Chapter 4. Transmission landscape

PGE owns transmission assets and holds transmission contract rights for reliable delivery of electricity from generation resources to load. Additional transmission rights will be required for PGE to access more diverse resources, decarbonize, and maintain adequacy. However, there is a limited amount of existing transmission available for future resources to use. This chapter provides an update on relevant evolving topics discussed more fully in the 2023 CEP/IRP and provides an overview of PGE's current transmission environment, projects in PGE's system planning, and options in IRP modeling.

Key Highlights

- The transmission system serving PGE customers is highly constrained, with limited existing transmission available for future resources, particularly on BPA's system which supports limited resource additions prior to further transmission upgrades.
- The North of Pearl (NOPE) flowgate has emerged as a significant constraint since August 2023, creating operational challenges that could be exacerbated by ongoing regional trends that are causing increasing south to north flows near Portland. Multiple projects are required to address reliability risks related to this flowgate.
- Transmission plays an essential role to access diverse generation resources that are unavailable within PGE's service territory. Several transmission projects in various stages of development have been identified to help PGE access new renewable resources from diverse geographic areas.

Developments Since 2023 IRP

This Update reflects significant developments in PGE's transmission planning since the 2023 CEP/IRP. The North of Pearl flowgate, which BPA established in August 2023, has created operational constraints during periods of renewable resource imports from California and the desert southwest across PGE's service territory. For the Bethel-Round Butte (also known as Warm Springs Power Pathway) project, PGE and the Confederated Tribes of Warm Springs have successfully secured a $250 million Grid Resilience and Innovation Partnerships (GRIP) Program grant, enabling survey work to begin. PGE has further refined additional transmission options in the modeling based on third-party analyses from Energy Strategies and Energy GPS, reflecting more realistic estimates of project timelines, achievable capacity, and market access benefits.

Strategic Implications

These changes highlight the growing urgency of PGE's transmission needs as the company works toward decarbonization goals while facing increasing load growth and system constraints. The emergence of the North of Pearl flowgate creates new operational challenges that will require collaborative solutions with BPA. The GRIP funding for the Bethel-Round Butte project improves its economics and solidifies its role as a valuable upgrade. Overall, the refined analysis of transmission options, further described in **Section 4.6 Transmission options for portfolio analysis,** provides a clearer picture of the timing and benefits of various projects, which will inform PGE's strategy for planning sufficient transmission capacity to access diverse resource zones and potentially lower cost markets.

Staff Recommendations Incorporated

The Update addresses several conditions from LC 80 Order 24-096. Broadly, the Update refined and expanded analysis of transmission and local resources as alternatives to large-scale transmission expansion. PGE has conducted a more comprehensive analysis of transmission constraints and potential solutions as supported by third party analysis. The company has expanded its evaluation of transmission options beyond BPA's system to include potential projects that would access more diverse climate zones, responding to stakeholder concerns about transmission development matching the urgency of PGE's needs. The update also reflects PGE's continued assessment of the Bethel-Round Butte 500 kV upgrade, which was identified by the OPUC as a project to study for increasing PGE's import capability.

4.1 Transmission and regulatory environment

PGE-owned and contracted-for generating resources to serve load are both directly connected to PGE's transmission system and remote to PGE's system. PGE's transmission portfolio – comprised of PGE-owned assets and held transmission rights – is designed to ensure reliable delivery of electricity from this broad array of generation resources to load. Variable energy resources that generate non-emitting electricity will need to be added to meet growing load and decarbonize towards the targets of HB 2021. Increasingly these resources are expected to be developed in new geographic areas, with their delivery to PGE's system requiring expanded transmission infrastructure and growing interconnectedness in the West.

4.1.1 Regulatory environment

As a vertically integrated investor-owned utility that is regulated by the Federal Energy Regulatory Commission (FERC), PGE is obligated by FERC to functionally separate its Transmission Function (PGET) from its Merchant function (PGEM). PGET is required to plan and operate PGE's transmission system in a non-discriminatory manner that provides open access to all transmission customers, including PGEM. This means PGET cannot unduly preference PGEM and, by extension, the retail customers that PGEM serves. PGET's transmission customers include

PGEM, Oregon-defined Electricity Service Supplier (ESS) customers, BPA, and transmission customers who utilize PGE's transmission system to transmit power across the region.

PGEM is responsible for purchasing transmission rights – on PGET's transmission facilities and other regional providers – to deliver power to PGE's service area to meet PGE's load obligations. PGEM holds extensive rights on PGET's transmission system, as well as the BPA transmission system, the largest transmission provider in the Pacific Northwest.

Consistent with Federal requirements, PGE must plan and build its transmission system to meet the needs of all PGET transmission customers, including PGEM, ESS customers, and all other transmission customers.[69] Transmission customers typically utilize PGE's transmission system to serve load contained within PGET's system footprint or to transfer power through PGET's system to other transmission systems.

Transmission customers who serve load located within PGE's Balancing Authority Area (BAA) generally use a transmission service called Network Integration Transmission Service (NITS). Transmission customers who move power through PGET's transmission system for delivery to a point on another transmission system typically use Point-to-Point (PTP) transmission service. For PGET to develop its transmission plans for most NITS customers, with the State of Oregon-defined Electric Service Supplier (ESS) customers being the exception, PGE uses the ten-year load-and-resource (L&R) forecasts supplied by NITS customers along with PTP transmission service commitments and requests. ESS customers are not currently obligated to designate generation resources to serve their loads because they are allowed to take a secondary form of NITS service under Oregon law.

PGET uses the NITS customers' L&R forecasts and the best available information, including transmission service requests, generation interconnection requests, and information from neighboring transmission providers' transmission planning and construction activities, to determine the need and timing for investments in the transmission system. The bulk of PGET's NITS customer-driven needs comes from PGEM, which supplies energy and capacity for PGE's retail customers. Oregon's HB 2021 is central to PGE's strategy and the resource decisions of PGET's transmission customers, including PGEM, resulting in the need to develop new transmission system investment and deployment plans. The 2025 L&R letter from PGEM to PGET documents the expectation that PGEM's future resource needs will change, given the need to meet growing load and comply with HB 2021. PGET works with its customers, including PGEM, to plan the PGET transmission system to maintain reliable service as its customers' resource mixes change over the next several years.

While PGE's transmission customers, except ESSs, are required to provide annual L&R forecasts looking ten years into the future, transmission development in the West requires lengthy planning, rights-of-way (ROW) acquisition, permitting, and construction timelines that often take years. As such, PGET cannot rely solely on the L&R forecasts to plan future transmission investments and must plan its transmission system on a longer time horizon.

[69] Such as the principles of FERC Order Nos. 890 and 1000 and requirements of PGE's FERC-approved open access transmission tariff (OATT).

4.1.2 PGE's transmission system

PGE's transmission system serves roughly half of Oregon's population and powers approximately two-thirds of Oregon's commercial and industrial activity. It is highly integrated with other transmission systems in the west due to the highly networked nature of the regional transmission system.

The PGE service area is a compact area located primarily in Oregon's Willamette Valley. PGE owns and operates its transmission system and BAA to deliver energy to retail customers while also providing transmission service to other wholesale transmission customers as required by FERC and in accordance with PGET's OATT. Most of PGE's existing, owned transmission assets are within the PGE service area. PGE also owns transmission assets in central and southern Oregon and Montana. PGE is obligated to plan, build, and operate the transmission system in a manner that reliably delivers power to serve customer load and the needs of PGET's OATT transmission customers.

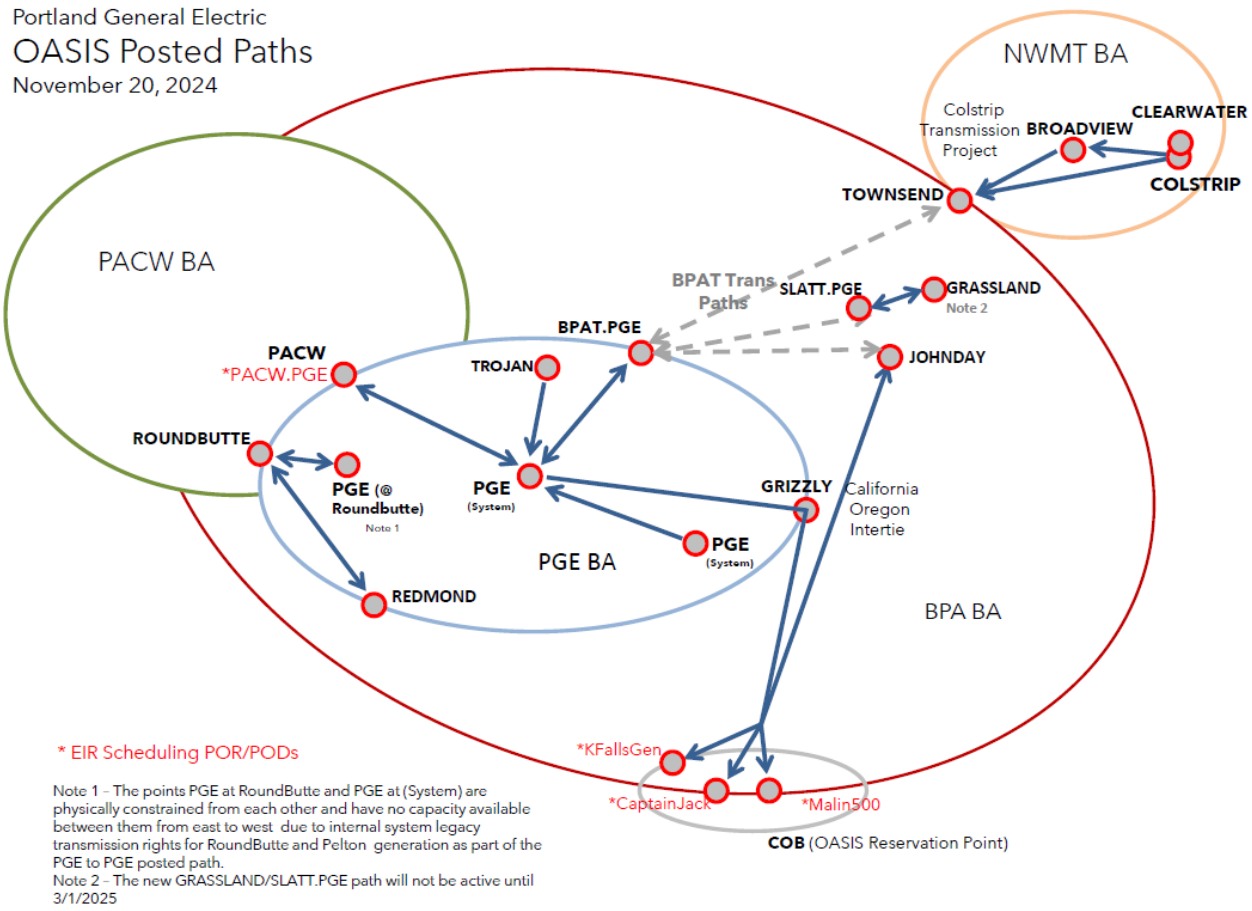
The PGE transmission system has 268 miles of 500 kV, 334 miles of 230 kV, and 559 miles of 115 kV lines, 454 circuit miles of 57 kV lines, and includes 176 substations and switching stations.[70]

4.1.3 Transmission system topology

PGE's transmission system (**Figure 29**) is highly interconnected with and exists almost entirely within the footprint of BPA. PGE is also interconnected to the western part of PacifiCorp's system, albeit with a much smaller transfer capability than PGE's interface with BPA. PGE's interface with PacifiCorp is primarily used to meet obligations within the Energy Imbalance Market (EIM). PGE is a co-owner of the Colstrip Transmission System, two 500 kV transmission circuits in Montana that runs between Colstrip and BPA's system in western Montana. Additionally, PGE owns one of the three 500 kV circuits in central Oregon that comprise the Northwest AC Intertie (NWACI), which is part of the California-Oregon Intertie, that connects Oregon to California. PGE jointly owns NWACI with BPA and PacifiCorp, and it is operated by BPA.

[70] An asset reclassification of PGE's 57 kV assets as transmission has been approved by the OPUC and is currently under review with FERC.

Figure 29. Oasis posted paths



4.1.3.1 BPA and Pacific Northwest transmission system

BPA is a federal power marketing administration (PMA) that operates approximately 75 percent of the transmission in the Pacific Northwest, consisting of more than 15,000 miles of high-voltage transmission lines. BPA operates transmission in Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah and Wyoming.[71]

4.1.3.2 PGE and BPA

PGE's system is largely surrounded by BPA's transmission system. PGE has long relied on BPA transmission to deliver energy from throughout the west to serve PGE load. PGE currently holds over 4000 MW of long-term firm transmission under contract with BPA. The rights held on BPA's system deliver energy from discrete points, either on BPA's system or from the edge of BPA's system to PGE. These rights are known as point-to-point transmission rights and the points of receipt and delivery are set in perpetuity. This means that if a resource that would normally utilize

[71] BPA transmission system: https://www.bpa.gov/-/media/Aep/about/publications/maps/bpa-transmissionlines-and-facilities.pdf.

certain rights is unavailable, the unused transmission rights cannot be used to access different points on BPA's system. As discussed by BPA and stakeholders throughout BPA's recent Transmission Study and Expansion Processes (TSEP), BPA's system is effectively fully subscribed, and incremental transmission requests are unlikely to be granted until the early to mid-2030s, pending significant upgrades. Additionally, BPA has recently announced a pause to their TSEP process entirely while they attempt to develop reforms to their transmission service request process. As such, future transmission planning and procurement activity recommended throughout this chapter is a way to expand and diversify transmission options as the energy associated with serving load is decarbonized. It is important to recognize that the identification and development of transmission solutions are long-lead-time activities that often take longer than the Action Plan window time horizon of the IRP. Given this dynamic, it is necessary to engage in transmission planning and development on a forward-looking basis beyond the Action Plan window. See the description of the West-Wide Transmission Study Project (**Section 2.3.1 Western Transmission Expansion Coalition (WestTEC)**), a 10-year and 20-year transmission study addressing interregional and interstate transmission needs spanning the Western Interconnection.

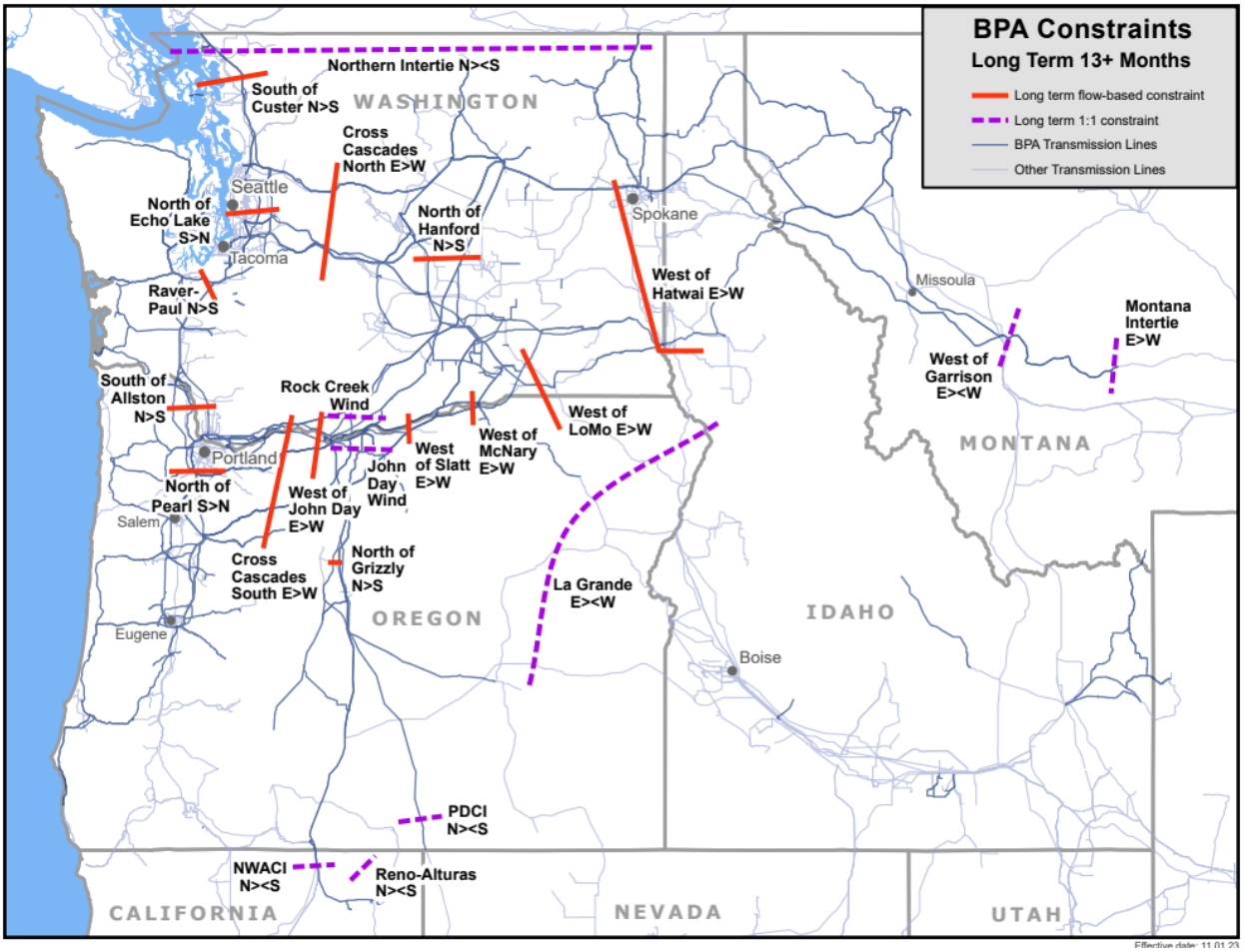
4.1.3.3 Paths and flowgates

To get to PGE's system, power generated or purchased from remote locations must travel through different paths and flowgates on the region's transmission system. A flowgate is a collection of transmission lines and facilities that collectively start in a geographically similar area and terminate in a different geographically similar area. These flowgates are typically operated by BPA and are shown in **Figure 30**. The flowgates that currently have the most significant impact on PGEM's transmission rights portfolio are North of Pearl, South of Allston, Raver Paul, West of John Day, and Cross Cascades South, all of which are constrained, with little or no ATC.

Flowgates are used by BPA as a way to monitor flow through areas of constraint on their system. Conceptually, when managed appropriately, the establishment of flowgates allows for a transmission provider to monitor system flows and take action to mitigate system constraints in the real-time operations horizon. Congestion at flowgates can be caused by different reasons including:

- Localized high loads at the receiving end of a flowgate in excess of flowgate capacity,
- Localized concentration of generation resources at the sending end of a flowgate trying in excess of flowgate capacity, and
- Flow-though, also known as loop flow, where far-flung regional load and generation dispatch scenarios create flows in excess of transmission capacity.

Figure 30. BPA Constraints[72]



The following summarizes the most significant flowgates and paths affecting energy delivery from remote resources to PGE's service area.

- The North of Pearl flowgate was instituted in August 2023 and has presented PGE with challenging operational scenarios since. The flowgate generally exists between the Wilsonville and Sherwood areas, SW of Portland. It is most constrained during periods of high renewable resource production in California and the desert southwest when it is also cool in the Pacific Northwest. Much less frequently, high Portland area loads can also contribute to high flows on North of Pearl. Further explanation of the North of Pearl flowgate will be described below.
- Some amount of energy from the majority of PGE's generating resources flows across the constrained South of Allston flowgate. This flowgate is most constrained during heavy summer and heavy winter loading periods. The South of Allston flowgate is a collection of several electrically parallel transmission lines that route from north to south just north of the

[72] Source: https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/atc-long-term-constraints-11-1-23.pdf.

Portland metro area. Historically, the South of Allston flowgate was most constrained in the summer months.

- A large portion of the energy flowing from PGE's remote resources flows across the West of Cross Cascades South (WOCS) flowgate. Additionally, depending on the resource location, energy will flow across the West of John Day flowgate and the Raver-Paul flowgate. The WOCS flowgate is typically most constrained during heavy winter loading, while the West of John Day and Raver-Paul flowgates are typically most constrained during heavy spring and summer loading. PGE's Bethel-Round Butte 230 kV transmission line is part of the WOCS path.

Energy from PGE's resources in Montana first flow over the West of Garrison flowgate before reaching several other flowgates on the way to PGE's load in the Willamette Valley.

4.1.3.4 North of Pearl

The North of Pearl (NOPE) flowgate consists of a combination of BPA and PGE lines that run between BPA's Pearl substation in Wilsonville, OR to PGE's Sherwood substation in Sherwood, OR. The flowgate is comprised of BPA's Pearl-Keeler 500kV line, the Pearl BPA-Sherwood #1 & #2 230kV lines, and the McLoughlin-Pearl BPA-Sherwood 230kV line. The flowgate was instituted on August 11, 2023, a few days prior to a heatwave that blanketed much of the PNW. The NOPE flowgate was originally intended to be enabled in November 2023, prior to the winter operating season, but was expedited by BPA with the extreme heat that occurred in August 2023.

The NOPE flowgate was originally enabled for the purposes of monitoring south-to-north (S-N) flows through the Portland area. Previously, S-N flows were monitored as part of the South of Allston flowgate, but in a S-N flow pattern. BPA eventually shifted the focal point for monitoring S-N flows from the South of Allston flowgate to the more appropriate NOPE location. The South of Allston S-N flowgate was retired in early 2024.

During spring of 2024 and 2025, there have been several occasions where the North of Pearl flowgate reached S-N transmission flow levels near the upper limits of the flowgate limit high renewable resource imports from California and the desert southwest and low hydro generation output from British Columbia. Additionally, unscheduled energy flows have been observed coming into the Pacific Northwest and through PGE's service territory. These unscheduled flows, and the load and resource dispatch patterns several hundreds of miles away from PGE's system in either direction, have caused BPA to take real-time mitigation actions that included: sending congestion signals to the EIM marketplace that dispatched PGE Port Westward gas resources unexpectedly, halting short-term firm transmission sales, stopping all hourly redirects on BPA's system, and curtailing approximately 4000 MWs of transmission schedules across the region. If these scenarios had happened at higher local Portland area load levels, BPA curtailment of firm transmission schedules could have resulted in reliability concerns for PGE.

As PGE anticipates significant load growth into the future from the semiconductor and data center industrial sectors, much of the forecasted growth will locate in the Beaverton/Hillsboro area on the west side of PGE's service territory. Existing constraints north of the NOPE flowgate will limit industrial growth here. Additionally, it is expected that solar deployments will continue

in California and the desert southwest, further exacerbating the NOPE flowgate constraint. PGE and BPA are collaboratively planning how to address the NOPE constraint. Constraint mitigation will require a combination of new and upgraded transmission facilities as well as new operational scenarios that are currently being evaluated.

4.2 PGE transmission projects

Various FERC and NERC compliance and regulatory obligations require that PGE develop, engineer, procure, and construct PGET-owned transmission projects. Transmission projects can develop as a result of NERC reliability obligations, be driven by transmission or interconnection customer actions, result in response to state policy actions, load growth, and resource forecasts and requests by PGET's network transmission service customers.

Key transmission projects placed in service in 2024 include:

- A new 1.7 mile 230 kV transmission line between BPA's Keeler substation and PGE's Horizon substation, both located in Hillsboro, Oregon.
- The Evergreen Substation, a new bulk substation located in Hillsboro, Oregon that facilitates the interconnection of PGE's Constable Battery Energy Storage Facility, as well as the ability to serve new load in Washington County.

PGE revisits transmission plans and projects on a specific time cadence, with those in **Table 12** representing current plans. Future needs will continue to be evaluated over time. For the Near-Term and Long-Term Planning Horizon, PGE has identified transmission projects which will be needed to maintain compliance with the NERC TPL-001-5 standard. Each project has identified a completion date and any long lead time items that are required as a part of the work. 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.

Table 12. Transmission Projects

Project Name	Anticipated In Service Date
Bethel-Round Butte 230kV Fixed Series Capacitor Project	2027 March
Bethel-Round Butte 500kV Project	2032 November
Blue Lake (Sundial) 230kV Battery Project	2025 June
Grassland 500kV Breaker Addition	2026 July
Harborton-Trojan #3 and #4 230kV	2033 May
Horizon-Keeler #1 & #2 230kV 4000A Upgrades	2029 April
Horizon-Keeler #1 230kV Reconductor Project	2026 May
Horizon-Keeler BPA #2 230 kV Project	2024 May
Jefferson Solar Project	2027 March
Madras Solar Project	2027 March
Memorial Substation Project	2025 July

Project Name	Anticipated In Service Date
Monitor Rebuild Project	2026 April
Pearl BPA-Sherwood 230 kV Project	2026 June
Reconductor Murrayhill-Sherwood 1&2	2027 May
Reconductor Murrayhill-St Marys #1, construct new Murrayhill-St Marys #2 section to create Sherwood-St Marys	2028 Q1
Reconfigure Murrayhill-Sherwood, Murrayhill-St Marys, Sherwood-St Marys	2028 Q1
Rivergate (Seaside) 230kV Battery Project	2025 June
Sherwood 115kV Project	2028 June
Shute and Sunset Facility Upgrades Project	2026 April
St Marys 115kV Breaker Replacement Project	2028 August
Sunset 115kV Bus Split Project	2027 April
Tonquin Substation Project	2026 December
Willamette Valley Resiliency Project (3 parts)	2035 May (latest part)
Hillsboro 500kV Expansion (Arden/Harrington)	2030 May

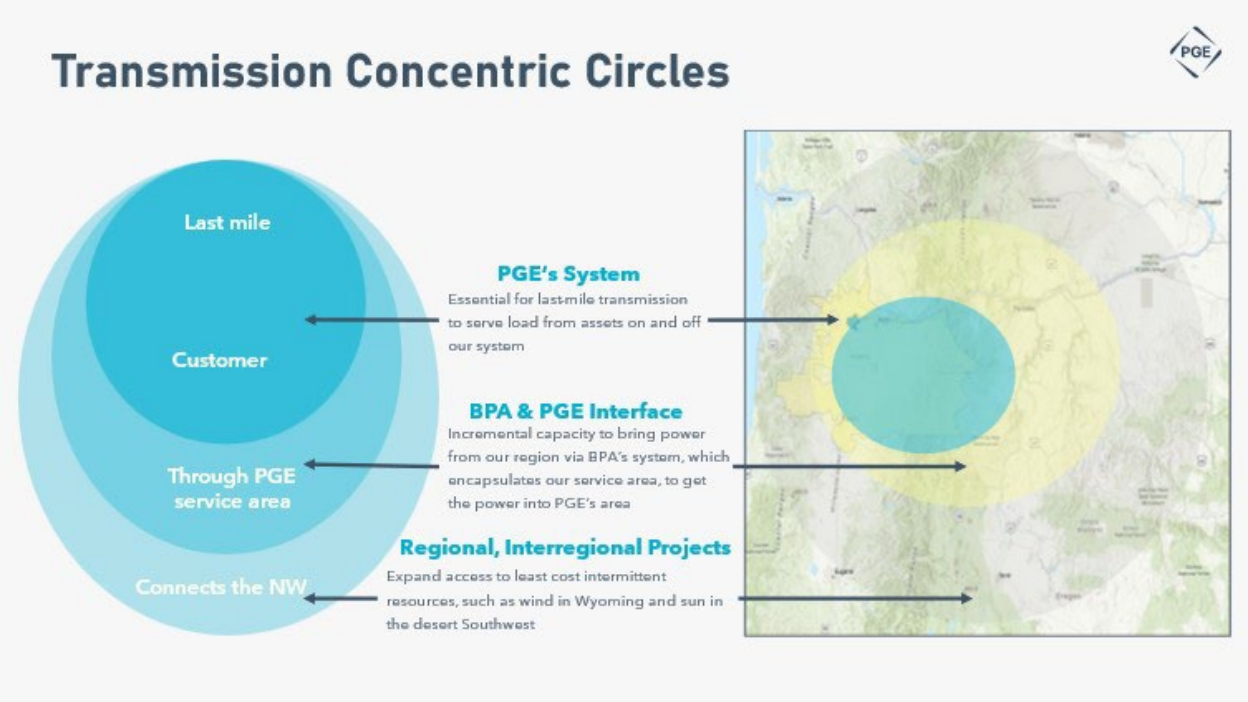
4.3 Transmission strategy/outlook

PGE will deploy a portfolio of strategies to meet future transmission needs and intends to explore expanding transmission access through the acquisition of rights on third-party systems, equity investment in regional projects as they are constructed, and PGE-developed projects, including upgrades of existing assets. PGE is also exploring Grid Enhancing Technologies (GETs), including actively putting in dynamic line ratings, with some of these projects utilizing advanced conductor and capacity enhancements. These different avenues of transmission expansion will allow PGE to optimize for the least cost and least risk plan to meet future needs and will continue to be discussed in the next full IRP.

4.3.1 Concentric circles of transmission

As PGE assesses strategies to meet load growth obligations and decarbonization goals and HB 2021 requirements, PGE must ensure transmission capacity is available from geographically diverse resources. Often, delivering energy to PGE's system requires multiple segments of transmission lines. Because PGE's network load is centralized in a compact service area, instead of dispersed out in multiple areas of load, PGE utilizes a concentric circle model to contemplate available transmission options, displayed below in **Figure 31**.

Figure 31. PGE Transmission Concentric Circles



4.3.1.1 PGE's system

The inner most circle in the model, 'Circle One', is predominantly used to move power through PGE's system for the purposes of safely and reliably serving PGE network load. It is important to remember that PGE network load includes PGE retail customer loads and also the loads of ESS customers and other transmission customers. PGE performs a series of annual transmission planning and reliability assessments. As Circle One on the system is planned, not only must PGE network load be accounted for, but also the potential for energy to flow through PGE's system enroute to other utilities in the western interconnection. These routine transmission planning efforts identify the projects necessary to reliably and safely serve PGE load, accounting for transmission service requested through PGE's service territory, and accounting for the impact regional resource dispatch patterns can have on PGE's transmission system.

4.3.1.2 Connecting PNW to PGE's transmission system

'Circle Two' in the model connects PGE's service territory to BPA's system and the rest of the PNW transmission system. Because PGE's service area is so concentrated in the northern Willamette Valley and new non-emitting generation resources will be generally located in remote geographic locations, PGE must determine how to best enable resources to reach the system. An example of Circle Two transmission would be transmission that enables energy to cross the Cascades enroute to PGE or adds additional capacity to the South of Allston flow gate flowing from north of the Portland Metro area.

4.3.1.3 Connecting the PNW to other regions

'Circle Three', the outer most circle, connects the PNW to other resource rich regions like the Dakotas and eastern interconnection, Rocky Mountains, and the Desert Southwest. Projects that connect multiple regions are often proposed and developed by large independent transmission companies who can more easily absorb the additional risk these large ambitious projects carry.

4.3.1.4 Grid Enhancing Technologies (GETs)

GETs are solutions that aid in the optimization of existing grid infrastructure. These technologies help PGE more effectively manage power flow for the aim of increasing capacity, efficiency and reliability on the system and to reduce the need for more costly grid expansion. The categories below detail GETs in use and planned for PGE's service area.

Dynamic Line Ratings (DLRs)

PGE is integrating DLRs beginning 2025 through partnership with the Electric Power Research Institute (EPRI) and BPA. DLRs are a method for determining available transfer capability of transmission lines utilizing real-time data to account for weather. DLRs can increase real-time capacities under favorable weather conditions (lower ambient temperature, higher wind speeds, and cloud shadowing) and derate capacities when weather is unfavorable. This additional operational flexibility is intended to help with reducing overloads due to unplanned outages or allow for better certainty of planned outages and system impacts. An impact analysis will be studied in 2025 and refined as the DLR system goes in-service and real time performance data becomes available over the second half of 2025.

Conductor Coating Technologies

PGE is integrating heat-dissipating overhead conductor coating technologies that reduce power loss and increase power carrying capacity. PGE's first use of the coating is for the 1.5 mile Horizon-Keeler #1 230 kV reconductor project is expected begin construction in 2026.

Topology Optimization

PGE utilizes switching of circuit breakers on the existing system to optimize power flow. PGE operations teams have long used this tool to more effectively change system flows as an alternative to costly options such as generation redispatch. PGE is upgrading a 230kV circuit breaker at the McLoughlin substation in 2025 to support this topology optimization practice.

Advanced Conductors

PGE is working with EPRI and other utilities on the Grid Enhancing Technologies for a Smart Energy Transition (GET SET) initiative to design and construct high temperature Aluminum Conductor Steel Supported (ACCS) lines in the territory. PGE has utilized ACCS conductors since 2006 to help ensure efficient power transmission and mechanical reliability across long-distance transmission lines and these new high temperature low sag conductors are already integrated in PGE's transmission planning studies.

4.3.2 Existing PGE projects/local transmission plan

*Refers to the inner circle in **Figure 31.***

To address the needs identified during PGE's transmission planning assessments, a local transmission plan is developed that identifies the portfolio of projects to meet the needs of PGE's customers and to maintain and operate a safe, resilient, and reliable system. Historically, PGE has focused on planning within the inner circle for reliable and load service-driven transmission given PGE's unique geographic footprint within BPA's system. This was primarily because BPA traditionally had ample ATC on their transmission system that PGE has been able to leverage to transfer new remote generation resources to PGE's system. With the recognition that ATC inventories on BPA's system have been fully allocated, and that changes in resource dispatch patterns have created a paradigm shift in regional flow patterns on the west-wide transmission system, PGE's transmission planning and strategy have necessarily evolved from an approach based primarily on reliability and load service to a more proactive approach that aligns with future load service needs (described in **Chapter 3 System needs**) as PGE decarbonizes. It is important to recognize the significant transmission planning and project development efforts already underway that are necessary for reliable load service and proper cost allocation within PGE's load service area. PGE's local transmission plan has identified more than 20 projects, discussed in **Section 4.2 PGE transmission projects**.

4.3.3 BPA projects important to PGE

*Refers to all circles in **Figure 31.***

PGE's and BPA's transmission systems are highly interconnected, both in PGE's service area and around Oregon and the PNW. Because of the highly networked nature of PGE's transmission systems, PGE has been collaboratively working with BPA to ensure BPA has sufficient system reinforcements planned that, in concert with PGE's planned transmission projects, will enable PGE to reliably serve load. As a result of this collaborative system planning, PGE and BPA have identified a suite of projects, both joint PGE-BPA projects and BPA-only projects as shown in **Table 13**, necessary for the safe and reliable operation of the region's transmissions system. Several joint projects are inflight that will help address the NOPE flowgate constraint. In addition to joint projects, BPA has identified several projects that only involve work to their infrastructure that will have significant impact for PGE and its customers. Several of them are currently in-flight or in the scoping phase.

Table 13. PGE-BPA and BPA-only Transmission Projects

PGE-BPA Transmission Projects	BPA-only Transmission Projects
Pearl-Sherwood-McLoughlin Bifurcation & Reconductor	Big Eddy-Chemawa Upgrade (Evolving Grid 1.0)
N. of Sherwood Reconductor	Keeler Transformer Bank Addition (Evolving Grid 1.0)
Horizon-Keeler #1 reconductor	Pearl-Keeler 500kV #2 (Evolving Grid 2.0)
Horizon-Keeler 4000A upgrades	North of Marion Upgrades (Evolving Grid 2.0)
Ross-Rivergate (BPA Evolving Grid 1.0 Project)	Ostrander-Pearl #1 Line Upgrade (Evolving Grid 2.0)
Harborton 230 kV Rearrangement	
Willamette Valley Resiliency Project	

Figure 32. PGE-BPA transmission projects

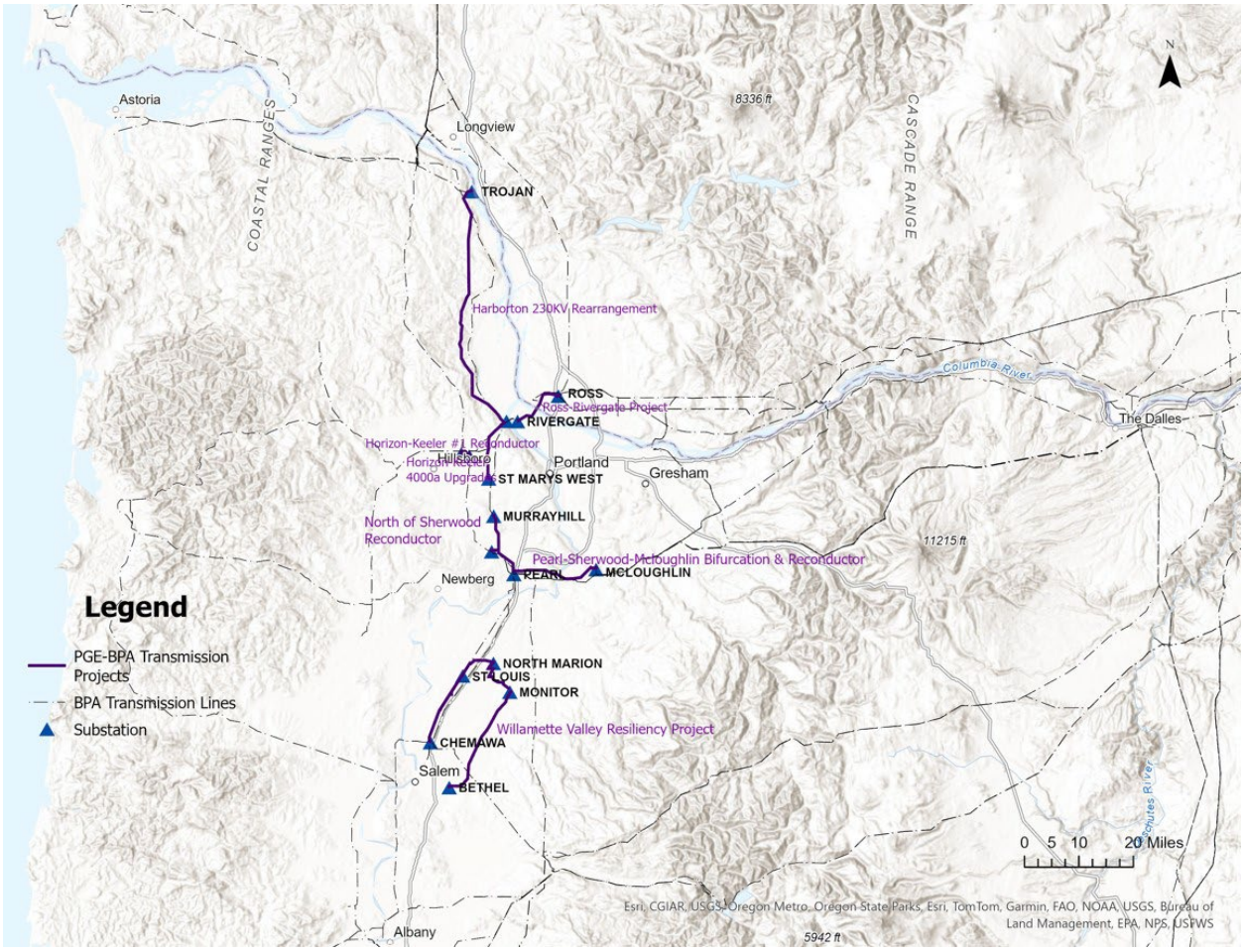
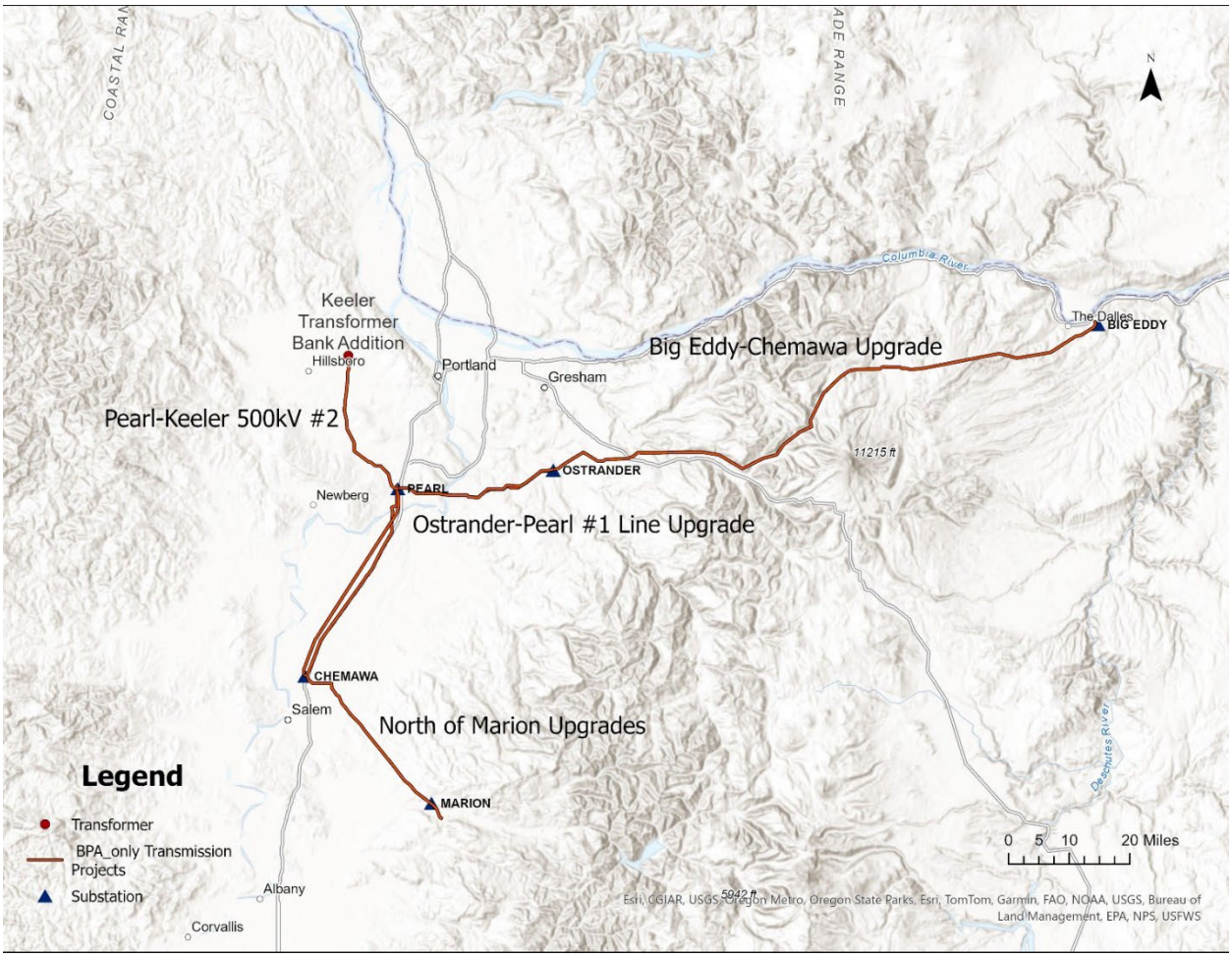


Figure 33. BPA-only transmission projects



4.4 Assessment of available BPA point-to-point transmission

Limitations on the region's transmission system constrain PGE's ability to access Pacific Northwest (PNW) renewable resources. For the 2023 CEP/IRP, PGE conducted a study of transmission service requests directed toward PGE in BPA's Transmission Study Request (TSR) Study and Expansion Process (TSEP) reports in order to estimate the quantity of transmission currently available. As part of the transmission-related assumptions and modeling in the 2023 CEP/IRP, PGE included these estimates of available capacity on BPA's transmission system as a resource build constraint in portfolio analysis. The total ATC available in the 2023 CEP/IRP was 1818 MW.[73]

PGE has refreshed these estimates for the Update with the most up-to-date data available. The updated values, shown in **Table 14**, are included as constraints on resource additions in portfolio analysis.[74] The total ATC has increased by 688 MW compared to the 2023 CEP/IRP to

[73] See Appendix H.7 of the filed 2023 CEP/IRP.
[74] The updated numbers and methodology were described by PGE in the October 2024 Roundtable Meeting. Available here:

2506 MW. Total ATC determines the quantity of resources that can be added to PGE's portfolio without incurring the costs associated with transmission upgrades or expansion (as described in **Section 4.6 Transmission options for portfolio analysis**).

Regional transmission constraints in the 2023 CEP/IRP required that each MW of new renewable resource had 1 MW of associated transmission capacity. In the Update, this assumption has been updated, with each MW of transmission capacity now allowing access to 1.33 MW of renewable resources (requiring that 75 percent of new resources have associated transmission rights).[75] This increases the quantity of accessible resources from 2506 MW to 3341 MW. Excluding offshore wind, which has additional constraints that push earliest COD in portfolio analysis out to 2036, this results in access to 2451 MW of off-system renewables prior to the first available transmission upgrade option in 2032. Transmission availability is identified by transmission zones, with the transmission zone associated with each proxy resource identified in **Table 15**.

Table 14. Transmission ATC by resource zone

Transmission Zone	Long-Term Firm	Conditional Firm	Total ATC
Christmas Valley	201	466	667
Gorge	179	418	667
McMinnville	45	105	150
Montana	96	224	320
Offshore	201	467	668
SE Washington	31	73	104
Total	753	1753	2506

https://assets.ctfassets.net/416ywc1laqmd/6Gv0U2lLocu2YCSnHv4JRP/43c13f8b70898a4476a4655f5f783fd4/IRP_Roundtable_October_24-6.pdf#page=23

[75] This modeling change was discussed in PGE's January 2025 Roundtable. Link: https://assets.ctfassets.net/416ywc1laqmd/7rqJJm9XGJaw6HPuh9Oz4L/7e071838b5f9cdfd7a9d9185b1fe0b53/CEP_IRP_Roundtable_January_25-1-74-.pdf#page=8

Table 15. Transmission zones of proxy resources

Transmission Zone	Proxy Resources
Christmas Valley	Christmas Valley Solar Christmas Valley Hybrids
Gorge	Gorge Wind Wasco Solar
McMinnville	McMinnville Solar McMinnville Hybrids
Montana	Montana Wind
Offshore	Offshore Wind
SE Washington	Southeast Washington Wind

4.5 Third-party assessment of PGE regional transmission options

In response to Staff comments on the transmission action item and modeling from LC 80 Order 24-096, PGE contracted with two third-party consultants to more thoroughly evaluate viable transmission options and their modeled benefits.

First, PGE contracted with Energy Strategies to assess transmission options identified by PGE, their general viability and any alternative, related CODs, and firm MW access assumptions.[76] Three key categories of changes resulted from Energy Strategies' analysis, which were incorporated as seven transmission options into PGE's modeling as discussed in **Section 4.6 Transmission options for portfolio analysis**:

1. Two alternative projects were identified to replace PGE's options of TransWest Express for accessing Wyoming Wind Proxy Resources and Western Bounty for access to Nevada Solar Proxy Resources. Energy Strategies proposed these alternatives due to policy, price, and timeline risks with WesternBounty and TransWest Express.
2. CODs were adjusted outward into the future based on Energy Strategies' understanding of project statuses and best estimates of completion timelines.
3. MW access assumptions were adjusted downward to account for Energy Strategies' assessment of ATC and rights on the identified transmission paths.

Second, PGE contracted with Energy GPS to conduct a market liquidity analysis for energy markets adjacent to the Pacific Northwest.[77] This analysis developed an understanding of the added benefit that a given transmission project may provide through its connection to a broader but nearby market. To estimate the additional market access benefits of a transmission project, Energy GPS analyzed correlations in PGE's hours of greatest load with high load hours in CAISO, Desert Southwest (DSW), Midcontinent ISO (MISO) North, and Southwest Power Pool (SPP) North

[76] PGE's January 2025 Roundtable - Transmission Options. See also **Appendix J Transmission options study**.
[77] PGE's November 2024 Roundtable - Transmission - Step 3 - Market Access.

markets. The analysis resulted in two key conclusions, which PGE incorporated into each modeled transmission option's market access benefits:

1. It is reasonable to assume transmission to SPP North or MISO North can provide access to energy and capacity during critical hours for both summer and winter.
2. It is reasonable to assume transmission to DSW or CAISO markets can provide access to energy and capacity during critical hours during winter.

4.6 Transmission options for portfolio analysis

The transmission necessary to reach resource rich geographical locations can often rely on multiple segments of transmission infrastructure to reach from generation site to where demand is located. PGE continues to analyze and explore all publicly known transmission project opportunities in the west that could be useful in serving PGE loads but generally do not directly connect to PGE. PGE identified a list of potential transmission projects within the BPA-PGE interface (Concentric Circle 2, as described in **Section 4.3.1 Concentric circles of transmission**) and greater region (Concentric Circle 3). These projects would provide access to proxy BPA resources such as Gorge Wind and Christmas Valley Solar, and proxy interregional resources such as North Dakota Wind and Nevada Solar. The resulting list provides known possibilities that may allow PGE to expand access to off-system renewable resources and markets. PGE continues to conduct analysis of these projects and will update this assessment in the 2026 CEP/IRP.

The remainder of this section describes project specific details of options modeled in the 2023 CEP/IRP Update based on Energy Strategies' analysis and the assumptions used in modeling transmission options.

Figure 34 illustrates the transmission options recommended for study by Energy Strategies.

Figure 34. Overview of PGE Transmission Options

4.6.1 Bethel-Round Butte upgrade

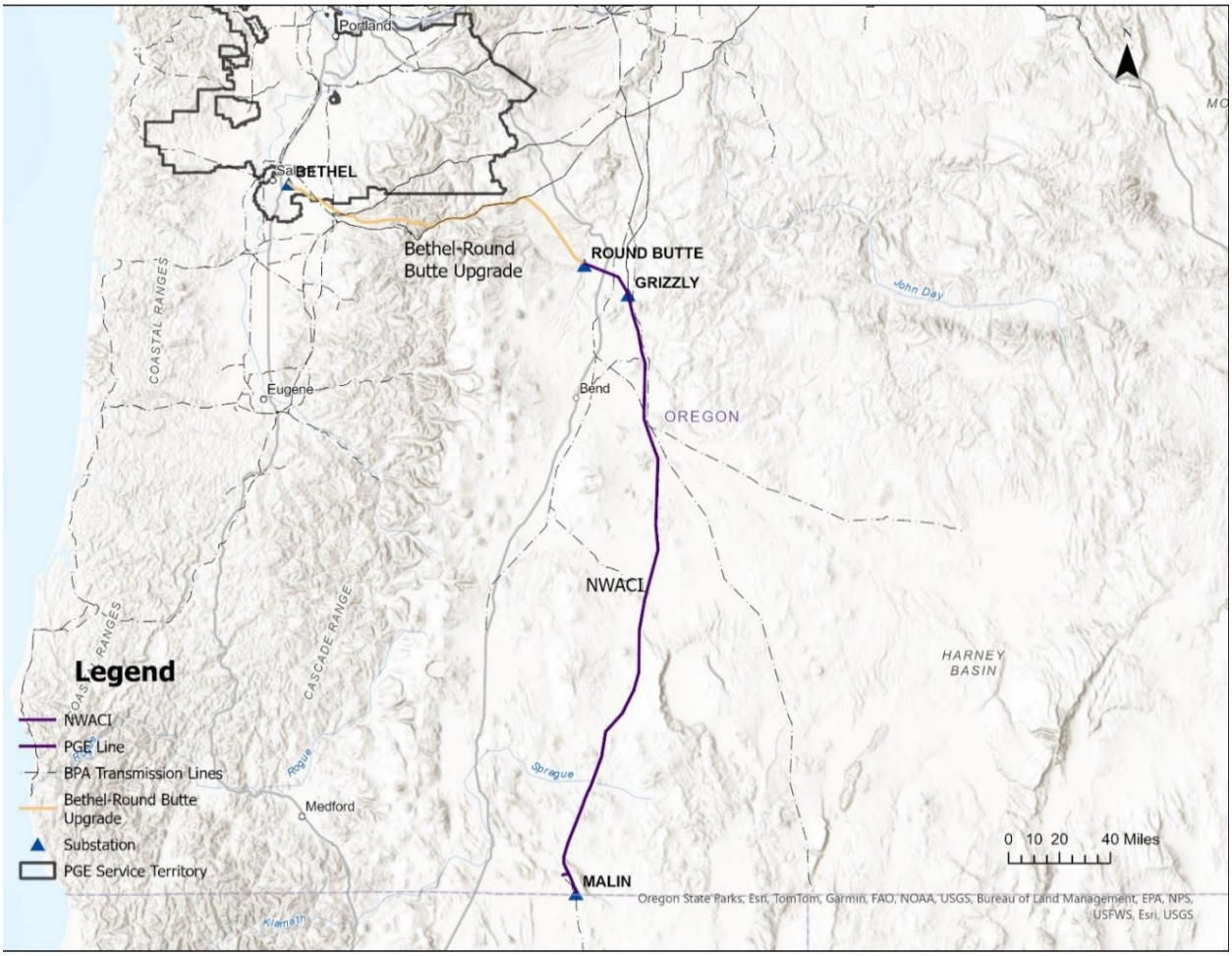
Bethel-Round Butte transmission project is a 98-mile 230 kV line upgrade running between PGE's Bethel and Round-Butte substations at the south-east edge of PGE's service territory. The project plans to rebuild the existing transmission line from 230 kV to 500 kV and build a second 500 kV line, enabling up to 3000 MW of additional resources from the BPA-PGE interface, or Concentric Circle 2 (**Section 4.3.1 Concentric circles of transmission**), to reach PGE's service territory. Resources within the BPA-PGE interface include: Wind Gorge, Wind SE WA, Solar CV, Solar MCMN, Solar Wasco, CV hybrids, and MCMN hybrids, and are resources that are assumed accessible by way of one wheel across BPA transmission infrastructure. Additionally, the project would increase access through the California Oregon Border (COB) to the CAISO market of 600 MW in winter.[78] The estimated commercial operation date (COD) for the upgraded line is 2032.

[78] PGE's November Roundtable - Transmission - Step 3 - Market Access.

The 2023 CEP/IRP characterized the Bethel-Round Butte transmission option as a valuable upgrade to the PGE system, necessary to integrate the scale of non-emitting resources required to offset fossil fuels.

In partnership with The Confederated Tribes of Warm Springs (CTWS), an application was submitted to the USDOE for a Grid Resilience and Innovation Partnerships (GRIP) Program grant for the Bethel-Round Butte upgrade. The GRIP application was successful, and a $250 million award was made to PGE's partners, the CTWS. The CTWS and PGE are currently in the process of developing the project.

Figure 35. Bethel-Round Butte Upgrade

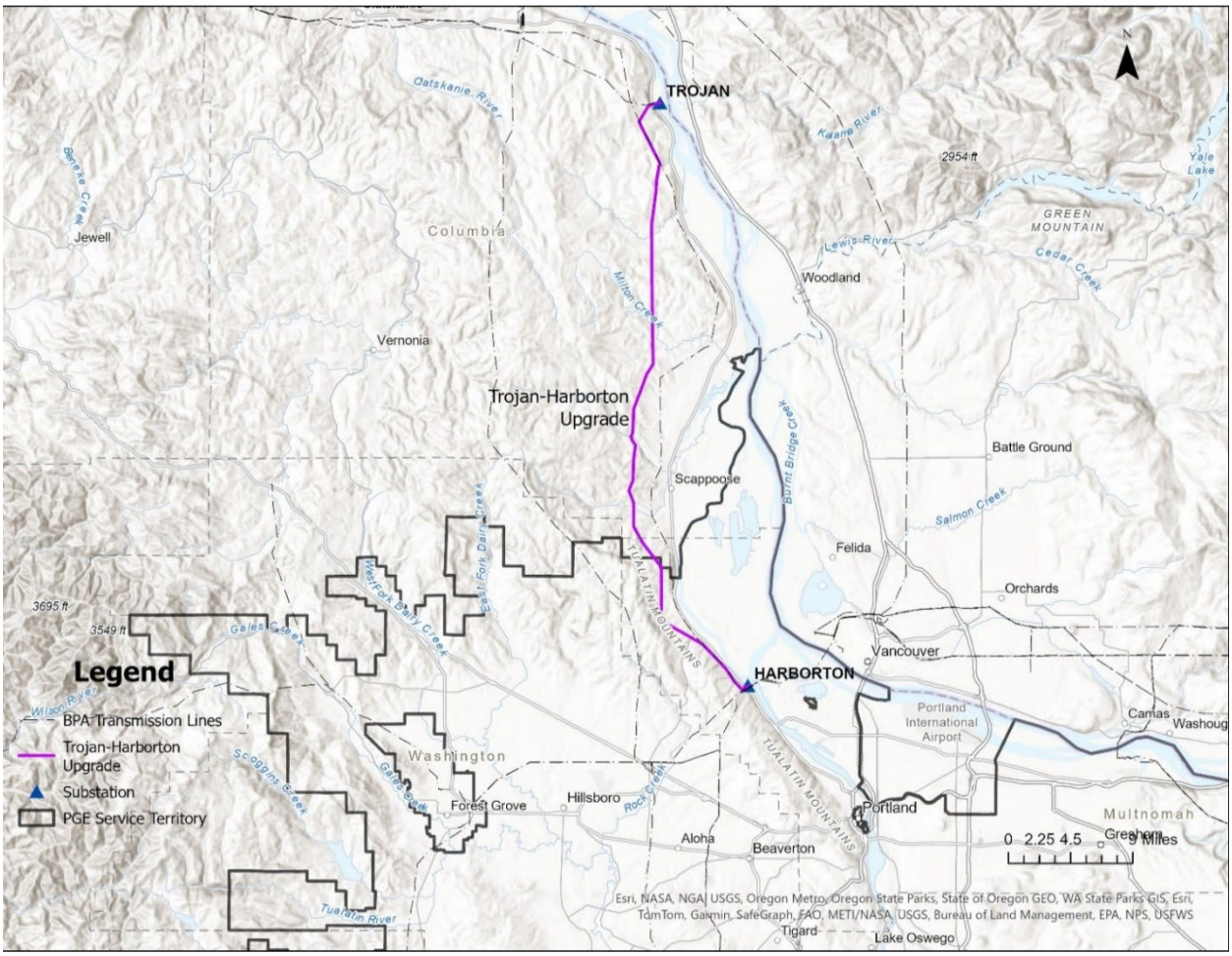


4.6.2 Harborton-Trojan upgrade

Harborton-Trojan Upgrade is a 34-mile 230 kV transmission option between these two PGE substations at the north-west edge of PGE's service territory. The project would run parallel to two existing PGE transmission lines, in service since the 1970s. PGE currently owns the right-of-way (ROW) necessary to complete this upgrade. The project is estimated to enable up to 800 MW from resources within the BPA-PGE interface to reach PGE customers, subject to cooperative

study and agreement with other South of Allston path owners, BPA and PacifiCorp. The anticipated COD of the project is 2035. It is assumed that the Harborton-Trojan option will provide no additional market-access benefits.[79]

Figure 36. Harborton-Trojan Upgrade



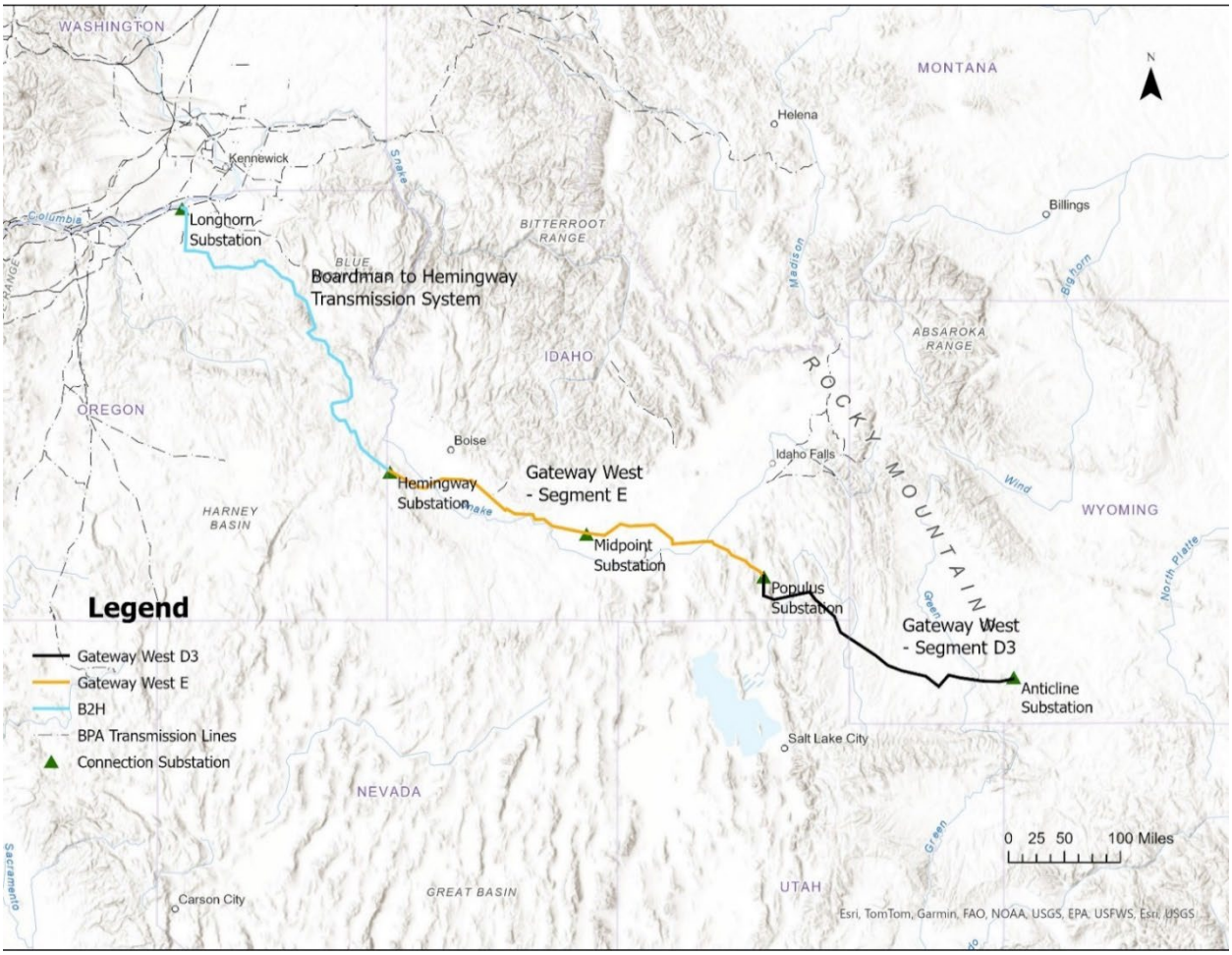
4.6.3 Gateway + B2H + Longhorn (Gateway)

The Gateway transmission option is modeled as the preferred path to access Wyoming Wind proxy resources. The Gateway option begins in western Wyoming, traversing 200 miles from Anticline to Populus substation along the Gateway West D-3 leg. The second segment covers 500 miles on Gateway West E segment where it terminates in Hemingway and then traverses 270 miles along the Boardman to Hemingway (B2H) leg. Finally, Longhorn to PGE is identified as a viable wheel to bring the energy to PGE service territory. The Gateway transmission option is estimated to provide up to 400 MW of capacity for Wyoming Wind by 2035. The 2035 COD reflects the expected timeline for new BPA Transmission Service Requests (TSRs) on the Longhorn to PGE leg. Additionally, Gateway is assumed to provide an additional 400 MW of

[79] PGE's November Roundtable - Transmission - Step 3 - Market Access.

market access during winter.[80] Securing firm transmission access for the Gateway option in the 2030's is uncertain due to competition with Pacific Power and Idaho Power Company and the required timely granting of transmission service requests.

Figure 37. Gateway Transmission Option



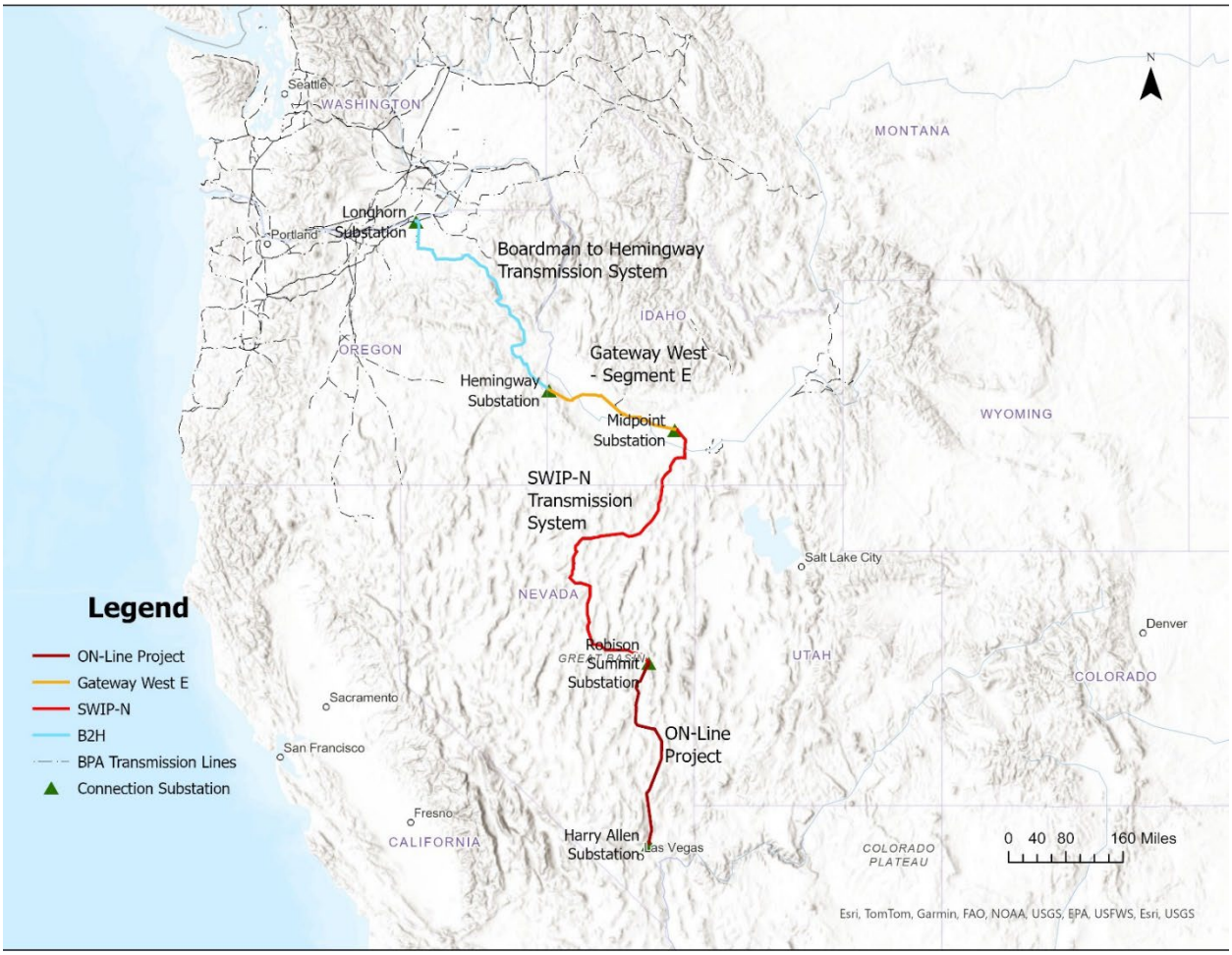
4.6.4 NVE + SWIP-N + Gateway + B2H + Longhorn (SWIP-N)

The SWIP-N transmission option includes approximately 673 miles of AC segments along the Southwest Intertie Project – North, Gateway West 8, and Boardman to Hemingway transmission projects. The option is composed of five segments, two of which are modeled as wheels. The first segment is represented as one wheel that captures PGE's need to move energy across the existing or committed NVE projects (Desert Link, ON-Line, Greenlink West, Greenlink North). Next, the option traverses the 275-mile Southwest Intertie Project – North project, then passes 128 miles along Gateway West 8 leg. The SWIP-N option utilizes the Boardman to Hemingway segment and a Longhorn to PGE wheel to bring energy to the PGE service territory. SWIP-N is estimated to provide capacity up to 400 MW of Nevada Solar by 2035 and an additional 400 MW

[80] PGE's November Roundtable - Transmission - Step 3 - Market Access.

of market access in winter.[81] The 2035 COD reflects the expected timeline for new BPA TSRs on Longhorn to PGE leg.

Figure 38. SWIP-N Transmission Option



4.6.5 North Plains Connector

The North Plains Connector (NPC) option includes a 412-mile 500kV HVDC incremental line segment and two additional wheels to reach PGE.[82] PGE has signed a non-binding memorandum of understanding with the developers of this line for a 20 percent stake (600 MW) in the 3000 MW line. Following PGE's MOU, on August 6, 2024, the US Department of Energy (USDOE) selected the NPC, in partnership with the State of Montana, for a $700 million GRIP grant. Pending the outcome of development and execution of definitive agreements, this significant GRIP grant is modeled to buy down the development costs for participation in the NPC project. Additionally, this grant apportioned $70 million for the upgrade of the Colstrip Transmission System (CTS).

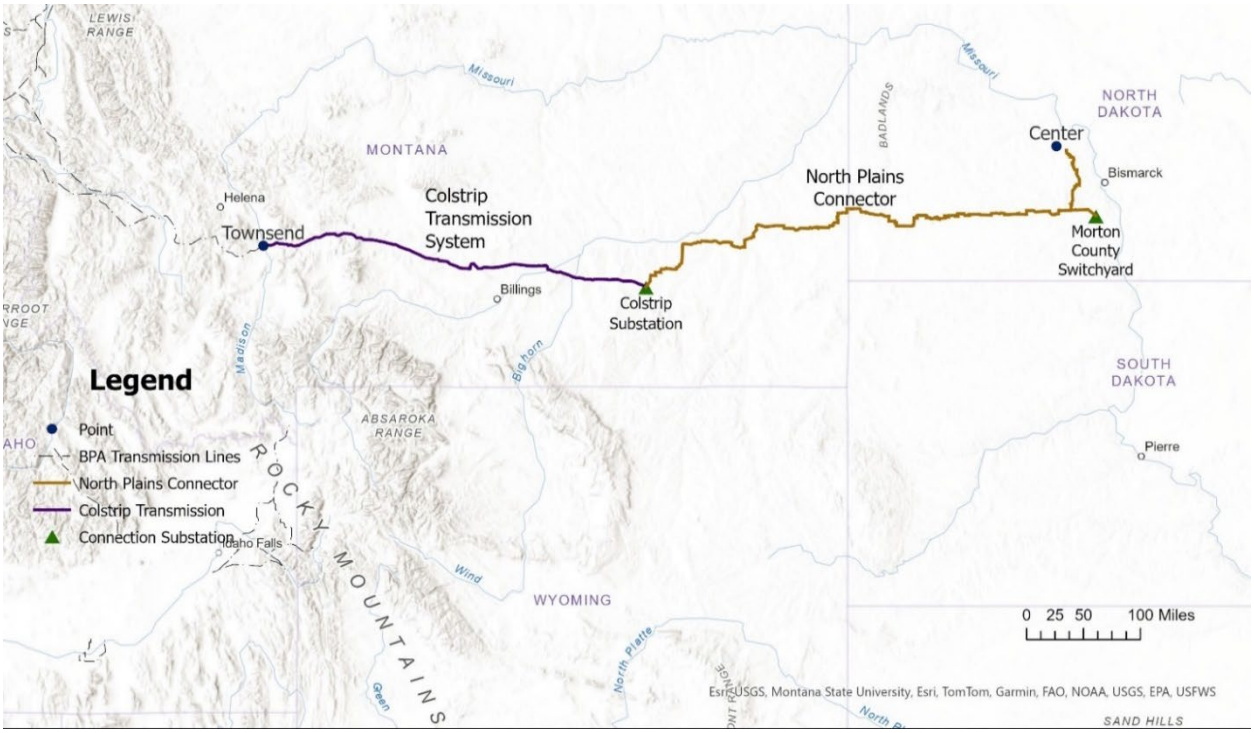
[81] PGE's November Roundtable - Transmission - Step 3 - Market Access
[82] The tariff charges incurred to transit both CTS and the Montana Intertie (Townsend-Garrison) are assumed equivalent to the rate of a BPA PTP+SCD wheel.

The NPC would allow PGE to utilize 270 MW of existing firm transmission to replace generation from Colstrip Units 3 & 4 with energy from some of the highest capacity factor renewable resources estimated as part of the 2023 CEP/IRP Update (Table 20). Further, the NPC connects to the Southwest Power Pool (SPP), and the Mid-Continent Independent System Operator (MISO) Zone 1 Market, where historical data suggests a surplus of supply during approximately 80 percent of PGE's highest demand hours.[83] As such, the NPC is a valuable transmission option for addressing PGE's winter reliability challenges as discussed in **Section 6.2.3 Preferred Portfolio resource adequacy testing**.

The NPC option is modeled to provide capacity up to 600 MW of North Dakota Wind proxy resource by 2038. This COD reflects expected timing to receive requested BPA and Northwestern (NWMT) TSRs. Six hundred MW represents what is assumed commercially available and aligns with PGE's existing transmission rights of 270 MW on CTS plus approximately 300 MW of firm and short-term rights on Northwestern path associated to PGE's Clearwater project. In addition, PGE has submitted TSRs for an additional 720 MW across BPA's and NWMT's system. Access to the benefits associated with the assumed 600 MW of potential capacity on this line requires that at least some of the additional submitted TSRs be approved. If submitted TSRs do not come to fruition, PGE's access to the capacity of the line would be only the current 270 MW of PGE's rights along the CTS. The 270 MW of firm transmission access across the CTS are available with the exit of Colstrip Units 3 & 4, assumed after 2029.[84] However, modeled access to these resources is not captured from 2030 to 2037. The NPC is modeled to provide access to an additional 600 MW of both summer and winter market access through its connection to the Eastern Interconnection, the SPP and MISO Zone 1.

[83] PGE's November Roundtable - Transmission - Step 3 - Market Access
[84] PGE's November Roundtable - Transmission - Step 3 - Market Access

Figure 39. North Plains Connector



4.6.6 NVE + Greenlink 3 + Cpt. Jack to Grizzly + BRB upgrade (Greenlink)

The Greenlink transmission option includes 300 miles of additional AC circuits, and one wheel along Nevada Energy (NVE) infrastructure. The Greenlink option is modeled with four line segments from generation site to PGE's service territory. The first segment is comprised of one wheel that captures PGE's need to move energy across the existing or committed NVE projects (Desert Link, ON-Line, Greenlink West, Greenlink North). Second, the path incurs 300 miles of incremental costs from Ft. Churchill substation in eastern Nevada to the Captain Jack substation near Path 66 at COB. Energy is then moved from Captain Jack to the Grizzly Substation, a point along the Northwest AC Intertie (NWACI) and adjacent to PGE's transmission footprint, using existing PGE rights. Finally, the path assumes the Bethel-Round Butte Upgrade is in place to bring the energy to PGE's service territory. The Greenlink option is estimated to provide PGE up to 627 MW of proxy solar resources from Nevada with an expected availability date of 2035. The COD reflects estimated timing of the Greenlink 3 segment from Fort Churchill to Captain Jack. Further, an additional 627 MW of market access in the winter is assumed.[85]

[85] PGE's November Roundtable - Transmission - Step 3 - Market Access.

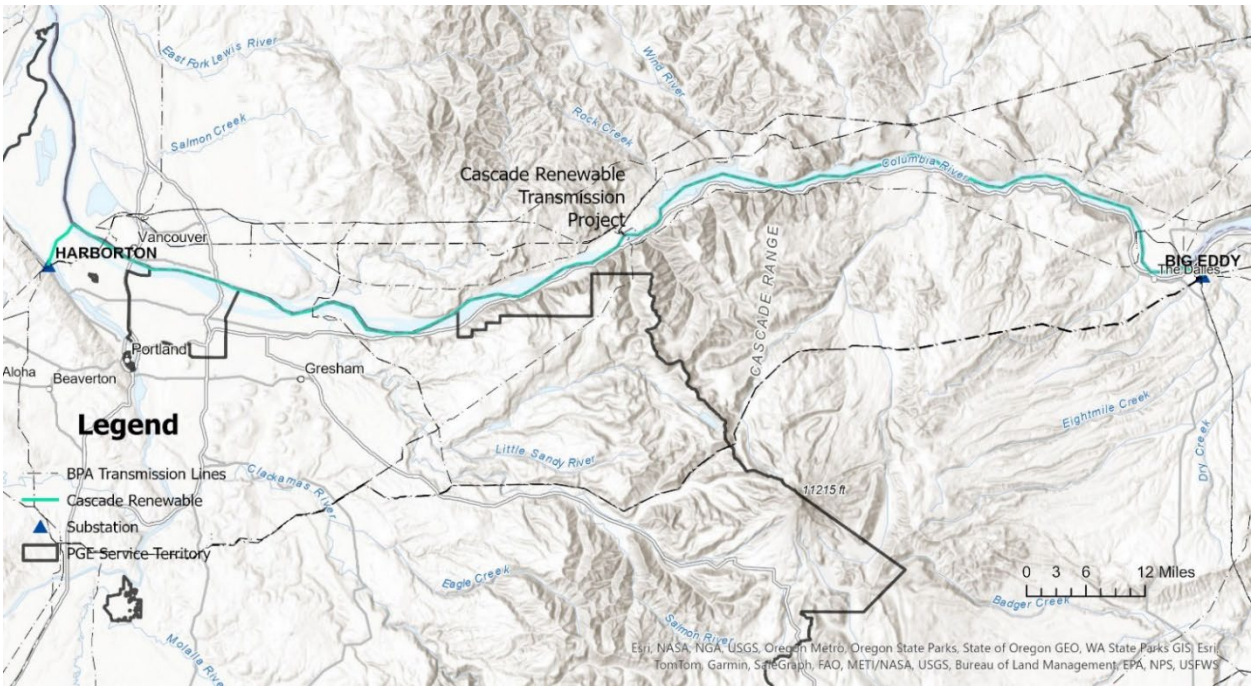
Figure 40. Greenlink Transmission Option

4.6.7 Cascade Renewable Transmission project

The Cascade Renewable Transmission Project (CRT) is an underwater HVDC transmission option of 100 miles that would route from BPA's Big Eddy substation near The Dalles, OR to PGE's Harborton Substation in NW Portland. The project is modeled as one incremental line of additional transmission. The project would allow up to 1100 MW of new east-west transmission capacity for PGE to access off-system proxy resources in the Pacific Northwest, such as Christmas Valley Solar and Southeast Washington Wind. The project will require additional BPA and PGE transmission expansion for PGE to access these benefits and is estimated available by 2038. Additionally, The CRT is assumed to provide no additional market access benefits.[86] PGE is not currently participating in CRT.

[86] PGE's November Roundtable - Transmission - Step 3 - Market Access.

Figure 41. Cascade Renewable Transmission Project



4.6.8 Transmission options summary

Table 16 provides a summary of the seven transmission options discussed above and their assumptions used for portfolio analysis.[87] PGE will continue to review and refine these options as part of the 2026 CEP/IRP.

Table 16. Transmission options

Project	COD[88]	Generation Resource	MW Available to PGE	Summer Market Access (% of MW Avail.)	Winter Market Access (% of MW Avail.)	Real-Levelized Cost ($/kW-mo)
Bethel-Round Butte	2032	BPA Resources	3000	0%	20%[89]	$ 5.52
Harborton-Trojan	2035	BPA Resources	800	0%	0%	$ 5.61
Gateway	2035	Wyoming Wind	400	0%	100%	$ 8.17

[87] BPA Generation resources refer to all Proxy Resources located within Concentric Circle 2 (**Section 4.3.1 Concentric circles of transmission**), including: Wind Gorge, Wind SE WA, Solar CV, Solar MCMN, Solar Wasco, CV hybrids, and MCMN hybrids.
[88] Project Commercial Operation Dates (CODs) represent the greatest COD for the underlying transmission segments.
[89] Assumed equivalent to PGE's existing rights at the California Oregon Border (COB).

Project	COD[88]	Generation Resource	MW Available to PGE	Summer Market Access (% of MW Avail.)	Winter Market Access (% of MW Avail.)	Real-Levelized Cost ($/kW-mo)
SWIP-N	2035	Nevada Solar	400	0%	100%	$ 9.56
North Plains Connector	2038	Montana & North Dakota Wind	600	100%	100%	$ 9.83
Greenlink	2035	Nevada Solar	627	0%	100%	$ 9.98
Cascade Renewable Tx Project	2038	BPA Resources	1100	0%	0%	$ 12.13

4.6.9 Transmission cost assumptions

The U.S. Department of Energy (DOE) "National Transmission Planning Study" and data from the GRIP are the primary sources used to calculate cost estimates for both AC and DC transmission options. All AC options are modeled as 500 kV single-circuit lines estimated at $2,048,670/mi and all DC options are modeled as 500kV HVDC circuits estimated at $4,600,000/mi.[90,91] Additionally, the DOE study provides terrain multipliers for AC options that are used to scale per mile estimates.[92] Federal cost share of GRIP awards was then subtracted from the estimated cost of a transmission option, where applicable.[93] These assumptions along with a project's estimated transfer capacity are used to derive costs for incremental transmission lines, those uncommitted projects that would require PGE ownership. Costs estimated are based on publicly available data and should be interpreted as a general estimate of the direct cost of line construction and do not account for additional development costs such as profit, balance of plant, permitting, procurement, and overheads.

Some transmission options required existing energized or committed projects to bring (wheel) energy home to PGE's service territory. Additional costs to wheel energy for such segments are included in the total cost for an option. The assumed rate for a wheel is $1.96 /kW-mo, based on BPA Point-to-Point Scheduling, System Control and Dispatch (PTP + SCD) costs for 2024. Lastly,

[90] U.S. Department of Energy. *The National Transmission Planning Study*. Ch 3. p.127.
[91] U.S. Department of Energy. The National Transmission Planning Study. Ch 3. p.70.
[92] Terrain multipliers are not identified for HVDC projects. Public information on project specific costs for HVDC options was used to calculate terrain multipliers for those HVDC projects.
[93] https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program-projects.

all projects are assumed to carry a $4.81 /kW-mo real-levelized cost for operations and maintenance in 2024 dollars.