May 2023

‘Appropriate and Required’: BPA and Building the Grid the Northwest Needs

For decades, the Bonneville Power Administration (“BPA”) has played an integral role in the economy of the Northwest. While BPA is often regarded as the steward of the region’s federal hydroelectric system—marketing power from 31 federal hydroelectric (“hydro”) dams and several non-federal facilities—BPA also performs a critical function as a transmission provider. Indeed, BPA operates and maintains approximately 15,000 miles of high-voltage transmission lines in its service territory, or roughly 75% of the region’s transmission system.

BPA did not become the dominant transmission provider in the Northwest by accident. This outcome was the result of repeated, focused attention by BPA, elected officials, market participants, and other stakeholders. It was not a foregone conclusion. Today, the Northwest is on the cusp of a significant transformation in how it sources power to meet the changing electricity needs of homes and businesses. The federal hydro system is a defining component of the region’s electricity supply. But BPA’s transmission system will receive increasing scrutiny. As utilities in the region shift the rest of their non-hydro resource mix toward a different fleet of non-emitting generation, the transmission grid will have to evolve just as rapidly. The ability of the region to meet these aggressive decarbonization goals is not assured and cannot come to pass unless the region makes significant investments through BPA and through other transmission providers to expand the availability of transmission infrastructure.

This whitepaper, produced by the Northwest & Intermountain Power Producers Coalition (“NIPPC”)[1] and Renewable Northwest (“RNW”),[2] explores how to ensure that BPA maintains

[1] NIPPC (www.nippc.org) is a membership organization that represents competitive power participants in the Pacific Northwest and adjacent Intermountain region. NIPPC members include owners, operators, and developers of independent power generation and storage, power marketers, transmission developers, and affiliated companies. Many NIPPC members are transmission customers of BPA and bear their applicable share of costs for BPA’s transmission upgrades.

[2] RNW (www.renewablenw.org) is a regional, non-profit renewable energy advocacy organization based in Oregon, dedicated to decarbonizing the region by accelerating the transition to renewable electricity. RNW members are a

one of its core purposes—transmitting power needed across the Northwest, regardless of which entity generates or consumes it—at a time of rapid change in the industry. By adopting the reforms laid out here, or some similar combination of reforms, BPA can help ensure that the grid the Northwest needs will be in place and on time so that all consumers in the region continue to enjoy affordable, clean, and reliable electricity. This paper may be updated as new information surfaces.

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I. Executive Summary

BPA plays a significant role in the economy of the Pacific Northwest by delivering energy across its transmission grid. However, the transmission facilities that the Northwest relies upon to access clean and reliable power were mostly built decades ago. Aggressive state and corporate policies to mitigate climate change by changing the generation mix in favor of carbon-free (non-carbon emitting) resources, combined with the impacts to loads and hydro availability from a changing climate, will require significant investment in new transmission facilities to ensure that the output of new resources can be moved from where it can be generated to where it will be consumed. In earlier periods of rapid transformation of the energy industry, BPA played a leading role in developing a transmission grid that met the region's needs. The Northwest now needs BPA to resume that leadership role in the development of new transmission resources, alongside other transmission providers.

Unfortunately, BPA's current transmission planning and related processes are not well-suited to ensure that transmission gets built in time for the wave of change underway. If BPA does not implement process reforms, the ability of consumers, communities, and states as a whole to meet clean energy requirements and goals will be jeopardized. Likewise, with increasing concerns over resource adequacy and climate-related extreme weather events, new and upgraded transmission lines can help ensure system reliability. Fortunately, if BPA implements the recommendations set forth below, which are permissible under its existing legal authorities, BPA can reassert itself as the region's leader in providing a backbone transmission system, alongside a wider range of private transmission developers complementing BPA's work than in the past. BPA appears to have begun recognizing this need for change.

This whitepaper first explores the need for new transmission in the region, establishing that loads in the Northwest are forecast to increase dramatically and that the current resource mix will change dramatically in favor of non-carbon-emitting resources that require more transmission capacity for several reasons. Next, we explore BPA's enabling statutes, which give BPA broad authority and discretion to provide transmission to customers in the Northwest. An appendix provides additional historical context about instances of BPA innovation and leadership in the field of transmission. We then review BPA's existing planning processes and compare them to best practices in other jurisdictions in the U.S., showing the limitations of BPA's processes. These limitations include assumptions that are too conservative, planning over a time horizon that is too short, and too heavy a reliance on discrete customers to shoulder the financial cost of expanding the grid. Due to these limitations, there is a significant risk that transmission facilities will not be available when they are needed. Finally, we propose a suite of reforms. If BPA adopts these recommendations, the region will be much more likely to continue to enjoy access to safe, reliable, and affordable electricity in the future, even as it copes with a changing climate and implements policies designed to reduce the region's reliance on carbon-emitting generation resources.[3]

While this paper focuses on the details of how BPA plans and builds transmission and the nexus between BPA, independent power producers, and utilities, this focus does not imply that BPA should be considered once again the transmission builder of first resort for all or most transmission in the Northwest. Competitive merchant and utility transmission projects should have an essential role in assuming some development risk and responsibility for transmission expansion in the Northwest, particularly for projects that fall outside of BPA's existing rights-of-way or primary network. Similarly, regional projects involving more than one transmission provider should be an important part of BPA's solution set. Nevertheless, the region's currently dominant transmission provider has a significant and indispensable role of its own to play in upgrading and potentially expanding its existing backbone grid, such as upgrading line ratings, doubling circuits, and building tie lines in gaps between existing BPA segments.

This paper does not address challenges and potential solutions to interconnecting new generation on BPA's system, given that BPA has already launched a proceeding to address that important problem. Nor does it address siting and permitting challenges that are a separate major impediment to expanding transmission capacity that affects all transmission providers, not just BPA.

Our proposed recommendations are summarized as follows:

1. **Planning reforms.** BPA should revise its planning process to:
   (A) consider a wider array of transmission projects' benefits;
   (B) regularly conduct proactive local and regional 20-year scenario planning, including a wide range of plausible (for example, at the 95th percentile) but uncertain extreme weather conditions and a range of new generation resources, with robust stakeholder input;
   (C) independently consider state policy requirements and other transmission demand drivers;
   (D) consider a wider range of transmission portfolio future scenarios, including co-optimizing storage and other technologies, in the 10- and 20-year planning timeframes, that may identify "no regrets" or "least regrets" portfolios; and
   (E) remain committed to regional and interregional planning with other transmission providers (recognizing that the best transmission solutions are sometimes regional or interregional, not contained within a single provider's system).

[3] This whitepaper does not endeavor to provide an exhaustive list of all potential transmission reforms that BPA or the region's policymakers should consider pursuing. Rather, this paper seeks to provide recommendations that are well-balanced, taking into account BPA's wide spectrum of customers, and that can be implemented on a relatively expedient basis in order to meet the region's significant transmission needs. More foundational potential statutory and mission-related changes (such as opening up the Pacific Northwest Electric Power Planning and Conservation Act) are not addressed here.

2. **Business case for commercial transmission.** In determining whether to move towards construction of new lines, BPA should:

(A) develop an open and transparent policy specifying the system benefits and revenue thresholds it considers in determining whether to offer customers service at an embedded or incremental rate;

(B) ensure that a wider array of benefits is considered and deducted from the revenue requirement that must be met through subscriptions;

(C) lower the apparently very high threshold of subscriptions (binding commitments to take transmission service) required to proceed to most construction; and

(D) separately develop an analytical framework to consider how to incorporate into its long-term planning facilities that appear repeatedly in multiple planning studies but lack a critical mass of subscribers committing financially to upgrades.

3. **Participant funding.** BPA should:

(A) develop a formal policy identifying the criteria under which it will conduct engineering, siting, and other pre-construction studies for transmission line upgrades at its own expense and identifying how those costs will eventually be recovered from customers; and

(B) revisit and consider lowering the currently high letter of credit/deposit requirement for Transmission Service Request Study and Expansion Process ("TSEP") subscribers, while addressing the need to protect against undue risks of stranded costs.

4. **Contracting innovation.** BPA should:

(A) explore using BPA's Transmission Business Line itself as an anchor, or backstop, tenant by exercising a "put option" on some carefully chosen commercial transmission built by BPA;

(B) explore whether investor-owned utilities ("IOUs") can and would be willing serve in some form as backstop subscribers for some new transmission capacity, perhaps until independent power producers ("IPPs") fill in the capacity on a given line in the course of delivering power to those IOU offtakers; and

(C) explore joint venture and partnership opportunities that rely on private capital and private projects to take initial development, construction, or subscription risk in lieu of BPA.

5. **Risk calculations.** BPA should:

(A) revisit the core question of how much risk the agency will assume in pursuing a renewed transmission construction agenda, including an analysis of potential benchmark levels of risk (for example, outcomes modeled at a 95^{th} percentile);

(B) review and share with stakeholders whether past transmission investments have actually resulted in any stranded assets (and whether the stranding was temporary or persistent); and

(C) analyze and consider new revenue opportunities to the agency from having and selling more transmission capacity through a variety of existing and potentially new transmission products.

6. **Process.** BPA should:

(A) conduct an iterative customer-facing initiative to consider and make the changes recommended above, including an active effort to solicit the perspective of state regulatory commissions, potentially as inputs into BPA's upcoming revision of its strategic plan and transmission business model;
(B) following such an initiative, conduct a formal tariff revision process to incorporate those reforms into its business practices or its transmission tariff, but in the tariff only to the extent a given reform requires such a revision; and
(C) advocate within NorthernGrid for the adoption of similar reforms in the planning processes of NorthernGrid and any successor organization.

7**. Transparency**. In considering and implementing the above-described processes and reforms, BPA should make the processes and decision points about reform transparent, including by ensuring that BPA's website acts as a repository of up-to-date information, as well as relevant historical documents.

8. **Compensation.** In order to support BPA recruiting and retaining the necessary transmission planning, business case, and associated transmission staff to carry out the reforms proposed in this whitepaper, Congress should pass competitive compensation reform for BPA.

II. The Need for New Transmission in the Pacific Northwest

Multiple independent analyses and market data indicate that the Pacific Northwest needs to expand its transmission grid. Operating conditions are changing: climate change is leading to longer and more severe extreme weather, putting pressure on the grid as operators seek to move electricity from areas with surplus generation to areas experiencing extreme weather conditions. The generation fleet is transforming: public policy and market economics have led to the retirement of fossil fuel-powered generation in favor of generation resources that do not emit carbon into the atmosphere. Demand is growing: state energy policies are also expected to lead to the rapid adoption of electric vehicles and electrification of other sectors, putting further pressure on the transmission grid. Numerous national and regional studies have demonstrated that these climate and policy drivers will require new transmission facilities. For example:

- One national study by researchers at Princeton University found that in order to meet energy demand by 2050—and in particular, demand for renewable electricity—transmission capacity will have to increase by 60%.[4]
- Another study by researchers at the Massachusetts Institute of Technology found that the U.S. will require a 90% increase in transmission capacity to meet the cost-optimized scenario to maintain global warming between 1.5-2 degrees Celsius.[5]
- A report by the non-profit Energy Systems Integration Group, summarizing research from six different studies, found that meeting the Biden Administration's goal to reach 100 percent clean electricity by 2035 and net-zero emissions across the economy by 2050 will require a doubling or tripling of the size and scale of the nation's transmission system.[6]

In February, the U.S. Department of Energy ("DOE") released a draft study of national and regional transmission needs, after reviewing over 200 scenarios from six recent capacity expansion modeling studies:

- DOE estimated that the Pacific Northwest will need to add 56% more transmission capacity (8.5 terawatt-miles ("TW-mi")) by 2040 in an aggressive decarbonization scenario.[7]

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[4] Larson et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, 13-14 (Dec. 15, 2020), *available at*: https://netzeroamerica.princeton.edu/img/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf.

[5] Brown, P. R., and A. Botterud, Joule5(1), *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the U.S. Electricity System,* 115-134 (2020), *available at*: https://doi.org/10.1016/j.joule.2020.11.013.

[6] Energy Systems Integration Group, *Transmission Planning for 100% Clean Electricity*, 10 (Feb. 2021), *available at* https://www.esig.energy/wp-content/uploads/2021/02/Transmission-Planning-White-Paper.pdf.

[7] U.S. Department of Energy, *Draft National Transmission Needs Study* ("DOE Draft Needs Study"), 89 (Feb. 2023) *available at:* https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf. The granular regional and interregional study results reviewed by DOE included the Princeton and MIT studies cited above.

- DOE estimated a nearly equal amount (7.7 TW-mi) needed in the surrounding Mountain region.
- To provide a sense of scale, if that combined 16.2 TW-mi need was met with discrete moderate-length alternating current ("AC") lines, it would require building 61 new 200-mile long 500-kV lines.[8]
- In the same aggressive scenarios, DOE also estimated a need in 2040 for 37% more transfer capacity (1.9 GW) between the Northwest and California and 308% more transfer capacity (39.2 GW) between the Northwest and Mountain states.[9]

Finally, regional estimates of the expected and potential generation build-out in the Northwest underscore this driver of the need for new transmission:

- According to the Northwest Power and Conservation Council, the region will need 3,500 MW of new renewable generation by 2027 and 14,000 MW of renewable generation by 2040.[10]
- According to the Pacific Northwest Utilities Conference Committee ("PNUCC"), the region will need 9,400 MW of new renewable generation by 2032 with associated transmission.[11]
- Analysis by Evolved Energy Research on behalf of the Clean Energy Transition Institution found that deeply decarbonizing all sectors in the Northwest would lead to a 60% increase in load (because of electrifying other sectors) and therefore a need for 100,000 MW of new resources by 2050, a quantity that may be considered an upper bound.[12]

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[8] Terawatt-miles are a measurement unit common in models for transmission capacity expansion because they allow a single unit to cover all potential new lines in a region by eliminating differences in their carrying capacity. AC lines that are shorter or have a higher nominal voltage have higher carrying capacity. For example, an uncompensated 200-mile 500-kV AC line has about the same carrying capacity as a 50-mile 345-kV line. (DOE Draft Needs Study, 88).

[9] DOE Draft Needs Study, 96-97. "Transfer capacity" is sometimes referred to interchangeably as "transfer capability," but *capacity* identifies only the ratings of transmission lines that account for their thermal limits, whereas *capability* accounts for other network elements that might limit the reliable transfer of power from one area to another.

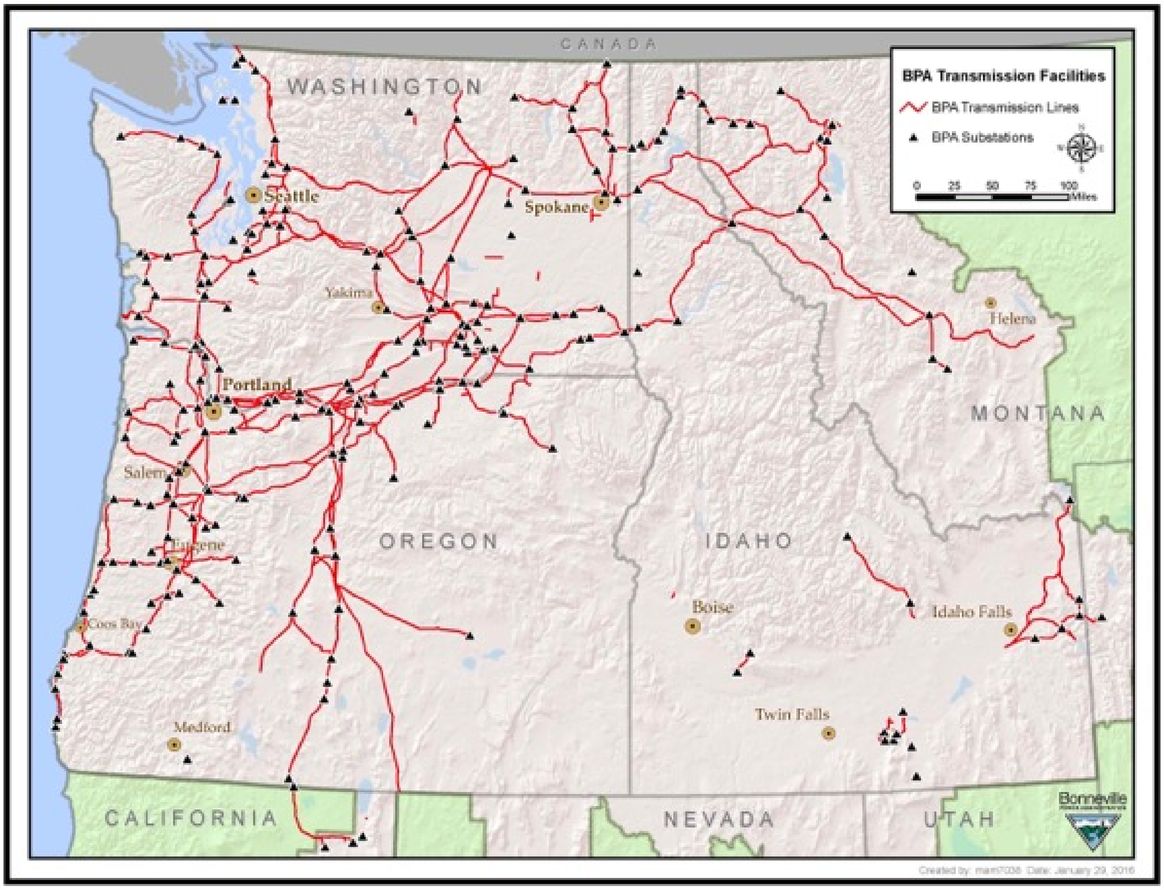
[10] Northwest Power and Conservation Council, *2021 Northwest Power Plan*, 71-77 (Mar. 2022), *available at*: https://www.nwcouncil.org/media/filer_public/4b/68/4b681860-f663-4728-987e-7f02cd09ef9c/2021powerplan_2022-3.pdf.

[11] Pacific Northwest Utility Conference Committee, *Northwest Regional Forecast of Power Loads and Resources 2022 through 2032* ("PNUCC 2022 Regional Forecast"), 11 (April 2022), *available at:* https://www.pnucc.org/wp-content/uploads/2022-PNUCC-Northwest-Regional-Forecast-final.pdf.

[12] Evolved Energy Research, *Northwest Deep Decarbonization Pathways Study*, 73-74 (May 2019), *available at:* https://uploads-ssl.webflow.com/5d8aa5c4ff027473b00c1516/6229312d39eca8b6b5fb8868_EER_Northwest_Deep_Decarbonization_Pathways_Study_Final_May_2019.pdf .

III. BPA Transmission and its Role in the Northwest

Figure 1. Map of BPA Transmission Facilities



Available at: https://www.bpa.gov/-/media/Aep/about/publications/maps/bpa-tlines-small.pdf

BPA's transmission forms the backbone for the electric grid in the Pacific Northwest and allows energy to flow from Montana to the West Coast and from Canada to California. BPA operates 15,179 circuit-miles of high voltage transmission lines and 259 substations across the states of Washington, Oregon, Idaho, and Montana, including interties to British Columbia, eastern Montana, and California. Facilities controlled by BPA represent 75% of the high voltage transmission capacity in the Pacific Northwest.[13] The region's load-serving entities—investor-owned utilities, consumer-owned utilities, and competitive retail service providers—depend on BPA transmission to deliver energy to their retail customers. As the mix of generation resources in the Pacific Northwest changes, the availability of transmission service to deliver energy from where it is needed to where it is consumed is becoming increasingly constrained.

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[13] BPA, *BPA Facts* (Aug. 2021), *available at:* https://www.bpa.gov/-/media/Aep/about/publications/general-documents/bpa-facts.pdf.

BPA has specific statutory obligations to the region (described more fully below in Section IV); these responsibilities include providing necessary transmission. However, unlike a transmission owner that is an investor-owned utility or a merchant transmission developer, BPA has no profit incentive to invest capital in new transmission.[14] This reality may contribute to suppressing BPA's current incentive to build more transmission.

NIPPC and RNW also strongly support competitive, private sector solutions to the Northwest's needs that help avoid or mitigate some stranded asset risks for BPA's rate base. But given BPA's dominant role in providing transmission service to the region, the private sector is ill-situated to solve by itself a transmission build-out of the magnitude anticipated. The Appendix explores how BPA has supported transmission in the past to meet the region's evolving energy needs. BPA itself has recently begun recognizing the evolving grid, changing demands on BPA, and the role that BPA might play in helping address the region's urgent transmission demands.[15] The remainder of this whitepaper explores what BPA is doing now to plan and build new transmission and suggests ways BPA could carry out these responsibilities more effectively.

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[14] Investor-owned utilities are guaranteed a rate of return on prudent investments. In contrast, as a government entity that must limit its rates to covering its costs and lacks shareholders who put their equity at risk, BPA does not have a profit motive to expand the grid similar to a private company.

[15] *See* BPA, *The Evolving Grid: Update on the State of Transmission* (April 27, 2023), *slides available at*: https://www.bpa.gov/-/media/Aep/transmission/transmission-business-model/042723-evolving-grid-bpat-final.pdf, *workshop recording available at*: https://youtu.be/rbYbQf-wD6E. This recent presentation is highly informative about BPA's current transmission planning queue and upcoming construction agenda.

IV. BPA's Legal Authorities Related to Transmission

A. Congress Has Given BPA Broad Discretion to Function in a Business-Like Manner, Including in Managing the Transmission System

Four statutes primarily govern BPA's operations: 1) the Bonneville Project Act of 1937 (the "Project Act");[16] 2) the Pacific Northwest Consumer Power Preference Act of 1964 (the "Preference Act");[17] 3) the Federal Columbia River Transmission System Act of 1974 (the "Transmission Act");[18] and 4) the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (the "Northwest Power Act").[19] Overall, these statutes afford BPA broad discretion, including over its management of the federal transmission system in the Pacific Northwest.

The Project Act recognizes that transmission is essential to "encourag[ing] the widest possible use of" federal power.[20] To that end, it has directed BPA since 1937 to "provide, construct, operate, maintain, and improve" such transmission facilities as BPA finds "necessary, desirable, or appropriate" for transmitting federal power.[21] In the words of the Ninth Circuit Court of Appeals (the "Ninth Circuit") in resolving a dispute about BPA's authority:[22]

> This delegation of authority is broad, allowing the [BPA] Administrator substantial discretion. This discretion is tempered only by the implied limitation that the Administrator's action not be inconsistent with other congressional decrees."[23]

The Preference Act directs BPA to provide for transmitting non-federal power any available transmission capacity that is in excess of federal power needs.[24] BPA is obligated to set "equitable rates" for such usage.[25] The Project Act had already provided BPA with broad

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[16] 16 U.S.C. §§ 832-832*l*.
[17] 16 U.S.C. §§ 837-837*h.*
[18] 16 U.S.C. §§ 838-838*l.* This Act is also sometimes referred to as the Pacific Northwest Federal Transmission System Act or simply the Transmission System Act.
[19] 16 U.S.C. §§ 839-839*h*. This Act is also sometimes referred to as the Regional Act.
[20] 16 U.S.C. § 832a(b).
[21] Aug. 20, 1937, ch. 720, §2, 50 Stat. 732 (codified as amended at 16 U.S.C. § 832a(b)); *see also* 16 U.S.C. § 832e (directing BPA to set customer rates for federal power "with a view to encouraging the widest possible diversified use of electric energy").
The Project Act, even as codified, refers specifically to BPA transmitting power from BPA's namesake, the Bonneville Dam. 16 U.S.C. § 832a(b). BPA's purview has since expanded to many other federal facilities. *E.g.,* the Flood Control Act of 1944, Dec. 22, 1944, ch. 665, §5, 58 Stat. 890 (codified in relevant part in 16 U.S.C. § 825s)*; see also* 16 U.S.C. § 839e(a)(1), 839e(k) (referencing BPA's continuing obligations under the Flood Control Act of 1944).
[22] The Northwest Power Act specifically vests the Ninth Circuit with jurisdiction to hear challenges to BPA actions. 16 USC § 839f.
[23] *California Energy Comm'n v. Bonneville Power Admin.*, 909 F.2d 1298, 1314 n.17 (9th Cir. 1990).
[24] 16 U.S.C. § 837e. The Transmission Act later affirmed this and required it to be done on a "fair and nondiscriminatory basis." 16 U.S.C. § 838d.
[25] 16 U.S.C. § 837e.

authority to negotiate contracts as BPA deemed "necessary,"[26] and BPA has since interpreted the Project Act to authorize it to establish generally applicable terms and conditions for transmission service of both federal and non-federal power.[27]

The Preference Act affirms BPA's historic focus on serving customers in the Pacific Northwest.[28] In that context, it generally prohibits BPA from constructing transmission facilities outside the Pacific Northwest.[29] Still, BPA may pursue such facilities as BPA "deems necessary to allow mutually beneficial power sales" with California.[30]

The Transmission Act granted BPA "even broader transmission authority."[31] It directs that:

> [BPA] shall operate and maintain the Federal transmission system within the Pacific Northwest and shall construct improvements, betterments, and additions to and replacements of such system within the Pacific Northwest as [BPA] determines are appropriate and required to:
>
> (a) integrate and transmit the electric power from existing or additional Federal or non-Federal generating units;
> (b) provide service to [BPA's] customers;
> (c) provide interregional transmission facilities; or
> (d) maintain the electrical stability and electrical reliability of the Federal system[.][32]

Thus, among other authority and obligations, the Transmission Act provides the statutory authority for BPA to build new transmission as needed to transmit non-federal power.

In addition, the Transmission Act freed BPA from relying on Congress's annual appropriations for transmission expenditures in the Pacific Northwest.[33] Under the Transmission Act, BPA

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[26] 16 U.S.C. § 832a(b).
[27] *E.g.*, TC-20 Tariff Terms and Conditions Proceeding, Record of Decision, TC-20-A-03 at 8-9 (Mar. 1, 2019) [hereinafter TC-20 ROD].
[28] *E.g.,* 16 U.S.C. § 837f. Such provisions are generally consistent with BPA's longstanding obligation to serve those persons "within economic transmission distance of the Bonneville project." 16 U.S.C. § 837c(d).
[29] 16 U.S.C. § 837g.
[30] 16 U.S.C. § 837g-1. This provision has been codified with the Preference Act, but it was actually enacted about 20 years later in the context of Congress authorizing BPA's participation in the development of the Third AC Intertie of the California-Oregon Intertie. Pub. L. 98–360, title III, July 16, 1984, 98 Stat. 416; see generally *Pacific Gas and Electric Company; Pacific Gas and Electric Company; Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company,* 63 FERC ¶ 63,018, 65,070 (June 30, 1993) (discussing this history).
[31] *Ass'n of Pub. Agency Customers v. BPA*, 126 F.3d 1158, 1170 (9th Cir. 1997).
[32] 16 U.S.C. § 838b.
[33] 16 U.S.C. § 838b. BPA does need some form of Congressional approval (but not appropriations) before constructing "major transmission facilities" in the region, which the statute defines as facilities "intended to be used to provide services not previously provided." 16 U.S.C. §§ 838a, 838b. There are prior examples of Congress approving such expenditures, either directly or by reference, such as in an appropriations legislative vehicle. *E.g.,*

became a self-financing agency primarily dependent upon revenues from the services it provides to sustain ongoing activity; this activity is capitalized primarily through funds borrowed directly from the U.S. Treasury and repaid with interest.[34] BPA must consider its obligations to repay Treasury funds when it sets customer rates.[35] Both the Transmission Act and the Northwest Power Act direct BPA to set customer rates consistent with "sound business principles."[36] BPA must also set rates "sufficient to assure repayment" of the federal investment in hydro generation, fish and wildlife recovery, and conservation.[37] Thus, BPA typically does not need specific Congressional authorization to move forward with projects in the Pacific Northwest once BPA has determined they are "appropriate and required" to meet BPA's statutory goals above. But BPA must charge rates sufficient to recover the costs of those projects.

The Northwest Power Act directs BPA to carry out its obligations "in a sound and businesslike manner."[38] It also, for the first time, specifically obligated BPA to undertake certain environmental and conservation endeavors.[39] The Ninth Circuit has noted that BPA's new "more typically governmental responsibilities" under the Northwest Power Act "suggest the propriety of even greater deference" to BPA's business-like decision-making.[40]

The Northwest Power Act also specifically vested the Ninth Circuit with jurisdiction to hear challenges to BPA actions, but the Ninth Circuit has generally, to date, taken a very deferential approach.[41] The Ninth Circuit has described BPA's governing statutes as endow[ing] the

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Consolidated Appropriations Act, 2014, Public Law 113-76, 128 Stat. 170 (approving BPA's request to spend its funds to construct a new high voltage line to serve customers in southern Idaho, southern Montana, and western Wyoming). Under the Transmission Act, BPA is still obligated to submit an annual budget to Congress; items included in the budget need no further appropriation, and BPA's annual submission may include a request for approval of major transmission facilities. *Id.* § 838i(a). Congress may impose limits on BPA, which BPA must adhere to. *Id.*, at § 838i(b).

[34] *See generally* 16 U.S.C. §§ 838i, 838k.

[35] 16 U.S.C. § 838g.

[36] The Transmission Act directs BPA to set rates "with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles." 16 U.S.C. § 838g. BPA must also consider its need to recover costs and repay its debts. *Id.* The Northwest Power Act directs BPA to set rates "in accordance with sound business principles" and other statutory provisions like the one quoted above, which FERC must approve upon a finding that the rates: 1) "are sufficient to assure repayment" of the federal investment; 2) "are based upon … total system costs"; and 3) for transmission rates, "equitably allocate the costs of the Federal transmission system between federal and non-Federal power" users. 16 U.S.C. § 839e.

[37] 16 U.S.C. § 839e.

[38] 16 U.S.C. § 839f(b).

[39] *See generally* 16 U.S.C. §§ 839-839*h*.

[40] *Ass'n of Pub. Agency Customers*, 126 F.3d at 1170.

[41] 16 USC § 839f. The Supreme Court has also commented on the deferential review due to BPA, based in part on the complexity of BPA's work and BPA's intimate involvement in the legislative drafting of BPA's statutes. *Aluminum Co. of America v. Central Lincoln Peoples' Utility Dist.*, 467 U.S. 380, 390 (1984).

Administrator with broad-based powers to act in accordance with BPA's best business interests—powers not normally afforded government agencies.[42]

The Ninth Circuit has recognized that Congress intended for "BPA to function more like a business than a governmental regulatory agency"[43] and that Congress "granted BPA an unusually expansive mandate to operate with a business-oriented philosophy."[44] In this context, the Ninth Circuit has recognized that its review has been "particularly deferential" to BPA.[45]

Finally, Congress has also declared broad policies which BPA should pursue. One is to "encourage … the development of renewable resources within the Pacific Northwest."[46] Another is "to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply."[47] These goals should inform BPA's exercise of its discretion and underscore BPA's important role in facilitating the development of renewable resources and the transmission needed to supply customers with electricity regardless of the generating source.

In summary, BPA has statutory obligations to maintain and improve the federal transmission system in the Pacific Northwest, which it may carry out with an unusually high level of discretion. Unlike most agencies, BPA is generally not subject to the typical appropriations approval process for agency action. Instead, it must, in a sound business-like manner, set rates for the services it provides with an eye to providing service while still recouping its costs, including its repayment of the federal investment in hydro generation, fish and wildlife recovery, and conservation.[48] BPA aims to keep rates low, but that goal does not ultimately trump BPA's obligations to maintain and improve the transmission system.

B. BPA Must Provide Transmission Service in Accordance with its Adopted Terms and Conditions for Providing Service

Like most transmission providers, BPA has streamlined its contracting process for offering transmission service by adopting generically applicable terms and conditions for such service. These generic terms and conditions are commonly referred to as an "Open Access Transmission Tariff" or "OATT," an industry term that was widely adopted following the seminal open access

[42] *Ass'n of Pub. Agency Customers*, 126 F.3d at 1170; *see also Bell v. BPA*, 340 F.3d 945, 949 (Ninth Cir. 2003) ("We will not second-guess the wisdom of BPA's winning business decisions, especially when it was responding to unprecedented market changes.").

[43] *Ass'n of Pub. Agency Customers*, 126 F.3d at 1170; *see also, e.g.,* 16 U.S.C. § 832a(b), 832a(f).

[44] *Ass'n of Pub. Agency Customers*, 126 F.3d at 1171; *see also Indus. Customers of Northwest Utils. v. BPA*, 767 F.3d 912, 923-924 (2014) (noting BPA has "wide latitude" both "in spending" and in deciding "how best to further BPA's business interests consistent with its public mission.") (citing *Aluminum Co.,* 467 U.S. at 789)).

[45] *Pac. Northwest Generating Coop. v. Dep't of Energy*, 580 F.3d 792, 806 (2009).

[46] 16 U.S.C. § 839(1)(B).

[47] 16 U.S.C. § 839(2).

[48] *See supra* footnote 21.

directive of the Federal Energy Regulatory Commission ("FERC"), Order 888.[49] As noted earlier, BPA has broad authority to negotiate contracts under the Project Act,[50] and BPA has since interpreted the Project Act to authorize it to establish generally applicable terms and conditions for transmission service of both federal and non-federal power.[51] This section of this paper addresses BPA's foundational obligation to adhere to its OATT.

Unlike most transmission providers, BPA is generally[52] not subject to FERC oversight or directives for setting generically applicable transmission terms and conditions.[53] In the past, BPA voluntarily sought (and sometimes obtained) FERC's approval of BPA's OATT in order to obtain "safe harbor reciprocity status,"[54] which would require most other transmission providers to provide transmission service to BPA pursuant to their own FERC-approved OATTs.[55] In 2013, FERC declined to grant BPA safe harbor reciprocity status,[56] and in 2016, rather than address FERC's criticisms, BPA decided not to seek reciprocity status.[57] Nonetheless, this history provides useful context in understanding BPA's decision-making within a policy space in which FERC and other transmission providers have established certain principles and ideals, even though BPA is generally not directly beholden to FERC's directives.[58] *See footnote 105 for additional distinctions between BPA and transmission-owning utilities.*

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[49] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[50] 16 U.S.C. § 832a(b).

[51] *E.g.*, TC-20 ROD at 8-9.

[52] FERC can enforce BPA's obligation to offer transmission service at rates comparable to those BPA pays and on terms and conditions that are "not unduly discriminatory or preferential." 16 U.S.C. § 824j-1(b); *see also Iberdrola Renewables, Inc. v. BPA*, 137 FERC ¶ 61,185, at ¶ 61,949 (Dec. 7, 2011) (exercising this authority); *cf.* 16 U.S.C. § 824k (describing additional FERC authority over BPA's terms of transmission service).

[53] BPA is not a "public utility" under key provisions of the Federal Power Act. 16 U.S.C. §§ 824, 824d, 824e. However, it can (and has) obligated itself to at least consider FERC's standards under certain of those provisions. TC-20 ROD at 9-10.

[54] *See generally BPA, Order on Petition for Declaratory Order,* 145 FERC ¶ 61,150 at PP 2-7 (Nov. 21, 2013) (addressing a BPA request for reciprocity status and discussing BPA's history).

[55] *See* FERC Order No. 888, 61 Fed. Reg. 21,540 at 21,613-14 and 21,668-69 (May 10, 1996); FERC Order No. 888-A, 62 Fed. Reg. 12,274 at 12,338-40 (Mar. 14, 1997).

[56] *BPA, Order on Petition for Declaratory Order,* 145 FERC ¶ 61,150 at P 1 (Nov. 21, 2013). While FERC accepted several proposed changes to BPA's OATT, FERC identified additional changes that would need to be made before FERC could grant BPA safe harbor reciprocity status. These changes include updates to Schedules 9 and 10 regarding BPA's provision of Generator Imbalance Service; removal of the price cap on transmission capacity reassignments; and minor updates to Attachment C, which describes BPA's Available Transfer Capacity methodology.

[57] *See* TC-20 ROD, Appendix 1 at 1. It is possible that BPA could change its mind in the future.

[58] Importantly distinct from this discussion of transmission terms and conditions is BPA's obligation to comply with certain FERC-jurisdictional reliability and safety standards, such as those promulgated by the North American Electric Reliability Corporation ("NERC") or the Western Electricity Coordinating Council ("WECC"). *See generally* BPA, *Reliability & NERC Standards, available at:* https://www.bpa.gov/energy-and-services/transmission/reliability-nerc-standards.

In 2018, BPA launched its own proceeding (distinct from a FERC tariff update) to update BPA's OATT.[59] Under the Energy Policy Act of 1992, Congress declared that BPA "may" hold a hearing when establishing transmission terms and service and that, if BPA pursues that option, then BPA must follow certain procedural requirements.[60] BPA did so in 2018, and in that proceeding developed an OATT that commits BPA to follow Congress's specified procedures for future changes to BPA's OATT.[61] Further, while BPA may generally amend its OATT through proceedings that comply with the statutory procedures,[62] BPA committed to its customers that BPA would not make changes to its OATT before October 1, 2028 without complying with the statutory procedures.[63]

In short, when considering the specific terms and conditions of BPA's OATT, discussed elsewhere in this whitepaper, it bears emphasis that BPA has committed itself to following an administrative procedure before changing any provisions of its OATT.[64]

C. BPA's Adopted Terms and Conditions for Providing Transmission Service Provide BPA a Reasonable Amount of Discretion to Manage Future Transmission Needs and Allocate Costs

BPA's OATT addresses both BPA's obligation to provide transmission service and transmission customers' obligations to agree to pay the costs that BPA incurs to provide transmission service. While BPA has general obligations to recover its costs, and bearing in mind statutory requirements applicable to BPA, BPA's OATT and related business practices afford BPA meaningful discretion in assessing when costs are properly attributable to a particular transmission customer(s) or should be spread broadly across the transmission system.[65]

Recall that BPA's statutory mandates give BPA significant discretion in managing costs. As discussed above, BPA is a self-financing agency that primarily relies upon raising capital using its Treasury borrowing authority and third-party contractual commitments, and generates

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[59] TC-20 ROD, at 1.

[60] Energy Policy Act of 1992, Pub. L. 102–486, title VII, §722, Oct. 24, 1992, 106 Stat. 2916 (codified at 16 U.S.C. § 824k(i)).

[61] TC-20 ROD, at 11-13; *see also* BPA OATT § 9 ("Subject to applicable law, Bonneville commits to open access transmission service. Bonneville shall follow the statutory procedures in Section 212(i)(2)(A) of the Federal Power Act to set generally applicable terms and conditions in its Tariff…"), *available at:* https://www.bpa.gov/-/media/Aep/transmission/open-access-transmission-tariff/bpa-open-access-transmission-tariff-20211001.pdf.

[62] BPA has in fact amended its OATT through proceedings that comply with the statutory procedures. *See generally TC-22 Tariff Proceeding*, Administrator's Final Record of Decision, TC-22-A-03 (July 2021); *TC-24 Tariff Proceeding*, Administrator's Final Record of Decision, TC-24-A-02 (Feb. 2023).

[63] TC-20 ROD, at 13. This date is significant for BPA; BPA anticipates entering into new power customer agreements that will take effect that date. *See generally* BPA, *Provider of Choice (Post-2028)*, *available at:* https://www.bpa.gov/energy-and-services/power/provider-of-choice.

[64] TC-20 ROD, at 11-13; *see also* OATT § 9 ("Subject to applicable law, Bonneville commits to open access transmission service. Bonneville shall follow the statutory procedures in Section 212(i)(2)(A) of the Federal Power Act to set generally applicable terms and conditions in its Tariff…").

[65] Due to BPA's transmission system being composed of three distinct segments, costs and rates are developed for these separate segments and charged to those seeking service on one or more of these segments.

revenues from the services it provides to sustain ongoing activity. BPA's revenue sources include its primarily cost-based power sales to power customers (who also rely on BPA to transmit that power) and its sales of transmission services to transmission customers. Under the Northwest Power Act, BPA must "equitably allocate" transmission costs between federal and non-federal users (i.e., between power customers and transmission-only customers),[66] and BPA must charge transmission customers at rates "comparable" to those BPA pays itself to deliver federal power.[67] Rate proceedings must follow specific procedures,[68] and BPA must submit its rates to FERC for limited review.[69] Discontented stakeholders may challenge BPA's rate submission before FERC and appeal rate decisions to the Ninth Circuit.[70] The Ninth Circuit is generally deferential to both BPA and FERC's decisions on ratemaking.[71]

BPA evaluates transmission needs both in its regular system planning process (OATT Attachment K)[72] and in considering new requests for transmission service. In brief, BPA determines whether its system and the adjacent sub-grid are adequate to provide service both as a regular practice to continue offering service and in response to new requests for service. (These planning processes are described in more detail in the next section.)

BPA's OATT reflects BPA's statutory authority to satisfy transmission needs, even when they require new investments. Recall that BPA's obligations include to "integrate and transmit the electric power from existing or additional Federal or non-Federal generating units" and to "maintain the electrical stability and electrical reliability of the Federal system."[73] This is true for both Network Integration Transmission Service and for Point-to-Point Transmission Service.[74] For Network Integration Transmission Service, the OATT declares that BPA must

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[66] 16 U.S.C. § 839e(a)(2)(C). The implications of the equitable allocation requirement are beyond the scope of this whitepaper. Note that power customers are all, or almost all, transmission customers as well, whereas many transmission customers buy only transmission service from BPA.
[67] *See* 16 U.S.C. § 824j-1(b).
[68] 16 U.S.C. § 839e(i). Notwithstanding the procedural steps BPA is required to follow, BPA ratemaking proceedings are unusual in that a major transmission owner acts effectively as prosecutor, judge, and jury of its own transmission rate decisions.
[69] 16 U.S.C. § 839e(a)(2). FERC's review of BPA ratemaking decisions is statutorily limited to whether the rates are based on system costs, sufficient to assure repayment, and, for transmission, equitably allocated between federal and non-federal users. *See generally U.S. Secretary of Energy, Bonneville Power Administration*, 20 FERC ¶61,292 (1982) (discussing the limits of FERC's review of BPA rates). This is a much more limited review than for a regulated transmission owner. *See* 16 USC § 824d (providing FERC broad authority to review whether rates are "just and reasonable" and nondiscriminatory).
[70] 16 U.S.C. § 839f(e)(1)(G).
[71] *See Aluminum Co. of America v. BPA*, 903 F.2d 585, 590 (1989) (discussing how the Ninth Circuit's review focuses on whether there is "substantial evidence" supporting BPA's determination and how the court must affirm the agency unless the decision is "arbitrary, capricious, an abuse of discretion, or in excess of statutory authority").
[72] See Section V.A for a more detailed discussion of Attachment K planning.
[73] 16 U.S.C. § 838b.
[74] Point-to-Point Transmission Service is defined as "The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff." OATT § 1.77.
By contrast, Network Integration Transmission Service is defined as "The transmission service provided under Part III of the Tariff." OATT § 1.59. For instance, Section 28.1 of Part III states "Network Integration Transmission Service

"plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K."[75] Similarly, for Point-to-Point Transmission Service, the OATT declares that BPA generally is "obligated to expand or upgrade its Transmission System," but that the customer generally must finance "any necessary transmission facility additions."[76]

Under the systemwide planning process, any new facilities' costs "are allocated to transmission rates in rate proceedings."[77] For new service requests, BPA must determine whether the costs of new facilities should be assigned directly to the customer requesting upgrades or expansion or included in BPA's transmission rate base.[78]

D. *In Summary, BPA Must Provide Transmission Service and Has Reasonable Discretion to Manage the Costs of Doing So in a Sound Business-Like Manner*

Congress has broadly authorized BPA to provide transmission service in the Pacific Northwest. Within statutory parameters such as rates needing to cover BPA's costs and transmission costs needing to be equitably allocated,[79] BPA has broad discretion to implement policies and procedures that best fulfill Congress's goals and BPA's directives. These include "encourag[ing] … the development of renewable resources within the Pacific Northwest,"[80] a policy clearly aligned with the growing number of state mandates to decarbonize. Applicable directives also include operating, maintaining, and expanding the transmission system to integrate and transmit power from existing or additional federal or non-federal generation. Indeed, with the exception of competitive compensation reform, we have encountered no limitation that would prevent BPA from pursuing the reforms described in this whitepaper or that would require any act of Congress to change or expand BPA's authority. BPA has all the legal authority it needs to improve its transmission planning and ultimately pursue construction of transmission upgrades.

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is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff."

[75] OATT § 28.2.

[76] OATT §§ 13.5, 15.4.

[77] OATT Attachment K § 8.2.

[78] Transmission customers are generally responsible for costs "to the extent consistent with [FERC] policy." OATT §§ 27, 34.

[79] 16 U.S.C. § 839e(a).

[80] 16 U.S.C. § 839(1)(B).

V. BPA's Transmission Planning Processes

BPA's OATT reflects BPA's statutory authority to satisfy transmission needs, including when new investments are required. This section describes BPA's several interrelated planning processes and their policy context in more detail.

To meet BPA's statutory and tariff obligations, BPA conducts multiple transmission planning processes consistent with FERC's open access requirements. BPA performs *local* planning to consider load growth and transmission demand over a 10-year time period. BPA also offers customers a *subscription-based* open season process, which aggregates requests for new service on the transmission system. In addition, BPA participates in *regional* planning through NorthernGrid, which considers regional transmission needs over a 10-year time horizon. While these planning processes are largely successful in meeting short-term regional reliability and economic needs by identifying incremental improvements to the grid, they are markedly less successful in identifying transmission upgrades that will be needed to meet public policy targets and mandates more than 10 years in the future and in moving those transmission projects towards construction.

A. Local Planning for Network and Point-to-Point Service

FERC issued Order 890 in 2007 to require utilities under its jurisdiction to engage in coordinated, open, and transparent planning at both the regional and local level. FERC memorialized this obligation in "Attachment K" of its OATT.[81] BPA has incorporated these planning obligations into its own transmission tariff.[82] As envisioned by FERC, transmission providers have the obligation to plan the transmission system for their customers. The OATT defines two types of transmission service—Network Integration Service and Point-to-Point Service—and transmission providers like BPA must plan for service to customers in both categories.

1. Network Integration Service

Network Integration Service Customers (also referred to as "Network Service" or simply "Network" Customers) take Network Integration Service and rely on the transmission provider to serve their load using generation resources the customers have designated, in addition to these customers' obligation to invest in upgrades on adjacent sub-grids that BPA does not cover.[83] For its Network Customers, a transmission provider like BPA also has the obligation to

[81] *Preventing Under Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (March 15, 2007).
[82] *See* BPA, *Transmission Services Open Access Transmission Tariff Attachment K*, 163, *available at*: https://www.bpa.gov/-/media/Aep/transmission/open-access-transmission-tariff/bpa-open-access-transmission-tariff-20211001.pdf.
[83] A Network Customer is a customer who has elected to take Network Integration Service from its transmission provider (BPA OATT Sec. 1.58). For customers who select Network Integration Service, BPA has the responsibility to integrate, dispatch and regulate the customers' current and planned Network Resources to serve their Network

plan its system to ensure that it can continue to serve these customers' needs as their loads grow in the future. The OATT establishes requirements for customers and their transmission provider to exchange information on load growth and future generation resources. For BPA, its Network Customers are mostly its public power customers, and particularly "load following" customers who obtain all the power they need from BPA.

2. Point-to-Point Service

In contrast to Network Customers, customers with Point-to-Point Service simply secure the right to move energy from one point on the transmission provider's system to another. While FERC's *pro forma* OATT also requires transmission providers to expand the transmission grid to meet the requests of Point-to-Point Customers, if a Point-to-Point Customer seeks to move more energy across a transmission provider's system in the future, it must submit a request for new Point-to-Point Service.[84] Unlike Network Service where a transmission provider must proactively collect data for its Network Customers' future needs, the transmission provider does not have an obligation to plan to meet the future needs of existing Point-to-Point Customers; rather, it can rely on its customers to submit discrete new requests for service to meet their needs in the future. A transmission provider's obligation to expand its system to provide Point-to-Point Service is contingent upon the transmission customer agreeing to compensate the transmission provider for upgrade costs.[85] BPA has adopted these relevant provisions in its OATT.[86]

An underlying problem with the reliance of transmission providers on the Attachment K process is its roots in a reliability study that attempted to get ahead of electrical engineering problems.

Load (all capitalized terms are defined in BPA's OATT; Part III of the OATT describes the nature of Network Integration Service). BPA's Network Customers are generally its public power preference customers – though some of BPA's larger public power customers who elected to assume the reliability and planning obligations of a transmission provider on their own rely on Point-to-Point Service from BPA. Network Customers have an obligation to provide data to BPA regarding their forecasted load growth and good faith estimates of the size, location, and type of future generation additions (Attachment K Sec. 6.1.1). Some IOUs that have load pockets within BPA's footprint also take service for some of that load as Network Integration Service. Like most of BPA's preference customers, the IOU would therefore provide BPA its load and resource forecast specifically for that load pocket (but not the rest of the IOU's native load). *See supra* footnote 74 for the tariff definitions of the two types of transmission service.

[84] Order 890 at P 419. Point-to-point customers are those who use transmission to deliver energy to a location outside of BPA's footprint (including customers who deliver energy from outside of BPA's system all the way through BPA's system to a load outside of BPA's system, transactions often called "wheel throughs"). BPA has no obligation to consider that an existing Point-to-Point customer's need for transmission service will grow in the future, until that customer submits a new request for service. BPA's point-to-point customers include independent power producers, power marketers, and investor-owned utilities. In fact, most of BPA's largest transmission customers (in terms of sales) are, in whole or in part, point-to-point customers. For example, BPA ten largest transmission customers are responsible for 60% of BPA transmission sales. Of that amount, IOUs, IPPs, and marketers are responsible for 78%. (Moody's, *BPA Credit Opinion*, 5 (Apr. 6, 2022), *available at:* https://www.bpa.gov/-/media/Aep/finance/rating-agency-reports/moodysfullreportmay2022.pdf)

[85] Order 890 at P 419.

[86] BPA OATT §§ 15.4, 27.

Transmission providers have obligations to plan their system under NERC's reliability standards.[87] Hence the focus on "short circuit," "steady state," "voltage stability," and "transient stability" studies in Attachment K reports. In Order No. 890, FERC adopted new requirements for utilities to conduct an open and transparent planning process with obligations to meet customer demand for system expansion under certain conditions.[88] However, FERC's efforts to expand transmission planning to look beyond reliability needs to meet forecast load growth and incorporate broader policy goals has been only partially successful. FERC's current open rulemaking, "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection" (Docket No. RM21-17), discusses the limitations of the current local and regional planning processes and identifies potential solutions, including scenario-based planning, a 20-year planning time horizon, and changes to the determinations of benefits and cost allocation.

B. BPA's Attachment K Process

As mentioned above, BPA engages in a planning process that is consistent with[89] the requirements of FERC's Open Access Transmission Tariff Attachment K.[90] The Attachment K transmission planning process requires an open, coordinated, and transparent process with opportunities for public participation. This process leads to the annual revision and publication of a transmission plan—"BPA's Plan," as described in BPA's Attachment K.[91] Like all transmission providers with Attachment K processes, BPA plans its system to meet anticipated load growth over the next ten years. For purposes of its local planning, BPA considers both forecasts of future loads as well as its long-term firm transmission service obligations. The Attachment K planning process applies reliability standards to the forecasts of future needs to identify upgrades necessary on BPA's system to maintain a safe and reliable transmission system for the Northwest. These upgrades might consist of new lines to locations that did not previously have access to transmission service, but more often consist of reinforcements to existing lines or facilities that increase the amount of energy that can flow across a line or provide BPA with greater situational awareness of and control over its transmission grid.

FERC also intended the OATT to create a mechanism for Point-to-Point Customers to fund upgrades needed to serve their needs while at the same time protecting the transmission provider's Network Customers from upward rate pressure. In practice, however, it proved nearly impossible for the developer of a generation project to single-handedly fund the construction of a major transmission upgrade. The *pro forma* OATT process requires

[87] NERC, *Standard TPL-001-4 Transmission System Planning Performance Requirements*, *available at:* https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf.
[88] Order No. 890 at P 599.
[89] See Section IV.B regarding BPA's decision to adopt a process "consistent with" FERC's Attachment K, notwithstanding its non-jurisdictional status.
[90] BPA, *Attachment K Planning*, see more information at: https://www.bpa.gov/energy-and-services/transmission/attachment-k.
[91] The current (December 2022) BPA Plan is available at: https://www.bpa.gov/-/media/Aep/transmission/attachment-k/2022-bpa-transmission-plan.pdf [hereinafter *2022 Transmission Plan*].

transmission providers to consider the incremental additions to the grid needed to meet customer requests one at a time in a strict sequence. FERC's *pro forma* OATT also required customers who needed new transmission lines to pay upfront for the costs of those lines (and receive credits for service on those lines once they are energized). Accordingly, the burden fell on the first customer in the sequence to make upfront financial commitments to fund all of the construction costs; subsequent customers who took service on the same facilities would provide refunds to the first customer. The customer at the head of the line would have the sole obligation to cover the costs of the transmission expansion, even when customers behind them would benefit from the same upgrades. The practical result of this policy for BPA was that as each customer reached the head of the line, it would drop out when presented with the estimated costs of the upgrades.

C. BPA's Subscription-Based Planning

1. Network Open Season (2008-2013)

To break this logjam, in 2008 BPA implemented a new process named Network Open Season ("NOS"). In BPA's open season model, the demand for transmission service from all the customers in the entire queue was aggregated, following a temporal window (usually annually) for customers to request long-term firm transmission service (typically for 5 years, with the right to renew ("roll-over") service). Where transmission upgrades needed to provide new service would result in sufficient future revenue from customers to cover the costs of the facilities, BPA committed to finance the construction from its Treasury borrowing authority. At the close of the 2008 NOS, 28 different customers with 153 separate transmission service requests ("TSRs") totaling 6,410 MW of new long-term transmission service had committed to contracts to support transmission upgrades needed to deliver that energy to load. Nearly 75% of those requests for transmission service were associated with new wind generation in the Columbia River Gorge. To meet the need for service reflected in the NOS requests, BPA determined that it could complete five separate transmission expansion upgrades (four of them at 500 kV) and offer service on those new facilities at BPA's embedded cost rate (i.e., without charging those customers an incremental rate for service). For one of those projects, BPA had already completed a preliminary environmental analysis under the National Environmental Policy Act ("NEPA"). For the other four projects, BPA elected to fund the necessary engineering and environmental studies itself.[92] BPA ran a NOS process annually for three years (2008, 2009, and 2010). As a result of the 2008-2010 NOS processes, BPA was able to expand its transmission

[92] BPA, 2008 NOS Administrator's Decision Letter (Feb. 16, 2009), *available at:* https://web.archive.org/web/20100527184244/http://www.transmission.bpa.gov/customer_forums/open_season/docs/Decision_Letter_02_16_2009.pdf; *see also* Attachment A, *available at:* https://web.archive.org/web/20100527132623/http://www.transmission.bpa.gov/customer_forums/open_season/docs/Attachment_A_-_Rationale_of_Rate_Treatment.pdf. The term "subscription" is used less often now by BPA to describe its commercial transmission service policy, but it remains a useful and accurate industry term to summarize the planning paradigm.

grid to enable 263 individual requests totaling 11,722 MW of new transmission service, including 7,105 MW of new wind generation.[93]

2. *Transmission Service Expansion Process (2013 to Present)*

In 2013, BPA modified its NOS and renamed it the Transmission Service Request Study and Expansion Process ("TSEP"). Compared to the prior NOS process, TSEP generally applies more stringent standards to transmission customers requesting service, requires higher participant funding from them, and incorporates more conservative risk management for BPA than NOS did. The combination of these changes generally reduced BPA's exposure to potential subscribers dropping out of the process mid-stream. BPA made these changes as the result of lessons learned from challenges in the wholesale market for new renewable projects amid the Great Recession in 2009-2010 and state legislation in California that restricted most utility procurement to in-state generating resources.

BPA currently conducts its TSEP annually. Through TSEP, BPA considers customers' eligible requests for transmission service in BPA's transmission queue. While similar to NOS in that it conducts a cluster study of all eligible TSRs, unlike NOS, TSEP customers are now responsible for paying the costs of the preliminary engineering and environmental studies. Both Point-to-Point and Network Service Customers are eligible to participate in the TSEP, although most requests are for Point-to-Point Service. New requests for Network Transmission Service rarely show up in TSEP because BPA already has the obligation to meet the load growth requirements of Network Service Customers under Attachment K and because the vast majority of BPA's Network Service Customers are also its public power preference customers with the first rights to electricity from the federal hydro system.

Under TSEP, BPA aggregates all eligible transmission service requests and studies all of them in a single cluster. For some of those requests, BPA can offer service without building additional upgrades. When BPA cannot offer customers service over facilities that are in place or already under construction, BPA identifies the additional transmission upgrades that would be necessary to offer the requested service. For the transmission service requests that do require upgrades, BPA requires each of the customers who seek service to make financial commitments to cover their pro rata share of costs of preliminary engineering studies, and any environmental studies, while also committing to a term of service that ensures BPA will recover the costs of the upgrades over time. Customers must also post a security deposit or line of credit to ensure that they can meet their future financial obligations to BPA.[94] The pro-rated share of

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[93] BPA, *Federal Transmission Expansion in the West*, 20 (Feb. 7-8, 2012), *available at*: https://www.energy.gov/sites/default/files/2013/07/f2/Transmission_Drummond_0.pdf.

[94] Under a form of preliminary transmission contract (a Precedent Transmission Service Agreement) used under NOS, BPA used to require customers to post security worth 12 months of their transmission service request (see BPA OATT § 19.10).

BPA's current TSEP financial security requirement is more stringent: customers must post security (either cash or an irrevocable letter of credit) for up to their total pro rata share of upgrade costs, calculated as the ratio of the preconstruction study costs and posting financial security are the "participant funding" currently required by BPA. If customers commit to all of those requirements, then BPA will incorporate the necessary facility upgrades in its next Attachment K planning process (and associated annual Transmission Plan).

Once customers make these participant funding commitments, BPA combines expected load growth on its system over the next ten years with customer requests for new transmission service from TSEP.[95] At that point, BPA's Attachment K process combines transmission expansion needed to serve forecasted load growth on BPA's system (from mostly preference customers) with transmission service requests (from all other system users) that commit to the requirements of the TSEP.

3. Embedded Rate v. Incremental Rate

BPA conducts a separate analysis to determine whether it will offer service on the new facilities at its rolled-in (a.k.a., embedded) rate or instead charge those customers an incremental rate. As part of its reforms in adopting the NOS process in 2007, BPA also devised a Commercial Infrastructure Financial Proposal ("CIFP," also referred to as the Commercial Infrastructure Expansion Policy). Under NOS, the CIFP established a clear and transparent analytical framework to determine whether BPA would offer service at its embedded rate or whether it would require customers to commit to an incremental rate. First, the CIFP defined the benefits that BPA would consider in this analysis. BPA attempted to quantify benefits associated with (1) expected future uses, (2) reliability of the grid, and (3) other economic benefits, the whole group of which would be allocated to all of BPA's transmission customers through its regular rate process. BPA would then determine whether the new revenues associated with service on the expanded transmission system would cover the remaining costs. If the incremental revenues were sufficient to cover the remaining costs, then BPA would offer those applicable customers service at BPA's embedded rate. On the other hand, if the incremental revenues could not cover the remaining costs, BPA would offer those customers the opportunity to take service at an incremental rate above BPA's embedded cost rate.[96] In practice, an incremental rate can be a kiss of death for a development project because concentrating the costs of

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customer's requested megawatts out of the total requested megawatts by customers, multiplied by the estimated costs of BPA's Plan of Service. This security must be posted prior to BPA proceeding with preconstruction activities. BPA releases the security incrementally over time. For example, BPA notes in its Business Practice that for a 5-year term of transmission service with a 4-year period of construction, the deposit or letter of credit would be held for the duration of those 9 years, with the amount reduced proportionally during each five years of actual service (post-construction). *See* BPA, TSEP Transmission Business Practice, Version 8 (3/24/2023), Section H, *available at:* https://www.bpa.gov/-/media/Aep/transmission/business-practices/tbp/tsr-study-expansion-process-bp.pdf.

[95] BPA, *2022 Transmission Plan*, Section 3.1 (Dec. 2022).

[96] BPA*, Proposal for a New Approach for Allocating Transmission Costs and Financing Commercial Infrastructure*, 2 (Aug. 2007) *available at:* https://nippc.org/wp-content/uploads/2023/05/2008-NOS-Commercial_Infrastructure_Financing_Proposal_Summary.pdf. The 2007 CIFP was a product of a workgroup formed by the Transmission Issues Steering Committee within BPA. For a number of years, BPA produced annual public documents evaluating the system-wide benefits of commercial transmission, as outlined in the CIFP.

transmission construction on a single generator or a handful of generators can dramatically erode their affordability.

Today under TSEP, BPA continues to apply a financial analysis to determine whether it will offer customers participating in TSEP service at BPA's embedded cost rate or whether it will require customers to commit to an incremental rate before BPA moves forward with a decision to pursue the Plan of Service[97] needed to satisfy the requests for transmission service. Under NOS, the details of this analysis were clearly defined and transparent. Under TSEP, however, the details of what benefits BPA determines it should allocate to the general customer base and the threshold for determining whether an incremental rate is appropriate are no longer transparently defined. NIPPC and RNW have explored this topic in some detail with BPA in the course of preparing this whitepaper, and there simply appears to be no public documentation of what suite of benefits are currently evaluated, nor, in establishing the need for transmission upgrades, how and whether such benefits accrue to the system as a whole or solely to those customers requesting service. While BPA still conducts this analysis for customers in the TSEP cluster study, BPA no longer publicly provides the specific benefit determinations and revenue thresholds used to determine whether an incremental rate will apply. A great deal hinges on this analysis; this is an obvious area for improvement. Section IX of this whitepaper provides additional detail about best practices in calculating transmission benefits.

C. Interconnection Requests

As part of its planning, BPA also considers the number of new generating projects that seek interconnection with BPA's grid.[98] The interconnection queue has its own separate study process. While developers often request both interconnection and transmission service from BPA in order to make a proposed new generating facility viable, plugging into the grid (interconnection) is different than moving power from one side of the grid to the other (transmission service). As of March 2022, BPA's interconnection queue contains 102 separate interconnection requests representing over 85 GW of new generation resources.[99] This paper does not address generator interconnection reform because BPA already has an important initiative underway in a tariff terms and conditions proceeding (TC-25) to address this topic.

D. Regional Planning: NorthernGrid

In addition to conducting the Attachment K and TSEP processes to develop plans of service for its own transmission system, BPA is also a member of the NorthernGrid regional planning

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[97] A Plan of Service includes the specific upgrades and timing that BPA proposes to meet customer needs. The Plan of Service could be driven by any combination of load growth, reliability needs, or customer demand for Point-to-Point service.

[98] BPA, *2022 Transmission Plan*, Section 3.1.3 (Dec. 2022).

[99] BPA, *TC-25 Tariff Proceeding Workshop*, slide 13 (Mar. 15-16, 2023), *available at:* https://www.bpa.gov/-/media/Aep/rates-tariff/TC-25/TC25workshopPPTfinal-externalrevisedMarch142023.pdf.

entity.[100] The NorthernGrid planning footprint includes Washington, Oregon, Idaho, most of Montana, Utah, and Wyoming, and portions of Nevada and California. NorthernGrid and its members conduct a biannual transmission planning process to explore whether regional transmission projects can more efficiently and cost-effectively meet members' needs compared to their individual Attachment K plans. The regional planning process is based on members' Attachment K plans and similarly explores a ten-year planning horizon.[101] Stakeholders and transmission developers who are not incumbent transmission providers can request that NorthernGrid (and other regional planning entities like WestConnect, NorthernGrid's counterpart in the Southwest) analyze specific future scenarios or proposed transmission lines in the biannual plan. NorthernGrid is under no obligation to accept these requests; Oregon utility regulators did successfully seek to include an offshore wind scenario in NorthernGrid's most recent study scope for the 2022-23 transmission planning cycle.[102] Accordingly, NorthernGrid is currently studying the transmission implications of the development of 3 GW of offshore wind on the southern Oregon coast by 2030. To its credit, BPA has also joined with a group of transmission owners in the region to voluntarily conduct a 20-year study (as opposed to the normal 10-year time horizon) of whether long-term transmission constraints exist in a low carbon future.[103]

True regional and interregional planning are the ideal ways to address transmission needs on a wide geographic basis. NIPPC and RNW support effective mechanisms to do so, which would require BPA and other transmission providers to work together in a transparent and public manner to determine the most important and cost-effective new transmission projects and determine cost allocation to pay for them. For example, the latest draft transmission plan (for 2022-2023) produced by the California Independent System Operator ("CAISO") would authorize 24 reliability-driven projects and 22 policy-driven transmission projects, with a total estimated cost of $9.3 billion, using forecast electricity demand from the state energy office (the California Energy Commission) and anticipated generating and storage resources forecast by the California Public Utility Commission.[104] The CAISO's draft plan demonstrates how an independent system operator("ISO") can proactively plan a portfolio of new transmission in an effective way that transmission owners, including BPA, have difficulty achieving.

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[100] NorthernGrid is the regional planning entity that IOUs have established in order to comply with the regional planning requirements of FERC Order Nos. 890 and 1000. BPA and other non-jurisdictional transmission providers (Seattle City Light, Chelan County PUD, Tacoma Power, Snohomish County PUD) have joined NorthernGrid not only to conduct regional planning voluntarily under Order 1000 but also to meet specific NERC and WECC reliability criteria that require coordination with adjoining transmission providers on specific topics. *See* NERC TPL-001-4 and TPL-001-WECC-CRT-3.2.

[101] NorthernGrid, *Regional Transmission Plan for the 2020-2021 NorthernGrid Planning Cycle*, 5 (Dec. 8, 2021), *available at:* https://www.northerngrid.net/private-media/documents/2020-2021_Regional_Transmission_Plan.pdf.

[102] NorthernGrid, *Economic Study Request Decision for 2022*, *available at*: https://www.northerngrid.net/private-media/documents/ESR_Decision_2022.pdf.

[103] Western Power Pool, *20-year Low Carbon Study,* (Nov. 23, 2022), *available at*: https://www.westernpowerpool.org/private-media/documents/20_Year_Study_Scope_2022.11.23.pdf.

[104] CAISO, *Draft 2022-2023 Transmission Plan*, 3 (Apr. 3, 2023), *available at:* http://www.caiso.com/InitiativeDocuments/Draft-2022-2023-Transmission-Plan.pdf.

Nevertheless, this ideal scenario of consistent, collaborative regional planning that encompasses BPA and IOUs remains elusive for the Northwest, both because FERC's Order 1000 has proven to be a weak forcing mechanism outside of regional transmission organizations ("RTOs") and ISOs, and because any successor rule that FERC may adopt will not address the fundamental lack of consistent requirements and jurisdiction over transmission owners in the region. It remains unclear when FERC may finalize a new planning rule. For these reasons, NIPPC and RNW support BPA pursuing changes to its internal transmission planning processes, while still encouraging the agency to collaborate as much as possible regionally and interregionally.

VI. Limitations of BPA's Existing Planning Processes

This section identifies principal limitations and drawbacks to BPA's current planning processes. Section IX critiques these same BPA processes by way of comparison to other transmission providers.

Insufficient Forecasts of Load Growth and Transmission Capacity Needs

NIPPC and RNW are concerned that the assumptions that BPA and transmission-owning utilities in the region are currently using to forecast load growth are too low.[105] The transmission planning reliability standards require BPA to base its assessment on standard base cases developed for the entire Western Interconnection.[106] NorthernGrid conducts its planning based on 0.6% annualized load growth for the entire footprint with individual utilities reporting changes in load from a 0.4% decline to a 1.1% increase.[107] PNUCC's regional load resource forecast, however, estimates annual load growth of about 0.9% over the next ten years with individual utilities ranging from a 0.9% decline to 2.9% increase.[108] PNUCC also notes that its load forecasts may underestimate actual load growth since utilities representing only 25% of the load in the region currently factor climate change into their planning estimates, and utilities representing only 30% of regional load incorporate the implications of electrification into their load estimates.[109]

For example, in Washington, the state building code (with a court challenge pending) requires, as of July 1, 2023, that most new residential and commercial structures use only electricity.[110] Similarly, in Seattle, both the King County Transit System and the Port of Seattle have declared their intention to pursue 100% electric or non-emitting goals by 2035 and 2050, respectively.[111]

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[105] Note that BPA is often mentioned in the same breath as utilities. In its transmission function, BPA does resemble transmission-owning utilities and is subject to some of the same federal requirements. But except for several narrow legal applications, BPA is not, in the usual sense of the term, a utility. It is a federal wholesale marketer of power to customers who are themselves utilities. How does this differ from a typical utility? BPA is not vertically integrated: it owns neither generation facilities nor distribution lines. The power plants whose electricity BPA markets are owned by other entities (the Bureau of Reclamation, Corp of Engineers, and Energy Northwest). And except for a handful of now defunct industrial consumers, BPA neither sells nor delivers power at the retail level.

[106] WECC is the Regional Entity (a legal term in the Energy Policy Act of 2005) that enforces reliability standards in the Western Interconnection. These reliability standards are developed by NERC. WECC and NERC are both self-regulatory industry membership organizations overseen in the U.S. by FERC.

[107] NorthernGrid, *Study Scope 2022-2023*, 3 (Sept. 21, 2022), *available at:* https://www.northerngrid.net/private-media/documents/NG_Study_Scope_2022-2023_Approved.pdf.

[108] PNUCC's membership includes most of the load-serving entities in the Pacific Northwest. PNUCC annually conducts a study (the Northwest Regional Forecast) that examines the region's loads, resources, and future power supply.

[109] PNUCC, *2022 Northwest Regional Forecast*, 6 (Apr. 2022), *available at:* https://www.pnucc.org/wp-content/uploads/2022-PNUCC-Northwest-Regional-Forecast-final.pdf.

[110] *See* Washington State Building Code Council Summary Meeting Minutes (Nov. 4, 2022), https://sbcc.wa.gov/sites/default/files/2023-02/sm11042022C_ah.pdf.

[111] *See* King County, *Attachment 13 - King County Metro Transit's Zero Emission Fleet Transition Plan* (May 2022), *available at:* https://kingcounty.gov/~/media/depts/metro/accountability/reports/2022/zero-emission-bus-fleet-transition-plan-may-2022; *see* Port of Seattle*, Maritime Climate and Air Action Plan* (adopted November 16, 2021),

Utility resource plans are lagging this aggressive mix of electrification requirements and objectives across the region.

Clean energy laws in many states in the West will shift the resource mix from conventional fossil fuels to renewables and other non-carbon emitting generation. Since 2019, utilities in the Northwest have retired 2,100 MW of coal capacity, with another 2,800 MW of coal capacity scheduled for retirement by 2026.[112] Utilities currently indicate plans to add 9,400 MW of new renewable generation resources in the next ten years.[113]

One overall transmission challenge facing the region is the nature of variable renewables as standalone resources because their capacity factor (the percentage of time across all hours that the resource actually generates power) is generally lower than a dispatchable thermal power plant. Overall, this intermittency can lead to greater demand for transmission capacity but less total electricity carried on any given new segment or circuit of transmission. These challenges can be mitigated by pairing renewable resources with storage, by pooling more resources regionally through centralized dispatch (such as day-ahead and real-time centralized energy markets), by widening the geographic area of pooled resources to ensure more complementary generation profiles, and by changing from contract-path physical transmission rights to flow-based financial rights. Nevertheless, each of these solutions also has its own financial or political hurdles.

Lack of Surplus Transmission Capacity under TSEP's Reactive Process

BPA's most recent TSEP Cluster Study Report shows that there is no longer any surplus of unallocated transmission from the east side of the Cascades (where many new wind and solar resources will need to be located) to the west side of the Cascades (where the load centers of Oregon and Washington are located).[114]

BPA is tentatively planning to move forward with six transmission projects that have commercial demand, as reflected in recent TSEP cluster studies. These projects (Portland Area Reinforcement, Cross-Cascades South, Chehalis-Cowlitz Tap, Cross-Cascades North, Ross-Rivergate, and Rock Creek-John Day) are important projects with reliability, commercial, and public policy benefits (enabling access to new non-emitting generation). They are all upgrades and reinforcements of existing lines, increasing their capacity, as opposed to brand new lines in new rights-of-way. The most significant project is a 70-mile rebuild of the existing Big Eddy-

detailing interim 2030 planned electrification actions (*e.g.*, electric for 100% of port-owned light-duty vehicles, 100% of home port cruise calls connected to power), *available at:* https://www.portseattle.org/page/charting-course-zero-port-seattles-maritime-climate-and-air-action-plan.

[112] *Id.,* at 8.

[113] *Id.,* at 11.

[114] BPA, *TSEP 2022 Cluster Study Report* ("2022 Cluster Study Report"), 57 (June 10, 2022). Transmission Service Requests which require service across the Cross Cascades North or Cross Cascades South paths can be accommodated only with significant upgrades of the existing system that, once begun, would be completed only in 2030. *Note that the last two Cluster Study Reports (2022 and 2021) whose contents are merely summarized here can be obtained upon request from BPA.*

Chemawa 230-kV line as a 500-kV line (crossing the Cascades southeast of Portland). The estimated total construction cost of these projects is $612 million, enabling an incremental 4,260 MW of additional power to move across those upgraded parts of the network. (Note that this figure is in aggregate, not an additional 4,260 MW across the overall system or any single point.) The construction cost is supported in large part by $57 million of annual expected transmission revenue, based on signed preliminary engineering agreements with customers requesting transmission service.[115]

BPA deserves credit for pursuing these important projects. But much more is needed. As BPA acknowledged at its April 27, 2023, public workshop,[116] these projects may assist in allowing utilities west of the Cascades to meet their 2030 resource procurement requirements (an informal conclusion that has not been tested by other stakeholders or market participants); however, they will not address the significant incremental 2030-2045 need. Furthermore, BPA should publicly disclose its tentative plans to pursue such projects sooner. The projects described above appear to have been in consideration for at least the preceding year without a meaningful public discussion of that consideration.

Significantly, several large upgrades that were identified in the 2022 Cluster Study as necessary to meet customer demand were *not* included in the 2022 Transmission Plan or the list of projects above. For example, upgrades in central Oregon costing $382 million could enable at least 3,645 MW of new generation by 2033, but those transmission facilities were not included in the 2022 Transmission Plan.[117] The best way to understand this outcome is that TSEP is not merely a planning exercise. Rather, BPA also uses the TSEP to inform customers whether BPA will offer service at an embedded rate or at an incremental rate and to secure binding financial commitments from customers in advance of BPA engaging in engineering studies, environmental reviews, and construction. But as noted above, the analysis that BPA currently uses to determine whether it will offer service at an embedded cost rate is no longer transparent.

Lack of Transparency about Benefits Evaluation and Cost Allocation Methodology

This lack of transparency means that stakeholders[118] in the region have no insight into whether any specific proposed Plan of Service to expand the grid to a new region with high renewable energy potential is uneconomic at any scale, or whether the proposed Plan of Service could support enough future generation development (that has not yet appeared in TSEP) to allow BPA to offer service at its embedded rate. Additional transparency with respect to the internal business case developed by BPA for transmission projects that have commercial interest—including benefits quantified or considered, anticipated fulfilment of BPA's revenue requirement, and the risk of creating a stranded asset—would greatly assist stakeholders to

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[115] BPA, *Evolving Grid*, 20-27. These slides include valuable high-level maps of each project.

[116] See a link to a recording in *supra* footnote 15.

[117] *See 2022 Cluster Study Report*, 57. The cluster study considered a total of 2,595 MW in the Central Oregon-South zone, at 40, and an additional 750 MW in the Central Oregon-Buckley zone, at 43.

[118] Stakeholders in this context include not only generation project developers, but also load-serving entities, public utility commissions, and anyone else with an interest in ensuring that states meet their clean energy goals.

prioritize procurement from specific regions and stage expansion of the transmission grid more efficiently.

Participant Funding and the Mismatch of Generation and Transmission Procurement

While BPA's TSEP reflects that developers are acting on the knowledge that the region needs new renewable generation located in places like central Oregon, eastern Washington, and Montana to meet clean energy targets, those developers are often not able to make the financial commitments to BPA to underwrite the costs of development and construction of the necessary upgrades. But the unwillingness or inability of these prospective transmission customers to commit now to repay BPA for transmission upgrades does not mean the added transmission capacity would go unused in years to come. Instead, it indicates that the demand on the *load* side (the utilities who would purchase the power) is not yet willing to execute contracts for generation resources that will be needed more than several years in the future.

Utility procurement processes based on integrated resource planning typically look to procure new generation capacity two to three years in advance of need (as most integrated resource planning is done on a two-year cycle). Few renewable energy developers are in a position to make the financial commitments now to build transmission that will enable new renewable generation to bid into procurement processes that will be held ten or fifteen years from now.

One root of the problem is that the Northwest's main power buyers (utilities) solicit new supplies of power only several years in advance and primarily to fill in the gap between their current supply and what their anticipated load and state laws require in the 2030-2045 timeframe. At the same time, the Northwest's main transmission provider (BPA) has a planning and project execution process that is reactive principally to power suppliers (developers) requesting transmission service that may require very expensive transmission upgrades that could take more than a decade to complete.

Not surprisingly, the temporal mismatch between the utility procurement processes and BPA's transmission service expansion process is resulting in physical bottlenecks and significant underinvestment in the BPA transmission system. Resource developers are often stuck in between: until they are confident a utility (or corporate consumer) will buy their power, they will be reluctant to allocate significant capital by signing an agreement with BPA to pay for service towards the cost of transmission upgrades needed to enlarge BPA's system. In many cases, the developer simply cannot take this risk. On the other hand, winning the competitive bidding process to sign a contract with an offtaker (a purchasing utility) often requires already having a transmission service agreement in place.

Pros and Cons of Reactive Planning

There are two positive effects of BPA's current approach worth recognizing. First, power producers have developed some (imperfect) expertise in identifying locations in the Northwest with the lowest cost upgrades needed to secure transmission service from BPA. This helps squeeze the most use out of the existing system as possible. It is a more refined approach, suitable for a mature grid, than the approach that created the transmission network in the first place: drawing and building ambitious new lines on a map to connect proposed dams and coal plants to big cities (*see the Appendix for more details on this history*). Second, because developers (or any entity requesting new transmission service) bear the upfront costs of BPA's upgrade studies and must provide financial commitments to BPA sufficient to ensure that their future payments for service will cover the actual construction costs, there is a controlling incentive for developers to avoid lumpy new transmission investments. Taken together, these effects help to suppress BPA's transmission rates by avoiding triggering new capital-intensive projects.

The negative effects of this reactive approach are the flip side, and they are significant: the TSEP cluster studies show that BPA's transmission system is out of room for the major wave of power development needed to comply with state laws and related policies, and BPA's transmission planning, cost allocation, and project execution processes are not designed to respond effectively to that need.[119] Determining appropriate solutions to a conservatively reactive planning paradigm and the temporal procurement mismatch highlighted above will require joint effort and brainstorming among independent power producers, BPA, and load-serving entities, among others.

Lack of Treatment of Recurring Transmission Demand

Emblematic of the problems in TSEP is that BPA, at least publicly, treats each TSEP cluster in isolation. The TSEP cluster studies reflect demand from developers for transmission service from geographic areas where new generation can be developed most cost effectively. Sometimes transmission demand appears repeatedly over several years at the same points on the BPA network, but not with sufficient committed customer interest in a single year for BPA to justify proceeding. While BPA may be acting prudently in avoiding a construction plan in some of these cases, BPA has no public process where it openly considers transmission upgrades that have been identified in repeated TSEP cluster studies to meet recurring demand from transmission customers.

[119] In Section 5 of its 2022 Transmission Plan, BPA does identify the myriad policy and market changes driving the need for transmission, but reciting these drivers is not the same as designing a process that is actually responsive to them.

VII. Additional Issues Unique to BPA That Impact Transmission Planning

A. Regional Cost Allocation

As a federal agency with specific statutory authorities and requirements, BPA is not subject to FERC's requirements on transmission planning and cost allocation of transmission expansion. Nevertheless, BPA has voluntarily taken on a combination of standard FERC planning processes (such as Attachment K and regional planning through NorthernGrid) as well as processes unique to BPA (such as the TSEP). With respect to cost allocation, however, BPA is uniquely situated relative to other transmission providers in the Northwest. Most obviously, in deciding to join NorthernGrid to satisfy its regional transmission planning obligation, BPA (with FERC's approval of the methodology) is not subject to the standard mandatory cost allocation mechanisms when the NorthernGrid process identifies a regional transmission project (one that would be more economical than the member utilities' standalone plans). Instead, BPA has discretion in voluntarily choosing to take on a share of the costs of a regional transmission project—or not. If BPA were to decline to accept its share of such a project, BPA's share of those costs would be allocated to the other beneficiaries, likely with a negative impact to the cost-benefit analysis for the project. In any event, neither NorthernGrid nor its predecessor organizations have ever identified a regional transmission project appropriate for regional cost allocation.

B. Transmission Siting

BPA is also directly subject to NEPA, which requires federal agencies to determine if their proposed actions will have significant environmental effects and to consider the environmental, social, cultural, and economic effects of their proposed actions. Accordingly, virtually all BPA decisions related to transmission development are subject to NEPA and related reviews under the Endangered Species Act and the National Historic Preservation Act, a nearly blanket application that is not true of non-federal transmission providers. While important and necessary, these processes can take significant time and money to perform, adding time and cost to any proposed transmission project. In practice, most minor decisions by BPA are addressed through applying an administrative categorical exclusion. While other transmission providers are subject to NEPA and similar laws to the extent their projects are located on federal land or significantly affect the environment or cultural resources (and thereby require approval of a federal agency), BPA is unique in that its transmission upgrade decisions automatically trigger a review by BPA itself, often alongside federal land managers and fish and wildlife agencies.

Based on a review of the timeline for many of the major transmission upgrades by BPA since 2010, the environmental and cultural reviews of those projects, as indicated by their final environmental impact statements and records of decision, did not appear to materially delay BPA's construction of those projects (see *infra* footnote 208). Nevertheless, the effect of future reviews is likely to be more difficult in the case of the more significant volume and type of transmission upgrades contemplated in this whitepaper.

Finally, BPA's significant federal eminent domain authority is a powerful siting tool held by the agency. Historically, it has been a driving factor in regional entities seeking and securing BPA's participation in transmission projects. (See the Appendix for one high profile instance of this history with respect to the Colstrip line.)

C. The Assumption of Risk

Determining what the public interest is for a federal power marketer and transmission provider to assume various risks for developing new infrastructure requires careful, public deliberation. It is not self-evident. It may change over time, and it may differ significantly from the risk appropriate for a private company or non-federal public entity to assume. At present, BPA has a highly conservative approach to assuming risk for transmission expansion in the Northwest, an approach in contrast to much of the agency's history of constructing the high-voltage grid as we know it. NIPPC and RNW recommend that elected officials, BPA customers, and stakeholders in the region re-examine this core question in light of the generational change underway in the power sector.

For example, in addition to being a planning process that identifies transmission expansion needed to meet customers' requests for service, TSEP is also a contracting mechanism that insulates BPA from revenue shortfalls. After identifying the necessary upgrades to meet customers' requests, BPA then contacts those customers to determine if they would like to make the upfront financial commitments that will relieve BPA of any financial risk for undertaking the engineering studies, environmental assessments and, eventually, of using BPA's borrowing authority to cover construction costs. Customers are required to fund their pro rata share of the engineering and environmental studies; but they are also required to provide a deposit or letter of credit to BPA for their pro rata share of the total costs of the upgrades. TSEP customers must maintain this financial security through construction and until the end of the term of service in their TSR. BPA essentially uses an "open season" process that aggregates the demand for new transmission and allocates the responsibility to repay BPA's capital costs among all the customers who will take service on the upgrades. So even if BPA uses its own borrowing authority to finance construction of TSEP upgrades, BPA is not at risk because it can call upon customer financial guarantees to ensure that BPA receives the revenues it forecast in the financial analysis around whether to proceed with construction of the Plan of Service.[120]

To illustrate the effect of this, imagine a transmission upgrade that will cost subscribing customers $100 million for a total of 1,000 MW of TSRs received in an annual TSEP window. Customer A has a 100 MW TSR (10% of the total), resulting in a total securitization of up to $10 million. Customer B has a 500 MW TSR (50% of the total), resulting in a securitization of $50 million. If Customer B drops out late in BPA's construction of the upgrade, it may forfeit that total security. This would be equivalent to losing the entire cost of a hotel room for cancelling

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[120] BPA Business Practices, *TSEP Business Practice*, Section H, 10-11, *available at:* https://www.bpa.gov/-/media/Aep/transmission/business-practices/tbp/tsr-study-expansion-process-bp.pdf.

too close to a reservation date. If Customer B drops out early in the process, BPA may re-allocate the securitization to other customers. This would be equivalent to your hotel reservation cost increasing because a guest next door cancelled. Customer A's previous 10% of the total TSRs could now be 20%, requiring it to post another $10 million of security, perhaps jeopardizing Customer A's willingness to stay in the process. This can lead to a spiraling effect in which an upgrade is simply cancelled as customers successively drop out. BPA confronts the unfortunate choice to abandon a transmission expansion due to individual customers' commercial situations, regardless of the long-term (multi-decade) likelihood of the new transmission capacity actually being used.

Nonetheless, TSEP is an improvement over the *pro forma* OATT, where a single customer would be on the hook for the cost of the expansion with the opportunity for refunds from subsequent customers who took service on the same lines. The reality is that no single generator is likely to be able to finance the construction of a major line that will benefit multiple customers. TSEP partially solved this problem by spreading the upfront financial commitments associated with a long-term service contract across a broader group of customers. The requirement that customers execute long-term contracts for service also insulates BPA from building facilities that do not generate revenue (and spreading those costs to customers who do not use the new facilities). The core issue of potential stranded transmission assets—bridges to nowhere, as it were, that BPA and its existing customers naturally wish to avoid—deserves closer scrutiny, given the robust history of transmission projects built well in advance of need (including BPA's own initial lines) that have generally been fully utilized and paid off over time.

The TSEP process works best when the time horizon is a relatively short 2-4 years from subscribers making the financial commitment to BPA energizing the facilities. This short horizon is typically available only for upgrades or expansion of existing facilities; it does not work for new lines to new geographic zones that typically require 10 or more years to plan, permit, and build. The reality is that the costs and risks to generation developers of tying up capital for more than a decade—waiting for BPA to finish a line or upgrade—are simply too great, even if they are able to share those costs with other developers. As a result, NIPPC and RNW believe that consumers in the Northwest may be missing out on some of the best and most affordable generating resources that the region has to offer.

VIII. Avoiding the Consequences of Business as Usual

If sufficient transmission is not available, consumers in the region may face higher costs of meeting state energy targets, and regulated entities (utilities and competitive marketers) may be at risk of failing to meet the targets altogether.[121] At a macro level, the obvious cost of not having the most efficient, highest capacity factor renewable resources available because of transmission constraints is a reliance on relatively more expensive, less efficient, lower capacity factor resources, and related effects such as curtailment of those concentrated resources. In other words, the availability of transmission (or lack thereof) effectively limits competition among resource suppliers despite the demand for such resources. The challenge of coordinating aggregate demand for new transmission among so many different load-serving entities, all with different governance and regulatory approval requirements, is complex and likely beyond the ability of any single group of customers (or their state utility commission) to successfully navigate.

NIPPC and RNW are concerned that BPA's various planning processes are not identifying the need for new transmission sufficiently in advance to ensure that transmission facilities are in place on time. Construction of new transmission lines, or major upgrades to existing facilities, of course requires more than simply identifying a need. Significant time is required to conduct necessary site identification, environmental reviews, and related siting or permitting processes before construction can begin. For example, the Boardman to Hemingway project is a 290-mile, 500-kV transmission line that crosses eastern Oregon and southwestern Idaho. While construction is likely to begin in 2023, with energization in 2026, the project was first identified in Idaho Power's 2006 Integrated Resource Plan.[122] From the identification of a potential need to the expected energization date, twenty years will have elapsed. A ten-year time horizon (BPA's current policy) to identify transmission needs is simply insufficient time to ensure that the lines will be in place when they are needed. But making a simple adjustment to instead use a 20-year planning horizon would not solve the problem so long as individual generation developers shoulder the primary financial risk of expanding the transmission grid. New policies are also needed to share development and construction risk more appropriately and to ensure that detailed engineering and environmental studies are conducted on an appropriate timeline (including potential expanded use of third-party contractors) to ensure that new facilities are energized on time.

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[121] Portland General Electric's ("PGE") 2023 Integrated Resource Plan and Clean Energy Plan, for example, notes on page 217 that "the delivery capabilities of the Pacific Northwest's transmission system … have not kept pace with … changing demands," and as a result, the company may "not rely on BPA transmission to the same extent PGE has historically relied on BPA." PGE concludes on page 227 that the "contrast" between a "need for additional generating resources" and "lack of available long-term transmission" means the company must begin planning now for alternative transmission solutions. PGE's plan is available at: https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp.

[122] *See* Idaho Power Company, *Boardman to Hemingway: A Clean Energy Superhighway*, and *B2H History* at www.Idahopower.com, https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/current-projects/boardman-to-hemingway and https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/current-projects/boardman-to-hemingway/b2h-history.

BPA could play a much greater role in guiding regional transmission expansion. For example, Congress recently passed a new contracting authority for DOE that may be worth considering as an example of how BPA could underwrite some new transmission using its plenary authorities (as detailed above in Section IV). Under the Transmission Facilitation Program ("TFP"), DOE serves as a temporary anchor tenant for new transmission lines.[123] DOE's role is to evaluate the risk of whether a line will be fully utilized in the future, eliminate the need to allocate cost and risk among multiple beneficiaries in the near term, and thereby reduce the overall risk of the line for private investment. As customer demand for the facilities grows, DOE can then offload its position to actual transmission customers who will utilize the line. DOE received dedicated funding for this program and is directed to take a calculated, prudent risk. While BPA's risk appetite in performing a similar anchor tenant role may be smaller, because it has customers ultimately responsible for those costs (rather than just a freestanding revolving fund), BPA should not simply set its risk tolerance at zero (or close to zero) for transmission upgrades that the region will rely on over the coming decades. Readers should note that this position in favor of a greater—but calculated—risk tolerance by BPA in no way diminishes the value and opportunity for other transmission developers to play a leading role in the Northwest that complements BPA's role.

In summary, BPA should adjust its current policies to take on more of the responsibility to expand the grid in the Pacific Northwest and, to some meaningful degree, in coordination with load-serving entities that require new resources. BPA has a statutory obligation to operate, maintain, and expand its transmission system to serve its customers—both new and existing—in the Pacific Northwest.[124] Congress's recent decision to expand BPA's borrowing authority suggests a congressional desire for BPA to continue to embrace this role in the region, a view underscored by the legislative debate about this provision.[125] On the other hand, BPA should not bear this responsibility alone; the major load-serving entities in the region could and should do more to support transmission upgrades and expansion farther in advance of their short-term procurement needs. In addition, private transmission development also has a significant complementary role to play in the Northwest. Nevertheless, Congress has seen fit to designate and maintain BPA as a transmission provider with significant statutory authority to meet the transmission needs of the region and given BPA unique financing capabilities to meet this responsibility.[126] BPA can and should lead.

Section X of this whitepaper lists a set of more granular recommendations based on the analysis above.

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[123] Department of Energy, Grid Deployment Office, *Transmission Facilitation Program Fact Sheet* (Nov. 22, 2022), *available at*: https://www.energy.gov/sites/default/files/2022-11/11.22.22%20TFP%20Fact%20Sheet_final_0.pdf.
[124] See Section IV.
[125] In the Infrastructure Investment and Jobs Act, Congress permanently increased BPA's borrowing authority by $10 billion. *See* 16 U.S. Code § 838m.
[126] See the earlier discussion in Section IV.

IX. Comparison of Best Practices in Transmission Planning Elsewhere to BPA

This section steps back to provide a national, comparative review of best transmission planning practices, set alongside BPA's current processes. The best practices detailed here inform the concluding recommendations in Section X, in some cases bolstering analysis and conclusions reached in preceding sections.

Over the past few years, the electric industry nationally has been undergoing a rapid transformation. FERC and many industry participants have acknowledged that transmission needs increase as more non-emitting generation is built. In addition, end-use electrification of transportation, heating, and industrial processes is adding load, increasing concerns around resource adequacy, resilience, and reliability. Robust long-haul transmission capacity is proving to be an indispensable tool during severe weather and drought periods to address supply shortfalls with power from neighboring areas.[127] In order to ensure future reliability and lower costs, most regions, encouraged by FERC, are moving towards longer term, more holistic transmission planning practices.

As previously discussed, BPA is facing a variety of changes in how its transmission system will be used in the future. These changes include thermal power plant retirements; significant new resource development, including the potential of floating offshore wind development, distributed generation, blended fuel resources, and new nuclear generation; increased extreme weather events; and aggressive state clean energy and emission reduction goals. BPA's current transmission planning processes are inadequate to address these challenges.

The TSEP and local planning processes that BPA employs are too conservative, too reactive, and largely overwhelmed by the current number of transmission service requests. Likewise, while BPA participates in regional planning through NorthernGrid, that process also does not regularly engage in proactive planning for the future resource mix.[128]

Fortunately, there is a set of well-established and common-sense transmission planning best practices against which any given transmission planner's approach, including BPA's, can be compared. One summary of these practices, in a Grid Strategies and Brattle report, *Transmission Planning for the 21st Century*, categorized these practices as: *proactive, multi-value, portfolio-based, and scenario-based planning.* The following should be considered best practices:

1) Proactively plan for future generation and load.

[127] Michael Goggin, *Transmission Makes the Power System Resilient to Extreme Weather* (July 2021), *available at*: https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.

[128] Nevertheless, see *supra* footnote 103 about a current voluntary effort of a subset of NorthernGrid members, including BPA, to carry out a one-time longer term planning exercise.

2) Account for the full range of transmission projects' benefits and use multi-value planning.
3) Address uncertainties and high-stress grid conditions explicitly through scenario-based planning.
4) Use comprehensive transmission network portfolios (as opposed to only line-specific assessments).
5) Jointly plan across neighboring interregional systems.[129]

In addition to these methodological practices, a best practice in terms of process is to engage states, utilities, consumers, and other stakeholders for review, comment, and development of consensus plans and fair allocation of costs. For the Pacific Northwest, in the absence of an RTO that addresses cost allocation, a long-term (20-year) transmission plan that identifies potential needs for transmission upgrades in the future becomes a necessary and critical input into the decision-making processes to move forward with any set of upgrades.[130]

This set of well-established and common-sense transmission planning best practices has been employed many times by different regions across the U.S. and has demonstrably lowered systemwide costs.[131] For example, the New York Independent System Operator ("NYISO") applies these best practices through a proactive, multi-value, scenario-based planning process in its Public Policy Transmission Planning Process ("PPTPP"). The Midcontinent Independent System Operator ("MISO") applies these planning best practices with its proactive, multi-value, scenario-based Multi-Value Projects ("MVP"), Renewable Integration Impact Assessment, and Long Range Transmission Planning ("LRTP")[132] planning processes. CAISO also utilizes a multi-value, scenario-based planning process along with a 20-year transmission outlook.[133]

The following subsections summarize transmission planning best practices in order to provide a basis for evaluating the quality of BPA's planning practices against the six commonly used best practices, and offer suggestions on where to focus reforms to modernize and improve BPA's planning practices.

A. Proactively plan for future generation and load

To ensure that the transmission system can keep up with changing needs and maintain reliability and affordability, it is essential for transmission planners to proactively plan for future

[129] Brattle Group & Grid Strategies, *Transmission Planning for the 21st Century*, 14 (2021), *available at*: https://gridprogress.files.wordpress.com/2021/10/transmission-planning-for-the-21st-century-proven-practices-that-increase-value-and-reduce-costs-7.pdf.
[130] A transmission plan in this context does not – and should not – yield an actionable construction program without significant stakeholder input from a broad spectrum of interests, including state public utility commissions.
[131] Brattle Group & Grid Strategies, *Transmission Planning for the 21st Century,* at 73-77.
[132] MISO now refers to this planning process as "Transmission Evolution", *available at*: https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-reliability-imperative/.
[133] Brattle-Grid Strategies, *Transmission Planning for the 21st Century*, at 15.

generation and load growth. This proactive approach contrasts with the reactive, incremental approach that much of the industry—including BPA—currently employs.

Proactive planning involves incorporating realistic projections of the generation mix, load levels (including estimates for electrification), and load profiles over the lifespan of the transmission investment. These projections should not only consider announced retirements but expected retirements as well. The projections should be based on the best available information, considering factors such as utilities' publicly stated decarbonization and/or clean energy targets, public policy mandates, and consumer preferences. Transmission planners should also incorporate these projections into long-term planning, considering a horizon of at least 20 years.

In recent years, both MISO and CAISO have taken steps to plan for future generation and load more proactively over a 20-year planning horizon. MISO in its Transmission LRTP planning process incorporated "load growth, electrification, carbon policy, generator retirements, renewable energy level, natural gas prices, and generation capital costs" to model capacity expansion over a 20-year period.[134] This past year, CAISO released its 20-year Transmission Outlook plan. CAISO used generation and load projections that meet California's 2045 public policy greenhouse gas reduction objectives, including projected generation retirements and estimates of distributed resources. The 20-year Transmission Outlook also incorporated projections of load growth due to electrification.[135]

BPA's performance on proactive planning

According to the methodology for BPA's Attachment K transmission planning process, BPA does not plan for future generation or load growth beyond the business-as-usual expected forecasts incorporated into the annual system assessment.[136] BPA's planning processes do not incorporate public policies from states in the region, realistic projections of the anticipated generation mix, or expected retirements, nor do they include planning over an appropriate time horizon. Although BPA has conducted a preliminary study on floating offshore wind[137] and is

[134] MISO, *MISO Futures Report*, 2 (2021), *available at*: https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf.

[135] CAISO, *20-Year Transmission Outlook*, 15-25 (2022), *available at*: http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf.

[136] *See generally* BPA, *2022 Transmission System Assessment Assumptions and Methodology* (April 2022), *available at*: https://www.bpa.gov/-/media/Aep/transmission/attachment-k/2022-system-assessment-assumptions-methodology.pdf.

[137] However, BPA did, in response to customer requests, examine the upgrades needed to integrate offshore wind in its 2022 TSEP cluster study, BPA, *2022 Transmission Plan Open Access Transmission Tariff Attachment K Planning Process*, 13 (2022), *available at*: https://www.bpa.gov/-/media/Aep/transmission/attachment-k/2022-bpa-transmission-plan.pdf.

obviously aware that the future generation mix will be changing due to public policy,[138] there is no evidence that these scenarios have been integrated into the Attachment K planning process.

In its Transmission Plan, BPA merely notes that it works with its Transmission Grid Modeling Group (and the Load Forecasting and Analysis Group) to update the base cases used in the system assessment and forecasted customer load, but BPA does not provide specific details on what inputs are used or modifications are made that result in forecasts of average and peak loads.[139] The Transmission Plan also notes that the base cases "modeled, at a minimum, those resources with firm transmission service. Beyond that, other resources were modeled as needed to meet the forecast customer demands (load forecast) and expected firm transmission service," with no additional details provided on how those other resources are modeled.[140]

At present, BPA incorporates "forecasted load growth, projected firm transmission service commitments, interconnection requests, and system reliability assessments."[141] BPA starts with WECC base cases in its planning processes to validate past System Assessments,[142] which consider generation additions and retirements reported by individual utilities over the next ten years.[143] WECC base cases are relatively conservative and only consider announced generation additions and retirements with a high degree of certainty.[144] In comparison, MISO's LRTP process includes its own independent estimates of generation retirements on top of what utilities report using age and other factors.[145] The BPA base cases also do not appear to include electrification estimates, fuel price forecasts, or hydroelectric power forecasts. BPA relies on utilities to incorporate those forecasts into the load estimates they report to WECC; however, many of the utilities within BPA's transmission service territory do not include electrification estimates in their IRPs.[146] In some cases, regulated utilities have disincentives to report anticipated generation retirements and the need for new resources because such reporting triggers subsequent regulatory actions, including resource solicitations, effects on depreciation schedules, and increased avoided cost pricing for the utility's competitors under the Public

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[138] For example, BPA included an entire chapter summarizing the regulatory landscape and how it is shifting to promote carbon-free energy generation, but it is not clear how the changes are incorporated into generation and load forecasts, BPA, *2022 Transmission Plan*, at Chapter 5.
[139] *Id.,* at 20.
[140] *Id.,* at 33.
[141] *Id.,* at 15.
[142] BPA, *2022 Transmission System Assessment Assumptions and Methodology*, 2-3 (2022), *available at*: https://www.bpa.gov/-/media/Aep/transmission/attachment-k/2022-system-assessment-assumptions-methodology.pdf.
[143] *See* WECC, *WECC Data Preparation Manual for Steady-State and Dynamic Base Case Data*, 6, (accessed Feb. 24, 2023), *available at*: https://www.wecc.org/Reliability/WECC_Data_Preparation_Manual.docx, and BPA, *2022 Transmission Plan*, at 20.
[144] WECC, *WECC Data Preparation Manual for Steady-State and Dynamic Base Case Data*, at 6.
[145] MISO, *MISO Futures Report*, at 14-15.
[146] *See* Renewable Northwest Comments on Notice of Proposed Rulemaking, *Building for the Future Through Regional Transmission Planning and Cost Allocation and Generator Interconnection*, FERC Docket No. RM21-17-000, 179 FERC ¶ 61,028, 20, 37-38 (Aug. 17, 2022), *available at*: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=F96CCE4A-B04C-C4C2-9FFD-82AB9F100000.

Utility Regulatory Policies Act.[147] BPA has also acknowledged that the peak load reference cases used for the load area assessment assumed minimal renewable generation on-line. This assumption was made because of the intermittent nature of wind and lack of significant solar resource.[148]

This assumption is almost impossible to square with the state clean electricity mandates in Oregon and Washington, the two states with the largest loads in BPA's footprint.

NorthernGrid's planning is similar to BPA's. Both processes rely on utilities to report future generation and load, although NorthernGrid notes in planning documents it is up to the discretion of individual utilities what is reported.[149] There is also no independent review of data submitted to NorthernGrid or use of third-party generation and load forecasts, which in past planning cycles, has resulted in members submitting varied future scenarios. While some utilities include resource additions and retirements from their IRPs, others submit data based only on what is currently in their queue.[150] For both BPA and NorthernGrid, their reliance on utilities creates a "planning lag," where neither consider state laws independently, instead relying on individual utility plans to comply with state law. For example, when a new state law is passed, any new requirements show up 1-2 years after the law is passed in the next utility IRP. This delay means NorthernGrid does not incorporate new state laws until the next regional

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[147] *E.g.,* Washington Administrative Code 480-107-009 ("A utility must issue an all-source RFP if the IRP demonstrates that the utility has a resource need within four years."). Similarly, Oregon avoided cost methodologies effectively encourage utilities to not report accurate resource needs because that has historically kept avoided costs low. For example, after the passage of SB 1547, which doubled the state's RPS requirements, PacifiCorp filed an avoided cost update cutting renewable avoided prices by 43% claiming that it did not need new renewable resources for more than twenty years. *See In re PacifiCorp, Application to Update Schedule 37 Qualifying Facility Information*, Or. Pub. Util. Comm'n Docket No. UM 1729, Supplemental Application (Mar. 1, 2016). Idaho Power's 2021 avoided cost update is another example. In June 2021, Idaho Power Company updated its avoided costs to indicate no need for capacity until 2028. *In re Idaho Power Update to Avoided Cost Rates, Schedule 85,* Or. Pub. Util. Comm'n Docket No. Docket No. UM 1730, Idaho Power Company's 2021 Annual May Update of Avoided Cost Rates and Post 2019 Integrated Resource Plan ("IRP") Acknowledgment Avoided Cost Update – Schedule 85, Cogeneration and Small Power Production Standard Contract Rates at 2 (Apr. 30, 2021); Or. Pub. Util. Comm'n Docket No. Docket No. UM 1730, Order No. 21-198 at 1 (June 15, 2021). Meanwhile, in May 2021, Idaho Power Company discovered an imminent 2023 capacity need, but the company did not bring this issue before the Oregon commission until December 2021 thereby resulting in avoided costs remaining low. *See Idaho Power Application for Waiver of Competitive Bidding Rules,* Or. Pub. Util. Comm'n Docket No. Docket No. UM 2210, Application for Waiver of Competitive Bidding Rules at 1-2 (Dec. 9, 2021).

[148] BPA, *2022 Transmission Plan*, at 33.

[149] NorthernGrid, *Approved Study Scope for the 2022-2023 NorthernGrid Planning Cycle,* 9, 15, 20, (2022), *available at*: https://www.northerngrid.net/private-media/documents/NG_Study_Scope_2022-2023_Approved.pdf.

[150] NorthernGrid, *Approved Study Scope for the 2022-2023 NorthernGrid Planning Cycle*, at 9-10; In the current planning cycle, Puget Sound Energy ("PSE") submitted 4,090 MW of resource additions and 370 MW in retirements to NorthernGrid, which is similar to its IRP findings. Puget Sound Energy, *2021 PSE Integrated Resource Plan*, 2-6 (2021), *available at*: https://oohpseirp.blob.core.windows.net/media/Default/Reports/2021/Final/IRP21_Chapter%20Book%20Compressed_033021.pdf. Meanwhile, PGE submitted 19 MW of resource additions and 0 MW retirements to NorthernGrid, despite stating in its IRP a need for 2,800 MW of new resources by 2030 and an exit from Colstrip by 2025. PGE, *PGE plans to nearly triple clean resources by 2030* (Oct. 15, 2021), *available at*: https://portlandgeneral.com/news/2021-10-15-pge-plans-to-nearly-triple-clean-resources-by-2030.

transmission planning cycle, which could be two years after utility IRP implementation and three to four years after the policy became law.

To its credit, BPA has engaged with a group of regional utilities to conduct two special transmission studies. The first will incorporate a 20-year planning horizon to study the region's transmission needs in 2042 with low carbon resource requirements.[151] The second will consider whether there are transmission constraints under extreme weather conditions in 2030, including extreme summer heat waves, extreme winter cold snaps, and wildfire risks.[152] Both of these studies will likely provide important information regarding future transmission needs to ensure a safe and reliable grid.

While moving to a 20-year planning horizon will provide needed breathing room to a complicated process, merely expanding the ten-year time horizon to 15 or 20 years will not, as noted, solve the problem. Moving to a 20-year planning horizon and incorporating scenario planning would be an improvement by giving policy-makers in the region more time to weigh the respective costs and benefits of different portfolios of generation and transmission expansion. But regardless of the time horizon or the study methodology used to identify facilities that will be needed in the future, the region needs a new mechanism to allow BPA to begin conducting pre-construction studies, including environmental assessments, and perhaps even construction sooner in the process.

B. Account for the full range of transmission projects' benefits and use multi-value planning

To comprehensively identify investments that cost-effectively address all categories of needs and benefits, transmission planning best practices include a mechanism to account for the full range of transmission projects' benefits and use multi-value planning. FERC Order Nos. 890 and 1000 provide three reasons that can be used to demonstrate a need for new transmission: economic, reliability, and public policy.[153] To demonstrate need in any of these categories, there is a well-known set of twelve transmission-related benefits. FERC recognized these benefits in its transmission planning NOPR (RM21-17). This list of benefits is particularly useful for demonstrating the economic or public policy needs for a new transmission line and is outlined below:

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[151] Western Power Pool, *20-year Low Carbon Study* (Nov. 23, 2022), *available at*: https://www.westernpowerpool.org/private-media/documents/20_Year_Study_Scope_2022.11.23.pdf.

[152] Western Power Pool, *2030 Low Carbon, Extreme Weather Study Scope* (Oct. 6, 2022), *available at*: https://www.westernpowerpool.org/private-media/documents/2030_Extreme_Study_Scope_2022.10.06_AuoA0s1.pdf.

[153] Advanced Notice of Proposed Rulemaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, FERC Docket No. RM21-17-000, 176 FERC ¶ 61,024, P 13-16 (proposed July 27, 2021).

1. Avoided or deferred reliability transmission projects and aging infrastructure replacement;
2. either reduced loss of load probability or reduced planning reserve margin;
3. production cost savings;
4. reduced transmission energy losses;
5. reduced congestion due to transmission outages;
6. mitigation of extreme events and system contingencies;
7. mitigation of weather and load uncertainty;
8. capacity cost benefits from reduced peak energy losses;
9. deferred generation capacity investments;
10. access to lower cost generation;
11. increased competition; and
12. increased market liquidity.[154]

The CAISO Transmission Economic Assessment Methodology ("TEAM") is an example of a process that accounts for the full range of transmission projects' benefits and uses multi-value planning. The process considers various benefits, including production cost savings and reduced energy prices from both a societal and customer perspective, mitigation of market power, insurance value for high-impact low-probability events, capacity benefits due to reduced generation investment costs, operational benefits, reduced transmission losses, and emissions benefits. This approach is incorporated in CAISO's economic transmission planning and allows the ISO to identify projects that provide multiple benefits, which can result in more cost-effective solutions.[155]

BPA's performance in multi-value planning

In BPA's 2022 Transmission Plan, the majority of proposed projects are intended for reliability purposes.[156] While only a few projects seem to have purposes beyond reliability, the two major projects that were identified that will enable the integration of significant new renewable or non-emitting energy resources come from the TSEP process.[157] The Attachment K planning process, apart from TSEP projects, does not consider transmission benefits beyond the NERC and WECC reliability standards, and its focus seems to be on identifying solutions for identified violations.[158] The TSEP process, while identifying major transmission expansions that better reflect the changing resource mix, is still a reactive process that is focused on near-term customer needs. Furthermore, BPA requires its transmission customers to provide deposits and commit to funding preliminary engineering and environmental studies as well as make long-

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[154] Notice of Proposed Rulemaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, FERC Docket No. RM21-17-000, 179 FERC ¶ 61,028, P 185 (Issued Apr. 21, 2022), *available at:* https://www.ferc.gov/media/rm21-17-000.
[155] CAISO, *2021-2022 Transmission Plan,* at 251-63 (2022). http://www.caiso.com/InitiativeDocuments/ISOBoardApproved-2021-2022TransmissionPlan.pdf.
[156] *See* Chapters 6 and 7 of BPA's 2022 Transmission Plan.
[157] *See id.,* at Chapter 6.
[158] *See* BPA, *2022 Transmission System Assessment Assumptions and Methodology*; *see also* Chapters 3 and 4 of BPA's 2022 Transmission Plan.

term commitments to take transmission service (in general, the unwritten policy appears to be to require full, or close to full, subscription) all before BPA will make a decision to begin construction.[159] In addition, the TSEP process does not provide clear information regarding the transmission benefits and costs being considered, and detailed modeling methods are not publicly available.[160]

Table 1 below shows the multiple benefits that are considered in various transmission planning efforts around the country, compared to BPA's. This comparison is intended as a starting point for analyzing and benchmarking BPA's approach, but it does not assume that BPA's responsibilities are identical to these other transmission providers.

Table 1. Use of expanded transmission benefits in analysis[161]

SPP **2016 RCAR, 2013 MTF**	**MISO** **2011 MVP ANALYSIS**	**CAISO** **2007 TEAM ANALYSIS OF DPV2 PROJECT**	**NYISO** **2015 PPTN STUDY OF AC UPGRADES**	**BPA** **Attachment K planning and TSEP Process**
Benefits Quantified 1. Avoided transmission project costs (1) 2. Production Cost Savings (reduced Ancillary Service Costs) (3) 3. Reduced transmission losses (4) 4. Lower transmission outage costs (5) 5. Capacity benefit energy cost benefit (8) **Other Benefits Quantified** 1. Value of reduced emissions 2. Value of reliability projects 3. Value of meeting policy goals 4. Increased wheeling revenues	**Benefits Quantified** 1. Reduced future transmission investment costs (1) 2. Reduced planning reserves (2) 3. Production Cost Savings (3) 4. Reduced transmission losses (4) 5. reduced operating reserves (8) 6. Reduced renewable generation investment costs (10)	**Benefits Quantified** 1. Production cost savings and reduced energy prices from both a societal and customer perspective (3) 2. Reduced transmission losses (4) 3. Insurance value for high impact low-probability events (6) 4. Capacity benefits due to reduced generation investment costs (10) 5. Mitigation of market power (11) **Other Benefits Quantified** 1. Operational benefits (Reliability Must-Run) 2. Emissions benefit	**Benefits Quantified** 1. Reduced refurbishment costs for aging transmission (1) 2. Production cost savings (includes savings not captured by normalized simulations) (3) 3. Capacity resource cost savings (8) 4. Reduced costs of achieving renewable & climate goals (10)	**Benefits Quantified** 1. It is not clear if BPA considered or quantified any expanded transmission benefits. 2. Within the TSEP process BPA identifies reliability and commercial upgrades. Reliability upgrades are then recovered through embedded transmission rates and commercial upgrades go through a cost allocation process.
Considered But Not Quantified	**Considered But Not Quantified** 1. Decreased wind volatility (7)	**Considered But Not Quantified** 1. Improved reserve sharing (2)	**Considered But Not Quantified**	**Benefits Not Publicly or Transparently Considered or Quantified[162]**

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[159] BPA Transmission Business Practice, *TSR Study and Expansion Process (version 7)*, 2 (Aug. 17, 2022); Steve Ernst, Clearing Up, *Upgrades to Cross-Cascades Lines May Put Clean-Energy Goals Within Reach* (Aug. 12, 2022), *available at*: https://www.newsdata.com/clearing_up/supply_and_demand/upgrades-to-cross-cascades-lines-may-put-cleanenergy-goals-within-reach/article_eb0cfd5c-1a6d-11ed-adcc-473caa5bbe08.html.

[160] *See* BPA, *TSR Study and Expansion Process (TSEP): 2019 Cluster Study Overview*, slides 10-11 (2019), *available at*: https://www.bpa.gov/-/media/Aep/transmission/tsr-study-expansion-process/062019-2019-cluster-study-results.pdf.

[161] *See* Brattle-Grid Strategies, *Transmission Planning for the 21st Century* at 31. The benefits with numbers in parentheses in this table correspond to the list of benefits in FERC's recent transmission planning NOPR. Each transmission provider in the planning processes in this table also either quantified or considered but did not quantify benefits beyond those listed by FERC. These are indicated without a number in parentheses.

[162] BPA's 2007 Commercial Infrastructure Financing Proposal, adopted and used in subsequent evaluations of potential benefits from commercial transmission construction, detailed some benefits previously considered by BPA (*see supra* at 25).

1. Reduced reserve margin; Reduced loss of load probability (2) 2. Reduced cost of extreme events (6) 3. Mitigation of uncertainty (7) 4. Increased competition/liquidity (11 & 12) 5. Improved congestion hedging 6. Reduced plant cycling costs 7. Societal economic benefits	2. Enhanced generation policy flexibility 3. Increased system robustness 4. Decreased nat. gas price risk 5. Decreased CO2 emissions 6. Increased local investment and job creation	2. Facilitation of the retirement of aging power plants 3. Encouraging fuel diversity 4. Increased voltage support	1. Protection against extreme market conditions (6) 2. Storm hardening and resilience (7) 3. Increased competition and liquidity (11 & 12) 4. Expandability benefits	1. Avoided or deferred reliability transmission projects and aging infrastructure replacement; 2. either reduced loss of load probability or reduced planning reserve margin; 3. production cost savings; 4. reduced transmission energy losses; 5. reduced congestion due to transmission outages; 6. mitigation of extreme events and system contingencies; 7. mitigation of weather and load uncertainty; 8. capacity cost benefits from reduced peak energy losses; 9. deferred generation capacity investments; 10. access to lower cost generation; 11. increased competition; and 12. increased market liquidity

Competitive compensation reform

NIPPC and RNW underscore that expanding the number of benefits evaluated by BPA, along with incorporating the other best planning practices detailed in this section, will require a meaningful change in how BPA recruits and retains transmission planning staff in order to complete analyses using this deeper and broader set of planning criteria. One key determinant of BPA’s transmission planning, business case, and project execution success is whether it pays these key personnel competitively with the rest of the industry. Today, BPA does not and, by statute, with rare exceptions that prove the rule, cannot. The region’s congressional delegation can alleviate this root cause problem by working to enact competitive compensation reform for BPA, akin to what its sister federal agency, the Tennessee Valley Authority, received in 2004. Indeed, this is the single recommendation in this whitepaper that requires an act of Congress. (NIPPC and RNW have separately released recommendations and a detailed review of competitive compensation for BPA and do not repeat those details here.)

C. Address uncertainties and high-stress grid conditions explicitly through scenario-based planning

Best practices include adopting a scenario-based planning approach to effectively manage uncertainties and high-stress grid conditions that encompasses a wide range of plausible long-term futures and real-world system conditions, including challenging and extreme events. This approach involves assessing a set of diverse scenarios that go beyond current needs and account for the full spectrum of long-term uncertainties. The scenarios should consider various factors, such as fuel price trends, future load and generation size and location, economic and public policy-driven changes to market rules or industry structure, and technological advancements, to evaluate the transmission system's effectiveness in different future scenarios and identify any necessary modifications. Through scenario-based planning, transmission planners can anticipate potential challenges and develop mitigation plans. The scenarios should have a long-term time horizon and address high-uncertainty futures, enabling planners to identify "least-regrets" solutions that can effectively meet the grid's needs across these challenging and unpredictable scenarios.

MISO's Long Range Transmission Planning process, described above, is an excellent example of scenario-based planning that considered a wide range of factors. In MISO, Multi Value Projects and the most recent LRTP Tranche 1 projects were a set of transmission lines determined to be needed under multiple scenarios and were therefore deemed to be a "least regrets" set of lines.[163] MISO developed three different scenarios to capture the range of uncertainty over its 20-year planning horizon. These scenarios were then applied to the development of transmission plans.[164] MISO has used scenario-based planning in the past with its Multi-Value Projects, which included the "CapX2020" initiative and the Regional Generator Outlet Study projects. These projects all employed "least-regrets" comprehensive regional network solutions rather than incremental upgrades, which helped reduce the cost of generator interconnections along with many other quantified benefits.[165]

BPA's use of scenario-based planning

In conducting its transmission plan, BPA incorporates limited scenarios and sensitivities.[166] However, these scenarios and sensitivities are based on *expected* peaks and focus on

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[163] MISO, *MTEP21 Report Addendum: Long Range Transmission Planning Tranch 1 Executive Summary*, 5-6, (2022), *available at*: https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf; MISO, *Multi Value Project Portfolio Results and Analyses*, 5 (2012), *available at*: https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf.
[164] *MISO Futures Report*, at 2.
[165] Brattle-Grid Strategies, *Transmission Planning for the 21st Century*, at 7; MISO, *MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Executive Summary*, at 5-6; MISO, *Multi Value Project Portfolio Results and Analyses*, at 5.
[166] BPA, *2022 Transmission Plan,* at Section 4.3.

engineering criteria.[167] If it were to follow best practices, BPA would incorporate more extreme scenarios to identify the transmission facilities that will be needed to safely and reliably serve load in the region more than 10 years in the future at the lowest possible cost. BPA would also include public policy scenarios in its planning process, to consider proactively that states may adopt more aggressive public policies in response to a changing climate. BPA does not include scenarios for high levels of renewables, extreme weather events, or electrification. Instead, BPA uses only the nearer-term and narrow NERC criteria for its system assessment studies.[168] These system assessment studies are validated based on "[h]istorical load levels for peak and off-peak conditions" to ensure that they represent reasonable base case loads.[169]

BPA states "the peak load reference cases used for the load area assessment assume minimal renewable generation," due to the "intermittent nature of wind and lack of significant solar resources."[170] In addition, while BPA included offshore wind in its TSEP cluster study, it does not appear to have been a sufficiently rigorous analysis, since BPA considered only binding agreements rather than forecasts.[171] In any event, the transmission upgrades needed to move offshore wind to load were not included in the TSEP Reinforcements identified in the Transmission Plan.[172]

BPA also does not include extreme weather events. BPA addresses the historic 2021 "heat dome" stating, although there were some new historic peak loads reached during the 2021 summer heat wave in the Northwest, this was considered an extreme event and most of the new summer peaks were still within the load levels previously studied over the ten-year Planning Horizon.[173]

Interestingly, BPA provides "long-range needs" estimates outside of the 10-year planning horizon when reviewing transmission needs by path in Chapter 8. These needs are primarily focused on reliability, and BPA does not indicate any timeline for addressing them.[174]

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[167] *Id.*, *see generally* Figures 10 and 11 where sensitivities included are defined. These sensitivities include steady state and transient stability analysis for expected winter and summer peaks in two, five, and ten years and a two-year off-peak spring scenario.

[168] *Id.*, at 31-32.

[169] *Id.*, at 33.

[170] *Id.*

[171] BPA studied 1,600 MW of offshore wind resources in its 2022 TSEP process; however, that study was based upon customer requests for service and not upon any realistic scenario of Oregon's actual offshore wind potential. *Compare* BPA Press Release, *Over 11 GW studied in 2022 Cluster Study, almost doubling the 2021 requests* (Aug. 3,2022), *available at:* https://www.bpa.gov/about/newsroom/news-articles/2022/20220804-over-11-gw-studied-in-2022-cluster-study-almost-doubling-the-2021-reques, *with* Northwest Power and Conservation Council, *The Future of Offshore Wind Development,* (Aug. 31, 2022), *available at:* https://www.nwcouncil.org/news/2022/08/31/the-future-of-offshore-wind-development/, noting that the Bureau of Oceanic Energy Management estimates Oregon has 20 GW of offshore wind potential.

[172] BPA, *2022 Transmission Plan*, at 107.

[173] BPA, *2022 Transmission System Assessment Assumptions and Methodology*, at 3.

[174] BPA, *2022 Transmission Plan*, at 98.

BPA does use limited form scenario-based power-flow cases in its TSEP cluster study. According to BPA:

> the objective of the scenario-based Needs Assessment[175] is to study a range of scenarios that adequately capture anticipated firm network path utilization. Scenarios were developed based on groupings of TSRs in the long-term transmission 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 from these requests on network paths.[176]

D. Use comprehensive transmission network portfolios

Best practices include evaluating comprehensive portfolios of transmission projects that consider other resources such as storage and other technologies to capture benefits such as network interactions. Storage can provide benefits to the grid by decreasing congestion, providing voltage support, and reducing local capacity requirements.[177] When storage and transmission are co-optimized, studies have found they are not substitutes but rather complementary, and optimal amounts of both technologies lead to the lowest system cost.[178] For example, MISO found in its Renewable Integration Impact Assessment report that a combined transmission and storage solution led to a lower system-wide cost than either technology on its own.[179] Considering transmission portfolios better addresses system needs, lowers systemwide costs, and when combined with portfolio-based cost recovery, can simplify cost allocation. Taking a project-by-project approach overlooks potential efficiencies in the highly interconnected transmission system and may lead to less support for cost allocation. To ensure the greatest system efficiencies, transmission planners should model the co-optimization of transmission, storage, and distributed energy resources and include a mix of alternating current ("AC") and direct current ("DC") transmission lines, reconductored lines, or new transmission lines, allowing for more stable and evenly distributed projects across the grid.

MISO has had great success using the portfolio approach to transmission planning and development, both via approval of the Multi-Value Projects across its service footprint over a decade ago and in the 2022 approval of the Tranche 1 projects that came out of the LRTP. The

[175] The "Needs Assessment" described here is specifically with respect to TSEP, not the broader forecast of transmission needs described in the Attachment K Transmission Plan.
[176] *Id.,* at 106.
[177] *See* NY-BEST and Quanta Technology, *Storage as Transmission Asset Market Study White Paper on the Value and Opportunity for Storage as Transmission Asset in New York*, (Jan. 2023), *available at*: https://cdn.ymaws.com/ny-best.org/resource/resmgr/reports/SATA_White_Paper_Final_01092.pdf.
[178] Brattle-Grid Strategies, *Transmission Planning for the 21st Century*, at 64.
[179] *See* MISO, *MISO's Renewable Integration Impact Assessment (RIIA), Summer Report* (Feb. 2021), *available at*: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf.

Tranche 1 projects are designed to "ensure a reliable and efficient regional and interregional transmission system that enables the changing portfolio across the near and long term."[180]

ISO-NE does not use portfolio-based transmission planning, but through the use of postage stamp cost recovery, they do conduct portfolio-based cost recovery of network transmission costs, which is broadly based on the entire ISO-NE portfolio.[181]

BPA's approach with respect to project portfolios

As BPA is not producing a holistic plan to meet anticipated future generation and load, it is not comparing alternative portfolios of transmission to meet that anticipated need. It does seem to include portfolios of projects for the narrow, near-term set of projects that are in the TSEP, but those are only based on binding customer transmission agreements as described above. In contrast, NorthernGrid in its current 2022-2023 transmission planning cycle is incorporating portfolio-based planning by evaluating 26 different combinations of proposed regional projects to determine which combination best meets regional needs.[182]

E. Jointly plan across neighboring interregional systems

Best practices include joint regional and interregional planning with neighboring systems using the above-described planning methods (proactive, multi-value, and scenario-based analysis). Unfortunately, most existing processes only evaluate transmission needs that are of the same type, such as reliability, market efficiency, or public policy, which may prevent the evaluation of needs that differ across regions. Therefore, to ensure interregional planning is effective, joint modeling and analysis of adjacent regions should be performed to evaluate transmission regional and interregional needs and analyze benefits based on a multi-value framework. This approach will ensure the recognition of regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

In its 2021-2022 Transmission Plan, CAISO has acknowledged that,

> the interregional coordination process has not met expectations and noted there are opportunities to remove certain barriers, foster collaboration with state regulators, and promote more rigor in, and reporting on, interregional coordination efforts. Accordingly, the ISO is exploring a few alternative courses of action to pursue potential interregional

[180] MISO, *Long Range Transmission Planning: Tranche 1*, slide 5 (2022), *available at:* https://cdn.misoenergy.org/20220325%20LRTP%20Workshop%20Item%2002%20Tranche%201%20Portfolio%20and%20Process%20Review623633.pdf.
[181] Brattle-Grid Strategies, *Transmission Planning for the 21st Century*, at 15.
[182] *See* NorthernGrid, *Approved Study Scope for the 2022-2023 NorthernGrid Planning Cycle,* at 21, 28.

> opportunities in addition to complying with all expectations, responsibilities and obligations under the ISO's interregional coordination tariff provisions.[183]

The Acadian Load Pocket ("ALP") Project in Louisiana is also an excellent and successful example of multi-jurisdictional planning. While not precisely interregional, it was developed along the seams of three transmission providers (two privately owned, one publicly owned) and was considered a multi-value project with different drivers and benefits for the parties involved, and each party was responsible for recovering costs through its own tariff.[184]

BPA's regional and interregional coordination

BPA is a member of NorthernGrid, which is responsible for conducting joint interregional coordination with the other FERC Order 1000 planning regions (CAISO and WestConnect). However, NorthernGrid's interregional coordination appears to be a "check-the-box" exercise.[185] In the most recent plan cited by BPA, NorthernGrid proposed 141 new and upgraded transmission line projects primarily for local load service and increased reliability, with only a few interregional lines proposed but not accepted as part of the plan.[186] BPA itself does not appear to participate significantly in joint interregional coordination exercises beyond NorthernGrid. There is little discussion within BPA's tariff about coordination with WECC and Northern Grid.[187] Additionally, coordination in the region on the Western Energy Imbalance Market, reserve sharing, or other one-off practices appears to be operational and near-term in nature.[188] The lack of meaningful interregional planning is similar to what occurs in other regions which to date have only included small near-term projects. This lack of interregional coordination on transmission planning stands in sharp contrast to BPA's robust engagement in recent processes to develop organized day-ahead markets in the West. It also contrasts with BPA's history of interregional engagement in joint transmission projects (*see the Appendix for more details*).

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[183] CAISO, *2021-2022 Transmission Plan,* at 13.

[184] The Brattle Group, *A Roadmap to Improved Interregional Transmission Planning*, at 36-37 (Nov. 2021), *available at*: https://www.brattle.com/wp-content/uploads/2021/11/A-Roadmap-to-Improved-Interregional-Transmission-Planning_V4.pdf.

[185] *See* NIPPC Comments on Advance Notice of Proposed Rulemaking, *Building for the Future Through Electric Transmission Planning and Cost Allocation and Generator Interconnection Regional*, FERC Docket No. RM21-17-000, 176 FERC ¶ 61,024 at 4-5 (Oct. 12, 2021), *available at*: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=2BD8D9B6-8347-CE44-8624-7C7A31500000; *see* also Public Interest Organizations Comments on Advance Notice of Proposed Rulemaking, *Building for the Future Through Electric Transmission Planning and Cost Allocation and Generator Interconnection Regional*, FERC Docket No. RM21-17-000, 176 FERC ¶ 61,024 at 45-49 (Aug. 17, 2021), *available at*: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=60f22f6b-c401-c6bc-b293-7c76ae400001.

[186] BPA, *2022 Transmission Plan*, at 41.

[187] BPA, OATT, Attachment K at 163-83.

[188] *See* BPA, *Coordinated Transmission Agreement*, (accessed Feb. 24, 2023), *available at*: https://www.bpa.gov/energy-and-services/transmission/coordinated-transmission-agreement.

F. Stakeholder engagement and input

Best practices associated with regional transmission planning include having an open planning process that engages many different perspectives through collaboration and stakeholder engagement. In Order No. 890, FERC established a set of transmission planning principles that emphasize the importance of transparency and providing opportunities for stakeholder engagement. The order highlighted several shortcomings in the existing criteria for transmission planning, including the lack of clarity around the transmission provider's planning obligations, the absence of requirements for customer, competitor, and state commission involvement in the planning process, and the lack of availability to customers of key assumptions and data underlying transmission plans. To address these issues, FERC directed all public utility transmission providers to produce a transmission planning process that adheres to nine principles and to clearly outline this process in Attachment K. The nine planning principles include coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects.[189] Subsequently, Order No. 1000 required revision of FERC-jurisdictional transmission providers' tariffs to include a transparent and detailed process that allows stakeholders to understand the selection of projects. Transmission planning best practices should include engaging states, utilities, consumers, advocates, environmental groups, and other stakeholders for review, comment, and development of consensus plans and fair allocation of costs. This collaborative approach helps to ensure that all perspectives are taken into account when making decisions and can lead to more informed and effective transmission planning decisions.

RTOs and ISOs create stakeholder committees and forums for transmission planning processes to take up issues of markets, policy mandates, and reliability. Not all RTO/ISOs handle this stakeholder aspect of transmission planning particularly well. Some do better than others. For example, MISO uses a comprehensive planning process that involves many stakeholders. The planning process allows MISO to address cost allocation, which can be contentious, but is needed for the development of large-scale transmission plans. One of the key drivers of the MISO Multi-Value Projects process was that states were asking MISO to study transmission options that could meet the region's renewable generation needs cost-effectively.[190] CAISO, in its transmission planning process has extensive coordination, particularly with California State Agencies including the California Energy Commission and the California Public Utilities Commission.[191] Both MISO and CAISO have extensive stakeholder advisory committees that support the ISOs in their transmission planning.[192]

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[189] Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 444-561.

[190] Brattle-Grid Strategies, *Transmission Planning for the 21st Century*, at 69.

[191] CAISO, *2021-2022 Transmission Plan,* at 1.

[192] For example, MISO has 32 entities, committees, and other stakeholder groups, https://www.misoenergy.org/stakeholder-engagement/committees/.

BPA performance engaging stakeholders for review and comment

BPA does have an open tariff and transmission planning process. Currently, interested parties must ask to participate, but anyone–states, utilities, consumers, and other stakeholders–is able to participate in the planning process.[193] BPA's transmission planning stakeholder engagement process includes two stakeholder meetings per planning cycle, but no stakeholder committees.[194] BPA could improve transparency around its Attachment K transmission study process. Currently, interested stakeholders must request results for economic[195] and system assessment[196] studies. In addition, BPA's OASIS System Planning Portal redirects to BPA's Attachment K website where there is information missing on the 2022 process and some of the links on the website do not link to the correct document. For example, BPA has not posted results from the 2022 TSEP Cluster Study Process.[197]

Conclusion

BPA's transmission planning process falls short in most of the key practices, other than stakeholder participation (not counting transparency). Stakeholder participation is about at the same level as many other regional planning entities. BPA does not, however, proactively plan for future generation and load, account for the full range of transmission projects' benefits or use multi-value planning, address uncertainties and high-stress grid conditions explicitly through scenario-based planning, use comprehensive transmission network portfolios (as opposed to only line-specific assessments), or jointly plan with neighboring interregional systems. Adopting the above-described best practices (also listed in the following section of recommendations) would significantly improve BPA's transmission planning process, better preparing BPA and the region to build the grid of the future.

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[193] *See* BPA, *Attachment K Planning* (accessed Feb. 27, 2023), *available at*: https://www.bpa.gov/energy-and-services/transmission/attachment-k.
[194] BPA, *2022 Transmission Plan*, at 15.
[195] *Id.*, at 17.
[196] Access to the Systems Analysis Study requires a FISMA attestation, BPA, *2022 Systems Assessment Summary* (2022), *available at*: https://www.bpa.gov/-/media/Aep/transmission/attachment-k/request-for-2022-system-assessment.pdf.
[197] *See* BPA, *Attachment K Planning*.

X. Concluding Recommendations

NIPPC and RNW offer the following recommendations based on the discussion and analysis above. These recommendations complement each other and may be considered as a suite of reforms.

1. **Planning reforms.** BPA should revise its planning process to:

(A) consider a wider array of transmission projects' benefits, drawing from the best practices of other transmission providers detailed in Section IX;
(B) regularly conduct proactive local and regional 20-year scenario planning, including a wide range of plausible (for example, at the 95th percentile) but uncertain extreme weather conditions and a range of new generation resources, with robust stakeholder input, and drawing from the best practices of other transmission providers detailed in Section IX;
(C) independently consider state policy requirements and other transmission demand drivers, in dialogue with state authorities such as utility commissions that have primary responsibility for compliance with these state requirements;
(D) consider a wider range of transmission portfolio future scenarios, including co-optimizing storage and other technologies, in the 10- and 20-year planning timeframes, that may identify "no regrets" or "least regrets" portfolios, and drawing from the best practices of other transmission providers detailed in Section IX; and
(E) remain committed to regional and interregional planning with other transmission providers (recognizing that the best transmission solutions are sometimes regional or interregional, not contained within a single provider's system).

2. **Business case for commercial transmission.** In determining whether to move towards construction of new lines, BPA should:

(A) develop an open and transparent policy (similar in form to the 2007 CIFP) specifying the system benefits and revenue thresholds it considers in determining whether to offer customers service at an embedded or incremental rate, consistent with recommendation 1.A above;
(B) ensure that a wider array of benefits is considered and deducted from the revenue requirement that must be met through subscriptions, consistent with recommendation 1.A above;
(C) lower the apparently very high threshold of subscriptions (binding commitments to take transmission service) required to proceed to most construction; and
(D) separately develop an analytical framework to consider how to incorporate into its long-term planning facilities that appear repeatedly in multiple planning studies but lack a critical mass of subscribers committing financially to upgrades.

3. **Participant funding.** BPA should:

(A) develop a formal policy identifying the criteria under which it will conduct engineering, siting, and other pre-construction studies for transmission line upgrades at

its own expense and identifying how those costs will eventually be recovered from customers; and
(B) revisit and consider lowering the currently high letter of credit/deposit requirement for TSEP subscribers, while addressing the need to protect against undue risks of stranded costs.

4. **Contracting innovation.** BPA should:
(A) explore using BPA's Transmission Business Line itself as an anchor, or backstop, tenant by exercising a "put option" on some carefully chosen commercial transmission built by BPA, drawing from the experience of DOE in implementing the new Transmission Facilitation Program; and
(B) explore whether IOUs can and would be willing to serve as backstop subscribers for some new transmission capacity, perhaps until IPPs fill in the capacity on a given line in the course of delivering power to those utility offtakers; and
(C) explore joint venture and partnership opportunities that rely on private capital and private projects to take initial development, construction, or subscription risk in lieu of BPA.

5. **Risk calculations.** BPA should:
(A) revisit the core question of how much risk the agency will assume in pursuing a renewed transmission construction agenda, including an analysis of potential benchmark levels of risk (for example, outcomes modeled at a 95th percentile);
(B) review and share with stakeholders whether past transmission investments have actually resulted in any stranded assets (and whether the stranding was temporary or persistent); and
(C) analyze and consider new revenue opportunities to the agency from having and selling more transmission capacity through a variety of existing or potentially new transmission products.

6. **Process.** BPA should:
(A) conduct an iterative customer-facing initiative to consider and make the changes recommended above (as well as other potential changes), including an active effort to solicit the perspective of state regulatory commissions, and potentially as inputs into BPA's upcoming revision of its strategic plan and transmission business model;[198]
(B) following such an initiative, conduct a formal tariff revision process to incorporate those reforms into its business practices or its transmission tariff, but in the tariff only to the extent a given reform requires such a revision; and
(C) advocate within NorthernGrid for the adoption of similar reforms in the planning processes of NorthernGrid and any successor organization.

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[198] BPA should consider similar approaches or forums as past initiatives such as the Transmission Issues Steering Committee that produced the 2007 CIFP and the Wind Integration Forum of that same era, the latter of which was co-sponsored by BPA and the Northwest Power and Conservation Council.

7**. Transparency**. In considering and implementing the above-described processes and reforms, BPA should make the processes and decision points about reform transparent, including by ensuring that BPA's website acts as a repository of up-to-date information, as well as relevant historical documents.

8. **Compensation.** In order to support BPA recruiting and retaining the necessary transmission planning, business case, and associated transmission staff to carry out the reforms proposed in this whitepaper, Congress should pass competitive compensation reform for BPA.

Appendix: BPA's Record of Transmission Innovation

This appendix details prominent examples in BPA's history of how the agency has leaned into its transmission mission in various ways—politically, financially, technically—to build more capacity and a stronger bulk power system, sometimes at the expense of competing interests. These examples demonstrate a record of innovation and ambition that can inform BPA's future direction.

Founding Ambitions

The basic authority for BPA to build a robust transmission network was heavily debated in Congress prior to the agency's creation. The Army Corps of Engineers, private utilities in the Northwest, and the Portland business community advocated for a limited transmission role, if any, for BPA. At the beginning, it was not even clear if Bonneville and Grand Coulee Dams would be interconnected. Even after BPA's creation in 1937, it was unclear how or by whom power would be marketed from Grand Coulee.[199]

When J.D. Ross became BPA's first administrator, he adopted an aggressive approach to transmission planning. Ross's view was that if BPA contented itself with building lines only incrementally as demand appeared, the demand might simply remain dormant. Ross therefore focused his attention on executing an ambitious construction agenda. Ross based this agenda on a 1935 master grid plan developed by Charles Carey for the Pacific Northwest Regional Planning Commission, a New Deal planning board. Carey went on to become BPA's chief construction engineer. Carey's plan, adopted in Ross's first annual report as administrator, featured two central double-circuit 220-kV lines: one between Grand Coulee Dam and Bonneville Dam, and the other between Bonneville Dam and the Portland area. This backbone segment formed one leg of a triangle that was the BPA network's core configuration. The other two legs joined Portland to Seattle and Seattle to Grand Coulee. Major radial lines extended from this central triangle to population centers and planned hydroelectric dams.[200]

Ross was a friend of President Franklin Roosevelt dating from his time leading Seattle City Light. This relationship was critical to both Ross's appointment as BPA Administrator and BPA's success building transmission. With Roosevelt's personal support, Ross obtained general fund appropriations for BPA's first major transmission line and additional funds from the Public Works Administration. He also secured a workforce from the Works Progress Administration to clear the initial rights-of-way. These combined acts significantly accelerated construction of the

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[199] Philip Funigiello, *Toward a National Power Policy: The New Deal and the Electric Utility Industry, 1933-1941* (Pittsburgh: University of Pittsburgh Press, 1973), 174-96; Gus Norwood, *Columbia River Power for the People: A History of the Policies of the Bonneville Power Administration* (Washington, D.C.: United States Department of Energy, 1981), 47-54.

[200] Paul Hirt, *The Wired Northwest* (Lawrence, Kansas: University Press of Kansas, 2012), 279; Norwood, 55, 108-09. Norwood was the longtime head of the Northwest Public Power Association who later wrote a history of BPA for the agency. He called the initial Grand Coulee-Bonneville intertie the "jugular vein" of BPA's transmission system.

major line that integrated output from the two dams. They also coincided with BPA receiving authority in 1940 (in an Executive Order) to market Grand Coulee's power. Ross, despite a brief tenure at BPA cut short by his premature death, established the template for BPA becoming the leading builder of transmission in the Northwest.[201]

Transmission Acquisitions

In the 1930s, Oregon and Washington authorized local voters to create public utility districts ("PUDs"), part of a backlash against private utilities and what they charged for power. The creation of PUDs, filling a gap between municipal utilities and rural cooperatives, was a key part of the public power movement nationally. Their early formation in Washington, in particular, influenced the enabling act of BPA.

Many of the newly formed PUDs attempted to purchase utility assets directly from the existing private utilities within their boundaries, particularly Puget Sound Power & Light (now Puget Sound Energy). Sometimes they turned to condemnation proceedings when the private utility refused to sell its assets, a legal but slow, expensive, and contentious process that BPA sometimes encouraged.[202] In these cases, voters had elected to form a new utility but remained either captive ratepayers or merely unserved by the incumbent private utility. With the threat of condemnation looming, BPA sometimes stepped into these local disputes and directly assisted PUDs in negotiating purchases of private assets. BPA would buy the transmission lines itself, and the PUD would purchase the dams and local distribution lines.[203] This aggressive action, taking place decades before meaningful wholesale and retail competition to investor-owned utilities emerged in the private sector, may be considered a high tide of consumer-owned utility consolidation in the region.

Joint Transmission Construction and Ownership

The Pacific Northwest/Pacific Southwest Intertie is the major electrical link between the Northwest and both California and the Southwest. In 1964, Congress appropriated funding for the federal share of the intertie. Congress was spurred on by drought in California and a lack of local power; slumping industrial electric sales in the Northwest and a surfeit of federal power, with nowhere to sell it; and Canadian demands in the Columbia River Treaty negotiations for transmission to deliver power from the treaty dams in Canada to buyers in California and the Southwest. The joint development of the Intertie is the most outstanding instance of coordinated transmission planning, construction, and operations in the West.

The Intertie consists of two separate systems: The Pacific DC Intertie is a 1,000-kV DC line between BPA's system and Los Angeles, energized in 1970. It is co-owned by BPA (the northern 246-mile segment), the Los Angeles Department of Water and Power, and other southern

[201] Norwood, 65-67, 111-17.
[202] Funigiello, 213.
[203] Hirt, 283-91.

California utilities. The California-Oregon Intertie consists of three separate 500-kV AC lines between the Northwest and northern California, first energized in 1968. Its various segments are co-owned by BPA (in Oregon) and a consortium of public and private utilities.[204]

The third line of the California-Oregon Intertie (known as the Third AC Intertie) was built 25 years later and energized in 1993. Its construction followed years of debate about persistent insufficient interregional capacity between California and the Northwest. In 1984, Congress authorized BPA and its sister agency the Western Area Power Administration ("WAPA") to participate in construction of this new segment, adding about 2,000 MW of transfer capacity between northern California and the Pacific Northwest (bringing the total AC capacity to 4,800 MW). In the intervening time between construction of the first two AC lines and this third line, BPA had become a self-financing agency rather than dependent on appropriations. BPA split ownership of the northern half of the line with Portland General Electric and Pacific Power & Light (now PacifiCorp). The southern half, in California, is co-owned by public and private California utilities, as well as WAPA.[205]

Private Sector Backstop

In the 1980s, BPA built its last major new backbone transmission line, the Colstrip line, a 350-mile double-circuit 500-kV line.[206] The line came about when the five private utility co-owners of the two new generating units at the Colstrip coal-fired plant failed to secure a transmission right-of-way across western Montana. The utilities had 1,480 MW of new generation under construction but no way to get it to their loads. They asked BPA to step in and build the line using a vacant right-of-way already held by BPA. BPA agreed to do so in 1977.

In the course of a contentious public debate in Montana about siting the line, BPA chose to adjust the route somewhat to avoid some viewsheds and land impacts. BPA also used a single-pole tower design in order to reduce the visual impact further. The line was built on a highly expedited timeline, given the impending operations of the Colstrip generators. For example, a 97-mile segment from Garrison to Townsend, Montana, was constructed in 15 months instead of a then-typical 30 months. The final segment was completed in 1987.[207]

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[204] Northwest Power and Conservation Council, *Intertie* (accessed May 2, 2023), *available at*: https://www.nwcouncil.org/reports/columbia-river-history/intertie/; Northwest Power Planning Council, *Pacific Intertie: The California Connection on the Electron Superhighway* (May 2001), *available at:* https://www.nwcouncil.org/media/filer_public/0d/23/0d23f7a3-3aa2-4acb-b05f-082a0186f8a5/2001_11.pdf.

[205] BPA, *Power of the River* (Washington, D.C.: Government Printing Office, 2012), 93-97.

[206] Based on a review by NIPPC and RNW of BPA records of decision and archival material, approximately six new 500-kV lines have been constructed since then, all of significantly shorter lengths and connecting parts of the existing BPA network: Kangley-Echo Lake (9 mi, energized in 2003); Grand Coulee-Bell (84 mi, 2004); Schultz-Wautoma (63 mi, 2005); McNary-John Day (79 mi, 2012); Big Eddy-Knight (28 mi, 2015); and Central Ferry-Lower Monumental (38 mi, 2015).

[207] *Power of the River*, at 71-78.

Non-Wires Solutions

BPA has a long record of pursuing non-wires solutions rather than building new transmission lines. One well-known example illustrates this approach.

In the winter of 1989, a sudden deep freeze took out one of the Colstrip line's new substations and threatened the stability of the transmission lines into Puget Sound. An obvious solution to the grid stability in western Washington was to build a new line across the Cascades. BPA avoided the environmental and financial challenge at the time of doing so by instead building the Schultz substation (completed in 1994) on the east side of the Cascades. BPA connected four of its existing cross-Cascades 500-kV lines into Schultz, thereby creating eight segments that could operate independently and increasing the grid's reliability. BPA also added series compensators that increased the cross-Cascades transfer capacity by approximately 300 MW.[208]

Non-wires solutions are generally cheaper in the short run than building a new line, help maximize the use of existing infrastructure, and avoid greater development impacts on the environment and local communities than a new line. Non-wires options are therefore a valuable part of any transmission provider's portfolio of solutions and can help establish the provider's credibility when it does seek to build a new line.

Since the 1980s, BPA has focused significant attention on non-wires solutions that reduce the need for customers to pay high construction costs and reduce the siting challenges associated with new transmission lines. The most recent high-profile non-wires solution adopted by BPA was in 2017 to avoid building a new 79-mile 500-kV line in the I-5 Corridor between Castle Rock, Washington, and Troutdale, Oregon, relieving system congestion north of Portland. At the time, BPA concluded that the line would result in more capacity than was needed for a purely reliability purpose and that the price escalation was too high (the original project cost of $346 million in 2009 had increased to $1.2 billion by 2016).[209]

While non-wires solutions can be a useful tool, they can also be overlook the need for and benefits of new lines. Within four years of BPA's 2017 decision to avoid building between Castle Rock and Troutdale, both Oregon and Washington had passed state laws mandating use of 100% non-carbon emitting electricity generation, driving significant new demand for transmission capacity. In short, a non-wires philosophy can become overly conservative when it repeatedly forestalls needed physical investments. While it is a prudent policy as a first resort, its limits have become apparent recently in the Northwest.

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[208] *Id.*, at 81.
[209] Ted Sickinger, The Oregonian, *BPA nixes costly and controversial I-5 power line proposal* (May 18, 2017), *available at:* https://www.oregonlive.com/business/2017/05/bpa_nixes_costly_and_controver.html; Elliot Mainzer, BPA, *Letter to parties interested in the I-5 Corridor Reinforcement Project* (May 17, 2017).

Technical Innovation

BPA has frequently been a leader in the field of transmission engineering. The Pacific DC Intertie was the first high-voltage DC line in the U.S. BPA ownership of the line includes the northern converter station (Celilo). BPA, in collaboration with its co-owners, has upgraded this line multiple times, more than doubling its original design of 1,440 MW capacity to 3,220 MW by replacing mercury arc valves with silicon-based thyristor valves, installing new converters, and optimizing the equipment's operation.[210]

In the 1980s, BPA engineers redesigned the basic physical component of transmission lines—high-voltage conductors—by changing the circular shape of the internal aluminum strands into a trapezoid. The joined trapezoids eliminated air space, allowing the same conductor to carry about 20% more aluminum and therefore 20% more power.[211]

Beginning in the late 1990s, BPA developed the Wide Area Measurement System. BPA experimented with phasor measurement units ("PMUs"), devices that measure voltage and current on transmission lines dozens of times per second, as an improvement over the standard supervisory control and data acquisition system that collects data much more slowly. BPA engineers designed data concentrators and display software to optimize use of the PMUs, controlling for differences in the timing of delivery of microwave signals across the transmission network. The combined "syncrophasor" technology has been adopted widely across the power sector since then. This BPA innovation has created a more efficient and reliable grid, allowing control centers to quickly identify cascading split-second disruptions.[212]

Contract Financing of Transmission

When Congress made BPA self-financing in 1974, it gave BPA authority to borrow directly from the U.S. Treasury at a relatively low interest rate and created a revolving fund to manage this debt, other BPA income, and receipts from sales of power and transmission. BPA's borrowing authority is subject to a statutory cap that has been raised by Congress five times. BPA's primary source of capital to fund investments in its transmission system is this federal debt. In contrast, private transmission owners can raise capital by issuing equity or debt in commercial markets. Non-federal public transmission owners can typically issue bonds as well.

BPA has two other principal options for raising capital to build transmission. One is revenue from customers—essentially cash advances—that is generally the most expensive way to finance long-lived assets because current customers pay upfront for assets that will benefit future generations. The other is "lease-purchase" financing that takes the form of a contractual

[210] Power of the River, at 83-85, and BPA, *Fact Sheet, Celilo Converter Station* (April 2016), *available at*: https://www.bpa.gov/-/media/Aep/about/publications/fact-sheets/fs-201604-Celilo-Converter-Station.pdf.
[211] Power of the River, at 85.
[212] *Id.*, at 91-93.

obligation by BPA to a third-party that issues revenue bonds under its own name that are dedicated to building a BPA transmission line.

A lease-purchase contract specifies that BPA will construct a line owned by the third-party and then lease and operate the line with an option for BPA to purchase it at the end of the term of the debt. These contracts are BPA's way of underwriting debt issued by someone else. This type of contract financing is similar to the "net-billing" debt that BPA incurred in backing nuclear plants pursued by the Washington Public Power Supply System (now Energy Northwest), including Columbia Generating Station. The cost of lease-purchase capital is higher than Treasury debt, making this a more expensive way to finance transmission.[213]

Encouraged by Congress to explore alternative financing, BPA came up with lease-purchase financing in the early 2000s as a way to preserve the agency's limited Treasury borrowing authority. To date, BPA has raised lease-purchase capital through three third parties—Northwest Infrastructure Finance Corporation, an entity created by a private corporation that specializes in infrastructure financing; the Port of Morrow, a port district under Oregon law with broad authority to issue bonds; and the Idaho Energy Resources Authority, a state entity authorized under Idaho law to issue bonds on behalf of consumer-owned utilities to finance infrastructure. Credit analysts view these third parties as "conduit issuers" of debt.[214] The capital raised has been used to finance several BPA transmission lines since 2000, including new 500-kV lines like the 63-mile Schultz-Wautoma and 84-mile Grand Coulee-Bell lines.[215] Combined with BPA's Energy Northwest debt, BPA's outstanding non-federal debt ($7.1 billion) is in fact higher than its outstanding federal debt ($6.9 billion), despite the agency's lack of authority to directly issue debt to commercial markets.[216] This basic financial reality is due the agency's broad contracting authority to enter into financial obligations.

When Congress raised BPA's Treasury borrowing authority by $10 billion in 2021 in the Infrastructure Investment and Jobs Act (Sec. 40110, P.L. 117-58), it alleviated BPA's need for the foreseeable future to secure more expensive debt through lease-purchase contracts.[217] But lease-purchase transmission financing nevertheless represents an important example of financial innovation by BPA, via partnerships with both public and private entities, in order to build new transmission.

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[213] The program is also known simply as "lease financing" and "third-party financing." *See* BPA, BPA's Lease Financing Program (2013), *available at*: https://www.bpa.gov/-/media/Aep/finance/lease-financing-program/lease-financing-program-overview-final.pdf.

[214] BPA, *Financial Plan Refresh: Grounding Workshop #2* (Nov. 16, 2021), *available at*: https://www.bpa.gov/-/media/Aep/finance/financial-plan-refresh/nov-16-workshop-presentation-new.pdf; Moody's Investor Service, *Bonneville Power Administration Credit Opinion* (Apr. 6, 2022), available at: https://www.bpa.gov/-/media/Aep/finance/rating-agency-reports/moodysfullreportmay2022.pdf.

[215] *Power of the River*, at 224.

[216] BPA, *Federal Columbia River Power System (FCRPS): Total Liabilities to Federal and Non Federal Parties as of 9/30/2022* (2022) *available at*: https://www.bpa.gov/-/media/Aep/finance/debt-optimization/2022-debt-pie-chart.pdf.

[217] BPA, *Financial Plan Refresh Public Workshop,* slide 8 (Mar. 23, 2022) *available at:* https://www.bpa.gov/-/media/Aep/finance/financial-plan-refresh/20222321-Mar-23-Workshop-Presentation.pdf.