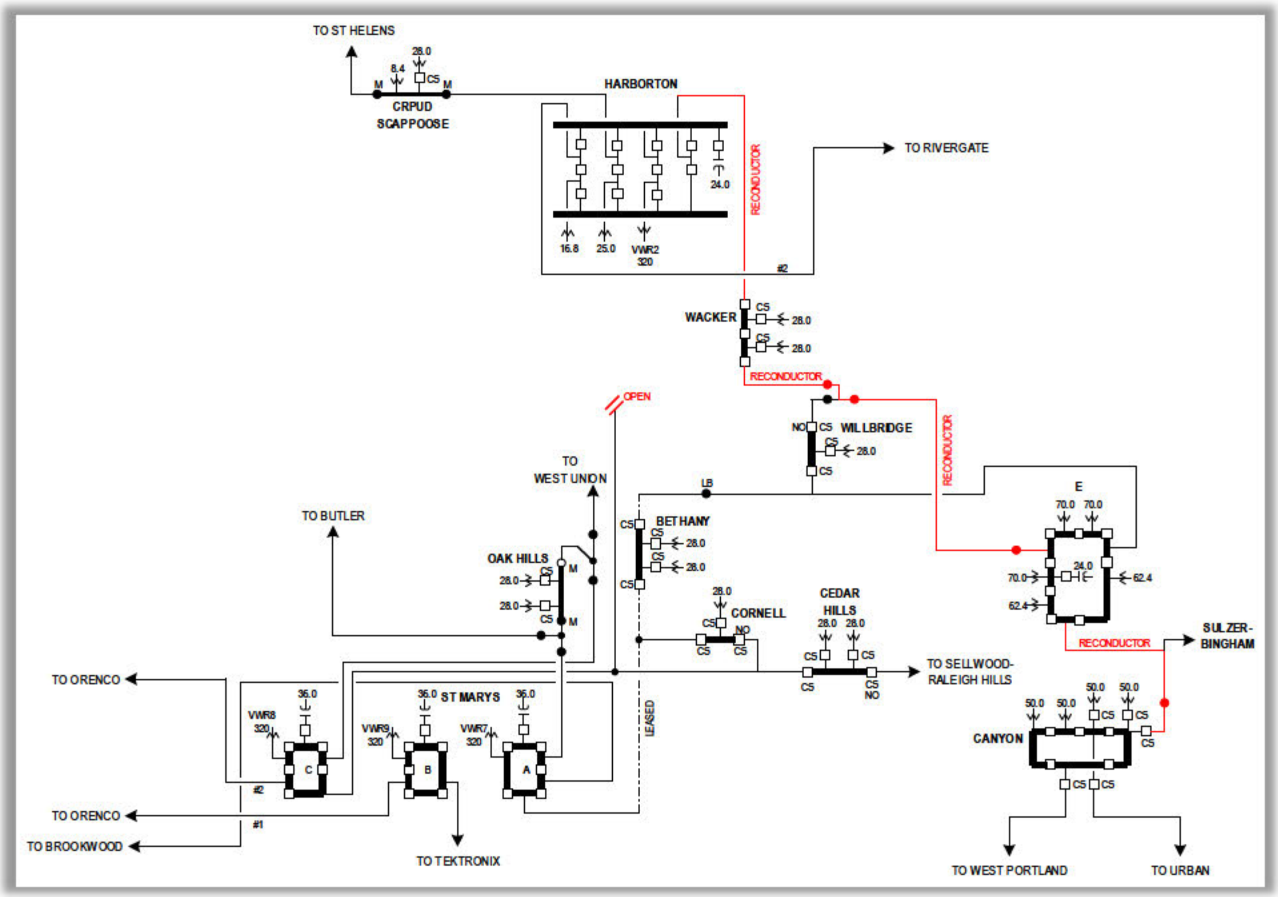


Figure 4: Harborton Reliability Project 115kV

Holgate 57kV to 115 kV Conversion

Justification: The Southeast Portland Conversion Project addresses antiquated equipment and resiliency in the SE Portland area. The project will be completed in multiple phases; the Holgate Substation Conversion is the only part of the project scheduled for completion in the Near-Term Planning Horizon.

Scope: The Holgate substation will be rebuilt to a 115 kV, 4-breaker GIS ring station. The Gresham-Harrison PACW 115 kV line will be looped into the substation, creating the Gresham-Holgate 115 kV line and the Harrison PACW-Holgate 115 kV line. The existing distribution transformers will be replaced with two 50 MVA transformers and two metal clad switchgear will be installed.

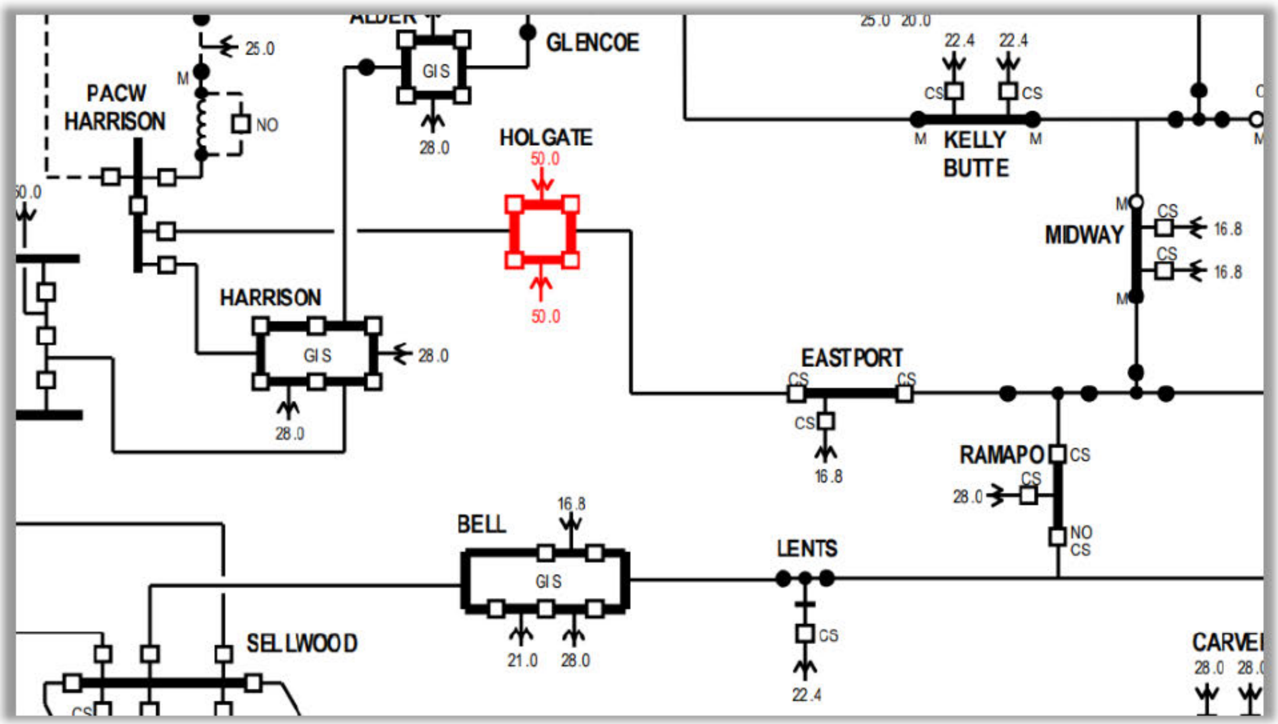


Figure 5: Holgate 115kV, 4-position ring bus built on the existing Gresham-Harrison PACW 115kV line

Horizon-Keeler BPA #1 230 kV Reconductor

Justification: Transmission planning has identified N-1 overloading of the Horizon-Keeler BPA #1 230 kV line upon the loss of the Horizon-Keeler BPA #2 230 kV line in studies of Heavy Summer conditions. The goal of the reconductor is to provide conductor that can supply up to 4000 A capacity for the Horizon-Keeler BPA #1 230kV transmission line facility. The Horizon-Keeler #1 and #2 lines are an important pathway to serving load in Hillsboro.

Scope: Reconductor the Horizon-Keeler BPA #1 230 kV line from 1272 ACSS to a 2156 ACSS with Maximum Operating Temperature of 250 degree Celsius. Additional work is being scoped to have 4000 A substation terminal equipment at Horizon and Keeler.

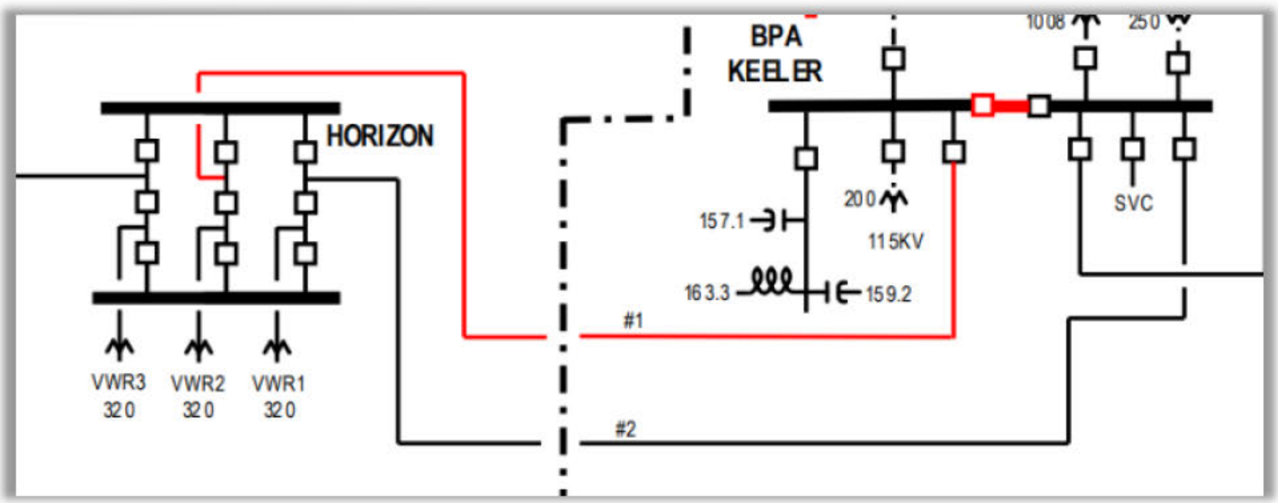


Figure 6: Horizon-Keeler BPA #1 Reconductor project

Horizon-Keeler BPA #2 230 kV

Justification: Significant load growth in the Hillsboro area has accelerated the need for another 230 kV source in the Near-Term Planning Horizon. Studies indicate that the loss of the Keeler BPA-St Marys 230 kV line can cause the Horizon-Keeler BPA 230 kV line to approach its thermal rating during peak summer conditions. Conversely, the loss of the Horizon-Keeler BPA 230 kV line can cause the Keeler BPA-St Marys 230 kV line to approach its thermal rating during peak summer conditions. The loss of both the Horizon-Keeler BPA 230 kV line and the Horizon-St Marys-Trojan 230 kV line results in significant overloads on the underlying 115 kV System that can occur during all loading conditions.

Scope: Construct a Horizon-Keeler BPA #2 230 kV line with 2156 ACSS conductor. A new bay will be installed on the east 230 kV bus at BPA's Keeler substation to accommodate the new line position. At Horizon substation, the remainder of the bay installed for the Horizon VWR3 transformer will be constructed. The existing lines at Horizon will both move one bay west, and the new line will terminate in the east-most bay. Additional work is being scoped to have 4000 A Horizon and Keeler terminal equipment.

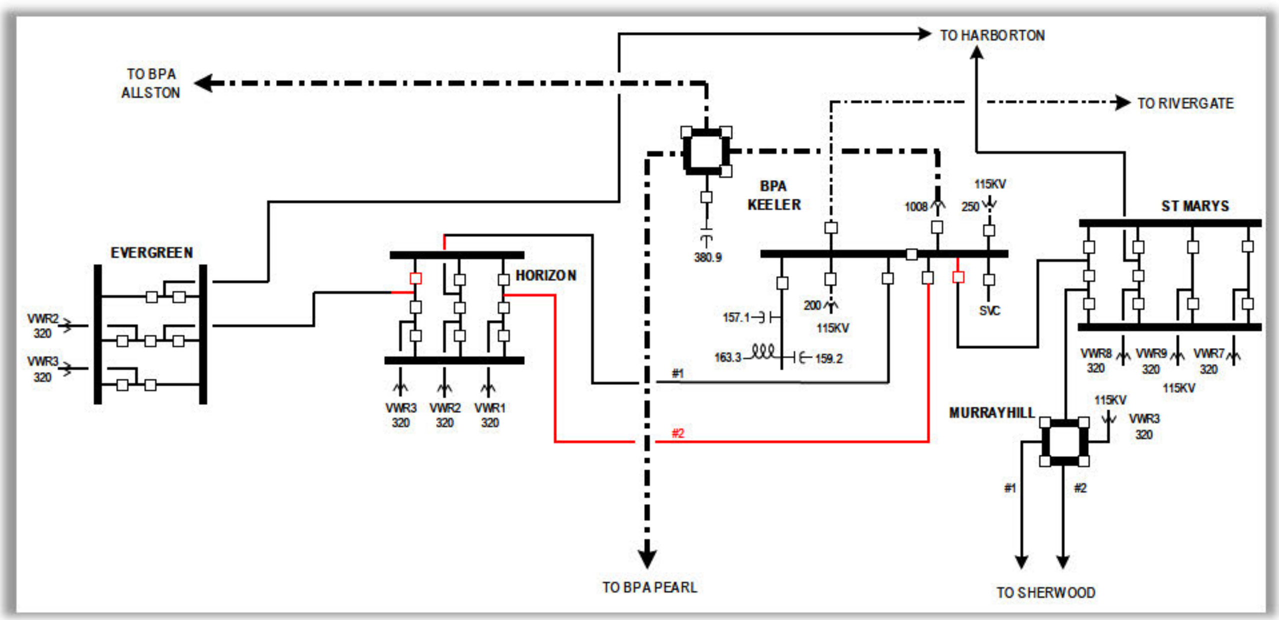


Figure 7: Horizon-Keeler BPA #2 230kV line

Linneman 115kV Project

Justification: The growing population in the Happy Valley, Pleasant Valley, and South Gresham areas have put a strain on the existing electrical infrastructure in the area. Pleasant Valley Substation experiences the highest load burden of the substations in the vicinity, with one transformer and several distribution feeders that are considered heavily loaded. Adding to this load burden are numerous residential and commercial developments scheduled to be connected to Pleasant Valley's heavily loaded equipment, approximately 12.6MVA of additional load demand by 2022 or 2023. Pleasant Valley Substation will not be able to reliably serve the customers in these areas without enacting both intermediate and long-term capacity solutions. The construction of a new substation at the Linneman site is considered a long-term capacity solution.

Scope: Linneman substation will intersect the exiting Gresham-Ruby 115kV line and create a Gresham-Linneman 115kV line and a Linneman-Ruby 115kV line. Construct the new Linneman Substation with 1-50MVA transformer and switchgear. Construct the site to be able to accommodate a second 50MVA transformer and switchgear in the future as load growth continues.

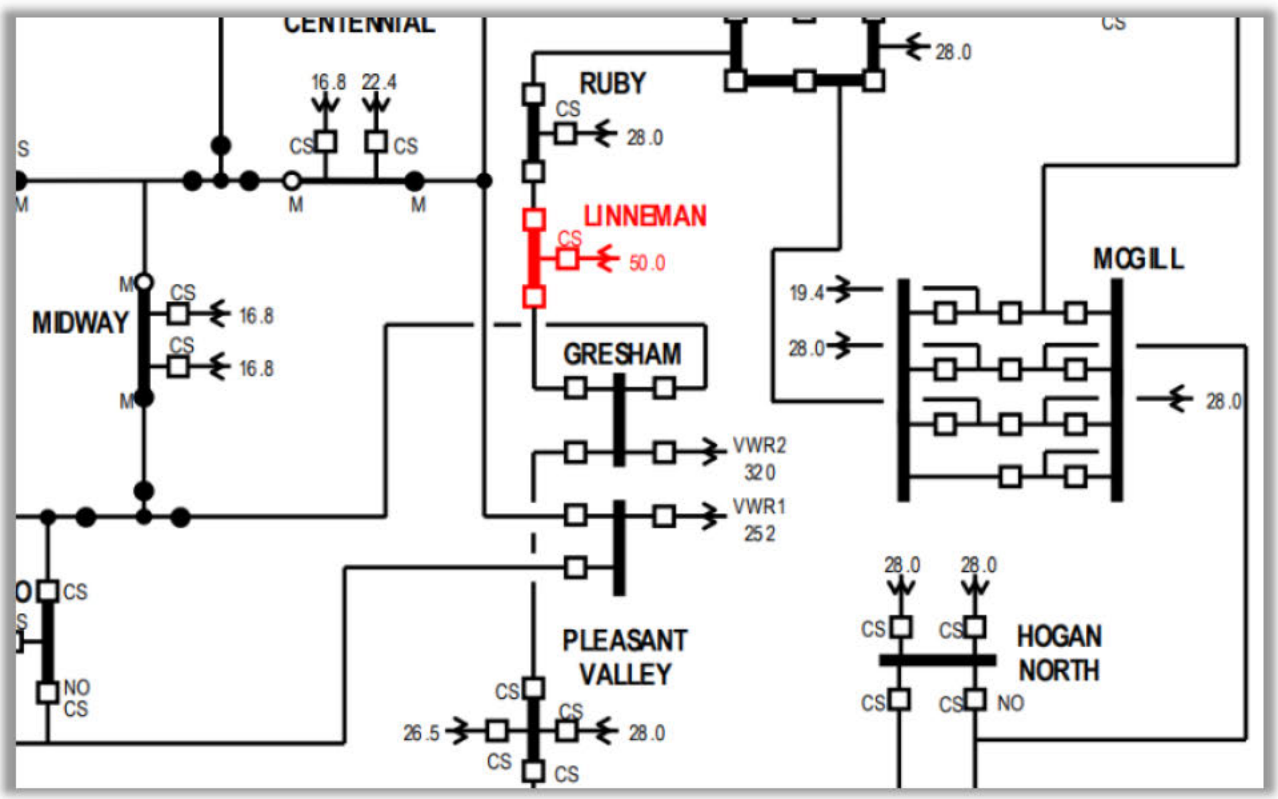


Figure 8: Linneman 230kV substation interconnecting on the Gresham-Ruby 115kV line

Main Substation 115 kV Conversion

Justification: The 57kV transmission system between Orenco and Cornelius is an aging system that would be best rebuilt on the 115kV system for more transmission capacity. The Hillsboro area 57kV system is being studied to develop a plan to eliminate 57kV transmission between Orenco and Cornelius and serve all of the stations in that path at 115kV. Main is the first and most straightforward substation to convert to 115kV.

Scope: The Main substation will be converted to 115 kV. The substation will be rebuilt to a 6-position ring bus configuration. Two new 115 kV lines will be constructed: the Brookwood-Main 115 kV line (utilizing a portion of the existing Cornelius-Orenco #1 57kV line) and the Main-Roseway 115 kV line. This project resolves loading issues on the Hillsboro area 57 kV system and replaces antiquated equipment. The project also provides a third 115 kV source to both the Brookwood substation and the Roseway substation, increasing operational flexibility and reliability.

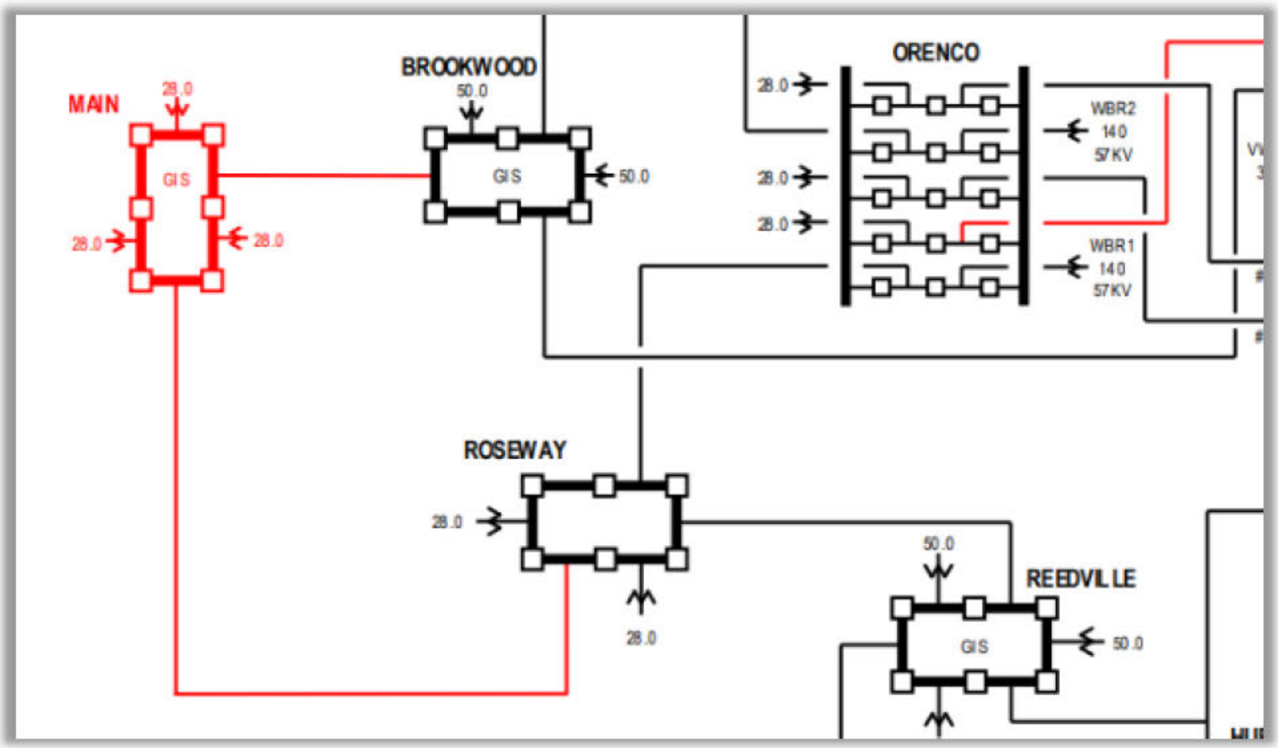


Figure 9: Main substation's 6 position, 115kV ring bus

Memorial 115 kV substation project

Justification: Increased area loading resulting from the construction of additional water treatment facilities in Wilsonville, OR, necessitate a new substation in the area.

Scope: Construct a new 115 kV ring bus breaker substation with two 115 kV line and two distribution transformer positions (one to be installed initially). Loop the existing Sherwood-Wilsonville 115 kV line into the substation, creating a Memorial-Sherwood 115 kV line and a Memorial-Wilsonville 115 kV line.

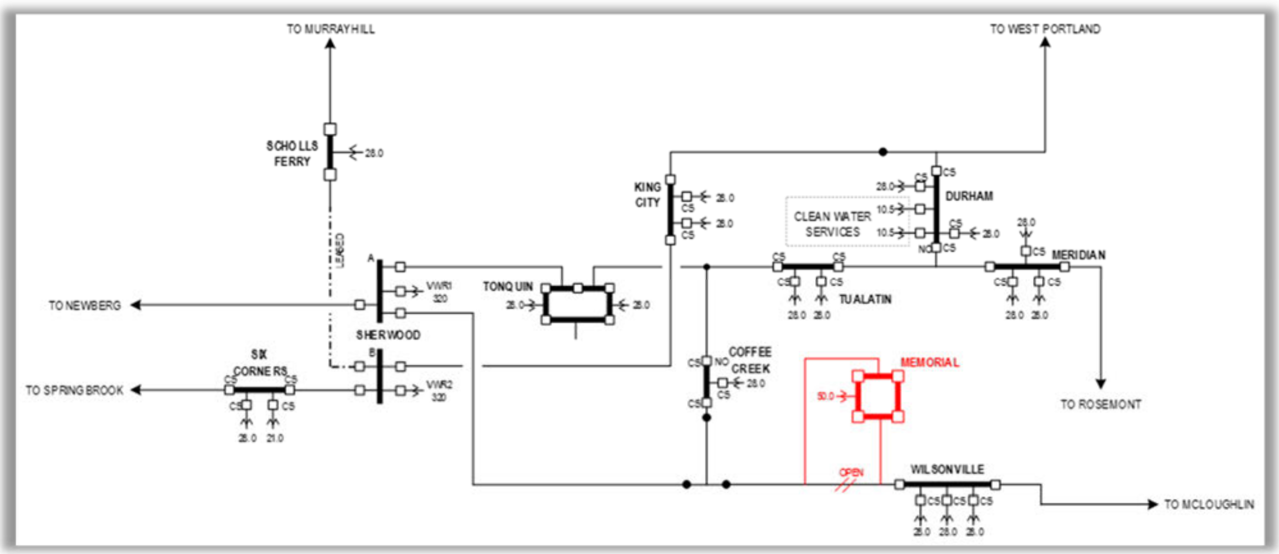


Figure 10: Memorial Substation build intersecting the existing Sherwood-Wilsonville 115kV line with a 4 position, 115kV ring bus.

North of Sherwood 230 kV Project

Justification: PGE is experiencing significant load growth on the west side of the system. Simultaneously, the Western Interconnection is experiencing increased penetration of solar generation facilities in Southern California and the Desert Southwest. This increased generation is causing never-before-seen regional flow patterns to emerge, namely, south-to-north flow on the California-Oregon Intertie and the South of Allston flow-gates during peak load hours. The electric system in the Pacific Northwest, and more specifically the west side PGE load has been historically designed for robust and stable operation under north-to-south power flow conditions. PGE's Annual 5-Year and 10-Year Transmission Assessment has identified N-1 overloading on the Murrayhill-Sherwood #1 & #2 230kV lines for the single loss of the Keeler BPA Transformer #2 as well as near-overloads on one of the Murrayhill-Sherwood 230kV lines for the loss of the other. Additionally, the Transmission Assessment has identified overloading of transformers and underlying 115kV facilities for various multiple element contingencies (N-1-1) that include the Murrayhill-St Marys 230kV line. The most severe of these is the loss of Murrayhill-St Marys 230kV and the Keeler BPA 500/230kV Transformer #2.

Oregon's HB 2021, and Washington's CETA (Clean Energy Transformation Act; SB 5116, 2019) will serve to reduce Oregon and Washington generation from fossil fuel sources. This reduction will have a net effect of exacerbating the problems currently identified, by causing generation patterns to follow the south-to-north direction more frequently, due to the abundance of renewable generation resources south and east of PGE service territory.

Scope: Reconductor existing 230kV lines between Sherwood, Murrayhill and St Marys to 2156 ACSS. Construct a second 230kV line from Murrayhill to St Marys in existing BPA-owned right-of-way. One of the Murrayhill-Sherwood 230kV lines will become the Sherwood-St Marys 230kV line. Upgrade all breakers and switches at the terminals of the lines to 4000 A equipment.

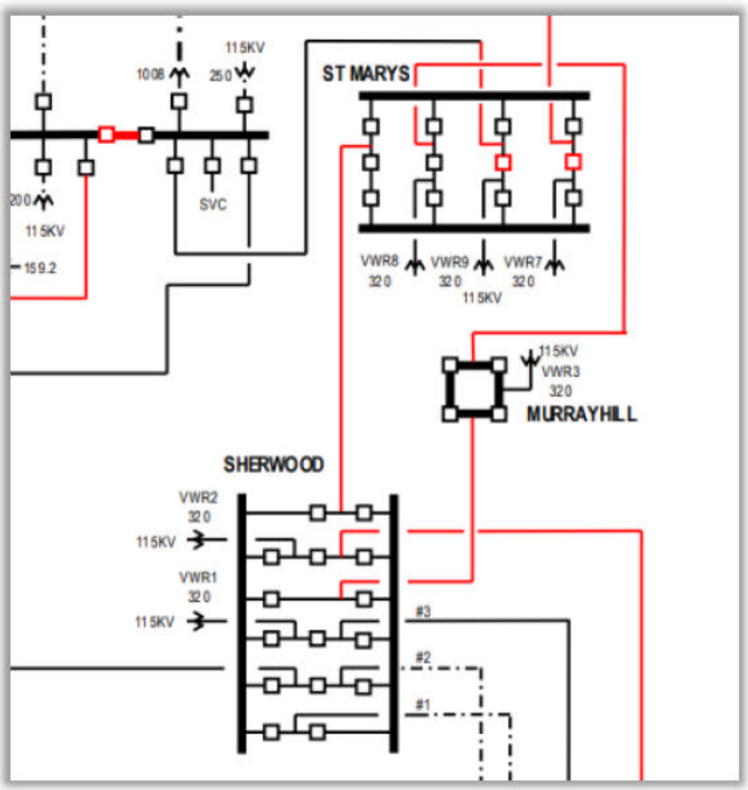


Figure 11: Murrayhill-Sherwood 230kV, Murrayhill-St Marys 230kV and Sherwood-St Marys 230kV lines

Pearl-Sherwood 230 kV Project

Justification: Studies indicate that the mitigations that exist in the Near Term Planning Horizon for alleviating overloads on the McLoughlin-Pearl BPA-Sherwood 230 kV line and the Pearl BPA-Sherwood 230 kV line are no longer effective. This project increase capacity between Pearl and Sherwood substations for south-to-north power flows. This project also improves contingency performance by bifurcating existing super bundled line sections into separate transmission facilities.

Scope: Sections of the McLoughlin-Pearl BPA-Sherwood 230 kV line and the Pearl BPA-Sherwood 230 kV line consist of paralleled conductor. The Pearl-Sherwood Project splits this paralleled conductor to create four 230 kV lines instead of two – three Pearl BPA-Sherwood 230 kV lines and a McLoughlin-Pearl BPA-Sherwood 230 kV line. New breaker positions will be required at both BPA's Pearl substation and the Sherwood substation, both of which have the space to accommodate these new positions.

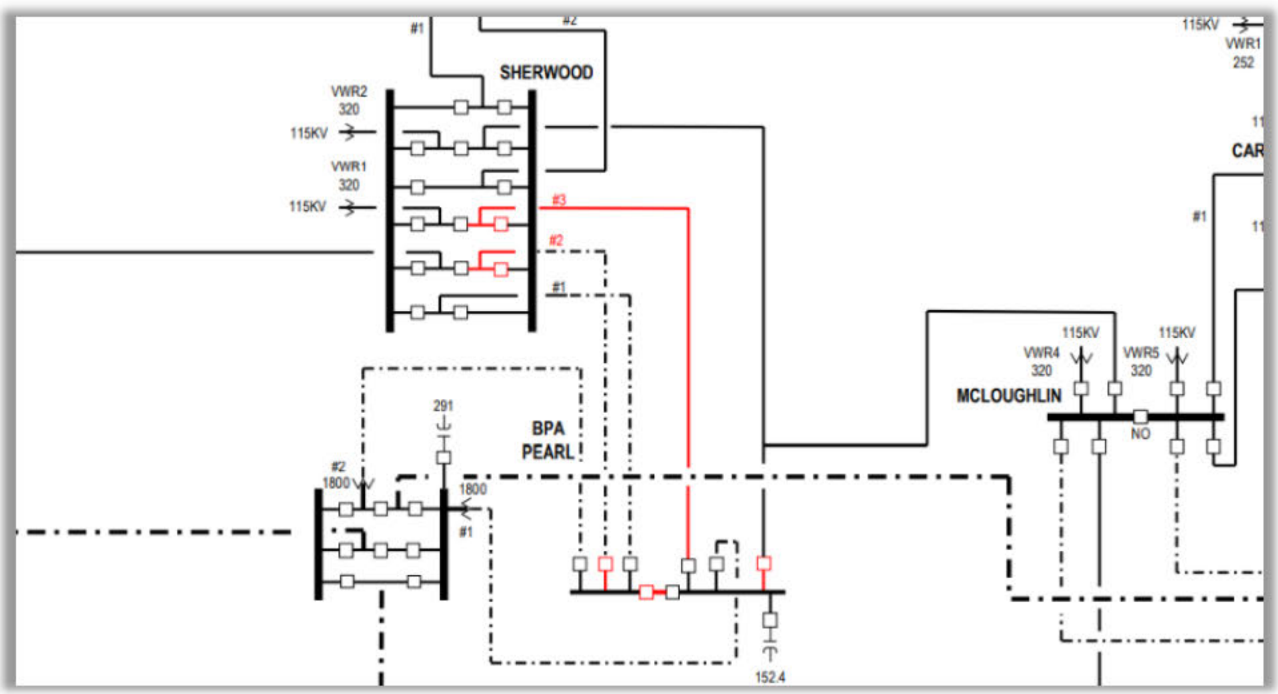


Figure 12: Bifurcation of Pearl BPA-Sherwood #1 230kV and McLoughlin-Pearl BPA-Sherwood 230kV into Pearl BPA-Sherwood #1, #2, #3 230kV and a McLoughlin-Pearl BPA-Sherwood 230kV line

Redland substation Rebuild Project

Justification: Load in the Redland and Leland areas has increased, resulting in the Redland substation becoming heavily loaded and in need of additional capacity. Additionally, Redland substation has many assets aged past their useful life span including antiquated communication systems, necessitating the need for a substation rebuild.

Scope: Completely rebuild Redland substation with two 28 MVA transformers. Replace existing high-side motor-operating switches with circuit switchers, maintain existing selective transfer station protection arrangement.

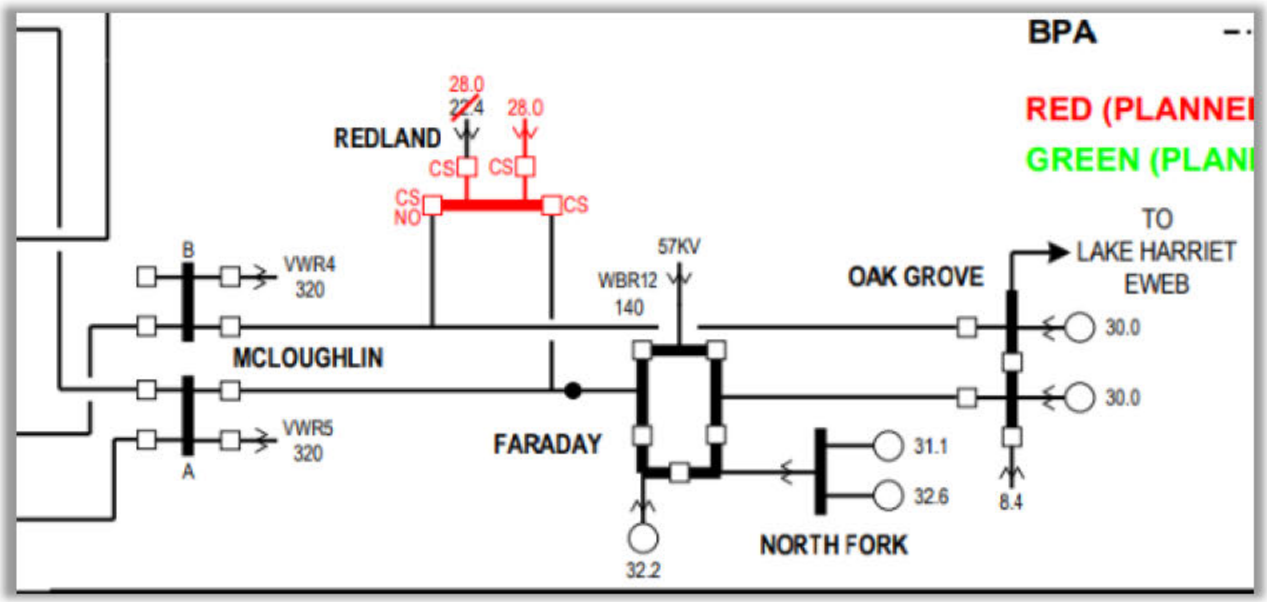


Figure 13: Redland Substation rebuild.

Reedville substation Rebuild Project

Justification: Address antiquated equipment and improve resiliency at the Reedville substation.

Scope: Rebuild the Reedville substation to a 115 kV GIS ring bus configuration with three 115 kV lines and three 50 MVA distribution transformers. Construct a new Reedville-St Marys 115 kV line using the existing St Marys-Huber 115 kV line and part of the existing Murrayhill-Reedville 115 kV line. Construct a new 795 ACSS line section to create a new Murrayhill-Reedville 115 kV line.

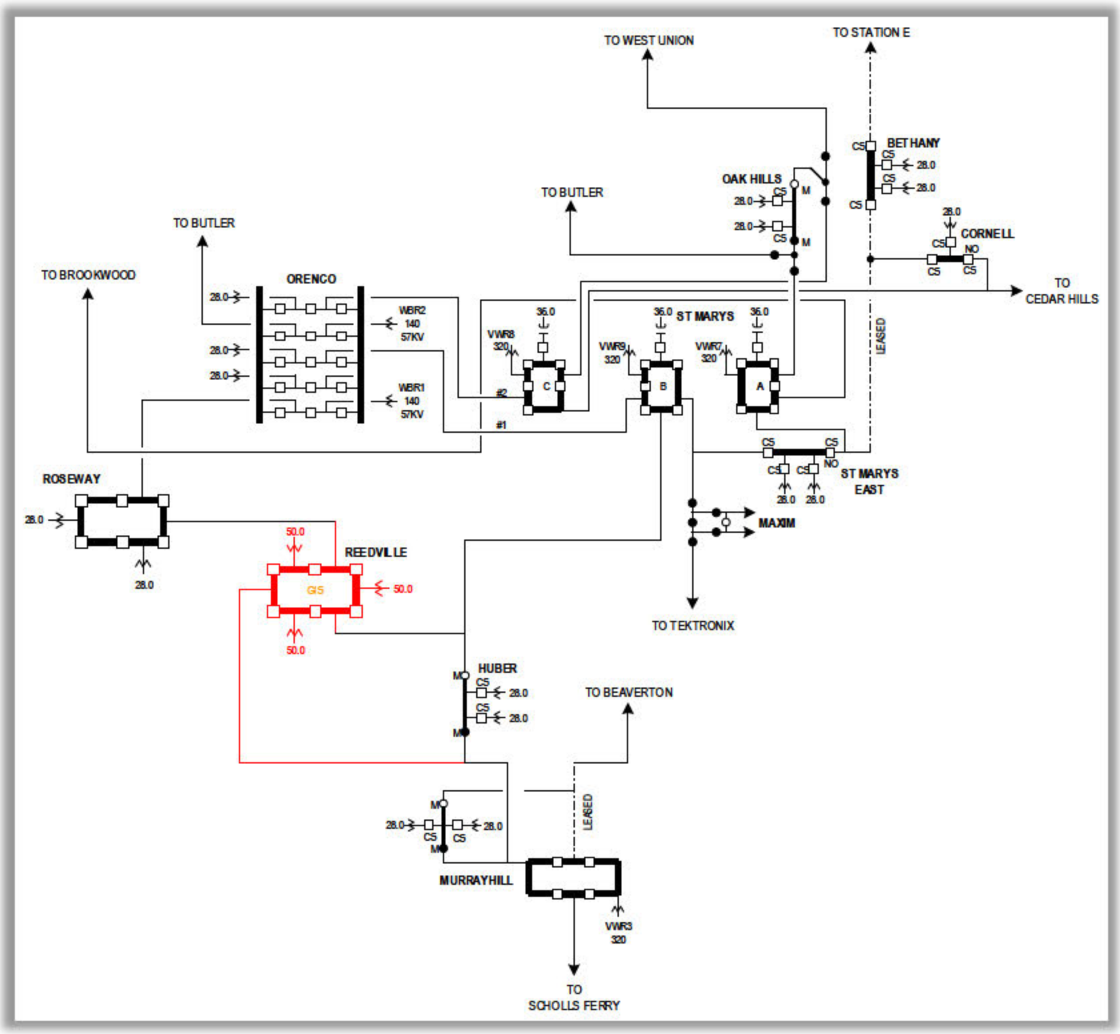


Figure 14: Reedville substation rebuild with 115kV, 6-position GIS ring

Scholls Ferry Substation Project

Justification: Address increased load in the Scholls Ferry region with an updated substation, converted to a 4-position ring bus, and an additional distribution transformer.

Scope: Expand the Scholls Ferry 115kV substation to a 4-position ring bus. Add an additional 50 MVA distribution transformer to the newly created position.

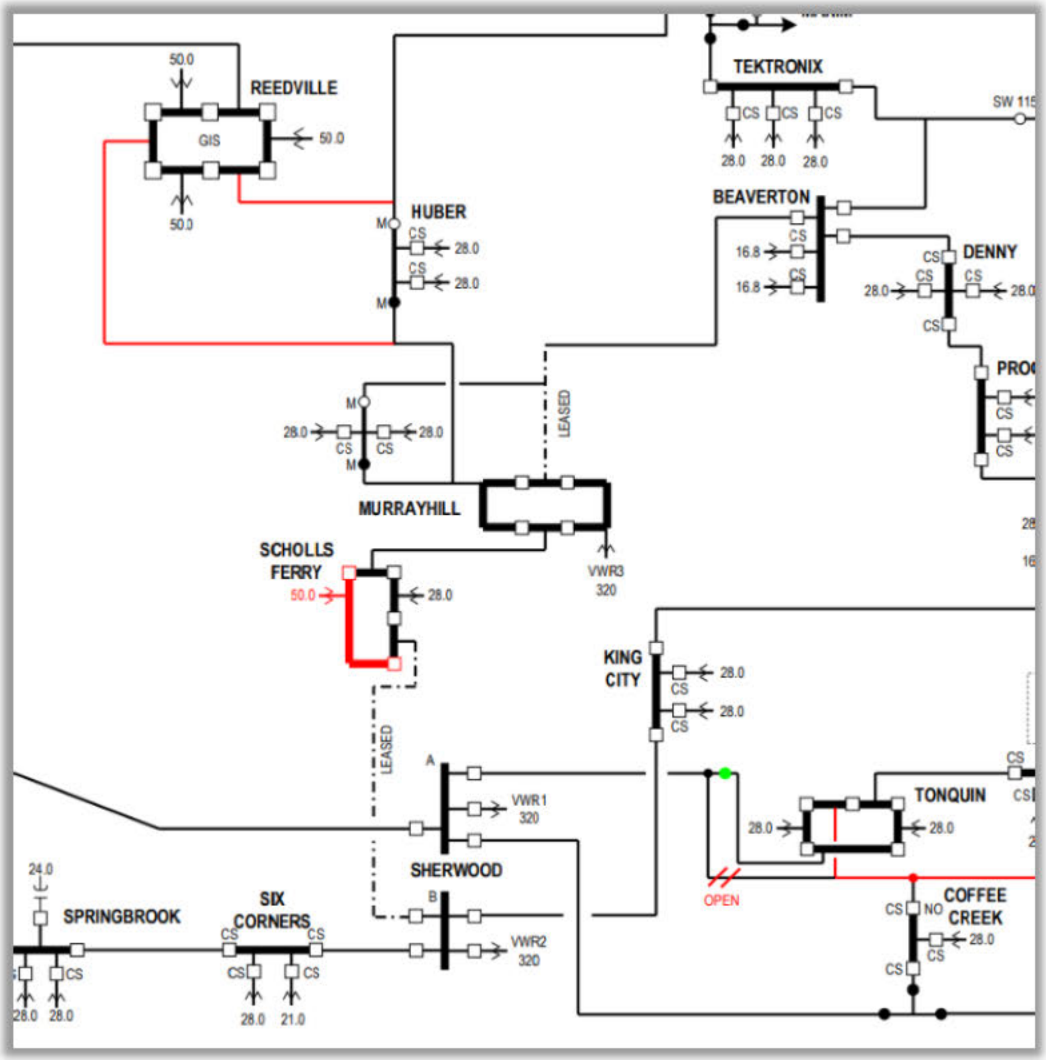


Figure 15: Scholls Ferry is expanded into a 4-position, 115kV ring bus with an additional 50 MVA distribution transformer added

Shute and Sunset 115kV Facility Upgrades Project

Justification: Load growth for industrial activity in the Hillsboro area is forecasted to continue increasing into the next decade and PGE must maximize transmission capacity in this area to maintain reliable system operation. PGE has existing plans for a total of six 320 MVA 230/115kV bulk transformers to feed the majority of the Hillsboro load (three at Horizon substation and three at Evergreen substation). The increasing power flow coming from BPA's Keeler substation, through the 230kV system, and downstream to the 115kV system forces upgrades to meet future demand in the area.

Scope: The 2000A switches at Shute substation for the Evergreen #1, Evergreen #2 and Sunset line positions will be upgraded to 3000 A. The 2000 A switches at Sunset substation for the Sunset line will be upgraded to 3000 A. The Shute-Sunset 115kV line will be reconductored with 2x 795 ACSS conductor to maximize facility rating to 3000 A.

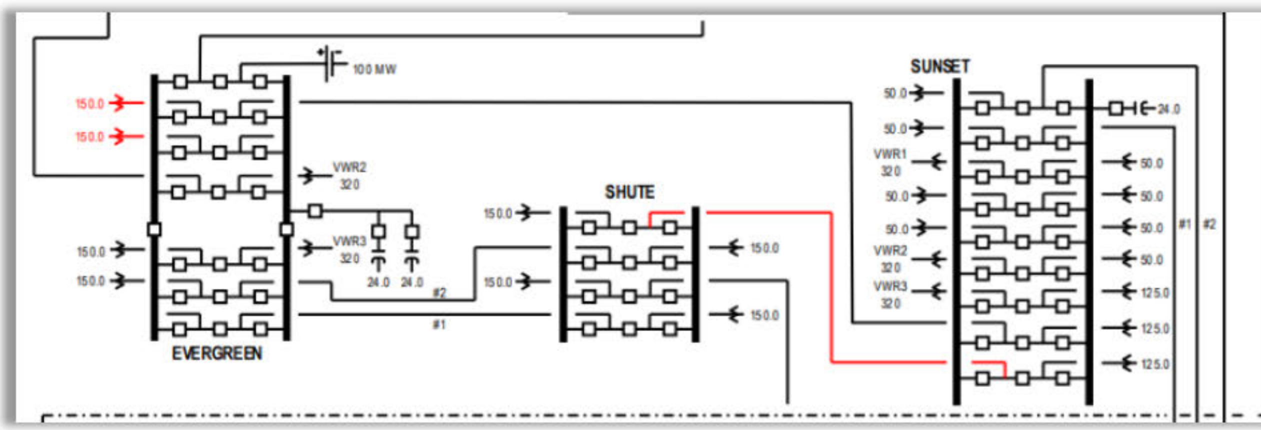


Figure 16: Shute-Sunset 115kV line is reconductored. 2000 A switches at Shute terminal for the Evergreen #1, Evergreen #2 and Sunset lines are upgraded to 3000 A. Sunset switches for the Shute-Sunset 115kV line are upgraded to 3000 A.

Sunset 115kV Bus Split Project

Justification: Three bulk transformers located at Evergreen substation and three bulk transformers located at Sunset substation have led to fault duties that are projected to become too high for the Sunset substation's 115kV circuit breakers to reliably interrupt faults. The solution is to bifurcate the existing Sunset 115kV bus. This project needs to occur before BPA installs their 500/230kV bank #5 transformer at Keeler substation.

Scope: Split Sunset 115kV bus into a West and East Bus by cutting the main buswork straddling breaker and a half bays in such a way to create a connection between the East and West Bus that can be used in operational emergencies to still connect the busses together. The Shute and Butler #2 line positions need to be swapped at Sunset substation.

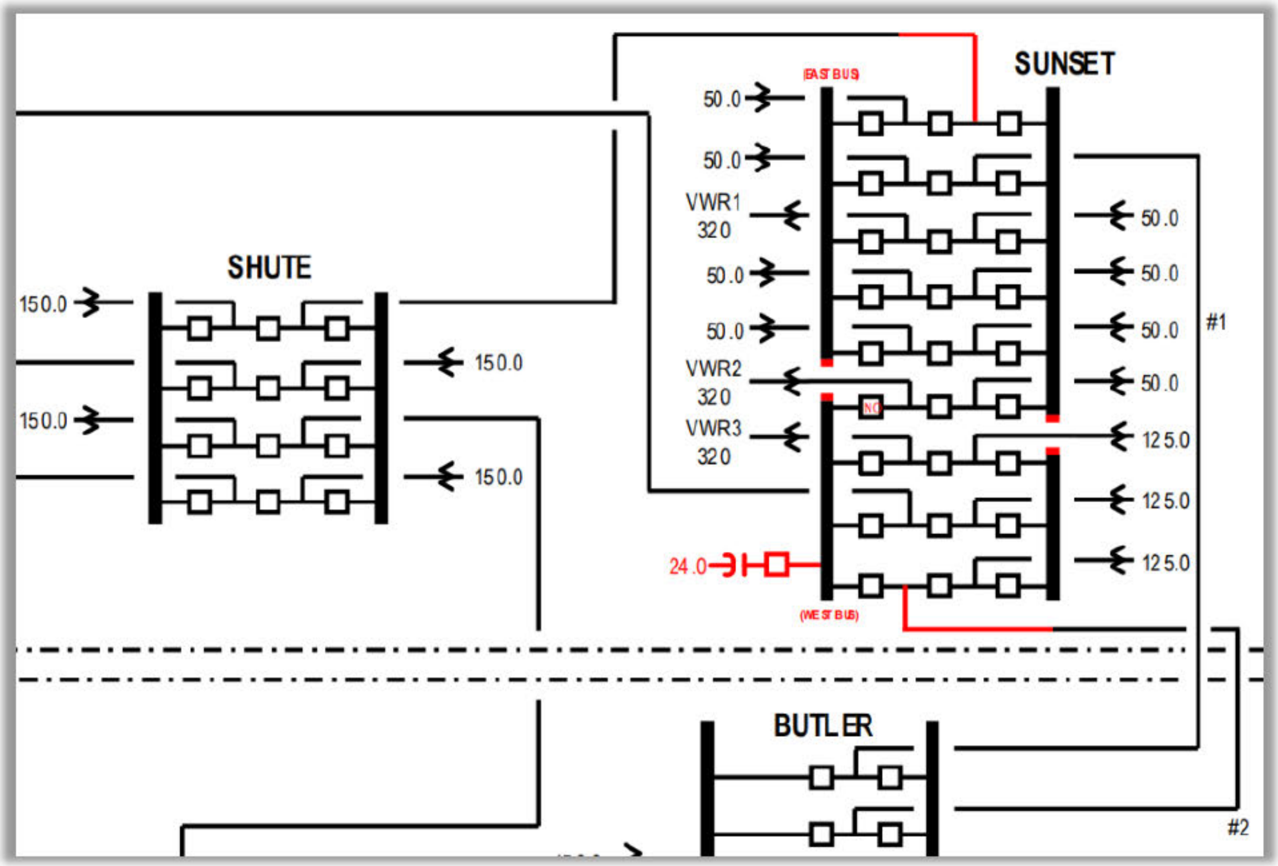


Figure 17: Sunset 115kV Bus split, Shute and Butler #2 lines swap position at Sunset

Tonquin Substation Project

Justification: Load is growing in the Tualatin/Sherwood area, due to the construction of a new water treatment plant, investments is semiconductor manufacturing, and general commercial and residential growth, necessitating a new substation in the area. Existing distribution loading issues at Tualatin and Meridian substations will also be addressed with the new substation. In addition, the loss of the Canemah-Sullivan 115 kV line section followed by the loss of the Sherwood-Tualatin 115 kV line section can result in an overload on the Oswego-West Portland 115 kV line during peak summer conditions. The line work associated with this project will mitigate this overload.

Scope: Tonquin substation will be built in two phases. The first phase will intersect the existing Meridian-Sherwood 115kV line make a Sherwood-Tonquin 115kV line and a Meridian-Tonquin 115kV line. The second phase of the project will take the McLoughlin-Wilsonville 115kV line and create a Rosemont-Wilsonville 115kV line and a McLoughlin-Tonquin 115kV line, by overbuilding existing PGE distribution circuits for a portion of the Rosemont-Wilsonville line.

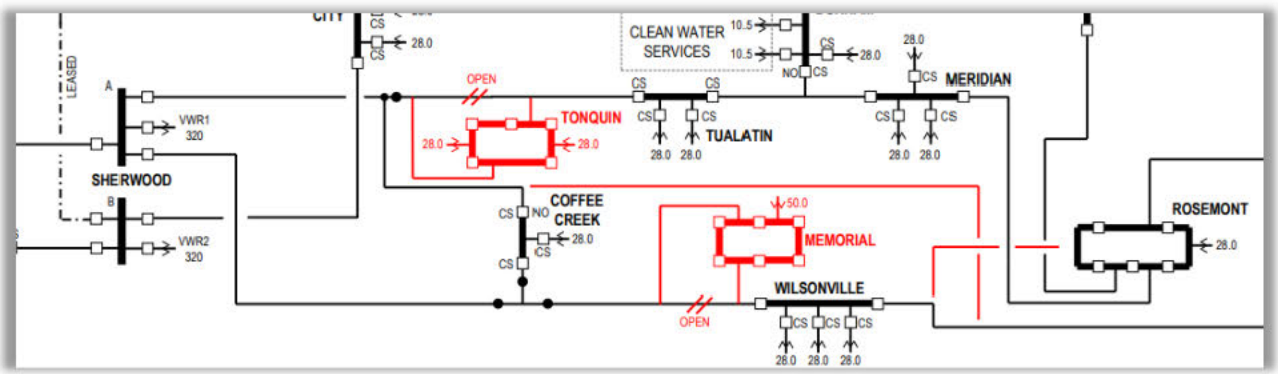


Figure 18: Phase 1 of Tonquin Project

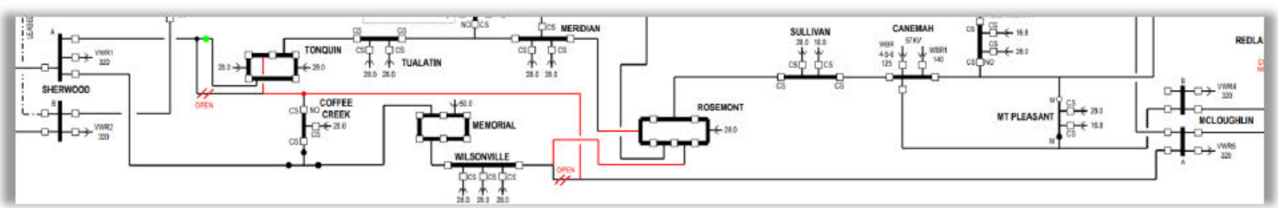


Figure 19: *Phase 2 of Tonquin Project*

Willamette Valley Resiliency Project (4 parts)

The Near Term and Longer Term planning studies indicate that multiple overloads in the Salem area can occur during peak summer conditions. This project will address the weak 57 kV system in the Willamette Valley by converting multiple substations to 115 kV and installing two new 115 kV lines. The new Bethel-North Marion 115 kV line will provide support to the Bethel VWR2 transformer and the 115 kV lines at Bethel substation, mitigating the overloads on these elements. This project will be sequenced to begin in the Near Term Planning Horizon but will ultimately be completed in the Longer Term Planning Horizon. In the Longer Term planning horizon, five 57 kV substations in the central region of PGEs service territory will be converted to 115 kV, with additional upgrades to existing 115 kV and 230 kV substations such as Bethel and Monitor.

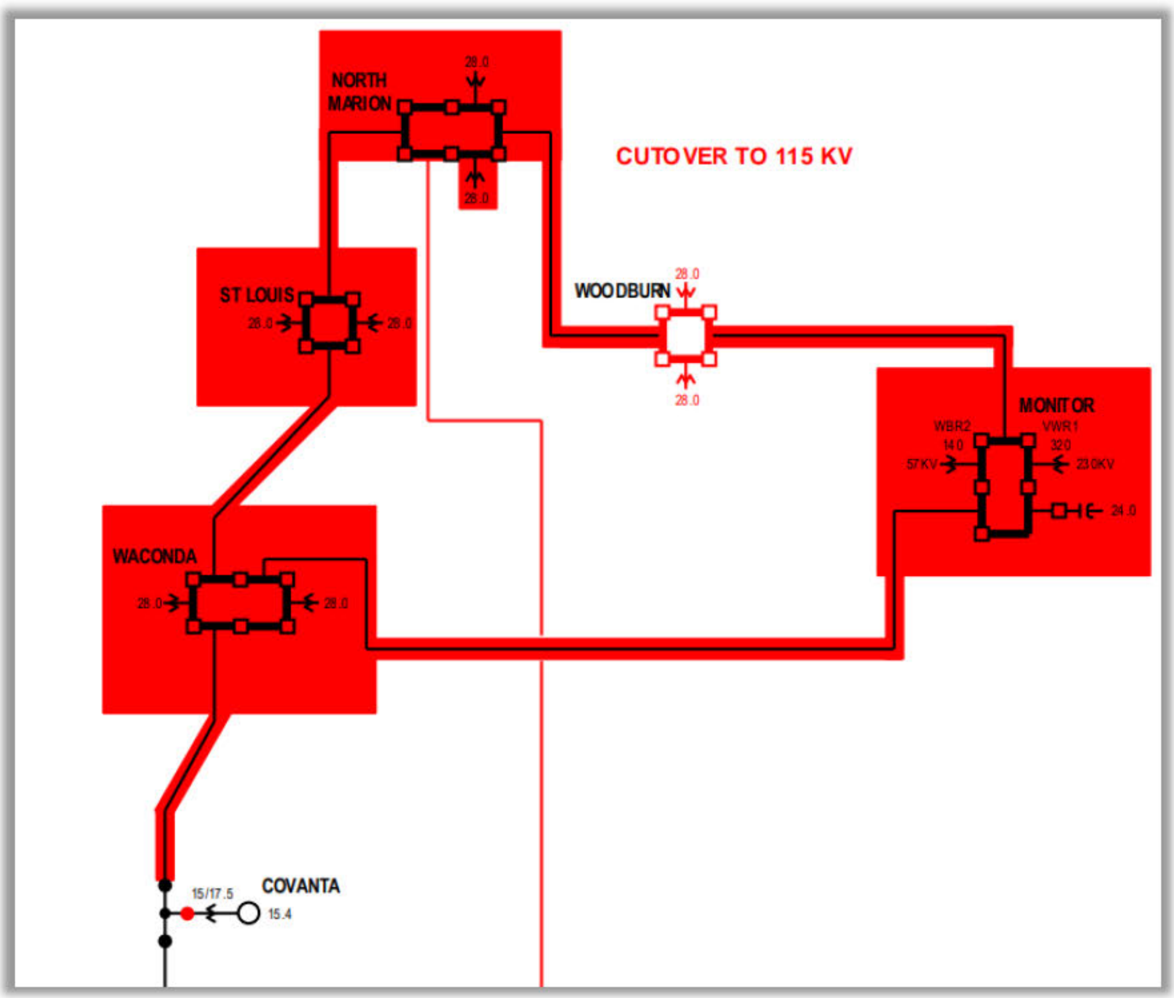


Figure 20: Ultimate WVRP configuration, with all substations converted to 115kV

Willamette Valley Resiliency Project – Monitor 115 and 230 kV Substation Project

- **Project Purpose**
  - Part of the Willamette Valley Resiliency Project. The intent of the project is to strengthen and increase the resiliency of PGEs system in the Central portion of PGE's territory, North of the Salem region. Monitor is being converted from a 57/230 kV simple substation to a 57/115/230 kV ring bus substation.
- **Project Scope**
  - Construct 115 and 230 kV ring bus for Monitor substation.
  - Monitor 115 kV will be built to a 5-position ring bus with two transformers (57/115 kV and 115/230 kV).
  - Monitor 115 kV will also include a capacitor bank.
  - Monitor 230 kV will be built as a 4-position ring bus.

Willamette Valley Resiliency Project – St Louis 115 kV Project

- **Project Purpose**
  - Part of the Willamette Valley Resiliency Project. The intent of the project is to strengthen and increase the resiliency of PGEs system in the Central portion of PGE's territory, North of the Salem region. St Louis substation is being converted from a 57 kV simple substation, to a 115 kV ring bus.
- **Project Scope**
  - Construct a 4-position 115 kV ring bus St Louis substation.
  - Two distribution 28.0 MVA transformers to be included.
  - Two 115 kV sources
    - Waconda-St Louis 115kV and North Marion-St Louis 115kV

Willamette Valley Resiliency Project – North Marion 115 kV Project

- **Project Purpose**
  - Part of the Willamette Valley Resiliency Project. The intent of the project is to strengthen and increase the resiliency of PGEs system in the Central portion of PGE's territory, North of the Salem region. North Marion substation is being converted from a 57 kV substation to a 115 kV ring bus.
- **Project Scope**
  - Construct a 6-position 115 kV ring bus North Marion substation.
  - Two distribution 28.0 MVA transformers to be included.
  - Three 115 kV Transmission Sources
    - North Marion-Twilight
    - North Marion-St Louis
    - North Marion-Woodburn

Willamette Valley Resiliency Project – Woodburn 115 kV Project

- **Project Purpose**
  - Part of the Willamette Valley Resiliency Project. The intent of the project is to strengthen and increase the resiliency of PGEs system in the Central portion of PGE's territory, North of the Salem region. Woodburn substation is being converted from a 57 kV substation to a 115 kV ring bus.
- **Project Scope**
  - Construct a 4-position 115 kV ring bus Woodburn substation.
  - Two distribution 28.0 MVA transformers to be included.
  - Two 115 kV Sources
    - North Marion-Woodburn
    - Monitor-Woodburn

Interconnection and Renewables Access Projects

Project Name	Project Completion Date
Bethel-Round Butte 500kV Project	March 2032
Harborton-Trojan #3 and #4 230kV	April 2030

Bethel-Round Butte 500kV Project

Justification: This project was identified in order to access new, decarbonized resources in order for PGE to meet obligations under Oregon's HB 2021 law. Converting the existing 91 mile long, 230kV transmission line to 500kV significantly increases its import capability between non-emitting resources in Central Oregon and the Willamette Valley, as well as creates a significant connection with the NWACI, providing access to diverse resources in other parts of the West.

Scope: The Bethel-Round Butte 500kV line project will replace the existing Bethel-Round Butte 230kV line. It will utilize the existing right-of-way and provide more transmission capacity from Madras, OR to Salem, OR. The project will also construct a 500kV Mountain View substation adjacent to Round Butte, and a 500/230kV transformer at the Bethel termination of the line.

Project Status: PGE is exploring implementing this project in the Longer Term Planning Horizon. This project will be submitted for a regional coordination study.

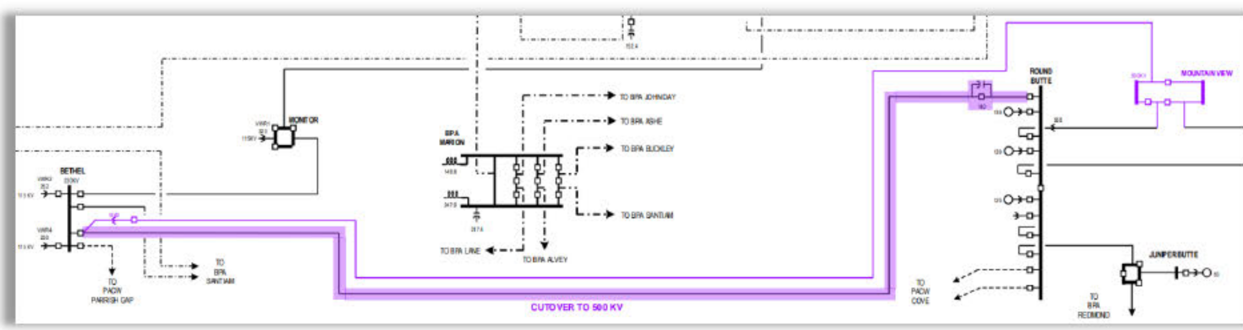


Figure 21: Bethel-Round Butte 230kV line is rebuilt at 500kV

Harborton-Trojan #3 and #4 230kV

Justification: This project was identified in order to access new, decarbonized resources in order for PGE to meet obligations under Oregon's HB 2021 law. The lines will be part of the SOA path, which is fully subscribed. Because of power transfer distribution factor (PTDF), nearly all transfers of power from any part of the WECC footprint have at least some impact on SOA. Given that SOA is fully subscribed, no new transmission service is available to PGE's service territory without adding new incremental capacity to the SOA path. It will construct two additional lines from Trojan to Harborton, utilizing existing right-of-way. This project will alleviate market congestion constraints on the SOA path for PGE and increase the total transfer capability between BPA and PGE.

Scope: PGE to construct two 230kV lines from Harborton to Trojan using existing right-of-way. The Harborton-Rivergate #1 230kV line will also be reconductored as part of this project.

Project Status: PGE is exploring implementing this project in the Longer Term Planning Horizon. This project will be submitted for a regional coordination study.

PGE Corporate Headquarters
121 S.W. Salmon Street | Portland, Oregon 97204
portlandgeneral.com

Portland General Electric Company's Longer Term Local Transmission Plan For the 2020-2021 Planning Cycle

December 30, 2021

Contents

1. Introduction

This 2021 Longer Term Local Transmission Plan reflects Quarters 5 through 8 of the local transmission planning process as described in PGE's Open Access Transmission Tariff (OATT) Attachment K. The plan includes all Transmission System facility improvements identified through this planning process. A power flow reliability assessment of the plan was performed which demonstrated that the planned facility additions will meet NERC and WECC reliability standards.

PGE's OATT is located on its Open Access Same-time Information System (OASIS) at http://oasis.oati.com/PGE. Additional information regarding Transmission Planning is located in the *Transmission Planning* folder on PGE's OASIS. Unless otherwise specified, capitalized terms used herein are defined in PGE's OATT.

1.1. Local Planning

This Local Transmission Plan (LTP) has been prepared within the two-year process as defined in PGE's OATT Attachment K. The LTP identifies the Transmission System facility additions required to reliably interconnect forecasted generation resources and serve the forecasted Network Customers' load, Native Load Customers' load, and Point-to-Point Transmission Customers' requirements, including both grandfathered, non-OATT agreements and rollover rights, over a ten year planning horizon. Additionally, the LTP typically incorporates the results of any stakeholder-requested economic congestion studies results that were performed. However, none were requested or incorporated during this particular cycle.

Projects identified in the Longer Term Local Transmission Plan's six to ten year planning horizon are not committed projects and are subject to modification and/or withdrawal. Projects described herein are not part of PGE's Expansion Plan as described in Section 12.2.3 of Attachment O to PGE's OATT.

1.2. Regional and Interregional Coordination

PGE coordinates its planning processes with other transmission providers through membership in the NorthernGrid and the Western Electric Coordinating Council (WECC). PGE uses the NorthernGrid process for regional planning, coordination with adjacent regional groups and other planning entities for interregional planning, and development of proposals to WECC. Additional information is located in PGE's OATT Attachment K, in our Transmission Planning Business Practice on OASIS, and on NorthernGrid's website at www.northerngrid.net.

2. Planning Process and Timeline

This plan is for the 2020-2021 planning cycle. PGE's OATT Attachment K describes an eight quarter study and planning cycle. The planning cycle schedule is shown below in Figure 1.

Figure 1: PGE OATT Attachment K Eight Quarter Planning Cycle

		Quarter	Tasks
Near Term	Even Years	1	Select Near Term base cases and gather load data
		2	Post Near Term methodology on OASIS, select one Economic Study for evaluation
		3	Select Longer Term base cases, post draft Near Term Plan on OASIS, hold public meeting to solicit stakeholder comment
		4	Incorporate stakeholder comments and post final Near Term plan on OASIS
Longer Term	Odd Years	5	Gather load data and accept Economic Study requests
		6	Select one Economic Study for evaluation
		7/8	Post draft Longer Term plan on OASIS, hold public meeting to solicit stakeholder comment
		8	Post final Longer Term plan on OASIS, submit final Longer Term Plan to stakeholders and owners of neighboring systems

PGE updates its Transmission Customers about activities and/or progress made under the Attachment K planning process, during regularly scheduled customer meetings. Meeting announcements, agendas, and notes are posted in the *Customer Meetings* folder on PGE's OASIS.

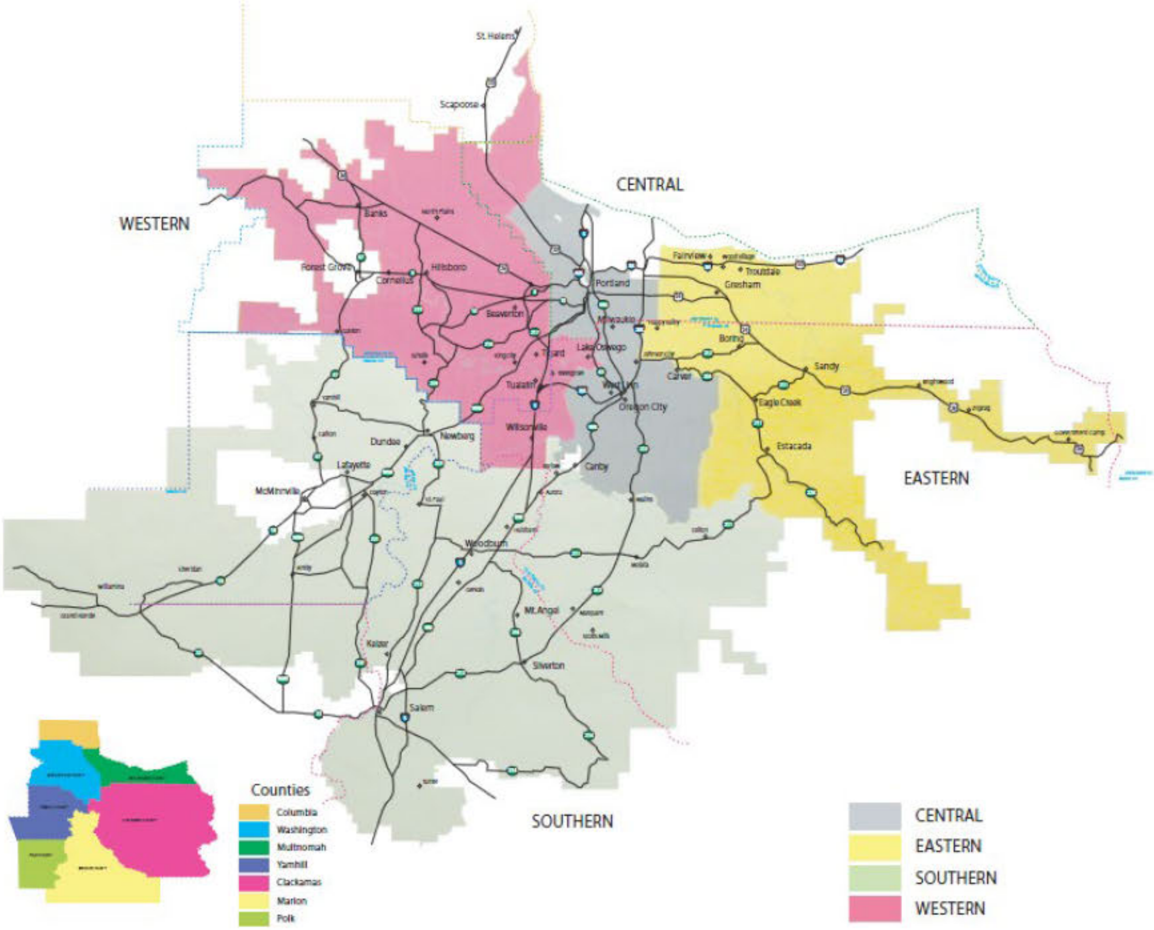
Meeting dates are posted on PGE's OASIS.

3. Transmission System Plan Inputs and Components

3.1. PGE's Transmission System

Portland General Electric's (PGE) service territory covers more than 4,000 square miles and provides service to over 900,000 customers. PGE's service territory is confined within Multnomah, Washington, Clackamas, Yamhill, Marion, and Polk counties in northwest Oregon, as shown in Figure 2.

Figure 2: Map of PGE's Service Territory



PGE's Transmission System is designed to reliably distribute power throughout the Portland & Salem regions for the purpose of serving native load. In addition to the load-service transmission facilities, PGE also maintains ownership of networked Transmission System circuits (See Figure 3) used to integrate transmission and generation resources on the Bulk Electric System (BES).

Figure 3: PGE-Owned Transmission System Circuits

Transmission Circuit	Circuit Miles	Transmission Path
Grizzly-Malin 500kV	178.5 miles	COI[1]
Grizzly-Round Butte 500kV	15.6 miles	
Colstrip-Townsend #1 500kV	37.3 miles (represents 15% ownership)	
Colstrip-Townsend #2 500kV	36.9 miles (represents 15% ownership)	
Bethel-Round Butte 230kV	99.2 miles	WOCS[2]
Horizon-St Marys-Trojan 230kV	45.8 miles	SOA[3]
Rivergate-Trojan 230kV	35.1 miles	SOA[3]

In total, PGE owns 1,630 circuit miles of sub-transmission and transmission at voltages ranging from 57 kV to 500 kV. (See Figure 4)

Figure 4: PGE Circuit Miles Owned (By Voltage Level)

Voltage Level	Pole Miles	Circuit Miles
500 kV	268	268
230 kV	285	329
115 kV	519	570
57 kV	429	463

3.2. Load Forecast

For load forecasting purposes, PGE's Transmission System is evaluated for a 1-in-3 peak load condition during the summer and winter seasons for Near Term (years 1 through 5) and Longer Term (years 6 through 10) studies.

The 1-in-3 peak system load is calculated based on weather conditions that PGE can anticipate experiencing once every three years. The summer (June 1st through October 31st) and winter (November 1st through March 31st) load seasons are considered the most critical study seasons due to heavier peak loads and high power transfers over PGE's Transmission and Distribution System to its customers. PGE defines the seasons to align with the seasons set by the Reliability Coordinator's seasonal planning process.

[1] California-Oregon Intertie
[2] West of Cascades South
[3] South of Allston

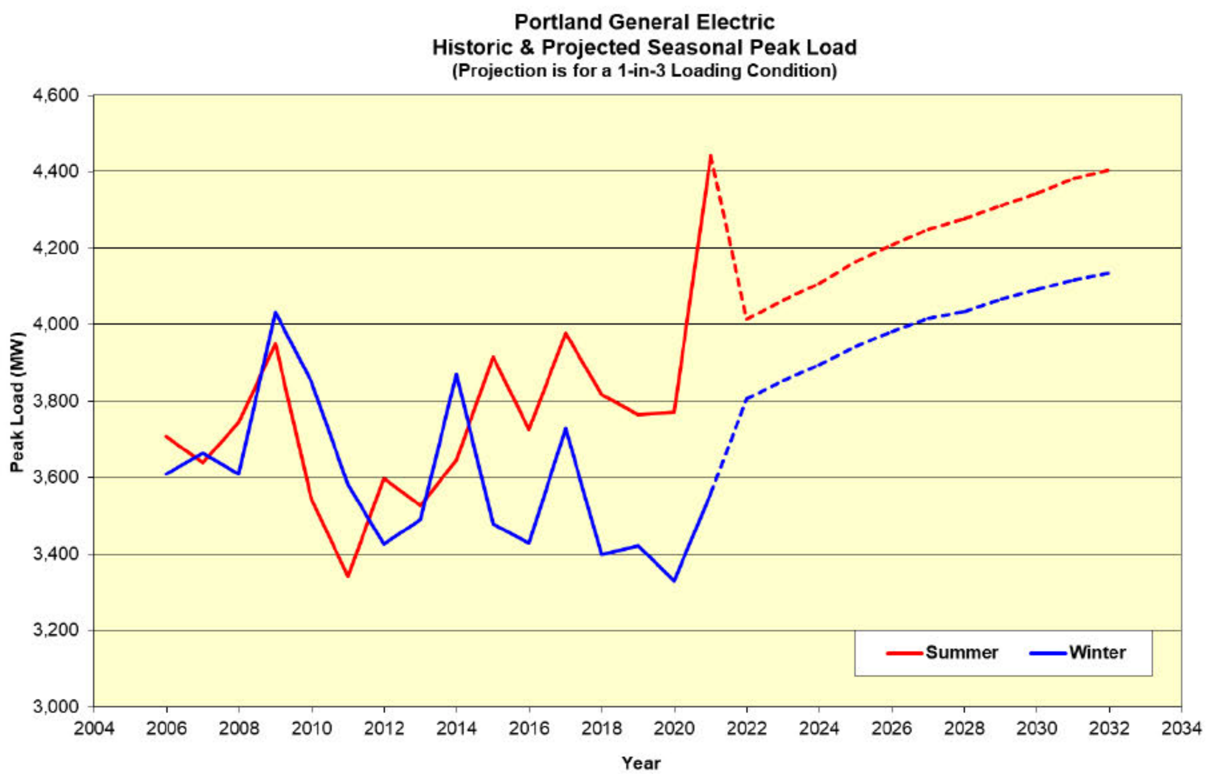
Figure 5: Summer/Winter Loading Conditions and Corresponding Daily-Averaged Temperatures

Winter	
1-in-2	28.6°F
1-in-3	26.8°F
1-in-5	25.1°F
1-in-10	23.2°F
1-in-20	21.7°F

Summer	
1-in-2	81.9°F
1-in-3	83.4°F
1-in-5	84.6°F
1-in-10	86.1°F
1-in-20	87.3°F

Figure 6: Portland General Electric's Historic & Projected Seasonal Peak Load

(Projection is for a 1-in-3 Loading Condition)



PGE's all-time peak load occurred on June 28, 2021, with the Net System Load[4] reaching 4441 MW. PGE's all time winter peak occurred on December 21, 1998, with the Net System Load reaching 4073 MW.

[4] The Net System Load is the total load served by PGEM, including losses. This includes PGE load in all control areas, plus ESS load, minus net borderlines.

3.3. Forecasted Resources

The forecasted resources are comprised of generators, identified by network customers as designated network resources, that are integrated into the wider regional forecasts of expected resources committed to meet seasonal peak loads.

3.4. Economic Studies

Eligible customers or stakeholders may submit economic congestion study requests during either Quarter 1 or Quarter 5 of the planning cycle. However, PGE did not receive any study requests during the 2020-2021 planning cycle.

3.5 Stakeholder Submissions

Any stakeholder may submit data to be evaluated as part of the preparation of the draft Longer Term Local Transmission Plan and/or the development of sensitivity analyses, including alternative solutions to the identified needs set out in prior Local Transmission Plans, Public Policy Considerations and Requirements, and transmission needs driven by Public Policy Considerations and Requirements. PGE received a Public Policy Requirement (PPR) study request in Q5 of the 2020-2021 planning cycle. The request is for PGE to study additional Available Transfer Capability (ATC) across the Bonneville Power Administration (BPA) Cross Cascades South Flowgate to address PGE's State of Oregon renewable portfolio standard (RPS) compliance obligations. PGE does consider the Oregon RPS to be a PPR obligation. PGE will study the PPR as a sensitivity in parallel with PGE's 2021 Longer Term Local Transmission Plan. However, PGE will conduct a sensitivity analysis of the WECC major path, West of Cascades South (WOCS), instead of BPA's Cross Cascades South Flowgate. The Cross Cascades South Flowgate is a construct that only exists within BPA's transmission system.

4. Methodology

PGE's Transmission System is designed to reliably supply projected customer demands and projected Firm Transmission Services over the range of forecast system demands. Studies are performed annually to evaluate where transmission upgrades may be needed to meet the performance requirements established in the NERC TPL-001-4 Reliability Standard and the WECC TPL-001-WECC-CRT-3.2 Regional Criteria.

PGE maintains system models within its planning area for performing the studies required to complete the System Assessment. These models use data that is provided in WECC base cases in accordance with the MOD-032 reliability standard. Electrical facilities modeled in the cases have established "Continuous Ratings" for the normal and emergency ratings required by the WECC Data Preparation Manual. PGE also publishes "Emergency 30-Minute Ratings" for use in the Operations Horizon. "Continuous Ratings" and "Emergency 30-Minute Ratings" are defined in PGE's Facility Ratings Methodology document. A Facility Rating is determined based on the most limiting component in a given transmission path, in accordance with the FAC-008-5 reliability standard.

Reactive power resources are modeled as made available in the WECC base cases. For PGE, reactive power resources include shunt capacitor banks available on the 115 kV Transmission System (primarily auto mode - time-clock, two auto mode - voltage control, and three fixed mode), and on the 57 kV sub-transmission system (primarily auto mode - voltage control, one fixed mode).

Studies are evaluated for the Near Term Planning Horizon (years 1 through 5) and the Longer Term Planning Horizon (years 6 through 10) to ensure adequate capacity is available on PGE's Transmission System. The load model used in the studies is based on PGE's corporate forecast, reflecting demand levels for 1-in-3 peak summer, 1-in-3 peak winter, and off-peak spring conditions with additions of anticipated large customer loads. Known outages of generation or transmission facilities with durations of at least six months are appropriately represented in the system models. Transmission equipment is assumed to be out of service in the base case system models if there is no spare equipment or mitigation strategy for the loss of the equipment.

In the Near Term, studies are performed for the following:

- System Peak Load for either Year One or Year Two
- System Peak Load for Year Five
- System Off-Peak Load for the same years as the peak load studies

Sensitivity studies are performed for each of these cases by varying the study parameters to stress the system within a range of credible conditions that demonstrate a measurable change in performance. PGE alters the real and reactive forecasted load and the transfers on the paths into the Portland area on all sensitivity studies. For peak summer and peak winter sensitivity cases, the 1-in-10 load forecast is used.

Studies are evaluated at peak summer and peak winter load conditions for one of the years in the Longer Term Planning Horizon.

Figure 7: Powerflow Base Cases Used in 2021 Assessment

		Study Year	Origin WECC Base Case	PGE Case Name	PGE System Load (MW)
SUMMER	Year One/Two Case	2023	2023 HS3	23 HS PLANNING	4270
	Year Five Case	2026	2026 HS2	26 HS PLANNING	4732
	Year One/Two Sensitivity	2023	2023 HS3	23 HS SENSITIVITY	4570
	Year Five Sensitivity	2026	2026 HS2	26 HS SENSITIVITY	5032
	Long Term Case	2031	2031 HS1	31 HS PLANNING	5192
WINTER	Year One/Two Case	2023-24	2022-23 HW2	23-24 HW PLANNING	4143
	Year Five Case	2026-27	2026-27 HW2	26-27 HW PLANNING	4543
	Year One/Two Sensitivity	2023-24	2022-23 HW2	23-24 HW SENSITIVITY	4443
	Year Five Sensitivity	2026-27	2026-27 HW2	26-27 HW SENSITIVITY	4843
	Long Term Case	2031-32	2030-31 HW1	31-32 HW PLANNING	4905
SPRING	Year One/Two Off Peak Case	2023	2024 LSP1	23 LSP PLANNING	2273
	Year Five Off Peak Case	2026	2024 LSP1	26 LSP PLANNING	2693
	Year One/Two Off Peak Sensitivity	2023	2024 LSP1	23 LSP SENSITIVITY	2273
	Year Five Off Peak Sensitivity	2026	2024 LSP1	26 LSP SENSITIVITY	2693

The BES is evaluated for steady state and transient stability performance for planning events described in Table 1 of the NERC TPL-001-4 reliability standard. When system simulations indicate an inability of the systems to respond as prescribed in the NERC TPL-001-4 standard, PGE identifies projects and/or Corrective Action Plans which are needed to achieve the required system performance throughout the Planning Horizon.

Short circuit studies are performed annually addressing the Near Term Planning Horizon. If the short circuit current interrupting duty on a circuit breaker exceeds 97% of its equipment rating, PGE identifies projects and/or Corrective Action Plans which are needed to achieve the required system performance throughout the Near Term Planning Horizon.

4.1. Steady State Studies

PGE performs steady-state studies for the Near-Term and Long-Term Transmission Planning Horizons. The studies consider all contingency scenarios identified in Table 1 of the NERC TPL-001-4 reliability standard (Categories P0-P7) to determine if the BES meets performance requirements. These studies also assess the impact of extreme events on the system expected to produce severe system impacts.

The contingency analyses simulate the removal of all elements that the protection system and other automatic controls are expected to disconnect for each contingency without operator intervention. The analyses include the impact of the subsequent tripping of generators due to voltage limitations and tripping of transmission elements where relay loadability limits are exceeded. Automatic controls simulated include phase-shifting transformers, load tap changing transformers, and switched capacitors and reactors.

Cascading, or the uncontrolled successive loss of system elements triggered by a disturbance that results in the inability of the elements of the BES to regain a state of operating equilibrium is defined as a system instability. Cascading is not allowed to occur for any contingency scenario. If the analysis of an extreme event concludes there is Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is completed.

The following process is used to test for Cascading:

1. Single contingencies and credible multiple contingencies that result in the exceedance of the lower of either:
    a. The facility(ies)'s trip setting, or
    b. 125% of the highest facility emergency rating (Note: if the trip setting is known to be different than the 125% threshold, the known trip setting should be used).
2. For each flagged contingency, open the original contingency elements and the elements flagged in step 1. Run steady state analysis without any manual system adjustments.
3. Repeat step 2 for any newly overloaded facilities that exceed Step 1 criteria. Continue repeating step 2 until no more facilities are removed from service or until the powerflow solution diverges.

    NOTE: If the process of tripping elements in steps 2 and 3 stops prior to divergence, then it can be concluded that the area of impact is predetermined by studies, and Cascading does not occur. If the powerflow solution diverges during the test described above utilizing the 125% of the highest facility emergency rating threshold, further investigation into post-contingency loading may be warranted prior to declaring that Cascading occurs.

Uncontrolled islanding is defined as a system instability that occurs when transmission operating actions, such as tripping for loading a given percentage above the highest facility emergency rating, result in the separation and loss of synchronism of a portion of the BES that includes generation or load. Generators disconnected from the system by fault clearing action or by Remedial Action Schemes (RAS) are not considered out of synchronism. Similarly, islands formed by disconnection from the system by fault clearing action or by a RAS are considered a sub-network island and not an uncontrolled island.

Characteristics of a sub-network island include:

- The presence of both generation and load to support the continuation of the island.
- A clear disconnect between formed sub-networks.

Characteristics of uncontrolled islanding include:

- Out-of-step generators.
- Off-nominal frequency disturbances.
  Eventual collapse of formed islands due to frequency or voltage instability caused by generation-load unbalance.

Capacity addition projects are developed when simulations indicate the system's inability to meet the steady-state performance requirements for P0 (System Normal), P1 or P2-1 events. For P2-2 through P7 events, PGE may develop projects to mitigate overload or voltage issues; however, manual post-contingency load-shedding may be identified as a mitigation to ensure that the BES remains within the defined operating limits, which is permissible (except for some categories of faults on equipment 300 kV and above) per TPL-001-4 for P2-2 through P7 events.

4.2. Voltage Stability Studies

PGE's Transmission System is evaluated for voltage stability in accordance with the WECC established procedures and criteria[5]. These performance criteria are summarized in the table below. Contingencies to PGE and adjacent utility equipment at 500 kV and 230 kV are evaluated.

Figure 8. Voltage Stability Performance Criteria

WECC Performance Level	TPL-001-4 Category	Disturbance	MW Margin (PV Method)	MVAR Margin (QV Method)
A	P0	No Contingency	≥5%	≥5% Load Increase
B	P1[6]	A Single Element	≥2.5%	50% of Margin "A"
C	P2-P7[7]	Any Two Elements	≥2.5%	50% of Margin "A"
D	N/A	Extreme Events	>0	>0

For PGE's real power margin assessment, the "transfer path" studied is identified by the Northwest (Area 40) generation as the (source) and PGE generation and load as the sink. Load internal to PGE's local Transmission System is scaled up to increase the "path" flow until a voltage stability limit is identified.

4.3 Transient Stability Studies

PGE evaluates the voltage and transient stability performance of the Transmission System for single or multiple P0-P7 contingencies to PGE and adjacent utility equipment at 500 kV, 230 kV, and 115 kV. The studies evaluate single line-to-ground and 3φ faults to these facilities, including generators, bus sections, breaker failure, and loss of a double-circuit transmission line. Extreme events are studied for 3φ faults with delayed fault clearing. Contingencies are selected based on the available clearing time data from PGE's System Protection Department. Distance relays are applied to the Northwest Transmission System with a Zone 1 mho circle of 85% along with the latest frequency relays on PGE generators and loads. The WECC composite load model used for the studies includes Motor A or air-conditioner motor stalling.

For all 500 kV and 230 kV breaker positions, PGE implements high-speed protection through two independent relay systems utilizing separate current transformers for each set of relays. For a fault directly affecting these facilities, normal clearing is achieved when the protection system operates as designed and faults are cleared within four to six cycles.

PGE implements breaker-failure protection schemes for its 500 kV and 230 kV facilities; and the majority of 115 kV facilities. Delayed clearing occurs when a breaker fails to operate and the breaker-failure

[5] "Guide to WECC/NERC Planning Standards I.D: Voltage Support and Reactive Power," prepared by the Reactive Reserve Working Group (RRWG) and approved by the Technical Studies Subcommittee (TSS) on March 30, 2006.
https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/Voltage%20Stability%20Guide.pdf&action=default&DefaultItemOpen=1

[6] Not all NERC TPL-001-4 Categorical outages are specifically identified in the WECC Performance Criteria.

[7] TPL-001-4 P6 is not included in the WECC Performance Criteria.

scheme clears the fault. Facilities without delayed clearing are modeled as such in the contingency definition.

The transient stability results are evaluated for compliance with the following NERC and WECC system performance requirements. The simulation durations are run to 20 seconds. All oscillations that do not show positive damping within 20 seconds after the start of the studied event shall be deemed unstable.

1. Rotor Angle Stability
   Generators must maintain synchronism with PGE's Transmission System and the rest of the Transmission System in the Northwest through the transient period and rotor angle oscillations must exhibit positive damping for the loss of either one or two System Elements.

2. Frequency Stability
   System frequency at any load bus must not fall below:
   - 59.6 Hz for 6 cycles or more following the loss of a single system element.
   - 59.0 Hz for 6 cycles or more following the loss of two system elements.

3. Voltage Stability
   Following fault clearing, the voltage shall recover to 80% of the pre-contingency voltage within 20 seconds of the initiating event for all P1 through P7 events, for each applicable BES bus serving load.

   Following fault clearing and voltage recovery above 80%, voltage at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds, for all P1 through P7 events.

   For contingencies without a fault (P2-1 category event), voltage dips at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds.

Failure to meet the above performance requirements for any transient stability simulation will necessitate some form of mitigation.

Contingency analyses simulate the removal of all elements that the protection system and other automatic controls expected to disconnect for each contingency without operator intervention. The analyses include the impact of the subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a fault where high speed reclosing is utilized
- Tripping of generators due to voltage limitations
- Tripping of transmission lines and transformers where transient swings cause protection system operation based on generic or actual relay models

Automatic controls simulated include generator exciter and governor controls, generator power system stabilizers, static var compensators, power flow controllers, DC Transmission controllers, RAS and under frequency load shedding (UFLS). Fault protection or automatic controls that result in unintended islanding as defined in the steady state section above is considered a System instability.

Cascading is not allowed to occur for any contingency analysis. If the analysis of an Extreme Event concludes there is Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is completed.

Corrective Action Plans are developed if the stability studies indicate that the system cannot meet the TPL-001-4 and WECC performance requirements.

- P1: No generating unit pulls out of synchronism
- P2-P7: When a generator pulls out of synchronism, the resulting apparent impedance swings do not result in the tripping of any BES elements other than the generating unit and its directly connected facilities
- P1-P7: Power oscillations exhibit acceptable damping

5. Results

5.1. Public Policy Requirement Request

PGE performed a sensitivity analysis as part of this Longer Term LTP to address potential transmission availability constraints on the WOCS path as renewable resources are added to the system in response to the State of Oregon RPS.

The 2019 PGE Integrated Resource Plan (IRP) has identified wind resources in Montana as having a high capacity factor. The 2019 IRP has also considered a sensitivity where the Colstrip 3 and 4 units are retired early. PGE studied replacing the installed MW nameplate of Colstrip units 3 and 4 with equal nameplate MW of new Montana wind to identify the impact of retiring and replacing thermal resources with renewable resources. The results identify that the retirement and replacement of thermal resources in Montana is sufficiently remote from the WOCS path as to have no practical impact on the transfer capacity. The results of this analysis are limited to the retirement and replacement of resources in Montana. The addition of resources in excess of the existing resources, or the addition of resources in areas other than Montana, will have effects that are not captured in these study results.

5.2. Steady State Results – Longer Term Evaluation

The Longer Term evaluation is completed using multiple loading and generation scenarios. The Longer Term planning studies identify transmission facilities with loading and/or voltage concerns under 1-in-3 peak summer or peak winter loading conditions. None of the contingencies evaluated in any of the studies will result in Cascading from PGE’s control area to another control area.

Hillsboro 230 kV System Loading Issues

The loss of the Horizon-Keeler BPA #2 230 kV line can result in an overload on the Horizon-Keeler BPA #1 230 kV line during peak summer conditions. A project has been identified to mitigate this overload in the Longer Term Planning Horizon. In addition, the loss of the Horizon-Keeler BPA #1 230 kV line followed by the loss of the Horizon-Keeler BPA #2 230 kV line can result in an overload on the Evergreen-Harborton 230 kV line during peak summer conditions. A project has been identified to mitigate this overload in the Longer Term Planning Horizon as well.

The loss of two of the three Horizon bulk power transformers can result in an overload on the remaining Horizon bulk power transformer during peak summer conditions. A project has been identified to mitigate this overload in the Longer Term Planning Horizon.

Beaverton 115 kV System Loading Issues

The loss of the Brookwood-Main 115 kV line followed by the loss of the Orenco-Roseway 115 kV line can result in an overload on the Murrayhill-Reedville 115 kV line during peak summer conditions. In addition, the loss of the Keeler BPA 500/230 kV transformer followed by the loss of the Murrayhill-St Marys 230 kV line can also result in an overload on the Murrayhill-Reedville 115 kV line during peak summer conditions. In spring or summer conditions with heavy south to north flow from Sherwood to St Marys, additional contingencies can cause overloads to occur on the Murrayhill-Reedville 115 kV line and the Beaverton-Tektronix 115 kV line. A project has been identified to mitigate these overloads in the Longer Term Planning Horizon.

Pearl BPA-Sherwood 230 kV System Loading Issues

The loss of the Keeler BPA 500/230 kV transformer, followed by the loss of the Pearl BPA-Sherwood 230 kV line, can result in an overload on the McLoughlin-Pearl BPA-Sherwood 230 kV line during peak summer conditions. Conversely, the loss of the Keeler BPA 500/230 kV transformer followed by the loss of the McLoughlin-Pearl BPA-Sherwood 230 kV line can result in an overload on the Pearl BPA-Sherwood 230 kV line during peak summer conditions.

In summer conditions with heavy south to north flow from Sherwood to St Marys, the single contingency loss of the Pearl BPA-Sherwood 230 kV line can result in an overload on the McLoughlin-Pearl BPA-Sherwood 230 kV line. Conversely, the single contingency loss of the McLoughlin-Pearl BPA-Sherwood 230 kV line can result in an overload on the Pearl BPA-Sherwood 230 kV line. A project has been identified to mitigate these overloads in the Longer Term Planning Horizon.

Murrayhill-Sherwood 230 kV System

The loss of the Keeler BPA 500/230 kV transformer followed by the loss of one of the two Murrayhill-Sherwood 230 kV lines can result in an overload on the remaining Murrayhill-Sherwood 230 kV line. Curtailing the SOA path per DSO 309 is not effective for this overload, as the flow on the Murrayhill-Sherwood 230 kV lines is south to north for this overload scenario. A project has been identified to mitigate these overloads in the Longer Term Planning Horizon.

Dayton/Newberg 115 kV System Loading and Voltage Issues

The loss of the Newberg-Sherwood 115 kV line and the Sherwood-Six Corners 115 kV line section can cause the Dayton-McMinnville BPA-Newberg 115 kV line to exceed its rating during peak summer conditions. A project has been identified to mitigate this overload in the Longer Term Planning Horizon.

5.3. Longer Term Transient Stability

The Longer Term transient stability studies were conducted with selected 500 kV, 230 kV, and 115 kV single or multiple P0-P7 Contingencies. The Contingencies were generated based on available clearing time data from PGE System Protection. Distance relays were also modeled with a Zone 1 mho circle of 85% that was applied to the Northwest Transmission System along with the latest frequency relays on PGE generators and loads. The WECC composite load model used for the studies did include Motor A or air-conditioner motor stalling. This was previously disabled in the WECC master dynamic file but was enabled for this year's studies, which affected the results with some fault induced delayed voltage recovery (FIDVR). The FIDVR results on the 115 kV and 57 kV System indicate potential TPL-001-WECC-CRT-3.2 concerns; however, there are known issues with the WECC composite load model. PGE will investigate these results further, including examining the composite load model, to determine if the FIDVR results are valid. If the results are determined to be correct, PGE will implement projects to add VAR support to the System.

The Longer Term transient stability studies indicate that PGE's system exhibits adequate transient stability throughout the 500kV, 230kV, and 115kV Transmission System. The minimum frequency response recorded did not dip below 59.5 Hz for any of the contingency events studied on PGE's system. UFLS relays are not affected because the set point for UFLS relays is 59.3 Hz. Additionally, there were no unnecessary distance relay tripping per PRC-026 or TPL-001-4 R4.3.1.3.

The N-1-1 event for the loss of the Grizzly BPA-Round Butte 500kV circuit followed by the loss of the Redmond BPA-Round Butte 230kV circuit will result in instability on the local Transmission System. These circuits do not share a common corridor or element; however, the loss of this combination of circuits will result in instability on a 100 mile, 230kV line serving the Pelton and Round Butte generation plants and approximately 20 MW of load. A RAS is installed at Round Butte substation to limit the total Pelton/Round Butte generation to 200 MW in the event of this contingency.

5.4. Projects Currently Included in the Longer Term Plan

There are twelve projects currently planned for implementation in the Longer Term Planning Horizon. The projects described in this Longer Term Plan are subject to modification and/or withdrawal. These potential projects are described in detail in Appendix A.

Appendix A: 10 Year Project List

Projects currently included in the Longer Term Plan are:

- Southeast Portland Conversion Project
- Sunset Bus Reconfiguration Project
- Pearl BPA-Sherwood Capacity Upgrade Project
- Hillsboro Reliability Project
- Willamette Valley Resiliency Project
- Murrayhill-Sherwood #1 & #2 230 kV Reconductor Project
- Beaverton-Tektronix and Murrayhill-Reedville 115 kV Reconductor Project
- Horizon-Keeler BPA #1 230 kV Reconductor Project
- Dayton Reliability Project
- Evergreen-Harborton 230 kV Reconductor Project
- Evergreen Third Bulk Power Transformer Project
- Evergreen-Sherwood 230 kV Line Project

These projects are described in more detail on the following pages.

Southeast Portland Conversion Project

- **Project Purpose**
    - Increase capacity in the Southeast Portland area
- **Project Scope**
    - **Near Term Planning Horizon**
        - Rebuild Holgate 57 kV substation to a 115 kV in-line breaker configuration
        - Retire Stephens substation
    - **Longer Term Planning Horizon**
        - Rebuild Sellwood 115 kV substation to a breaker and one half configuration
        - Rebuild the Hogan South 115 kV substation to a breaker and one half configuration
        - Rebuild Arleta 57 kV substation to a 115 kV selective transfer configuration
        - Retire Hogan North substation
        - Retire Lents substation
        - Construct the new Gresham-Hogan 115 kV line
        - Move 115/57 kV bulk power transformer from Sellwood substation to Hogan substation
- **Project Status**
    - Preliminary Planning
- **Project Completion Date**
    - Estimated 11/2029

Sunset Bus Reconfiguration Project

- **Project Purpose**
  - Address overdutied breakers at the Sunset substation
- **Project Scope**
  - Split the main buses at Sunset to reconfigure the substation from one large breaker and one half configuration to two smaller breaker and one half configurations
  - Swap Butler-Sunset #2 115 kV line position with the Shute-Sunset 115 kV line position at the Sunset substation
- **Project Status**
  - Preliminary Planning
- **Project Completion Date**
  - Estimated 3/2027

Pearl BPA-Sherwood Capacity Upgrade Project

- **Project Purpose**
  - Increase the capacity between Pearl BPA substation and Sherwood substation to eliminate thermal overload concerns

- **Project Scope**
  - Split the bundled conductor on the Pearl BPA-Sherwood 230 kV line to create a Pearl BPA-Sherwood #1 230 kV line and a Pearl BPA-Sherwood #2 230 kV line
  - Split the bundled conductor on the Pearl BPA and Sherwood segments of the McLoughlin-Pearl BPA-Sherwood 230 kV line to create a Pearl BPA-Sherwood #3 230 kV line a new McLoughlin-Pearl BPA-Sherwood 230 kV line.
  - Reconductor the Pearl BPA-Sherwood #3 230 kV line and the Sherwood segment of the McLoughlin-Pearl BPA-Sherwood 230 kV line to 1272 ACSS.
  - Install new breaker positions at Pearl BPA and Sherwood

- **Project Status**
  - Preliminary Planning
  - Coordination with BPA on joint project

- **Project Requirement Date**
  - Estimated 4/2027

Hillsboro Reliability Project

- **Project Purpose**
    - Increase system reliability and resiliency in the Hillsboro area
    - Address loading concerns on Horizon 230/115 kV bulk power transformers due to load growth with the new Evergreen Bulk Power substation
    - Address loading concerns on the Hillsboro area 57 kV system by converting the Brookwood and Main substations to 115 kV
    - Address overdutied breakers at the Orenco substation

- **Project Scope**
    - **Near Term Planning Horizon**
        - Reconductor the Orenco-Sunset 115 kV line to 1272 ACSS
        - Rebuild the Brookwood substation to a 115 kV ring bus configuration
        - Construct new Brookwood-Shute, Brookwood-St Marys, Brookwood-Main, and Brookwood-Roseway 115 kV lines
        - Rebuild the Orenco substation to a 115 kV breaker and one half configuration
        - Construct a new Evergreen Bulk Power substation
        - Loop the Harborton-Horizon 230 kV line into Evergreen substation creating the Evergreen-Harborton and Evergreen-Horizon 230 kV lines
        - Loop the Helvetia-Shute 115 kV line into Evergreen, creating the Evergreen-Helvetia and Evergreen-Shute 115 kV lines; reconductor the Evergreen-Shute 115 kV line to 1272 ACSS
        - Unbundle the Rock Creek-Shute-Sunset 115 kV line, creating the Evergreen-Rock Creek and Evergreen-Sunset 115 kV lines
    - **Longer Term Planning Horizon**
        - Rebuild the Main substation to a 115 kV ring bus configuration

- **Project Status**
  - The Orenco-Sunset 115 kV line reconductor was completed in 2020
  - The Brookwood substation and new 115 kV lines are under construction
  - The Evergreen substation and associated line work are in design and permitting
  - The Orenco substation rebuild is in design and permitting
  - The Main substation and associated line work are in the preliminary planning stage

- **Project Requirement Date**
  - The Brookwood 115 kV Conversion is scheduled for completion in June 2022
  - The Orenco substation rebuild is scheduled for completion in June 2023
  - The Evergreen substation construction and associated line work are scheduled for completion June 2024
  - The Main 115 kV Conversion is scheduled for completion in April 2027

Willamette Valley Resiliency Project

- **Project Purpose**
  - Increase system reliability and resiliency in the Willamette Valley area

- **Project Scope**
  - Rebuild the 115 kV yard in Bethel substation to a breaker and one half configuration
  - Rebuild the Monitor substation with a 230 kV ring bus configuration, a 115 kV ring bus configuration, and a 57 kV ring bus configuration
  - Rebuild the North Marion 57 kV substation to a 115 kV ring bus configuration
  - Rebuild the St Louis 57 kV substation to a 115 kV ring bus configuration
  - Rebuild the Waconda 57 kV substation to a 115 kV ring bus configuration
  - Rebuild the Woodburn 57 kV substation to a 115 kV ring bus configuration
  - Install two new bulk transformers at Monitor Substation (230/115 kV and 115/57 kV)
  - Rebuild the Chemawa BPA-Waconda 57 kV, Monitor-Woodburn 57 kV, North Marion-St Louis 57 kV, North Marion-Woodburn 57 kV and St Louis-Waconda 57 kV lines to 115 kV
  - Construct a new Monitor-Waconda 115 kV line
  - Construct a new Bethel-North Marion 115 kV line
  - Reconfigure the North Marion-Sullivan 57 kV line to create a new Monitor-Sullivan 57 kV line

- **Project Status**
  - Preliminary Planning

- **Project Requirement Date**
  - Estimated 6/2027

Murrayhill-Sherwood #1 & #2 230 kV Reconductor Project

- **Project Purpose**
    - Increase the capacity of the Murrayhill-Sherwood #1 & #2 230kV lines to eliminate thermal overload concerns

- **Project Scope**
    - Reconductor the Murrayhill-Sherwood #1 & #2 230kV circuits (approx. 5.58 miles each) to 1272 ACSS

- **Project Status**
    - Preliminary Planning

- **Project Requirement Date**
    - Estimated 6/2027

Beaverton-Tektronix and Murrayhill-Reedville 115kV Reconductor Project

- **Project Purpose**
  - Increase the capacity of the Beaverton-Tektronix and Murrayhill-Reedville 115 kV lines to eliminate thermal overload concerns

- **Project Scope**
  - Reconductor the Beaverton-Tektronix 115 kV line (approx. 1.54 miles) and the Murrayhill-Huber Tap section of the Murrayhill-Reedville 115 kV line (approx. 3.79 miles) to 795 ACSS

- **Project Status**
  - Preliminary Planning

- **Project Requirement Date**
  - Estimated 11/2027

Horizon-Keeler BPA #1 230 kV Reconductor Project

- **Project Purpose**
  - Increase the capacity of the Horizon-Keeler BPA #1 230kV line to eliminate thermal overload concerns

- **Project Scope**
  - Reconductor the Horizon-Keeler BPA #1 230kV circuit (approx. 1.47 miles) to 2156 ACSS

- **Project Status**
  - Preliminary Planning

- **Project Requirement Date**
  - Estimated 6/2028

Dayton Reliability Project

- **Project Purpose**
  - Increase reliability at the Dayton substation and McMinnville area

- **Project Scope**
  - Rebuild the 115 kV yard at the Dayton substation to a 115 kV ring bus configuration
  - Split the Dayton-McMinnville, BPA-Newberg 115 kV 3-terminal line into a Dayton-McMinnville 115 kV line and a Dayton-Newberg 115 kV line
  - Reconductor the new Dayton-McMinnville 115 kV line to 795 ACSS
  - Replace limiting CT at the McMinnville BPA substation

- **Project Status**
  - Preliminary Planning

- **Project Requirement Date**
  - Estimated 11/2028

Evergreen-Harborton 230 kV Reconductor Project

- **Project Purpose**
  - Increase the capacity of the Evergreen-Harborton 230kV line to eliminate thermal overload concerns

- **Project Scope**
  - Reconductor the Evergreen-Harborton 230kV circuit (approx. 10.01 miles) to 1272 ACSS

- **Project Status**
  - Preliminary Planning

- **Project Requirement Date**
  - Estimated 6/2029

Evergreen Third Bulk Power Transformer Project

- **Project Purpose**
  - Mitigate thermal overload concerns on the Horizon bulk power transformers

- **Project Scope**
  - Install a third bulk power transformer at the Evergreen substation

- **Project Status**
  - Preliminary Planning

- **Project Requirement Date**
  - Estimated 6/2030

Evergreen-Sherwood 230 kV Project

- **Project Purpose**
  - Address loading concerns on the Hillsboro area 230 kV system by adding another 230 kV source to the area

- **Project Scope**
  - Construct a new Evergreen-Sherwood 230kV line

- **Project Status**
  - Preliminary Planning

- **Project Requirement Date**
  - No date established; TBD

PGE/111

Ten-Year Load Forecast Supporting Need for Line

Exhibit 111 contains highly protected information

and is subject to

Modified Protective Order No. 24-087

(Redacted Copy)

REDACTED

SUBSTATIONS IMPACTED BY TONQUIN PROJECT - LOAD FORECASTS

Includes substations that are the most at risk of load shed until Rosemont-Wilsonville and McLoughlin-Tonquin 115kV lines are constructed
(All values in megawatts)

Substation Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
BOONES FERRY	[redacted]											
COFFEE CREEK												
MEMORIAL												
MERIDIAN												
OSWEGO												
ROSEMONT												
TONQUIN												
TUALATIN												
WILSONVILLE												
TOTAL LOAD:	**267.2**	**276.7**	**297.5**	**303.1**	**310.5**	**316.9**	**321.9**	**326.0**	**330.3**	**335.3**	**341.5**	**350.3**
LOAD GROWTH OVER 2023:	**0.0**	**9.6**	**30.3**	**36.0**	**43.3**	**49.7**	**54.7**	**58.9**	**63.2**	**68.1**	**74.3**	**83.1**

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of Portland General Electric Company's Direct Testimonies of Dr. Ian Beil, Larry Bekkedahl, Matt Gordanier, Jordan Messinger, Kevin Putnam, and Dan Nuñez on the parties to Docket PCN 6 on the date indicated below by email addressed to said person(s) at his or her last-known address(es) indicated below. Copies containing Highly Protected Information and Protected Information are being sent via encrypted zip file to the Filing Center and parties who have signed Modified Protective Order No. 24-087 and General Protective Order No. 23-132.

SERVICE LIST

PCN 6

Staff Isaac Kort-Meade **(C)(HC)** Public Utility Commission of Oregon P.O. Box 1088 Salem, OR 97308 Isaac.kort.meade@puc.oregon.gov	**Staff** Johanna Riemenschneider **(C)(HC)** Oregon Department of Justice Business Activities Section 1162 Court St. NE Salem, OR 97301-4796 Johanna.riemenschneider@doj.state.or.us
PGE Brendan McCarthy **(C)(HC)** Portland General Electric Company 121 SW Salmon St. 1WTC1301 Portland, OR 97204 Brendan.mccarthy@pgn.com Opucdockets@pgn.com	**PGE** Jocelyn C. Pease **(C)(HC)** McDowell Rackner Gibson PC 419 SW 11th Ave. Ste. 400 Portland, OR 97205 jocelyn@mrg-law.com dockets@mrg-law.com

DATED: April 17, 2024

Cole Albee

Cole Albee
Paralegal