UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection	**Docket No. RM21-17-000**

COMMENTS OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION

Pursuant to the June 17, 2021 Advanced Notice of Proposed Rulemaking ("ANOPR")[1] the Solar Energy Industries Association ("SEIA") submits these comments on the Commission's potential reforms to improve the electric regional transmission planning and cost allocation and generator interconnection processes.

To say the U.S. is on the precipice of a major change in the electric industry would miss the fact that these changes are already underway. Since 2000, the role of renewable resources in the U.S. markets has increased dramatically, from 9%, the majority of which was hydropower, to nearly 20% of all utility scale generation today.[2] Regional transmission organizations were established. They now engage in extensive planning processes to ensure the delivery of reliable energy to a majority of Americans. Energy consumers have become more sophisticated, demanding clean energy from the markets in order to meet their clean energy goals.[3] States

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[1] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 (2021) (ANOPR).

[2] U.S. Energy Information Administration, Electricity Data Browser, Table 1.2 Net generation by energy source, electric utilities, https://www.eia.gov/electricity/data/browser/ (accessed Oct. 5, 2021).

[3] *See* Amazon, Renewable Energy, https://sustainability.aboutamazon.com/ (establishing a goal of 100% renewable energy by 2025); Walmart, Setting Records, Walmart Continues Moving Toward Becoming a Totally Renewable Business, https://corporate.walmart.com/ (establishing a goal of 100% renewable energy by 2035); Apple, Apple powers ahead in new renewable energy solutions with over 110 suppliers, https://www.apple.com/newsroom/2021/03/apple-powers-ahead-in-new-renewable-energy-solutions-with-over-110-suppliers/ (establishing a goal of a carbon neutral supply chain by 2030); *see also* Rich Glick, Matthew Christiansen, FERC and Climate Change, 40 Energy L.J. 1, 8 (2019).

across the country are establishing renewable energy standards to address pressing climate change issues. The Commission itself went from an "obscure" government agency to one that has the power to make one of the largest positive impacts in the fight against climate change.

The generation mix and the energy goals in this country have changed and will continue to change. But the transmission system has not kept pace. Public policy and corporate goals will be an important driver of the generation mix, and the transmission needs of that mix. However, when it comes to transmission planning today, public policy and corporate goals are not the primary focus. Further, the principle guiding how the costs of those transmission needs would be allocated is not inclusive of the benefits that public policy and corporate goals seek. And often, the result is that independent power producers end up paying for transmission upgrades to meet the needs of increasing demand for clean energy. The reactive nature of our current approach to transmission planning no longer serves the public interest. It needs to look forward, not just to planned projects, but to what projects should be planned given a variety of known or foreseeable factors. Solutions should recognize the volume of generation and climate action that is needed in the coming years to meet the ambitious mandates set by state legislatures and corporate goals. Issues such as the timing and cost allocation for new generation interconnection and transmission planning lie squarely within the Commission's exclusive jurisdiction under the Federal Power Act (FPA). As such, the Commission has ample authority to foster a more efficient regulatory framework for the energy industry to meet the challenges of a rapidly evolving landscape.

I. COMMENTS

A. Regional Transmission Planning and Cost Allocation Processes – Planning for the Transmission Needs of Anticipated Future Generation

1. Limitation of the current transmission planning process

There are significant problems posed by the limitations of existing transmission planning processes. These limitations include:

- Reliability Studies – The present approach to conducting reliability studies is to ensure the ability to serve firm load. These studies are performed with a 10- to 15-year horizon.[4] The present approach, which limits reliability studies to relatively near-term impacts of congestion, fails to accommodate the effect of implementation of state renewable portfolio standards (RPS) over a much longer time horizon;
- Economic Need – The present planning approach targets only immediate congestion relief, but fails to accommodate long-term measures needed to allow for lower-cost power to come online;[5]
- Public Policy – There is only a limited requirement to consider local and regional public policy requirements, as long as those matters are within the Commission's authority under the FPA;[6] and finally,
- Local transmission (distribution) – Consideration is limited to a reliability analysis involving queued generation and projected loads.[7]

These hallmarks of the current planning process illustrate the limited and reactive approach that typifies traditional transmission planning.

However, an influx of new, clean generation resources is populating interconnection queues and coming online to address growing demand for clean energy. Additional clean energy

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[4] NERC Reliability Standard TPL-001-4.

[5] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119, P 523, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[6] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, P 111 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, P 207, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[7] Order No. 1000, 136 FERC ¶ 61,051 at P 262.

projects are needed to meet state and federal clean energy requirements. These resources have significantly different characteristics and transmission demands than most existing generation. While the transmission system was originally planned to accommodate the operational characteristics of mostly thermal generation resources, clean energy sources have markedly different operational characteristics and pose different transmission demands. In addition, clean energy sources such as battery storage facilities can address reliability issues quite differently than traditional thermal generation sources. The potential reliability benefits that battery storage systems can offer include providing instantaneous peaking capacity, minimizing the need for new generation and transmission infrastructure, and providing essential reliability services (e.g., frequency response, ramping and voltage support).[8]

The present approach to transmission planning is too limited. It fails to consider the geographic and other unique characteristics of clean generation, fails to appropriately accommodate the public policies that are promoting the pivot to clean generation, and fails to give adequate consideration of the positive regional and local reliability benefits associated with clean energy resources as well as the positive impact that distributed generation can have on local transmission. While Order No. 2222 presented a significant step forward by requiring regional grid operators to revise their tariffs to establish Distributed Energy Resource (DER) aggregators as a type of market participant (which would allow them to register their resources under one or more participation models that accommodate the physical and operational characteristics of those resources), the transmission planning process has thus far failed to evolve to reflect the physical and operational characteristics of such resources.

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[8] *See* NERC Whitepaper Energy Storage: Impacts of Electrochemical Utility-Scale Battery Energy Storage Systems on the Bulk Power System (February 2021); *see also* Hybrid Resource Coalition, Comments on Hybrid Resource Reports, at 21, Docket No. AD20-9 (Sept 20, 2021).

2. The transmission planning process must be expanded

SEIA recommends that the Commission issue a rule that requires transmission providers to consider the following factors in the transmission planning process. These factors will recognize and accommodate the growing role of clean energy resources and the public policy priorities that are spurring the growth of these clean energy resources. These factors include:

- Federal, state, and local climate and clean energy laws and regulations (including laws and regulations regarding the electrification of buildings and transportation), which will require significant transmission expansion to accommodate demand for new solar and other remotely sited renewable generation;

- Distributed energy resources, including the ability of those resources to reduce or defer the need to build additional large-scale transmission;

- The ability for existing and queued stand-alone solar or wind projects to convert to a hybrid resource;[9]

- Grid enhancing technologies that reduce the need to build additional transmission, consistent with FPA section 219(b)(3) ("… deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities"); and

- Anticipated resource retirements and foreseeable replacement generation, including evaluation of whether a resource will be replaced by a single generator or by multiple, smaller generators.

The Commission can accommodate these additional factors for transmission planning criteria within its obligation to ensure just and reasonable rates and within the requirements of FPA 206 to avoid any rules that are unjust, unreasonable, unduly discriminatory or preferential. Moreover, including such additional factors in transmission planning requirements will help the Commission to fulfill its obligation to maintain the reliability of the bulk transmission system. States, which have authority over generation, have not been reticent to exercise their FPA

[9] A transmission provider can assess the ability to convert standalone resources to hybrid resources by evaluating the resource with the resource owner.

sanctioned authority over the generation resource mix to adopt renewable portfolio standards consistent with the public policy objectives of constituents increasingly alarmed by the foreseeable ravages of climate change wrought by traditional thermal generation. The Commission should revise the transmission planning process to accommodate such state interests. A planning process that recognizes and accommodates state generation goals will result in efficient transmission buildouts. The factors that the Commission includes for consideration in the transmission planning process will also serve as inputs into the supply and demand curves that set the rates for pricing in the wholesale markets. To some extent, transmission already is planned for generation not in the queue. However, the process needs to be expanded to take into consideration expected generation associated with state and local climate goals.

3. Additional reforms are necessary before expanding the transmission planning process

The Commission must take several steps before issuing a final rulemaking to require transmission providers to include the above factors in the transmission planning process. The following preliminary steps will ensure that those factors will have a meaningful impact on transmission planning.

First, in order for DERs to participate in wholesale markets effectively, the Commission should clarify the interconnection process for DERs with regards to state versus federal jurisdiction of distribution facilities. Generally, DERs that want to participate in the wholesale market follow the state interconnection process unless the distribution facility to which they are attempting to interconnect is already subject to the Commission's jurisdiction.[10] A distribution facility becomes Commission-jurisdictional when a resource on the facility starts participating in the wholesale market.[11] However, it is the distribution utility that makes the facility jurisdiction determination. SEIA members often find that distribution utilities do not keep adequate track of the status of their facilities and cannot accurately articulate the facility status to interconnection customers. As a result, it is not clear whether the Commission or the state has jurisdiction over the facility and which interconnection process a customer should pursue. The ability of DERs to participate in the wholesale markets is hindered because the distributed resource may have the wrong interconnection agreement in place. In Order No. 2222, the Commission permitted DERs in aggregations to use the state interconnection process.[12] Given the difficulties DERs face in accessing the wholesale markets, the impact that jurisdictional uncertainty has on the operation of the wholesale markets, and the important role all DERs will serve in the grid of the future,[13] the Commission should issue a rulemaking that directs transmission providers to allow DERs to use the state interconnection process (if the DER chooses to do so), while clearly identifying the role, responsibility, and requirements of the transmission owner in determining the transmission impact of the DER interconnection request.

Second, certain interconnection rules must be modified to facilitate the integration of hybrid resources into the grid. Hybrid resources can provide relief to constrained points on the transmission system, both physically and temporally. Hybrid resources enhance and optimize the

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[10] Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 2222, 172 FERC ¶ 61,247, PP 95-96 (2020), *order on reh'g*, Order No. 2222-A, 174 FERC ¶ 61,197 (2021).

[11] Order No. 2222, 172 FERC ¶ 61,247, P 97.

[12] Order No. 2222, 172 FERC ¶ 61,247, P 294.

[13] Order No. 2222, 172 FERC ¶ 61,247, P 4.

delivery of clean, renewable energy that is vital to achieving clean energy goals, reducing congestion and curtailment, and optimizing the volume and quality of energy and reliability services from clean resources. In intervals when wind or solar resources have substantial covariance, hybrids can help to assure availability, reduce congestion costs, and reduce curtailment.[14] The fastest way to add hybrid resources to the grid is to modify existing stand-alone generation or planned generation in the queue. However, the process for doing so is often confusing and overly restrictive. SEIA recommends that the Commission issue a rulemaking in the Hybrids proceeding, currently underway in Docket No. AD20-9, to address the interconnection issues that hybrids face. Doing so will enable these resources to be incorporated into the transmission planning process.[15]

Finally, as part of a reformed transmission planning approach, the Commission, as the expert agency on transmission, should file programmatic comments on National Environmental Policy Act (NEPA) reviews of transmission construction. SEIA urges the Commission, concurrent with any NOPR in this proceeding, to issue a policy statement on how the Commission will participate in transmission-related NEPA reviews. This is an issue especially important in the Western United States, where transmission often crosses federal land. In addition, concurrent with any NOPR in this proceeding, the Commission should encourage the use of existing utility and transportation rights-of-ways to site transmission.[16]

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[14] For a full discussion of the role that hybrids will play in the grid off the future, *see* Hybrid Resource Coalition, Comments on Hybrid Resource Reports, at 3-4, Docket No. AD20-9 (Sept 20, 2021).

[15] *See* Hybrid Resource Coalition, Comments on Hybrid Resource Reports, at 2, Docket No. AD20-9 (Sept 20, 2021) ("By initiating a rulemaking to remove barriers to the participation of hybrid resources in the RTO/ISO markets, as well as in non-RTO/ISO regions, the Commission would enhance competition and, in turn, help to ensure that electricity markets produce just and reasonable rates.").

[16] For innovative ideas regarding use of existing transportation right-of-way, see the work being performed by The Ray. including solar renewable energy generation in the state-owned and maintained right-of-way.

B. Cost Allocation for Transmission Facilities Planned through the Regional Transmission Planning Process

The existing approach to cost allocation in regional transmission planning processes fails to consider the full suite of benefits of the transmission facilities necessary to transition to the grid of the future. SEIA recommends that the "benefits" included in "beneficiary pays" include carbon reduction and integrating new renewable generation in a regional resource mix as well as grid resiliency benefits.[17] Efforts to decarbonize the energy grid will require cost-effective regional and interregional transmission projects. Regulatory reforms are needed to allow transmission providers to accommodate the interconnection of additional generation with greater dispatch and to more equitably allocate the financial burdens of expanding the transmission grid to meet anticipated demands. Greater consideration of societal benefits, such as access to generation that will reduce emissions or offer interregional reliability benefits, is essential because failing to consider broader societal benefits will not lead to efficient transmission development. The Commission, therefore, should require transmission providers, and ISO/RTOs in particular, to monetize the broader societal effects in transmission planning and cost allocation.

The Commission has broad authority to address cost allocation pursuant to sections 206 and 309 of the FPA. Pursuant to section 206, the Commission has the obligation to ensure just and reasonable rates and to avoid any rules that are unjust, unreasonable, unduly discriminatory or preferential. Section 309 of the FPA further states, in relevant part, "[t]he Commission shall have power to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions

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[17] ANOPR, 176 FERC ¶ 61,024, P 70.

of this chapter."[18] The Commission has the authority to revisit the existing approach to cost allocation in regional transmission planning processes and to reallocate the suite of benefits—and the associated beneficiaries—produced by transmission facilities developed to meet the transmission needs of the changing resource mix.

Expanding the definition of "benefits" would also help protect competitive entry into the markets. The barriers to competitive entry are more complex and more systemic than the mere discriminatory treatment of the past. The Commission has held that interconnection is a critical component of open access transmission service.[19] And it further held that interconnection plays a crucial role in bringing much-needed generation into the market to meet the growing needs of electricity customers. Relatively unencumbered entry into the market is necessary for competitive markets.[20] The purpose of Order No. 2003 was to remove the often complex and time-consuming disputes about interconnection feasibility, cost, and cost responsibility. The Commission reasoned that such delay undermined the ability of generators to compete in the market.[21] Order No. 2003 was essential for its time to remedy undue discrimination in the provision of interconnection related transmission service. Under Order No. 1000, the Commission promoted interregional planning and cost allocation, but it did not require it. Now, more is needed. Only the Commission is positioned to unblock the interconnection bottleneck

[18] 16 U.S.C. § 825h (2020).

[19] *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, P 9 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 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).

[20] Order No. 2003, 104 FERC ¶ 61,103, P 11.

[21] Order No. 2003, 104 FERC ¶ 61,103, P 11.

and interregional transmission expansion that serves as a barrier to cost-effectively decarbonizing the U.S. electric grid.

The Commission can undertake these reforms based on its existing authority under the FPA. Under section 201 of the FPA, the Commission has jurisdiction over "the transmission of electric energy in interstate commerce . . . [and] all facilities for such transmission."[22] Under section 205 of the FPA, the Commission can approve "just and reasonable," and not "unduly discriminatory or preferential" rates for the transmission of electric energy in interstate commerce, proposed by the relevant transmitting utility and under section 206 it can prospectively modify such rates.[23] In addition, the pro-active identification of anticipated transmission expansion is consistent with the Commission's authority to establish voluntary regional districts for the efficient transmission of electricity.[24]

C. Participant Funding and Crediting Policy for Funding Interconnection-Related Network Upgrades

1. History of Participant Funding and the Transmission Crediting Mechanism

In Order No. 2003, the Commission identified two methods for initially funding Network Upgrades identified in the generation interconnection process. Under the participant funding option, the interconnection customer provides funds to the transmission owner to cover all network upgrade costs until the upgrades are completed and operational. The transmission owner then must either repay the interconnection customer over time by providing transmission credits

[22] 16 U.S.C. § 824(b)(1).

[23] 16 U.S.C. § 824d(e).

[24] 16 U.S.C. § 824a(a).

against the cost of transmission service or provide cash reimbursement if the interconnection customer did not take transmission service.[25] After application of credits or cash reimbursement, the transmission owner could then include the network upgrade amount in its transmission rate base and earn a rate of return.[26] The transmission crediting policy, which was a key feature of this funding mechanism, recognized that though the interconnection customer caused the Network Upgrades, once constructed, it is the entire transmission system that benefits from those upgrades.[27]

Order No. 2003 alternatively allowed for the interconnection customer and transmission provider to mutually agree that the transmission provider could fund the Network Upgrades itself, "with no advance payment by the Interconnection Customer, and thus no need for subsequent credits."[28] This allowed the transmission owner to initially fund Network Upgrade costs and roll these costs into its transmission rate base, developing a corresponding charge consistent with the "higher of" policy[29] that would be assessed to the interconnection customer.[30]

The Commission granted independent entities, such as RTOs and ISOs, permission to propose customized interconnection procedures and interconnection agreement provisions that fit the needs of their region instead of adhering strictly to the *pro forma* procedures and agreements prescribed in Order No. 2003 (referred to as "independent entity variations" under Order No.

[25] Order No. 2003, 104 FERC ¶ 61,103, PP 28, 721.

[26] Order No. 2003-A, 106 FERC ¶ 61,220, P 581.

[27] Order No. 2003-A, 106 FERC ¶ 61,220, P 584.

[28] Order No. 2003, 104 FERC ¶ 61,103, P 720.

[29] A transmission provider has the option of charging the higher of the incremental cost rate for Network Upgrades required to interconnect a generating facility or an embedded cost rate for the entire transmission system (including the cost of the Network Upgrades). Order No. 2003-A,106 FERC ¶ 61,220, P 580.

[30] Order No. 2003-A, 106 FERC ¶ 61,220, PP 581, 657, and 694.

2003).[31] Under PJM's variation, interconnection customers would not receive monetary reimbursement for the upgrades but would instead be eligible to obtain tradable transmission rights.[32] The Commission granted a similar variation to the NYISO[33] and MISO.[34]

Following Order No. 2003, many things about the transmission system have changed. Utilities have largely divested their transmission assets from their generation assets.[35] Generation resources have shifted from coal, to gas, and now to renewable resources.[36] Transmission patterns have shifted. With new resources, it is possible to site generation much closer to load than it had been.[37] When the Commission first instituted participant funding, it served the transmission at that time. With the changes in the system, the financing must change as well.

2. The Participant Funding Model is no longer just and reasonable

The participant funding model, as it exists today, no longer serves the needs of the transmission system. The significant changes to the resource mix and transmission patterns will require clear, forward-looking transmission plans. To some extent, a better transmission planning system may mitigate the concerns raised by participant funding, as better planning for large-scale

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[31] Order No. 2003, 104 FERC ¶ 61,103, P 827 ("With respect to an RTO or ISO, at the time its compliance filing is made, as discussed above, we will allow it to seek 'independent entity variations' from the Final Rule pricing and non-pricing provisions.").

[32] *PJM Interconnection, L.L.C.*, 108 FERC ¶ 61,025 (2004).

[33] *New York Indep. Sys. Operator, Inc.*, 108 FERC ¶ 61,159 (2004).

[34] *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,060 (2009).

[35] Bushnell, J. B, & Wolfram, C. (2005), Ownership Change, Incentives and Plant Efficiency: The Divestiture of U.S. Electric Generation Plants. *UC Berkeley: Center for the Study of Energy Markets*. Retrieved from https://escholarship.org/uc/item/8dv5c0t1.

[36] U.S. Energy Information Administration, Electricity Data Browser, Table 1.2 Net generation by energy source, electric utilities, https://www.eia.gov/electricity/data/browser/ (accessed Oct. 5, 2021).

[37] PJM Interconnection, L.L.C., Interconnection Policy Workshop – Session 3, Data Analysis (July 22, 2021), https://www.pjm.com/-/media/committees-groups/committees/pc/2021/20210827-workshop-4/20210827-item-04-data-analysis-presentation.ashx.

transmission will alleviate the need for large-scale, ad hoc network upgrades. But, as it stands now, in the transmission system of today, participant funding creates perverse incentives.

Network upgrades associated with interconnection requests only address the incremental changes of a single interconnection request, or cluster of requests, on the transmission system. Interconnection-related network upgrade facilities are, by definition, the network upgrades that "would not be in [the transmission provider's] transmission expansion plan but for the interconnecting Generating Facility."[38] With potentially increasing load due to electrification and new generation resources coming online, these incremental additions to the transmission system will not be cost effective for interconnection customers or consumers. This will result in unjust and unreasonable rates.

The cost of interconnection related network upgrades has grown significantly over the last few years.[39] Several projects have resulted in *billion* dollar network upgrade costs.[40] Often network upgrade costs significantly increase the overall cost to the projects, and at times, make the project uneconomic. With significant cost increases, projects drop out of the interconnection queues, leading to further restudies and queue delays.[41]

As the Commission noted in Order No. 2003, though the interconnection customer caused the network upgrades, once constructed, *it is the entire transmission system that benefits*

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[38] Order No. 2003, 104 FERC ¶ 61,103, P 677.

[39] Jay Caspary, Michael Goggin, Rob Gramlich, Jesse Schneider, Disconnected: The Need For A New Generator Interconnection Policy (January 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf.

[40] Vish Sankaran, Himali Parmar, Ken Collison, Just & Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits, at 1-2 (2021), https://acore.org/wp-content/uploads/2021/09/Just-Reasonable-Transmission-Upgrades-Charged-to-Interconnecting-Generators-Are-Delivering-System-Wide-Benefits.pdf.

[41] Jay Caspary, Michael Goggin, Rob Gramlich, Jesse Schneider, Disconnected: The Need For A New Generator Interconnection Policy (January 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf.

from those upgrades.[42] That was the Commission's justification for allowing participant upfront funding *with* the crediting mechanism.[43] Without the crediting mechanism, the interconnection customer becomes solely responsible for paying for the network upgrade costs, while the entire transmission system benefits. This violates the Commission's longstanding "beneficiary pays" principle and, accordingly, is no longer just and reasonable.

3. Transmission Owners should fund the cost of network upgrades

The Commission has the authority to remedy the unjust and unreasonable rates resulting from participant funding without proceeding with a rulemaking on this matter. Participant funding was created by the independent entity variations the Commission granted from the original requirements of Order No. 2003.[44] While they may have worked then, those variations are no longer just and reasonable. Interconnection customers cannot wait until the Commission initiates a rulemaking, and accepts compliance filings, for the just and reasonable replacement rate. The Commission should, as an interim measure, initiate an investigation as to whether the RTOs/ISOs that received variations from Order No. 2003's crediting mechanism should remain entitled to those variations. If interconnection customers provide the upfront funding for network upgrades that benefit the entire transmission system, then those customers should be compensated for providing that funding through transmission credits.

In the long-term though, the transmission crediting mechanism may not work for the grid of the future. As part of the rulemaking in this proceeding, the Commission should do away with the participant funding and crediting mechanism entirely, instead requiring transmission

[42] Order No. 2003, 104 FERC ¶ 61,103, P 584.

[43] Order No. 2003, 104 FERC ¶ 61,103, P 584.

[44] Order No. 2003, 104 FERC ¶ 61,103, P 584.

providers to establish a fee, separate from any interconnection deposit, based on project size, to be charged for submitting an interconnection request.[45] For projects that require network upgrades, the fee would be applied towards the cost of the network upgrades. The remaining cost of the network upgrade would be allocated to the load zone served by the project.

Participant funding was intended to address certain concerns, including the efficient siting of resources.[46] Over time, consumer advocates viewed participant funding as a way to protect retail ratepayers from the cost of network upgrades. With the change in resource mix, and the lack of significant upgrades to the transmission system, those concerns are not as prevalent as they once were. The efficient siting of renewable resources not only includes access to transmission, but also siting in areas that would provide optimal access to solar and wind inputs. The increased network upgrade costs are often reflected in the project's market bid, which is ultimately paid by the end use customer. The participant funding model, as it stands today, is incongruent with the resources now entering into the interconnection queues. In addition to doing away with participant funding for Commission-jurisdictional facilities, SEIA urges the Commission, once such reforms are enacted, to ensure that interconnection subject to state-jurisdictional interconnection processes, under the Public Utility Regulatory Policies Act, would be subject to the same standard, and would not bear the full burden of any network upgrades required for interconnection.

Addressing participant funding will mitigate some of the need for interconnection queue reforms, as much of the delays in the process stem from delays resulting from the cost allocation of network upgrades. The Commission seeks comment on proposals that would address

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[45] *See* ANOPR, 176 FERC ¶ 61,024, P 135.

[46] Order No. 2003, 104 FERC ¶ 61,103, P 695.

"speculative requests" as a way to address the interconnection queue backlog,[47] but the best way to address that backlog is through better transmission planning. Alleviating the need to build ad hoc network upgrades in the first place will reduce queue withdrawal and the subsequent retools and restudies. If the Commission were to address interconnection reform without addressing the underlying transmission issue, it may have the unintended effect of further hindering project development. Many factors dictate the success of a development that have nothing to do with interconnection costs and timelines including: local and state level permitting, regulatory requirements, supply agreements/supply chain issues, and tax policy. It is not clear that a definition of "speculative projects" could be developed in such a way that balances those competing interests. Further, deigning projects as "speculative" assumes that some resource developers are acting in bad faith when entering the interconnection queue. At a time when the country demands more new renewable generation, the Commission must ensure that its policies promote unencumbered market entry.

D. Enhanced Transmission Oversight – Independent Transmission Monitor

With new transmission needed to meet the needs of a changing resource mix, there is a need to ensure that the planning processes for the development of new transmission facilities, and the costs of the facilities, do not impose excessive costs on consumers.[48] There are

[47] ANOPR, 176 FERC ¶ 61,024, P 153.

[48] *See* ANOPR, 176 FERC ¶ 61,024, P 160 ("Nevertheless, particularly in light of potential costs of new transmission infrastructure that may be needed to meet the needs of the changing resource mix, we seek comment on whether additional measures may be necessary to ensure that the planning processes for the development of new transmission facilities, and the costs of the facilities, do not impose excessive costs on consumers.").

mechanisms that ensure efficient transmission planning—RTOs and ISOs.[49] But those mechanisms do not exist in all parts of the country.

There are no independent regional transmission planners in the Southeast or the West. Transmission is planned by transmission utilities with a financial interest in the facilities. Often transmission is planned in silos, as those utilities generally do not coordinate with other utilities on a holistic regional transmission plan. When there is coordination, because it is done outside of an RTO, the coordinating organization does not require the same characteristics or minimum functions that would improve efficiencies in transmission grid management and improve grid reliability.[50] A coordinating organization is not independent, but comprised of utilities, giving little opportunity for states, independent power producers, or other potential stakeholders a meaningful opportunity to participate in the planning process. Transmission planning in non-RTO regions locks out the generation developers that will be providing power to the grid of the future from the very process that builds that grid. Yet there are times that these generation developers must shoulder the costs of that new grid. By taking the incremental step toward independent review of transmission plans, by establishing an independent transmission monitor, the Commission will ensure just and reasonable rates in non-RTO regions.

An independent transmission monitor that reviews and evaluates plans to ensure that the projects are the most efficient or cost-effective transmission solutions, and who has the authority

[49] *PacifiCorp*, 170 FERC ¶ 61,298 (2020) (approving the creation of NorthernGrid, consisting of PacifiCorp, NorthWestern Corporation, Avista Corporation, Puget Sound Energy, Inc., Idaho Power Co., MATL, LLP, and Portland General Electric Co.); *see also* Southeastern Regional Transmission Planning, http://www.southeasternrtp.com/ (showing that SRTP is sponsored by TVA, Dalton Utilities, American Electric Coop. Inc., Duke Energy, LG&E/ KU, MEAG Power, PowerSouth Energy Coop., Southern Company, and Georgia Transmission).

[50] *See Regional Transmission Organizations*, Order No. 2000, 89 FERC P 61,285, p. 12,111 (2000), *order on reh'g*, Order No. 2000-A, 90 FERC ¶ 61,201 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

to make referrals to the Commission when those plans are not,[51] could ensure that projects benefit the whole region, and not just a single utility. One approach would be to require regional planning entities to have independent boards and staff. Another option to consider is merging the sub-regional planning entities with existing or newly independently managed institutions. The primary benefit of merging functions under one independent entity would be to reduce the number of places and processes which regulators and stakeholders must engage with.

But review and referral are not enough. *All* stakeholders need a voice in the transmission planning process. And the way to ensure that these voices are heard is through an RTO framework that provides an adequate opportunity for stakeholder participation. RTOs are financially independent from their market participants.[52] The RTO decision-making process is independent of control by any market participant.[53] RTOs maintain tariffs that promote efficient use and expansion of transmission and generation facilities.[54] And these are just a few of the reasons why RTOs save consumers money.[55]

An independent transmission monitor would ensure that transmission is planned efficiently and would provide transparency to interested stakeholders, but it does not ensure just and reasonable rates like an RTO does. There has been some progress towards the creation of

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[51] *See* ANOPR, 176 FERC ¶ 61,024, P 164.

[52] Order No. 2000, 89 FERC P 61,285, p. 12,111.

[53] Order No. 2000, 89 FERC P 61,285, p. 12,111.

[54] Order No. 2000, 89 FERC P 61,285, p. 12,113.

[55] *See* Christopher TM Clack, et al., Maximizing Cost Savings and Emission Reductions: Power Market Operations for the Southeast United States, at 4, https://acore.org/wp-content/uploads/2021/09/Maximizing-Cost-Savings-and-Emission-Reductions_Power-Market-Options-for-the-Southeast-United-States.pdf; Metin Celebi, et al., Western Energy Imbalance Service and SPP Western RTO Participation Benefits, at 18, https://www.brattle.com/wp-content/uploads/2021/05/20622_western_energy_imbalance_service_and_spp_western_rto_participation_benefits.pdf.

RTOs in non-RTO regions,[56] but that progress does not ensure the transparency needed for efficient transmission development like the establishment of a formal organization or independent transmission monitor would. However, while SEIA recognizes that progress and hopes that it leads to an RTO, SEIA requests that the Commission give time for non-RTO regions to establish formal markets. In the meantime, the Commission should begin to move towards an independent transmission monitor. If, by January 2024, there has been no demonstrable progress towards the creation of an RTO in those regions, SEIA recommends that the Commission then establish an independent transmission monitor.

[56] *See* 2021 Colo. Sess. Laws 2110 (setting forth the out deadlines and conditions under which an electric utility that owns and controls transmission facilities (transmission utility) is required to join an Organized Wholesale Market); *and* 2021 Nev. Stat. SB 448 (requiring the Public Utilities Commission of Nevada to require every transmission provider in this State to join a regional transmission organization on or before January 1, 2030); *see also* Several Western Power Providers Announce Plans to Explore Market Options (Oct. 5, 2021), https://www.businesswire.com/news/home/20211005005324/en/Several-Western-Power-Providers-Announce-Plans-to-Explore-Market-Options (announcing that several utilities in the west are "exploring the potential for a staged approach to new market services, including day-ahead energy sales, transmission system expansion, and other power supply and grid solutions consistent with existing state regulations").

II. CONCLUSIONS

SEIA respectfully request that the Commission accept its comments and recommendations regarding the Commission's potential reforms to improve the electric regional transmission planning and cost allocation and generator interconnection processes.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned certifies that a copy of this pleading has been served this day upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC this 12th day of October 2021.

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