Use of Network Open Seasons in the Electric Industry

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1. Open seasons have a solid foundation in energy regulatory policy

Open season processes enable fair and efficient access to newly created capacity and provide a means of sharing risk between industry beneficiaries of the new capacity and existing system users. They have been used in the gas industry[1] because the industry has regulated monopoly pipelines, shippers who either are unaffiliated firms or who otherwise must operate at arm's-length from interstate pipelines, and it is possible to define rights to pipeline capacity. The Federal Energy Regulatory Commission (FERC) has used open season processes to help satisfy its requirements under Section 7 of the Natural Gas Act of 1938 (NGA), which requires FERC to make a determination as to whether new natural gas pipeline or storage capacity or expansion meets the public convenience and necessity standard to approve the new facilities.[2] Essentially, open seasons provide a market test of "need" (demand), and a means of assuring non-discriminatory access such that no party (including pipeline affiliates) have unfair access to the capacity.

Open seasons are less common in electricity mainly because of the properties of the grid where power flows freely across the integrated AC network. This free flow makes it harder for funders of new capacity to have exclusive rights to what they fund. Transmission has "public good" characteristics. Another aspect of the electric sector is relatively small size of most electricity customers, such that it would be impractical to organize hundreds of users to voluntarily contribute to transmission expansion from which they could all benefit. However, open seasons have been employed in the sector in order to prove out the need for additional transmission to provide up-front payments for it. We offer some examples both in DC point-to-point contexts (similar to pipelines), and integrated AC network contexts. We describe these examples below.

2. Examples of Open Seasons in the Electric Industry

a. Merchant transmission

There are several examples of using open seasons for merchant DC transmission. This particular sub-sector operates more like gas pipelines than integrated AC power networks. Delivery is

[1] *See* Rockies Express Pipeline L.L.C., 116 F.E.R.C. ¶ 61,272 (2006).

[2] *See* 15 U.S.C. § 717(f)(c) (2006).

point-to-point, rights are defined similarly, and power flow can be controlled and limited to those who subscribe.

Two examples of the use of open seasons in merchant transmission are the Chinook and Zephyr projects.[3] Both projects proposed to construct over 1,000 miles of 500 kV HVDC line providing approximately 3,000 MW of capacity to the Southwestern US. For both projects, FERC approved an initial allocation of 50 percent of the project's capacity to anchor tenants and the remaining 50 percent of the project's capacity would be allocated through an open season auction.[4] This methodology was applied to other merchant transmission projects, such as the initial rate approval for SunZia, which recently commenced construction.[5] In several cases, FERC allowed up to 75 percent of the projects capacity to be allocated to anchor tenants while the remaining capacity was subject to an open season auction.[6] Critically, FERC has noted that open seasons do help provide some financial certainty for developers as well as allow the developers to "right-size" their project based on demand.[7]

b. Bonneville Power Administration's Network Open Season Process

In the late 2000s, the Bonneville Power Administration (BPA) was facing a shortage of transmission capacity to meet the requested transmission capacity by new generators that wanted to interconnect with BPA's system as well as demand for transmission service from customers. In 2008, BPA's transmission service request (TSR) queue reached over 9,000 MW, while the load forecast for BPA, public utilities, cooperatives, and investor-owned utilities in the Pacific Northwest from 2008 through 2017 was only roughly 2,500 average MW.[8]

Historically, BPA had required new generators and customers seeking transmission service to fund the costs incurred by the transmission provider to expand the system. BPA also required the entity requesting transmission service to provide the funds for the upgrade upfront. These requirements resulted in a situation where an individual generation developer or customer may

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[3] *See Chinook*, 126 F.E.R.C. ¶ 61,134 (2009).
[4] *Id.*
[5] *SunZia Transmission, LLC*, 135 FERC ¶ 61,169 (2011); *SunZia Transmission, LLC*, 131 FERC ¶ 61,162 (2010).
[6] *See*, e.g., *Champlain Hudson Power Express, Inc.*, 132 FERC ¶ 61,006 (2010); *Rock Island Clean Line LLC*, 139 FERC ¶ 61,142 (2012); *Southern Cross Transmission LLC*, 137 FERC ¶ 61,207 (2011).
[7] *TransEnergie I*, 91 F.E.R.C. ¶ 61,230, 61,839 (2000).
[8] 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 ("*2008 NOS Administrator's Decision Letter*"); 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 ("*Attachment A*").

be required to fund the development of a significant transmission upgrade or expansion, despite the benefit each subsequent entity would accrue from the upgrade.

In practice, this meant entities seeking transmission service would receive an estimate of the required cost for an upgrade to receive transmission service and withdraw their request. This created a bottleneck where no one was able to capitalize on the significant economies of scale that are achieved from development of major transmission projects to accommodate multiple requests for transmission service at a time. Instead, it was nearly impossible to connect new generation to BPA's system.

To resolve this barrier, in 2008, BPA created a new transmission service request process known as "Network Open Season" (NOS). The NOS process was designed to overcome the bottleneck created by the serial generator interconnection process which was preventing new generation from coming online and preventing the development of the more efficient higher capacity set of lines that could most efficiently serve the demand. The NOS process was modeled on similar approaches that had been used successfully to procure new natural gas pipeline capacity as well as for merchant transmission.[9] As a part of the process, BPA submitted Open Access Transmission Tariff (OATT) modifications to the Federal Energy Regulatory Commission (FERC) to implement NOS, which FERC approved in June 2008, noting that "Bonneville's Open Season process and Precedent Agreement substantially conform to or are superior to pro forma OATT provisions."[10]

BPA required all entities to participate in the NOS process for transmission service or else lose their position in the interconnection queue. Annually, BPA collected requests for transmission services from all customers in the queue and aggregated the demand for long-term firm transmission service. As a part of the request for transmission service, participants were required to sign a Precedent Transmission Service Agreement (PTSA). The PTSA obligated participants in the NOS process to take transmission service if BPA in a timely manner could meet two conditions: "(1) BPA determines that it can reasonably provide service for TSRs in the cluster at embedded cost PTP [Point-to-Point] and NT [Network Transmission] transmission rates, and (2) if facilities must be built to provide the service, BPA decides, after completion of a BPA-funded National Environmental Policy Act (NEPA) study, to build the facilities." The PTSA

[9] *See Texas Eastern Transmission Corporation*, 82 FERC ¶ 61,236, 61,915-916 (1998); Joseph H. Fagan, Becky M. Bruner, and Natara G. Feller, "FERC Opens Door to Merchant Transmission Line Development—Expands Opportunity to Bring Renewables to Market," February 26, 2009; Order Conditionally Authorizing Proposal and Granting Waivers, 148 FERC ¶ 61,122, Docket No. ER14- 2070-000, August 14, 2014.
[10] *Bonneville Power Administration*, 123 FERC ¶ 61,264 (2008).

also included a security payment equal to one year of transmission revenues for their requests.[11] Participants unwilling to make this financial commitment dropped out of the queue.

For all the participants that signed a PTSA, BPA performed a cluster study, similar to many now conducted by ISOs and RTOs. This study replaced the previously separate feasibility, system impact, and facilities studies BPA had conducted. After BPA completed the study, if an upgrade was identified that could meet the two PTSA conditions described above BPA would proceed with an environmental review, and if the review was acceptable, BPA would construct the project. In order to determine if BPA could satisfy condition one of the PTSA and offer service at embedded rates–allocating costs to the integrated network–BPA conducted a net present value analysis. For the analysis, any reliability benefits to the system were deducted and if the long-term transmission service commitments made by the participants that signed PTSAs were equal to the remaining project costs then BPA deemed that transmission service could reasonably be provided at embedded rates and the project could move forward.[12]

For PTSAs that BPA determined could not be offered transmission service at an embedded cost rate, the PTSA was terminated and the security deposit refunded. These participants were allowed to reenter future NOSs or seek an individual TSR under BPA's OATT.[13]

For the first NOS conducted in 2008, BPA determined 74 PTSAs, associated with 3,699 MW of transmission service, could be provided service at embedded cost rates. This was over half of the initial 153 PTSAs which totaled 6,410 MW of new long-term transmission service. In addition, for 8,054 MW no PTSAs were signed, and BPA removed these TSRs from the queue. BPA stated it believed these projects were likely speculative and removing them from the queue freed transmission capacity that allowed 1,782 MW of transmission service without new construction.[14] To meet the needs of the 74 PTSAs that were signed, while maintaining embedded cost rates, BPA identified five major transmission expansion projects, four of which were over 500 kV.

Overall, BPA's NOSs were successful relative to the status quo ante. Given the initial success BPA conducted the NOS process annually for two more years in 2009 and 2010. Over these three NOS cycles, BPA expanded its transmission capacity allowing for 263 individual requests totaling 11,722 MW of new transmission service, including 7,105 MW of new wind generation, to be added to its system.[15]

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[11] *See 2008 NOS Administrator's Decision Letter*; *See also Attachment A.*

[12] *Id.; See also* K. Porter, S. Fink, C. Mudd, and J. DeCesaro, *Generation Interconnection Policies and Wind Power: A Discussion of Issues, Problems, and Potential Solutions*, NREL (January 2009), https://www.nrel.gov/docs/fy09osti/44508.pdf.

[13] *See 2008 NOS Administrator's Decision Letter*.

[14] *See Attachment A.*

[15] 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.

The NOS process enabled BPA to alleviate bottlenecks within its interconnection queue and expand its transmission capacity to meet demand for transmission services. One of the keys to the success of the NOS process was the proactive planning and development of transmission based on the PTSAs. The NOS allowed BPA to identify more demand for transmission than it was able to identify through its previous serial interconnection processes, and to capture the economies of scale by combining multiple requests into one cohesive transmission plan. It ultimately proved to be successful in identifying demand for transmission relative to a system that relied exclusively on signed interconnection agreements. The NOS also allowed BPA to distribute risk between itself and its transmission customers.

One key to the success of the BPA NOS was the size of the transmission customers, which were generally generation project developers. They were large enough to have the financial wherewithal to make the financial commitment required.

Another key to the NOS success was that it provided firm value to those customers who made the financial commitments. Even though the integrated AC network retained many public-goods characteristics, the transmission customers were able to receive firm transmission rights, and they were valuable enough to justify the payments.

c. Conclusion

The above examples demonstrate that transmission capacity and interconnection have been sold through a bidding process to market participants representing both supply and demand. While less frequently used in the electric industry than in the gas-pipeline industry, it would be appropriate to use an open-season process where circumstances suggest that new electric transmission offers a clearly defined benefit to certain parties, especially new entrants. Such an open season can be used as a market-based check on the need for and the right-sizing of transmission facilities, defining the quantity of demand that is genuinely necessary. It can also be used as a risk-sharing and cost-allocation tool, allowing beneficiaries to self-identify and pay up-front costs for transmission in exchange for a guarantee of service from the new infrastructure that open season would fund.