



Toward a more holistic and adaptive treatment of BPA transmission rights in Northwest utility planning and procurement processes

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ABSTRACT

The practice of requiring long-term firm (LTF) point-to-point (PTP) transmission rights for new generators in the Pacific Northwest traditionally supported reliability for utilities that rely on BPA transmission, but has not adapted well to an environment with increasing penetrations of renewable resources. Applying this practice to renewables effectively prioritizes avoidance of renewable curtailment above considerations like affordability and policy compliance in planning and procurement decisions. It discourages more efficient utilization of the transmission system; artificially constrains renewable development; and sends the wrong signals to BPA regarding the need for transmission upgrades to maintain reliable load service.

Historical path flow data and transmission curtailment data suggest that BPA's system is much less physically constrained than it is contractually constrained. For most paths, the lack of long-term ATC has not translated into frequent congestion or transmission curtailments.

We propose that utilities in the region take a more adaptive portfolio-based approach to acquiring and managing their transmission rights on BPA's system to integrate renewables, rather than requiring LTF transmission rights for individual renewable resources. Under our proposal, utilities would evaluate resources based on how well they utilize existing transmission infrastructure and transmission rights. The utility would then adjust their strategy for securing incremental transmission based on the resources they acquire.

For planning analyses, we describe approaches to incorporating transmission constraints into economic dispatch and resource adequacy evaluations that allow the utility to reflect some degree of short-term flexibility in how they use their transmission rights while considering the physical limits of the existing transmission system. For procurement processes, we describe approaches to estimating transmission risk associated with bids that do not deliver to the utility's BA over LTF transmission rights.

1 INTRODUCTION

Utilities in the Pacific Northwest have traditionally used long-term firm (LTF) point-to-point (PTP) transmission rights to deliver generation across the BPA system to their BAs on a project-by-project basis. This practice has generally supported reliability and reduced transmission curtailment risk, but it has not adapted well to an environment with increasing penetrations of renewable resources in the region. Today, this practice effectively prioritizes avoidance of renewable curtailment above considerations like affordability and policy compliance in planning and procurement decisions. It also discourages more efficient utilization of the transmission system; artificially constrains renewable development; and sends the wrong signals to BPA regarding the need for transmission upgrades to maintain reliable load service.

In this paper, we propose changes that utilities can make to their planning analyses and procurement processes to support improved utilization of the transmission system, to shift priority away from transmission upgrades that primarily promote renewable delivery versus reliable load service, and to integrate more renewable resources on to the BPA system without compromising reliability. We propose that utilities take a portfolio approach to evaluating their needs for LTF transmission within their planning processes, rather than adopting requirements for individual renewable projects to deliver to their BAs over LTF transmission. To support such strategies, we present analytical approaches that can be applied in IRPs and RFPs to recognize the benefits of resources that utilize the existing transmission system and the utility's existing portfolio of transmission rights and that provide more granular information regarding the need for incremental transmission. This type of analysis could be used to evaluate transmission curtailment risk in IRPs and RFPs and could inform utility transmission strategies, including BPA Transmission Service Requests (TSRs) and transmission investments that balance affordability, policy compliance, and reliability considerations in a more holistic and rigorous manner.



2 BACKGROUND

Why have utilities traditionally required LTF transmission rights for new generation and why doesn't this apply to renewables?

LTF PTP transmission rights serve to reduce the likelihood that generator output will be curtailed due to transmission congestion. This reduction in risk occurs in two ways. First, securing firm transmission rights for a project pushes that project down in the priority order of projects that may be curtailed when congestion occurs. When a curtailment is needed in a given part of the transmission system, projects in that part of the system with non-firm rights will generally be curtailed before projects with firm rights. This does not reduce the physical risk of curtailment, but shifts that risk from customers with firm rights to customers with non-firm rights.

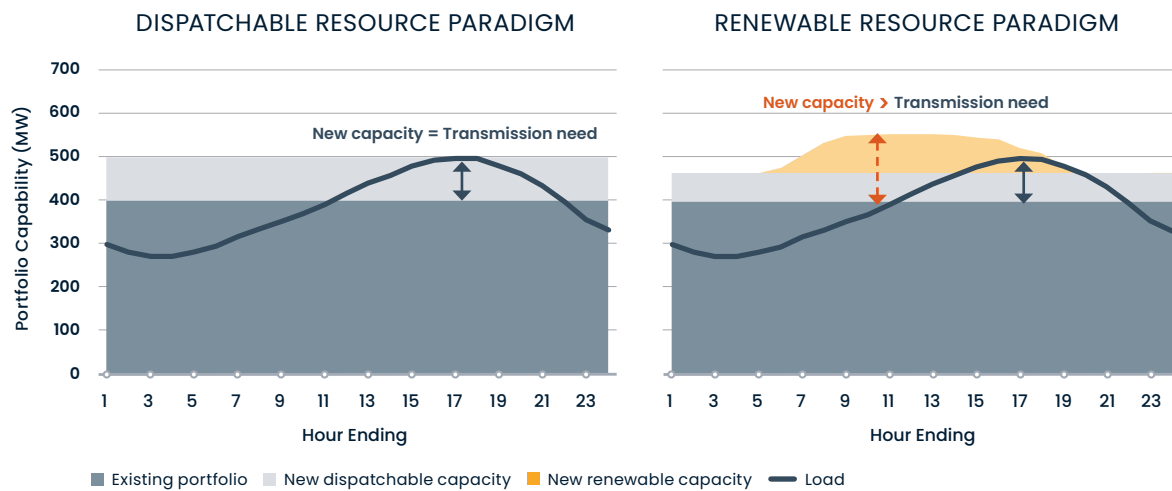
TABLE 1.
BPA curtailment priority for PTP rights

E-TAG PRIORITY	PTP TRANSMISSION RIGHTS
1	Non-firm (NF) Secondary Hourly
2	NF Hourly
3	NF Daily
4	NF Weekly
5	NF Monthly
6	Conditional Firm (CF) (not “firmed up”)
7	All Firm PTP products, including “firmed up” CF

Second, when a transmission customer requests LTF transmission rights through the Transmission Service Request (TSR) process, BPA conducts a study to identify any upgrades that would be needed to the transmission system to avoid overloading elements of the system when power is injected at the requested Point of Receipt (POR) and withdrawn at the requested Point of Delivery (POD) under certain circumstances. This TSR Study & Expansion Process (TSEP) may result in upgrades to the system in order to grant LTF transmission rights and these upgrades reduce the likelihood of transmission curtailments for all customers.

Traditionally, requiring delivery of dispatchable generation to the utility's BA over LTF PTP transmission has helped to promote reliable load service in a fairly straightforward manner. In dispatchable generation-based systems, both capacity additions and transmission needs are driven by load growth. New capacity is sized to meet the demand that cannot otherwise be met by the existing portfolio and the utility plans for this new capacity to generate at or near its maximum output during the most challenging circumstances. To meet load during these circumstances, the utility must also acquire enough transmission to deliver the full output of the new capacity resource to their system. Under this planning paradigm, requiring LTF transmission rights for new resources serves as a reasonable proxy for securing enough transmission to reliably meet load.

FIGURE 1. Conceptual example of how integrating renewables changes the relationship between capacity additions and transmission needs to support reliable load service.



This logic does not apply to variable renewable resources. Variable renewables rarely, if ever, generate at their maximum capacity during the most challenging circumstances. They are primarily procured to provide energy to the system, not to meet the next increment of peak demand. In fact, when variable resources are generating at or near their maximum capacity, other dispatchable resources in the utility's portfolio typically generate less in

service to meeting demand.¹ In most hours, adding renewable resources does not increase the total flows into the utility's system — it simply shifts the flows from dispatchable PORs and market hubs to renewable PORs. In hours when renewables help to meet load that could not otherwise be met by the existing portfolio, they are typically generating less than their maximum output — this is why their capacity contributions are much lower than 100%. Unlike dispatchable resources, securing LTF transmission for renewable project output does not serve as a reasonable proxy for meeting incremental transmission needs associated with load growth. In these systems, capacity additions exceed the LTF transmission needed for reliable load service. More granular information about the timing of loads and project output and more targeted strategies are needed to secure the transmission rights that reliably serve load in the most cost effective manner.

While much of the discussion of transmission requirements focuses on reliability, under most circumstances, transmission constraints do not threaten reliability. In most cases, encountering a transmission constraint (e.g., having transmission service curtailed or having a short-term redirect or TSR rejected) shifts generation from more preferred or lower variable cost generators that are affected by the constraint to less preferred or higher cost generators that are not affected by the constraint. This redispatch could result in higher operating costs, higher GHG emissions, and/or lower renewable deliveries. Securing LTF transmission rights for renewables primarily acts to minimize these consequences. When a utility is subject to an RPS or clean energy requirement, transmission constraints could also require the utility to procure more renewable resources to offset curtailed renewable generation. In this way, requiring LTF transmission for renewables could reduce the amount of renewable infrastructure required to meet policy requirements — but it does so by requiring more transmission infrastructure. A core question at the heart of determining transmission requirements for renewables is whether this additional transmission infrastructure is lower cost than experiencing some renewable curtailment.

What has resulted from current practice?

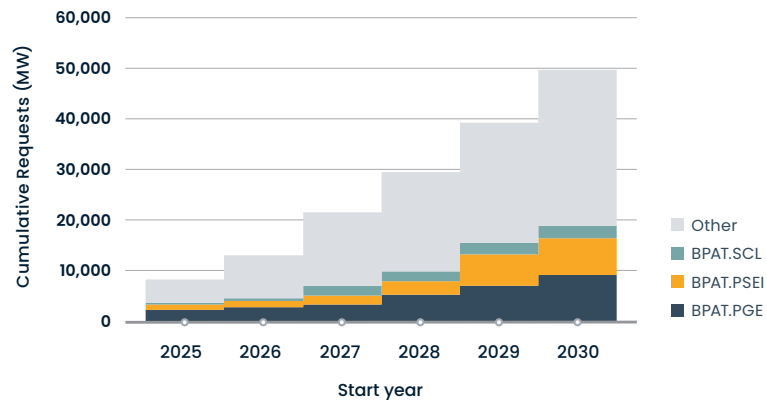
Utilities in the region have historically applied the same transmission requirements for renewables in their procurements as they have for dispatchable resources — requiring LTF transmission for delivery of most or all project output to their BA. Over time, as utilities sought more renewable energy to meet policy requirements and developers responded to that demand, the quantity of TSRs for LTF PTP transmission submitted to BPA expanded rapidly.

As TSRs were granted, the available transfer capability (ATC) over key paths that sit between renewable development areas and major load centers eroded. BPA stopped pub-

¹ Generator output may still be high during these periods if there is a market for the additional generation needed beyond the utility's needs for load service. However, generation in excess of what is needed to serve load need not be delivered to the utility's BA to support reliability or to be available to the market.

lishing ATC over internal paths in October 2023, but at that time the pending queue exceeded the remaining ATC on critical paths sitting between renewable development areas and major load centers in the region. Figure 2 shows the pending queue for LTF rights by POR as of March 2025. We highlight three PORs corresponding

FIGURE 2. BPA's LTF pending queue as of March 2025.



to utilities at major load centers that heavily rely on PTP transmission service to meet load (Portland General Electric, Puget Sound Energy, and Seattle City Light). Through 2030, the pending queue includes nearly 20 GW of TSRs to deliver to these three utilities, far exceeding the transmission needs associated with their forecasted load growth. Looking across all POD's, BPA's pending LTF TSRs total nearly 50 GW. In response to this unmanageable demand for LTF transmission service, BPA announced a pause in the 2025 TSEP Cluster Study in February 2025.² The pause of the 2025 TSEP Cluster Study only increases the urgency for utilities to consider more creative and flexible transmission solutions to support continued development of renewables in the region.

Utilities who have applied requirements for LTF transmission for renewable resources over the years may have transmission portfolios that are in large part driven by renewable resource acquisitions. With the erosion of ATC across key paths, these same utilities may struggle to find new renewable projects that can meet their transmission requirements. Some utilities now allow renewable projects to bring Conditional Firm (CF) transmission, which has more flexibility than LTF, but this shift has not mitigated the core challenges that this paper attempts to address.

How constrained is the current transmission system?

Despite the unavailability of LTF transmission rights, there is little evidence to suggest that BPA's transmission system is as physically constrained as it is contractually constrained on a forward basis. According to BPA data,³ between 2008 and October of 2024, transmission curtailments occurred during only 0.17% of hours. In those hours, curtailments averaged 401

² More information available at: <https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/Transmission-PlanningPauseQA-FINAL-DRAFT-030625.pdf>.

³ BPA network curtailment data was obtained from: <https://www.bpa.gov/energy-and-services/transmission/hourly-firm-data-monitoring-evaluation>

MWh in magnitude across the entire BPA system. When considering only days with very high regional demand conditions,⁴ transmission curtailment statistics are largely the same (0.17% of hours and average curtailment of 414 MWh), and when considering the specific hours of highest demand, they occur a bit less frequently and with smaller average magnitude (0.14% of hours and average curtailment of 219 MWh). This data suggests that transmission curtailments are both rare and small under typical operating conditions and are no more likely or severe during regional peak load conditions.

TABLE 2. Historical BPA transmission curtailments across all hours and during hours with greater regional resource adequacy risk.

	ALL HOURS (2008–2024)	CAPACITY CRITICAL HOURS (2012–2022)	HOURS ON DAYS WITH CAPACITY CRITICAL HOURS (2012–2022)
Hours with curtailment (% of hours)	246 (0.17%)	4 (0.14%)	44 (0.17%)
Total curtailed MWh	98,590	875	18,195
Priority 7 Firm curtailed MWh	21,505	787	6,508
% Curtailment that had Priority 7 Firm rights	21.8%	89.9%	35.8%

Furthermore, securing firm transmission service does not guarantee that a resource will be unaffected by curtailments when they do occur. Across all curtailment events between 2008 and 2024, 21.8% of the curtailed energy had Priority 7 firm transmission rights. On days with high regional loads, 35.8% of the curtailed energy had Priority 7 firm transmission rights, and on high regional load hours, 89.9% of curtailed energy had Priority 7 firm transmission rights. When the system is most constrained, firm transmission rights seemingly offer less protection from transmission curtailments than when the system operates under typical conditions.

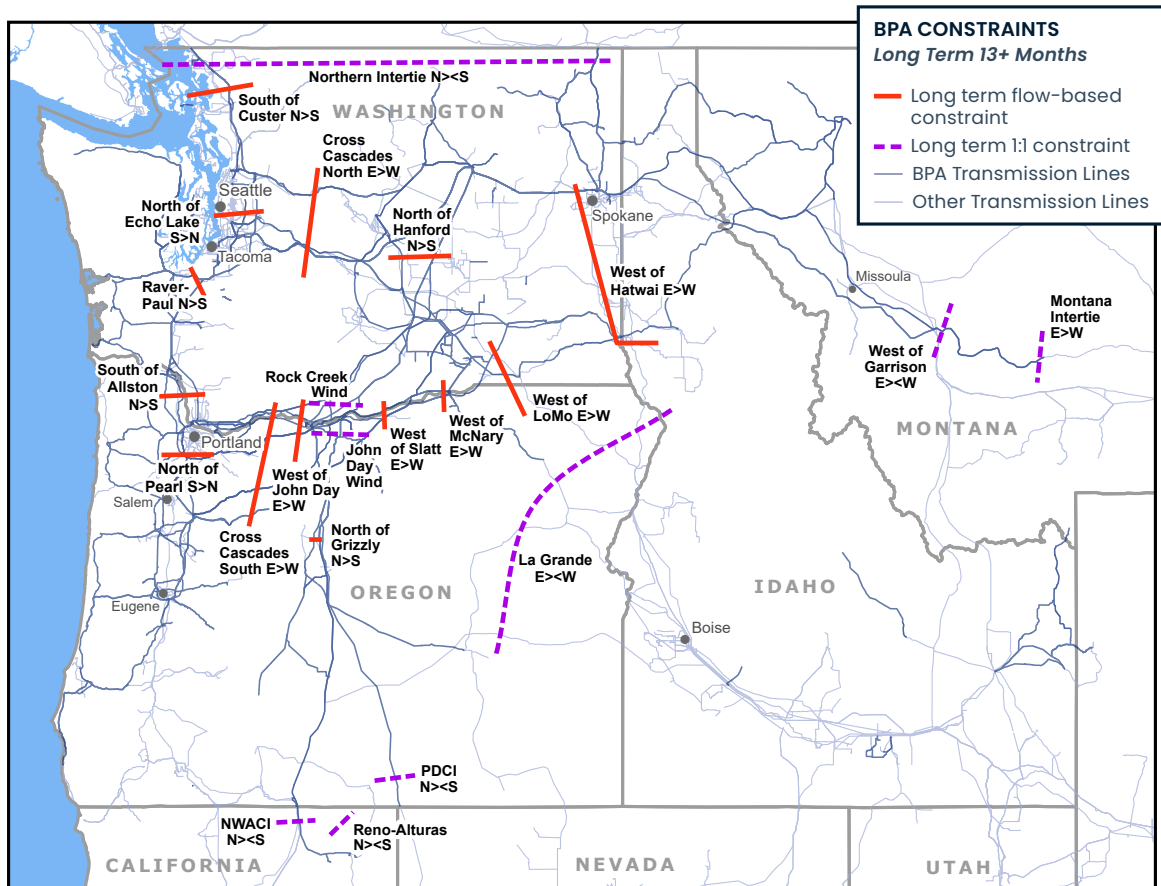
While transmission curtailments are rare, there are specific parts of the BPA transmission system that do experience congestion. When congestion occurs, BPA may redispatch BPA system resources or, less often, third parties via bilateral agreements prior to resorting to curtailment.⁵ [Figure 3](#) shows BPA’s long-term paths and [Table 3](#) provides an indication of

⁴ We use historical Capacity Critical Hours (CCHs) as identified by the Western Power Pool as part of the WRAP to identify very high regional demand hours.

⁵ <https://www.bpa.gov/-/media/Aep/transmission/business-practices/tbp/redispatch-and-curtailment-procedures-bp.pdf>

how congested BPA's internal paths have been in recent history. Here we define congestion as a condition in which the actual flow meets or exceeds the total transfer capability (TTC) of the path and we define a low headroom event as a condition in which the actual flow meets or exceeds 90% of the TTC.

FIGURE 3. BPA's long-term paths as of November 2023.



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

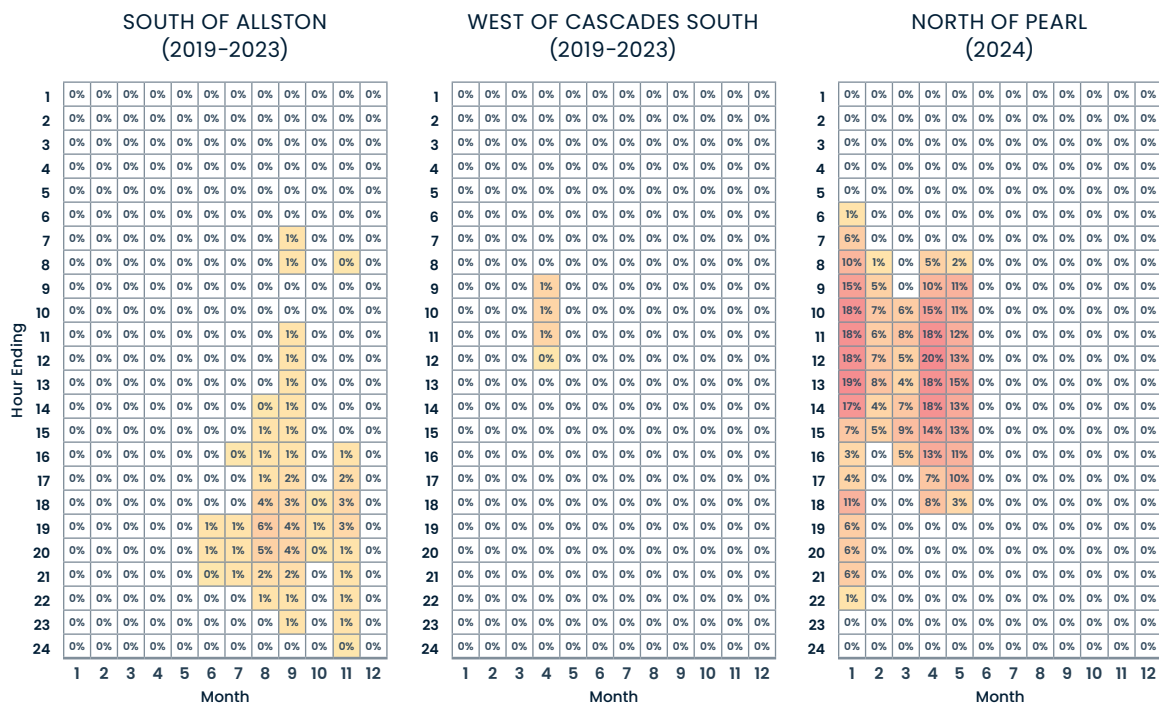
Most of the internal BPA paths experienced congestion in fewer than 10 hours per year on average during the recent historical record, and many experienced congestion in less than 1 hour per year on average. North of Pearl and Raver-Paul are exceptions. For other paths, even those with no remaining long-term ATC, between about one quarter and one half of the TTC is available 95% of the time, suggesting that the long-term contractual reservations across these paths far exceed their actual use almost all of the time.

TABLE 3. Recent historical occurrence of congestion events and < 10% headroom events on key BPA paths. Statistics for all paths but North of Pearl and North of Grizzly are based on flows between 2019 and 2023. Statistics for North of Pearl and North of Grizzly are based on flows in 2024.

PATH OR INTERTIE	CONGESTION EVENTS (FLOW EXCEEDS TTC)		LOW HEADROOM EVENTS (FLOW EXCEEDS 90% OF TTC)		HEADROOM AVAILABLE 95% OF THE TIME (% OF TTC)
	% OF INTERVALS	AVERAGE HRS/YR	% OF INTERVALS	AVERAGE HRS/YR	
North of Grizzly (N-S)	0.11%	9.2	0.21%	18.5	39%
North of Hanford (S-N)	0.06%	5.1	0.11%	9.7	53%
North of Pearl (S-N)	0.74%	64.9	2.12%	186.1	18%
Raver-Paul (N-S)	0.17%	14.8	0.65%	56.7	32%
South of Allston (N-S)	0.06%	5.0	0.22%	18.8	38%
South of Boundary (N-S)	0.00%	0.3	0.43%	37.7	27%
West of Cascades North (E-W)	0.03%	2.6	0.40%	34.8	26%
West of Cascades South (E-W)	0.01%	0.6	0.01%	0.7	36%
West of John Day (E-W)	0.00%	0.2	0.03%	3.0	38%
West Of Lower Monumental (E-W)	0.00%	0.0	0.01%	1.0	51%
West Of McNary (E-W)	0.00%	0.0	0.00%	0.1	46%
West Of Slatt (E-W)	0.00%	0.0	0.00%	0.1	41%

Congestion on different paths also have different drivers and temporal patterns. Figure 4 shows the likelihood of experiencing low headroom over the recent historical record on three key paths that are affected by deliveries into the Portland Metro area. South of Allston has seen low headroom primarily in summer evenings, while North of Pearl has seen low headroom primarily mid-day in the winter and spring. Low headroom has rarely been experienced over West of Cascades South, but when it has arisen, it has occurred in the spring. These seasonal patterns have implications for those attempting to make better use of the existing headroom on these paths. For example, constraints on South of Allston may limit contributions of new off-system resources to meeting incremental loads during summer evening peaks in the Portland Metro area, while constraints on North of Pearl may be more limiting for delivering solar resources under high spring hydro run-off conditions.

FIGURE 4. Probability of low headroom (actual flow exceeds 90% of TTC) in recent historical record



Historical BPA path flow and curtailment data paint a dramatically different picture of BPA's transmission system than the long-term ATC inventory. While BPA's system appears to be fully or nearly fully subscribed on a long-term basis, the system as a whole experiences constraints relatively infrequently in operations and the most severe consequences of encountering transmission constraints — transmission curtailments — are exceedingly rare. This suggests that the use of LTF transmission rights may be reserving much more of the system than is necessary to support reliable operations.

3 A MORE HOLISTIC AND ADAPTIVE APPROACH

It has become clear that business-as-usual transmission strategies will impede Northwest utilities from making progress toward their clean energy requirements. But the case for change goes beyond clean energy policy implementation. Utilities that require renewables to bring LTF transmission rights are effectively prioritizing the avoidance of transmission-associated renewable curtailment above other key considerations that are weighed in planning and procurement decisions, cost in particular. The current approach also places the responsibility for mitigating transmission curtailment risk on renewable developers, who have fewer options for managing this risk. And it leads to significantly more LTF TSRs than will ever need to be granted to reliably meet load.

A more holistic approach would instead involve active management on the part of the utility of their portfolio of LTF transmission rights on behalf of customers to minimize costs while maintaining reliability. In such an approach, the utility would not require renewable resources to bring their own transmission rights and would instead secure transmission rights over time that best suit their needs, given their entire portfolio of resources. They would incorporate transmission risk analysis into both their IRPs and RFPs to recognize the benefits of resource options and bids that make the best use of the existing transmission system and the utility's existing portfolio of transmission rights. Unlike the traditional approach, which effectively sets and forgets LTF transmission rights based on resource acquisitions, the utility would actively revisit their transmission strategy on an ongoing basis as their needs evolve, the transmission system itself evolves, and as they incorporate learnings from their short-term operations. Over time, as these drivers evolve, the utility's transmission strategy would also evolve.

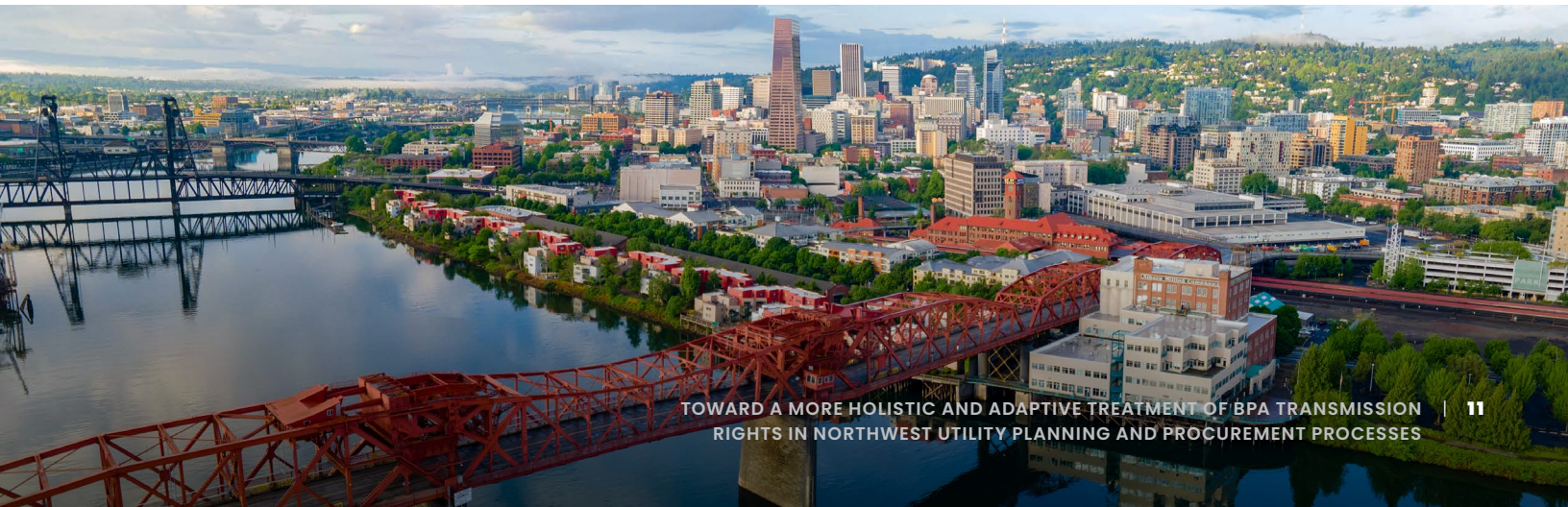
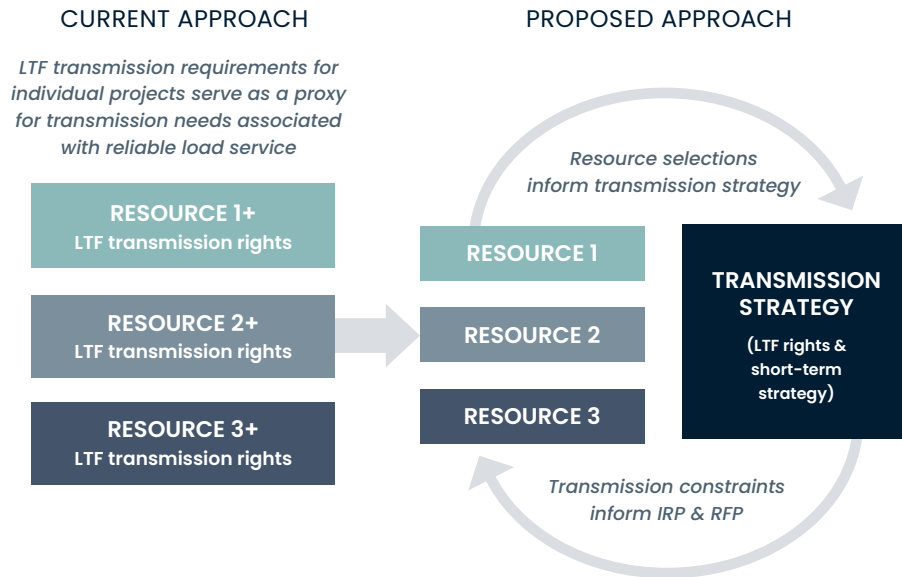


FIGURE 5.

Proposed reforms to the treatment of transmission rights in planning and procurement processes



This shift in strategy would almost surely require utilities to take on more renewable curtailment risk, but this is not an undesirable outcome. Planning studies have consistently shown that some amount of renewable curtailment will be a common and economically efficient phenomenon in future systems — in some systems, this is already the case. The amount of “optimal” renewable curtailment will depend on the system, but it is most certainly not zero. Overbuilding the transmission system in an attempt to eliminate all renewable curtailment increases costs without necessarily providing commensurate value to customers. This is especially concerning in an environment with growing loads and real concerns regarding reliability and affordability.

Adopting a more holistic and dynamic approach to managing transmission risk would require changes to planning, procurement, and operations. Below we describe at a high level potential reforms in each of these areas.

Planning reforms

Under the proposed approach, the utility would incorporate more granular transmission constraints into their IRP analysis based on their portfolio of LTF transmission rights and assumptions about their ability to further optimize their transmission portfolio within the year. IRP analysis may identify resources that improve the utilization of existing transmission rights or reduce the need for incremental transmission. The IRP analysis may also help to identify incremental transmission that would support reliability or that would reduce costs associated with redispatch and/or policy compliance. The IRP analysis could be used to target and right-size LTF TSRs, to identify areas where incremental transmission investments

would bring value, or to evaluate various transmission options available to the utility. In Section 4, we describe options for incorporating hourly transmission constraints into IRP economic dispatch and resource adequacy models to glean these types of insights.

Procurement reforms

Core to this proposal is the lifting of requirements for renewable projects bid into an RFP to deliver their output to the utility over LTF transmission rights. To enable more efficient use of the existing system and to surface information about the cost trade-offs for pursuing resources with varying degrees of transmission risk, RFPs would allow busbar products and projects that have secured LTF or CF transmission rights to other locations on the grid. Under the reformed process, the utility would be responsible for reasonably estimating transmission risks associated with each bid based on its POI or POD and updating their transmission strategy based on the bids selected. In Section 5, we describe some options for evaluating transmission risk in RFPs and provide some illustrative examples.

The proposed RFP reforms would represent a significant shift in risk management strategy for a utility accustomed to using RFP transmission requirements to minimize long-term transmission risks. In this approach, the utility typically assumes that LTF rights secured to deliver a resource will deliver that resource for its entire operational lifetime and this provides some degree of certainty to the utility regarding the project deliverability over its full operational life. In the proposed framework, while the utility would preserve the option to rollover LTF rights, they may shift their transmission strategy over the life of the resource as conditions change on the transmission system and as their resource portfolio evolves. The long-term risks associated with their LTF portfolio would be examined in the IRP, rather than addressed through the RFP, and may result in the utility submitting LTF TSRs that result in transmission upgrades that are high priority to the utility over time. By adopting this more adaptive approach through the IRP, the utility may have more leeway to focus on near-term transmission risks in selecting resources in an RFP.

Short-term transmission portfolio optimization

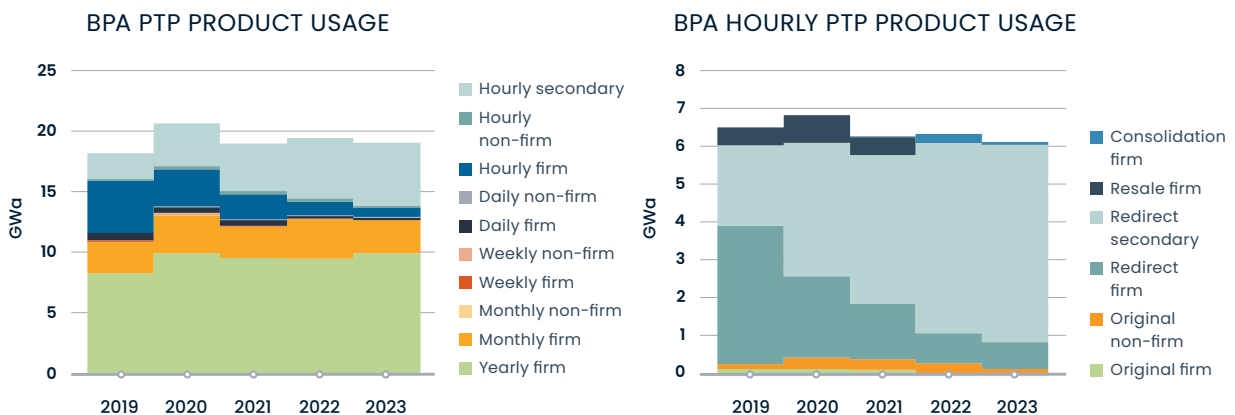
BPA provides multiple options for transmission customers to optimize their transmission portfolios within the year. Transmission rights can be redirected from one POR/POD combination to another, provided that there is adequate capacity on the system over the term of the redirection. LTF rights can be redirected to LTF, short-term firm, hourly firm, or non-firm secondary hourly rights.⁶ Redirects can promote more efficient use of the transmission system by allowing for some realignment of transmission reservations with transmission needs within the year. Transmission rights can also be sold from one

⁶ <https://www.bpa.gov/-/media/Aep/transmission/business-practices/tbp/redirects-bp.pdf>

transmission customer to another.⁷ Resales do not change the type of rights or the POR/POD combination associated with the rights, but they may promote more or higher value utilization of transmission reservations by transmission customers. Finally, the utility may request short-term transmission rights over various timeframes within the operating year, including requesting hourly firm transmission on a day-ahead basis.⁸

BPA data suggests that some utilities already actively manage their transmission portfolios over short timescales to optimize their operations. Several LSEs in the region have noted the importance of hourly firm transmission and redirects not only for optimizing market activities, but also for load service.⁹ Under the proposed reforms, these utilities could use information gained through their short-term operational activities to better inform the transmission risk estimations occurring in their planning and procurement analyses.

FIGURE 6. BPA PTP product usage in recent years



As shown in Figure 6, BPA transmission product usage data from 2019 through 2023¹⁰ suggests that hourly transmission products are commonly used by BPA transmission customers. In 2023, 32% of all PTP transmission product usage was for hourly products. The historical data also indicates that while the total quantity of hourly transmission rights has held relatively constant in recent years, transmission customers have shifted toward more redirects for non-firm secondary rights versus firm rights. This aligns with a shift in BPA practice regarding hourly reservations. Beginning in July 2019, BPA began limiting hourly firm reservations based on short-term ATC and beginning in January 2020, BPA began requiring all hourly

7 <https://www.bpa.gov/-/media/Aep/transmission/business-practices/tbp/resale-of-transmission-service-bp.pdf>

8 <https://www.bpa.gov/-/media/Aep/transmission/business-practices/tbp/requesting-transmission-service-bp.pdf>

9 From TC-20 - Comments of Avangrid Renewables, LLC, Avista Corporation, PacifiCorp, Portland General Electric Company, and Puget Sound Energy, Inc. on the June 26, 2018 TC-20 Tariff Proposals (<https://www.bpa.gov/-/media/Aep/rates-tariff/tc-20/customer-comments/18Jul18/avangrid-pac-pge-pse-comments-071818.pdf>) : "The BPA hourly firm product plays an important role in the Northwest and is essential, for example, for BPA transmission customers in serving load (e.g., through redirects) and for facilitation of short-term economic transfers."

10 Available at: <https://www.bpa.gov/energy-and-services/transmission/hourly-firm-data-monitoring-evaluation>

firm reservations to be made prior to the operating day.¹¹

Reliance on short-term flexibility in the use of transmission rights may vary from utility to utility depending on the nature of their portfolio, their operational sophistication, and their risk appetite. Improved transparency into how individual utilities utilize their portfolio of LTF transmission rights and engage in short-term redirects, purchases, sales, and TSRs could support improved planning assumptions and analysis for those utilities.

It should also be acknowledged that BPA transmission customers may see changes in the utilization of and short-term flexibility provided by the BPA transmission system as day ahead markets expand into the Northwest. Day ahead markets offer the opportunity for BPA to further optimize federal resource dispatch subject to transmission constraints, but impacts to the short-term flexibility available to BPA transmission customers will depend on market design and could be impacted by market seams between BPA and their transmission customers. To promote more efficient use of the transmission system, ongoing discussions around market participation and market design should carefully consider the impacts of such decisions on the short-term operational flexibility available to BPA transmission customers.

¹¹ <https://www.bpa.gov/-/media/Aep/rates-tariff/tc-20/TC-20-Settlement-Agreement-111308-redlined-to-110818-version-attorney-call-edits.pdf>

4 ESTIMATING TRANSMISSION RISK IN LONG-TERM PLANS

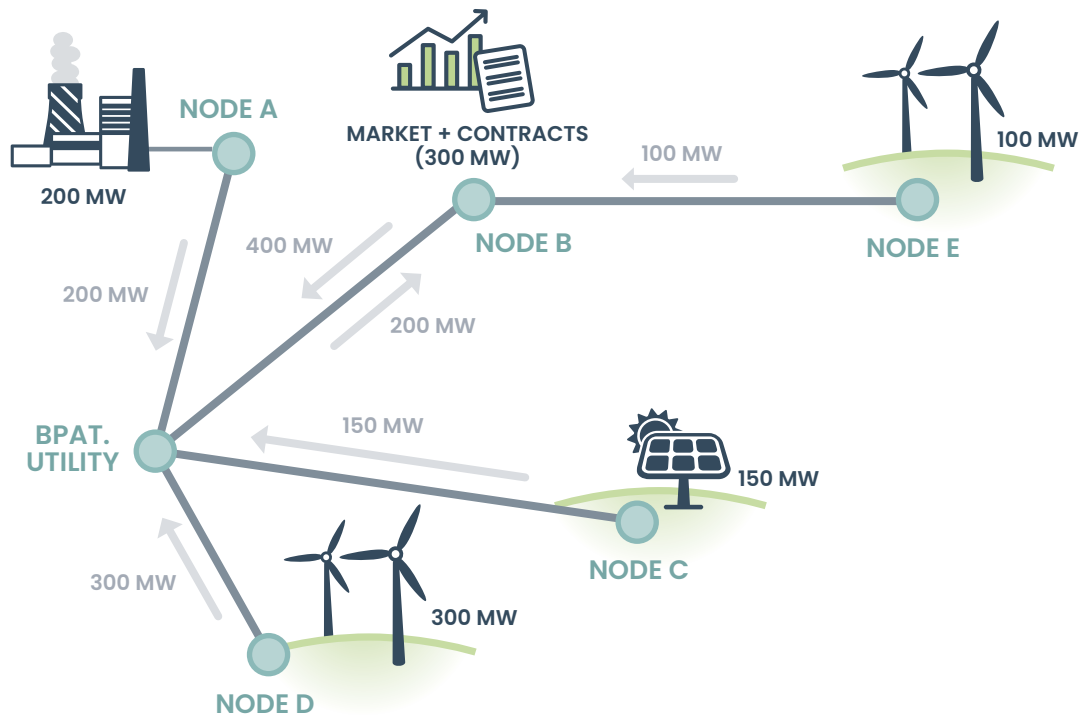
The first step in estimating transmission risk in long-term plans is to incorporate transmission constraints into the production cost and resource adequacy models used in planning. For a utility that relies on BPA transmission, transmission constraints in these models may not resemble a typical nodal or zonal transmission topology often seen in production cost models. Instead, transmission constraints may be designed to represent and constrain use of PTP transmission rights and impacts to key paths in the region. These are described below, with illustrative examples.

Pipe-flow modeling of PTP transmission rights

Some utilities already represent the availability and use of PTP transmission rights in production cost models as part of their planning analysis. These models are called pipe-flow models because they estimate flows between nodes or zones as if power were flowing between them through pipes — similar to how PTP transmission rights allow contractual flows over the system. These models do not capture the physical constraints or how power flows on a transmission system, but they do capture how a utility might use their PTP rights to support their operations.

A pipe-flow model may be nodal, in which case it may include any POR or POD at which the utility has transmission rights as nodes, or zonal, which involves aggregating PORs and PODs in a reasonable manner to reduce the computational complexity of the problem. The example in [Figure 7](#) shows how a portfolio of PTP transmission rights can be translated into a nodal pipe-flow model. The production cost model would track flows between all of the POR/POD combinations and constrain them to not exceed the corresponding quantity of rights held by the utility in each direction. In [Figure 7](#), where constraints are not listed, directional flows are constrained to be zero.

FIGURE 7. Pipe-flow representation of LTF PTP transmission rights for an illustrative utility



While pipe-flow models are useful for tracking the use of PTP rights, they can also over-constrain the dispatch problem. If the utility uses short-term options like redirects, transmission purchases, and short-term TSRs to, for example, sell into a market, a pipe-flow model based only on LTF rights will not account for these opportunities. This may result in overestimates of curtailment and underestimates of market value.

If more flexibility is desired to reflect more realistic operations in the planning analysis, the planner may need to relax some of the pipe-flow constraints. This can be accomplished by allowing flows that exceed the quantity of LTF rights held over each segment, while tracking and potentially penalizing the excess flows to reflect any incremental costs associated with securing transmission rights on a short-term basis to support the flows. The planner may also allow some of these excess flows without incurring cost penalties to the extent that they are comfortable assuming that redirects are available from unused LTF rights elsewhere. Redirect constraints may be imposed by capping the sum of flows in each hour over those LTF rights from which and to which the utility may request redirects by the total quantity of LTF rights held over those segments. Redirects may be further constrained based on utility-specific data on the availability and use of redirects in utility operations.

When incorporating short-term flexibility, such as short-term purchases and short-term redirects, into the transmission model, the utility must exercise care to ensure that any

rights that are acquired or redirected on a short-term basis are reasonable, given physical transmission constraints in the region. The next section describes additional constraints that can be applied to restrict flows that exceed LTF transmission rights in a manner that is grounded in the physical constraints on the transmission system.

Flow-based constraints on BPA internal paths

When the utility seeks to incorporate some flexibility in the use of transmission rights for the purposes of planning, physical constraints on the transmission system can be approximated by overlaying flow-based transmission path constraints on top of the pipe-flow model. The flow-based transmission path constraints estimate the flows resulting across transmission paths in the region that correspond to the contractual flows in the pipe-flow model. This model leverages power transfer distribution factors (PTDFs), which are provided by BPA and estimate the impact that injecting 1 MW at each POR while withdrawing 1 MW at each POD has on flows across the BPA internal paths based on DC power flow analysis. An illustrative calculation of path flows corresponding to a hypothetical dispatch solution is shown for the illustrative utility in [Table 4](#).

TABLE 4. Example estimation of path flows associated with meeting load with the utility's resource portfolio in an example hour

POR	POD	PTDFs		EXAMPLE HOURLY FLOWS (MW)		
		PATH 1	PATH 2	CONTRACTUAL FLOW	PATH 1 FLOW	PATH 2 FLOW
Node A	BPAT.Utility	0.80	0.17	190	$190 \times 0.80 = 152$	$190 \times 0.17 = 33$
Node B	BPAT.Utility	0.29	0.63	81	23	51
Node C	BPAT.Utility	0.17	0.74	135	23	100
Node D	BPAT.Utility	0.18	0.72	11	2	8
Node E	Node B	-0.03	0.00	28	-1	0
BPAT.Utility	Node B	-0.29	-0.63	0	0	0
		Total		445	200	191

Because the estimated path flows are each a linear combination of the contractual flows from the pipe-flow model, path flows can be solved for endogenously in the dispatch model by incorporating these as linear constraints.

A more challenging problem is deciding how to constrain path flows within the dispatch simulation. While historical TTC data can be used to derive constraints on total flow across a path, a utility planner must decide what portion of the TTC is reasonable to assume may

be available to the utility in the future for the purposes of planning. One relatively simple approach to this is to allocate the TTC on each path to the utility based on the utility's portfolio of LTF transmission rights. By holding those rights, the utility has effectively reserved flow across the impacted paths (approximately according to the PTDFs) and these reservations should be preserved even as other transmission customers secure rights on those paths in the future. An example of this calculation is shown in [Table 5](#). The utility may also apply derates to their allocated TTC to reflect transmission outage risk or operational constraints based on utility-specific or BPA data.

TABLE 5. Estimation of the utility's access to path TTC based on their portfolio of transmission rights

POR	POD	PTDFs		ESTIMATION OF UTILITY TTC RESERVATION (MW)		
		PATH 1	PATH 2	RIGHTS	PATH 1 FLOW	PATH 2 FLOW
Node A	BPAT.Utility	0.80	0.17	200	200 x 0.80 = 160	200 x 0.17 = 34
Node B	BPAT.Utility	0.29	0.63	400	116	252
Node C	BPAT.Utility	0.17	0.74	150	26	111
Node D	BPAT.Utility	0.18	0.72	300	54	217
Node E	Node B	-0.03	0.00	100	0	0
BPAT.Utility	Node B	-0.29	-0.63	200	0	0
		Total		1,350	356	615

In this example, the utility might constrain flows over Path 1 to never exceed 356 MW and flows over Path 2 to never exceed 615 MW or they may apply more conservative hourly constraints that also incorporate path derates and other risks. Applying these constraints on top of the pipe-flow model will constrain the model's ability to purchase short-term rights and make short-term redirects in a manner that better approximates the physical constraints on the transmission system.

Planning insights from transmission-constrained analysis

When hourly transmission constraints bind in a production cost or resource adequacy simulation, the system may experience a range of consequences. Output from generators behind binding transmission constraints may be reduced or curtailed and purchases from markets to which access is limited by a binding transmission constraint may be reduced. When possible, output from generators and/or purchases from markets for which transmission constraints do not bind will increase as needed to meet load in these hours. This will generally result in increased dispatch costs. If there is not enough generation and

market access to meet load while satisfying all transmission constraints, the system will experience unserved energy.

The impacts of transmission constraints on the dispatch solution could have various consequences for a planning exercise, including:

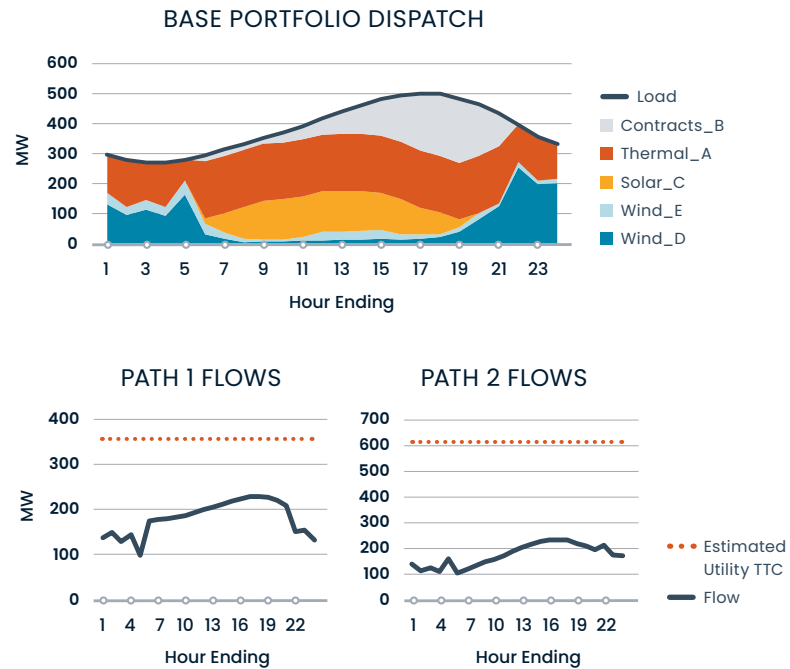
- **Cost.** Transmission constraints may prevent the utility from accessing the lowest cost resources and market opportunities, leading to increased dispatch costs for portfolios for which transmission constraints bind.
- **Policy compliance.** If renewable generation is curtailed as the result of a transmission constraint, this may impact the utility's ability to meet an RPS, clean energy, or emissions requirement. Depending on the design of the policy, the utility's ability to meet an RPS, clean energy, or emissions requirement may also be affected in circumstances when renewable generation can be delivered to a market hub and sold (generating revenues for the utility), but cannot be delivered to the utility's BA due to a transmission constraint between the market hub and the utility's BA. Depending on the nature of the policy requirement and how the planner has set up the analysis, the portfolio may incur an additional cost penalty or the portfolio may require additional renewable resources to ensure policy compliance. GHG emissions and emissions-based policy compliance may also be affected by the need to dispatch resources with higher emissions intensities in hours when lower emissions intensity resources are behind a binding transmission constraint.
- **Reliability.** Under the most severe circumstances, transmission constraints may result in or exacerbate a resource adequacy challenge. In particular, if the dispatch optimization encounters a transmission constraint and exhausts all alternative options (e.g., dispatching resources in less constrained areas, including on-system resources), the last resort will be to shed load. In this case, the planner may need to modify the portfolio to select resources in less constrained areas, including on-system resources, expand demand side solutions, or, if it is available, secure additional transmission to improve the deliverability of off-system resources in order to meet the resource adequacy requirement.

Illustrative planning example

We demonstrate this approach in a simplistic manner by simulating dispatch for the illustrative utility to meet load in each hour of a summer day. Figure 8 shows simple heuristic dispatch and the resulting flows on Path 1 and Path 2 to meet the utility's load in each hour. Because the utility has acquired firm transmission to deliver the full project output of all resources in the portfolio to meet load, none of the pipe-flow constraints bind for this system and the flows on Path 1 and Path 2 are far from approaching the maximum flow that could be accommodated by the utility's transmission rights.

FIGURE 8.

Heuristic dispatch on a summer day for the illustrative utility's base portfolio and the resulting estimated flows over affected paths



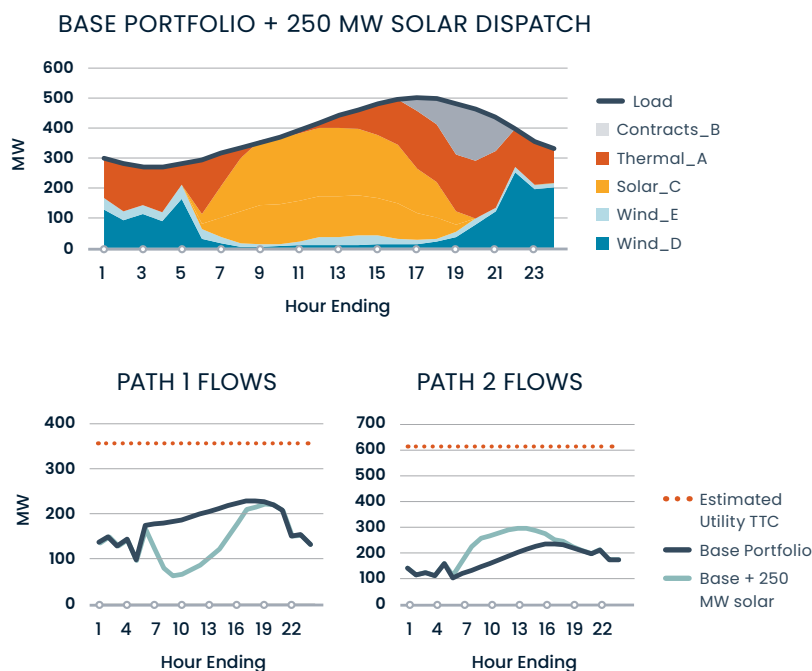
The utility is interested in adding more solar to the portfolio, but is not able to acquire additional LTF transmission to deliver the solar to their BA. They test the addition of 250 MW of additional solar, delivered to Node C in the transmission-constrained dispatch model to estimate the flexibility that may be available on a short-term basis to deliver the additional solar.¹² Figure 9 shows the resulting dispatch and path flows.



¹² Note that the incremental resource could also be delivered to a node from which the utility has no transmission rights and the same analysis could be conducted. We assume delivery to Node C in this example simply because we have already provided PTDFs for that node.

FIGURE 9.

Heuristic dispatch on a summer day for the illustrative utility's base portfolio plus 250 MW of additional solar delivered to Node C and the resulting estimated flows over affected paths



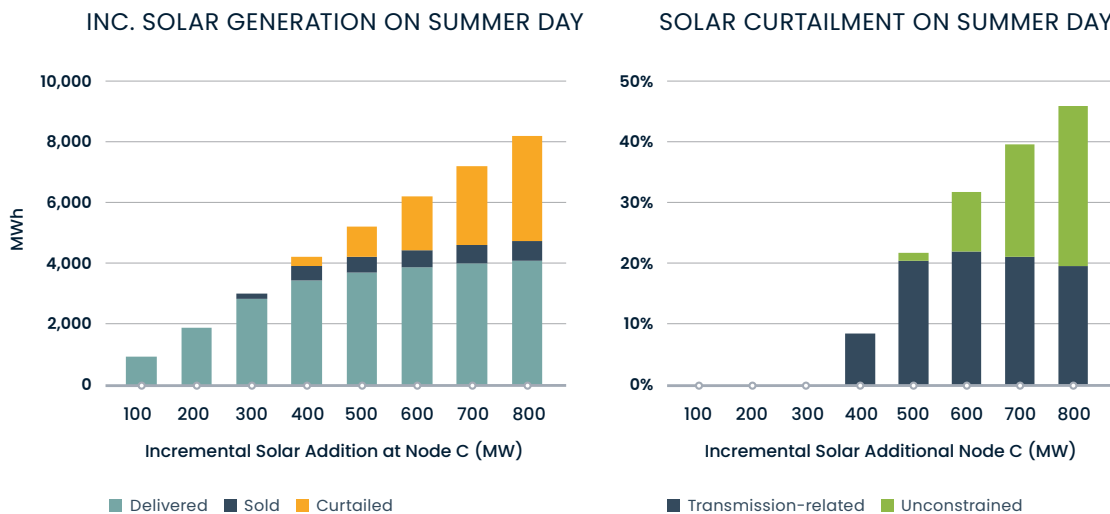
On this particular day, adding incremental solar displaces thermal generation and contract purchases when the solar is generating. Because the thermal resource and contracts are at nodes with larger impacts to flows over Path 1 than Node C (per the path PTDFs), displacing the thermal generation and contract purchases with solar reduces flows over Path 1. In contrast, injections at Node C have a greater impact on flows over Path 2 than injections at Node A or Node B, so displacing the thermal generation and contract purchases with solar increases flows over Path 2.

The estimated flows still fall well below the utility's estimated TTC reservations over Path 1 and Path 2, suggesting that there may be adequate physical flexibility on the transmission system in the short term to deliver the additional solar generation to the utility's BA on this day. To access this flexibility, the utility may use unused LFT rights from Node C to BPAT. Utility, redirect some of their other LTF rights to deliver to BPAT. Utility from Node C, or purchase incremental short-term rights. The utility constrains redirects by assuming they can only redirect rights from Node D to retain the flexibility to deliver more output from their thermal resource and to access their contracts at Node B. This, in combination with the unused rights from Node C, provides between 276 and 369 MW of transmission rights across the daylight hours because wind output is relatively low during this day. The redirect constraint does not bind in any hour with the 250 MW solar addition.

The utility repeats this analysis with various solar addition sizes delivered to Node C and finds that curtailment begins to arise with between 300 and 400 MW of additional solar

due to the redirect constraint. The path flow constraints do not bind in any of their tests. To contextualize the transmission-associated curtailment risk, the utility repeats this exercise while lifting the transmission constraints to understand how much curtailment would be expected due simply to overgeneration conditions. The utility confirms that transmission constraints increase curtailment on this day, but overgeneration takes over as the primary driver of increased curtailment for solar additions larger than about 600 MW.

FIGURE 10. Estimated curtailment on a summer day as a function of solar additions at Node C without incremental LTF rights



None of the utility’s tests result in unserved energy because the existing resource and LTF transmission portfolio was adequate to meet load. If the utility had tested a scenario with loads exceeding the capabilities of the existing portfolio and relied on the solar additions to meet those additional loads, solar curtailments could have resulted in unserved energy, depending on their timing and magnitude.

This type of analysis could be conducted across all hours that are evaluated in the utility’s economic dispatch and resource adequacy modeling as part of their long-term planning to understand the potential impacts of transmission constraints on cost, renewable curtailment, and reliability.

Considering incremental LTF transmission rights and transmission investments

So far, the approach has focused on characterizing the flexibility provided by the utility’s portfolio of existing LTF transmission rights and has not addressed the question of whether, where, and in what quantities the utility should pursue additional LTF transmission rights

or transmission investments. These strategies can be tested by making corresponding changes to the pipe-flow model and the flow-based constraints.

To represent additional LTF rights on the BPA system, the utility could add those rights to the pipe-flow model, include them in the flow-based constraints, and update their allocated TTC estimates to include the flow impacts of those rights. This approach assumes for the purpose of planning that acquiring the additional LTF rights (and triggering any associated upgrades) would not materially affect the PTDFs. If including additional LTF rights, the utility should exercise care in developing assumptions for when, where, and in what quantities these rights may become available. Given long-term constraints on the system and the size of the LTF queue, it may not be reasonable to assume that this option is available in the near term.

If the utility is considering making transmission investments to address transmission constraints identified in the IRP, they may add those segments directly to the pipe-flow model and model their use on a contractual basis assuming that the utility reserves a portion of the segment to meet their demand. To the extent the utility's transmission investments also expand TTC on a BPA path, this approach may underestimate the flexibility provided by those investments. This flexibility can be incorporated into planning analyses as more concrete information becomes available about the impacts of the investment.

Endogenous selection of incremental LTF transmission rights and transmission investments in capacity expansion models is also possible, but may require simplifications similar to those employed in capacity expansion models for resource selections. Care should be taken in designing these simplifications and testing the resulting selections in more granular transmission-constrained production cost and resource adequacy models (i.e., conducting roundtrip modeling).

5 ESTIMATING TRANSMISSION RISK IN RFPS

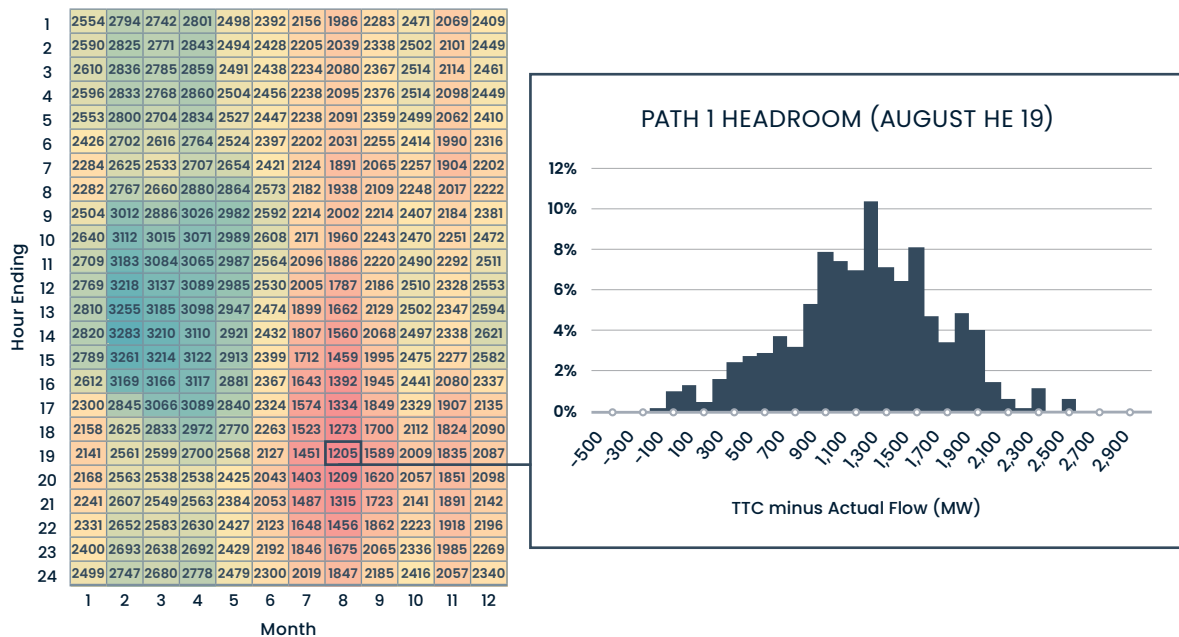
If the utility has already established a methodology for characterizing operational transmission constraints in their IRP, they may rely on the same methodology to estimate transmission risks for bids in an RFP. However, if the utility does not yet have a robust approach to quantifying transmission risk in the IRP or does not leverage their IRP portfolio models for RFP scoring (e.g., they use a more simplistic scoring methodology), they may adopt a more simplistic approach to estimate transmission risks in the RFP. For example, the utility may estimate transmission risks by derating the hourly project output used to estimate the value of each bid. Below we describe several options for calculating these derates for a utility seeking to acquire resources that make use of the existing transmission system and their existing portfolio of LTF rights. We use the same illustrative utility described in the prior section to demonstrate how a utility might adjust their RFP analysis to reduce the quantity and cost of incremental transmission rights the utility may need to pursue to integrate any acquired resources.

Path flow-based derates

To understand the physical constraints on the existing system, the illustrative utility examines historical flows over key paths that affect deliveries to their system and calculates the historical hourly headroom on each path by subtracting the hourly flows from the hourly TTC. The hourly headroom represents the total additional flow that could have been available for use by BPA transmission customers across the historical record. The utility uses the historical hourly headroom data to derive probability distributions for the available headroom on a month-hour basis. [Figure 11](#) shows the average headroom by month-hour on Path 1 and the underlying distribution of hourly headroom in an example bin — hour ending (HE) 19 in August.¹³

¹³ For the purposes of realistic illustration, historical path flow data for South of Allston was used to characterize Path 1.

FIGURE 11. Path 1 month-hour average headroom (MWa) and full headroom distribution for an example bin (August HE 19)



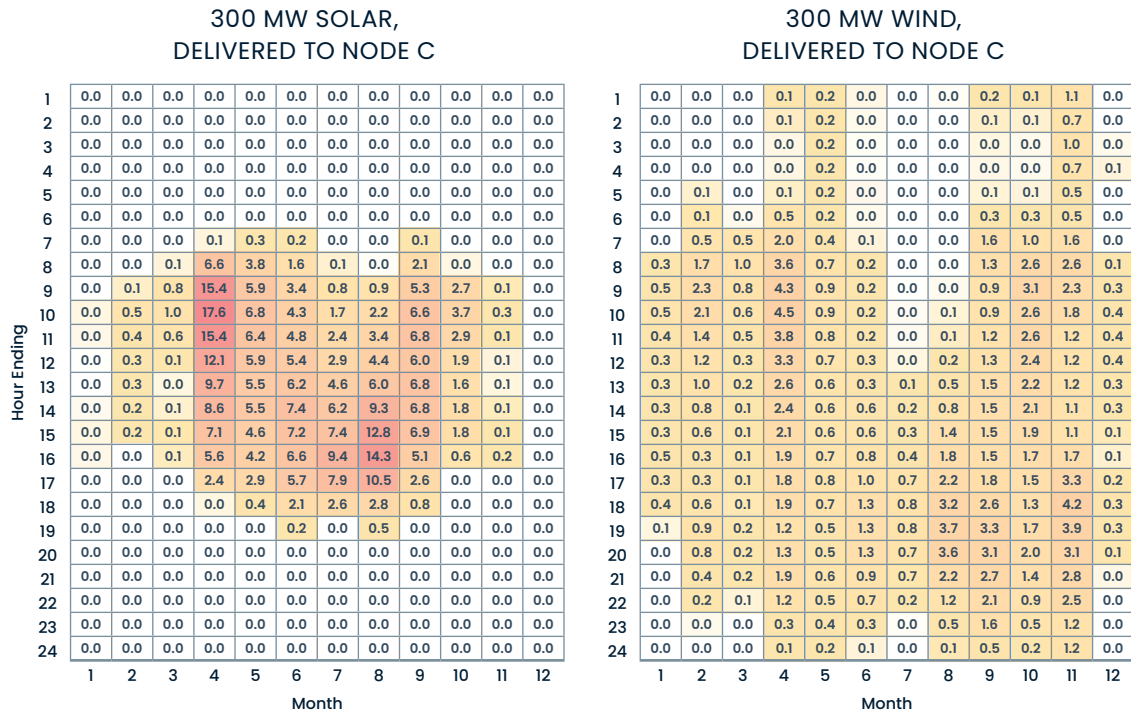
In addition to binning by month-hour, the utility can also bin the data by other variables to capture additional correlations – for example they could bin the data by load conditions if there is a strong relationship between their load and the path availability. And if they observe trends in the historical data, they could modify the distributions to project those trends forward.

The illustrative utility expects that other transmission customers will also be planning to utilize some of the hourly headroom going forward, whether to meet growing loads, integrate new resources, or both. Because it is not possible to forecast how other transmission customers will use the transmission system, the utility adopts a simplifying assumption that they will have access to a fixed pro rata share of the headroom based on the estimated TTC reservations associated with their portfolio of LTF transmission rights (the calculation in Table 5). To estimate their share of headroom on each path in each hour, they divide their estimated path TTC reservation by the annual TTC for the path to calculate a path TTC allocation factor.

TABLE 6. Estimation of path allocation factors for path flow-based derates in RFP evaluation

PATH	ANNUAL TTC (MW)	ESTIMATED UTILITY TTC (MW)	TTC ALLOCATION FACTOR
Path 1	3,450	356	10.3%
Path 2	7,200	615	8.54%

The utility multiplies this allocation factor by the hourly headroom to derive utility-specific distributions for each path. These distributions allow the utility to estimate whether project output is likely to be curtailed due to transmission congestion. They estimate the expected curtailment in each hour by comparing the flows over each path required to deliver the project output to their BA to their allocated share of the month-hour headroom distribution for the path. When the path flow exceeds the allocated headroom, they estimate the resource curtailment required to achieve the necessary reduction in flow using the PTFDs. Finally, they sum the curtailments resulting from congestion across all the affected paths. The resulting month-hour average curtailment is shown for two example bids – a 300 MW solar bid and a 300 MW wind bid, both delivered to Node C – in Figure 12.

FIGURE 12. Estimated average month-hour curtailment (MWa) for illustrative solar and wind bids based on flow impacts over Path 1 and Path 2

Contractual derates

Beyond constraints associated with the physical transmission system, the utility may also consider contractual transmission constraints when evaluating bids. For example, they may be interested in understanding how much they can leverage their existing LTF rights and how much incremental short-term transmission may be needed beyond their LTF rights to deliver bid output to their BA.

To understand their contractual limits to access the transmission system, the utility estimates the contractual flows associated with delivering their existing renewable generation to their load over their LTF transmission rights. For each POR from which the utility has LTF transmission that delivers to their BA, they use hourly generation or availability data for their existing resources to derive distributions representing the quantity of LTF transmission rights that remain available for use after accounting for delivery of their existing resources. They develop these distributions on a month-hour basis to recognize seasonal and hourly patterns (see [Figure 13](#)) and they derate bid project output in each hour based on the probability that the project output exceeds the unused LTF rights in that hour. [Figure 14](#) shows the derated output resulting from applying this method to the 300 MW solar and wind bids delivering to Node C. For both bids, derates are significant during daylight hours when existing solar uses up most of the LTF rights delivering from Node C to the utility's BA (See [Figure 14](#)). The utility decides to use this approach to derate project output shapes for use in their capacity contribution calculations in their RFP to conservatively err on the side of underestimating short-term transmission flexibility in the context of RA.

For the purposes of evaluating energy value and policy compliance contributions, the utility instead assumes that unused LTF transmission rights can be redirected from other PORs that deliver output from existing renewables up to the physical capability reflected by the path flow-based derated output. To estimate the availability of potential redirects for this purpose, the utility sums the unused capacity across the PORs delivering renewables to their BA in each hour (see [Figure 15](#)). Because such large quantities of the utility's LTF rights go unused much of the time, allowing redirects results in much more modest derates to project output for the energy value and policy compliance contribution evaluations (see in [Figure 16](#)).

FIGURE 13. Month-hour average unused LTF rights (MWa) from Node C to BPAT.Utility and the corresponding distribution for an example bin (August HE 19)

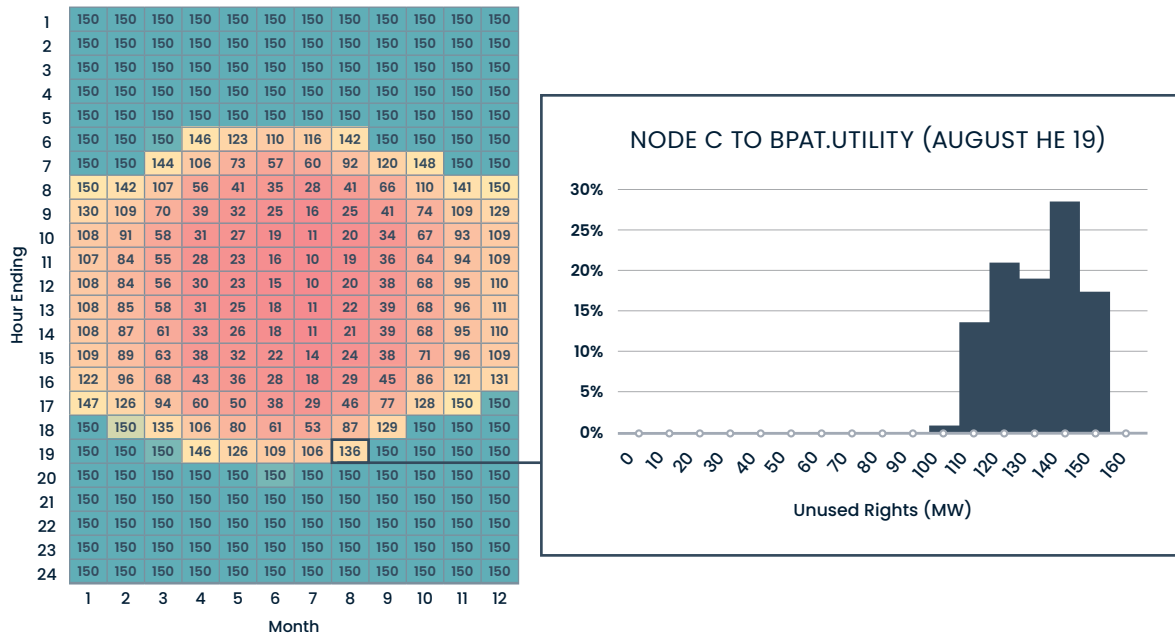


FIGURE 14. Month-hour average derated output for illustrative solar and wind bids when output is limited by unused LTF rights from Node C to BPAT.Utility (does not allow redirects)

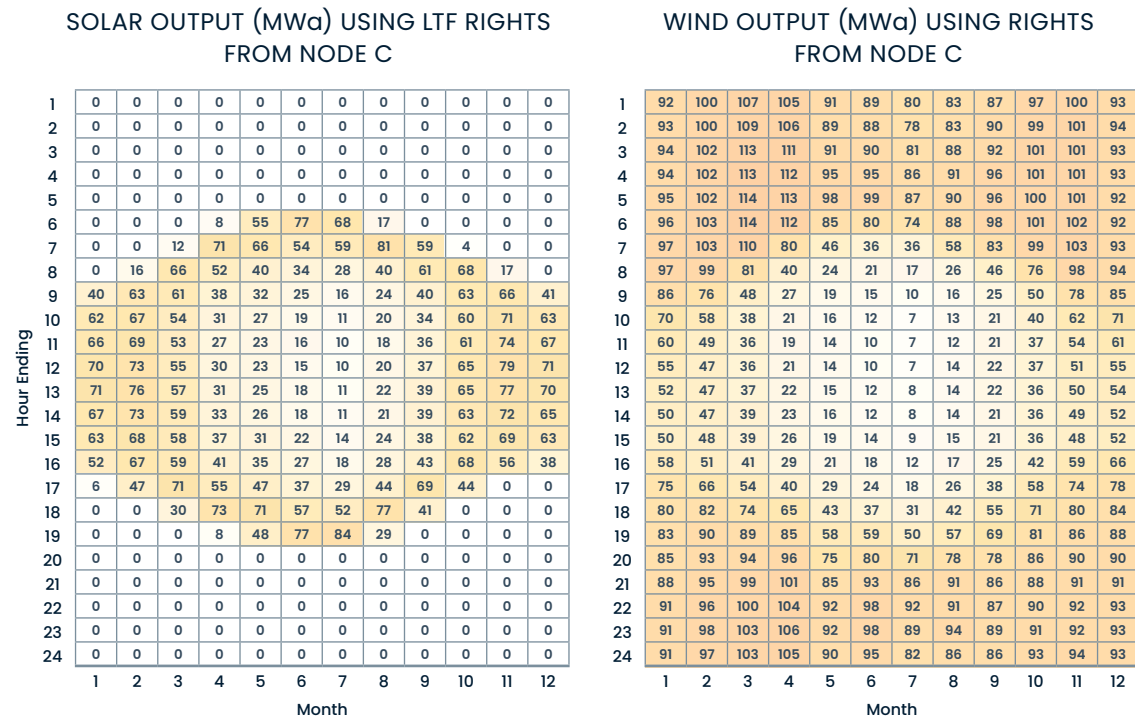


FIGURE 15. Month-hour average unused LTF rights (MWa) from Node C, Node D, and Node E to BPAT. Utility and the corresponding distribution for an example bin (August HE 19)

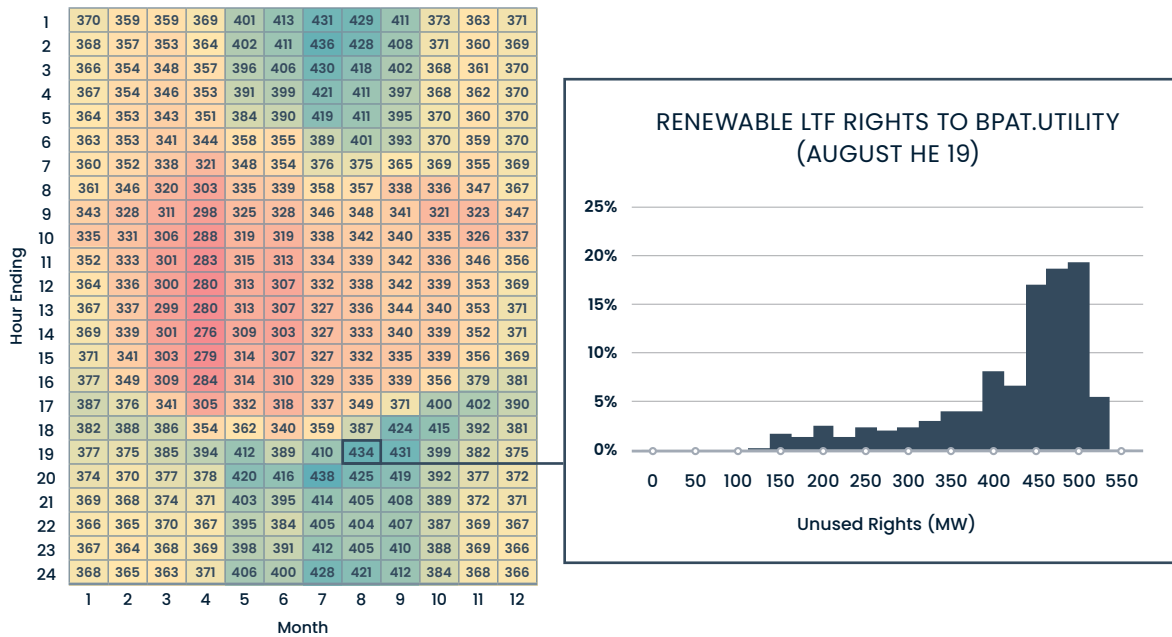
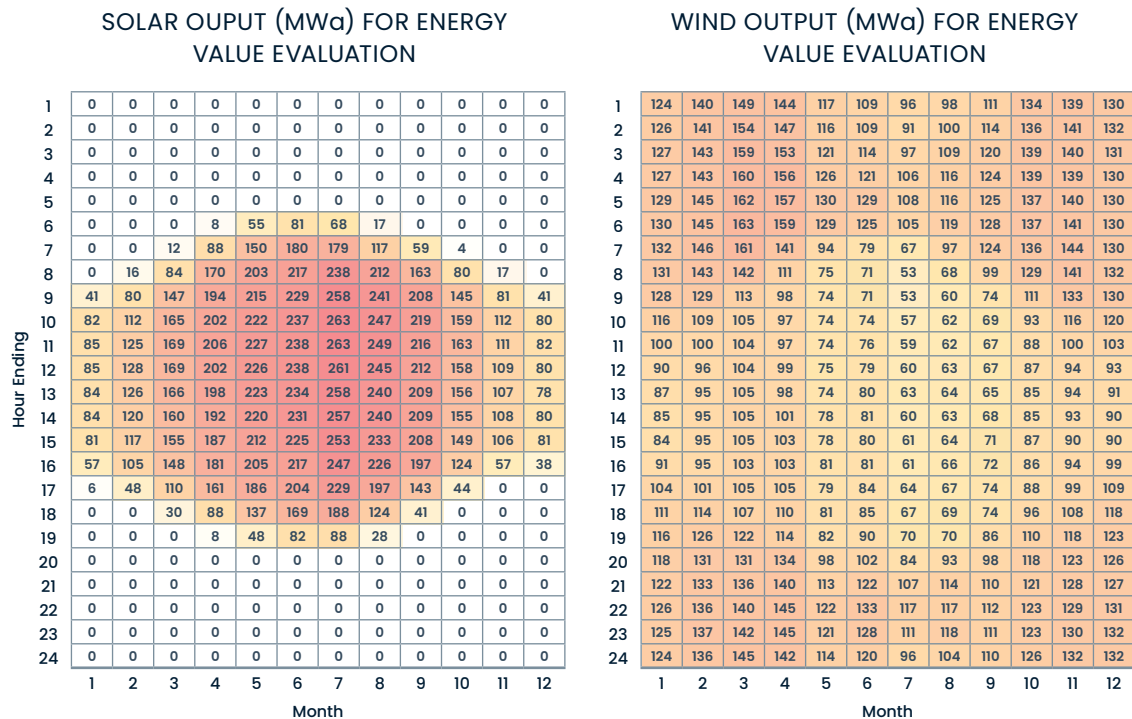


FIGURE 16. Month-hour average derated output for illustrative solar and wind bids when output is limited by total unused LTF rights from Node C, Node D, and Node E to BPAT.Utility (allows redirects from Node D and Node E)



Transmission cost adders

To the extent that the utility's bid evaluation assumes that project output will exceed the capabilities of their existing LTF transmission portfolio (including their assumed access to redirects), the utility may also impose transmission cost adders to these excess contractual flows. In the examples described above, the utility curtails any generation that would lead to excess flows and so they would not apply incremental transmission costs to the example bids. If instead, the utility were to allow excess contractual flows and assess value (e.g., energy value or policy compliance value) for the corresponding generation, it may be appropriate to also apply transmission cost adders. These transmission cost adders, which could be based on short-term transmission rates, could be used to estimate the additional costs the utility may incur to secure transmission to deliver the additional project output, rather than curtail it.

6 CONSIDERATION OF WRAP TRANSMISSION REQUIREMENTS

Capturing the interactions between transmission constraints and resource adequacy is a complex undertaking and an evolving field. For many Northwest utilities, this discussion is occurring in the context of the Western Resource Adequacy Program (WRAP) transmission requirements and so a discussion of those requirements and their planning and procurement implications is relevant to the reforms proposed in this paper.

Meeting WRAP Forward Showing Transmission Requirements

The WRAP Forward Showing program requires participants to hold firm transmission rights that deliver from their qualifying resources to their load in a total (i.e., portfolio-wide) quantity that equals or exceeds 75% of the participant's total Forward Showing capacity requirement. Firm transmission rights only qualify to contribute to this requirement up to the Qualifying Capacity Contribution (QCC) of the resources that are delivered over the rights.¹⁴

The design of the Forward Showing transmission requirement gives participants, particularly those who have historically secured LTF transmission for resources in their portfolio, considerable flexibility. A hypothetical demonstration of meeting the Forward Showing transmission requirement is shown for the illustrative utility in [Table 7](#). In this example, the utility has a Forward Showing capacity requirement of 600 MW and a Forward Showing transmission requirement of 450 MW.¹⁵ The utility has qualifying LTF rights equal to 100% of their capacity requirement, so they exceed the 75% transmission requirement by 150 MW. Technically, the illustrative utility could have met their transmission requirement without any of the LTF rights they secured to deliver renewable generation to their load, as they hold 490 MW of qualifying firm rights from Nodes A and B.

¹⁴ See Section 16.3.1 of the WRAP Tariff. https://www.westernpowerpool.org/private-media/documents/WRAP_Tariff_Effective_3.16.25.pdf

¹⁵ Resource QCCs in these examples are illustrative and not based on the WRAP QCC methodologies.

TABLE 7. Illustrative calculation of qualifying firm transmission in the WRAP Forward Showing program

RESOURCE	INTERCONNECTION LIMIT (MW)	QCC (MW)	LTF RIGHTS (MW)	QUALIFYING LTF RIGHTS (MW)	UNUSED LTF RIGHTS (MW)
Thermal_A	200	190	200	190	10
Contracts_B	300	300	300	300	0
Solar_C	150	30	150	30	120
Wind_D	300	60	300	60	240
Wind_E	100	20	100	20	80
Total		600	0	600	450
Forward Showing Requirements		600		450	



In this example, because the utility has already secured LTF transmission rights to deliver the full output of their wind and solar resources, well beyond the corresponding resource QCCs, they also have 450 MW of LTF rights that do not contribute to meeting the Forward Showing transmission requirement. If the utility were to deliver additional resources to the PORs associated with these rights, the portion of the transmission rights contributing to the Forward Showing transmission requirement would increase by the QCCs of those additional resources up until the point at which the total QCC of all resources delivered to the node equaled the total firm transmission rights held from the node to the participant's BA. An example of this is shown in Table 8 for a circumstance in which the illustrative utility acquires 300 MW of additional wind that delivers to Node C and 300 MW of additional solar that delivers to Node D to meet a 120 MW increase in their Forward Showing capacity requirement. By delivering to nodes with existing LTF rights, the utility increases their quantity of qualifying transmission by 120 MW without securing any additional firm rights. In this way, the WRAP Forward Showing program allows utilities to leverage their existing transmission rights on a planning basis.

TABLE 8. Illustrative calculation of qualifying firm transmission in the WRAP Forward Showing program with additional renewables delivering to the utility’s LTF transmission portfolio

RESOURCE	INTERCONNECTION LIMIT (MW)	QCC (MW)	LTF RIGHTS (MW)	QUALIFYING LTF RIGHTS (MW)	UNUSED LTF RIGHTS (MW)
Thermal_A	200	190	200	190	10
Contracts_B	300	300	300	300	0
Solar_C + 300 MW wind	450	30 + 60 = 90	150	90	60
Wind_D + 300 MW solar	600	60 + 60 = 120	300	120	180
Wind_E	100	20	100	20	80
Total		720	0	720	330
Forward Showing Requirements		720		540	

To plan for their WRAP Forward Showing, participants may include estimates of their future Forward Showing capacity and transmission positions for each portfolio considered within their planning analysis. Between the planning timeframe and the Forward Showing timeframe, participants may also pursue additional firm transmission rights, including monthly short-term firm transmission via TSRs, purchases, or redirects to meet the Forward Showing transmission requirement.

Mitigating WRAP Operations Program transmission risks

The WRAP Operations Program requires participants to deliver resource output to load over firm transmission, though unlike the Forward Showing program, the Operations Program does not include a regular showing of firm transmission rights. Failure to secure adequate firm transmission to meet load in a given hour could only result in delivery failure charges if the participant experiences an energy delivery failure during a sharing event.¹⁶ An energy delivery failure occurs when a participant is called upon to provide energy to another participant under the constraints described in the WRAP tariff (i.e., an energy deployment) and fails to do so. The WRAP tariff states that energy deployments must be delivered to a central transmission hub in the participant’s WRAP subregion or a mutually agreed upon alternative delivery point.¹⁷ In other words, the participant may only need transmission to the central transmission hub in their subregion to enable delivery of energy deployments, not necessarily to their load. However, if the utility fails to secure adequate firm transmission

¹⁶ See Section 20.6 of the WRAP Tariff. https://www.westernpowerpool.org/private-media/documents/WRAP_Tariff_Effective_3.16.25.pdf

¹⁷ See Section 20.4.1.1 of the WRAP Tariff. https://www.westernpowerpool.org/private-media/documents/WRAP_Tariff_Effective_3.16.25.pdf

to meet their own load in a given hour and they are called upon for an energy deployment in that hour and they cannot deliver to the subregional central transmission hub in that hour, then they may face a delivery failure charge that is due in part to inadequate firm transmission.

Utilities could take a variety of approaches to mitigate this risk. Because providing an energy deployment when the participant is long requires delivery to the central transmission hub and accessing an energy deployment when the participant is short requires delivery from the central transmission hub, a utility might secure some firm transmission rights specifically to support deliveries to and from the central transmission hub as a backstop, unless they are confident their existing portfolio of transmission rights will allow them to both provide and access energy deployments during sharing events.

A WRAP participant might also address transmission risk associated with the WRAP Operations Program by reducing the likelihood that they would need to turn to non-firm transmission to meet load during a sharing event. One simple and conservative approach to this is to limit the capacity contribution of resources in IRPs and RFPs based on the portion of the resource that can be delivered to the utility's BA over LTF transmission rights. This would help ensure that the utility has access to adequate capacity that delivers over firm transmission rights to meet load in each hour without requiring LTF rights for the full project output of all resources in the portfolio. In an hour when there is not enough firm transmission to deliver the full output of a resource that is generating above its QCC to load, this approach ensures that the utility will have enough capacity available elsewhere in their portfolio to avoid a delivery failure charge. Under this strategy, the utility may see higher curtailment risk for renewable resources that do not have full LTF transmission rights during sharing events, but they would not see increased reliability or WRAP compliance risk.

When the utility includes the unused portion of their own LTF transmission rights in this evaluation, this approach is equivalent to the methodology described for calculating capacity contributions of bids in the prior section (i.e., applying derates to project output as shown in Figure 14). This approach is conservative because it errs on the side of underestimating the flexibility that the utility has to further optimize their transmission portfolio on a monthly, weekly, daily, and hourly basis and because it neglects contributions that resources can make during sharing events even if they cannot be delivered to the utility's load (i.e., if they can still be delivered to the central transmission hub). Resources may therefore have larger contributions to regional resource adequacy than would be identified by this approach. Nevertheless, this approach provides a way forward for utilities aiming to mitigate WRAP-associated transmission risks without requiring incremental LTF transmission rights for all resource options or bids.

7 SUMMARY

In this paper, we describe planning and procurement reforms that utilities in the Northwest can implement to move toward a more adaptive and holistic strategy for securing and managing transmission rights on the BPA system. The reforms focus on the treatment of transmission for renewable resources, for which traditional approaches have led to overly conservative LTF transmission portfolios and a vastly oversized queue for LTF transmission service. [Table 9](#) and [Table 10](#) summarize the analytical options presented for planning and procurement analyses.

TABLE 9. Summary of planning approaches to characterizing transmission constraints and flexibility

METHOD	DESCRIPTION AND PURPOSE
LTF-based pipe-flow constraints	Represent use of LTF rights (i.e., contractual flows) with a pipe-flow model. Captures contractual transmission constraints and tracks any flows that exceed LTF rights.
Flow-based path constraints	Constrain estimated flows over regional transmission paths based on use of contractual rights and corresponding PTDFs. Estimates physical constraints on the transmission system to help constrain contractual flows that exceed LTF rights.
Redirect constraints	Constrain redirects between LTF rights within a specified subset of the utility's transmission portfolio (e.g., the LTF rights that deliver renewables to load) by constraining the sum of hourly contractual flows to not exceed the aggregate quantity of rights held over the subset. Allows flexibility for redirects between transmission rights that deliver complementary renewables.
Hourly transmission cost penalties	Apply short-term transmission costs to flows that exceed LTF rights (after allowed redirects) to estimate incremental transmission purchases. Penalizes resource selections that require more incremental transmission rights.

TABLE 10. Summary of bid evaluation options for accounting for transmission risk in RFPs

METHOD	DESCRIPTION AND PURPOSE
Portfolio analysis	Add project to transmission-constrained economic dispatch and RA planning models from the IRP. Provides a holistic evaluation of transmission risk associated with each bid, given the utility's portfolio of transmission rights and existing resources.
Flow-based derates	Apply derates to project hourly availability based on the estimated flow impacts of delivering the bid to the utility's BA (based on PTDFs) and estimated distributions of headroom available to the utility on affected paths. Penalizes bids that are likely to require flows over constrained paths during constrained conditions.
Contractual derates	Apply derates to project hourly availability based on access to unused LTF rights to deliver to the utility's BA after accounting for contractual flows associated with delivering existing resources. May or may not allow for redirects, depending on the application. Encourages bids that deliver to PORs in the utility's LTF transmission portfolio and bids that are complementary to the utility's existing renewable resources.
Transmission cost adders	Apply short-term transmission cost adders to hourly project output that exceeds unused LTF rights from the bid POD to the utility's BA in a manner consistent with the redirect assumptions in the bid valuation. Estimates the additional costs the utility may incur to acquire incremental transmission rights.

Just as with other planning analyses, these approaches leverage simplifications to help inform decision making. These methods are not intended to reflect or replicate detailed transmission planning exercises, but to help resource planners recognize the potential benefits and risks of resources that face different types of transmission constraints (both physical and contractual). In many ways, these approaches are similar in nature to other ongoing efforts to better account for operational flexibility and operational constraints in long-term planning exercises and procurement decisions, including flexibility value and renewable integration costs. Because every utility has their own operational practices and faces unique operating constraints, these efforts may be improved using utility-specific operational information to either benchmark findings or to develop constraints that reasonably estimate operational realities. At the same time, utilities in the Northwest that are pursuing large quantities of renewables should be asking themselves how their operational practices will need to evolve to realize their ambitious plans. Developing a more holistic and flexible transmission strategy is only one facet of this complex endeavor.

Finally, it is worth acknowledging that there are several ongoing initiatives to expand regional transmission availability and improve regional transmission planning that would have impacts to utilities in the Northwest. Specifically, BPA is pursuing a number of transmission upgrades through the Evolving Grid initiative and the Western Transmission Expansion

Coalition (WestEC) is developing a regional transmission plan to inform future transmission investments. These and other transmission planning efforts are crucial. This proposal is intended to complement these efforts, under the premise that adopting strategies that make better use of existing infrastructure will help target new infrastructure to the areas of highest need and will help ensure that the full benefits of new infrastructure are realized. This is especially important as utilities in the Northwest attempt to meet growing demand while prioritizing customer affordability.



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