UNITED STATES OF AMERICA
BEFORE
THE FEDERAL ENERGY REGULATORY COMMISSION

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Establishing Interregional Transfer	)	Docket No. AD23-3-000
Capability Transmission Planning and	)	
Cost Allocation Requirements	)	
	)	

OPENING STATEMENT OF
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Panel 4: Meeting the Goal of Increased Interregional Transfer Capability
Commission Staff-Led Workshop
Dec. 6, 2022

I. Introduction

This workshop began wisely with a presentation of "empirical estimates of transmission value using locational marginal prices." As that presentation suggests, substantial benefits may be produced by trading energy across interconnections and regions, net of the costs of transmitting it. These opportunities give rise to a business case for transmission connections between regions and interconnections. The Commission should establish processes that encourage such businesses to be right-sized and be paid for through voluntary purchases of capacity rights between interconnections and possibly regions. By the same token, the Commission should avoid decision-making that administratively specifies a particular quantity of transfer capability and allocates all of its costs through regulation to potentially unwilling counterparties.

My comments focus primarily on the Electric Reliability Council of Texas ("ERCOT"), which has four commercially operational Direct Current ("DC") ties to other interconnections. ERCOT likely would benefit from additional ties, but as I explain further in these comments, these ties should be right-sized through the discovery of a solicitation and open-season process and then paid for through capacity subscriptions by those market participants who plan to ship or trade energy over those ties, or who are required by their state regulators to purchase the tie's capacity as a form of insurance related to resource adequacy. While it is true that many transmission investments produce benefits that redound so broadly that some form of involuntary cost allocation is necessary to prevent free-ridership, that is not necessarily the case with DC ties between interconnections. Strong and concentrated financial incentives exist to promote these investments, although the Commission and state regulators may take steps to clarify and reinforce a merchant model for their development, and to encourage a routine process of transmission planning in which these investments can emerge.

II. Existing ERCOT Transfer Capability

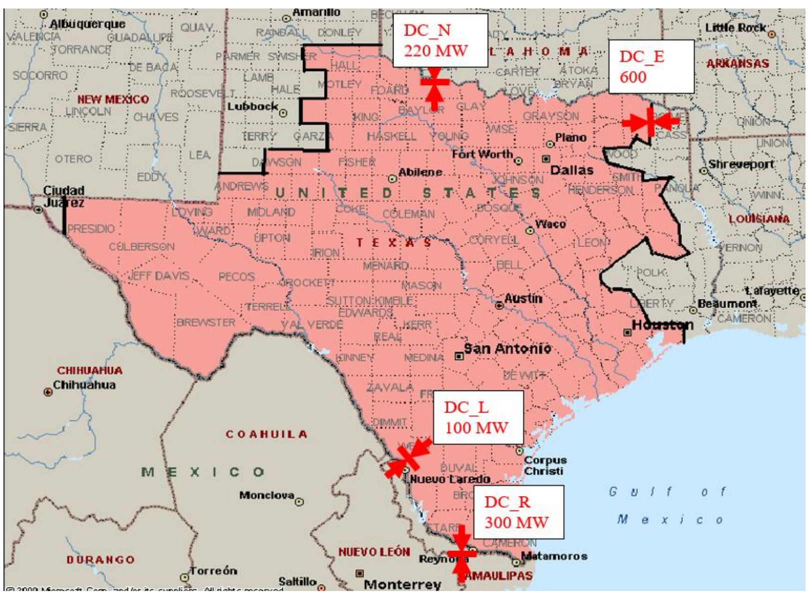
Before presenting thoughts on how any increased transfer capability can be sized and its costs allocated, it is useful to examine the *status quo* of ERCOT's existing DC tie capacity, how it is paid for, its performance during Winter Storm Uri, and its interrelationship with ERCOT's energy market design.

a. ERCOT's Four DC Ties

ERCOT has three back-to-back high voltage DC converter stations that tie together ERCOT with other grids, as well as one transmission facility that is configured to act as a DC Tie. The bulk of capacity is oriented north and east to the Eastern Interconnection through the Southwest Power

Pool ("SPP"), with two other, smaller and less frequently used facilities, connecting ERCOT to Mexico's National Center for Energy Control ("CENACE").[1] In addition to the four existing DC ties, ERCOT has had at least one other DC tie that has been decommissioned after experiencing a forced outage in March 2020 for which replacement parts were unavailable: the small, 36-megawatt Eagle Pass DC Tie.[2] Meanwhile, two other ties—both longer distance DC lines—have been proposed in the past decade, Southern Cross[3] and Pecos West.[4] If either project became operational, it would more than double existing transfer capability into and out of ERCOT, which currently is limited to approximately 1,220 megawatts.

Figure 1: Existing ERCOT DC Ties



[1] The two commercially operational DC Ties between ERCOT and the Eastern Interconnection are: North (DC_N) located near Oklaunion and East (DC_E) located near Monticello. The two commercially operational DC Ties between ERCOT and CENACE are: Railroad (DC_R) located near McAllen and Laredo (DC_L), which is a Variable Frequency Transformer (VFT) that can act as a DC tie.

[2] A description of the Eagle Pass decommissioning can be found at the materials associated with the ERCOT Board of Director's vote to delete the associated load zone: https://www.ercot.com/files/docs/2020/08/04/7_Deletion_of_Eagle_Pass_DC_Tie_Load_Zone.pdf

[3] ERCOT's dashboard associated with ongoing work on Southern Cross is available at: https://www.ercot.com/mktrules/puctDirectives/southernCross

[4] PUCT Project No. 53758, available at: https://interchange.puc.texas.gov/search/filings/?UtilityType=A&ControlNumber=53758

Trading across the existing DC ties in ERCOT depends on scheduling and transmission-reservation practices on both sides of the tie border.[5] At a high level, trading occurs bilaterally on hourly schedules in the day-ahead market, subject to an adjustment period where schedules may be changed until the hour that precedes the operating hour in ERCOT. The ties are not dispatched in real time. My company observes trading on these ties closely, and nearly all trading appears to be premised on the expected value of energy arbitrage between the markets. ERCOT sometimes has been an annual net exporter of electricity across the DC ties, but became a net importer across the DC ties starting 2018—a trend that has continued in the years since.[6] The ties also have detailed protocols associated with their use in emergency conditions.[7]

b. *Transmission Cost Allocation for Existing ERCOT Capacity*

Exports over the ties to another market are axiomatically treated as loads, and they are consequently assessed transmission charges consistent with the basic practices of FERC and certain other states that exercise jurisdiction over transmission rates. The existing rate design authorized by the Public Utility Commission of Texas ("PUCT") assesses a seasonal on-peak transmission rate for use of the ties during the summer. However, the PUCT has proposed in a rulemaking this year to change this to a postage stamp rate applicable to any hour when exports occur.[8] This flattening of the charge would result in a less substantial hurdle to exports. While generally conceding that a demand-related seasonal rate is inappropriate because it presents an inefficient hurdle, debate among commentators in the ongoing PUCT proceeding concerns the

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[5] ERCOT, "ERCOT DC Tie Operations," Version 3.0, Rev. 13 (July 2020), available for download at: https://www.ercot.com/files/docs/2020/07/30/ERCOT_DC_Tie_Operations_Document.docx
[6] Potomac Economics, *2021 State of the Market Report for the ERCOT Electricity Markets* (May 2022), p. 34. https://www.potomaceconomics.com/wp-content/uploads/2022/05/2021-State-of-the-Market-Report.pdf
[7] *Supra* fn. 5.
[8] *Review of Transmission Rates for Exports from ERCOT,* PUCT Project No. 53169, Proposal for Publication available at: https://interchange.puc.texas.gov/Documents/53169_16_1227547.PDF

appropriateness of a postage-stamp rate versus one that has a time-of-use characteristic (such as during summer on-peak hours).[9] In any case, no market participant owns long-term transmission rights for capacity on the ties, and the available capacity is allocated on an essentially open-access or first-come, first-served basis.[10] As I propose below, it would be appropriate to allow market participants to take merchant capacity positions in the ties in exchange for funding investments in them under negotiated rates or through an open-season auction.

c. Performance of DC Ties during Winter Storm Uri

Increased DC ties likely would not have prevented the worst outages during Winter Storm Uri, although they could have mitigated the duration of the event as it continued over several days. Two of ERCOT's DC ties, linking Texas to Mexico, saw no imports or exports for essentially the entire duration of the storm as CENACE experienced its own severe weather.[11] Meanwhile, the DC ties linking ERCOT to SPP did not import to ERCOT at full capacity during the storm, and were substantially or entirely curtailed during the daytime hours of February 16 and 17, 2021.[12] Increased DC capacity between ERCOT and SPP would have done little to obviate the conditions on the ERCOT grid during those times. However, increased DC capacity to other markets, or increased capacity between SPP and other grids may have had a beneficial effect in the duration of the emergency.

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[9] Comments by parties in PUCT Project No. 53169 are available here: https://interchange.puc.texas.gov/search/filings/?UtilityType=A&ControlNumber=53169&ItemMatch=Equal&DocumentType=ALL&SortOrder=Ascending

[10] SPP formally uses its OASIS for transmission reservations, while ERCOT does not accept reservations, instead allowing the submission of bilateral schedules by Qualified Scheduling Entities ("QSEs") doing business in ERCOT, with corresponding NERC e-Tags for all scheduled interchange.

[11] ERCOT, "DC Tie Flows During Winter Storm Uri." Available at: https://www.ercot.com/files/docs/2022/02/14/DCTieFlows_February2021.pdf

[12] *Ibid.*

The PUCT, as part of its response to Winter Storm Uri and in response to Texas legislative requirements, has opened a project on the potential for increased interconnection between ERCOT and other grids.[13] ERCOT and others noted in that project the currently pending projects referenced above, which would greatly expand the DC tie capacity between ERCOT and other interconnections, including the Western Interconnection.[14]

d. Interrelationship of Expanded Import Capability and ERCOT Market Design

ERCOT and its neighbors lack a common market design for resource adequacy, which is to say that ERCOT either does not have one or has at best an indirect mechanism, while ERCOT's neighboring regions do have one. The *status quo* design of ERCOT's market depends on energy scarcity pricing for resource adequacy. The expectation, or hope, is that as reserves diminish in a given real-time market interval on the ERCOT system, that the demand curve associated with the procurement of operating reserves ("ORDC") will cause energy prices to escalate beyond what a purely real-time supply/demand balance for energy alone would produce. This will translate into higher real-time energy prices during the hours when operating reserves are at their lowest, which can be expected to propagate higher forward energy prices than otherwise would exist on the prospect of this scarcity pricing. In turn, those forward energy prices will produce sufficient investments—it is hoped—to maintain the reliability of the ERCOT system.

The PUCT has worked diligently since Winter Storm Uri to augment or replace this scarcity-price–driven approach to resource adequacy, which is unique in the United States to

[13] *ERCOT Interconnection Study for 2023 Biennial Report,* PUCT Project No. 54163, available at: https://interchange.puc.texas.gov/search/filings/?UtilityType=A&ControlNumber=54163&ItemMatch=Equal&DocumentType=ALL&SortOrder=Ascending
[14] For example, see: Comments of ERCOT (Oct. 21, 2022), PUCT Project No. 54163. https://interchange.puc.texas.gov/Documents/54163_23_1247376.PDF

Texas, with a comprehensive resource adequacy market design that actually obligates resources to offer to produce energy during extreme weather conditions and other system-critical hours. However, such a market design is not yet in place, and may never be.

Without a comprehensive resource adequacy policy in place for ERCOT, there likely would be harmful interactions between the one market-based tool ERCOT does use for resource adequacy—energy scarcity pricing—and imports across DC ties. Imports would naturally erode the revenues on which intra-ERCOT resources depend to stay in or enter the market.[15] At the same time, it is not known whether imported resources (in all likelihood, given ERCOT's neighbors, monopoly utilities' off-system sales) are spoken for by some other market's resource-adequacy policy and may consequently be unavailable to ERCOT during a situation of dire crisis when two adjoining markets face significant emergency conditions, as occurred during Winter Storm Uri.

Generally, imports benefit consumers with respect to energy pricing and reliability. But in ERCOT, which depends on energy scarcity pricing for resource adequacy, imports ironically could have a negative effect on long-term reliability. Put simply, without additional resource adequacy reforms in ERCOT, which NRG supports, incremental transfer capability ironically could harm reliability in the long run within ERCOT.

[15] One may take a hypothetical example that contours to ERCOT's typical summertime performance to illustrate this interrelationship. Let us assume that a market participant estimated 6 hours of significant scarcity where ORDC Online Reserves reached 3,000 MWs, triggering a scarcity event where prices reached the ERCOT price cap, while all other hours of the summer on-peak period were not scarcity-priced and instead were based on the market's marginal heat rate multiplied by the current-day gas-price. In this scenario, the scarcity hours would contribute about 40% of the total cost of the summer on-peak strip. Meanwhile, if an additional 1,000 MWs of transfer capability into ERCOT increased imports during the hours of most significant scarcity, then it would raise ORDC Online Reserves from 3,000 MWs to 4,000 MWs, still triggering scarcity but at levels less than half the price cap. This would result, all by itself, in a reduction of the forward price signal by 26% for the summer on-peak period.

III. A Solicitation and Open Season Model for DC Ties' Transfer Capability

Although they are transmission facilities, DC ties perform a similar function in the market to energy-storage assets, acting either as a load (when exporting) or resource (when importing). When it imports to ERCOT, a DC tie will capture a locational marginal price that is profitable so long as it is offset by the costs to produce that energy, and when it exports from ERCOT it acts as a load, increasing demand and thus local prices. To the extent possible, these DC ties should have a similar kind of business model as the assets they effectively act as and substitute for, in order to allow investors to trade off between different technologies, including DC ties, that may solve similar problems.

As Prof. Timothy J. Brennan observes in a recent Resources for the Future paper, there is a sometimes unacknowledged tension between electric transmission, which often is planned by a monopoly or a central administrator and paid for through ratemaking decisions vis-à-vis captive customers, and the competitive market for power resources, including distributed energy resources and demand response, which "provides a means to reward entrepreneurs for finding and acting on private information to discover new markets, reduce costs, and deploy innovative technologies."[16] Many transmission investments do not rely on a truly competitive model—indeed, even advocates for transmission "competition" rely on the unspoken premise that there inevitably must be a regulator making people pay for transmission. It could not be otherwise, because many if not most transmission investments confer benefits upon so broad a base of consumers and market participants that a scheme of regulatory cost allocation is inevitable. Happily, DC ties need not be boxed into this paradigm of central planning and involuntary cost

[16] Timothy J. Brennan, *Is Transmission Expansion for Decarbonization Compatible with Generation Competition?*, Resources for the Future, Working Paper 22-12 (August 2022), p. 11. https://media.rff.org/documents/Working_Paper_22-12_1x8MkMR.pdf

allocation, because a DC configuration is often more "pipe" than "mesh" in the network schema, and an owner of capacity in the pipe can capture much of the differential between the two locations the DC tie or line connects. As such, DC ties offer discrete investment opportunities in which those who decide to build and buy capacity in them can capture sufficient benefits from those investments—even while they benefit society generally.

These considerations are especially profound in ERCOT, which is unlike many of its neighbors, where the generation and retailing of electricity remains largely in the hands of monopolies. In ERCOT, most generators, distributed energy resources, and demand response all operate under a predominantly merchant business model. Likewise, so do most of the load-serving entities that provide retail electricity supply.[17] To the greatest degree possible, capacity on DC ties that act to substitute for these other businesses should itself be subject to a business model that provides only the same assurances of cost recovery any other market participant in ERCOT has, and no more or less. By the same token, a developer of that transmission should have greater flexibility than someone developing a cost-of-service asset to innovate around its business model. This is something the Commission has recognized for more than a decade, including when it approved an approach by which one proposed DC tie line into ERCOT, Southern Cross, would be permitted to bilaterally negotiate the sale of much of its capacity in order to obtain financing, while committing to an open season for the remainder.[18]

The Commission may also look to the regulation of literal pipelines for inspiration on how DC ties should be treated. In order to be certificated, and thus have an opportunity both to be constructed and benefit from the Commission's economic regulation, a natural-gas pipeline

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[17] Notwithstanding the presence of competition for most of ERCOT, a large number municipal and electric-cooperative utilities that possess monopoly service territories continue to exist in ERCOT.
[18] *Southern Cross Transmission LLC*, 137 FERC ¶ 61,207 (2011).

developer must demonstrate that its project is needed. As the Commission has recently observed "in practice, applicants generally elected to submit and the Commission accepted, precedent agreements with prospective customers for long-term firm service as the principal factor in demonstrating project need."[19]

FERC should adopt a similar viewpoint with respect to transfer capability over DC ties, allowing shippers to participate in solicitation or open season offered by the line's developer in order to bilaterally negotiate or participate in an auction to take capacity on that line. This has the benefit both of right-sizing the tie's capacity and also assuring that market participants who can use the tie's capacity to substitute for generation, storage, distributed energy resources, or other technologies can take long-term positions in the DC tie and make trade-offs between technologies on an equitable basis. NRG believes a variety of market participants would be interested in such capacity if it were understood that holding it would confer a property right obtained through a solicitation or open season would not be eroded by government-backed approaches that cause rival DC ties to be constructed and paid for in a more cost-socialized manner. However, like in the gas pipeline markets, the Commission and local regulators could assure rules up front on the genuineness of the solicitation or open season and on the back end related to capacity release and other features that ensure a liquid market and the efficient use of the valuable transmission capacity that the ties would create, even while assuring payments for its use redound to the ultimate investors in long-term capacity.

The Commission already has formulated a policy on merchant electric transmission, which allows transmission developers to depart from a cost-of-service model and sign up off-

[19] *Draft Updated Policy Statement on Certification of New Interstate Natural Gas Facilities*, 178 FERC ¶ 61,107, at P 10 (2022) (*citing Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *clarified*, 90 FERC ¶ 61,128, *further clarified*, 92 FERC ¶ 61,094 (2000) (1999 Policy Statement) at 61,747).

takers of a line's capacity through a solicitation followed by bilateral negotiations for a number of anchor tenants, then followed by an open season process for remaining capacity.[20] The Commission requires transmission developers who follow this approach to file their approach to or actual allocation of capacity with the Commission for approval, together with documentation around the integrity of the solicitation and open season.[21] The Commission policy statement also blesses a participant-funded, but cost-of-service, approach that allows greater Commission supervision over costs, but continues to allocate them and the corresponding benefit of capacity in the line to a set of identified off-takers.[22] The Commission should revivify its policy statement and make it fit to the purpose of this workshop.

Even within this model, the regulation of the retail part of the electricity sector may ensure that state-jurisdictional entities purchase capacity when beneficial. Many state and local regulators, in the exercise of their prerogatives, often allow or require the electric and gas companies that serve retail customers to take long-term positions in generation or storage assets, or to purchase long-term capacity on gas pipelines. To the extent that interregional transfer capability is intended as a kind of insurance against extreme weather events, one may expect t observe market participants organically wishing to purchase directly or from others the tie's capacity as a physical protection against a damaging event, which would offset damage and earn revenues associated with that protection. However, as in the insurance markets, a state utility regulator could be interested in causing its jurisdictional entities to purchase at least a minimum amount of insurance, or some quantity calibrated to local prudential considerations. This recognizes that one of the primary benefits of these ties is to act to augment resources during

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[20] Final Policy Statement in Dockets No. AD12-9-000 and AD11-11-000, 142 FERC ¶ 61,038 (2013), at PP 16-18, 23-28.
[21] *Id*. at PP 29-38.
[22] *Id.* at PP 39-42.

scarce times and support the goals of resource adequacy, a primarily state prerogative. The benefit of this approach, rather than one mandated on high from the Commission, is that it would respect the differences in the approach and scale of regulation that state governments have chosen to impose on their jurisdictional entities in the name of mitigating risk.

This Commission, meanwhile, should revivify its policy statement on merchant transmission and make clear that it is not only applicable but also the default approach to the development of DC ties between interconnections. At the same time, should the Commission be concerned that opportunities to capture the difference in value between prices in abutting markets may not organically arise, then the Commission should incorporate DC development opportunities into its transmission planning process and associated requirements. The Commission can undertake several concrete steps in relation to modernizing its policies to improve interregional transfer capability:

i. **Reaffirm and refocus the Merchant Transmission Policy Statement.** The Commission should announce that a solicitation and open-season model for DC ties described above is both the preferred course for their development, especially between interconnections, and is consistent with FERC's decade-old policy statement on merchant transmission.
ii. **Transmission planning.** Business models may arise organically through the creative initiative of developers; for example, Pecos West, which is represented on this panel today. But if the Commission is concerned that no one is taking the initiative to develop potentially valuable DC ties, it should require—if no one has proposed to develop one between interconnections or between regions within a certain window of time—the RTO or local transmission utility to propose a project and initiate an open season, as part of the existing transmission planning process to ensure there is an opportunity to right-size the market and allocate costs. The RTO should work with relevant state regulatory authorities to ensure that the timing of these open seasons coheres to any state resource-adequacy processes, such as integrated resource planning, that exist within their jurisdictions. The Commission should incorporate this consideration into its ongoing rulemaking activities regarding electric transmission.

iii. **Upstream/downstream upgrades**. To the extent that DC ties require upgrades elsewhere on the alternating-current system, the Commission (and relevant state and local regulatory authorities, if applicable) should require that these costs be identified up front. Alternatively, the regulator(s) should predefine operational standards for the DC tie that obviate those costs.[23] Like the above recommendation, this should be incorporated into the Commission's pending rulemaking activities.

IV. Conclusion

On behalf of the NRG companies, I appreciate the opportunity to participate in this important workshop, and urge the Commission to take an approach that encourages market participants to expand interregional transfer capability, especially between interconnections, in a manner that right-sizes and properly allocates its costs.

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[23] For example, the ERCOT Planning Guide requires DC ties be curtailed when necessary to meet reliability criteria, which meant that for Southern Cross, reliability-based upgrades were not cost-allocated to the DC tie because Southern Cross's flows would be suspended instead of triggering a reliability violation. However, as a trade-off, this means that such a line may not be as valuable during the most system-critical hours. *See* ERCOT's Tenth Status Update (June 22, 2022), PUCT Project No. 46304. Available at: https://interchange.puc.texas.gov/Documents/46304_25_1217031.PDF