UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF CYPRESS CREEK RENEWABLES, LLC

Cypress Creek Renewables, LLC ("Cypress Creek" or "we"), a developer and owner of solar and storage projects throughout the U.S.,[1] appreciates the opportunity to provide these comments to the Federal Energy Regulatory Commission ("FERC" or "the Commission") in response to the Notice of Proposed Rulemaking ("NOPR")[2] issued in the above-captioned proceeding.

I. INTRODUCTION

Cypress Creek agrees with the Commission that the existing standard procedures and agreements for interconnection to the transmission system are not just and reasonable and are unduly discriminatory or preferential. The instant NOPR has preliminarily identified certain useful reforms that may improve interconnection procedures and agreements; however, Cypress Creek respectfully submits that such improvements are of only incremental value, at best, because the NOPR excludes certain necessary reforms in key areas, which we address herein, the absence of which will otherwise undermine the improvements proposed in this proceeding. We address these missing reforms in Section II.A, below (in which we also affirm the importance of concurrent

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1 With more than 2 gigawatts of installed capacity, Cypress Creek has one of the largest operating solar portfolios in the U.S. Through our asset-management and O&M offerings, we provide services to a total of 4 gigawatts of capacity. More information is available at https://ccrenew.com/.

2 *Improvements to Generator Interconnection Procedures and Agreements*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,194 (2022) ("NOPR").

reforms to transmission planning), and we provide NOPR-specific responses in Sections II.B, II.C, II.D, and II.E.

II. COMMENTS

Our comments first focus on those reforms that we respectfully submit the Commission should have included in the NOPR, and for which we believe the notice and comment process will provide a substantial basis for a final rule that includes these reforms. Nonetheless, we specifically urge the Commission to 1) host a technical conference focused on (a) generator interconnection study criteria in jurisdictional *and* non-jurisdictional regions, and (b) the interaction between generator interconnection processes and transmission planning;[3] and then 2) develop revised reforms in any final rule, or, alternatively, include new proposals in a future NOPR, to remedy the wide disparity among these criteria.

In addition, as part of the implementation of the transmission planning reforms described herein, Cypress Creek recommends that the Commission adopt and apply a uniform standard that any requested variations from the revised *pro forma* approach must be "consistent with or superior to" the *pro forma* tariff. This standard should apply to transmission providers both within and outside of Regional Transmission Organizations ("RTOs") or Independent System Operators ("ISOs"). The application of this standard will help to ensure that the revised interconnection planning process developed through this rulemaking will be applied by transmission providers in the manner intended by FERC.

[3] Other entities have engaged in similar efforts, but they lack the Commission's statutory authority. An example is available at https://www.esig.energy/event/joint-generator-interconnection-workshop/, a workshop process hosted by ESIG, NAGF, NERC and EPRI. This subsequent process should also include experience from non-jurisdictional regions.

A. Additional Interconnection Reforms, Beyond Those in the NOPR, are Needed.

Cypress Creek submits that reforms to two foundational aspects of generator interconnection processes and procedures are missing from the NOPR but are necessary in order to ensure that rates are just and reasonable and not unduly discriminatory or preferential. First, interconnection study criteria and approaches must be reformed to ensure that costs derived from interconnection studies are just and reasonable, replicable, inclusive of market-based approaches to manage congestion, and reflective of the full range of interconnection service options. Second, generator interconnection reforms must be integrated into a short-and long-term regional planning process that treats interconnections of new generation and storage resources as part of a proactive assessment of reliability, economic and public policy needs, rather than as disruptions to an illusory steady-state system.

(1) Reforms to Interconnection Studies Are Essential to Interconnection Reform

In Commission Docket No. AD21-15-000, the Clean Energy Coalition stated that the current approach to identifying upgrades and costs for generator interconnection varies widely across the U.S. and is a critical risk factor for generators.[4] We agree.

Generators—regardless of interconnection rights—face continued uncertainty with respect to the types and scope of network upgrades identified in study results. In one extreme example, a group of non-firm, energy-only resource interconnection service ("ERIS") requests triggered the

[4] 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, Docket No. AD21-15-000 at 17 (June 6, 2022) ("AD21-15 Clean Energy Coalition Comments").

need for upgrades up to 1,000 miles away on three different systems,[5] despite the fact that ERIS should, in theory, grant to the system operator greater flexibility to curtail the generator as an energy-only resource (as opposed to treating it as a network resource for which capacity must be built throughout the system to guarantee deliverability). Similar, if less extraordinary, surprises commonly arise in interconnection study processes due to the lack of standardized interconnection study criteria and approaches.

With two narrow exceptions regarding affected system studies[6] and studies of co-located resources,[7] however, the NOPR leaves generator interconnection study criteria unaddressed.[8] We propose reforms to remedy this shortcoming in the following sections.

i. Interconnection Studies Must be Just and Reasonable, Transparent and Replicable

In Cypress Creek's experience, certain transmission providers apply tests in ways that are not facially just and reasonable. For example, the application of North American Electric Reliability Corporation ("NERC") Reliability Standard TPL-001-4 affords transmission providers

[5] Johannes Pfeifenberger, Principal, The Brattle Group, *Transmission Upgrades identified through Interconnection Process vs Transmission Planning Process Pros and Cons* (Aug. 9, 2022), https://www.esig.energy/download/generation-interconnection-and-transmission-planning-johannes-pfeifenberger/?wpdmdl=9241&refresh=62f38b6a0e44a1660128106 ("Brattle Transmission Upgrades"). By definition, ERIS should provide non-firm interconnection rights; however, ERIS power flow models used to identify network upgrades may treat generator power as a static firm injection during extreme conditions and consequently treat ERIS resources similarly to NRIS resources. More dynamic power flow models reflecting conditions throughout the year would more accurately reflect conditions under which curtailment would take place and more clearly distinguish between character of service in assigning network upgrades.

[6] *See* NOPR at P 182, *et seq.*

[7] *See* NOPR at P 208, *et seq.*

[8] In the instant proceeding, we appreciate that the Commission acknowledges the problem with studying deep network upgrades commonly identified through network resource interconnection service studies in affected system studies, which may be hundreds of miles away from the interconnecting generator. It should also apply the same logic to network upgrades that may be identified hundreds of miles away within the host RTO, particularly for ERIS resources.

the ability to exercise engineering judgment, particularly for the P3 and P6 contingency types, that can influence the outcome of interconnection studies and required upgrades, which, in turn can result in unreasonable network upgrade identification and subsequent cost assignment to new interconnection customers, even though the primary contributors to such upgrades are pre-existing reliability issues, or, in some cases, highly improbable contingencies. Furthermore, our experience is that interconnection studies for two similarly situated and geographically proximate generators on the same system, each choosing identical service options, can receive dramatically different network upgrade identifications and cost assignments because of non-standardized and non-transparent application of NERC reliability standards.[9]

Increased transparency in interconnection studies will help to identify when such contingency cases and resulting unjust or unreasonable cost allocations exist, and, we recommend, subsequently allow interconnection customers to provide alternatives or address with transmission providers[10] why such allocations are not just and reasonable. We propose that transmission providers should clearly document study assumptions and criteria in a readily comparable format and make such documentation readily available to interconnection customers. At minimum, interconnection customers must have sufficient transparency to replicate and confirm study results, as well as determine whether the transmission provider made best use of available solutions or to suggest alternatives (each of which should be prerequisites for finding cost allocations just and reasonable).

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[9] AD21-15 Clean Energy Coalition Comments at 18.

[10] Because of the lack of an independent arbiter to assess whether results are based on just and reasonable assumptions, we recommend interconnection study review as within the scope of an Independent Transmission Monitor, as discussed at the Commission's Technical Conference on Transmission Planning and Cost Management on October 6, 2022.

ii. Standardized Economic Market Re-dispatch is a Necessary, but Under-Utilized, Option That Can Reduce Costs and Delay

Transmission providers frequently use market-based generation re-dispatch and resource adequacy constructs to facilitate real-time operations, but such strategies—to the detriment of interconnection customers—are not necessarily reflected in interconnection studies.[11]

To remedy this shortcoming, we suggest that economic re-dispatch should be a standard approach to limiting regional upgrades identified in the interconnection process, particularly for ERIS requests, and as discussed below, transmission providers should rely on near- and long-term regional planning to identify most cost-effective upgrades beyond a specified cost threshold (and therefore not allocate such upgrade costs solely to generators). Because the models used to simulate market-based re-dispatch can incorporate widely varying assumptions, such models should be standardized by market (subject to stakeholder input) and made transparent to the interconnection customer during the interconnection study process. In the case of non-RTO/ISO markets, where historical nodal energy prices are unavailable, it may be necessary to rely on additional historical market condition information to address the potential for curtailment.

In support of this recommendation, we note that Electric Reliability Council of Texas ("ERCOT") assumes that market-based re-dispatch will address deeper network upgrades within its interconnection study scope, consistent with its reliance on market-based mechanisms to manage deeper network constraints in real time operations. Because of this, ERCOT provides interconnection to substantially more generation in less time than other systems, despite its

[11] *Id*. Some RTOs conduct power flow analyses that consider redispatch opportunities (*e.g.*, NYISO via a manual process, PJM via a simplified approach) but many do not check if generation redispatch can address an identified criteria violation. Due to concern about using re-dispatch for capacity resources due to capacity performance constructs and rights, we suggest doing so for ERIS interconnections only initially.

significant request volume, its lower "readiness requirements" than in other markets, and its processing of interconnection requests on a serial basis.[12]

ERCOT Facilitates the Most Generation Interconnection

Region/ISO/RTO	MW Capacity Addition (2021)[13]
ERCOT	8,139
Non-ISO/RTO	5,328
MISO	5,082
PJM	4,629
SPP	2,425
CAISO	1,656
NYISO	359
ISO-NE	341

The visible downside to ERCOT's approach is the potential for increasing levels of congestion and consequent curtailment to the generator after commercial operation.[14] This potential underpins our suggestion in Section II.A.2, below, that if FERC is to realize the aims of its NOPR, FERC must limit the scope of interconnection costs via standardized interconnection study criteria and *concurrently* make reforms to transmission planning to identify congestion and mitigate it through regional transmission investment (an approach that is demonstrably more cost-

[12] Mario Hayden, Senior Manager, Transmission, Enel Green Power North America, *The ERCOT Generation Interconnection Study Process* (Aug 10, 2022) https://www.esig.energy/download/the-ercot-generation-interconnection-study-process-mario-hayden/?wpdmdl=9258&refresh=62f4df6d3bf471660215149. To this end, we note that one of the key purposes of Order No. 2003 was to "expedite the development of new generation." Order No. 2003 at P 11.

[13] "Nearly 28 GW of New U.S. Generating Capacity Added in 2021, Led By Wind," Susan Dlin, *S&P Global Market Intelligence* (Feb 7, 2022) https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/nearly-28-gw-of-new-us-generating-capacity-added-in-2021-led-by-wind-68435915#.

[14] *See Item 8: Independent Market Monitor (IMM) Report*, Carrie Bivens (ERCOT IMM Director), (June 21, 2022) https://www.ercot.com/files/docs/2022/06/13/8%20Independent%20Market%20Monitor_IMM_2021%20State%20of%20the%20Market%20Report%20for%20the%20ERCOT%20Electricity%20Markets.pdf.

effective than the current piecemeal, interconnection-driven approach).[15] The secondary limitation of the comparison to ERCOT is that ERCOT's market treats all generators as energy-only generation (with the exception of resources providing ancillary services via day-ahead markets), a shortcoming we address below, through use of a two-step ERIS-NRIS (network-resource interconnection service) process described below.[16]

In the event that the Commission elects not to take further action (whether through technical conference, a final rule in this proceeding, or a subsequent rulemaking) to address generator interconnection study criteria before, or as part of, issuing a final rule in this proceeding, we respectfully request that the Commission formally address, in the final rule, why it has determined that closer examination of generator interconnection study criteria is not warranted at this time.

iii. Interconnection Customers Need Actual Flexibility Afforded Through Study Options and Operating Parameters

We respectfully submit that the Commission's reform efforts should also address the absence of flexibility for interconnection customers to choose appropriate levels of study and therefore suggest that the following options should be made generally available.

First, we support the approach proposed by Enel Green Power,[17] that transmission providers should allow interconnection customers to seek energy-only injection as a default and

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[15] *See* PJM, MISO examples on slides 9, 10, Pfeifenberger, Generation Interconnection and Transmission Planning, ESIG Special Topic Workshop, August 9, 2022

[16] Moreover, we recognize ERCOT allocates certain localized upgrade costs to load, a topic we recognize the Commission has deferred.

[17] *Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning* (Enel Green Power, Working Paper) https://www.enelgreenpower.com/content/dam/enel-egp/documenti/share/working-paper.pdf.

provide a subsequent process (needed to address capacity-market constructs) by which a generator can add firm rights.[18] This approach is currently available in SPP,[19] and should be replicated more widely.

As part of this approach, energy-only or other non-firm interconnection options should receive meaningfully different treatment in planning processes and potential network-upgrade cost allocations, where currently that difference does not exist, or exists only facially. To that end, the Commission notes that for cluster studies, requirements to study firm- and non-firm interconnection customers together for network-upgrade purposes, without respect to underlying nature of service,[20] an approach that limits the effectiveness of options that already exist, and may result in cost allocations that are not just and reasonable, and that are unduly discriminatory and preferential, for those electing non-firm service.

Finally, Cypress Creek supports the Commission's proposal to allow the interconnection customer to provide operational parameters for co-located generator and battery storage resources, which have greater flexibility to manage operations to avoid triggering thermal and stability violations based on output variation.[21] We suggest that the Commission should consider extending this approach to all generating resources. To this end, technology performance assumptions in power flow models should match actual technology performance, and interconnection customers should have opportunities to submit operating profiles for standalone generators that have the

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[18] *See id.*

[19] *See* Southwest Power Pool - Open Access Transmission Tariff, Sixth Rev. Vol. No. 1, Attachment V, Section 11A (providing for an interim generation interconnection agreement).

[20] *See* NOPR at P 50, n 115, citing to Order No. 2003, 104 FERC 61,103 at PP 153-156.

[21] NOPR at P 280.

technological ability to ramp down when needed[22] (which can similarly limit or eliminate the need for network upgrades).

(2) Effective Transmission Planning Reform is Necessary for Optimization of Interconnection Reform

As we addressed in our reply comments to RM21-17-000,[23] proactive, multi-value long-term regional transmission planning ("LTRTP") is the most cost-effective way to lower interconnection costs and associated complexity and delay.

As a general matter, the interconnection study criteria changes and related approaches recommended in the preceding paragraphs will help to produce just and reasonable studies that are more replicable and that result in a more just and reasonable scope of network upgrades while maintaining reliability. However, even with those approaches, there remains a possibility that interconnection studies will identify deeper network upgrades that could be more appropriately addressed though regional transmission investment. In order to achieve truly just and reasonable outcomes, therefore, transmission planning and interconnection processes must be structured so as to optimize benefits.

i. Interconnection Study Costs Beyond a Determined Threshold Should be Addressed in Near-Term Transmission Planning Processes

In Docket No. RM21-17-000, the Commission addressed the integration of interconnection results with LTRTP. We support the American Clean Power Association's initial comments in that proceeding, which asserted that the Commission's "third time's the charm" approach (in

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[22] Energy and Environmental Economics, Inc., *Investigating the Economic Value of Flexible Solar Power Plant Operation* (October, 2022) https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf.

[23] Reply Comments of Cypress Creek Renewables, LLC, Docket No. RM21-17-000 (Sept. 19, 2022) ("Cypress Creek Reply Comments").

which certain upgrades must have been identified, but not selected or constructed, at least twice in the past five years to be incorporated in the LTRTP) is inherently reactive and therefore contrary to the aims of proactive, multi-value long-term transmission planning.[24]

A proactive approach would instead determine a threshold (based on a criterion like total identified network upgrade ($) or by using the DFAX method), above which generator interconnection costs would be automatically assigned to future near-term transmission planning processes (*i.e.*, transmission-planning processes between long-term planning cycles).[25] Long-term transmission planning efforts may not identify or result in upgrades until 10 or more years from the initial study year; hence near-term planning processes are appropriate to respond to shorter interconnection timeframes. Further, transmission providers could consider pooling cluster study results that reach or exceed this threshold, in order to look for portfolio-based, cost-effective solutions. To protect consumers from unjust cost shifts, generator interconnection costs above the specified threshold should be evaluated within multi-value planning frameworks that can apply to near-term assessments, and allocated to load only if shown to benefit consumers in excess of a specified benefit-cost threshold.

ii. LTRTP Reforms Remain Critical to Addressing Longer Term Regional Needs

In order to address cumulative congestion that can result from ERIS-style localized studies, we submit that the LTRTP improvements we advocated in our comments in Docket No. RM21-

[24] *See* Comments of the American Clean Power Association, Alliance for Clean Energy-New York, Clean Grid Alliance, Mid-Atlantic Renewable Energy Council, and New York Offshore Wind Alliance on Notice of Proposed Rulemaking, Docket No. RM21-17-000 at 14 (Aug. 17, 2022).

[25] We urge the Commission to consider discussing this threshold within the recommended technical conference related to generator interconnection study criteria.

17-000[26]—including collapsing reliability and economic silos, and ensuring LTRTP is sequenced ahead of local reliability upgrades—are necessary complements to interconnection reforms. Without these transmission-planning changes, FERC is unlikely to develop an interconnection process that is just, reasonable, and not unduly discriminatory or preferential.

B. Cypress Creek Generally Supports FERC's Reforms to Implement a First-Ready, First-Served Cluster Study Process, Subject to Modifications

The Commission's proposal to transition from first-come, first-served and serial interconnection to first-ready, first-served and cluster-based interconnection process is a notable improvement because it allocates network upgrade cost based on a fairer (and therefore more just and reasonable) evaluation of the combined impact of the cluster and spreads that cost across multiple projects. This means that costs are less likely to be disproportionately allocated to any single project, thereby reducing the likelihood of withdrawal and the resultant need for restudy of the remaining projects. We respectfully submit, however, that the Commission's proposed reforms do not go far enough.

While the cluster-based study process may help to address some concerns about cost allocation or cost-shifting based on queue position, we note that many markets with long interconnection delays (*e.g.*, MISO) are cluster-based.[27] In contrast, ERCOT (addressed earlier in our comments) uses a serial process, has a two-to-three-year interconnection time horizon, and leads the nation in timely interconnection completion. Consequently, a cluster-based approach alone, without further changes, will not provide adequate reform.

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[26] *See, generally*, Cypress Creek Reply Comments.

[27] *See* Brattle Transmission Upgrades at 4. (Showing that 98% of MISO's interconnection requests have been in the queue for longer than 500 days, while 82% have been in the queue for longer than 1,000 days.)

Moreover, the Commission makes several recommendations related to increasing stringency for queue entry through increased study and readiness deposits and site control requirements. Such measures are framed as necessary to reduce so-called "speculative" projects, despite the fact that entering the queue and receiving study results is necessary for a project to determine its network upgrade costs, the determinant factor in assessing commercial viability. As such we suggest such requirements are helpful to increase the bar by which projects must be ready to enter, but *must* be combined with (i) generator interconnection criteria reforms discussed above; (ii) greater accountability for transmission provider interconnection studies; *and* (iii) flexibility for interconnection customers to commission consultant-led studies that can subsequently be approved by transmission providers. With respect to specific NOPR proposals, however, we provide the following feedback:

(1) Proposed Transparency Measures Require Further Refinement, and Some May Be Counterproductive

In the NOPR, the Commission proposes requirements for informational interconnection study requests and for making additional interconnection-related information publicly available.[28] Here, we believe that greater transparency into hosting capacity is conceptually attractive, but it must result in binding, commercially actionable information. Non-binding information provides no certainty to project owners, either within the interconnection process, or the proposed "informational study," which provides an even weaker guarantee that the results are accurate and binding.

In addition, greater transparency also must not provide a way for transmission providers to avoid providing timely and accurate response to interconnection customer data requests, such as

[28] NOPR at PP 42, 49.

the request for interconnection study criteria discussed above, and it also must not distract the already limited transmission provider staff resources from meeting applicable tariff interconnection milestones, which the instant NOPR seeks to strengthen. As a broad consideration, the particular types of transparency that are valuable should be determined by Commission consultation with market participants, who are best positioned to inform the Commission regarding what information ultimately matters in financing and constructing new projects.[29]

Finally, we suggest that additional benchmarking with respect to interconnection cost is likely to be of little value given that utility systems are very different. Nonetheless, the Commission should track a sufficient scope of interconnection information in order to identify when a particular transmission provider is substantially underperforming.

(2) Greater Cost Transparency and Certainty Is Necessary

Under the current standards, an interconnection customer receives a non-binding cost estimate of interconnection facility and allocated network upgrades required to interconnect its project in its Interconnection Facilities Study report and interconnection agreement.[30] However, if the actual cost incurred by the transmission provider to construct the required upgrades exceeds the estimate, the interconnection customer is required to pay the difference. An interconnection customer therefore may receive an invoice from the transmission provider months or years after

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[29] As an example, interconnection cost data by zone for each Transmission Provider would help to determine the cause of costs in a given location. In MISO, deeper network upgrades assigned to projects in certain zones indicates such costs represent the dominant driver of new interconnection costs. *See* Lawrence Berkeley National Lab, *Generator Interconnection Costs to the Transmission System*, ELECTRICITY MARKETS & POLICY (last visited Oct. 13, 2022) https://emp.lbl.gov/interconnection_costs.

[30] Section 8.3 of the LGIP allows the interconnection customer to choose whether to receive an Interconnection Facilities Report that is either (1) provided by the Transmission Provider within 90 calendar days with no more than a +/- 20% percent cost estimate or (2) provided by the Transmission Provider within 180 calendar days with no more than a +/- 10% percent cost estimate.

signing its interconnection agreement, requiring it to pay hundreds of thousands or even millions of dollars in excess of its cost estimate. This practice results in substantial and unreasonable financial risks for the interconnection customer, which must rely on these cost estimates when making business decisions whether or not to proceed with the project, including posting significant interconnection deposits. This practice also provides little incentive to transmission providers to construct upgrades within the cost estimate provided to the interconnection customer.

While not directly addressed in the NOPR, we recommend that FERC should make needed improvements to interconnection construction cost transparency and certainty within the scope of reforms implemented in this proceeding.[31] To this end, numerous state interconnection processes have applied cost "envelopes" or cost caps applicable to certain categories of interconnection construction costs.[32] Although cost envelopes alone may simply encourage a transmission provider to inflate cost estimates to ensure that actual costs do not exceed the estimate, cost envelopes combined with the measures described below would provide a reasonable means of controlling interconnection construction costs and avoiding material and unanticipated financial risks for interconnection customers.

First, in order to encourage uniformity in cost estimation standards, FERC should specify that cost estimates must be established using industry-standard cost estimation guidance, such as

[31] Cypress Creek's recommendations in this section draw from comments submitted by the North Carolina Clean Energy Business Alliance to the North Carolina Utilities Commission, to which Cypress Creek was an active contributor.

[32] For example, Minnesota, Utah, California, Massachusetts, Oregon, and New York have all implemented a version of a cost envelope. In Massachusetts, utilities must comply with a 25% cost envelope following System Impact Study and a 10% cost envelope after Interconnection Agreement. Costs in excess of the cost envelope are borne by utility shareholders. In Minnesota, the PUC requires public accounting for projects that exceed 20% of estimated costs.

those developed by the Association for the Advancement of Cost Engineering ("AACE").[33] Applicable professional standards for licensed engineers conducting or managing the cost estimates such as the Project Management Institute's ("PMI") Project Management Professional ("PMP") and Professional Engineer ("PE") certifications should also guide cost-estimation practices.[34] Benchmarking standards such as RS Means should be used to estimate or validate different categories of costs within cost estimates.[35] The application of these standards and practices would help increase the accuracy of cost estimates and provide more standardized cost benchmarks, both in the context of an initial estimate and in any dispute regarding the final costs incurred.

Second, FERC should require greater transparency during and following the construction process, including replicable cost estimates and scopes of work provided to the interconnection customer, project progress and cost updates during construction, and transparent documentation of any cost overages following project completion.[36]

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[33] AACE provides industry-standard guidance for cost estimating using a tiered approach that includes Classes 1-5. Class 5 includes the lowest level of project definition and the highest permissible range of expected accuracy. Class 1 includes the highest level of project definition and the lowest permissible range of expected accuracy. *See*, AACE International Recommended Practice No. 18R-97.

[34] PMI generally follows four estimating standards, including Analogous; Parametric; Three-points; and Bottom-up. These standards may be applied in different scenarios based on the necessary accuracy of the estimate, the information available to the cost estimator, and the timeline to develop the estimate.

[35] RS Means is a well-known and widely accepted construction cost database used by contractors, subcontractors, estimators, engineers, and others, for the purposes of arriving at reasonable project cost estimations. Data stored by RS Means includes materials, labor, transportation, and storage, compiled on an annual basis by RS Means researchers dedicated to providing this information for thousands of line item costs. These tools may allow Transmission Providers to publish cost tables that provide typical equipment prices in order to provide customers greater visibility into the expected cost of upgrades.

[36] This should include a requirement that the transmission provider notifies the interconnection customer if, during construction, the transmission provider reasonably anticipates that the actual costs will exceed the estimated cost by more than 15%.

Third, transmission providers that demonstrate the application of the cost estimation and project management processes described above, which result in final project costs that do not exceed the cost estimate, should be eligible for performance-based incentives to encourage the use of these best practices.

Each of these reforms would provide greater transparency and certainty regarding the costs to construct interconnection upgrades and would assist in the development of just and reasonable rates.

(3) Restudy Requests Should Be Limited in Number; Restudies Should Be Faster

The Commission believes that a cluster-study approach will reduce the number of required re-studies,[37] and requests comment on whether there are provisions that could further improve the efficacy of the re-study process.[38] Under the proposed cluster-study approach, the Commission will require a restudy whenever "(1) a higher-queued interconnection request withdraws from the interconnection queue, (2) a higher-queued interconnection request modifies its proposed generating facility pursuant to section 4.4. of the *pro forma* LGIP, or (3) the interconnection customer redesignates its point of interconnection,"[39] and grants transmission providers 150 days to conduct a re-study of the cluster within 150 days of informing the cluster of the need for re-study.[40]

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37 NOPR at P 64.

38 NOPR at P 78.

39 NOPR at P 59.

40 NOPR at P 64.

First, we respectfully submit that the Commission's proposed cluster-study reforms should address the lack of any limit in current tariff language on restudy requests,[41] a known shortcoming that results in essentially unlimited time and resource obligations for interconnection customers. Second, a 150-day window for each restudy is unworkably long. We propose that a 30-day window per restudy is more reasonable because network models are already built, and therefore substantially fewer staff resources should be required than for the initial study. A shorter restudy window will also help avoid potential significant delays in a cluster study process in which multiple restudies are required.

(4) The Material Modification Process Requires Further Reform

The Commission proposes several changes to increase flexibility in the generator interconnection process, including changes to the material modification process and allowing co-located generation resources behind one point of interconnection.[42] These proposed changes involve revising the definition of material modification to limit the meaning to modifications with "a material impact on the cost or timing of interconnection requests with a later or equal queue position."[43] We submit, however, that further improvements are necessary for the material modification process.

In general, we support the concept of expedited study, provided that an expedited approach does not change the level of service, that there is no impact on cost or timing of a request that is lower or equally queued, and that it does not cause reliability concerns. Moreover, we suggest that

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41 *See, e.g.*, PJM Manual 14A: New Services Request Process (2021); PJM Manual 14G: Generation Interconnection Requests (2021). "During the Facilities Study phase, stability analysis is performed and the System Impact Study results are retooled **as necessary** to reflect changes in the New Services Queue." PJM Manual 14A at 26.

42 NOPR at PP 242, 255.

43 NOPR at P 65.

the Commission should modify the current material modification definition to clearly state that certain project equipment changes are not material, such as changing solar modules, changing inverter models, adding storage capacity, or making minor adjustments to inverter performance, so long as planned export and import capacity remains the same, and so long as technology changes comport with interconnection agreement requirements. In addition, transmission providers must allow more than one generation resource to co-locate on a shared site and to co-locate with large, controllable load.

(5) Cost Allocation

In the NOPR, the Commission proposed methods for allocating both study costs and network upgrade costs. The proposed study cost allocation method would allocate 90% of the applicable costs *pro rata*, based on megawatts included in the applicable cluster, and 10% of the applicable costs allocated per capita, based on the number of interconnection requests included in the applicable cluster.[44] For network upgrade costs, transmission providers will be required to allocate the costs using a proportional impact method.[45]

We support the proposed proportional capacity method of allocating study costs. Moreover, we agree that network upgrade costs should be allocated based on a "proportional impact/causation method" and not a "proportional capacity method" because, as a general matter, the latter is more fair and reasonable. However, we request that FERC clearly specify a standard for what the "proportional impact" method entails, or at least specify limits so that projects are not assigned costs that they did not cause, while preferably avoiding the complexities that would result from imposing sub-group clusters. Finally, we urge the Commission to reconsider proposed

[44] NOPR at P 82.

[45] NOPR at P 88.

retroactive cost-sharing provisions because they are not readily predictable or financeable, and upset the settled expectations of the parties.

(6) Study and Security Deposit Amounts Should Have a Clear Basis

To discourage speculative interconnection requests, the Commission proposes more stringent financial deposits for queue milestones, including to enter the cluster study, to conduct a cluster restudy, and to conduct the facilities study. The NOPR also proposes that an interconnection customer provides an LGIA deposit, which is specified as nine times the study deposit amount.[46] Aside from addressing inter-cluster cost allocation, the Commission does not, however, address when an interconnection customer must make its payment for allocated upgrades under the new proposed *pro forma* LGIA.[47]

Cypress Creek generally supports increased study and security deposits, but we suggest that the Commission should provide additional justification for the identified deposits—including study and commercial readiness deposits—in any final rule.

While the Commission specifies that study deposits are refundable, and the transmission provider would refund any portion of the study deposits above applicable study costs and withdrawal penalties after (i) the interconnection customer executes the LGIA, (ii) requests the filing of an unexecuted LGIA, or (iii) withdraws from the queue, the NOPR fails to provide any further justification for study costs (*i.e.*, based on a market analysis or other method), saying only that the proposed amounts "better approximate the cost of the interconnection study process." In Cypress Creek's experience, study costs can vary widely depending on the transmission provider,

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[46] NOPR at P 271.

[47] We assume therefore, that the Commission does not propose any changes to current practices in this regard.

the staff resources it has available to conduct the study, and whether it needs to contract with external resources to conduct the study. Furthermore, in our experience, the study cost has no impact on when the study is ultimately delivered or how accurate it is.[48] Without any alternative to conduct the study using our own contracted consultants, the interconnection customer is at the mercy of the transmission provider and has no recourse if study costs include unreasonable elements, such as significantly inflated administrative overhead.[49]

We submit that study costs must not be arbitrary and should be tied to desirable policy outcomes, such as the timely delivery of cluster studies, cluster restudies, and facilities studies, including, for example, to account for any increases in staffing necessary for achievement of interconnection study timelines.

Further, we urge the Commission to provide a non-arbitrary basis for its proposed security deposit of nine times the study deposit. While the NOPR identifies deposits in lieu of readiness from certain transmission providers as seven times the study deposit amount after receipt of the facilities study, it does not provide specific justification for the nine times figure. We suggest that this figure should instead have a basis in the network impact resulting from the most recent cluster study, cluster restudy, or facilities study. We note that a similar proposal is contained in recent interconnection reform proposals before FERC, which we support as fair and reasonable.[50]

Finally, we request that the Commission specify allowable financial instruments, including letters of credit or surety bonds.

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[48] In one example, our interconnection facilities study costs increased by ten times from initial estimates to final study, while the study continues to be delayed.

[49] In another example, our study costs for a project included costs of training additional personnel used to conduct other project studies.

[50] *See, e.g.*, the "Readiness Deposits" proposed by PJM Interconnection, L.L.C. in Docket No. ER22-2110.

(7) Site Control Proposals Should Better Reflect Development Realities

Another proposed means of limiting speculative interconnection requests is through more stringent site control requirements.[51] Cypress Creek generally supports increased demonstration of site control at the time an interconnection application is submitted, but the current proposal does not reflect realities of development, which includes stringent permitting requirements. We suggest that 75% site control is reasonable for proposed generating facilities but only 50% should be necessary for generation tie facilities at the time of an interconnection application, with 100% of each required by the time a facilities study is initiated. We also support a limited option of additional payments to allow interconnection customers to pursue project on sites with regulatory barriers to immediate site control. Finally, we note that, to the extent the Commission intends that a "land right" should involve zoning approval, we believe that such a proposal would be unreasonable because developers do not typically initiate local permitting until the system impact study phase, due to its impact to overall project commercial viability.

(8) Commercial Readiness Requirements Should Reflect Development Realities

The Commission proposes a framework that requires demonstration of commercial readiness at early stages of the interconnection process.[52] Cypress Creek opposes several elements of these commercial readiness requirements, including the requirement for an executed term sheet or offer into a resource solicitation plan, or the financial equivalent of either, in early phases of the interconnection process. In our experience, such a requirement should not apply until an interconnection customer receives the results from the proposed initial cluster study, which may

[51] NOPR at P 115.

[52] NOPR at P 128.

be required in order to bid into a resource solicitation. Consequently, it is discriminatory (insofar as it forces certain interconnection applicants to provide additional financial support) and impractical to include such a requirement at such early stages. Moreover, this construct is not workable in markets where merchant sales are common, and where necessary financial equivalents would therefore discriminate in favor of interconnection customers that seek a power purchase agreement or solicitation-based offtake arrangement. Consequently, we recommend the additional option of showing evidence of a commitment to participate in such markets, developed in consultation with market participants.

C. Reforms to Increase the Speed of Interconnection Queue Processing: Penalties Should Be Commensurate with Delay Impacts, Transmission Owners Should Bear Costs

The Commission proposes to eliminate the "reasonable efforts" standard for transmission provider processing of interconnection requests, and instead proposes to impose firm study deadlines along with penalties for failing to meet those deadlines.[53] In addition, the Commission proposes that no penalties will be applied until one cluster study cycle (that is, not in a transitional study cycle) after the effective date of an accepted compliance filing. Further, recognizing the not-for-profit status of RTOs and ISOs, the Commission proposes to allow compliance tariff filings under FPA Section 205 to address recovery of the costs of study penalties, including to allocate penalties to the transmission owner(s) responsible for the delay.[54]

Cypress Creek supports the elimination of the "reasonable efforts" standard and replacement with firm deadlines and penalties both for delays in studies and for inaccurate study results, subject to several caveats. First, we oppose capping penalties; instead, they should

[53] NOPR at P 168.

[54] NOPR at P 172.

continue to increase as delays increase in order to serve as a meaningful deterrent (moreover, delay penalties have the potential to exceed study costs). Second, we urge that, in line with proposed direct payment by transmission providers in non-RTOs/ISOs, that ISOs and RTOs must pass penalties along to transmission owners with no exceptions beyond *force majeure*; that is, the transmission owner must ultimately be responsible for payment of the penalty, and must streamline operations and data sharing with the RTO/ISO to facilitate compliance with applicable deadlines.

Further, the penalty must not be recoverable from the relevant transmission owners' ratepayers, in order to ensure costs of failure to comply are not simply passed along to customers. Third, and consistent with our first point in this section, we urge that penalties should, as a general matter, be substantially larger so that they serve as meaningful deterrents to delayed and inaccurate study results, and so they are also commensurate with the magnitude of liquidated damages that interconnection customers face if they do not meet their contractual deadlines. Fourth, we suggest that the Commission eliminate the reasonable effort standard immediately after the effective date of this order. We recognize certain elements of the cluster study require new systems and services; however, the proposed effective date could (if PJM Interconnection's queue reforms are any indication) take years to complete. Without eliminating the reasonable effort standard within the transition and first cluster, we would expect such clusters to be further delayed, based on our significant experience.

D. The Transitional Process Should Protect Late-Stage Projects' Interests While Being Fair and Transparent

The Commission proposes to require transmission providers to offer existing interconnection customers the option to either enter a transitional serial interconnection facilities

study or a transitional cluster study, with commercial readiness requirements, or else permit them to withdraw from the interconnection queue without penalty.[55]

Transitional serial study eligibility would be extended to those willing to provide a deposit equal to 100% of the interconnection facility and network upgrade costs allocated in the system impact study report, with additional evidentiary requirements to prove site control, as well as commercial requirements. Transitional cluster study eligibility would be extended to those willing to make a $5 million deposit (drawn on evidence from Public Service Company of Colorado), which is equivalent to costs that could be allocated to the customer via the transitional cluster study.

Cypress Creek supports basing eligibility for the transitional process on having received a system impact study by the effective date of the implementing transmission provider's approved process. However, based on our experience with recent and ongoing queue reform efforts, we strongly suggest that eligibility for the transitional serial cluster be based on 1) a specified queue window developed through a stakeholder process that extends to late stage projects and 2) an objective assessment of the plotted distribution of total network upgrades (in terms of millions of dollars) to which the candidate project contributes, such that the total number of projects eligible for transitional serial and transitional cluster studies is known and so transitional studies can be completed by a reasonable deadline. The distribution curve of network upgrades will help support eligibility to those projects on the lower half of impacts. Any projects that do not qualify would then be processed in a transitional cluster. Finally, we suggest a date certain by which the transitional serial process would conclude, and by which the transitional cluster process would

[55] NOPR at P 156.

conclude. Any projects not completed by either outside date would then be moved to the subsequent new cluster process.

Following these transitional studies, the new cluster study process should commence, in lieu of the second transitional cluster proposed by the Commission. We suggest that allowing projects to either pay the full cost of allocated network upgrades or a $5M deposit is logical in some ways, but insufficient to grant certainty to market participants as to when the new cluster study process commences. This more rapid transition more appropriately balances interconnection rights of late-stage projects with the clear need to move to the new process.

E. Technology Advancement and Study Flexibility Reforms

Cypress Creek strongly believes that transmission providers should utilize expanded technology options to address violations more cost effectively, consistent with FERC's endorsement of grid enhancing technologies ("GETs") in Docket No. RM21-17-000.[56] Cypress Creek proposes that study results should incorporate GET options wherever appropriate to avoid delays and reduce costs.

[56] *See*, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 at P 256, *et seq.* (2022).

III. CONCLUSION

For the foregoing reasons, Cypress Creek strongly, and respectfully, encourages the Commission to act to reform interconnection processes, consistent with the comments herein, and to initiate whatever procedural next steps—including a technical conference in the context of this proceeding or a subsequent rulemaking, in either case to address disparate generator interconnection study criteria and the interaction between generator interconnection processes and transmission planning—the Commission deems necessary.

Respectfully Submitted,

/s/ Matthew Crosby

Matthew Crosby
Senior Director
Policy & Strategy
Cypress Creek Renewables, LLC
3402 Pico Blvd
Santa Monica, CA 90405
matthew.crosby@ccrenew.com

October 13, 2022