UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Innovations and Efficiencies in Generation Interconnection	§ §	Docket No. AD24-9-000

Pre-Workshop Comments of the R Street Institute

I. Issue Summary

The Federal Energy Regulatory Commission (FERC or Commission) will convene a staff-led workshop on Sept. 10, 2024 on improving innovations and efficiencies in generation interconnection processes. One of the specific topics of the workshop is to consider the extent to which transmission planning and generator interconnection processes may be further integrated beyond the reforms adopted in Order No. 1920. This panel will explore ideas to more efficiently and proactively plan for and interconnect new generation with lower cost and increased cost certainty. These comments respond to specific questions posed in advance of the workshop.

II. Summary of R Street's Position

The R Street Institute (R Street) has provided multiple comments and input on the topic of generation interconnection and the need for more efficient transmission expansion processes.[1] Most recently, R Street, in conjunction with multiple consumer groups, submitted a letter to FERC seeking methods to reduce network upgrade costs via transmission planning, which consumers mostly pay for indirectly.[2] Our position may be summarized as needed transmission network expansion should be identified and implemented as timely and cost-effectively as

[1] "R Street Input to FERC's Generator Interconnection Workshop," D Hartman and B Garza, May 13, 2024. https://www.rstreet.org/outreach/r-street-input-to-fercs-generator-interconnection-workshop;
"Comments by the R Street Institute on Improvements to Generator Interconnection Procedures and Agreements," Docket No. RM22-14-000, Oct. 13, 2022. https://www.rstreet.org/outreach/comments-by-the-r-street-institute-on-improvements-to-generator-interconnection-procedures-and-agreements;
"Initial Comments of the R Street Institute on Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," Docket No. RM21-17-000, Aug. 17, 2022. https://www.rstreet.org/wp-content/uploads/2022/08/20220817-5207.pdf;
"Comments of the R Street Institute on the Advanced Notice of Proposed Rulemaking: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," Docket No. RM21-17-000, Oct. 12, 2021. https://www.rstreet.org/wp-content/uploads/2021/11/ANOPR-Initial-Comments-FINAL.docx.pdf.
[2] "Consumer groups, R Street urge FERC to expand interconnection reform proposal to increase savings," E Howland, *Utility Dive*, pub June 9, 2023. https://www.utilitydive.com/news/ferc-interconnection-reform-proposal-r-street-elcon-nasuca/652570/

possible. With more efficient processes the costs to consumers will decrease, and cost allocation can better align with the beneficiary pays principle.

Better integration of generator interconnection processes with transmission planning, especially using regional transmission planning to drive network upgrades, has the potential to improve the transmission expansion process. This improved efficiency translates into major cost reductions for network upgrades, which consumers ultimately pay for, either directly or indirectly. Because transmission costs are so heavily incurred by consumers, large savings from more efficient network upgrades reduces costs to consumers irrespective of cost allocation method. Consumer groups, having recognized the costs they are bearing from expensive network upgrades, were motivated to sign a letter prior to Order No. 2023 that sought reexamination of pathways to lower network upgrade costs via transmission planning.[3] Most of the same consumer groups then backed Senate legislation to advance this issue post-Order No. 2023.[4] We are pleased the Commission elected to respond to such consumer requests, including its framing of this panel.

III. Responses to Pre-Workshop Questions

Question 1. *Can efficiencies be gained through closer integration of generator interconnection processes with transmission planning processes? If so, how? What considerations need to be taken into account? What are the advantages/disadvantages, including impacts on consumers, to closer integration of these processes?*

In FERC-jurisdictional independent system operators (ISOs), the status quo for expanding the transmission system is increasingly inefficient, resulting in rates that are unjust and unreasonable. Network upgrades via generation interconnection requests increase upgrade costs by multiples and add tens of billions of dollars per region in extra costs.[5] Generation interconnection wait times have risen from under two years for projects built in 2000-2007 to a median of five years for projects built in 2023.[6] The concern is not only inflated rates caused by avoidable costs and excessive delays, but that new resource delays are severe enough to potentially induce resource adequacy concerns amid resurgent load growth, such as in PJM.[7] The problem is worsening as the transmission system becomes saturated, the volume of new

[3] Ibid.
[4] Senator Catherine Cortez Masto Press Release, April 18, 2024. [Cortez Masto Introduces Legislation to Improve Reliability of America's Electricity Grid, Lower Energy Costs - Senator Catherine Cortez Masto (senate.gov)]
[5] "Initial R Street Comments," Docket No. RM22-14, Oct. 13, 2022.
[6] "Queued Up: 2024 Edition," Lawrence Berkley National Laboratory – J Rand, et al., April 2024. https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf
[7] "Energy Transition in PJM," PJM, Feb. 24, 2023. https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx

generators seeking interconnection increases, and the composition of interconnected generators grows more dispersed.[8] Order No. 2023, although helpful, will not resolve the root problem of interconnection inefficiencies.[9]

Generation interconnection works well for local upgrades, such as transmission facilities adjacent to a generator.[10] Generation interconnection does not work well for network upgrades like rebuilding old lines or substations, which benefit a broader array of generators and load. Upgrade cost trends bear this out. For example, average interconnection costs in PJM grew eightfold from 2017-2019 to 2020-2022.[11] Local upgrade costs remained a modest $12/kilowatt (kW), but network upgrades reached $71/kW.[12] Thus, local upgrade costs are appropriate to remain in interconnection scope.[13] However, the economic evidence is compelling to at least reduce the scope of network upgrades in interconnection.[14] The recent literature increasingly supports this direction.[15] From Oct. 9, 2022 to Sept. 6, 2023, PJM experienced a $138.13 million net increase in total network upgrade costs.[16] Network upgrades are the cause of most interconnection cost increases in other ISOs.[17]

The efficiency gains of conducting network upgrades via regional planning in lieu of generation interconnection may be achieved through a variety of effects.[18] First, the computational planning and physical execution time of network upgrades is far lower for a consolidated transmission plan than a series of uncoordinated interconnection requests. Second, generator certainty is increased, which reduces excessive interconnection requests that are otherwise motivated to obtain information on network upgrade costs. Third, process duplication is reduced, eliminating the constant reshuffling in the interconnection queue which causes extensive re-studies of network upgrades. Fourth, transmission planning is inherently more

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[8] "Finishing Generator Interconnection Reform," D Hartman and B Garza, Dec. 5, 2023. https://www.rstreet.org/commentary/finishing-generator-interconnection-reform/
[9] Ibid.
[10] "Initial R Street Comments," Docket No. RM21-17, Aug. 17, 2022.
[11] "Interconnection Cost Analysis in the PJM Territory," J Seel, J Rand, et al., January 2023. https://eta-publications.lbl.gov/sites/default/files/berkeley_lab_2023.1.12-_pjm_interconnection_costs.pdf
[12] Ibid.
[13] Ibid.
[14] "Generation Interconnection and Transmission Planning," J Pfeifenberger, Aug. 9, 2022. https://www.brattle.com/wp-content/uploads/2022/08/Generation-Interconnection-and-Transmission-Planning.pdf
[15] "Beyond FERC Order 2023," T Norris, August 2023. https://nicholasinstitute.duke.edu/sites/default/files/publications/beyond-ferc-order-2023-considerations-deep-interconnection-reform.pdf
[16] Network Upgrades Presentation to PJM Transmission Expansion Advisory Committee, Jan. 9, 2024. https://www.pjm.com/-/media/committees-groups/committees/teac/2024/20240109/20240109-item-04---network-upgrades-presentation.ashx
[17] "Generator Interconnection Costs to the Transmission System," Lawrence Berkeley National Laboratory - J Seel, J Mulvaney Kemp, et al., June 2023. https://eta-publications.lbl.gov/sites/default/files/berkeley_lab_interconnection_cost_webinar.pdf
[18] "Initial R Street Comments," Docket No. RM22-14, Oct. 13, 2022.

capable of identifying the extent and location of network upgrades to maximize net benefits, provided there is a conduit for commercial interest to inform network upgrade identification. More elaboration on this point is provided in response to Question 2.

These are not theoretical arguments; there is clear evidence from the Electricity Reliability Council of Texas (ERCOT) and growing evidence from FERC-jurisdictional ISOs supporting these proposed improvements. ERCOT is distinct in that it employs a "connect-and-manage" approach, where transmission network upgrades are determined by transmission planning and generation interconnection does not include deliverability requirements. This results in a simple generation interconnection process with low barriers to entry, in sharp contrast to the "invest-and-connect" approach of other ISOs.[19] To be clear, ERCOT's restructured status and "energy-only" resource adequacy construct may limit the external validity of some of its generation interconnection practices to FERC-jurisdictional ISOs.[20] Nevertheless, as R Street noted in our RM22-14 Initial Comments filed in 2022, the "advantages of ERCOT's transparency and treatment of transmission network upgrades is applicable to all regions."[21]

R Street's recommendations to improve the efficiency of transmission expansion from our RM22-14 Initial Comments remain true, even after Order No. 2023. That is, "[f]old transmission network upgrade evaluations into transmission cluster planning and instill a conduit for commercial interest to drive upgrades. Realign transmission network upgrade cost allocation consistent with the beneficiary pays principle. Ensure advanced transmission technologies are incorporated into available solution sets."[22]

There are several important considerations for incorporating network upgrades in transmission planning. All available transmission solutions should be considered, including grid-enhancing technologies and redispatch capabilities.[23] Transparency in study assumptions, and evaluation criteria is paramount.[24] An accurate, robust conduit for commercial interest in new generation is important to inform the location and volume of economical new entry. Generation interconnection requests should inform transmission planning. Just as importantly, anticipating generator-specific derates and retirements is critical to inform network upgrade needs. This topic is discussed further in response to Question 2.

The most important consumer consideration is minimizing system costs while maintaining system reliability. There is a common misconception that costs directly borne by

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[19] Ibid.
[20] "R Street Input to FERC's Generator Interconnection Workshop"
[21] "Initial R Street Comments," Docket No. RM22-14, Oct. 13, 2022, page 7.
[22] Ibid.
[23] "Finishing Generator Interconnection Reform"
[24] Ibid.

generators are solely generators' concern.[25] Cost-of-service generators pass through all costs, including network upgrades, to retail consumers. Higher network upgrade costs imposed on independent power producers (IPPs) act like a tax; they are partially passed onto consumers.[26] This is evident in power purchase agreements (PPAs), where risk premiums reflect network costs and uncertainty.[27] Interconnection uncertainty, delays, and costs are placing pronounced upward pressure on PPAs.[28] There is evidence of price elastic supply, based on higher withdrawal rates for projects with higher interconnection costs, where most cost increases stem from network upgrades.[29] This suggests supply elasticity may exceed demand elasticity, in which case most network upgrade costs incurred by IPPs are likely passed through to consumers.

Irrespective of network upgrade cost allocation, the top factor influencing consumer costs is the excessive cost of network upgrades. Even in the eastern regional transmission organizations (RTOs), where IPPs cannot pass the full costs on to consumers, consumers could be better off even if they paid the full costs of network upgrades. For example, if determining network upgrades on a comprehensive basis via transmission planning lowered network upgrade costs 60 percent but shifted the consumer cost burden from 50 percent to 100 percent, consumers would go from paying $35/kW for $70/kW upgrades to paying the entirety of $28/kW. These values are just for illustrative purposes; the allocation of network upgrades costs remains important. More elaboration is provided in response to Question 3.

Transmission costs are borne by consumers, either directly or indirectly. Therefore, it is in consumers' best interests that transmission expansion efforts be most efficient. Separating network upgrades from the generation interconnection process is one way to improve efficiency.

Question 2. *How might transmission providers more proactively, rather than reactively, identify zones where new transmission capacity could most efficiently accommodate proposed generating facilities?*

Transmission network upgrades have economies of scale and provide benefits to numerous generators and load, not just a single new generator. As such, network solutions can be cost-effectively identified by anticipating changes across numerous generators and load simultaneously, as opposed to one-off interconnection requests. Further, there is a planning gap between generation interconnection studies and long-term transmission planning today. Generation interconnection analyses typically focus on the next five years, whereas long-term

[25] "Consumer groups, R Street urge FERC to expand interconnection reform proposal to increase savings"
[26] "Comments of the R Street Institute on the Advanced Notice of Proposed Rulemaking," RM21-17, Oct. 12, 2021.
[27] Ibid.
[28] "After Soaring for Years, North America Solar PPA Prices Show Signs of Stabilization in Q2," LevelTen Energy, July 18, 2023. https://www.leveltenenergy.com/post/2023q2-ppa-price-index
[29] For e.g., see "Generator Interconnection Cost Analysis in the Southwest Power Pool (SPP) Territory," J Seel, et al., Jan. 21, 2024. https://escholarship.org/content/qt8qv3n1sx/qt8qv3n1sx.pdf

planning uses time horizons of 10 or more years.[30] Transmission planning is capable of performing such synergistic analysis proactively, whereas interconnection is well-suited for reactive upgrades that accrue solely to an individual generator.

There are several options to bridge the gap between the time horizons of generation interconnection studies and long-term transmission planning. R Street has previously suggested a short-term transmission planning process that could readily respond to upgrade requests and feed into the long-term planning process.[31] Another example, used by ERCOT, is to define certain milestones that once met by generation under development, the generator is assumed to be part of long-term planning.[32]

ERCOT's creation of and transmission buildout to Competitive Renewable Energy Zones (CREZ) remains the largest and most comprehensive example of proactive transmission expansion. In a period of less than 10 years, the CREZ buildout went from a concept enabled by state legislation to 3,600 circuit-miles of new transmission lines constructed at a cost of roughly $6.9 billion. The package of CREZ lines were designed to enable roughly 18.5 gigawatts GW of new wind development in west Texas. However, one of the key benefits from the CREZ buildout was unanticipated. Some of those transmission lines, ostensibly built to carry wind generation eastward toward metropolitan areas, provided initial support to serve increased load in west Texas; increased load driven by the fracking production of oil and gas.[33] This concept of unanticipated benefits will come up again in the response to Question 3, but it must be recognized that transmission lines carry electricity; electricity which can flow either direction, without regard for the fuel source used to generate it.

Drawing on the ERCOT experience with developing zones for areas with lots of location specific resources, such as wind, hydro, and solar, rough geographic zones can be identified using a process as simple as drawing on a map. Drawing on expertise from a variety of perspectives, such as developers, national laboratories, and industry groups, transmission planners can establish initial estimates of resource potential. Developing a comprehensive plan for build out to identified areas could be influenced by the quantity and location of generation interconnection requests in the queue. Alternatively, a higher level of financial commitment from generators could be specifically required prior to project buildout. The ERCOT CREZ process established a method by which generators could demonstrate their financial commitment by either private contracts or specific collateral payments to transmission providers. Financial

[30] "Proactive Planning for Generation Interconnection," Brattle with EnerNex, September 2022. https://www.esig.energy/wp-content/uploads/2022/09/ESIG-Proactive-GI-Planning-Final-Study.pdf
[31] "Initial R Street Comments," Docket No. RM22-14, Oct. 13, 2022, page 5.
[32] "R Street Input to FERC's Generator Interconnection Workshop," page 7.
[33] "The Competitive Renewable Energy Zones Process," ERCOT – W Lasher, Aug. 11, 2014. https://www.energy.gov/sites/prod/files/2014/08/f18/c_lasher_qer_santafe_presentation.pdf

obligations for the ERCOT CREZ zones were fully met. Further, actual generation installations quickly exceeded the planned export capabilities of some of the zones.

Given the fully unbundled and deregulated nature of ERCOT's wholesale energy market, coupled with Texas' relatively low barriers to construction and investment, the ERCOT CREZ example may not be easily transferable to other regions. However, there are many ongoing activities ERCOT performs which may be applicable to other regions because they provide insight into the capabilities of the transmission system. One report of note is the annual "Constraints and Needs" report.[34] This annual report lists the 10 most expensive constraints from the past year plus what are expected to be the 10 most expensive constraints for the next few years. The report also includes the 10 most significant transmission system upgrades expected within the next six years. All this is shown on three pages. This simple and direct public report provides the information needed to identify locations to avoid building generation (or encourage load siting) in the short term with insight as to how the transmission system is expected to change.

Accurately anticipating new generation is challenging. This underscores the importance of having a conduit of commercial interest informing generation expectations in transmission planning. R Street has previously stated that generation assumptions should be informed by generator requests, "perhaps in a format similar to the open season processes for pipeline expansion."[35]

Proactively planning network upgrades in regional transmission expansion processes is clearly advantageous to relying on the generation interconnection process. A comparative analysis of ISOs shows that the California Independent System Operator has the leading approach to proactively planned upgrades.[36] The report identifies ERCOT's generation interconnection process as the most efficient, however it points out shortcomings in proactive regional transmission planning which have hampered recent generation development.[37] Limitations in the effectiveness of ERCOT's regional planning process have been recognized by ERCOT leadership. In a recent presentation to the ERCOT Board of Directors, the concept of developing "Generation Hubs" was introduced as a way to try and address the disparity of timelines between generation (and load) additions and transmission expansion.[38] The concept is expected to be further fleshed out by ERCOT late this year.

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[34] "Report on Existing and Potential Electric System Constraints and Needs," ERCOT, December 2023. [2023-Report-on-Existing-and-Potential-Electric-System-Constraints-and-Needs.pdf (ercot.com)]
[35] "Initial R Street Comments," Docket No. RM22-14, Oct. 13, 2022, page 5.
[36] "Generator Interconnection Scorecard," J Wilson, et al., February 2024. https://gridstrategiesllc.com/wp-content/uploads/2024/03/AEI-2024-Generation-Interconnection-Scorecard.pdf
[37] Ibid. page 6.
[38] "CEO Board Update – REVISED," Board of Directors Meeting, April 23, 2024, page 8. https://www.ercot.com/files/docs/2024/04/24/5%20CEO%20Update%20REVISED.pdf

Although the question specifically focuses on accommodating new generation facilities, it is important to recognize that the need for transmission expansion may also be driven by generation retirements and large load additions. The effects of generator retirements may be more acutely felt in regions where generation is not supported by regulated revenues, i.e. competitive generation. Changes in the location of generation sources may require additional transmission facilities. Efficiently planning for these types of changes to the transmission system requires advanced notice of unit retirements. Advanced notice could be explicitly required,[39] or inferred by evaluating the economic expectations for installed generation.[40]

In March 2022 ERCOT implemented a process governing the interconnection of large loads.[41] Since that time, more than 4,000 megawatts (MW) of large loads have received ERCOT approval to energize.[42]

Additional requirements for large loads seeking interconnection are currently under development. One possibility to consider is whether creating a commercial conduit for large loads, similar to an open season for pipeline capacity, might be a workable process. Regardless of the ultimate process, the first step in being able to effectively plan for regional transmission system upgrades is to have a comprehensive understanding of the loads to be served and generation resources available to serve them.

Question 3. *What mechanisms may be appropriate for transmission providers to use to determine the cost responsibility for such proactively planned network upgrades? Is it appropriate for any such costs to be allocated to load and if so, why? If it is appropriate, how should such costs be allocated between load and interconnection customers both: a) in regions that use participant funding, i.e., where interconnection customers are directly assigned network upgrade costs and b) in regions that do not use participant funding, i.e., where load is assigned network upgrade costs? What are the advantages/disadvantages, including impacts on consumers, of varying approaches to cost responsibility?*

In 2021, R Street explained why participant funding resulted in inefficient interconnection processes that contradict the beneficiary pays principle.[43] The share of benefits

[39] "ERCOT Nodal Protocols," Section 3.14.1.1. Available at https://www.ercot.com/mktrules/nprotocols/current
[40] For e.g., "PJM State of the Market – 2023," Monitoring Analytics, Section 7. Available at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023.shtml
[41] ERCOT Operations Notice W-A032522-01 Interim Large Load Interconnection Process," issued March 25, 2022. https://www.ercot.com/services/comm/mkt_notices/W-A032522-01
[42] ERCOT Nodal Protocol Revision Request 1234. Available at https://www.ercot.com/mktrules/issues/NPRR1234#keydocs
[43] "R Street Comments on the ANOPR," Docket No. RM21-17, Oct. 12, 2021.

from a network upgrade that accrue to a single generator have declined with the more dispersed nature of contemporary power generation compared to previous eras.[44] Since many of the benefits of transmission expansion do not accrue to the interconnecting generator, relying on interconnecting generators to fund network upgrades will result in chronic underinvestment in network upgrades.[45] This erodes net benefits to generators and consumers. Reforms that align cost allocation with beneficiary pays would increase system-wide net benefits with lower aggregate cost and risk profile to consumers.[46]

At the same time, full cost allocation of network upgrades to load may not align with the beneficiary pays principle. It also may undermine the siting incentives for new generators.[47] ERCOT has recently changed its unconstrained 'loads pay for all transmission' policy in response to concerns raised about generation-siting incentives. Recent Texas legislation requires that an interconnection cost allowance be imposed beginning Jan. 1, 2026. Any interconnection costs greater than the allowance will be incurred by the requesting generator.[48]

For IPPs, full allocation of network upgrade costs to load would increase the cost burden on consumers relative to a beneficiary pays allocation. IPPs do not directly pass upgrade costs in full to customers, although there is evidence that some costs are passed through via costs charged for purchase power.[49] Imposing transmission costs onto IPPs provides an incentive to minimize those costs as they make siting decisions. For cost-of-service generators, full cost allocation to load may not alter consumer incidence of network upgrade costs, nor distort generator siting. This is because cost-of-service generators have the opportunity to pass all upgrade costs through to retail customers reducing any incentive to site generation in a least-cost manner in the first place.

Cost allocation reforms should abide by the beneficiary pays principle. The benefit to consumers of increased transmission capability is access to the lowest-cost energy, whereas the benefit to generators is unconstrained access, resulting in the potential to receive higher prices. One possible method is to calculate generator benefits by expected increases in wholesale market revenues. Consumer benefits could be calculated by wholesale rate reductions and the value of avoided lost load.[50]

[44] "Disconnected: The Need for a New Generator Interconnection Policy," J Caspary, et al., January 2021. https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf
[45] "Initial R Street Comments," Docket No. RM22-14, Oct. 13, 2022.
[46] "R Street Comments on the ANOPR," Docket No. RM21-17, Oct. 12, 2021.
[47] Ibid.
[48] 16 Tex. Admin. Code §25.195(f)(3). Available at https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/electric.aspx
[49] "After Soaring for Years, North America Solar PPA Prices Show Signs of Stabilization in Q2," LevelTen Energy, July 18, 2023.
[50] "Initial R Street Comments," Docket No. RM22-14, Oct. 13, 2022.

A key question is how much variance there is in beneficiaries for each network upgrade. If there is a large variance, it may be administratively challenging and contentious to determine exact beneficiaries. In that case, it may be useful to have a default cost allocation based on average network upgrade beneficiary ratios between load and generation. In the absence of beneficiary breakdown analysis, a 50/50 cost share may serve as a prudent starting point. This could be customized as needed to make it roughly commensurate with the beneficiary pays principle. In many situations, the advantages of having a generally defined and well-understood methodology may outweigh the costs of a more detailed and time-consuming methodology with perceived improved precision.

The ERCOT example provided in response to Question 2 bears repeating here. Although significant transmission expansion was initially intended to carry wind generation eastward toward metropolitan areas, some of that transmission provided initial support to serve increased load—driven by the fracking production of oil and gas—in west Texas.[51] Over the course of just a few years, what would have been determined as the initial beneficiaries had now changed. Transmission lines are long-lived assets enabling the flow of electricity, which can and will likely flow in both directions over the lifetime of the assets. Without creating burdensome analytical overhead, it is impossible to determine a precise allocation of benefits over the life of transmission assets. The goal is cost allocation that is roughly commensurate with the benefits received.

As stated in response to Question 1, irrespective of network upgrade cost allocation, the top factor influencing consumer costs is the excessive cost of network upgrades. By focusing on making sure network upgrades are identified, planned, and constructed efficiently, consumers can be better off, even if more of the costs are directly assigned to them.

Question 4. *Where the costs exceed estimates for such proactively planned network upgrades, what are some approaches transmission providers could use to address concerns regarding ensuring adequate funding? For any given approaches proposed to ensure adequate funding, would these mechanisms increase or decrease the time and/or costs required to interconnect new resources, and how would this impact interconnection customers?*

After completing a myriad of complex analyses, achieving consensus about what facilities to build, and having reached agreement on how costs will be allocated, a transmission provider starts the process of turning a plan into a physical project. Sometimes, the provider realizes that project costs will exceed what was planned and approved. With a large increase, the

[51] "The Competitive Renewable Energy Zones Process," ERCOT – W Lasher, Aug. 11, 2014.

initial justification for the project may no longer hold. Or, depending on how the costs are shared, individual participants may no longer see net benefit from the project.

There are multiple reasons why this situation may arise. These include poor planning estimates, subsequent supply chain disruptions affecting equipment costs, or inefficient project development or management by the transmission provider.

One way to handle changing project cost estimates would be to use a default cost allocation based on proportionate shares, rather than specific dollar amounts. A contingency protocol for cost increases would also reduce ad hoc decision making. Transmission providers should be required to communicate expected costs increases proactively. Per ERCOT Protocols, transmission providers are required to provide notice, including an explanation of the cost increase, if estimated project costs exceed 110 percent of the cost described in ERCOT's endorsement.[52]

In areas where cost allocation is split between load and generation, the greater funding risk would seem to be related to ensuring generator payments. Interconnection agreements and associated collateral requirements are the first level of protection. A second layer would be to create a mechanism to transfer interconnection rights from a defaulting generator to another party.

IV. Conclusion

R Street appreciates the opportunity to provide this input prior to the upcoming staff-led workshop.

Respectfully submitted,

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[52] "ERCOT Nodal Protocols," Section 3.11.4.10. Available at https://www.ercot.com/mktrules/nprotocols/current