Commercial Power Flow Study
February – March 2024

For Evaluation of Long-Term Transmission Service Requests
and Network Integrated Transmission Service Forecasts
Queued December 2023/January 2024

Updated May 23, 2024

Objective

The objective of the Commercial Power Flow Study is to use scenario analysis to capture anticipated Network path utilization of new Point-To-Point (PTP) Transmission Service Requests (TSRs) and/or Network Integration Transmission Service (NT) load and resource forecasts – collectively referred to as TSR/FTSRs. The results are then used to determine whether sufficient transmission capacity exists to offer any firm service and/or encumber capacity for forecasted needs without further study or system upgrades, taking into consideration the capacity needed to enable earlier-queued TSR/FTSRs. Offers of service and/or forecast encumbrances resulting from this Study honor queue priority.

This document identifies any resulting paths of constraint for new TSR/FTSRs (as identified by the Commercial Power Flow study or 1:1 path ATC), as well as any potential subgrid limitations. If no path or subgrid constraints are identified for a TSR/FTSR, it will be considered awardable.

TSRs impacting the AC, DC, Montana Intertie, or RATS line were not included in this study and are evaluated solely using Long-Term ATC and subgrid findings.

Methodology

BPA has developed scenarios based on groupings of TSR/FTSRs in the Long-Term Pending Queue with similarly situated Point of Receipt (POR) location and/or expected resource type, and by considering which market and weather conditions may induce the greatest firm transmission utilization on Network paths. These scenarios are described in further detail in the “Scenarios and Descriptions” section of this document.

Cases representing three seasonal load and generation profiles were used as a starting point for the study, with additional adjustments made depending on scenario descriptions (described in further detail below). Northwest (Area 40) load was 35,681 MW in winter peak, 20,595 MW in light spring, and 32,368 MW in summer peak scenarios. Reference cases were developed by modifying loads according to the scenario descriptions. NT loads were increased if forecasts within the starting cases were lower than levels accepted through the NT Annual Load and Resource Forecasting process.

As TSR/FTSRs were modeled, a pre-determined and unique resource displacement approach was implemented for each scenario. For thermal units in the Pacific Northwest, an approximate economic merit order was implemented using analysis of historical yearly capacity factors and Production Cost Model (PCM) yearly average capacity factors to determine the frequency of thermal generation contributing to the grid. The thermal heat rates and costs of running the plants were then used to further group the generation into categories: peaking/inefficient units, base load generation, or a generic group with the remaining thermal generators. Only the peakers/inefficient plants and generic group were considered flexible enough to be used within the thermal merit order groupings. Peakers and inefficient plants were assumed to be reduced first. Puget Sound area generation (SCL, PSE, and Snohomish) in Northwest Washington was not reduced to below 680 MW during the winter scenarios, as agreed upon by BPA and PSANI Transmission Planners and documented in various regional studies. For FCRPS hydro merit order estimation, resource displacement categorized “flexible hydro” resources based on input from BPA Long-Term Power Planning staff and existing minimum generation requirements. Economic merit order adjustments are provided with more detail in the scenario descriptions (below).

The scenario cases provide a thorough representation of potential future path utilization, and the exceedance of a path’s commercial Total Transfer Capability (TTC) within any scenario case signals an inability for BPA to offer additional service to and/or encumber capacity for TSR/FTSRs with non-*de minimis* impacts on the path. Queue priority is taken into account when determining whether the studied TSR/FTSR exceeds TTC. TSR/FTSRs with impacts beyond the capacity threshold for a particular path (with non-*de minimis* impacts on said path) will not receive an offer of Transmission Service and/or have capacity encumbered. They will remain in STUDY status in OASIS while additional evaluation is performed (either via TSEP or individual studies) and capacity becomes available or the (F)TSR is DECLINED by BPA or WITHDRAWN or otherwise modified by the customer.

Subgrid analysis takes place externally to the Commercial Power Flow study and considers localized constraints not currently enveloped by Network path definitions.

General Description of New TSR/FTSRs

The Long-Term Pending Queue includes TSR/FTSRs requesting service and/or forecasting needs from identical resources or interconnection points which were then grouped together for analysis. BPA staff have tried to identify conditions in which new modeled resources would have the largest effect on Network paths based on POR locations and expected resource fuel type. These TSR/FTSRs and potential new resources informed the scenarios described in this document.

The tables below show the resource and delivery clusters of the previously unstudied requests analyzed in this Commercial Power Flow Analysis. Table 1 shows the total requested demand for this assessment is 2,500 MW.

Table 1

	Delivery Point Cluster				
Resource Cluster	**Central WA**	**NW Market Hub**	**PDX**	**SE WA/ NE OR**	**Grand Total**
Albany-Eugene 115			80		80
Buckley 500	320	160		160	640
Buckley-Marion 500	160	160			320
Diamond Butte 500	160	160			320
Longhorn 500	160	160			320
Stanfield 500	320	240			560
Vantage 230		260			260
Grand Total	**1120**	**1140**	**80**	**160**	**2500**

Depending on which scenario is being analyzed, unstudied TSR/FTSRs may not be assumed to operate simultaneously in each of the power flow cases. This approach assumes that new wind and solar TSR/FTSRs are only modeled in the scenarios that specify wind on and/or solar on. In addition, TSR/FTSRs are not modeled in scenarios where the POR/POD combination is in the opposite direction of the prevailing flows in the basecase since we do not assume those rights to be exercised to create counterflow, which would increase availability in the prevailing direction. For scenarios where all thermal generation in the merit order stack has been completely displaced, unstudied thermal TSR/FTSRs are not modeled in the power flow cases because it is expected that those resources would also not be utilized. Energy storage is assumed to be discharging during the summer sunset hour and is otherwise discharging as a sensitivity, but only if the co-located generation is not online.

Scenarios and Descriptions

The following is a brief description of each scenario, and the Network paths expected to heavily load.

Summer Sunset Hour with No Wind, No Solar, with Battery Discharge

This scenario reflects an hour near sunset (around 7:00 pm) with high north-to-south flows across the BPA Network. When the sun is going down and wind is not generating, the gas fleet and flexible hydro chase high spot power prices. This aligns with an observed pattern from recent summers where the peak South of Allston flow has shifted to a later hour in the day, due to increasing solar buildout in California. Due to the late hour of the day, the Pacific Northwest load in this scenario was adjusted to 80% of the original peak value, scaling only non-fixed loads, which freed up enough spare resources to export to California but also reduced counter flow from serving Puget Sound area loads. The magnitude of the California solar ramp is projected to get steeper each year for the foreseeable future. Lower Snake and Lower Columbia hydro typically have less flexibility than Upper Columbia hydro due to non-power constraints. The COI and PDCI could be modeled up to their full N>S path capacities as resource levels allowed, and we would expect higher flows on North of Hanford due to this.

The 20% reduction in Pacific Northwest loads also affected NT load values and the obligation to serve them from the FCRPS. A pro-rata reduction in the Big 10 generation equal to the decrease in NT load forecasts was performed and balanced through decreased flows to California.

This would potentially stress South of Custer, West of Slatt, North of Hanford, North of Grizzly, and the I-5 corridor.

For this scenario, the case was balanced by:

- Reducing thermal generation based on economic merit order dispatch.

Summer Sunset Hour with Wind, No Solar, with Battery Discharge

This scenario also reflects an hour near sunset (around 7:00 pm) at 80% of peak load, but with north-to-south exports to California potentially driven higher by Northwest wind generation at full contract rights. Historical analysis points to a regular occurrence of summer sunset conditions with wind generation operating over a wide range of outputs.

This would potentially stress West of Slatt, West of McNary, West of John Day, North of Grizzly, and the I-5 corridor, particularly Raver - Paul.

For this scenario, the case was balanced by:

- Reducing Upper Columbia hydro generation.

Summer Peak Hour with Solar, No Wind

This scenario represents a traditional peak summer afternoon when Northwest end-use demand peaks, but additional solar generation coming online serves local load and surplus power is sent to California. Solar and dispatchable resources should both be high because of peak loading and the time of day. Exports to California are more moderate. This scenario was traditionally the most limiting on the I-5 corridor prior to the recent solar buildout, where peak flow hours occurred in the afternoon rather than sunset hours.

This would potentially stress the West of Slatt, West of McNary, West of John Day, and the I-5 corridor.

For this scenario, the case was balanced by:

- Reducing thermal generation based on economic merit order dispatch.

Summer Peak Hour with High Renewables

This scenario assumes availability of both wind and solar generation during peak summer hours, offsetting the use of dispatchable resources. This would represent aggressive carbon policies and/or Renewable Portfolio Standard (RPS) requirements. Exports to California would be at moderate or high levels, as California power prices could still exceed Northwest prices during this condition.

This would potentially stress West of Slatt, West of McNary, West of John Day, and the I-5 corridor.

For this scenario, the case was balanced by:

- Reducing Upper Columbia hydro generation.

Spring Mid-day Hour with High Renewables

This scenario represents a moderately high load hour in the middle of an early spring day, before the peak of the Columbia River System runoff. To represent the potential impacts of Oregon and Washington state clean energy policies, thermals are assumed offline. Pacific NW hydro generation is low to facilitate utilization of renewables. Most interties are initially assumed to be floating or at low interchange levels, with exports to BC driving flows in a south-to-north direction across the transmission system.

This would potentially stress North of Pearl and North of Echo Lake.

For this scenario, the case was balanced by:

- Reducing Northwest (area 40) wind generation pro rata based on firm and requested rights.

Spring Night Hour with Runoff, NW Wind/Solar OFF, and MT Wind ON

In this scenario, the Northwest has surplus energy and very low spot market prices, which leads to high exports on the Northern and Southern Interties. The sun may have gone down but we have abundant hydro and high wind generation imports from Montana. The Northwest is sending power to BC on the Western interconnection of the Northern Intertie so they can store additional water, and sending low or zero cost power to California so they can capitalize on the Northwest runoff instead of utilizing thermals after the sunset.

This would potentially stress North of Hanford, West of Hatwai, West of Garrison, North of Echo Lake, West of Lower Monumental, North of Grizzly, and West of Slatt.

For this scenario, the case was balanced by:

- Reducing thermal generation based on economic merit order dispatch.

<u>Winter Mid-Day Hour with High Renewable Availability</u>

This scenario reflects a sunny mid-day hour during a cold snap (around 11:00 am) with exports to BC Hydro. This scenario assumes British Columbia will be even colder than the Northwest and also experiencing near-peak loads. High availability of renewable resources within the Northwest provides BC with the opportunity to save water for later peak hours. Due to the hour of the day, the Pacific Northwest load in this scenario was adjusted to 90% of the original peak value. Montana is assumed to be consuming the available power from its local resources, as their winter weather is often more extreme. Imports from California are modeled until an oversupply within the Northwest occurs. This scenario aligns with peak North of Echo Lake S>N flows in Production Cost Model analysis.

The 10% reduction in Pacific Northwest loads also affected NT load values and the obligation to serve them from the FCRPS. A pro-rata reduction in the Big 10 generation equal to the decrease in NT load forecasts was performed and balanced through increased production at lowest-cost thermal resources.

This would be expected to stress North of Echo Lake, Cross Cascades North, and Cross Cascades South.

For this scenario, the case was balanced by:

- Increasing exports to California via the COI and PDCI.

<u>Winter Peak Hour with Wind, No Solar</u>

This is a high Northwest and Montana wind scenario with peak winter loads. Northwest generation is serving load centers west of the Cascades. Dispatchable thermal resources are running high, and solar is not available.

This would potentially stress Cross Cascades South, Cross Cascades North, West of Lower Monumental, North of Grizzly, and North of Echo Lake.

For this scenario, the case was balanced by:

- Increasing exports to California via the COI.

TSR/FTSR Analysis Results

AREF	Service Type	Start Date	Stop Date	Source	Sink	Demand (MW)	Transmission Constraints	TSR/FTSR Analysis Determination
Clearway Renew LLC					**1 TSR**	**260 MW**		
101584146	ORIGINAL LTF-YEARLY PTP	06/1/2026	06/1/2031	NEWPOINT (Vantage 230)	NWMRKTHUB(NWH)	260	No Network path or Subgrid constraints identified	Awardable
COR TX VII LLC					**27 TSRs**	**2160 MW**		
101827142	ORIGINAL LTF-YEARLY PTP	6/1/2030	6/1/2035	NEWPOINT (Stanfield 500)	MIDWAY230MIDCR	80	Subgrid: • NEWPOINT • MIDCREMOTE	Unawardable
101827148	ORIGINAL LTF-YEARLY PTP	6/1/2030	6/1/2035	NEWPOINT (Stanfield 500)	MIDWAY230MIDCR	80	Subgrid: • NEWPOINT • MIDCREMOTE	Unawardable
101827153	ORIGINAL LTF-YEARLY PTP	6/1/2030	6/1/2035	NEWPOINT (Buckley 500)	MIDWAY230MIDCR	80	Subgrid: • NEWPOINT • MIDCREMOTE	Unawardable
101827158	ORIGINAL LTF-YEARLY PTP	6/1/2030	6/1/2035	NEWPOINT (Buckley 500)	MIDWAY230MIDCR	80	Subgrid: • NEWPOINT • MIDCREMOTE	Unawardable
101827164	ORIGINAL LTF-YEARLY PTP	10/1/2032	10/1/2037	NEWPOINT (Stanfield 500)	MIDWAY230MIDCR	80	Subgrid: • NEWPOINT • MIDCREMOTE	Unawardable
101827168	ORIGINAL LTF-YEARLY PTP	10/1/2032	10/1/2037	NEWPOINT (Stanfield 500)	MIDWAY230MIDCR	80	Subgrid: • NEWPOINT • MIDCREMOTE	Unawardable
101827210	ORIGINAL LTF-YEARLY PTP	10/1/2032	10/1/2037	NEWPOINT (Buckley-Marion 500)	MIDWAY230MIDCR	80	Subgrid: • NEWPOINT • MIDCREMOTE	Unawardable
101827223	ORIGINAL LTF-YEARLY PTP	10/1/2032	10/1/2037	NEWPOINT (Buckley-Marion 500)	MIDWAY230MIDCR	80	Subgrid: • NEWPOINT • MIDCREMOTE	Unawardable
101827233	ORIGINAL LTF-YEARLY PTP	6/1/2030	6/1/2035	NEWPOINT (Stanfield 500)	NWMRKTHUB(NWH)	80	Subgrid: • NEWPOINT	Unawardable
101827236	ORIGINAL LTF-YEARLY PTP	6/1/2030	6/1/2035	NEWPOINT (Stanfield 500)	NWMRKTHUB(NWH)	80	Subgrid: • NEWPOINT	Unawardable

AREF	Service Type	Start Date	Stop Date	Source	Sink	Demand (MW)	Transmission Constraints	TSR/FTSR Analysis Determination
101827246	ORIGINAL LTF-YEARLY PTP	10/1/2032	10/1/2037	NEWPOINT (Buckley 500)	NWMRKTHUB(NWH)	80	Subgrid: • NEWPOINT	Unawardable
101827248	ORIGINAL LTF-YEARLY PTP	10/1/2032	10/1/2037	NEWPOINT (Buckley 500)	NWMRKTHUB(NWH)	80	Subgrid: • NEWPOINT	Unawardable
101827251	ORIGINAL LTF-YEARLY PTP	10/1/2032	10/1/2037	NEWPOINT (Stanfield 500)	NWMRKTHUB(NWH)	80	Subgrid: • NEWPOINT	Unawardable
101827254	ORIGINAL LTF-YEARLY PTP	6/1/2030	6/1/2035	NEWPOINT (Buckley-Marion 500)	NWMRKTHUB(NWH)	80	Subgrid: • NEWPOINT	Unawardable
101827267	ORIGINAL LTF-YEARLY PTP	6/1/2030	6/1/2035	NEWPOINT (Buckley-Marion 500)	NWMRKTHUB(NWH)	80	Subgrid: • NEWPOINT	Unawardable
101827269	ORIGINAL LTF-YEARLY PTP	6/1/2030	6/1/2035	NEWPOINT (Buckley 500)	MRWFLAT230UEC	80	Subgrid: • NEWPOINT • Umatilla Area	Unawardable
101827279	ORIGINAL LTF-YEARLY PTP	10/1/2032	10/1/2037	NEWPOINT (Buckley 500)	MRWFLAT230UEC	80	Subgrid: • NEWPOINT • Umatilla Area	Unawardable
101827286	ORIGINAL LTF-YEARLY PTP	6/1/2030	6/1/2035	NEWPOINT (Buckley 500)	MIDWAY230MIDCR	80	Subgrid: • NEWPOINT • MIDCREMOTE	Unawardable
101827290	ORIGINAL LTF-YEARLY PTP	10/1/2032	10/1/2037	NEWPOINT (Buckley 500)	MIDWAY230MIDCR	80	Subgrid: • NEWPOINT • MIDCREMOTE	Unawardable
101827300	ORIGINAL LTF-YEARLY PTP	6/1/2030	6/1/2035	NEWPOINT (Diamond Butte 500)	MIDWAY230MIDCR	80	Subgrid: • NEWPOINT • MIDCREMOTE	Unawardable
101827303	ORIGINAL LTF-YEARLY PTP	6/1/2030	6/1/2035	NEWPOINT (Diamond Butte 500)	MIDWAY230MIDCR	80	Subgrid: • NEWPOINT • MIDCREMOTE	Unawardable
101827310	ORIGINAL LTF-YEARLY PTP	6/1/2030	6/1/2035	NEWPOINT (Longhorn 230)	MIDWAY230MIDCR	80	Subgrid: • NEWPOINT • MIDCREMOTE	Unawardable
101827317	ORIGINAL LTF-YEARLY PTP	6/1/2030	6/1/2035	NEWPOINT (Longhorn 230)	MIDWAY230MIDCR	80	Subgrid: • NEWPOINT • MIDCREMOTE	Unawardable
101827320	ORIGINAL LTF-YEARLY PTP	10/1/2032	10/1/2037	NEWPOINT (Diamond Butte 500)	NWMRKTHUB(NWH)	80	Subgrid: • NEWPOINT	Unawardable
101827326	ORIGINAL LTF-YEARLY PTP	10/1/2032	10/1/2037	NEWPOINT (Diamond Butte 500)	NWMRKTHUB(NWH)	80	Subgrid: • NEWPOINT	Unawardable
101827329	ORIGINAL LTF-YEARLY PTP	10/1/2032	10/1/2037	NEWPOINT (Longhorn 230)	NWMRKTHUB(NWH)	80	Subgrid: • NEWPOINT	Unawardable
101827331	ORIGINAL LTF-YEARLY PTP	10/1/2032	10/1/2037	NEWPOINT (Longhorn 230)	NWMRKTHUB(NWH)	80	Subgrid: • NEWPOINT	Unawardable

AREF	Service Type	Start Date	Stop Date	Source	Sink	Demand (MW)	Transmission Constraints	TSR/FTSR Analysis Determination
TX NW I LLC					**2 TSRs**	**80 MW**		
102005891	REDIRECT LTF-YEARLY PTP	1/1/2027	1/1/2032	NEWPOINT (Albany-Eugene 115)	PGE_CNTGS	40	Network paths: • South of Allston N>S • North of Pearl S>N	Unawardable
102005957	REDIRECT LTF-YEARLY PTP	1/1/2029	1/1/2034	NEWPOINT (Albany-Eugene 115)	PGE_CNTGS	40	Network paths: • South of Allston N>S • North of Pearl S>N	Unawardable