UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Improvements to Generator Interconnection Procedures and Agreements	)))	Docket No. RM22-14-000

COMMENTS OF PUBLIC INTEREST ORGANIZATIONS

I. Introduction

Sustainable FERC Project, the Sierra Club, Natural Resources Defense Council, Earthjustice, Acadia Center, Environmental Defense Fund, National Audubon Society, Southern Environmental Law Center, and Southface (together "Public Interest Organizations" or "PIOs") hereby submit these reply comments in response to the Federal Energy Regulatory Commission's ("FERC" or "the Commission") June 16, 2022, Notice of Proposed Rulemaking ("NOPR") proposing reforms to its generator interconnection procedures and agreements.[1]

II. Executive Summary

The reforms proposed in the NOPR represent a common-sense expansion of industry best practices to all FERC-jurisdictional transmission providers. PIOs broadly support the NOPR's proposal to require all transmission providers to implement a first-ready, first-served cluster study process.

PIOs also largely agree with FERC's assessment of the need for reform. Nationwide, interconnection queue delays have reached the point where they are hobbling commercial

[1] Improvements to Generator Interconnection Procedures and Agreements, 179 FERC ¶ 61,194 (2022) ("NOPR").

investment, are providing inadequate and insufficient services to states[2], and threaten reliability. The reforms proposed in the NOPR are both necessary and timely. However, we also provide evidence that concerns of an epidemic of 'speculative' interconnection requests are exaggerated, and that in fact queue withdrawal rates haven't changed much in ten years. Based on this, PIOs recommend that FERC emphasize the information sharing and process improvement aspects of the reforms over the aspects that introduce barriers to applications.

III. Need for Reform

A. Reforms to Interconnection Procedures Are Necessary

When it established standard generator interconnection procedures, the Commission listed four roles for those procedures to fulfill: (1) minimize opportunities for undue discrimination; (2) expedite the development of new generation; (3) protect reliability; and (4) ensure that rates are just and reasonable.[3] Current interconnection procedures, to varying degrees in various regions, are failing to accomplish at least three of those roles. The premise of the current NOPR, supported by ample data, is that current procedures are not expediting the development of new generation.[4] Given that "[i]nterconnection is a critical component of open access transmission service"[5] current procedures result in unjust and unreasonable outcomes. Developers are facing unpredictable delays and costs, and any unreasonable delays in

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[2] 16 U.S.C. § 824f.

[3] *Standardization of Generator Interconnection Agreements & Proc.,* Order No. 2003, 68 FR 49845 (Aug. 19, 2003), 104 FERC ¶ 61,103 (2003), order on reh'g, Order No. 2003-A, 69 FR 15932 (Mar. 5, 2004), 106 FERC ¶ 61,220, order on reh'g, Order No. 2003-B, 70 FR 265 (Jan. 19, 2005), 109 FERC ¶ 61,287 (2004), order on reh'g, Order No. 2003-C, 70 FR 37661 (July 18, 2005), 111 FERC ¶ 61,401 (2005), aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC, 475 F.3d 1277 (D.C. Cir. 2007) (NARUC v. FERC). ("Order 2003") at 11.

[4] *See* NOPR Section I.B, Need for Reform.

[5] Order 2003 at 12.

interconnecting new supply, which often operates at a lower cost than existing supply, in turn causes unreasonable and avoidable increases in costs to ratepayers.

Worse still, interconnection delays threaten to endanger reliability. As states, acting under their Federal Power Act (FPA) authority, increasingly regulate generation to reduce greenhouse gas emissions and lower reliance on volatile fossil fuel markets, the low-carbon resources needed to replace older resources languish in interconnection queues. We note, for example, that the capacity shortfall in MISO's recent planning reserve auction would be filled by only a fraction of the resources that have been in MISO's interconnection queue for more than 3 years.[6]. The Federal Power Act entitles states to adequate and sufficient FERC-jurisdictional services.[7] This should include interconnection processes that support the development of generation driven by state policies, utility goals, and economics in a reasonably timely manner.[8]

Existing generator interconnection policies, rules, and procedures are not achieving their purpose of facilitating the interconnection of the next generation of resources. States with mature Renewable Portfolio Standards (RPS) and private demand[9] are driving the development and construction of wind, solar, battery, and hybrid generation resources among other distributed energy technologies. Federal incentives and tax credits also continue to encourage the development of renewable generation.[10] Together with rising fossil fuel prices, these efforts have made renewable generators the primary power plants that developers are requesting to

[6] Counting just wind and solar, and applying 15.5% and 50% planning resource credit respectively, MISO's interconnection queue contains 6,332MW of resources requesting NRIS service that entered the queue in 2019 or earlier. The queue also contains 1,783MW of solar plus storage projects that entered in the queue in the same timeframe. MISO's is 1,230MW short of its capacity target for 2022/23.

[7] 16 U.S.C. § 824f.

[8] *See, e.g.,* Stanek comments at joint task force, referenced in NOPR fn 61.

[9] *See* NOPR at ¶ 20.

[10] Inflation Reduction Act, Section § 13101, § 13702 (amending 26 U.S.C. § 45).

interconnect to the grid. In 2020, experts estimated that renewable generators would comprise 75 percent of the interconnection queues across the country.[11] However, the processing rates of interconnection requests have stagnated, due in part to known weaknesses of the existing interconnection processes and outdated interconnection policies.

Regarding known weaknesses, familiar issues with the first-come, first-served process persist. To avoid having to pay for network upgrades, some developers are still submitting multiple interconnection requests to occupy different queue positions so that they can withdraw an interconnection request that requires network upgrades while still occupying another position in the queue.[12] While this approach benefits the individual developer seeking to avoid network upgrade costs, it could trigger the need for the RTO/ISO to re-study various technical requirements and re-assess cost responsibilities, all of which could strain the respective RTO's resources and cause other interconnection customers to withdraw from the queue.[13]

With respect to outdated policies, Order Nos. 2003 and 2006 were designed to encourage generators to connect to the grid at locations with remaining available transmission capacity.[14] However, these rules are not suited to modern siting practices designed to reduce human and environmental impacts, nor are they suited to the modern generation fleet of renewable resources, which must be sited where there are desirable weather patterns and appropriate land capacity, in locations that often do not align with available transmission capacity.[15] As a result, many renewable generators are being developed in areas that currently lack sufficient long-

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[11] Jay Caspary, Michael Goggins, Rob Gramlich, Jesse Schneider, *Disconnected: The Need for a New Generator Interconnection Policy*, Americans for a Clean Energy Grid, January 14, 2021, at 5 ("Disconnected").

[12] Interconnection Queuing Practices, 122 FERC ¶ 61,252 at 15 (2008); Disconnected 16-17.

[13] *Interconnection Queuing Practices*; Disconnected 16-17.

[14] 122 FERC ¶ 61,252 at 15 (2008); Disconnected at 8; *Interconnection Queuing Practices*.

[15] Disconnected at 7-8.

distance transmission facilities, increasing the costs of some interconnection projects by 50 to 100 percent of the project's costs.[16]

Queue reform alone will not resolve increasing interconnection delays and costs. Multiple studies show that regional transmission planning can address transmission needs at lower cost than the piecemeal approach resulting from interconnection-driven upgrades. As noted earlier, the Commission has other active proceedings that will reform the regional transmission planning process to consider the future resource mix and address transmission capacity shortages and, in turn, regional cost allocation for transmission facilities. But, while interconnection reform alone cannot solve interconnection problems, well-functioning interconnection processes remain a critical component of just and reasonable rates. Thus, the Commission is correct in its preliminary finding that interconnection reform is necessary.[17]

B. Concerns Regarding an Increase in Speculative Interconnection Applications May Be Overstated

The NOPR suggests that one cause of delays in interconnection queues may be speculative interconnection requests made by developers for purposes of gaining information or securing an early queue position.[18] Such projects may eventually withdraw their requests. In a first-come, first-served process, withdrawals can have ripple effects that delay projects further down in the processing queue, leading the NOPR to state that "In recent years, late-stage withdrawals of interconnection requests have caused significant delays in interconnection study processes."[19]

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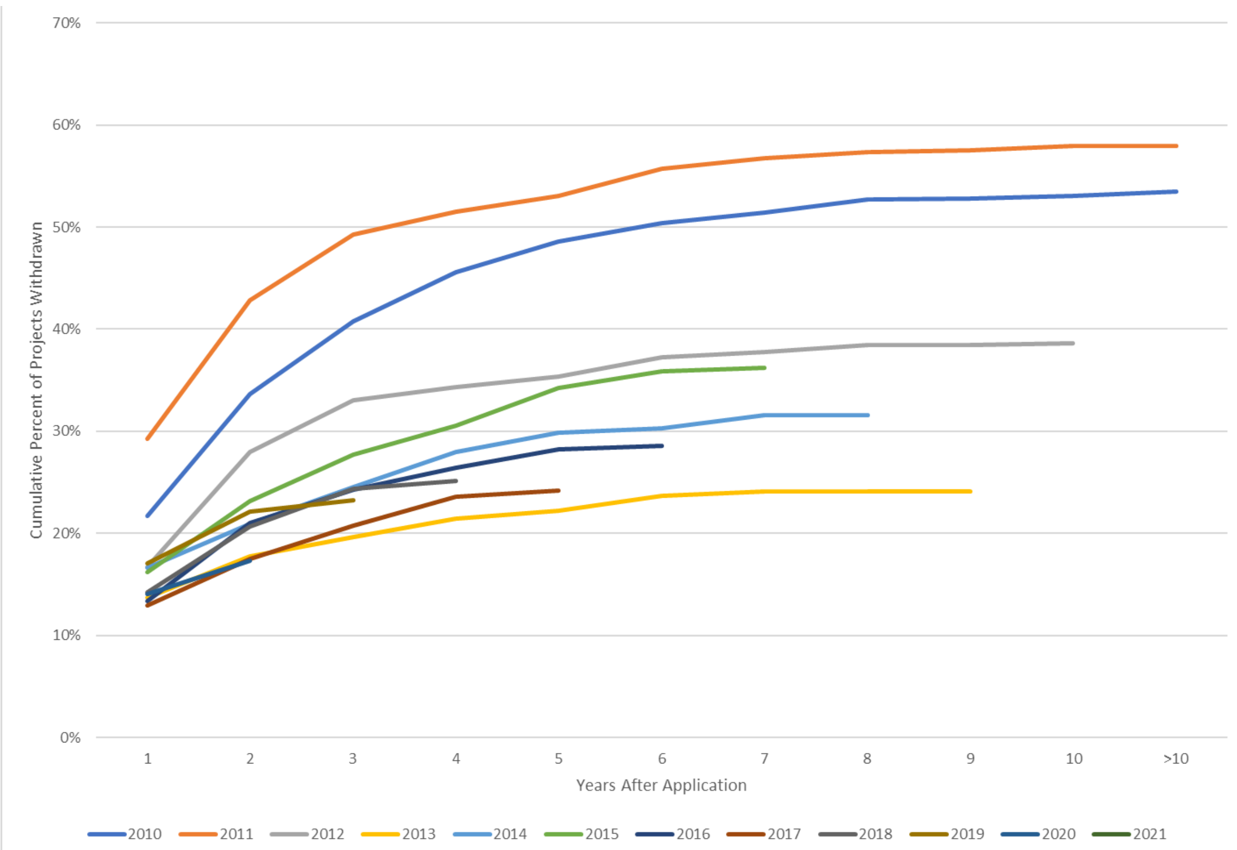
[16] *Id.* 6.
[17] NOPR at ¶ 36.
[18] *Id.* at ¶ 20-27.
[19] *Id.* at ¶ 37.

However, the rate at which projects withdraw from the queue has been consistent over the last decade and does not warrant the punitive measures that the NOPR recommends. Lawrence Berkely National laboratory maintains a dataset of national interconnection applications which formed the basis for the *Queued Up* report prominently cited in the NOPR.[20] PIO analysis of interconnection requests made from 2010 on[21] does not show any obvious increase in requests dropping out in recent years (Figure 1).

Figure 1: Withdrawal Rates of Interconnection Applications



[20] Joseph Rand et al., Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2021, *Queues 2021 Data FILE XLSX*, Lawrence Berkeley National Lab (Apr. 2022) ("Queued Up"), *available at* https://emp.lbl.gov/sites/default/files/queued_up_2021_04-13-2022.pdf.

[21] Although the Berkley Data goes back to requests made in 2000, a large portion of requests made before 2010 are marked as withdrawn but do not have a withdrawal date.

In the above figure, each line represents the projects applying for interconnection in each year and shows the cumulative percent of those projects withdrawn over time. Withdrawal rates were highest for projects applying in 2010 and 2011.[22] Other than that, there does not appear to be any pattern of higher withdrawal rates from projects applying for interconnection recently (easily identifiable as the shorter lines in Figure 1). In recent history, projects applying in 2015 had the highest withdrawal rates and those applying in 2013 the lowest, with other years falling in between.[23]

Of course, even if withdrawal rates have stayed about the same, the large increase in the total number of projects applying for interconnection means that the number of withdrawals will also increase. But this fact suggests that difficulties arising from withdrawals are simply one aspect of the difficulties transmission providers have had in scaling up their processes to handle more interconnection requests. Process reforms to reduce withdrawals by improving access to information or to minimize the effects of withdrawals on other projects in the queue remain important. However, PIOs urge the Commission to avoid punitive reforms intended to "disincentivize interconnection customers from entering multiple speculative interconnection requests into the interconnection queue or minimize the risk of late-stage withdrawals of interconnection requests."[24]

[22] This may be due to queue reforms made in 2012-2013. *See* Queued Up at 25.

[23] This conclusion is based on nationwide data and does not contradict any statements made by individual transmission providers about their circumstances.

[24] NOPR at ¶ 30.

C. Regional Discussions

1. RTO Regions

RTO/ISO interconnection processes vary widely across the country. RTOs/ISOs have significantly different approaches for cluster studies, disclosing information, requirements for site control, study times, penalties, cost allocation methods, and use of alternative transmission technologies. What remains consistent, however, is the substantial backlogs, increased study times, and rising interconnection costs that persist across RTOs/ISOs.[25]

Fundamentally, RTO/ISO interconnection processes are not meeting the needs of the electric system. As outlined above and as the Commission recounts in the NOPR, queue sizes have grown significantly in recent years. Where prior to 2018 RTO/ISO interconnection queues remained relatively consistent year-over-year, the past four years have seen dramatic rises in the number of projects in queue.[26] The number of new projects seeking interconnection each year now vastly outstrips the number of projects RTO/ISO processes can handle. For example, prior to 2018 the total capacity of projects in PJM's interconnection queue was typically between 60 GW and 80 GW.[27] Since 2018, the queue has gone up every year, from approximately 88 GW in 2018 to more than 246 GW in 2021. Across all RTOs/ISOs, there were more than 770 GW of projects seeking interconnection at the end of 2021.[28] Of those projects, approximately 730 GW, more than 90 percent, were storage or renewable generation projects.[29]

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[25] Disconnected at 13-18.

[26] Lawrence Berkeley National Lab, Generation, Storage, and Hybrid Capacity in Interconnection Queues, *available at* https://emp.lbl.gov/generation-storage-and-hybrid-capacity.

[27] *Id.*

[28] *Id.*

[29] *Id.*

With this increase in projects in the RTO/ISO queues, the typical time for a project to get through an interconnection queue increased from around 2 years to 3.5 years from 2009-2020.[30] As of 2021, one-third of projects in PJM seeking interconnection have been waiting more than 500 days for a study decision.[31] In MISO, often considered the leader in interconnection processes, the average project takes more than 500 days to get through the queue,[32] and the median time to reach an interconnection agreement has increased by about 50% since 2018.[33] A Lawrence Berkeley National Lab study found that the median number of days between submitting an interconnection request and entering into commercial operation was approximately 1,500 days across CAISO, ISO-NE, NYISO, and PJM in 2020.[34]

Existing interconnection processes at RTOs also lead to an increase in interconnection costs. According to Leyline Renewable Capital, site control costs and working capital for line items such as staff, legal and technical consulting, and administrative costs increase the longer a project is in development.[35] In addition, the costs of transmission upgrades deemed necessary for interconnection by transmission has grown significantly in recent years. A 2021 report from Grid

[30] Herman K. Trabish, "Gridlock in transmission queues spotlights need for FERC action on planning", Utility Dive (Jul. 18, 2021), *available at* https://www.utilitydive.com/news/gridlock-in-transmission-queues-spotlights-need-for-ferc-action-on-planning/603128/

[31] Advanced Energy Economy, PJM Interconnection Queue Summary Data Table by State for Clean Energy Projects (2016-2021), *available at* https://info.aee.net/hubfs/EWM%20Documents/Final%20PJM%20Queue%20analysis%20summary%20data%20chart%2012.8.21.pdf

[32] Kelley Welf, "Miso leads in reneable energy interconnection", Renewable Energy World (Sep. 1, 2021), *available at* https://www.renewableenergyworld.com/solar/misos-improved-interconnection-process-saves-precious-time/#gref

[33] Queued Up at 22.

[34] Joseph Rand et al., Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2020, Lawrence Berkeley National Lab, 6 (May 2021) *available at* https://eta-publications.lbl.gov/sites/default/files/queued_up_may_2021.pdf

[35] Leyline Renewable Capital, "The Growing Impact of Delays on Solar Development Costs Across Different Regions", *available* at https://leylinecapital.com/news/the-growing-impact-of-delays-on-solar-development-costs-across-different-regions.

Strategies LLC found that interconnection costs for wind projects in MISO were five times higher in 2021 ($317/kW) than in 2018 ($66/kW).[36] The same report found that costs have more than doubled in PJM over the same period.[37] A 2021 study by ICF Resources found that costs of interconnection in SPP have reached higher levels than MISO and PJM, clocking in at approximately $448/kW in 2021,[38] more than 30 percent of the total project cost.[39]

Reactive transmission upgrades through the existing interconnection processes also result in higher costs and lost benefits compared to a proactive regional planning approach. A 2021 report from Brattle and Grid Strategies analyzed results from the PJM offshore wind integration study showing that the current interconnection process approximately doubles the transmission costs of offshore wind compared to a proactive process.[40] Under the PJM regional planning scenario, the reliability upgrades needed to interconnect the amount of offshore wind to meet state policy goals also result in substantial benefits that would not be realized using existing interconnection methods, including congestion relief, customer load LMP reductions, reduced CO2 emissions, and reduced renewable curtailment.[41] The current outpacing of the transmission interconnection processes at RTOs/ISOs leads to unjust and unreasonable rates and unduly discriminatory or preferential treatment in multiple ways. First, the delays in the interconnection

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[36] Disconnected at 13-14.

[37] Disconnected at 14 (finding costs increasing from $54/kW to $131.90/kW).

[38] ICF Resources LLC, Just and Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits, 2 (Sep. 9, 2021) ("Just and Reasonable"), *available at* https://acore.org/wp-content/uploads/2021/09/Just-Reasonable-Transmission-Upgrades-Charged-to-Interconnecting-Generators-Are-Delivering-System-Wide-Benefits.pdf.

[39] *See* National Renewable Energy Laboratory, "2020 Cost of Wind Energy Review", 8 (Jan. 2022).

[40] Brattle Group and Grid Strategies, Transmission Planning for the 21st Century 4-5 (Oct. 2021). *Available at* https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf

[41] PJM, Offshore Transmission Study Phase 1 Results, slide 24 (Jul. 2021). *Available at* https://www.pjm.com/-/media/committees-groups/state-commissions/isac/2021/20210729/20210729-isac-presentation.ashx

process and the uncertainty of interconnection costs lead to skyrocketing costs for interconnection customers. Second, the delay in bringing low-cost renewable generation online leads to increased costs to ratepayers. Finally, delays in getting renewable generation online harm the ability of states to meet their renewable energy goals.

2. Non-RTO regions

i. West

The Western states have adopted very high clean energy goals over the past few years, stimulating vast sums of capital investment into development planning for new projects to fill electricity portfolios with new renewable energy projects..[42] Meeting these goals will require more than 9 GW of renewable energy to come online from 2025 through 2030.[43] Utilities are signaling frustration with the queue processing as they face the need to expand the transmission system and interconnect new projects at a steady pace. PacifiCorp's processing of resource plans with solicitations every two years through 2030 requires careful coordination with its interconnection cluster study process.[44] Public Service Company of Colorado ("PSCo") is poised to issue a solicitation to acquire 3-4 GW of new wind solar and battery storage, to be followed by

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[42] CO: https://energyoffice.colorado.gov/clean-energy-programs
NM: https://www.governor.state.nm.us/2019/03/22/governor-signs-landmark-energy-legislation-establishing-new-mexico-as-a-national-leader-in-renewable-transition-efforts/
NV: https://climateaction.nv.gov/our-goals/
OR: https://www.oregon.gov/deq/ghgp/Pages/Clean-Energy-Targets.aspx
WA: https://www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act

[43] Energy Strategies for Western Interstate Energy Board, "Western Flexibility Assessment", 121 (Dec. 2019), *available at* https://westernenergyboard.org/wp-content/uploads/2019/12/12-10-19-ES-WIEB-Western-Flexibility-Assessment-Final-Report.pdf

[44] See, e.*g.*, PacifiCorp's description of the tracking between RFP modeling and cluster study timing in Rocky Mountain Power's Reply Comments (June 15, 2020), Utah Public Service Commission Docket No. 20-035-05, at 17, *available at* https://pscdocs.utah.gov/electric/20docs/2003505/314266RMPRplySupApplApprSolProc6-15-2020.pdf.

another RFP in 2026.[45] Reliability requirements also require renewable energy projects to come online on a timely basis,[46] and delayed interconnection studies will only add to the challenges already faced by developers due to other volatile market conditions. Additional tax credits extended by the Inflation Reduction Act will also spur new deployment of renewable energy over the next ten years,[47] dramatically increasing interconnection requirements.

Unfortunately, interconnection queues are clogged and processing is delayed throughout the West, interrupting business plans for projects which are laid out years in advance and significantly increasing overall costs due to factors outside the control of renewable energy developers.[48] The delays are caused by a myriad of challenges including overloaded queues, modeling errors and lack of dedicated resources by transmission providers, and inefficient processes.

For example, despite tariff revisions and cleared queues from the FERC order approving its queue reform entered merely 3 years ago[49] PSCo's queue has grown so that over 13 GW of new resources were in the queue earlier in 2022. PSCo itself serves a peak network load of 7,

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[45] "Colorado's Clean Energy Plan", Xcel Energy, *available at* https://co.my.xcelenergy.com/s/environment/clean-energy-plan.

[46] Energy and Environmental Economics, "Resource Adequacy in the Desert Southwest", 29 (Feb. 10, 2022), a*vailable at* https://www.ethree.com/wp-content/uploads/2022/02/E3_SW_Resource_Adequacy_Webinar_Summary_2022-02-10.pdf

[47] Forbes, "Inflation Reduction Act Benefits: Clean Energy Tax Credits Could Double Deployment" (Aug. 23, 2022), *available at* https://www.forbes.com/sites/energyinnovation/2022/08/23/inflation-reduction-act-benefits-clean-energy-tax-credits-could-double-deployment/?sh=4c336dc76727.

[48] *See generally*, NREL, "Benchmarking Non-Hardware Balance of System Soft Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey - 2nd Ed." (Oct., 2013), at 44; *available at* https://www.nrel.gov/docs/fy14osti/60412.pdf

[49] *See* FERC Docket No, ER19-2774-000, Order on Tariff Request (Dec. 4, 2019) and Informational Report filed December 9, 2019 ("Informational Report).

426 MW. As indicated in the 2-year follow-up Informational Report after its last queue reform, the interconnection study requests are expanding.[50]

Tri-State Generation and Transmission Company has its own queue as does Black Hills Energy. Each anticipates or is already undergoing resource planning processes which include requests for proposals for hundreds of MWs of new renewables, stimulating new development activity and new queue requests in order to determine the necessary information so each project developer can properly evaluate the prospects of interconnection for each site.

NV Energy recently filed its own application for tariff revisions[51] indicating that it "strongly prefers to start making progress on clearing backlogs in its queue sooner than the implementation date of any Final Rule that emerges from Docket No. RM22-14."[52] NV Energy reports growth in its queue have made processing unwieldy, as follows:[53]

> From 2019 until the last cluster, NV Energy had 39,524 MW from 164 requests in its interconnection queue.[54] Of the 164 requests, 54% remain in the study phase, 15% of the proposed projects have executed LGIAs and remain active, and 42% of the requests are either in default, have withdrawn or their LGIAs are in suspension.

NV Energy has seen an over 300% increase in the number of requests, increasing from 13 requests in the 2019 Spring Cluster to 41 requests in 2022 Spring Cluster.[55] It also has experienced a 500% increase in the MW seeking to interconnect to the NV Energy transmission system between the Spring 2019 cluster (2,190 MW) and the Spring 2022 cluster (10,518

[50] Informational Report, Fig. 2, p. 15.
[51] FERC Docket ER22-2993, filed Sept. 26, 2022 ("NV Energy Tariff Revision Request").
[52] *Id.* at 2.
[53] *Id. at* 5.
[54] *Id.* at 5-6.
[55] *Id. at* 6.

MW).[56] All of these projects likely seek information to enable development and interconnection to serve NV Energy, commercial and industrial customers and customers in neighboring balancing areas or markets. These numbers make the studies time-consuming to process.[57]

On the positive side, there is evidence that FERC's tariff reforms can be successful, so PIOs support the NOPR and additional reforms to standardize and incorporate best practices. Revisions to the *pro forma* tariff as adopted by each transmission provider have enabled progress towards resolving delays in the past. PSCo reported that immediately after its last tariff revisions, the numbers of interconnection requests in the queue fell dramatically, and the processing improved.[58] PSCo now contemplates additional revisions including additional modeling enhancements to limit restudies, minimize modeling errors and reduce overall processing time. When PSCo was able to conduct its resource solicitation cluster pursuant to its revised tariff, the most cost-effective processes selected from a highly competitive resource plan solicitation process were advanced through interconnection study processes so as to achieve interconnection on a timely basis. Overall, PSCo's cluster studies conducted soon after the revised tariff was adopted resulted in large generator interconnection agreements ("LGIAs") in less than two years' of total processing time, whereas prior to the revisions requests were unable to be studied and would have required three years or more to even start the study. [59]

ii. Southeast

At first glance, the Southeast would appear well-positioned to avoid the queue backlogs affecting the rest of the country. Lacking both an organized wholesale energy market and retail

[56] *Id.*
[57] *Id.* at 5.
[58] PSCo Informational Report.
[59] PSCo Informational Report at 24.

choice, the region's opportunities for offtake are largely limited to procurement by vertically integrated utilities, whose overwhelming incentives to build their own generation facilities yield relatively fewer third-party power purchases. While these conditions should, in theory, limit the volume of generators seeking to interconnect to the utilities' transmission systems, each of the region's public utilities has experienced significant interconnection study delays and queue backlogs. A review of the interconnection study delay reports required by Order No. 845 shows that Duke Energy Progress, LLC and Duke Energy Carolinas, LLC (collectively, Duke);[60] Dominion Energy South Carolina, Inc. (Dominion);[61] Louisville Gas and Electric Company and Kentucky Utilities Company;[62] Florida Power & Light Company (FPL);[63] and Tampa Electric Company[64] have all experienced significant study delays, which most attribute to the sheer volume of interconnection requests.[65] Representatives from Georgia Power Company (Georgia Power) explained in its recent state Integrated Resource Planning proceeding that interconnections to the transmission system average three to four years to complete.[66]

These challenges are poised to worsen in the coming years. For example, in North Carolina, state law requires Duke to reduce its carbon emissions 70 percent from 2005 levels by

[60] *See* Duke, Informational Report Under OATT LGIP Section 3.5.4(i), Docket No. ER19-1507-000, at 1-2 (filed Aug. 8, 2022) ("Duke Report").

[61] *See* Dominion, Informational Report in Compliance with Section 3.5.4 of DESC's LGIP, Docket No. ER19-1946-000, at 3-4 (filed Aug. 12, 2022) ("Dominion Report").

[62] *See* Louisville Gas and Electric Company and Kentucky Utilities Company, Report on Interconnection Study Metric, Docket No. ER19-1916-000, at 1-2 (filed Aug. 12, 2022) ("LG&E/KU Report").

[63] *See* FPL, Interconnection Study Deadlines Information Report for Q2 2022, Docket No. ER20-1384-000 (filed July 29, 2022).

[64] *See* Tampa Electric Company, Informational Report Pursuant to OATT LGIP Section 3.5.4; Second Quarter – 2022, Docket No. ER19-1920-000, at 1-3 (filed July 29, 2022) ("TEC Report").

[65] *See, e.g.*, Duke Report at 2; Dominion Report at 3; LG&E/KU Report at 2; TEC Report at 1.

[66] *See Georgia Power Company*, Docket No. 44160, Tr. 444:16-18 (Ga. Pub. Serv. Comm'n Apr. 4, 2022) ("For transmission interconnect that followed the LGIP process, it's 36 to 48 months.").

2030 and reach carbon neutrality by 2050.[67] The North Carolina Utilities Commission (NCUC) is currently developing a plan for Duke to reach these benchmarks, which will almost certainly require greater integration of wind and solar resources, electric storage, energy efficiency, and demand response, as well as newer resources like nuclear small modular reactors and hydrogen solutions.[68] Southern Company, corporate parent of public utilities Georgia Power, Alabama Power Company, and Mississippi Power Company (collectively, Southern Company), has committed to reach net zero greenhouse gas emissions by 2050.[69] More specifically, Georgia Power plans to integrate 6,000 MW of new renewable energy resources by 2035.[70] Finally, in Florida, FPL's corporate parent NextEra Energy has committed to eliminate all carbon from its operations by 2045.[71] Coupled with a raft of coal retirements, these and similar initiatives threaten to exacerbate the failings of the region's interconnection processes.[72] As the NOPR recognized, the inability of generation to interconnect in a "reliable, efficient, transparent, and timely manner," may result in rates that are not just and reasonable or are unduly discriminatory or preferential.[73]

Two of the region's public utilities, Duke and Dominion, have sought to address these concerns by proactively adopting first-ready, first-served cluster study approaches, similar to

[67] 2021 N.C. Sess. Laws 165, § 1.

[68] *See Duke Energy Progress, LLC and Duke Energy Carolinas, LLC*, Docket No. E-100, Sub 179, Duke, Carolinas Carbon Plan, Executive Summary, at 12 (N.C. Utils. Comm'n May 16, 2022).

[69] *See Southern Company Releases Plan on Net Zero Carbon Emissions Goal*, Southern Company (Sept. 21, 2020). *Available at* https://www.southerncompany.com/newsroom/clean-energy/plan-on-net-zero-carbon-emissions-goal.html

[70] *See Georgia Power Company*, Docket No. 44160, Georgia Power, 2022 Integrated Resource Plan, Main Document, at 11-72 (Ga. Pub. Serv. Comm'n Jan. 31, 2022).

[71] *See Zero Carbon Blueprint*, NextEra Energy, at 6, *available at* https://www.nexteraenergy.com/content/dam/nee/us/en/pdf/NextEraEnergyZeroCarbonBlueprint.pdfint.pdf.

[72] Any reforms to the wholesale energy market in the region would have a similar effect.

[73] NOPR at ¶ 22.

those proposed in the NOPR.[74] The remainder of the region's utilities have retained the first-come, first-served approach, leaving them vulnerable to further delays as an influx of renewable resources enter their queues. For Duke and Dominion, it is too soon to tell whether those reforms have had the desired effect, as they continue to process their transitional cluster studies. Their interconnection processes would stand to benefit from the other proposals contained in the NOPR, such as the improvements to the affected systems study process, among others. Duke, in particular, has experienced significant difficulties addressing affected systems, which, as the NCUC and North Carolina Commission Public Staff recently cautioned, are only expected to intensify.[75] Accordingly, the need to reform generator interconnection processes applies with equal force to the Southeast.

IV. Proposed Reforms

A. First-Ready, First-Served Cluster Study

The NOPR proposes a set of three interlocking reforms to address the shortcomings in current interconnection queue processing: improved information access so that developers can assess the viability of sites without having to apply for interconnection; a first-ready, first-served cluster process that studies projects in groups based on readiness rather than application date; and increased financial and readiness requirements to discourage non-viable projects.

[74] *See Dominion Energy S.C., Inc*., Docket No. ER22-301-000 (Dec. 28, 2021) (delegated order); *Duke Energy Carolinas, LLC*, 176 FERC ¶ 61,075 (2021).

[75] *See NCUC and North Carolina Commission Public Staff, Initial Comments*, Docket No. RM21-17-000, at 12 (filed Aug. 17, 2022) ("When developers locate generating facilities in the adjacent [Dominion North Carolina] service territory, which is part of PJM, then [Duke]'s retail ratepayers must pay for 70% of the affected system costs caused by these facilities. The current estimated total of the affected system costs for [Duke] of recent projects in the [Dominion North Carolina] territory, based on Class 5 estimates, is on the order of $150 million. However, the NCUC and the Public Staff are concerned that this is just the tip of the iceberg. Affected systems studies are ongoing, and affected system costs are likely to increase significantly, particularly as Virginia's offshore wind comes online near the North Carolina border.").

PIOs appreciate the Commission's integrated approach, acknowledge that the NOPR proposal draws on industry best practices, and support the broad outlines of the NOPR's approach. However, we believe that lack of information and queue processing inefficiency play a larger role in creating interconnection backlogs than insincere interconnection applications. Improved information and study processes will reduce the incentive for speculative applications and the impact of withdrawals. Finally, PIOs are concerned that some of the financial and readiness measures proposed go too far and will undermine competition and create barriers to otherwise viable projects.

For these reasons, our comments in this section propose modifications to the NOPR to maintain all three aspects but give relatively more weight to information access and cluster studies and less emphasis to financial commitments and readiness requirements.

1. Information Access

PIOs believe that access to information is critical to speeding the interconnection process and eliminating some of the current inefficiencies. We agree with FERC that the lack of information available to interconnection customers when they are planning projects before entering the interconnection queue increases the number of applications and contributes to interconnection study delays. We emphasize that the delays and uncertain costs inherent to current processes create risk for developers and that hedging this risk through multiple applications is an entirely rational response by developers.[76]

To address this issue, we support the Commission's proposals to require transmission providers to offer both an informational interconnection study process and public access to a

[76] *See, e.g.,* NOPR at FN 75.

summary of relevant public interconnection information.[77] In addition to the two categories of information identified in the NOPR, we propose a third category of information related to process transparency that will improve the ability of stakeholders, including state regulators, lawmakers, and public interest organizations to engage with transmission providers.

i. Public Interconnection Information

The NOPR addresses the lack of public information available to interconnection customers who are contemplating building new facilities. Companies that want to build generation look for geographic areas where there is good wind, solar, geothermal, or other resources, with sufficient land area relatively near a transmission substation where interconnection would be available. Several pieces of critical information would help them decide whether to submit an application to the TO for interconnection at the particular location, including:

1. Available interconnection capacity – how much can be interconnected without substantial cost (the "hosting capacity" of the substation and associated transmission lines)
2. Limiting elements to additional interconnection capacity in the substation and associated transmission infrastructure and the hosting capacity that would be gained
3. Projects currently in queue and the interconnection capacity those projects are requesting
4. Available transfer capacity/available transmission service on the existing lines -- transmission congestion that would impact the prospective project
5. Planned transmission builds that would allow additional transmission service (transfer) capacity

[77] NOPR at ¶¶ 42-52.

As an example of this, "Hosting Capacity" is a concept that has received wide acceptance in the distribution world to "help utilities, policymakers, and solar developers better understand the impact of adding new distributed photovoltaic (DPV) systems to the electrical distribution system."[78] Many utilities provide hosting capacity information publicly on heat maps and in tables to assist solar developers in deciding where they can market new systems without encountering grid upgrade costs. Many states require that such analysis is provided on utility websites and updated regularly.

FERC should require an analogous concept of all transmission providers for substations that are near potential generation resource areas (i.e. all substations except urban substations, where there is no suitable land or high potential generation resources). At a minimum, the hosting capacity provided should include a snapshot of the existing interconnection capacity available at each substation and its associated transmission during "heavy summer" conditions (high load). Hosting capacity should be updated every quarter, at a minimum, and made publicly available. Utilities should be required to go a step further and evaluate their grids for incremental improvements that can increase injection capacity at each substation. An excellent example of this type of analysis was recently completed by Tri-State Generation and Transmission in their "Incremental Improvements Study Report," available as Attachment 1 to these comments. This study was published publicly as part of a CPCN docket for new transmission Tri-State is proposing to build and looks at limitations that constrain injection capacity on their grid as several substations. The PIOs believe that this type of analysis would be very useful to

[78] National Renewable Energy Laboratory, *Advanced Hosting Capacity Analysis, available at* https://www.nrel.gov/solar/market-research-analysis/advanced-hosting-capacity-analysis.html

prospective applicants for interconnection and can be included in publicly disseminated information.

ii. Informational Interconnection Study

The NOPR also proposes an optional Informational Interconnection Study.[79] Such studies may be useful if they meet three conditions: (1) they provide information not publicly available; (2) they are faster or cheaper than full interconnection studies; and (3) their results remain valid for long enough for a potential interconnection customer to rely on them when considering making an interconnection application.

A major potential benefit of the Informational Interconnection Studies would be to reduce interconnection applications by giving potential interconnection customers a way to screen out infeasible projects prior to application. In this light, several of the restrictions proposed in the NOPR appear counterproductive, and the Commission should relax them in a final rule.

- Limit on number of concurrent studies by one customer. PIOs appreciate and agree with the need to avoid overburdening transmission providers, and to ensure that scarce study capability is fairly allocated. However, limiting access to information studies may be a false economy, as every information study performed is a full study potentially avoided. Limiting how many studies one customer can request would perpetrate the status quo of developers making interconnection applications to gain information. The proposed limit of no more than five concurrent studies by should be a minimum standard, and transmission providers should be free to propose

[79] NOPR at ¶ 42-48.

alternative arrangements so long as they are equal or superior. Transmission providers should also be required to create a fair procedure for rationing study requests when their capability is oversubscribed.

- Specificity of study requests. The NOPR proposes that "each configuration of an interconnection request would require a separate informational interconnection study."[80] Transmission providers who wish to provide more flexible or comprehensive informational studies should be allowed to do so. For instance, it may well be that it is more efficient to study multiple configurations of a single project in one study than in a series of separate studies; nothing in the final rule should prevent transmission providers from offering such an alternative.

  Current study procedures generally require interconnection customers to fully specify their project before interconnection studies begin, encouraging a highly inefficient "guess and check" approach that may contribute to queue backlogs. The final rule should allow transmission providers to offer more flexible informational studies, keeping in mind the ultimate purpose of helping customers make good interconnection applications. For example, an informational study option that identified how large a project could be *without* triggering the need for system upgrades would be useful to many developers.

The NOPR requests comment on if transmission providers should be required to establish a request window during which they accept informational interconnection study requests. Transmission providers should not be required to do so; a transmission provider that wishes to

[80] NOPR at ¶ 44.

accept requests at any time should be allowed to. Request windows would be most useful when coordinated with cluster study schedules to provide clarity as to the base case for informational studies, and to offer a clear, lower-risk path from a positive informational study result to a formal interconnection application.

iii. Process Information

Improving the speed of interconnection processing has become an issue of acute interest for state regulators, legislators, and advocacy organizations such as PIOs. In PIOs' work with transmission providers, we are often frustrated by the opaque nature of transmission provider processes. Based on conversations with state and local policymakers and others, we believe that we are not the only stakeholder group that finds itself unable to effectively advocate for improved interconnection process due to near-complete lack of knowledge of what's going on "behind the curtain."

For example, at any given moment, an interconnection application might be in various stages of processing, awaiting its turn for attention, or on hold pending resources external to the transmission provider. Additionally, we suspect, but have been unable to verify, that RTO interconnection work often relies on delegating tasks to transmission owners, raising the question of if delays are arising within RTO offices or from transmission owners. For state regulators, this lack of transparency means they must act without clear knowledge whether interconnection delays should be addressed at RTOs or if they should turn their attention to incumbent transmission owners partially under their jurisdiction. It is effectively impossible for outside observers to determine how efficient any given transmission provider is at the core task of performing studies, the prudence and usefulness of investments made to improve processing, or where resources might be focused to resolve delays.

To improve this situation, PIOs propose that FERC mandate additional transparency from transmission providers, to include:

- Documentation of their study process in sufficient detail for stakeholders to understand the phase of the process where applications are spending all those years, and, critically, when the transmission provider relies on other organizations.
- Enhance on-line queue tracking systems to identify where in the internal process applications sit, how long they've been there, and what they are waiting on to move forward.
- Periodic reports on performance metrics, including average person-hours, dollars, and any other key resources spent per application study such as staffing and funding levels and resource constraints that have bottlenecked processing.

PIOs appreciate that these transparency requirements may appear burdensome to transmission providers. It is not our intent to add additional administrative tasks unnecessarily. Rather, this level of transparency is critical for improvement of the concerns identified in the NOPR. At the core of the entire interconnection problem sits the actual work of doing the engineering studies that determine transmission needs. That work is mostly invisible in these proceedings, but ultimately, if interconnection applications come in faster than studies can be done, no amount of rearranging the queue processes will help. At the moment, there is no way of knowing which transmission providers are exceptional at that task and which ones have fallen behind. It may be that the transmission providers themselves don't know. In a competitive industry, market forces would sort out the efficient from the inefficient. But transmission service is not a competitive industry. It is a regulated monopoly, and one of the perils of monopolies is inefficiency. Absent competition, the level of transparency we request here is the only way to ensure transmission monopolies competently provide the services they are entrusted with, or, more optimistically, to identify and spread best practices.

2. Cluster studies

The NOPR proposes to "require transmission providers to eliminate the serial first-come, first-served study process and instead use a first-ready, first-served cluster study process."[81] PIOs agree that the proposed process offers a host of benefits:

- Addressing multiple interconnection requests in one study promises efficiency of effort and avoids piecemeal identification of network upgrades.
- Costs of network upgrades benefiting many projects are allocated across an entire cluster, rather than to the one unlucky project that triggers them.
- Specific queue position becomes less important, eliminating one of the possible incentives for making multiple interconnection applications.
- The process may be less vulnerable to the "cascading re-study" flaw associated with the serial interconnection processes.

For the foregoing reasons, PIOs support the proposed requirement that transmission providers be required to use a cluster study process.

[81] NOPR at ¶ 64.

3. Incentives to Ensure Interconnection.

The NOPR acknowledges that proposed reforms should reduce the incentive for developers to "to submit multiple speculative interconnection requests and later withdraw those requests" and the mitigate the impact of withdrawn requests on queue processing.[82] None the less, the NOPR proposes a suite of more stringent eligibility requirements to "discourage speculative interconnection requests."[83]

PIOs are concerned that the "speculative request" problem is exaggerated. As discussed in section III.B above, at a national level, there does not appear to have been any increase since 2010 in the rate at which projects withdraw from interconnection queues. Rather, the primary issue appears to be that flaws in the serial queue approach cause the disruption caused by withdrawals to increase disproportionately as the overall number of interconnection requests grows.

Developing a powerplant is a complicated affair, and even the best-intentioned projects may fail for any number of reasons. All development projects are speculative to one degree or another; FERC and transmission providers are not well positioned to discriminate based on their assessment of project's risk. While it may serve the public interest to discourage frivolous projects from making interconnection applications, it would be a larger disservice to erect new barriers or support anticompetitive outcomes. Similarly, several sections of the NOPR appear to interpret commercial enthusiasm for building solar plants as a problem that the Commission should address. This is dangerous territory, and edges FERC towards substituting its judgement for private investors' or picking commercial winners and losers.

[82] NOPR at ¶ 102.
[83] NOPR at ¶ 103.

By far the best solution to queue backlogs are processes that can handle large numbers of interconnection requests, and that are not disrupted when projects withdraw at similar rates as they have in the past. FERC should treat attempting to reduce queue backlogs by creating barriers to entry as an undesirable last resort.

i. Demonstration of Site Control

The NOPR proposes to have transmission providers set acreage requirements for various technologies and require interconnection customers to demonstrate 100% site control when they submit their request. These rules are too inflexible and place otherwise viable projects at risk of being derailed by *de minimis* difficulties.[84] For perspective, the proposed LGIP allows projects to decrease their output by up to 60% without losing queue position;[85] it verges on the absurd that a project with the right to cut itself in half could be prevented from proceeding by a dispute over a few square feet. Any final rule should relax control requirements to less than 100%, and allow for reasonable flexibility to deviate from acreage requirements with adequate documentation.

The NOPR also proposes to require interconnection customers to remedy any change in site control within ten days or have their request withdrawn. This is both unreasonably inflexible and an unreasonably short cure period. In terms of flexibility, the Commission should again consider a project's right to reduce its output by up to 60% when determining the threshold for terminating an interconnection application over site control issues—if nothing else, a project should be able to retain its queue position by reducing its output to match the lost site acreage, consistent with technological limitations. It is unduly discriminatory to, e.g., allow a thermal project to keep its queue position after downsizing its turbines, but terminate a wind farm that

[84] Troublingly, the NOPR appears to state that preventing viable projects from entering the queue is just and reasonable because it reduces the number of interconnection requests made. NOPR at ¶ 120.

[85] NOPR, Appendix B, Section 4.4.1.

loses its lease on a few pad sites. Similarly, the cure period should be long enough to allow for routine events such as probate court settling the affairs of a deceased landowner who leased their property to a wind developer, or a change in ownership of a shopping mall hosting a solar development. Absent those changes, the proposed rule is likely to cause far more queue withdrawals than it prevents.

ii. Commercial Readiness

The NOPR proposes to require interconnection customers to either demonstrate "commercial readiness" or provide increasing deposits.[86] At least as applied to RTO/ISO regions, this proposal is unsupported by the record, and would be unreasonable and unduly discriminatory.

The NOPR asserts that generating facilities are generally not constructed without some form of off-take agreement.[87] This is not supported by any sources, and generation developer business models was not a major theme of the transmission planning and cost allocation NOPR[88]. While comments in the current proceeding will likely provide more information, it is unlikely the record will give the comprehensive view of the variety of commercial and financing arrangement needed to support findings about what types of projects are commercially viable.

The conditions proposed in the NOPR do not reflect commercial reality and are unreasonable. The vast majority of power purchasers seek projects with advanced interconnection queue positions (with preference for a finalized generator interconnection agreement) before signing a PPA or state procurement. From the generation developer's point of

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[86] *Id.* at ¶¶ 128-134.
[87] *Id.* ¶ 124.
[88] Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation & Generator Interconnection, 86 FR 40266 (July 15, 2021), 176 FERC ¶ 61,024 (2021)

view, entering PPAs before knowing the time and cost of interconnection creates exposure to potentially ruinous risk.[89] Utilities conducting RFPs for their resource plans often require at least a position in an interconnection queue as a precondition of offering. In practice, projects not affiliated with incumbent utilities will have great difficulty meeting the NOPR's proposed commercial readiness requirements, regardless of their actual viability, making the proposal unduly discriminatory and anticompetitive.

The proposed commercial readiness conditions are unreasonable when applied to RTO/ISO regions. Requiring resources located in RTO/ISO regions without off-take agreements to make additional deposits is tantamount to FERC making a blanket determination that power markets do not support commercially viable projects. This contradicts decades of precedent that entry/exit decisions should be based on individual participant's assessment of market signals.[90] Additionally, our understanding is that a meaningful portion of projects in RTO/ISO regions are intended as merchant projects selling all or part of their output into spot markets. At the very least, the Commission should find that any project applying for interconnection in an RTO/ISO region is presumptively able to sell into that RTO/ISOs markets and so meets the commercial readiness requirements without further evidence.

In summary, the Commission should not include any version of the commercial readiness requirement in its final order. The requirement sets unreasonable standards for off-take

[89] *See, e.g., Motion to Intervene Out of Time and Protest,* Filed Sept.16, 2022 in Docket No. ER22-2110 (FERC Accession # 20220916-5015).

[90] *See, e.g., ISO New Eng., Inc.,* 162 FERC ¶ 61,205 at 21 (finding that "A capacity market should facilitate robust competition for capacity supply obligations, provide price signals that guide the orderly entry and exit of capacity resources, result in the selection of the least-cost set of resources that possess the attributes sought by the markets, provide price transparency, shift risk as appropriate from customers to private capital, and mitigate market power.").

agreements, subverts wholesale power markets, and results in undue discrimination against merchant developers and in favor of vertically integrated utilities.

4. Cost Allocation Reforms

As detailed above and in the NOPR, the cost of interconnection has risen dramatically in recent years and has reached a level that can often make otherwise-economic projects no longer feasible. Under existing cost allocation processes, individual projects are often responsible for the full costs of network upgrades even if adjacent projects later in the queue or submitted in subsequent years benefit from the upgrades. This all-or-nothing cost allocation results in significant jockeying for queue position,[91] with project developers seeking to have a project approved as quickly as possible but late enough to avoid the need for costly network upgrades associated with interconnection. Developers are thus incentivized to add and remove projects to/from the queue in order to find just the right queue position.

In the NOPR, the Commission proposes to revise the allocation of interconnection costs in several ways to reduce the burden of network upgrades on any single project and to eliminate the "free rider" problem that contributes to queue churn and withdrawn projects. First, the Commission-proposed pro forma LGIP will allocate shared costs of cluster studies 90 percent pro rata based on requested MWs and 10 percent on a per capita basis.[92] Second, the pro forma LGIP will allocate network upgrade costs to interconnection customers within a cluster using a proportional impact method.[93] Third, the pro formal LGIP will allocate network upgrade costs

[91] *See* NOPR at ¶ 25.
[92] *Id.* at ¶ 82.
[93] *Id.* at ¶ 88.

between interconnection customers in earlier cluster studies and subsequent cluster studies who benefit from those earlier upgrades.[94]

PIOs generally support these three expansions of cost allocation for interconnection studies and necessary network upgrades. However, these cost allocation improvements alone are insufficient to achieve just and reasonable rates and eliminate undue discrimination and preferential treatment. Specifically, PIOs remain concerned that network upgrade costs associated with some cluster studies will prevent otherwise economic and beneficial generation projects from interconnecting. This is most likely where the network upgrades required by a cluster study are not necessary simply to connect a project to the grid but rather are significantly geographically removed from the interconnecting projects. In those instances, it is likely that while the interconnecting projects in the cluster study are the "but for" cause of need for the network upgrade, the beneficiaries of the upgrade extend well beyond the interconnecting customers.

In most interconnection processes, the costs of network upgrades are borne by the interconnecting customers. In MISO, for example, interconnecting customers pay for 100% of upgrades below 345 kV and 90% of upgrades at 345 kV and higher.[95] In SPP, 100% of costs are allocated to interconnecting customers regardless of voltage.[96] Yet often these upgrades accrue significant economic and reliability benefits to parties well beyond the interconnecting customers. For example, a study by ICF Resources in 2021 found that in a representative sample

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[94] *Id.* at ¶ 98.

[95] Midcontinent Independent Transmission Operator Tariff Attachment FF III(A)(2)(d).

[96] ICF Resources LLC, Just & Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits, 3 (Sep. 9, 2021), *available at* https://acore.org/wp-content/uploads/2021/09/Just-Reasonable-Transmission-Upgrades-Charged-to-Interconnecting-Generators-Are-Delivering-System-Wide-Benefits.pdf

of 12 network upgrades from MISO and SPP, 10 of them saw positive adjusted production cost ("APC") savings ranging from $2.9 million to $335.8 million.[97] Only two of the 12 lines resulted in negative APC savings (of -$4.8 million and -$8.9 million).[98] The ICF Resources study further found benefit to cost ratios for the 10 projects with positive APC savings that ranged from 0.06 to 1.52.[99] And the study authors believe that the study's conservative assumptions around reference scenarios and limiting evaluations of projects to single network upgrades only understated the economic benefits to grid of these network upgrades.[100]

This suggests unduly discriminatory treatment. Take, for example, the two projects with the highest B/C ratios in the ICF Study: Big Stone South – Alexandria 345kV, with a B/C ration of 1.52, and Wichita – Benton 345kV at 1.85. If either of those projects had been identified in MISO's RTEP, they would have exceeded the 1.25 B/C threshold and been to be included in the rate base and earn the transmission owner's ROI. Instead, because these projects were identified through an interconnection request, they are funded by the developer with no cost recovery mechanism. Even within a model based on participant funding, being entirely blind to benefits of transmission investments leads to disparate treatment of otherwise similarly situated investments.

While PIOs are hopeful that the Commission's proposed revisions to regional planning and cost allocation in RM21-17 will help eliminate the need for broadly beneficial network upgrades to be planned and paid for through the interconnection process, it is important that this rulemaking address any remaining unjust and unreasonable and unduly discriminatory or preferential treatment caused by the existing model of assigning network upgrade costs predominantly to interconnecting customers. In those cases, it may be mere chance or lack of

[97] *Id.*
[98] *Id.*
[99] *Id.*
[100] *Id.*

good regional planning that shifts the costs from broad beneficiary pays cost allocation pursuant to Order 1000 to the participant funding model of the existing interconnection processes, leading to unjust and unreasonable rates and unduly discriminatory or preferential treatment. We therefore urge the Commission to require transmission providers to assess the costs of network upgrades to cost causers and beneficiaries.

PIOs believe that adopting a broader beneficiary pays process for network upgrades not required to physically connect generators to the grid need not be overly burdensome or further delay the interconnection process. In many instances, network upgrades that bring benefits to stakeholders beyond the interconnecting customers will still be geographically limited in scope. Transmission planners are already experienced with allocating costs of transmission projects to beneficiaries. We urge the Commission to require transmission planners to utilize existing cost allocation methods for determining who stands to benefit from network upgrades, and then allocate the costs of these deep system upgrades accordingly.

B. Reforms to Increase the Speed of Processing

As an initial matter, PIOs support the Commission's proposal to eliminate the "reasonable efforts" standard and replace it with more meaningful guidelines in order to better incentivize transmission providers to evaluate generator interconnection requests timely.[101] As highlighted in Section III(A) above, the slow pace at which interconnection requests are evaluated has contributed to a ballooning of interconnection queues across the country, which has discouraged the incorporation of much-needed new generation and stunted the transition of the grid more broadly to a clean energy future.

[101] *Id. at* ¶¶ 168-169.

We also agree with FERC that binding deadlines are the most effective option for ensuring that prospective generation receives timely responses to interconnection requests. Unfortunately, as the Commission has highlighted, the "reasonable efforts" standard has not served as an effective tool to increase the speed at which transmission providers process these requests: they "regularly fail to meet interconnection study deadlines."[102] As a result, interconnection queue wait times have steadily risen, and backlogs have skyrocketed. Binding deadlines will give stakeholders, and in particular interconnection customers, more power to ensure that transmission providers are meeting their obligations and queues are efficiently processed.

PIOs partially support the Commission's proposal to ensure compliance with binding deadlines by imposing a penalty of $500/day, up to a maximum of the total study deposit received for the late study from the interconnection customer.[103] While we agree that some sort of financial consequence is necessary to actually incentivize transmission providers to act, we believe that the NOPR's proposal as constructed is not adequately constructed to meaningfully improve the rate of interconnection study completion. PIOs therefore propose the following set of changes to the Commission's proposal, both to the penalties for noncompliance and to how those penalties are used.

First, we believe that the monetary penalty amount should be dictated by the scope and cost of the study that is late, rather than being a set amount. Daily penalties could be set as a percentage of the total study deposit received per day. Tethering the penalty amount to the deposit size will ensure that the penalty maximum, of 100% of the interconnection study deposit, is reached in an equivalent amount of time for both smaller and larger projects, which will also

[102] Id. at ¶ 166.
[103] *Id.* at ¶ 169.

reduce the possibility that transmission providers facing delays might maximize their penalty amount for smaller studies before completion (and thereby lose any financial incentive to complete those studies). It will also resolve the Commission's question in the proposal[104] about how to treat cluster studies: under our proposal, penalties will increase linearly with the overall deposit required to conduct the study, which automatically increases penalties for large, complicated cluster studies. And finally, this tethering will ensure that any penalties established in this NOPR remain appropriately benchmarked to actual study costs in the event of inflation or other cost shifts in the industry.

Second, although we support the idea that transmission providers should face financial consequences for missing binding deadlines, we note that the motivating impact of this penalty in RTO/ISO regions is likely to be at least slightly muted. PIOs do agree with and support the rationale behind allowing any RTO/ISO to simply seek the cost of any penalty amounts from other parties;[105] as the Commission notes, RTOs/ISOs are nonprofits (or revenue neutral LLCs) and will thus require some form of additional revenue stream to pay. Similarly, PIOs support the Commission's proposal to allow RTOs/ISOs to recover these amounts from "entities that are responsible for, or contributed to" any penalty-causing delay;[106] but although this will help RTOs/ISOs incentivize other parties (particularly transmission owners) not to delay interconnection studies through their inaction, it will not address delays that result from the RTOs/ISOs' own procedural failings.

Third, PIOs are concerned about what might happen when transmission providers reach the maximum penalty for delay of an interconnection study, for two reasons: first, at the point the

[104] *Id.* at ¶ 173.
[105] *Id.* at ¶ 172.
[106] *Id.* at ¶ 172.

penalty reaches its maximum, the financial incentive to ensure timely compliance will disappear; and second, a delay that extreme is indicative of a larger failing at the transmission provider. To remedy these extreme circumstances, we urge the Commission to impose additional, non-monetary penalties in the event that the financial penalty reaches its cap of 100% of the total study deposit. As one suggestion, the Commission could require any transmission provider that reaches the 100% financial penalty cap to issue a compliance statement explaining in detail the sources of delay, including between the transmission provider and any transmission owners.

PIOs' second suggestion is to require any transmission provider that reaches the 100% financial penalty cap to continue paying the penalty amount; but instead of having that money go to the interconnection customer or to an internal fund, requiring that the transmission provider hire a third-party consultant to provide modeling or other assistance to help complete both the delayed interconnection study, as well as all pending or newly filed studies that are filed for a period of three years. This requirement would not impose any novel practice: for instance, ISO-NE regularly uses outside firms such as Siemens to assess interconnection requests. ISO-NE also has a practice of issuing orders requiring the use of outside consultants and/or requiring transmission owners to conduct a study and submit those results to the ISO.[107]

PIOs offer the following additional thoughts on how this process should be structured. First, the funding for this third-party consultant should be required to be at the transmission provider's expense (i.e. below the line, so that it is not recoverable in Commission or state rates). On the implementation side, the Commission would need to also specify how this third party

[107] Indeed, ISO-NE defines an "Interconnection Facilities Study" as "a study conducted by the System Operator, Interconnecting Transmission Owner, *or a third party consultant for the Interconnection Customer*" ISO-NE Tariff, Schedule 22, Large Generator Interconnection Procedures, Sec. I, *available at* https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/sch22/sch_22_lgip.pdf (emphasis added).

may be selected—for instance, the Commission could require a process by which transmission providers are mandated to engage a slate of third-party engineers to be hired on a consistent basis to assist with interconnection studies (transparent to the interconnection customer); or it could leave this process to the transmission providers. The Commission would also likely need to confirm that the transmission provider should of course retain final control over the interconnection study results.

1. Optional Resource Solicitation Studies

PIOs fully support the Commission's proposal to require transmission providers to offer optional Resource Solicitation Studies (RSSs) to resource planning entities, both to examine the costs of all-source procurements and to evaluate particular geographic areas such as offshore wind lease areas.[108] This is in large part because, as highlighted in the Need for Reform Section above, there is a distinct absence of pathways available to resource planning entities, including states, to secure holistic consideration of a portfolio of resources.[109] These pathways are important: in general, considering interconnection of multiple resources simultaneously is far more efficient than conducting individual interconnection studies on a resource-by-resource

[108] *See, e.g.*, Louisiana Pub. Serv. Comm'n, Integrated Resource Planning Rules for Electric Utilities in Louisiana at ¶ 1 (Louisiana's Rules "do not mandate a specific outcome, nor do they mandate any specific investment decisions to be made"), ¶ 9(f)(xi) ("The Commission may also, at its discretion, provide recommendations to the utility for improvements to the utility's IRP inputs and process, including the IRP Report"); Arkansas Pub. Serv. Comm'n, Resource Planning Guidelines for Electric Utilities § 3 ("Guidelines do not mandate a specific outcome nor do they mandate specific investment decisions"), § 3 ("The Resource Plan shall be submitted to the Commission for informational purposes."), *available at* https://www.sos.arkansas.gov/uploads/rulesRegs/Arkansas%20Register/2007/jun_2007/126.03.07-003.pdf; Kansas Corp. Commission, Order Adopting Integrated Resource Plan and Capital Plan Framework at 4, 6 , Docket No. 19-KCPE-096-CPL (The Commission "may also address any comments or concerns raised by the parties if it so chooses. However, the Capital Plan Reporting framework does not constitute Commission approval or rejection of the plan. . . . This review shall not limit the ability of [the utility] to take any actions deemed appropriate by [the utility]"), *available at* https://estar.kcc.ks.gov/estar/ViewFile.aspx/20200206105827.pdf?Id=da24762e-a6b9-4288-9cde-09ab47dac275; *see also,* Indiana Code § 8-1-8.5-3 (providing for an informational resource plan process).

[109] Supra Sec. III(A); *see also,* NOPR at ¶ 219-20.

basis. And given the complexity, financial uncertainty, and (current) temporal uncertainty of the interconnection process, it benefits resource planning entities immensely to be aware what barriers exist to different portfolios of new generation as part of their selection process.

PIOs also support the Commission's proposal to explicitly include states among the set of resource planning entities who are entitled to request RSSs: both the Commission and multiple stakeholders have made clear time and again the importance of respecting the allocation between states and the Commission and transmission providers under the Federal Power Act: states must maintain the right to guide resource development based on their legitimate public policies, and it should remain the responsibility of the transmission providers, to the extent possible and without enabling unjust and unreasonable rates, to respond to and enable those generation preferences.

PIOs partially support the Commission's proposal to impose a 135-day time limit on transmission providers from receipt to issuance of each RSS.[110] We agree that a 135-day timeline should be sufficient in most circumstances for transmission providers to complete RSSs. However, PIOs recommend that the Commission grant some extra flexibility to transmission providers on the timeline they are given to complete batches of RSSs: although we generally support strict timelines for transmission providers, in cases where a single transmission provider is responsible for a large geographical area (i.e. RTO/ISO regions), there is a risk that a transmission provider could face difficulties when receiving multiple RSS requests in a short timeframe, potentially for the same circuits and thus requiring some consideration of other interrelated RSSs. In such circumstances, they should be granted the flexibility to determine an appropriate order of completion of the RSSs. Specifically, we recommend that the Commission grant a conditional waiver of the strict 135-day deadline when a transmission owner receives

[110] NOPR at ¶ 233.

multiple RSS requests, so long as that transmission provider issues at least two RSSs every 135 days, and never takes longer than 270 days from submittal to release an RSS, no matter how many are submitted.

PIOs also support the Commission's proposal to limit the availability of RSS requests to be used on resource procurements that use "competitive procurement techniques,"[111] but believe the Commission needs to reform how it applies this standard. To be clear, we do not object to the proposed guidelines for what constitutes a "competitive procurement technique"—that it be "open, fair, and employ the services of an independent third party that applies standardized evaluation criteria"[112]—but we believe FERC needs to clarify who will be authorized to enforce this requirement. If a resource planning entity seeks an RSS for a procurement process that is not competitive, what recourse is available to the transmission provider to refuse that request; or for a stakeholder to object to a transmission provider's decision to grant that request? Or conversely, if a resource planning entity seeks an RSS and the transmission planner denies that request on the basis that the procurement process was not competitive, what recourse does the planning entity have? PIOs believe it would be appropriate to make explicit that this is a firm standard, enforceable by all stakeholders, and that disputes of application of the standard could appropriately be resolved by an Administrative Law Judge at the Commission. But in any event, the Commission needs to resolve questions about these limitations on transmission providers' obligation to provide RSSs before imposing a caveated legal obligation.

PIOs do not, however, support the Commission's proposed alternative pathway to a guaranteed RSS, for a "resource planning entity whose resource plan or resource solicitation

[111] *Id.* at ¶ 230.
[112] *Id.* at ¶ 230.

process . . . "is substantively reviewed and approved or directly managed by a relevant state agency, . . ."[113] Again, while we support the availability of RRS status for competitive processes, the proposal's broad deference to state resource plan processes is not warranted, for at least two reasons.

First, although we continue to believe the Commission should defer to states' formal public policies or determinations about what resource mix is ultimately appropriate (as we made clear above), we do not believe this means that the Commission should defer to the resource planning process in all cases, especially in those states where the resource planning process is merely informational or where state regulators and stakeholders lack the ability to meaningfully review, modify, and reject resource plans. Unfortunately, there is not uniform enforcement of state public policies, and so an individual state entity's approval of a specific procurement process offers no protection against manipulation of the procurement process. PIOs have seen this play out in numerous contexts. Indeed, as the proposal notes, several states' resource planning processes are simply informational; in several other states, the commissions may review the resource plan, but lack the authority to substantively revise or reject a resource plan.[114]

As the NOPR recognizes, the lack of meaningful oversight in the state resource planning process raises a real risk that the RSS process could be unfairly used to favor the resource planning entities' own economic self-interest.[115] A state commission's mere "substantive

[113] *Id.* at ¶ 230.
[114] *Id.* at ¶ 230.
[115] *Id.* at¶ 230. There is evidence supporting the Commission's concern about manipulation. Entergy Louisiana, for example, has been the subject of investigation for anticompetitive practices by the Department of Justice relating to the utility's "exclusionary conduct in its four-state utility service area," and whether Entergy's "serial acquisitions" of combined-cycle gas turbine power plants owned by competing power suppliers constituted exclusionary conduct under Section 2 of the Sherman Act." Entergy, *Entergy Corporation Cooperating with the U.S. Department of Justice on Civil Investigation* (Oct. 12, 2010) https://www.entergynewsroom.com/news/entergy-corporation-cooperating-with-u-s-

review" of a utility's resource plan is not sufficient to mitigate that risk. Instead, the RSS process should be reserved for utilities in those states with "competitive" resource procurement processes. Alternatively, the proposed rule should be modified to make clear that the RSS process is available to states with resource plans that are "substantively reviewed by state agencies with authority to reject, modify, or direct the utility to revise the plan." Such safeguards will provide reasonable protection against unfair manipulation of the process.

Second, as noted, the NOPR appears to allow another pathway for an automatic RSS: Entities may be entitled to opt for an RSS if they have resource planning processes that are "agency-managed, and authorized or required by Applicable Regulations."[116] Indeed, the disjunctive use of "or" in the proposed definition of Resource Plan indicates that mere authorization of a resource planning process and mere commission oversight would be sufficient for an automatic RSS. That broad definition undermines the Commission's well-founded concerns that the resource planning process could be unfairly used to favor the utility's interests. Again, rather than offering an alternative pathway to qualify for an automatic RSS, the Commission should universally apply its requirement that any procurement process for which a planning entity seeks a RSS should use "competitive procurement techniques." At a minimum,

department-justice-on-civil-investigation/. The Department of Justice believed that Entergy may have unfairly favored use of its own power plants, controlled transmission lines to strangle rival independent power generators, and then acquired the rival plants for a discount because of that artificially depressed capacity. Department of Justice, *Justice Department Statement on Entergy Corp.'s Transmission System Commitments and Acquisition of KGen Power Corp.'s Plants in Arkansas and Mississippi* (Nov. 14, 2012) https://www.justice.gov/opa/pr/justice-department-statement-entergy-corp-s-transmission-system-commitments-and-acquisition. Louisiana and Arkansas's resource planning rules, and the lack of meaningful oversight, increase the risk of that kind of continued anticompetitive behavior.

[116] Proposed pro forma LGIP section 1 (proposed definition of "Resource Plan" and "Resource Solicitation Process").

the Commission should revise the definition of a qualifying "Resource Plan" or "Resource Solicitation Process," respectively, as reflected below:

> "Resource Plan" is "any process for, *inter alia*, the selection of Generating Facilities that is competitive, <u>or</u> substantively ~~state agency~~ reviewed and approved <u>by state agencies with authority to reject, modify, or direct the utility to revise the plan</u>~~, or state agency-managed, and authorized or required by Applicable Laws and Regulations~~."

> "Resource Solicitation Process" is "any process for the acquisition of Network Resources that is competitive, <u>or</u> substantively ~~state agency~~ reviewed and approved <u>by state agencies with authority to reject, modify, or direct the utility to revise the planned acquisition</u> ~~, or state agency-managed, and authorized or required by Applicable Laws and Regulations.~~"

Assuming the Commission makes the changes outlined above to ensure that any process receiving an RSS uses competitive procurement techniques, PIOs believe the Commission is missing an opportunity to make RSSs even more helpful to the efficient dispensation of interconnection requests. Currently, the Commission is proposing not to require transmission providers to give any actual preference in interconnection queues to resources that are selected coming out of competitive resource procurements that received an RSS; we encourage FERC to go a step further and require transmission providers to grant that interconnection preference. However, we believe this subsequent preference should only be granted to procurement processes that have been "substantively reviewed and approved or directly managed by a state agency." Thus, competitive procurement plans not managed by a state agency would get access to an RSS study, but not to subsequent interconnection prioritization. Any prioritization will inevitably be disruptive, so we believe it would be best limited to resources procured through state processes, consistent with the preference states should receive in order to maintain control over their generation mix.

There are several ways such a preference could be granted without disrupting the processing of the overall interconnection queues. The simplest method would be to allow resource planning entities to select one portfolio of resources, from those that were submitted for an RSS, and have that portfolio slot into the queue position of one of the individual projects that was included in that portfolio. For RSSs that did not include any resources that have already entered into the queue, this would provide no benefit at all; but to the extent one or more of the resources in a portfolio selected by a resource planner already holds positions in the queue, it would be far more efficient to process interconnection of the entire portfolio at once than, after completion of an RSS, to then process each resource individually (or even semi-individually in conjunction with the Commission's proposed reforms elsewhere in the NOPR).

C. Reforms to Incorporate Technological Advancements

1. Increasing Flexibility in the Generator Interconnection Process

i. Co-Located Generation Interconnection Request Processing Must Be Standardized and Streamlined

In the NOPR, the Commission preliminarily finds that the lack of standardized procedures to process an interconnection request with multiple resources sharing a single point of interconnection may lead to a disparate or case-by-case treatment of these resources by transmission providers during interconnection processes.[117] In some regions, for instance, the Commission notes that the co-location of resources may be expressly prohibited by a

[117] NOPR at ¶ 173-175.

transmission provider.[118] This case-by-case treatment may thus "serve as a barrier to entry" for co-located resources, "hindering competition and rendering the Commission's existing *pro forma* LGIP unjust and unreasonable or unduly discriminatory or preferential."[119]

PIOs strongly agree with FERC that the current case-by-case approach to the interconnection of co-located resources has the potential to unfairly limit the development of these resources, putting at risk the significant benefits that these resources can provide to the grid, including mitigating the variability and curtailment of renewable energy resources and alleviation of grid congestion.[120] Because of the significant growth in recent years of resources seeking to interconnect jointly behind a single interconnection point,[121] allowing transmission providers to require co-located resources to submit separate interconnection queue requests would perpetuate and exacerbate the delays currently seen in many queues across the country. As such, we support the Commission's proposed revisions to the *pro forma* LGIP and *pro forma* LGIA to create a "standardized procedure" that requires transmission providers to allow co-located resources to submit a single interconnection request.[122] To that end, we also support FERC's proposals in the NOPR defining "Co-Located Resources" as "more than one resource located behind the same point of interconnection," modifying the definition of "site control" to "allow interconnection customers to demonstrate shared land-use for generating facilities that

118 *Id.* at 175-176.

119 *Id.* at 175.

120 FERC, *Hybrid Resources White Paper* (May 2021), Docket No. AD20-9-000, at 22, https://www.ferc.gov/sites/default/files/2021-05/white-paper-hybrid-resources.pdf

121 Joseph Rand et al., *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2021*, Lawrence Berkeley National Laboratory (April 2022), at 18, https://emp.lbl.gov/sites/default/files/queued_up_2021_04-13-2022.pdf

122 NOPR at ¶ 176.

include more than one resource," and requiring generating facilities that are co-locating to have technology to address differences in terminal voltage.[123]

ii. The Material Modification Rule Must Be Revised to Allow for the Seamless Addition of Generating Resources That Do Not Materially Change the Interconnection Request

As the Commission notes in the NOPR, there has been significant growth in recent years in the number of interconnection customers seeking to add generating resources to their interconnection requests.[124] These modifications, particularly the addition of electric storage for the creation of hybrid resources, are not currently explicitly allowed under the *pro forma* LGIP, in part due to the nascent and rapid growth of storage and hybrid resources. This leaves the determination of whether the modification is material under Order No. 2003 up to the transmission provider, resulting in dramatically different, case-by-case treatment, as the Commission finds in the NOPR. For instance, as the Commission notes, some transmission providers (e.g., PJM) automatically determine the addition of electric storage to be a material modification regardless of the impact the addition has on the interconnection service level.[125] This type of treatment can actively discourage interconnection customers from adding generation and storage resources to their projects, causing the grid to lose out on the potential benefits provided by these resource additions, such as the firming up of variable renewable generation, avoided curtailment, congestion relief, and in the case of grid-forming inverters and batteries, fast frequency response and other grid flexibility services.[126]

[123] *Id.* at 176-177.
[124] *Id.* at 178.
[125] *Id.* at 180.
[126] *Id.* at 184; *see also,* FERC "Hybrid Resources White Paper" at 22.

PIOs agree that the lack of a standardized definition in the *pro forma* LGIP regarding what additional generating facilities—particularly electric storage for hybrid resources—amount to material modifications, is leading to a "lack of uniformity" among transmission providers and "disparate outcomes" with the "potential for undue discrimination."[127] We strongly support the Commission's proposal in the NOPR to "require transmission providers to evaluate the proposed addition of a generating facility to an interconnection request as long as the interconnection customer does not request a change to the originally requested interconnection service level" and that such an addition cannot be automatically considered a material modification.[128] The Commission's inclusion of a 60-day timeline for the transmission provider to perform an evaluation is critically important for continuing to reduce delays in interconnection queue processing.

Additionally, if an interconnecting generator indicates that co-located storage is to be operated in a manner that does not impact the transmission service (i.e., the storage is charged solely off of the co-located resource prior to any connection on the transmission system), then no additional interconnection study should be required. However, if other operational modes (i.e. charging off of the transmission grid for peak load shaving or other reasons) do indicate that they might impact the transmission system, the TP should study them to the extent that the storage device's charging and discharging load profiles might impact the load profile on the grid at that time. The TP and interconnecting generator must work closely to clearly identify the temporal and physical charging characteristics to be agreed upon. Further specification by the Commission regarding complex load are likely unnecessary since those attributes will be tied to the unique

[127] *Id.* at 183.
[128] *Id.* at 184.

properties of the grid at that location and assessed during the aforementioned process to ensure that charging load and operational profiles do not adversely impact the system.

iii. Realistic Operating Assumptions Must Be Adopted for All Generating Technologies Consistent with Regards to Physical, Operational, and Market Realities

As the Commission discusses in the NOPR, the current operating assumptions in the *pro forma* LGIP include only "general requirements" developed prior to the advent of new types of generation technologies, such as renewable generation and electric storage technologies, as well as hybrid resources.[129] PIOs are concerned that this lack of guidance has led to transmission providers using potentially inaccurate and unrealistic operating assumptions, both for electric storage and hybrid technologies, and also for wind, solar, and other renewable resources..[130] PIOs agree with the Commission that these inaccurate operating assumptions can result in "excessive and unnecessary network upgrades," "rates, terms, and conditions that are unjust and unreasonable," and "unduly discriminatory or preferential barrier[s]"[131] for not only electric storage and hybrid resources, as the Commission finds, but for all new renewable resources.

PIOs support the reforms proposed by the Commission in the NOPR to revise the *pro forma* LGIP and require transmission providers to use operating assumptions for electric storage or co-located resources with electric storage (including hybrid resources) that "reflect the proposed operation" of said resource and are provided by the interconnection customer as part of the initial interconnection request.[132] We further recommend that if a transmission provider finds

[129] *Id.* at 190-191.

[130] For instance, as FERC mentions in the NOPR at ¶ 191, "some transmission providers may assume that resources will operate in a manner in which they are physically incapable of operating, such as assuming that solar resources will produce electricity after the sun sets, for example, or that wind will produce maximum output in a less windy season."

[131] *Id.* at 201.

[132] *Id.* at 201.

an interconnecting customer's proposed operating assumptions to be in conflict with "good utility practice," the transmission provider should be required to provide the interconnecting customer with a clear explanation of why the submitted operating assumptions are insufficient or inappropriate, and allow the interconnecting customer to revise and re-submit the proposed operating assumptions as necessary, within a reasonable time period. This would allow the transmission provider and interconnecting customer to engage in an interactive dialogue to develop a set of operating assumptions that both satisfy the customer's operational desires and align with "good utility practice."

The Commission seeks comment on whether operating assumption reforms should be expanded to include "additional generating facility technologies that may currently be inaccurately modeled, such as variable energy resources."[133] PIOs urge the Commission to include reforms to operating assumptions for all generation technologies, especially new renewable generators. At minimum, FERC should require that all operating assumptions for the purpose of interconnection studies, whether submitted by the interconnecting customer or not, reflect physical realities. This would include ensuring that interconnection studies do not assume that solar resources will generate electricity at night, or that wind will generate at peak output during low-wind seasons. Further, PIOs encourage FERC to consider a requirement that would ensure operational and market realities are appropriately reflected in operating assumptions for the purposes of interconnection studies. This could include both operational practices and procedures as well as market-based price signals for curtailment and congestion management. Furthermore, fossil generating units should not be expected to generate at or near peak output

[133] *Id.* at 206.

during times when market prices are depressed, such as during periods of high renewable generation.[134]

If interconnection studies do not adequately consider the full suite of economic options to manage grid congestion through operations and markets, they may identify unnecessary grid upgrade costs that ultimately lead to unjust and unreasonable rates. PIOs recommend that all interconnection customers for any generation technology be allowed to submit their own operating assumptions for consideration by the transmission provider. We also recommend requiring transmission providers to work with interconnection customers to ensure operating assumptions reflect physical, operational, and market realities, "good utility practice" and applicable reliability standards. By extending the reforms from electric storage and hybrid resources to all generation technologies, the Commission enables the interconnecting customer to inform the transmission provider as to how its resource is realistically expected to perform in a given market context, rather than leaving that determination solely up to the transmission provider, which may open the door to disparate treatment by different transmission providers and ultimately lead to unjust and unreasonable rates or unduly discriminatory or preferential treatment. Consistent with the Commission's proposed reforms for electric storage and hybrid resources, transmission providers should have the ability to suggest modifications to a customer's proposed operating assumptions in line with "good utility practice." As we noted earlier, however, PIOs urge the Commission to allow interconnection customers time to revise and resubmit their operating assumptions if the transmission provider finds them to not be in accordance with "good utility practice." Interconnection customers should also be held accountable to the operating assumptions agreed upon with the transmission provider and be

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[134] Joe Daniel & Sam Gomberg, "Why does Wind Energy Get Wasted?", Union of Concerned Scientists (Nov. 16, 2021), *available at* https://www.ucsusa.org/resources/wind-oversupply-myths

required to install any necessary control technologies, as the Commission notes in its proposed reforms for electric storage and hybrid resources.

iv. Allow Accelerated ERIS Interconnection Service

As the Commission discusses throughout the NOPR, customers in increasingly backlogged interconnection queues are experiencing escalating delays,[135] which is preventing mostly renewable and storage resources from providing important benefits to the grid in the form of lower electricity prices, reliability services, and emissions reductions. One key contributor to these delays is the practice of studying, as part of the interconnection process, extensive and often "deep" or "downstream" network upgrades needed to connect large amounts of new generation to the grid. The size and cost of these types of network upgrades are generally substantially larger for customers who apply for Network Resource Interconnection Service (NRIS), since the "Transmission Provider would study the Transmission System at peak load, under a variety of severely stressed conditions, to determine whether, with the Generating Facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load, consistent with the Transmission Provider's reliability criteria and procedures."[136] NRIS is useful for interconnection customers seeking to dispatch their full output during peak load conditions or in other instances of grid stress and is necessary for interconnection customers seeking capacity payments through a capacity market or other resource adequacy mechanism.[137]

In some instances, however, an interconnecting generator may be satisfied with operating more flexibly during peak load times in exchange for a reduction or elimination of required

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[135] NOPR at ¶ 19-20.
[136] FERC Order No. 2003 at 149.
[137] NOPR at ¶ 150-151.

network upgrade costs. In these cases, the customer may apply for Energy Resource Interconnection Service (ERIS), an alternative to NRIS that does not reserve firm transmission capacity for the interconnection customer's resources. Under an ERIS regime, the interconnecting generator would operate on an "as-available basis," allowing the grid operator to curtail its generation as necessary.[138] Because ERIS therefore typically does not require network upgrades that are as substantial as those required for NRIS, it should theoretically take significantly less time for an interconnecting customer to be approved and connected under ERIS than under NRIS.[139]

PIOs recognize the potential that ERIS holds to reduce the delays that interconnecting customers are currently experiencing. There is ample experience from both abroad and from within the United States, where an ERIS-centric interconnection process has produced significantly faster interconnection timelines. The UK's "Connect and Manage" approach has reduced lead times by 5 years compared to its previous "Invest and Connect" approach by emphasizing the value of economic congestion management to address network constraints after interconnection.[140] Similarly, Germany's grid operators apply the NOVA (*Netz-Optimierung vor Verstärkung vor Ausbau*) principle in interconnection processes, which translates to "grid optimization before upgrades before expansion." Finally, ERCOT is also able to achieve faster interconnection timelines compared to other RTOs, partly because it manages network constraints through market-based curtailment and then periodically reassesses the entire transmission network for required system upgrades.

[138] *Id.* at 147.
[139] *Id.* at 148.
[140] Johannes Pfeifenberger, Generation Interconnection and Transmission Planning, ESIG Special Topic Workshop presentation, August 9, 2022.

We strongly urge the Commission to further consider the benefits that offering ERIS and market-based grid optimization and congestion management can provide for accelerating interconnection queues. The Commission could, for instance, require transmission providers to process ERIS requests and/or clusters on an accelerated timeline, given the reduced network upgrade and study needs compared to NRIS requests. Ideally, the interconnecting customer would receive an upfront estimate of typical curtailment levels to be expected under ERIS and would have the option to apply for NRIS at a later date if experienced curtailment levels rise above acceptable levels, without being saddled with overly onerous or duplicative study requirements. The Commission should also explore whether NRIS requests can be connected more quickly on an ERIS basis while NRIS-related network upgrade study and construction work is still pending. Doing so would eliminate an administrative barrier that delays otherwise viable sources of energy from participating in markets.

2. Incorporating Alternative Transmission Technologies

The Commission proposes to modify the pro forma LGIP to require transmission providers to study, upon request of the interconnection customer, whether alternative transmission technologies can be used in place of traditional network upgrades in the interconnection process.[141] The Commission limits its definition of alternative transmission technologies to a handful of technologies: advanced power flow control, transmission switching, dynamic line ratings, static synchronous compensators, and static VAR compensators.[142] The Commission also proposed to require transmission providers to file annual informational reports detailing whether, and if so how, they considered alternative transmission technologies in

[141] NOPR at ¶ 297.
[142] *Id.* at ¶ 298.

interconnection requests in the previous year.[143] PIOs support requirements that bring alternative transmission technologies into the interconnection process. However, the Commission should not limit the definition of alterative transmission technologies in this rulemaking. The Commission should also require transmission providers to identify in their annual reports barriers to using alternative transmission technologies in the interconnection process.

(a) The Commission Should Not Specify a Limited Set of Technologies That Can Be Studied as Alternative Transmission Technologies.

Alternative transmission technologies are no longer speculative technologies with unknown benefits. Many of the technologies listed by the Commission in this rulemaking, as well as technologies not listed, are in use in the United States and abroad and can be useful in solving transmission issues typically limited to traditional network upgrades.[144] Alternative transmission technologies fulfill the needs of some interconnection customers faster and/or at lower cost than traditional network upgrades, resulting in lower costs for interconnection and faster interconnection of low-cost, resilience-boosting generation.[145] A 2021 study by the Brattle Group found that a combination of advanced power flow control, dynamic line rating, and topology optimization can in many cases bring renewable generation online faster and cheaper

[143] *Id.* at ¶ 302.

[144] *See, e.g.*, Prepared Statement of Robert Bradish, Vice President of Transmission Planning and Engineering, American Electric Power, AD19-19 (Nov. 12, 2019); Prepared Statement of Frank Kreikemaum, Senior Vice President of Products and Solutions, Smart Wires Inc., AD19-19 (Nov. 12, 2019); Kiran Kumaraswamy, Jaad Cabbabe and Dr. Holger Wolfschmidt, Redrawing the Network Map: Energy Storage as Virtual Transmission (2020). *Available at* https://info.fluenceenergy.com/hubfs/Collateral/Storage%20as%20Transmission%20White%20Paper.pdf?hsLang=en

[145] *See* Kerinia Cusick, Jon Wellinghoff, and Lorenzo Kristov, Transmission Planning Protocol: Leveraging Technology to Optimize Existing Infrastructure (Aug. 2019).

than traditional network upgrades.[146] Further, many studies, utilities, and the Commission's own proceedings on grid-enhancing technologies recognized that technologies other than those listed by the Commission in this rulemaking can act as alternative transmission technologies.

The Commission proposes to specify which technologies count as alternative transmission technologies for the purposes of this rulemaking in order to "provide more certainty for evaluation purposes, and focus on technologies that serve a transmission function and thus are subject to Commission jurisdiction."[147] The Commission should not limit the kinds of technologies transmission planners consider when evaluating alternative transmission technologies.

Limiting evaluation of alternatives to specific technologies necessarily omits technologies not currently developed or feasible that may become so in future years. By codifying the list of technologies in a rulemaking, the Commission ensures that transmission providers will not be required to use the best technologies available in all instances and risks cementing unjust and unreasonable rates for interconnecting customers that would otherwise benefit from technologies not listed in this rulemaking. It is well within the expertise of interconnecting customers and transmission providers to identify technologies that may be preferable to traditional network upgrades. In fact, the list in the NOPR omits storage as transmission, a technology the Commission has identified as jurisdictional and that is already being used to meet transmission needs in the United States and abroad.[148] As several

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[146] Brattle Group, Unlocking the Queue with Grid Enhancing Technologies (Feb, 1, 2021). *Available at* https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf

[147] NOPR at ¶ 298.

[148] *See* Notice Inviting Post-Workshop Comments re Grid-Enhancing Technologies, AD19-19 (Jan. 17, 2020) (listing storage as transmission as a grid-enhancing technology identified by participants in a Commission technical conference and seeking comment on what other technologies should count as

commentors in the Commission's docket on grid-enhancing technologies agreed, a technology-neutral definition of these technologies is preferable given the changing landscape of alternative transmission technologies.[149]

It is reasonable for the Commission to provide a list of exemplary technologies that fit the definition of alternative transmission technologies and that are clearly within the Commission's jurisdiction. The Commission then need simply state that interconnecting customers must limit their request for additional studies to technologies that are within the Commission's jurisdiction and that meet a general definition of alternative transmission technologies. While transmission providers should not be expected to evaluate every speculative technology, the Commission should not prevent interconnecting customers from requesting study of technologies that meet the definition of alternative transmission technologies and are clearly within or likely would be found to be within the Commission's jurisdiction.

(b) The Commission Should Require Transmission Providers to Include an Assessment of Barriers to Alternative Transmission Technologies in Their Annual Reports

As the Commission notes in this rulemaking, while many alternative transmission technologies have a demonstrated ability to provide benefits over traditional network upgrades, they are not yet widely adopted in the United States.[150] Many of these technologies have demonstrated their use for years and are widely implemented in other nations. Requiring transmission providers to state clearly why alternative transmission technologies are not used in

grid-enhancing technologies). *See also*, Sharon Thomas, Storage as Transmission Gaining Traction in Many RTOs/ISOs (Dec. 15, 2020). *Available at* https://energystorage.org/storage-as-a-transmission-alternative-is-gaining-traction-in-many-rtos-isos/

[149] *See* Post-Technical Comments by American Wind Association, Grid Policy Inc., International Transmission Company, Public Interest Organizations, Smart Wires Inc., The WATT Coalition (Feb. 14, 2020).

[150] NOPR at ¶ 294.

the interconnection process would be both helpful not only to interconnecting customers seeking study of these technologies, but also to the transmission providers themselves as a way of keep track of limitations of and barriers to these technologies on their systems and also to the Commission for better understanding what if any steps should be taken going forward to incentivize their use.

V. Conclusion

PIO's appreciate the opportunity to provide these comments on the Commission's timely and important NOPR and ask that the Commission consider the recommendations made herein in this rulemaking.

Respectfully submitted this 13th day of October, 2022

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing document has been served on this day or the next upon each person designated on the official service list compiled by the Secretary for this proceeding.

Dated at Chicago, Illinois this 13th day of October 2022.

/s/ Justin Vickers
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