Filing Receipt

Filing Date - 2024-08-09 02:52:40 PM

Control Number - 55718

Item Number - 33

PROJECT NO. 55718

RELIABILITY PLAN FOR THE PERMIAN BASIN UNDER PURA § 39.167	**§ §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

NRG ENERGY, INC.'S COMMENTS ON THE PERMIAN BASIN RELIABILITY PLAN

NRG appreciates the opportunity to provide comments in this project in response to Staff's request for comments. NRG has attached a white paper regarding a "Network Open Season" concept it proposes below, as Attachment A. The executive summary is included as the last page of this filing, as Attachment B.

INTRODUCTION

At a projected cost between ~$13 to $15 billion,[1] the Permian Basin Reliability Plan (PBRP) represents one of the largest electric transmission infrastructure development plans that any U.S. regulatory commission has ever been asked to approve, far exceeding the $7 billion competitive renewable energy zone (CREZ) transmission plan in scope and cost,[2] as well as MISO's $5.1 billion Multi-Value Projects portfolio[3] and the $10.3 billion MISO Long-Range Transmission Planning (LRTP) Projects.[4]

Given the importance and cost of the PBRP, NRG would support a longer timeframe than provided by the instant request for comments and the associated proposed September timing for approval of the PBRP[5] to allow an opportunity for more thorough stakeholder input and Commission analysis and deliberation. As a point of comparison, the CREZ transmission plan (at a cost of roughly half that projected for the PBRP) was adopted only after a multi-year contested

---

[1] Project No. 55718, ERCOT's Reliability Plan for the Permian Basin Region, cover letter at 2 (Jul. 25, 2024).

[2] *E.g.*, Public Utility Commission of Texas, *Report to the 84th Texas Legislature* (2015), at 60 (Appendix C) (2015).

[3]https://www.prnewswire.com/news-releases/itc-to-undertake-portions-of-miso-approved-mvp-projects-135430753.html

[4] MISO Board Approves $10.3B in Transmission Projects (misoenergy.org).

[5] Project No. 55718, Order Directing ERCOT to Develop a Reliability Plan for the Permian Basin Region, at Attachment A (Dec. 14, 2023).

case proceeding,[6] followed by many related contested proceedings[7] before the associated certificates of convenience and necessity (CCNs) were ultimately filed. While NRG understands that the Commission is operating under statutory timing constraints for the PBRP that did not exist for CREZ, NRG respectfully submits that the Commission has time for additional deliberation and opportunity for stakeholder input without interfering with the required statutory timing.[8] In short, NRG supports prudent investment in the ERCOT transmission system to support robust customer demand growth but also recommends the Commission provide sufficient time for stakeholders to thoroughly comment on the many policy issues related to this significant project, including giving consideration to the innovative regulatory policy that NRG proposes below.

NRG's comments focus primarily on Staff's "Affordability and Cost" questions. NRG proposes to incorporate a Network Open Season (NOS) for new large loads in the region. A properly designed NOS would right-size the transmission approved pursuant to the plan, obtain appropriate assurances that the load forecasts undergirding the plan will be realized, and ensure that the plan's up-front costs are properly allocated. Taking this step would significantly address affordability and cost concerns, while facilitating the acceleration of electricity demand growth by willing buyers in the Permian Basin.

GENERAL COMMENTS ON KEY PRINCIPLES

Need for Load Forecast Certainty

The ERCOT system is poised to grow rapidly as society electrifies more computing loads and oil and gas development, while accommodating a possible increase in electrolytic hydrogen production. ERCOT's transmission planning process should accommodate this load growth and

[6] *See Commission Staff's Petition for Designation of Competitive Renewable Energy Zones*, Docket No. 33672 (Initial application was filed in January 2007, and the Order on Rehearing was issued in October 2008).

[7] *E.g.*, *Commission Staff's Petition for the Selection of Entities Responsible for Transmission Improvements Necessary to Deliver Renewable Energy from Competitive Renewable Energy Zones*, Docket No. 35665 (2009); *Proceeding to Sequence Certificate of Convenience and Necessity Applications for the Priority Projects for the Competitive Renewable Energy Zones*, Docket No. 36801 (2009); *Commission Staff's Petition for Determination of Financial Commitment for the Panhandle A and Panhandle B Competitive Renewable Energy Zones*, Docket No. 37567 (2010).

[8] 88th Tex. Leg., R.S., House Bill 5066 provides for the expiration of Section 39.167, Texas Utilities Code, which is the section specifically requiring a reliability plan for the Permian Basin, on September 1, 2025. With that said, the provisions that HB 5066 added to Chapter 37 of the Texas Utilities Code, related to certificates of convenience and necessity, do not have an expiration date. Thus, arguably, the PBRP need only be adopted by September 1, 2025, with implementation to follow. In addition, the broader directive for a reliability plan related to rapid electrical growth (not limited to the Permian Basin), in Section 39.166, Texas Utilities Code, has no expiration date.

allow for Transmission System Providers (TSPs) to expand their systems in anticipation of increased customer demand. The intent of HB5066 was exactly for that purpose, to allow the Commission to approve transmission projects that include forecasted load "for which the electric utility has yet to sign an interconnection agreement."[9] NRG supports this effort and has participated in discussions in the ERCOT stakeholder process to help define how anticipated loads are incorporated into load forecasts for transmission planning purposes. To improve transparency of what loads are being included in the load forecasts used for transmission planning, NRG recommends increased reporting by ERCOT of which loads have secured site control in addition to loads with contracts with the TSPs and loads confirmed by TSP executive letter, both of which ERCOT already reports on occasion.

More importantly, to help ensure more certainty of future load growth and to provide a tangible basis of need to the Commission to justify project approval, NRG also proposes incorporation of a NOS concept as explained in more detail later in these comments. As part of a NOS, large customers would essentially "reserve" capacity on the expanded transmission system through a financial commitment sufficient to cover a portion of the costs of constructing the upgrades (with a proportional refund of an upfront deposit to occur over an extended period following energization). This would be conducted through an open and competitive process for customers without a signed interconnection agreement with the TSP. TSPs could prioritize expedited construction of transmission to serve customers that have participated in a NOS and have reservations for service. These reservations would help the Commission and ERCOT stakeholders better understand the prospective customer demand and provide further support for approval of the proposed projects to meet the "need" requirements of the CCN process.[10]

---

[9] 88th Tex. Leg., R.S., House Bill 5066 (effective Jun. 13, 2023), *available at*: 88(R) HB 5066 - Enrolled version (texas.gov).

[10] While HB5066 adds certain considerations to the "need" criterion for CCN applications to account for transmission projects built to serve underserved load in remote locations (such as the load that will benefit from the PBRP), whether that criterion has been satisfied is still likely to be contested in the individual CCN projects, and the NOS process would help to demonstrate that need. *See* HB5066, § 1, codified in PURA § 37.056(c)(4)(F) ("The commission shall grant each certificate on a nondiscriminatory basis after considering: … (4) other factors, such as: … (F) the need for extending transmission service where existing or projected electrical loads will be underserved, including where: (i) the existing transmission service is unreasonably remote; (ii) the available capacity is unreasonably limited at transmission or distribution voltage level; or (iii) the electrical load cannot be interconnected in a timely manner.").

Transmission Cost Allocation

The allocation of transmission costs in ERCOT has utilized the four coincident peak (4CP) methodology since the implementation of restructured wholesale and retail competitive markets over 20 years ago. Under this methodology, transmission costs charged to large industrial and commercial customers are determined based on their demand in the peak 15-minute intervals for the months of June, July, August, and September.[11] At the end of each year, ERCOT determines the load ratio share of each distribution service provider (DSP) during those four summer peak intervals, which sets its share of the 4CP and its corresponding allocation of the yearly ERCOT transmission cost-of-service (TCOS) for the following year.[12] DSPs also employ 4CP to allocate transmission costs to customer classes, and then use a variety of rate designs to collect that allocated cost of service from their customers.[13] Large commercial and industrial customers' rates are typically based on each customer's kW load during the identified 4CP intervals. Therefore, unlike other customers, large customers can reduce their share of the total transmission costs by reducing their electricity consumption during those four 15-minute summer peak intervals. If applied to the PBRP, this rate design could allow new large loads to avoid the cost of building the very transmission that had been justified by the emergence of these large loads.

By ensuring a direct allocation for at least a certain share of PBRP costs, the NOS concept proposed by NRG in these comments is a safeguard to protect other customers, especially residential customers, as the transmission system is expanded to serve large customers. In addition, while not the focus of our comments in this matter, NRG also takes this opportunity to note that the underlying premise of 4CP—that transmission serves and thus should be allocated to summertime gross peak loads—is no longer accurate and no longer forms the basis of ERCOT transmission planning. While this policy should be reconsidered in the future, for purposes of evaluating and approving the PBRP, the use of a NOS concept in the PBRP context would be a balanced and appropriate solution for the shorter term.[14]

---

[11] *See* 16 Tex. Admin. Code (TAC) § 25.192(b).

[12] *Id.* § 25.192(d).

[13] This allocation methodology is reflected in the Commission-approved Retail Delivery Service tariffs for the individual TSPs: Transmission and Distribution Rates for Investor Owned Utilities (texas.gov).

[14] Recent large transmission improvement projects have been unrelated to ERCOT coincident peak load. These include CREZ, the Rio Grande Valley improvements, Far West Texas upgrades, and now the PBRP. This fact calls into question the continued wisdom of using 4CP as the allocative methodology for all transmission, because

RESPONSE TO QUESTIONS

Question 4: With the understanding that the cost of these projects will be passed along to all the ratepayers in ERCOT, what considerations should the Commission address to minimize rate impacts? Are there any guardrails the Commission should implement?

NRG shares the concern inherent in this question regarding the potentially significant cost impact of the PBRP and suggests the Commission should evaluate novel approaches, such as the NOS proposal detailed below, to ensure that the PBRP is right-sized and to allow for some of the associated costs to be borne by the direct beneficiaries of the PBRP. While the Public Utility Regulatory Act (PURA)[15] generally dictates the required cost allocation methodologies for wholesale transmission[16] and retail delivery service,[17] the Commission's rules (and the associated retail delivery service tariffs) also allow for TSPs to collect refundable deposits from customers that request extensions of the existing system infrastructure, with the deposit to be paid back following energization.[18] Given that the PBRP represents a significant extension of the existing system infrastructure, with an equally significant price tag, the Commission should consider adopting a similar concept for the PBRP, by allowing for some of the construction costs to be allocated to the direct beneficiaries of the PBRP via a NOS process, with proportional refunds of upfront deposits paid back to those large customers over a number of years.[19]

In essence, a NOS process for large load interconnections would accomplish two purposes. First, it would help demonstrate the need and help identify which of any alternative transmission

---

4CP's premise is that all transmission is closely related to serving gross peak loads in the summer. The ERCOT transmission planning process does not base the need for transmission projects to resolve reliability planning criteria violations on ERCOT system summer peak load. The negative consequences of the current 4CP mechanism are explained in detail by Dr. William Hogan and Dr. Susan Pope in their "Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT" study published in PUCT Project No. 47199. 47199_2_941113.PDF (texas.gov).

[15] Tex. Util. Code §§ 11.001-66.016 (PURA).

[16] PURA § 35.004(d) (requiring that wholesale transmission service, which includes construction and enlargement of facilities (*see id.* § 31.002(20)), be allocated via the postage stamp methodology).

[17] PURA §§ 36.003, 36.004 (requiring that retail delivery service be charged to customers based on Commission-approved tariffed rates that are just, reasonable, and not discriminatory).

[18] 16 Tex. Admin. Code § 25.195.

[19] NRG recognizes that this would be a novel approach to allocation of transmission construction costs and may benefit from more specific statutory language that could be pursued in the upcoming Legislative session, if the Commission so desires. With that said, NRG views the existing deposit provisions for facilities extensions as providing a useful framework and analogy to support a NOS concept potentially without any statutory changes.

plans are best suited to serve load in the Permian. Second, it would ensure that, even if load forecasts change, spending on transmission does not result in unreasonably high stranded costs. Instead, it could be used to allocate costs to the new loads that are the principal beneficiaries of at least some part of the plan's total costs.

More specifically, the NOS concept would add a crucial step between a conditional approval of the PBRP conceptually as the reliability plan for the Permian Basin and the individual TSPs' CCN proceedings where the specific projects would be litigated and approved, to ensure customer demand growth is anchored by willing buyers of future transmission capacity designed to import energy into the Permian Basin. This would provide more transparent indications from new-large-load customers themselves of the need for expanded transmission in the Permian Basin region, and also allow for a portion of the costs, as determined by the Commission, to be funded by those large-load customers that benefit from the investment. The NOS would be an important guardrail on wider customer cost impacts. Under the NOS concept, large customers with reservations could fund a portion of the transmission expansion, similar to posting a deposit for facilities extensions under existing TSP tariffs, and then after energization, receive proportional refunds of that deposit over an extended period of time (e.g., 10 years). A party's successful participation in NOS would also convey a transferable right that could be sold for market value on the secondary market, should the particular buyer ultimately not desire to move forward with a large-load project of its own. If the customer never interconnects or exits the ERCOT market prematurely, the remaining balance of their deposit would be used to lower transmission costs for remaining ERCOT consumers.

Network Open Seasons have been used extensively in natural gas pipeline and gas-storage development to determine the need for, and appropriate size of, facilities and to allocate the costs of capacity. NOS concepts also have been employed in the electricity space. These examples are described in the white paper, *Use of Network Open Seasons in the Electric Industry*, which NRG asked Grid Strategies to prepare for these comments and is attached as Attachment A. The extension of this concept, with appropriate modifications for the ERCOT market, is well-suited to the present situation.[20] The PBRP's principal beneficiaries are new, large loads, and it is

[20] The principal differences between the Bonneville Power Administration's NOS, referenced in the white paper, and the NOS proposed here is that the former is for new renewable generators while the latter is for new large loads, as well as that BPA through its transmission rate design could be relatively assured of collecting substantial

appropriate to go directly to the large-load-market to ask for transmission capacity reservations and expect a portion of the PBRP's upfront costs to be directly allocated to the same. If designed as proposed in these comments, sufficient protections would exist before and after a NOS to ensure that existing load and future beneficiaries that are not part of the NOS will also pay for benefits they receive.

NRG proposes that a NOS for PBRP could consist of the following five steps:

1. The PUCT would direct ERCOT, as part of a conditional approval of the PBRP, to identify the benefits to new load versus existing load that arise from the component parts of the PBRP. For the purpose of this process, the component parts either could be the "local" versus "import" buildout, or it could involve a more exacting decomposition of the benefits of the particular facilities that will be assigned to transmission utilities and subject to further CCN proceedings.
2. The costs represented in the PBRP would be updated, if necessary, and then categorized on the basis derived from Step 1 to the benefits accruing to new loads' interconnection. These costs, rendered on a per-MW basis for firm transmission service at a particular location, would constitute an indicative cost for bidders in the NOS.
3. The NOS would commence. Loads, as well as any party wishing to buy the transferable right for a large load to interconnect, would express a location, volume, and a willingness to make a firm financial commitment based on those indicative values identified in Step 2. As part of a NOS bid, a party would make an initial refundable deposit.
4. Based on NOS bids, ERCOT or the relevant utility would identify one of the PBRP alternatives, and also revise per-MW costs within a predefined tolerance band (e.g., +/- 15%), in line with the volume and location of customer interest. The initial PBRP plan presents various alternatives in the sizing of transmission build-out; this step of the NOS ensures that future transmission is right-sized based on customers' willingness to pay.
5. The NOS is closed, and results are announced. If sufficient customer interest existed in the NOS to subscribe one of the plan alternatives, then the remainder of the financial commitments are made in the proportional amounts derived from earlier Steps. These commitments directly reflect the costs of the transmission upgrade allocable to NOS bidders, who may transfer that right on a secondary market. Such financial commitments need not be an immediate payment in full, but instead letters of credit, with costs payable as the TSP accrues costs. Bidders' initial deposits would be applied against any Construction Work in Progress, or refunded in the event of a NOS that demonstrates that transmission was not needed. Bidders' upfront payments would be refunded in a proportional amount to interconnected large loads over an extended period following energization (e.g., 10 years).

---

transmission revenue from any interconnecting generator, while that is not necessarily the case with new large loads subject to 4CP-based transmission charges in ERCOT.

In sum, the NOS process to interconnect large loads would add to and leverage the ability of Texas to timely site and permit transmission and would align with the natural advantages of the restructured supply market. A successful NOS could be taken as constituting a kind of rebuttable presumption of need for a project, which in a CCN application may otherwise be hotly contested due the speculative basis of the new load and the possibility that alternative service (such as generation closer to load) would exist to serve any of these relatively remote loads that come to exist in the Permian.[21] A NOS layered atop these existing energy policies can help Texas "win" the market for large loads, while minimizing cost shifts and impacts on reliability.

Question 6: <u>In approving this plan, how can the Commission ensure cost effectiveness for the listed projects? Please explain in detail and specifically address risks and offer potential mitigation solutions relating to: a) Load forecast, because this will be the first time the Commission will rely on load forecast methodology based on PURA § 37.056(c-1). B) Cost estimates, because projects will not be vetted through ERCOT's Regional Planning Group, the stakeholder committee that regularly reviews proposed transmission projects.</u>

While HB5066 does allow for the expansion of the transmission planning process to include future loads that do not have signed contracts with the TSPs in accordance with PURA § 37.056(c-1), the Commission should still apply a level of scrutiny to ensure investments in the transmission system will not be stranded. Requiring officers of the TSPs to attest to future customer growth to support transmission expansion is a good step in the process, but very little information is known other than that (i.e., customer load is confirmed by TSP officer letter). More due diligence and transparency would be beneficial for all. For example, what information or commitment does the customer provide to the TSP to support inclusion in the TSP's load forecast that is confirmed by officer letter? Does the customer have to commit to a duration of service, or can they exit the ERCOT system after a few years with no consequence? Does the customer have proof of site control, proof of ownership, or a lease for the land for which electric service will eventually be needed, or can they demonstrate a path to ensure the customer will eventually possess the tangible property in need of service? Can a large customer submit multiple prospective sites for inclusion within a single TSP territory or across multiple TSP territories? NRG supports the expansion of the transmission system to serve growing customer demand and prudent investment in the

[21] *See supra* note <u>10</u>.

necessary infrastructure, but additional transparency would help all stakeholders, including the Commission, in supporting this effort.

Further, the best evidence of project need and cost-effectiveness will be provided through a NOS. This will allow the Commission to ensure cost effectiveness by verifying the load forecasts through customer reservations provided in an open and competitive process. A NOS thus would provide the Commission market-based data to support this significant investment. The Commission could determine the amount of financial commitment required to reserve transmission capacity and establish an amount to be refunded after the customer interconnects and takes electric service for an extended period of time to show justification for the investment. In other words, in a NOS concept, customers would reserve the amount of peak load they believe they would need, and the system could be designed to that specification.

In addition, a significant portion of the load growth related to the PBRP is associated with crypto-mining facilities and data centers, some of which can respond to high wholesale prices. It is unclear how much load these types of customers will contribute during system peak load or peak net load. ERCOT currently estimates a peak contribution of 15% of the total customer load for these types of customers. In reality, the amount of peak load contribution of each customer will vary based on prices and that customer's particular business model, server technology, and their market conditions that are unrelated to the ERCOT wholesale market. Encouraging these loads to be registered and to participate in the ERCOT wholesale market as Controllable Load Resources (CLRs) is critical for operational awareness and system reliability. With or without a NOS concept, a requirement (or encouragement) for registration as CLRs also should reduce the amount of transmission required to serve their load.

Finally, unlike transmission projects based on economic criteria, which are justified using cost estimates submitted by the TSP, the PBRP is designated by statute as serving a reliability purpose[22] and is justified based on load growth and violations of the reliability planning criteria related to that load growth. During the CCN process, whether or not the Commission pursues NRG's proposed NOS concept, NRG expects the Commission to thoroughly vet the costs related

[22] *E.g.*, PURA § 37.056(c-1) includes projects that are for underserved load (added by HB5066) in the category with reliability projects, which, unlike economic projects, do not have to meet the test referenced in PURA § 37.056(d). PURA §§ 39.166 and 39.167 also characterize the PBRP as a "reliability plan."

to the PBRP projects and look for areas for potential cost savings. While ERCOT operates independently during their analysis and the development of the PBRP, given the scope and cost of this project, the Commission could consider hiring an independent professional engineer specializing in electrical engineering or power systems to review the plan and costs and provide any recommendations that may deviate from what ERCOT provided in the PBRP.[23]

CONCLUSION

NRG appreciates the Commission's consideration of its comments, including its "Network Open Season" concept. NRG looks forward to additional opportunities to work with the Commission on developing solutions to the important policy considerations raised by the PBRP.

Respectfully submitted,

Bill Barnes

Travis Kavulla
Vice Pres. Regulatory Affairs
Bill Barnes
Sr. Dir. Regulatory Affairs
Mandy Kimbrough
Dir. Regulatory Affairs
State Bar No. 24050613
NRG Energy, Inc.
1005 Congress Avenue, Suite 950
Austin, Texas 78701
Telephone: (512) 691-6137
travis.kavulla@nrg.com
bill.barnes@nrg.com
mandy.kimbrough@nrg.com

[23] During the CREZ process, ERCOT used a consultant, AWS Truewind, to assist with the development of the CREZ transmission plans that it proposed for consideration in the CREZ designation proceeding in Project No. 33672. *See* Docket No. 33672, ERCOT's CREZ Transmission Optimization Study at 13 (Apr. 2, 2008).

GridStrategies

Use of Network Open Seasons in the Electric Industry

Prepared for NRG Energy

August 9, 2024
Rob Gramlich and Zach Zimmerman, Grid Strategies LLC

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).

GridStrategies

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

---

[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*").

GridStrategies

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]

---

[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.

GridStrategies

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.

ATTACHMENT B

NRG ENERGY, INC.'S EXECUTIVE SUMMARY

At a projected cost between ~$13 to $15 billion, the Permian Basin Reliability Plan (PBRP) represents one of the largest electric transmission infrastructure development plans that any U.S. regulatory commission has ever been asked to approve, notably, far exceeding the $7 billion competitive renewable energy zone (CREZ) transmission plan, which was evaluated over a multi-year period through multiple contested case proceedings. Given the importance and significant projected cost of the PBRP, NRG would support a longer deliberation period to allow for a more comprehensive review by stakeholders and the Commission. While the plan may be well justified based on expected growth in the Permian, the Commission should institute a market-based check on the plan's assumptions to ensure adequate safeguards for affordability and cost.

There are at least two fundamental risks that the Commission should grapple with:

1. That the load forecasts embedded in the PBRP may be too uncertain or at least not firm enough to properly right-size a plan from among PBRP's alternatives; and,
2. That the new large loads who are identified as the primary beneficiaries of the plan's spending may effectively avoid paying for a fair share of the costs of the very transmission that had been justified by those loads in the first place.

To answer these concerns, NRG's proposes a Network Open Season (NOS), an innovative regulatory policy that draws from prior experience detailed in a newly published white paper attached to these comments, but which is tailored for use in ERCOT.

This NOS could follow five steps by which the PBRP's benefits are allocated between new and existing loads; the costs proportional to the benefits accruing to new load could be rendered on a per-MW basis; loads and other parties submit bids indicating their willingness to make a financial commitment to secure that service; the costs are updated within a moderate tolerance band to reflect the volume and location of customer interest; and finally binding financial commitments are made to pay the allocable upfront costs of the PBRP, refundable over an extended period following energization (e.g. 10 years). By following these steps, a NOS would simultaneously right-size transmission approved pursuant to the PBRP and ensure that its upfront costs were properly allocated.

Finally, NRG proposes several other recommendations. These include improvements to transparency and information collection for large loads that are estimated through TSP officer letters, a requirement that certain large loads register as Controllable Load Resources, and a review by a Commission-hired professional engineer of the PBRP and costs arising from it.