Commercial Power Flow Study
December 2023 – January 2024

For Evaluation of Long-Term Transmission Service Requests
and Network Integrated Transmission Service Forecasts
Queued October/November of 2023

January 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 32,760 MW in winter peak, 18,738 MW in light spring, and 29,278 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 3,747 MW.

Table 1

	Delivery Point Cluster						
Resource Cluster	**Central WA**	**Mid C**	**PDX**	**SE WA/ NE OR**	**Seattle-North**	**Seattle-South**	**Grand Total**
Ashe-Marion 500	1038			500	300		1838
COI						3	3
Idaho						126	126
John Day-Marion 500	550		148	150	50		898
Mid-C Market Purchase						2	2
Montana (Garrison 230/500)	100	200			100	400	800
Union Gap 230	80						80
Grand Total	**1768**	**200**	**148**	**650**	**450**	**531**	**3747**

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.

Cumulative Demand

There are instances where a customer submitted multiple TSR/FTSRs with demand in excess of the existing or Generation Interconnection (GI) generation capability cited in their corresponding Data Exhibits (e.g. 300 MW of TSR/FTSRs all cite the same generating facility with 100 MW of maximum capability). Based on subsequent written correspondence between BPA and these customers, BPA was able to confirm that either their intention was to execute contracts only up to the cited generation amount, or the customer provided additional cited generation to support the full TSR/FTSR demand. As a result, for those cases in which the customer communicated that they did not intend to execute transmission service in excess of their cited generation, BPA only modeled an output up to their cited resource capability. Customers who modified Data Exhibits to include additional generation removed any potential cumulative demand issue associated with their Transmission Service Reservations and were modeled to the full demand of their TSR/FTSRs. Table 2 is the list of customer(s) for which the cumulative demand scenarios are applicable:

Table 2

Customer	GI#	TSR Demand (MW)	TSR Modeled (MW)
Brookfield Renewable Trading and Marketing	G0711/G0712	898	748
Brookfield Renewable Trading and Marketing	G0344	588	488
Brookfield Renewable Trading and Marketing	G0687	1250	900

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.

Winter Mid-Day Hour with High Renewable Availability

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.

Winter Peak Hour with Wind, No Solar

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
Brookfield Renewable Trading and Marketing					**21 TSRs**	**2736 MW**		
101455642	ORIGINAL LTF-YEARLY PTP	01/01/2028	01/01/2048	NEWPOINT (John Day-Marion 500)	PGE_CNTGS	98	Network paths: • South of Allston N>S • Cross Cascades North E>W • Cross Cascades South E>W • North of Pearl S>N	Unawardable
101455658	ORIGINAL LTF-YEARLY PTP	01/01/2028	01/01/2048	NEWPOINT (John Day-Marion 500)	MIDWAY230MIDCR	100	Subgrid: • NEWPOINT • MIDCREMOTE	Unawardable
101455662	ORIGINAL LTF-YEARLY PTP	01/01/2028	01/01/2048	NEWPOINT (John Day-Marion 500)	MIDWAY230MIDCR	120	Subgrid: • NEWPOINT • MIDCREMOTE	Unawardable
101455666	ORIGINAL LTF-YEARLY PTP	01/01/2028	01/01/2048	NEWPOINT (John Day-Marion 500)	COLMBIA230CHPD	130	Network paths: • Cross Cascades South E>W • North of Pearl S>N	Unawardable
101455678	ORIGINAL LTF-YEARLY PTP	01/01/2028	01/01/2048	NEWPOINT (John Day-Marion 500)	MCNARY230UEC	150	Subgrid: • NEWPOINT • Umatilla Boardman Area	Unawardable
101455682	ORIGINAL LTF-YEARLY PTP	01/01/2028	01/01/2048	NEWPOINT (John Day-Marion 500)	PSEI_CENTCNTGS	50	Network paths: • Cross Cascades North E>W • Cross Cascades South E>W • North of Pearl S>N • North of Echo Lake S>N	Unawardable
101455686	ORIGINAL LTF-YEARLY PTP	01/01/2028	01/01/2048	NEWPOINT (John Day-Marion 500)	PGE_CNTGS	50	Network paths: • South of Allston N>S • Cross Cascades North E>W • Cross Cascades South E>W • Raver-Paul N>S • North of Pearl S>N	Unawardable
101455697	ORIGINAL LTF-YEARLY PTP	01/01/2028	01/01/2048	NEWPOINT (John Day-Marion 500)	COLMBIA230GCPD	100	Network paths: • Cross Cascades South E>W • North of Pearl S>N	Unawardable
101455700	ORIGINAL LTF-YEARLY PTP	01/01/2028	01/01/2048	NEWPOINT (John Day-Marion 500)	COLMBIA230GCPD	100	Network paths: • Cross Cascades South E>W • North of Pearl S>N	Unawardable
101455746	ORIGINAL LTF-YEARLY PTP	06/01/2027	06/01/2047	NEWPOINT (Ashe-Marion 500)	COLMBIA230CHPD	100	Network paths: • Cross Cascades South E>W	Unawardable

AREF	Service Type	Start Date	Stop Date	POR	POD	Demand (MW)	Transmission Constraints	TSR/FTSR Analysis Determination
101455752	ORIGINAL LTF-YEARLY PTP	06/01/2027	06/01/2047	NEWPOINT (Ashe-Marion 500)	PSEI_CENTCNTGS	100	Network paths: • Cross Cascades North E>W • Cross Cascades South E>W • North of Pearl S>N • North of Echo Lake S>N	Unawardable
101455762	ORIGINAL LTF-YEARLY PTP	06/01/2027	06/01/2047	NEWPOINT (Ashe-Marion 500)	COLMBIA230GCPD	125	Network paths: • Cross Cascades South E>W • North of Pearl S>N	Unawardable
101455769	ORIGINAL LTF-YEARLY PTP	06/01/2027	06/01/2047	NEWPOINT (Ashe-Marion 500)	MCNARY230UEC	125	Subgrid: • NEWPOINT • Umatilla Boardman Area	Unawardable
101455772	ORIGINAL LTF-YEARLY PTP	06/01/2027	06/01/2047	NEWPOINT (Ashe-Marion 500)	COLMBIA230CHPD	138	Network paths: • Cross Cascades South E>W • North of Pearl S>N	Unawardable
101455776	ORIGINAL LTF-YEARLY PTP	06/01/2027	06/01/2047	NEWPOINT (Ashe-Marion 500)	RKYRCH230MIDCR	75	Subgrid: • NEWPOINT • MIDCREMOTE	Unawardable
101455779	ORIGINAL LTF-YEARLY PTP	06/01/2027	06/01/2047	NEWPOINT (Ashe-Marion 500)	PSEI_CENTCNTGS	100	Network paths: • Cross Cascades North E>W • Cross Cascades South E>W • North of Pearl S>N • North of Echo Lake S>N	Unawardable
101455782	ORIGINAL LTF-YEARLY PTP	06/01/2027	06/01/2047	NEWPOINT (Ashe-Marion 500)	PSEI_CENTCNTGS	100	Network paths: • Cross Cascades North E>W • Cross Cascades South E>W • North of Pearl S>N • North of Echo Lake S>N	Unawardable
101455793	ORIGINAL LTF-YEARLY PTP	06/01/2027	06/01/2047	NEWPOINT (Ashe-Marion 500)	MCNARY230UEC	100	Subgrid: • NEWPOINT • Umatilla Boardman Area	Unawardable
101455802	ORIGINAL LTF-YEARLY PTP	06/01/2027	06/01/2047	NEWPOINT (Ashe-Marion 500)	MCNARY230UEC	275	Network paths: • South of Allston N>S • Cross Cascades North E>W	Unawardable
101455841	ORIGINAL LTF-YEARLY PTP	06/01/2027	06/01/2047	NEWPOINT (Ashe-Marion 500)	COLMBIA230CHPD	300	Network paths: • Cross Cascades South E>W • North of Pearl S>N • North of Echo Lake S>N	Unawardable
101455857	ORIGINAL LTF-YEARLY PTP	06/01/2027	06/01/2047	NEWPOINT (Ashe-Marion 500)	COLMBIA230GCPD	300	Network paths: • Cross Cascades South E>W • North of Pearl S>N • North of Echo Lake S>N	Unawardable

AREF	Service Type	Start Date	Stop Date	POR	POD	Demand (MW)	Transmission Constraints	TSR/FTSR Analysis Determination
Cypress Creek Renewables Transmission					**1 TSRs**	**80 MW**		
101113970	ORIGINAL LTF-YEARLY PTP	12/01/2025	12/01/2030	MIDWAY230PAC	MIDWAY230MIDCR	80	No Network path or Subgrid constraints identified	Potentially awardable, pending further discussion with affected parties
Puget Sound Energy					**6 TSRs**	**926 MW**		
100988319	REDIRECT LTF-YEARLY PTP	01/01/2024	01/01/2025	LAGRAND230BPA	COVNGTN230PSEI	126	Network paths: • Cross Cascades South E>W • North of Pearl S>N • West of Hatwai E>W • LaGrande E>W	Unawardable
101321978	ORIGINAL LTF-YEARLY PTP	12/01/2026	12/01/2031	GARRISON500CLS	PSEI_STHCNTGS	112	Network paths: • Cross Cascades North E>W • Cross Cascades South E>W • West of Lower Monumental E>W • Raver-Paul N>S • North of Pearl S>N • West of Hatwai E>W • West of Garrison E>W	Unawardable
101321981	ORIGINAL LTF-YEARLY PTP	12/01/2026	12/01/2031	GARRISON500CLS	VANTAGE230MIDC	200	Network paths: • West of Lower Monumental E>W • South of Custer N>S • West of Hatwai E>W • West of Garrison E>W	Unawardable
101321984	ORIGINAL LTF-YEARLY PTP	12/01/2026	12/01/2031	GARRISON500CLS	PSEI_CENTCNTGS	100	Network paths: • Cross Cascades North E>W • West of Lower Monumental E>W • West of Hatwai E>W • North of Echo Lake S>N • West of Garrison E>W	Unawardable
101321988	ORIGINAL LTF-YEARLY PTP	12/01/2026	12/01/2031	GARRISON500CLS	MIDWAY230MIDCR	100	Network paths: • West of Lower Monumental E>W • West of Hatwai E>W • West of Garrison E>W	Unawardable
101328650	ORIGINAL LTF-YEARLY PTP	12/1/2030	12/01/2035	GARRISON500CLS	PSEI_SKGCNTGS	288	Network paths: • Cross Cascades North E>W • Cross Cascades South E>W • West of Lower Monumental E>W • South of Custer N>S • West of Hatwai E>W • West of Garrison E>W • North of Echo Lake S>N • North of Pearl S>N	Unawardable

AREF	Service Type	Start Date	Stop Date	POR	POD	Demand (MW)	Transmission Constraints	TSR/FTSR Analysis Determination
Tacoma Power					**2 TSRs**	**5 MW**		
101374122	REDIRECT LTF-YEARLY PTP	04/01/2024	05/01/2028	MIDWAY230GCPD	TACOMACNTGS	2	Subgrid: • MIDC Area Resources	Unawardable
101374131	REDIRECT LTF-YEARLY PTP	04/01/2024	09/01/2027	JOHNDAYINT500	TACOMACNTGS	3	Network paths: • North of Pearl S>N	Unawardable