UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Joint Federal-State Task Force on Electric Transmission	)	**Docket No. AD21-15-000**
Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection	)	**Docket No. RM21-17-000**

Joint Supplemental Comments of the American Clean Power Association, Advanced Energy Economy, the Solar Energy Industries Association, and the American Council on Renewable Energy on Generation Interconnection Queue Processing and Cost Allocation Reforms

The American Clean Power Association,[1] Advanced Energy Economy,[2] the Solar Energy Industries Association,[3] and the American Council on Renewable Energy[4] (jointly, "Clean Energy Coalition") appreciate the opportunity to provide comments in response to the Joint Federal-State Task Force on Electric Transmission's ("Task Force") May 6, 2022 meeting.[5] On

[1] ACP is a national trade association representing a broad range of entities with a common interest in encouraging the expansion and facilitation of wind, solar, energy storage, and electric transmission in the United States. The views and opinions expressed in this document do not necessarily reflect the official position of each individual member of ACP.

[2] AEE is a national association of businesses that are making the energy we use secure, clean, and affordable. AEE is the only industry association in the United States that represents the full range of advanced energy technologies and services, both grid-scale and distributed. Advanced energy includes energy efficiency, demand response, energy storage, wind, solar, hydro, nuclear, electric vehicles, and more.

[3] SEIA is the national trade association of the solar energy industry. As the voice of the industry, SEIA works to support solar as it becomes a mainstream and significant energy source by expanding markets, reducing costs, increasing reliability, removing market barriers, and providing education on the benefits of solar energy.

[4] ACORE is a national nonprofit organization that unites finance, policy and technology to accelerate the transition to a renewable energy economy, supported by members that include developers, manufacturers, top financial institutions, major corporate renewable energy buyers, grid technology providers, utilities, professional service firms, academic institutions and allied nonprofit groups.

[5] *See generally* https://elibrary.ferc.gov/eLibrary/filelist?accession_num=20220511-3106.

February 14, 2022 in Docket No. RM21-17, and on April 15, 2022 in Docket No. AD21-15, members of the Clean Energy Coalition submitted joint comments recommending changes that the Federal Energy Regulatory Commission ("FERC" or "Commission") could implement through a rulemaking that would enhance the interconnection process.[6] While those comments emphasized the importance of addressing the rapidly growing interconnection queues, they did not address reforms to the cost allocation of Network Upgrades in detail. The Clean Energy Coalition submits these comments in part to identify three specific Network Upgrade cost allocation methodologies for consideration, each of which would substantially improve upon the status quo.

I. Executive Summary

A. Current Interconnection Processes are Inefficient and Deeply Flawed

The current process for interconnecting new generators to the nation's transmission grid and funding required Network Upgrades in most Regional Transmission Organizations is deeply flawed. Many high-voltage transmission facilities are designated as Network Upgrades and are developed outside of the regional transmission planning process, shifting the burden of identifying, planning for, and funding of these broadly beneficial upgrades onto the interconnection process, and the costs onto Interconnection Customers.[7] The problems in the interconnection queue started years ago, when RTOs/ISOs and other Transmission Providers failed "to identify the coming demand for these remote fuel-savings, renewable-based resources

[6] Comments of the Clean Energy Coalition, at 6-9, Docket No. RM21-17 (Feb. 14, 2022) ("Clean Energy Coalition Comments").

[7] Transcript 17:3-6 (Thomas); Transcript 19:1-16 (Phillips); LBNL study.*** All references to the Transcript in this document refer to the Commission's transcript of the May 6, 2022 Federal State Joint Transmission Task Force, available in Docket No. AD21-15.

over that time period and to create the capacity for their interconnection as they were coming along."[8]

"The "Participant Funding" framework used to pay for Network Upgrades through the generation interconnection process used incentivizes most RTOs/ISOs and Transmission Providers to avoid engaging in long-term planning. This framework, which typically requires Interconnection Customers to pay, without reimbursement, for all (or nearly all) of the costs of transmission system upgrades identified in generation interconnection studies—many of which are high-voltage and long-distance—has led to a costly, piecemeal expansion of regional transmission grids, and misallocation of the costs of the expansion to only a subset of beneficiaries. In particular, the current "Participant Funding" framework:

1. Stunts the clean energy transition sought by federal and state policymakers, corporations (including utilities and energy consumers), and a majority of Americans;

2. Increases risk due to Network Upgrade cost uncertainty, which significantly increases the cost of capital for generation development;

3. Needlessly increases electricity costs for consumers demanding clean energy by delaying the construction of new clean generation, which will provide lower-cost power than existing electricity production;

4. Allocates all (or almost all) costs to a single group of beneficiaries, even for high-voltage upgrades that produce benefits for all transmission system users, and in many cases address pre-existing problems; and

5. Yields an inefficient and excessively costly transmission grid due to incremental upgrades without reference to system-wide costs, a process which fails to identify more cost-effective solutions through proactive regional planning.

The lack of transparent, uniform interconnection study standards also results in significant uncertainty and differences in the determination of whether and to what extent

[8] Transcript 20:21-21:1 (French).

Network Upgrades are required, as well as the times at which upgrades are identified in different regions—even for otherwise identical projects.

B. FERC Should Seize the Opportunity to Develop and Implement Substantial Interconnection Reforms

The Commission should act now to fix the current queue process, study standards, and Network Upgrade cost allocation problems plaguing the interconnection process. Such action is urgently needed because the success of and potential benefits from transmission planning reforms currently under consideration may take years to realize.[9] Moreover, transmission planning reforms will not be impactful if:

1. The interconnection process preempts the identification of more cost-effective transmission network solutions through proactive regional planning;

2. The interconnection study process in most regions remains lengthy, administratively inefficient, and overly burdensome, particularly amid significant and growing customer demand; and

3. Network Upgrade costs continue to be unpredictable and disproportionately allocated to Interconnection Customers, maintaining the same, persistent barriers to new entry.

To achieve a sustainable, just and reasonable interconnection process, immediate attention and meaningful improvements are needed in several critical areas:

1. Rebalancing the funding of required Network Upgrades commensurate with benefits through an appropriate and legally durable cost allocation methodology.

2. Requiring adoption of study processes that appropriately identify required Network Upgrades and ensure costs are just and reasonable, including the following:

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[9] *See generally Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (2022).

a. Provide Interconnection Customers with transparent, reasonable, comparable, and verifiable interconnection study assumptions,[10] particularly for Network Upgrade contingency assumptions, and identification of solutions that are comparable to those used by transmission providers to address operational challenges on their systems (*e.g.*, grid enhancing technologies and other operational strategies);

b. Provide Interconnection Customers with consistent, reliable study completion timelines and Network Upgrade cost estimates, including where Affected Systems are identified;

c. Automate model-building, processing, and other study methodologies across Transmission Owners to the maximum extent possible; and

d. Establish a clear and objective readiness framework, and tighter RTO/Transmission Provider performance requirements for Affected System studies.

3. Integration of generation interconnection processes into proactive transmission planning processes that can identify more cost-effective solutions to simultaneously meet known and projected public policy, economic, and reliability needs.

Some of these reforms have already been approved by FERC as just and reasonable in certain parts of the country. Implementing these proposals in other regions would be consistent with existing Commission policy. We recognize that there are several interconnection reform proceedings underway across the country. The reforms proposed in these comments can be pursued without disrupting the stakeholder processes underway, and could enhance reforms currently being considered.

[10] Consistent with FERC's stated goal of facilitating more efficient utilization of the existing transmission injection capacity, we support limiting the interconnection study to a local injection study focused on the direct impact the queued generation has on the local transmission system. This is enabled by having transmission providers redispatch system wide generation to identify the most cost-effective Network Upgrades required to accommodate the requested interconnection injection rights and meet other system-wide needs. This proposed streamlined local interconnection study approach is also consistent with how RTO/ISOs will redispatch their respective markets and will avoid triggering unnecessary and costly Network Upgrades, thereby helping to lower overall costs to ratepayers.

II. Rebalancing Participant Funding Policies

A new framework for the Participant Funding model in RTOs/ISOs is critical to ensuring that Network Upgrade funding is commensurate with benefits and consistent with current cost allocation principles and legal requirements.[11]

The Participant Funding model is no longer just and reasonable. The current allocation methodology for Network Upgrades does not assign their costs in a manner that is cost effective and aligned with the benefits to interconnecting generators and the transmission system. A September 2021 report by ICF Resources found that, while the entire power system typically benefits from significant transmission upgrades, new wind and solar projects are being required to foot nearly the entire bill of these upgrades as they connect to the grid. In an analysis of interconnection-related Network Upgrades in the Midcontinent Independent System Operator, Inc. ("MISO")" and Southwest Power Pool, Inc. ("SPP") regions, the study found significant system-wide benefits in two-thirds of the Network Upgrades evaluated, which other users of the shared system receive at little to no cost.[12] As a further example, Emmons Logan Wind, LLC ("Emmons-Logan"), a NextEra Energy Resources project that interconnects in North Dakota, has been required under MISO Participant Funding rules to pay approximately $55 million for Network Upgrades on the transmission systems of several MISO Transmission Owners. As a result of the upgrades funded by Emmons-Logan, there has been a significant reduction in curtailments in the area, primarily benefitting local load. Indeed, adding these upgrades into

[11] The Participant Funding reform proposals described in these comments are recommended as potential replacement funding mechanisms for the existing Participant Funding processes that currently exist in the various RTO/ISOs other than CAISO.

[12] ICF 2021, *Just & Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits,* prepared for the American Council on Renewable Energy, https://acore.org/wp-content/uploads/2021/10/Just_and_Reasonable.pdf.

MISO's Transmission Expansion Plan 2021 Future 1 Model shows $93.4 million in annual energy cost savings in 2025, increasing to $188.9 million in energy cost savings by 2030.

This failure to align benefits is inconsistent with the Seventh Circuit Court of Appeals' holding in *Illinois Commerce Commission v. FERC*,[13] where the Court found that the allocation of transmission facilities' costs must be "roughly commensurate" with the benefits received.[14] Consistent with this requirement, courts have rejected cost allocation approaches that assigned 100 percent of costs to customers receiving only a fraction of the benefits.[15] Indeed, the D.C. Circuit has admonished that the Commission "may not single out a party for the full cost of a project, or even most it, when the benefits of the project are diffuse."[16] More recently, in *Long Island Power Authority v. FERC*, the Court of Appeals for the District of Columbia Circuit upheld a transmission cost allocation method that appropriately recognized that high voltage transmission projects provide both local and regional benefits, and accordingly allocated costs to both local and regional beneficiaries.[17] Allocating 100% (or 90%, in the case of certain high-voltage upgrades in MISO) of costs to a single customer does not comport with applicable cost allocation precedent, as decided by the appellate courts.

Regarding Network Upgrades, FERC recognized in Order No. 2003-A that these facilities, once constructed, benefit the *entire* transmission system;[18] however, in RTOs/ISOs with Participant Funding, *only* the Interconnection Customer bears the cost of Network Upgrades identified in interconnection studies. While Interconnection Customers surely benefit from

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[13] *See* Transcript 107:13-19 (Phillips).
[14] *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009).
[15] *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1261 (D.C. Cir. 2018)(rejecting as "grossly disproportionate" the assignment of 100% of transmission costs to parties receiving only 43 and 47% of benefits, respectively).
[16] *BNP Paribas Energy Trading GP v. FERC*, 743 F.3d 264, 268 (D.C. Cir. 2014).
[17] *Long Island Power Auth. v. FERC*, 27 F.4th 705, 713–14 (D.C. Cir. 2022) ("[T]he materials we have cited make clear that regional and local benefits are both substantial, thus requiring a significant weight for each component of the formula.").
[18] Order No. 2003-A, 106 FERC ¶ 61,220 at P 584 (2004).

expanded transmission, the current Participant Funding approach presumes that they are the *sole* beneficiaries and that no reliability, resilience, locational marginal pricing reduction, or other benefits exist for other customers—a proposition that is demonstrably untrue.[19]

The most economically precise way to allocate the cost of Network Upgrades would be based on an individual analysis of the costs and benefits of Network Upgrades location and interconnecting associated with each generator interconnection. However, this would require an administratively burdensome process of conducting a benefit-cost analysis for each interconnection request, which would significantly increase costs and risk further delays. A project-specific approach is also *not* required by applicable precedent, which expressly allows for the use of evidence-based presumptions.[20] Any such benefit-cost analysis would also be dependent on specific study assumptions and projected market conditions, and thus be subject to variations over time and disagreements over study assumptions. In lieu of a serial benefit-cost analysis, various evidence-based metrics common to the interconnection process can be used to estimate the presumptive threshold between costs and benefits that should be attributed to projects and those that have larger system-wide implications. Multiple proposals of such "evidence-based modeling" have been submitted to FERC as part of the Advanced Notice of

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[19] *See generally* https://acore.org/wp-content/uploads/2021/10/Just_and_Reasonable.pdf.

[20] *See Illinois Commerce Commission v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009)("We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars… If it cannot quantify the benefits to the midwestern utilities from new 500 kV lines in the East, even though it does so for 345 kV lines, but it has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in PJM's region, then fine; the Commission can approve PJM's proposed pricing scheme on that basis. For that matter it can presume that new transmission lines benefit the entire network by reducing the likelihood or severity of outages.")(internal citations omitted); *Long Island Power Auth. v. FERC*, 27 F.4th 705, 715 (D.C. Cir. 2022) ("[W]hile FERC may create different rules for different kinds of projects… "a regulator need not always carve out exceptions for arguably distinct subcategories of projects"… Nor must a regulator always consider cost-allocation rules on a project-by-project basis, which would unravel the framework of *ex ante* tariffs established by Order No. 1000 and approved by this Court…. Instead, FERC must ensure only that there is "some resemblance" between costs and benefits.")(internal citations omitted).

Proposed Rulemaking ("ANOPR") proceeding and include the following threshold-based mechanisms:

1. Using a Transfer Distribution Factor ("TDF") to determine the impact of the interconnecting generator on the Network Upgrade in question.[21]

2. Using the voltage of the facilities being upgraded to inform the determination of costs and benefits.

3. Using the CAISO "Participant Financing" Model whereby a cap on generator reimbursement informs and incentivizes efficient siting decisions.

The cost of generator interconnection upgrades should be allocated in a fair, straightforward, administratively simple, and legally durable way that recognizes that these upgrades often benefit *both* generation and load.[22] Each of these mechanisms, which are discussed in greater detail below, involve the sharing of costs among generators and load. If the RTOs/ISOs that currently utilize Participant Funding were required to instead adopt *ex ante* cost allocation methodologies like those discussed herein, generators seeking interconnection to the grid would finally achieve the predictable, financeable results needed to advance projects, while load would pay their share of the cost commensurate with the production cost savings, reliability, resiliency, and other benefits they realize from system upgrades. Critically, RTOs/ISOs and their constituent Transmission Owners that currently rely on the interconnection study process and Participant Funding by generators to upgrade the transmission system in a purely reactive

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[21] TDF measures the percentage of the electricity produced by a generator that travels on a given transmission facility. As an example, if a 100 MW generator adds 25 MW of loading to a transmission line, it would have a 25% TDF on that line. Transmission Providers commonly use the TDF metric in interconnection processes today but use low TDF thresholds and/or thresholds based on group impacts. This creates a large degree of interdependency between projects and greater uncertainty in the interconnection process.

[22] *See e.g. Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 at P187, Table 1 (2022)(listing 13 quantifiable transmission benefits).

manner would be incentivized to proactively plan and construct transmission facilities in the most cost-effective and efficient manner for all stakeholders.

The following section outlines how each mechanism can be used to ensure costs are allocated based on the impact of the needed upgrades and in a manner that is both roughly commensurate with benefits and legally durable under applicable legal standards.

A. TDF Approach

The following proposal determines the generator's cost responsibility for Network Upgrades beyond the interconnection substation using the flow-based TDF metric, which is already commonly used by transmission providers when performing interconnection studies. TDF analysis allows for a more accurate assessment of the extent to which a generator is using a particular transmission system element as compared to other system users, and allocates costs accordingly. This ultimately protects consumers and ensures efficient outcomes. Moreover, it is relatively simple to implement, with the categories of upgrades allocated as follows:

1. Interconnection Substation Network Upgrades ("ISNUs"):

    a. 100% participant funded by the Interconnection Customer, without reimbursement, as these Network Upgrades allow the generator to connect to the grid in a specific location and, typically, do not increase or reinforce transfer capability.

2. Downstream Network Upgrades ("DNUs"):

    a. Interconnection Customer-driven upgrades

i. If the TDF[23] > 20%[24], then costs would be split 75% Interconnection Customer (without reimbursement) / 25% load[25] to account for the local benefits these upgrades provide to the Interconnection Customer, while recognizing the partial system benefits to load.

b. System-wide upgrades

i. If the impact indicates a TDF > 5% but < 20%, or an identified % megawatt ("MW") impact based on the rating of an overloaded element, then costs would be split 75% load[26] / 25% Interconnection Customer to account for the benefits these upgrades provide to load, due to a wider system need.

ii. If DNUs are identified for facilities that were over or within 3% of the operational threshold prior to the Interconnection Customer's injection, or the TDF ≤ 5%,[27] then the Network Upgrade would not be deemed needed as a result of the interconnection request due to the fact that the Interconnection Customer is making at most a *de minimis* contribution to what is likely an existing system issue. Furthermore, load benefits from addressing these upgrades in a more cost-efficient way via the regional planning process.

[23] The proposed TDF thresholds here assume energy-only service. The TDF threshold should be adjusted to reflect varying levels of interconnection/transmission service *(i.e.,* NRIS) and voltage levels of the lines being upgraded.

[24] Both SPP and MISO already use a 20% TDF threshold to identify upgrades that must be constructed before a generator can safely interconnect to the grid and begin producing power. Interconnection CustomerIn these regions, upgrades with a TDF greater than 20% must be built before an Interconnection Customer can reach commercial operation. See, e.g., MISO Business Practice Manual, p. 34 available at https://www.mnpower.com/Content/Documents/CustomerService/miso-interconnection-process-12-2014.pdf. In *Southwest Power Pool, Inc.*, 171 FERC ¶ 61,219 (2020), FERC approved SPP's use of a 20% TDF threshold as part of SPP's FERC Order No. 845 compliance process based on the following justification: "SPP states that its proposed 20[%] distribution factor for ERIS is based in part on the general power transfer concept that larger distribution factors are effective at identifying constraints driven primarily by generator injections, while lower distribution factors are more effective at identifying load-driven constraints." Having accepted a 20% TDF already for identifying Network Upgrades that are driven primarily by generator injections rather than load-driven constraints, FERC could readily extend this logic to Network Upgrade cost allocation.

[25] Interconnection Customers would provide up-front funding for 100% of the cost of DNUs but would receive reimbursement for the portion that is cost-allocated to load under FERC's *pro forma* crediting policy within a period of 20 years after the generator achieves commercial operation. As a result, Customers would not bear any risk from incomplete facilities and the financing costs to generators over a 20-year period would provide incentives for efficient site selection.

[26] *See id.*

[27] 5% is the threshold utilized by MISO when performing interconnection studies. This should be the minimum threshold permitted, but regions should have flexibility to adopt higher thresholds on a case-by-case basis.

To illustrate, in this example, the interconnection study process identifies Network Upgrades with a total cost of $45 million for a 300 MW solar project using an existing RTO's current TDF screening criteria. The following table compares the cost allocation using the current 100% Participant Funding cost allocation methodology used in most RTOs/ISOs with the cost allocation using the TDF approach discussed above:

Network Upgrade	**Cost Allocation under Current Policy**	**Cost Allocation under TDF Approach**	
	IC Cost Responsibility	***Load Cost Responsibility***	***IC Cost Responsibility***
ISNUs	$6 million	$0	$6 million
DNUs (TDF 35-20%)	$22 million	$16.5 million	$5.5 million
DNUs (TDF ≥ 20%)	$17 million	$4.25 million	$ 12.75 million
TOTAL	**$45 million**	**$20.75 million**	**$24.25 million**

B. Voltage-Based Approach

An alternate method to reform Participant Funding would be the use of voltage thresholds to determine cost allocation. This approach parallels the model already implemented in SPP's "highway" or "byway" regional transmission expansion cost allocation process,[28] under which facilities are split into three categories:

- greater than 300 kV;
- greater than 100 kV, but less than 300 kV; and
- less than 100 kV.[29]

[28] SPP Tariff, Attachment J §§ III.A, III.A.3; *see also City Utilities of Springfield, Missouri v. Southwest Power Pool, Inc.*, 170 FERC ¶ 61,024 at n.3 (2020).
[29] As part of this methodology, RTOs/ISOs would need to include studies and other evidence to support the selected voltage thresholds.

The cost allocation would be based on the RTO/ISO demonstrating the appropriate voltage-based beneficiary allocation in their compliance filing. A potential allocation could be:

1. Interconnection Substation Network Upgrades ("ISNUs"):
   100% participant funded by the Interconnection Customer, without reimbursement, as these Network Upgrades allow the generator to connect to the grid in a specific location and, typically, do not increase or reinforce transfer capability.

2. High voltage transmission lines and other downstream Network Upgrades (DNUs) over 300kV would be allocated 75% to load[30] and 25% to Interconnection Customers, as facilities over 300 kV are typically backbone bulk transmission facilities and provide significant regionalized benefits to a broad array of transmission system users, including providing reliability and resiliency.[31]

3. Transmission lines and DNUs 100kV between 100 kV and 300 kV would be allocated 25% to load and 75% to Interconnection Customers, as facilities under 300 kV typically have greater localized benefits, including to the interconnecting generator, than regional benefits for the broader transmission system.[32]

4. Transmission lines and DNUs that are less than 100 kV would be allocated 100% to Interconnection Customers as these are typically for the primarily purpose of interconnecting and integrating the new generation.

Transmission kV level	**Load share**	**Generation share**
> 300	75%	25%
100 << T < 300	25%	75%
< 100	0%	100%

These voltage threshold percentages are recommended because transmission upgrades operating at a higher voltage typically transmit power over longer distances, covering larger load and generation zones, benefitting a larger share of system load. In addition to SPP, other

[30] As with the TDF-based cost sharing proposal described above, Interconnection Customers would provide up-front funding for 100% of the cost of the Network Upgrades under any voltage-based cost sharing mechanism but would receive reimbursement for the portion that is cost-allocated to load under FERC's *pro forma* crediting policy within a period of 20 years after the generator achieves commercial operation. *See* note 25, *supra*.
[31] *See Sw. Power Pool, Inc.,* 131 FERC ¶ 61,252 at PP 73-75 (2010) (approving SPP's highway-byway cost allocation).
[32] *Id*.

interconnection and transmission planning processes use voltage thresholds to determine benefits and allocate upgrade costs. MISO uses a voltage threshold in recognition of the fact that higher voltage backbone upgrades are very likely to be used by and benefit load[33] and in its regional planning process.[34] PJM uses voltage thresholds in its regional planning process. CAISO requires that facilities must operate at 200 kV or above to be eligible for regional cost allocation.[35] Further, the Commission itself recently proposed setting a voltage threshold of at least 200 kV and/or estimated cost of at least $30 million for consideration of interconnection-related upgrades through the regional planning process.[36]

C. The CAISO Model: "Participant Financing," Subject to a Cap on Generator Reimbursement

Comments submitted in response to the ANOPR also discussed the Network Upgrade funding mechanism currently used in the CAISO region, which seems to be working well for most stakeholders.[37] Unlike the other RTOs/ISOs, CAISO's FERC-approved independent entity variation from the crediting policy does not require generators to pay all or most of the cost of

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[33] MISO Tariff, Attachment FF Section III.A.2.d.1.

[34] MISO Tariff, Attachment FF, Section II.B (Market Efficiency Projects generally must involve facilities with voltages of 230 kV or higher); *id.* Section II.C.3(e) (Multi-Value projects "must include, but not necessarily be limited to, the construction or improvement of transmission facilities operating at voltages above 100 kV"); *see also* "MISO Regional and Interregional Cost Allocation Reference Document," (Aug. 12, 2020), available at: https://cdn.misoenergy.org/MISO%20Regional%20and%20Interregional%20Cost%20Allocation%20Reference90295.pdf.

[35] "Comments of the California Independent System Operator Corporation on Advance Notice of Proposed Rulemaking," Docket No. RM21-17-000, at 54 (Oct. 12, 2021) ("In the CAISO BAA, only transmission facilities at 200 kV and above are eligible for regional cost allocation. This requirement also applies to LCRIFs. As discussed in Section II.B.1.a., this voltage threshold requirement aligns with the design and operation of the CAISO system and recognizes that high voltage transmission facilities support and provide benefits to all customers on the CAISO grid.").

[36] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028, at P 166 (2022).

[37] *See, e.g.* Comments of the California Independent System Operator Corporation on Advance Notice of Proposed Rulemaking, Docket No. RM21-17-000, at 92 (Oct. 12, 2021). *See also* Reply Comments of SEIA, Docket No. RM21-17-000 at 15 (Nov. 30, 2021); Reply Comments of ACP, Docket No. RM21-17-000 at 3 (Nov. 30, 2021).

interconnection upgrades without reimbursement. Rather, CAISO's funding mechanism, which it terms "participant financing," requires generators to pay 100% of the cost of Network Upgrades up front, subject to reimbursement within a period of five years for generators that achieve commercial operation. Unlike FERC's *pro forma* crediting policy, however, reimbursement is not unlimited but rather subject to a cap on total reimbursement of $72,902 per MW[38] of installed generation capacity. The cap is escalated annually for inflation.

The CAISO funding mechanism provides two dimensions of cost-sharing as between generators and load. First, like the *pro forma* crediting policy, generators are required to fund 100% of the cost of Network Upgrades up front and are only reimbursed over a period of time once the generator achieves commercial generation. This upfront funding requirement impacts near term project returns and cash flows, and, as such, provides a strong incentive for efficient siting decisions by generators, while exposing customers gradually over the reimbursement period to the full rate impact of the upgrade. Second, because reimbursement is capped, CAISO transmission customers are shielded from unlimited cost exposure, and generators assume the financial consequences of inefficient siting decisions. Under the current CAISO cap, load in CAISO can be assured that it will be responsible for no more than $7.29 million of Network Upgrade costs for each 100 MW generator that interconnects to the grid – an amount which would be unlikely to pay for even 10 miles of a new high voltage transmission line.

Like the TDF and voltage-based cost allocation proposals described above, the CAISO methodology may not be a one-size-fits-all solution for every RTO/ISO. One reason the cost cap has worked well in CAISO is because CAISO has done a comparatively good job of identifying system upgrades needed to support new interconnection requests through the regional planning

[38] *See* http://www.caiso.com/Documents/CurrentReliabilityNetworkUpgradeReimbursementLimits.pdf.

process. Network Upgrade costs are typically lower for generators interconnecting in the CAISO region, meaning interconnecting generators are not asked to shoulder a disproportionate share of costs in excess of the cap. RTOs/ISOs that have not planned as well and have higher Network Upgrade costs for interconnecting generators might need to consider a higher reimbursement cap until regional planning brings down the cost of interconnection so that generators are not asked to bear a disproportionate share of costs that is not roughly commensurate with benefits.

RTOs/ISOs might also reasonably differ on the appropriate reimbursement period. While CAISO uses a five-year period, it has a relatively low cap on total reimbursement. Regions with higher upgrade costs and a higher reimbursement cap might reasonably choose to reimburse costs over a longer period of time, such as the 20-year period under FERC's *pro forma* crediting policy, both to incentivize efficient siting decisions and to mitigate through a longer payback period the rate impact to customers of more expensive upgrades.

Any proponent of a "participant financing" mechanism like what is used in CAISO would need to demonstrate that it is just and reasonable and consistent with applicable cost allocation precedent. Incorporation of this reform may therefore entail accompanying improvements in the individual RTO/ISO transmission planning and Network Upgrade cost determinations.

III. Regardless of the cost allocation method, the underlying costs must be derived in a just and reasonable manner.

Under the Federal Power Act, the rates and terms for the transmission and sale of wholesale power—including those related to interconnection—must be just and reasonable.[39] To ensure that interconnection and transmission costs are just and reasonable, in addition to

[39] 16 U.S.C. §§ 824d(a), 824e(a).

establishing appropriate cost allocation processes, FERC must also ensure that the scope and price of Network Upgrades are appropriately determined, before allocating those costs.

The current approach to identifying and estimating interconnection upgrades, their costs, and the associated costs of delivery for generator interconnection, including firm interconnection rights, varies widely across the United States and is a critical risk factor for generators. To address this risk and its associated cost, the Commission should establish uniform, transparent, and reasonable interconnection study assumptions and criteria that allow for reproducible study results. Such a standard should require consideration of alternatives to conventional Network Upgrades that more efficiently resolve thermal violations identified through such studies, including a combination of grid enhancing technologies and market mechanisms that could help decrease required Network Upgrades and their associated cost.

A transparent interconnection process relying on reasonable study assumptions and predictable processes protects consumers. The current approaches to identifying and estimating costs of delivery vary significantly, include assumptions that are unreasonable and unsupported by cost allocation and cost causation principles, are subject little to no stakeholder input, and often rely upon black box modeling and subjective engineering judgment. A standardized study approach would protect Interconnection Customers, and ultimately ratepayers, by reducing the uncertainties and risks to interconnecting generators, thereby allowing for more efficient development and financing.

There are several areas in need of reform within the current study process. First, though Transmission Providers must meet Open Access Transmission Tariff requirements and reliability standards such as FAC-001, FAC-002, and TPL-001 within interconnection study processes, they have great latitude in how they apply study cases, assumptions, and criteria. Two similarly situated Interconnection Customers in two different regions could receive two very different sets of study results, and therefore Network Upgrade costs, if the two regions apply different study cases, assumptions, and criteria to implement the same reliability standards. For example, North American Electric Reliability Corporation ("NERC") TPL-001 contains extreme contingency cases that, when used in interconnection studies, can result in unreasonable upgrade identification and cost assignment because certain study cases trigger upgrades for pre-existing reliability issues or highly improbable contingencies that are not triggered by other cases. Such outcomes patently fail to meet the "but for" test governing cost allocation stipulated by Order 2003.[40] Further, they result in unjust and unreasonably costly upgrades that can render interconnection uneconomic, and that may not actually be required for compliance with NERC reliability standards.[41]

Second, Transmission Providers do not always reflect operational strategies (such as generation redispatch opportunities) in their interconnection study assumptions. While RTOs/ISOs use market-based congestion management and resource adequacy constructs to facilitate their real-time operations, these practices and assumptions are not typically reflected in generator interconnection studies. Standard operational practices to manage congestion and resource adequacy constructs to capture limited deliverability impacts should also be considered

[40] *See* Order No. 2003 at P 695.

[41] The NERC TPL contingency P3 simulates loss of a generator, redispatches the system without that generator, then reverts to N-1 outage conditions. P3-related overloads identified are either pre-existing or can be otherwise mitigated. Because the condition for this contingency type was pre-existing to the interconnecting generator, it is unreasonable to assign the cost of mitigating the condition via a Network Upgrade to that project when the allowable redispatch period within the NERC reliability standards would otherwise mitigate the condition. Additionally, P6 contingencies simulate N-1 of a transmission element, redispatches the system without that element, then simulates the next N-1 contingency. Similar to P3 contingencies, any overloads identified due to a P6 are either pre-existing or can be mitigated by turning off the new project as part of the allowable redispatch period. In practice, P3 and P6 contingencies are not always simulated with the inclusion of the redispatch period resulting in modeling of a NERC Extreme contingency type, and upgrades beyond what is required to mitigate.

in generation interconnection studies.[42] The failure to consider, study, and incorporate standard system operational practices results in over-identification of upgrades and inflated upgrade costs, which ultimately flow into rates that are unjust and unreasonable.

Third, across RTOs/ISOs and non-RTO/ISO regions alike, solutions to resolve any identified violation of thermal overload or other constraints are, in most cases, limited to conventional upgrades. GETs such as power flow control devices or dynamic line ratings, generally are not allowed to be considered as solutions to identified criteria violations. In addition, the selection of proposed solutions and associated cost calculations are opaque, and ultimate results are unverifiable. The interconnecting generator has no recourse to review whether a less expensive grid alternative could solve the identified overload. The failure to consider and incorporate reasonable, well-proven, and available alternatives (such as GETs) results in cost allocations that are unjust and unreasonable.

A uniform and transparent set of minimum interconnection study requirements is necessary to ensure the upgrades identified and the total upgrade cost are reasonable *before* any costs are allocated. The Clean Energy Coalition urges FERC to presumptively require transmission providers to adopt transparent, standardized interconnection study assumptions and processes to ensure that the results of such studies are reproducible and verifiable. Such a standard will help ensure just and reasonable total interconnection costs, while also decreasing overall study costs and timelines. It will also allow generators to study interconnection points and select the most attractive grid locations, which will reduce costs and the time required for generation interconnection processes.

[42] Redispatch between N-1 events is an allowable system adjustment to manage congestion and mitigate adverse system impacts.

Standardization and transparency will also help address an issue that has beleaguered the interconnection process for years: Affected System Network Upgrades. When an interconnection request impacts an Affected System, the Affected System applies its own study assumptions to determine what Network Upgrades are necessary, which will often yield upgrades not identified by the host system (even if the Affected System is modeled). There is little transparency or opportunity for Interconnection Customer input into this study process. This process is not subject to a strict timeline, and as a result, expensive Affected System Network Upgrades can be (and, in fact, are) assigned to the Interconnection Customer after it has already signed a host system interconnection agreement. Transparency and consistency in study performance, processes, and assumptions between regions, as well as the enforceable study deadlines described in the next section, is a critical reform that will drive appropriate interconnection costs, reduce overall interconnection delays, and facilitate efficient queue management incorporating host and Affected System study impacts.

IV. All Transmission Providers must be subject to enforceable study deadlines.

Achieving just and reasonable rates cannot be achieved through reformed study and cost allocation criteria alone. Providing interconnecting generators with consistent, reliable timelines for the completion of Network Upgrades or other identified solutions is critical to management of project financing costs, deployment of new energy resources, and attainment of state policy goals; this includes accurate Network Upgrade cost estimates, including where Affected Systems are identified.

The *pro forma* Large Generator Interconnection Agreement requires Transmission Providers to use "reasonable efforts" to meet the study deadlines.[43] But many Transmission Providers are overloaded and cannot meet these deadlines.[44] Should they fail to meet these deadlines, there is little recourse, because the "reasonable efforts" standard is not a particularly high bar,[45] and rarely enforced.[46] Interconnection Customers are also often prohibited from using third-party consultants to produce the required interconnection studies, further frustrating efforts to keep the interconnection process on track. Without a firm definition of "reasonable efforts," and with Interconnection Customers often having no alternative to produce studies on-schedule, Transmission Providers lack the incentive to devote sufficient resources to, or allow others to devote resources to, interconnection studies.[47]

The Clean Energy Coalition urges FERC to adopt standards for interconnection study timeliness and accuracy with enforceable, non-recoverable financial penalties for underperformance, and to provide Interconnection Customers the option of using third-party consultants to produce required studies if a Transmission Provider cannot do so on-schedule.[48] This will incentivize Transmission Providers to devote sufficient resources and staffing to completing accurate studies on time. Such incentives should account for study result accuracy, which is a concern mitigated (if not resolved) by more transparent and verifiable study assumptions as discussed above. Further, automating modeling building, processing, and other

[43] Transcript 17:21-23 (Clements); LGIA Transcript 17:21-23 (Clements); *pro forma* Large Generator Interconnection Agreement at Art. 1 (''Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.'')
[44] Transcript 17 :23-25 (Clements)
[45] Transcript 62:16-21 (Clements)
[46] *See generally Tenaska Clear Creek v. Southwest Power Pool*, Docket No. EL21-77.
[47] Transcript 63:17-20 (Clements); Transcript 73:12-17 (Glick).
[48] *See* Joint Supplemental Comments of ACP, AEE, and SEIA, Docket No. RM21-17 at 7 (Feb. 14, 2022).

study methodologies across transmission owners to the maximum extent possible will reduce study costs and schedule delays by providing more information to market participants earlier.

V. FERC should apply the "consistent with or superior to" standard to any proposed variations to standardize interconnection processes.

During the Task Force meeting, several commissioners expressed the need to provide for regional flexibility when it comes to interconnection reforms. Regional flexibility is important in addressing certain issues, such as how to cluster interconnection requests and project site control requirements, both issues that depend on geography and local governments. However, interconnection best practices that increase transparency, process efficiency, and resolve information asymmetry are not location dependent. The technologies, and even the personnel, that enable interconnection reforms do not rely on geography. Regional flexibility should not stand in the way of progress.

FERC has generally applied the "independent entity variation" to RTO/ISO-proposed interconnection rules. But as RTOs/ISOs have recognized, some of those variations caused the interconnection queue delays seen today. [49] To reduce the potential that future interconnection-related Commission-directed reforms have the same, unintended consequences, FERC should apply the "consistent with or superior to" standard to any proposed variation from standardized interconnection rules.

[49] MISO, Informational Report, FERC Order 845 Study Delays, Docket No. ER19-1960, at 8 (Nov. 15, 2021); PJM, Informational Report on Interconnection Study Performance Metrics, Docket No. ER19-1958, at 10 (Aug. 16, 2021).

VI. Conclusion

The Clean Energy Coalition appreciates the opportunity to provide these comments for the Task Force's consideration. We look forward to continued engagement with FERC, NARUC, and the State Commissions on these vital issues.

Respectfully submitted,

/s/ Gabe Tabak
Gabe Tabak
Counsel
Gene Grace
General Counsel
American Clean Power Association
1501 M St., N.W., Ste. 900
Washington, D.C. 20005
(202) 383-2500
gtabak@cleanpower.org
ggrace@cleanpower.org

/s/ Melissa Alfano
Sean Gallagher
Vice President of Regulatory Affairs
Ben Norris
Senior Director of Regulatory Affairs
Melissa Alfano
Director of Energy Markets and Counsel
Solar Energy Industries Association
1425 K St NW Ste. 1000
Washington, DC 20005
(202) 566-2873
sgallagher@seia.org
bnorris@seia.org
malfano@seia.org

/s/ Jeff Dennis
Jeff Dennis
Managing Director and General Counsel
Katherine Burnham
Principal
Advanced Energy Economy
1010 Vermont Ave. NW
Washington, D.C. 20005
(202) 380-1950
jdennis@aee.net
kburnham@aee.net

/s/ Elise Caplan
Elise Caplan
Director of Electricity Policy
American Council on Renewable Energy
1150 Connecticut Ave NW, Suite 401
Washington, D.C. 20036
(202) 507-4634
caplan@acore.org

Attachment 1: Benefits of Transmission

Benefit Category	Transmission Benefit
Traditional Production Cost Savings	Production cost savings as currently estimated in most planning processes
1. Additional Production Cost Savings	a. Impact of generation outages and A/S unit designations
	b. Reduced transmission energy losses
	c. Reduced congestion due to transmission outages
	d. Mitigation of extreme events and system contingencies
	e. Mitigation of weather and load uncertainty
	f. Reduced cost due to imperfect foresight of real-time system conditions
	g. Reduced cost of cycling power plants
	h. Reduced amounts and costs of operating reserves and other ancillary services
	i. Mitigation of reliability-must-run (RMR) conditions
	j. More realistic "Day 1" market representation
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects
	b. Reduced loss of load probability or c. reduced planning reserve margin
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses
	b. Deferred generation capacity investments
	d. Access to lower-cost generation resources
4. Market Benefits	a. Increased competition
	b. Increased market liquidity
5. Environmental Benefits	a. Reduced emissions of air pollutants
	b. Improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of meeting public policy goals
7. Employment and Economic Stimulus Benefits	Increased employment and economic activity; Increased tax revenues
8. Other Project-Specific Benefits	Examples: storm hardening, fuel diversity, flexibility, reducing the cost of future transmission needs, wheeling revenues, HVDC operational benefits