Study Methodology

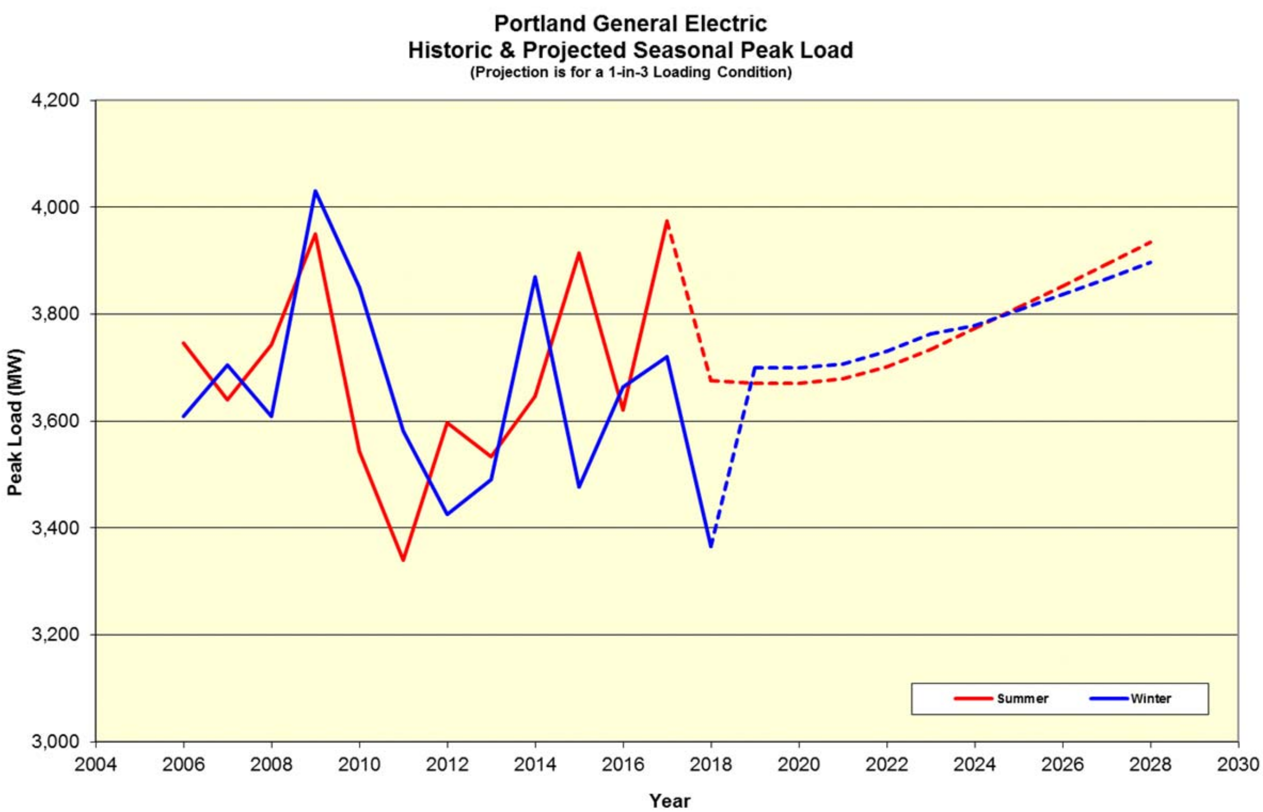
PGE's transmission system is designed to reliably supply projected customer demands and projected Firm Transmission Services over the range of forecast system demands. Studies are performed annually to evaluate where transmission upgrades may be needed to meet the performance requirements established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

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 Peak Reliability Coordinator Seasonal Operations Planning Coordination Process, Appendix 'VI'.

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

Summer	
1-in-2	79°F
1-in-3	81°F
1-in-5	83°F
1-in-10	85°F
1-in-20	87°F

Winter	
1-in-2	28°F
1-in-3	24°F
1-in-5	21°F
1-in-10	18°F
1-in-20	15°F



As depicted in the figure above, 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.

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 115kV transmission system (primarily auto mode – time clock; one auto mode – voltage control; one fixed) and on the 57kV transmission system (primarily auto mode – voltage control; one fixed).

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 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.

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 one of the five years

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 system sensitivity cases, the 1-in-10 load forecast is used.

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.

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	2020	2018 HS4	20 HS PLANNING	3671
	Year Five Case	2023	2023 HS2	23 HS PLANNING	3734
	Year One/Two Sensitivity	2020	2018 HS4	20 HS SENSITIVITY	3794
	Year Five Sensitivity	2023	2023 HS2	23 HS SENSITIVITY	3859
	Long Term Case	2028	2028 HS1	28 HS PLANNING	3934
WINTER	Year One/Two Case	2019-20	2019 HW3	19-20 HW PLANNING	3699
	Year Five Case	2022-23	2023 HW1	22-23 HW PLANNING	3763
	Year One/Two Sensitivity	2019-20	2019 HW3	19-20 HW SENSITIVITY	3883
	Year Five Sensitivity	2022-23	2023 HW1	22-23 HW SENSITIVITY	3949
	Long Term Case	2027-28	2028 HW1	28-29 HW PLANNING	3896
SPRING	Near Term Off Peak Case	2020	2021 LSP1	20 LSP PLANNING	2386
	Near Term Off Peak Sensitivity	2020	2021 LSP1	20 LSP SENSITIVITY	2386

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-001-4 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 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.

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 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 areas where manual post-contingency "load-shedding" may be required to ensure that the BES remains within the defined operating limits.

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 500kV and 230kV are evaluated.

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[3]	A Single Element	≥2.5%	50% of Margin "A"
C	P2-P7[4]	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.

Transient Stability Studies

PGE evaluates the transient stability performance of the BES for contingencies to PGE and adjacent utility equipment at 500kV and 230kV. 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 500kV and 230kV 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 500kV and 230kV facilities; and the majority of 115kV 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.

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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-001-4 Categorical outages are specifically identified in the WECC Performance Criteria.

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

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. <u>Rotor Angle Stability</u>
   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. <u>Frequency Stability</u>
   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. <u>Voltage Stability</u>
   The maximum transient voltage dip must not exceed:
   - 25% at any load bus or 30% at any non-load bus following the loss of a single system element.
   - 30% at any bus following the loss of two system elements.

   The transient voltage dip must not exceed 20% for more than:
   - 20 cycles at any load bus following the loss of a single system element.
   - 40 cycles at any load bus following the loss of two system elements.

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 BES elements other than the generating unit and its directly connected facilities
- P1-P7: Power oscillations exhibit acceptable damping