Green Power

Working Paper

Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning

Creating a more efficient interconnection and transmission planning process to unleash America's clean energy economy.

Unleashing America's clean energy economy depends on building transmission to renewable -rich regions and interconnecting projects in a timely and cost-efficient manner. Our nation's existing interconnection and transmission planning processes are inadequate for the current and projected volume of new generation projects wishing to construct and interconnect to the transmission system. Across the RTOs, there are lengthy queue delays, uncertain timelines and upgrade costs, and insufficient transmission, that combine to prevent the timely development of new projects.

The following proposal addresses the root causes of both generation interconnection and regional transmission planning woes by consolidating the two processes into a streamlined process. The resulting process will facilitate the timely and optimal deployment of new generation while expanding the transmission system in the most efficient and cost-effective way.

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Introduction

Enel Green Power North America is a leading developer, long-term owner and operator of renewable energy plants in North America, with a presence in 15 US states and one Canadian province. The company owns and operates 60 plants with a managed capacity of over 6.7 GW powered by wind, geothermal, energy storage and solar energy resources. Enel Green Power has more than doubled its managed capacity over the past five years and is committed to continued investment and growth in North America, as demonstrated by our several GW development pipeline. Despite this success, the generator interconnection process has significantly slowed project development and threatens future growth opportunities.

There is an urgent need for reforming the generation interconnection process and for integrating the process with transmission planning. The need is growing more extreme as the volume of projects wishing to construct and interconnect steadily rises. Across the Independent System Operators (ISOs), Regional Transmission Organizations (RTOs) and utility Transmission Providers (collectively, "TPs"), there are lengthy queue delays, uncertain timelines and upgrade costs, and insufficient transmission capacity preventing the timely development of new generation projects. Failure to address these issues will harm consumers through decreased competition, will impede reliability due to fewer resources coming online, and will jeopardize America's transition to a clean energy economy.

With the release of the Advance Notice of Proposed Rulemaking ("ANOPR") on July 15th, 2021[1], the Federal Energy Regulatory Commission ("FERC" or the "Commission") recognized the scale of the problem and is actively seeking input on how best to address it. The ANOPR solicits comments on potential reforms for electric transmission planning, cost allocation, and generator interconnection processes. Specifically, FERC explained that in spite of landmark reforms issued more than a decade ago in Order Nos. 890[2] and 1000[3], additional transmission planning and cost allocation changes may be necessary. The Commission is now providing the opportunity to consider generation interconnection procedure reform, to optimize planning procedures, and to fairly allocate costs based on benefits yielded for both system loads and new generation.

This paper sets forth a proposal for comprehensive reform that addresses the root causes of both interconnection and regional transmission planning challenges and that consolidates the two processes into a single, more streamlined process. If adopted, the proposal will facilitate the timely and optimal deployment of new generation through the following four primary reforms:

1) Consolidation of all planning inputs into a single regional transmission planning process.

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[1] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 at P 183 (2021) ("ANOPR"). See also 86 FR 40266 (Jul. 27, 2021). Available here: https://www.federalregister.gov/documents/2021/07/27/2021-15512/building-for-the-future-through-electricregional-transmission-planning-and-cost-allocation-and.

[2] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 at P 157 (Mar. 15, 2007) ("Order 890"), FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats & Regs. ¶ 31,261 (2007).

[3] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 76 Fed. Reg. 49,841 (Aug. 11, 2011) ("Order 1000"), *order on reh'g*, Order No. 1000-A, 77 Fed. Reg. 32,184 (May 31, 2012), *order on reh'g and clarification*, Order No. 1000-B, 77 Fed. Reg. 64,890 (Oct. 24, 2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

2) Narrowly defined interconnection study parameters focused on direct, localized impacts of new generation with binding results for identified network upgrades.
3) Direct cost allocation of resulting network upgrades to generators when the cost causation relationship is strong and justified.
4) Stringent proof of readiness and financial deposit requirements for generators to proceed into the regional transmission planning process based on these early binding results.

This paper first summarizes the root causes behind the failure of today's interconnection and transmission planning processes then details the four-step proposal for addressing these root causes.[4]

The Root Causes of Today's Failing Interconnection and Transmission Planning Processes

The generator interconnection process is a crucial part of expanding and improving energy infrastructure and facilitating competition through open access. Interconnection policy has, without intention, become an obstacle to the implementation of municipal, state, and corporate clean energy goals. Problems in the interconnection process, both in the ISO and RTO regions and non-ISO/RTO regions, result in significant costs, delays, and other risks that limit the development of these new energy resources.[5]

Furthermore, current generator interconnection and regional transmission planning processes proceed on largely separate tracks and there is little to no joint optimization of transmission projects that facilitate interconnections for new generation and transmission projects that meet the reliability, economic, and/or public policy needs of system loads. Without this joint optimization, there are no means to jointly assess the benefits and allocate the costs of transmission projects that yield benefits to both system loads and new generation.

To provide context for our proposal, we first summarize the root causes of today's failing interconnection and transmission planning processes (see Table 1).

Table 1: Root Causes of Interconnection and Transmission Planning Process Inadequacy[6]

Root Cause	Detail
1. Interconnection studies often have a very low threshold for determining whether an interconnecting customer is responsible for new upgrades.	Because of this low threshold, TPs identify and assign network upgrades to interconnection customers ("ICs") that are hundreds of miles or even 1000+ miles away, even when these ICs bear negligible responsibility for the upgrade. Please see Appendix B for a real-life example of projects in North Dakota paying for upgrades in Missouri. Assigning network upgrades in this way leads to interdependency between projects due to more ICs being

[4] Although the proposal contains four major reforms, not every step contains a reform, and certain steps (primarily step 1), include multiple reforms.

[5] Generation queues across the US are dominated by renewable energy and intermittent resources. *See*, https://pv-magazine-usa.com/2020/09/08/interconnection-queues-across-the-us-are-loaded-with-gigawatts-of-solar-wind-and-storage/

[6] Table 1 is not intended to be exhaustive of interconnection policy inadequacy, however, the items therein represent the focus of topics analyzed in this paper.

	responsible for a single upgrade. This creates a paradigm where one projects actions, such as dropping out of the queue, can have drastic impacts to all other projects. Because of this interdependency, TPs constantly have to perform restudies, which significantly lengthens the entire interconnection process and can lead to surprise upgrade costs to generators. We address this root cause in Step 1 of our proposal.
2.Transmission Study Coordination	Building on the first root cause, complex coordination is necessary for each TP (both RTO and non-RTO) to study projects in queue priority within their regions **and on adjacent systems** (known as "Affected Systems"). The low threshold highlighted above, or low impact threshold criteria, results in upgrades being assigned at greater distances into neighboring systems, resulting in additional interdependency between generation projects and greater re-study needs following withdrawals. We address this root cause in Step 1 of our proposal.
3. Rapidly Growing Queue Volume	High customer demand for clean energy and smaller project sizes will continue to drive a high need for new projects. Furthermore, queue delays from process inadequacies lead to higher volumes in subsequent queue cycles to meet increasing demand We address this root cause in Step 1 and Step 2.
4.Lack of Interconnecting Utility Incentives and Oversight	Regulatory structures fail to incentivize utilities to complete studies on time and on budget, provide accurate results, or build facilities in a timely manner. Despite this being a significant root cause, this is outside of the scope of this working paper at the moment, but we are aware that our trade association Advanced Energy Economy is proposing a solution.[7]
5.Lack of Transmission	Regional/interregional transmission planning processes are building inadequate transmission for several reasons, including restrictive study inputs that fail to capture project development potential in renewable-rich areas and economic transmission needs. Inadequate regional transmission investment manifests as outsized network upgrade costs. We address this root cause in Step 3 of our proposal.
6.Siloed planning	Planning efforts remain issue specific **–** i.e., traditional regional planning processes, load additions, retirements, transmission service, etc. High volume of model building activity required without clear integration of results. Lack of joint optimization results in cost-inefficient solutions for load. We address this root cause in Step 3 of our proposal.
7.Shortage of qualified engineering staff	The industry is experiencing a shortage of experienced engineering staff to meet the collective transmission planning and facility design needs of TPs, transmission owners, interconnection customers and consultants. This shortage is especially acute at RTOs and utilities. While our proposal does not address this root cause, state and

[7] Please refer to Advanced Energy Economy's ANOPR submission for more details

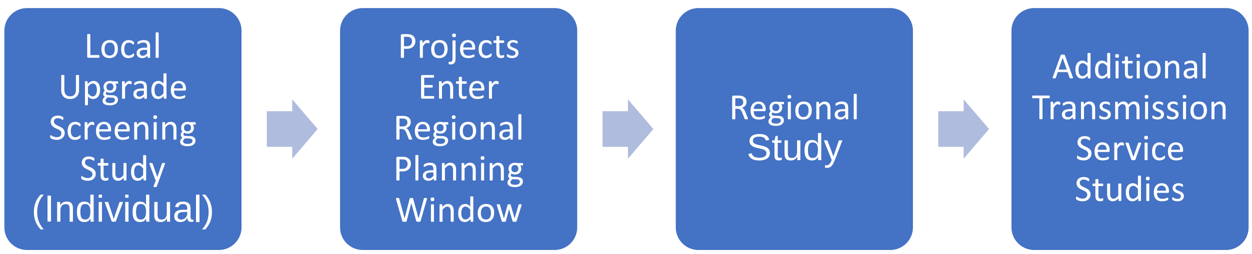
	federal regulators and policymakers should consider measures to attract and retain top talent for these positions.

In response to the ANOPR, Enel has developed a comprehensive proposal to address the root causes in Table 1. The proposal is a combination of best practices that certain TPs are currently using and conceptual reforms that TPs have yet to implement.

Comprehensive Proposal for Interconnection and Transmission Reform

Consolidation Proposal Summary

The flow chart below depicts the process to consolidate generation interconnection, transmission service, and regional transmission planning studies. In the following sections, we summarize each step and how it addresses the root causes highlighted in Table 1.



Here is a brief summary of each step:

- **Local Upgrade Screening Study** - Individual screen identifies upgrades, determines scope of upgrades and associated cost estimates for ICs. The study determines upgrades needed for basic interconnection service (ERIS) only.
- **Projects Enter Regional Planning Window** – Includes stringent readiness hurdles to enter regional study. The proposal requires the IC to post security and demonstrate site control including portion of generator tie line and point of Interconnection facilities (subject to confirmation from Transmission Owner of required land).
- **Regional Study** - Transmission designed efficiently in consolidated regional study with a focus on reliability and economic benefits for load. This includes a potential for cost contributions by generators to increase funding available for regional transmission upgrades.
- **IC Higher Interconnection Service and Additional Transmission Service Studies** – After the Regional Study, TPs would conduct studies for additional transmission rights (including Network Resource Interconnection Service ("NRIS"), Capacity Interconnection Rights ("CIRs"), Transmission Service Requests ("TSRs"), or others as are applicable by region). The TPs would conduct the studies at the requested levels of service, while granting flexibility to ICs to reduce the requested service amount to avoid upgrades that the IC deems uneconomic for their project.

Detailed Consolidation Proposal

Consolidating the generator interconnection process into the regional transmission planning processes allows for a joint optimization of transmission projects that facilitate interconnections for new generation and transmission projects that meet the reliability, economic, and/or public policy needs of system loads. Though current regional economic and public policy planning processes often do rely on Futures scenarios that go beyond firm interconnection commitments, those processes are separate and on different timelines than the generator interconnection process. Therefore, there are no means to jointly assess the benefits and allocate the costs of transmission projects that yield benefits to both system loads and new generation.[8]

Step 1: Local Upgrade Screening Study

The first step in the proposed process is a Local Upgrade Screening Study ("Screening Study"). The purpose of this step is to identify local upgrades needed for a new IC to reliably connect to the existing transmission system and to determine what the IC should pay for such upgrades. The goal of this step is to provide ICs with a firm scope of upgrades with an estimated price for the network upgrade costs they would face if they decide to move forward with the project.[9]

The key to making this Local Upgrade Screening Study a successful framework for interconnection is to reduce the interdependency between queued generation interconnection projects that we highlighted in Table 1 of the Root Causes section. If an IC faces the risk of paying for upgrades that are several hundred miles away with no meaningful link to its generation, it will increasingly result in ICs dropping out of the queue. When ICs drop out of the queue, it triggers the restudies that are partly responsible for lengthy queue delays. FERC can therefore reduce interdependency and restudies by reforming the interconnection study process to focus on individual local impacts and providing greater certainty on interconnection costs and timelines.

Specifically, as part of the Local Upgrade Screening Study, we recommend the Commission adopt the following solutions to reduce interdependency:

1. **Harmonized Transfer Distribution Factors for Upgrade Identification**

Interconnection customers should only pay for network upgrades "local" to their project where direct cost causation can be shown. Transfer Distribution Factor (TDF), which measures the percentage of the electricity produced by a generator which travels on a given transmission facility,[10] is a good metric for determining electrical distance from a generation facility and what constitutes "local". TPs commonly

[8] It is worth noting, however, that absent other reforms in this proposal which simplify studies, reduce interdependency, increase certainty, and motivate Transmission Owners, consolidation of the interconnection and regional planning processes would likely be disastrous as two separate processes, each containing their own risks of process delay, would compound upon each other.
[9] Industry leading tools such as those used by PJM for interconnection power flow studies would enable rapid completion of studies from a common base case.
[10] Transfer Distribution Factor is defined as the change in MVA flow on a transmission facility divided by the size of the transfer being studied. In the case of generation interconnection studies, the transfer size is the amount of generation added to the system. Each transmission line will have a distinct TDF relative to each generation interconnection location. The TDF also depends on what other generator(s) are reduced to offset the addition of the new generator. 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.

use the TDF metric in interconnection processes today, but regional upgrades are often assigned using low TDF thresholds and thresholds based on group impacts. This creates a large degree of interdependency between projects. [11]

The Commission should set a common TDF threshold of 20% for all TPs to assign network upgrades to ICs as Energy Resource Interconnection Service ("ERIS") [12] **customers and should consider similar voltage impact thresholds on an individual project basis as well, such as a 3% voltage change caused by an individual project.**[13]

The TDF threshold would limit new network upgrades to only those local to a generation project. When the TDF is greater than 20%, the TP would deem the upgrade as local, and when the TDF is less than 20%, the upgrade would not be local. This fits within FERC's standard of ERIS being "as available" while not guaranteeing protection from curtailment in all circumstances. However, it still creates an efficient way for mitigating local constraints and reducing congestion and/or curtailment for an individual generator. A reasonable TDF threshold for cost allocation to limit the scope of upgrades for a generator is also consistent with NERC reliability standard TPL-001-4, which allows for curtailment of non-firm (i.e., ERIS) generation to mitigate transmission constraints prior to requiring a system upgrade to be built.

2. Individual Study with Binding Results.

In order to reduce interdependency, TPs should transition from cluster studies to individual studies (or much smaller, more local clusters). Most TPs, especially RTOs and ISOs, have transitioned to cluster studies to evaluate multiple generator interconnection requests simultaneously. While this has some benefits, including a reduction in the volume of studies to perform and the possibility of multiple generators funding upgrades together to overcome costly transmission constraints, recent cluster interconnection studies are resulting in significant regional transmission constraints with very high associated upgrade costs and long construction schedules[14]. Our proposal seeks to preserve a portion of these benefits to the extent possible, while reducing the negative aspects highlighted above. To avoid the potential for an overwhelming number of individual studies, later in this section we propose strict criteria for an IC to meet to request a Local Upgrade Screening Study.

Under our proposal, an individual study would identify any adverse impacts of the individual new generator on the transmission system. If the study determines the system constraints are local based on

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[11] Please see Appendix B and Enel's ANOPR comment submission for examples how low TDF criteria and group impact criteria result in excessive regional upgrade identification.

[12] See FERC pro forma Large Generation Interconnection Procedures definition of Energy Resource Interconnection Service and section 3.2.1.1. The term ERIS herein is used generically in reference to basic interconnection service as defined within various Transmission Provider OATTs.

[13] Note that the 20% TDF is used to determine whether an upgrade is built as a result of the interconnection study. It is not meant to describe a specific cost allocation mechanism such as participant funding, crediting, load paying for facilities, etc.

[14] For example, the recent SPP DISIS-2017-001 Phase 2 study identified $4.7B of upgrades for 10.4 GW of generation, an average cost of around $450k/MW. These were the results after the first round of generators had already withdrawn at Decision Point 1 of the SPP three stage interconnection process. SPP has now consolidated their sixteen regional study groupings into only five for the DISIS-2017-002 studies, which Enel expects will create new pre-existing constraints primarily along state lines due to SPP including previously unstudied dispatches in their base study models. Those new regional constraints will drive large network upgrades that will be assigned to new generators in the study cycle.

applicable TDF and voltage impact criteria, the TP will identify these upgrades as binding specific to the parameters of the IC request. Because of the fact that the upgrades identified in this study phase are critical for ERIS, they are clearly cost causally related to the proposed interconnection, thus these upgrades are bound to the particular IC request and set the basis for direct cost recovery from the IC based on its request. These results determine the maximum scope of upgrades and (by estimate) the total amount the IC pays for the upgrades that are related to the IC's interconnection to the transmission system for ERIS identified by the 20% TDF threshold. These binding upgrades follow the IC request through the process or until terminated. Constraints on transmission facilities of either the host TP or adjacent systems where the IC's TDF is less than 20% would be mitigated in the regional planning process if the regional studies determine an upgrade is necessary for load-serving reliability or economically beneficial to load.[15]

3. Fuel-based Dispatch

The Commission should direct all TPs to implement fuel-based dispatch assumptions in studies to further reduce interdependency between interconnection requests.[16] By studying new generators only in seasons and load profiles that match the likely generation profile of the fuel source, interconnection requests become less dependent on the results of interconnection studies for generators of different fuel types. For instance, a solar project may produce more during the summer, and a wind project may produce more during the winter. Studying the two projects as if they will achieve maximum output at the same time for several hours of the year could create the false impression that upgrades are necessary to integrate the two projects on the grid. This would create interdependence, such that one project dropping out would trigger a restudy for the other project and queue delays. With fuel-based dispatch, it becomes clear that the two projects will not achieve maximum output at the same time for many hours of the year and avoid the interdependence and need to restudy.

Later in this section describing Step 1, we highlight a regional transmission entity that is already taking steps to reduce interdependency.

Criteria for IC to Request Local Upgrade Screening Study

To prevent immature and unlikely projects from creating unnecessary study volume, threshold requirements need to be set for IC's requesting a Local Upgrade Screening Study. The criteria that TPs utilize to permit an IC to request a Local Upgrade Screening Study should be discrete and measurable. For example, requiring ICs to have site control of the generating facility and a portion of the generator's high voltage transmission line[17] will help ensure the project is likely to proceed. The Screening Study could be split into two parts, including a power flow only study with lower entry requirements to help ICs size their projects, and higher milestones including detailed project layouts and design before

[15] The model adopted herein comports with current cost causation principles. *See*, *Illinois Commerce Comm'n v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009) (Illinois Commerce Commission) (citing *K N Energy*, 968 F.2d at 1300; *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 708 (D.C. Cir. 2000); *Pacific Gas & Elec. Co. v. FERC*, 373 F.3d 1315, 1320-21 (D.C. Cir. 2004); *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004) (Midwest ISO Transmission Owners); *Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009); *Sithe/Independence Power Partners, L.P. v. FERC*, 285 F.3d 1, 4-5 (D.C. Cir. 2002) (Sithe); 16 U.S.C. 824d).
[16] Some TPs already use the fuel-based dispatch concept, including MISO and PJM.
[17] Only a portion of the generator tie line should be required early in the process as feedback from the interconnecting Transmission Owner may regarding the POI may not be available yet.

starting more detailed studies. This would be very similar to the ERCOT study process, which terms the two studies Screening Study (performed by ERCOT) and Full Interconnection Study (performed by the interconnecting utility).[18]

For projects at the Local Upgrade Screening Study stage, the IC should provide a full design and layout prior to studies other than power flow. TPs should afford significant sizing flexibility to help ICs optimize project size before entering the regional process, though TPs would need to complete studies on the near final project size prior to the IC entering the regional study.

At the conclusion of the Local Upgrade Screening Study, the TP should provide ICs a reasonable time to determine whether it desires to pursue the next stage of the process, entry into the Regional Study phase. Should a project desire to delay entry into this next study phase, yet not terminate its interconnection request, the TP should require the IC to post an additional non-refundable study deposit to avoid lingering in the queues and to fund future studies that a nearby project might trigger when entering the regional study process. This will prevent stagnation of projects in the Screening Study phase with the intent of avoiding restudy for delayed or deferred projects.

ERCOT's Success in Limiting Interdependency

The ERCOT interconnection process demonstrates the value of an interconnection process with minimal interdependency. One of the core differences that allows for such rapid processing of Interconnection Requests in ERCOT is that projects do not have an interdependent queue priority and are ultimately not allocated any transmission costs if the generator achieves commercial operation.[19] When a project pulls out of the queue in ERCOT, it does not trigger a need for ERCOT to conduct a restudy.

As a result. new interconnection requests in ERCOT can achieve commercial operation within approximately three years of entering an initial interconnection request, which includes the time to build required interconnection facilities and network upgrades. By way of comparison, stakeholders do not expect interconnection requests that were submitted to SPP in early 2018 to have initial interconnection study results until mid-2022 and GIAs until mid-2023.[20] Per PJM's posted study metrics, the average time to receive a facility study has ranged from 616 days to 821 days over the past eighteen months.[21] This does not even include the actual engineering, procurement, and construction work ("EPC work") that a Transmission Owner must complete after executing a GIA, which we estimate to take up to four years for some utilities. It is notable that ERCOT and its individual Transmission Service Providers (as utilities are known in ERCOT) achieve this rapid pace of processing the interconnection queue without imposing any significant security payments on Interconnection Customers prior to GIA

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[18] For avoidance of confusion, this paper generally refers to all interconnection studies performed in advance of the regional process as the Screening Study, including dynamic stability, short circuit, etc.
[19] It is important to note that we are not recommending the Commission to adopt all aspects of ERCOT's interconnection and transmission planning processes. However, the flaws in ERCOT's transmission planning processes are due to overly restrictive economic criteria for developing new transmission, and not the limited interdependence of projects in interconnection studies.
[20] SPP's weekly study schedule update dated 9/30/2021, posted at https://opsportal.spp.org/documents/studies/sppgistudyupdate_weekly.pdf
[21] Page 9 of PJM's Informational Report on Interconnection Study Performance Metrics filed with FERC on August 16, 2021. https://www.pjm.com/-/media/documents/ferc/filings/2021/20210816-er19-1958-003.ashx

execution, which many of heralded as the chief solution for managing queue volume and mitigating extreme backlogs.

Process and Legal Considerations

The implementation of the Local Upgrade Screening Study construct would require minimal changes to the current pro forma Generator Interconnection Procedures and fits within current legal precedent. The IC would initiate the Local Upgrade Screening Study by filing a typical interconnection application form and study agreements, similar in content to Appendices 1-3 of the *pro forma* Large Generator Interconnection Procedures (LGIP). Stakeholders will likely need to make amendments to existing OATTs to modify the current LGIP appendices to accommodate the Screening Study process requirements and scope differences. The necessary scope of amendments would vary by region.

Additionally, at the time the IC submits the request for the Local Upgrade Screening Study to the TP, in regions that have specified levels or various types of interconnection service, the IC would also need to specify the type of interconnection service they are electing so that the scope of the study process, including the higher interconnection service studies in Step 4 below, accommodates for the IC's capacity delivery requirements. TPs would study basic interconnection service (typically ERIS) in the Local Upgrade Screening Study, while they would study more firm levels of interconnection service (such as NRIS or capacity interconnection service) in Step 4. Stakeholders would not need to change the *pro forma* Appendix A application forms to indicate the desired type(s) of interconnection service. It should be noted that this proposal assumes all generators need to be studied for ERIS service as a base service prior to studying other types of interconnection service.

How Step 1 Addresses the Root Causes of Our Failing Interconnection and Transmission Planning Processes

The Local Upgrade Screening Study that we propose addresses the first three root causes that we highlighted in Table 1. By utilizing a TDF threshold of 20% to limit upgrades to only what is local to an IC, Step 1 removes the low threshold (Root Cause #1) that TPs currently use for cost allocation of upgrades. With a reasonable TDF, ICs are assigned upgrades that they are directly causing and remove the interdependency between projects that drives constant restudies and the resulting astronomical queue delays (Root Cause #3). The 20% TDF threshold also reduces the likelihood that multiple TPs will need to study the same project and the need for Transmission Study Coordination (Root Cause #2).

Step 1 also addresses the third root cause of astronomical queue delays by requiring near final design to complete the Screening Study phase, such that binding upgrades are determined for the IC request to be allowed to move to the Regional Study Window Phase.

Step 2: Entry into Regional Planning Window

In this section, we describe the process for an IC to enter the Regional Planning Window following the completion of the Screening Study phase. In the proposal, the Regional Planning Window is a major commitment decision point for the IC. Once the IC commits to move forward at this phase, the cost of abandoning the project becomes substantial.

For the TPs, the cost commitment detailed herein will filter out projects unlikely to get built and produce a high degree of certainty for the interconnection requests that will advance to actual construction and that TPs should include in the Regional Planning Study models. Construction readiness milestones and substantial deposit requirements will lead to more realistic planning proposals from the Regional System Planning process regarding upgrades serving generation-interconnection customers.[22]

Requirements for Regional Planning Window Entry

To assure IC commitment to project construction, TPs would impose significant readiness criteria which could include the posting of a non-refundable cash deposit or letter of credit in the amount of 100% of the upgrades identified for direct IC cost recovery from the Local Upgrade Screening Study. In addition to the posting of security, TPs would require the IC to meet shovel ready milestones, such as 100% site control, site control for 90% of the generator's tie line[23] and 100% of any point of interconnection-related land. The Transmission Provider would require the IC to meet the development milestones in Article 11.3 of the *pro forma* Large Generation Interconnection Procedure in order to enter the Regional Planning window. The Commission could also consider more significant milestones related to permitting. [24] The combination of these requirements should be sufficient to demonstrate near certain commitment from the IC to proceed with project development and should be more palatable to developers due to avoiding the uncertainties of queue priority and queue churn that plague existing processes.

Facility Studies, GIAs, and Expansion of Upgrade Construction Options

Upon entry into the Regional Process, generators would proceed immediately with their facility study, GIA, and upgrade construction. Upon completion of the facility study, the relevant parties would enter into a GIA and any needed construction agreements. Once parties execute the GIA, TPs would commence EPC work for the upgrades that studies identified assigned to the IC in the Local Upgrade Screening Study. Once the option for construction start is triggered, the IC must continue in the Regional Study Window or risk forfeiture of its transmission investment. Construction of upgrades would occur in parallel with the Regional Study, thus expediting the timeline for energization of the generator.

Process and Legal Considerations

This proposal would require the modification of existing OATTs to accommodate the criteria and collateral/credit requirements for evidence of site control and project readiness. The incorporation of these requirements would reside in modifications to generation interconnection procedures. Most if not all these concepts exist within present interconnection procedures, however the timing and deposit requirement amounts proposed herein will require adjustments.

This also raises a fairness issue. To the extent that stringent requirements for project readiness are implemented, it will impact the ability of many interconnection requests to remain in the queue. However, these criteria are not unduly discriminatory, as projects resulting from the Regional Study that demonstrate positive cost benefit ratios could lead to new upgrades and may reduce interconnection costs for ICs that are not ready to pass through the Regional Planning Window phase.

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[22] In the event a project completes a Screening Study but chooses not to enter the regional planning process, the proposed project design and location will be used in the regional planning model as an additional indication of future generation development

[23] Includes some leniency for site control items like railroad or river crossings, which may take a significant amount of time to obtain.

[24] It would not be appropriate to simply state "all permits" must be obtained, as many less substantial and non-controversial permits are often acquired during construction.

If multiple similarly located generators enter the same regional planning process and are expected to have overlapping generation profiles (e.g., common fuel types), TPs could study those generators in a tandem study at the beginning of the regional process to identify any new transmission constraints caused by the combination of the two plants. Common upgrades that TPs identify in the initial screening study could be shared between the generators to reduce cost allocation to each, and if the combined study identifies new upgrades that are cost effective for mitigating congestion and curtailment concerns, the generators could opt to share those costs and/or reduce sizes in some proportionate amount. Stakeholders could create rules requiring these additional upgrades if the total cost of upgrades in the combined study did not result in a net cost increase to the interconnection customers. While this additional study is not necessary to implement, it is one possible solution to a frequently asked question about this proposal.

How Step 2 Addresses the Root Causes of Our Failing Interconnection and Transmission Planning Processes

The Regional Planning Window that we propose primarily addresses the issue of rapidly growing queue delays (Root Cause #3). Qualifications regarding project readiness milestones, substantial deposits for binding upgrade costs from the Screening Study, execution of a GIA as well as commitments to proceed with construction provide stringent requirements to proceed into the Regional Study. Risk of forfeiture of investment will significantly reduce queue volume at this stage. Arguably, reducing queue volume also assists with the lack of qualified engineering staff (Root Cause #7), by reducing the study burden on TPs.

Step 3: Regional Study

The goal of the Regional Study we propose here differs from existing regional study planning processes in two significant ways. First, the regional study will include IC requests that have passed through the Regional Planning Window. Second, we include the potential for cost contribution from new generation to reduce the cost of regional transmission projects. Similar to existing regional and interregional planning processes, the Regional Study uses power flow, dynamic, and short circuit studies to ensure system reliability for load and an economic optimization model to design the transmission system to produce the lowest total energy rates for end users. The inclusion of IC requests entering the Regional Study Window adds the benefit of identification of regional transmission upgrades that may provide economic benefits to the region through load having better access to new, cost competitive generation.

Study specifics

The planning and economic models used in the Regional Study identify new transmission that maximizes benefits and minimizes costs to end users. The models should include resource adequacy, reliability, and economic considerations while considering future scenarios of new interconnection requests. The goal of this step is to match present interconnection needs with transmission solutions apparent in the near-term planning scenarios, while also preparing for future generation needs by providing access to fuel rich areas.

Regional models should include ICs which have met the requirements to enter the Regional Study as well as the upgrades associated with their interconnection. Consideration could be given to allowing upgrades assigned to ICs to be expanded or optimized in the Regional Study using additional funding from load, but care should be taken to ensure that the generator's schedule, upgrade costs, and congestion impacts (notably due to delays to upgrades) are not harmed. Temporary solutions such as those discussed below could be used to mitigate constraints temporarily to protect the new generator if an associated upgrade completion is delayed.

Under this consolidated process proposal, we recommend TPs not redo regional studies if a generator withdraws after entering the regional process. It is reasonable to assume that vacancy left by the cancelled generator will still roughly represent some future generator in the same way as other generators included in the futures model that were not based on an actual project entering the Regional Study. The full provision of security by generators for assigned upgrades should further ensure that the associated upgrades are still built if needed for the transmission system, reducing the impact of leaving the generator in the planning models. This approach provides the necessary stability to the study process to allow for interconnection and regional planning studies to be combined and not be derailed through existing issues like late stage withdrawals and associated re-studies in the interconnection process and other delays commonly experienced in regional planning processes. The Commission should consider the treatment of security for cancelled generation projects to determine whether there are scenarios in which the generator would receive a refund (e.g., if there is no harm to the regional process or other generators). If forfeited, TPs could apply these sizable securities to complete the capacity upgrades which were assigned to the generator, or the Commission could consider rolling the costs into a pool of funds for building future regional transmission.

How the Regional Study identifies and allocates costs for network upgrades

The focus of the Regional Study is to maximize benefits and minimize costs to load. Modeling of the upgrades from all generators that have passed through the Regional Study Window should result in a suite of transmission upgrades which prevents load from paying for transmission closely correlated to the interconnection of new generators and will limit transmission costs assigned to load to those regional transmission upgrades that are beneficial to reliability and economics for load.

In the Regional Study, if identified transmission additions and upgrades meet a pre-set benefit-cost threshold, and/or the upgrade meets a reliability need that cannot be mitigated through re-dispatch of generation (i.e. replacing lower cost generators with higher cost generators to relieve the transmission constraint), the transmission project would be paid for by regional load, similar to most current TP planning processes.[25] The transmission solutions with positive net cost benefits would be placed into the transmission planning process for adoption into the transmission system plan, and constructed in accord with existing methodology within the control area.

In addition to load exclusively funding these upgrades, as is done today, the Commission could add a new construct wherein generators could contribute capital to help fund regional transmission in limited circumstances. Specifically, when the TP completes a Regional Study and identifies new transmission solutions, some economic constraints on the system will be left unmitigated because the benefit to cost ratio was not met. In situations where the benefit to cost ratio was close to meeting criteria, TPs would analyze the economic benefit of completing the upgrades (i.e., lowered congestion and curtailment[26]) to new generators which entered the Regional Study in that window. If a portion (e.g., 20-30%) of the

[25] The proposed cost allocation assumes that the identified upgrades effectively meet a definition of Market Efficiency Transmission Upgrades. The concept has been adopted in several ISO/RTO regions and allows for regional cost recovery of beneficial upgrades meeting certain cost benefit criteria. An example of the concept is found in the ISO New England OATT, Section II, at Attachment N (Procedure for Regional System Plan Upgrades) and Attachment K (Regional System Planning Process). *See also*; ISO New England Inc. FERC Docket Nos. ER13-193-001 ER13-193-003 ER13-196-001 ER13-196-002. *Order on Rehearing and Compliance*, at P. 324. March 19, 2015.

[26] These data points regarding economic benefit to generators should be tracked during the course of the studies so the RTO/ISO is not repeating work.

expected congestion savings to each of the generators was contributed by the generators up front as capital contribution in aid of construction ("CIAC"), the overall cost of the transmission project would effectively be lowered, thus improving the benefit to cost ratio. If the regional criteria for funding the upgrade was met after this contribution from generators, the Regional Study process would approve the upgrade, thus increasing reliability and economic benefit to load, and also providing an expected net benefit to the contributing generators.[27] A framework for generators which are operating, or which entered prior regional planning windows to also elect to contribute funds could also be considered.

Public Policy or IC Participant Funding Assistance

If the Regional Study produces certain transmission solutions that fail to meet the benefit-cost threshold for the purpose of cost allocation to load, existing mechanisms provide the opportunity to allow a desired upgrade or transmission solution to be built. Transmission solutions for necessary upgrades that do not have a positive benefit cost ratio for the region are permitted to be participant funded by either generators or states pursuant to public policy project rules adopted pursuant to Order 1000. Alternatively, an IC, or group of ICs, could opt to participant fund the project. The Commission should explore more creative mechanisms such as allowing participant funding to carry the capital cost of the project to meet the required regional cost benefit ratio, and the solution could then be partly split for cost allocation between load and the IC(s) and/or states based on the percentage by which load benefits from the project. These mechanisms are raised for future discussion and are beyond the scope of this proposal.

How Step 3 Addresses the Root Causes of Our Failing Interconnection and Transmission Planning Processes

The Regional Study that we propose addresses root causes #4, #5, and #6 that we identified in Table 1. By studying remote upgrades identified in the Screening Study collectively, and removing various layers of otherwise siloed planning studies, regional upgrades that are economically beneficial to load are more likely to be identified. Because the depth of the queue is dominated by renewable resources at this time, the resulting suite of economically viable upgrades will also identify viable transmission solutions reaching renewable energy rich areas. Economically viable projects provide the opportunity for incumbent Transmission Owners to sponsor Market Efficiency upgrades that are eligible from recovery by load, and for recovery of the applicable rate of return on investment. This will provide incentive for transmission expansion in near term planning horizons for those entities seeking transmission investment.

Step 4: Higher Interconnection Service and Transmission Service Request Studies

Following the Regional Study process and identification of both ERIS upgrades for ICs in the Screening Study (i.e. what the generator needs for ERIS) and regional upgrades in the Regional Study (i.e. what load wants to build in order to access cost-effective generation and maintain reliability), the TP will move to the final stage of the study process to evaluate higher levels of interconnection and transmission service requests for generators, such as NRIS, CIRs, Network Integration Transmission Service (NITS), Point to Point Transmission Service (PTP), or other transmission products needed for firming energy and capacity

[27] Under current precedent, the transmission owner would earn a rate of return on its investment, but not the portion of the project funded under the CIAC.

delivery (collectively referred to as “Higher Services”).[28] In many cases these Higher Services are required to provide a market product such as capacity accreditation, rights to participate in a capacity market, or hedges against congestion through firm service, and thus are not required for a generator to connect.[29] These products are primarily a financial trade-off between the cost of upgrades and the value of revenues received for the service provided.

We placed this study of Higher Services after the Screening Study and Regional Study for the following reasons. First, the proposal limits studies for these Higher Services o certain generators, reducing study volume, queue churn, and unrealistic results caused by less mature projects in the queue. Thus, it is desirable to perform these studies after the full security posting. However, posting full security for interconnection upgrades without full knowledge of NRIS/CIR/TSR results represents a significant financial risk to generators. To balance this risk to generators, the studies were placed after the Regional Study (which typically will not study generators at full output in reliability models). This will result in first identifying transmission that is optimal to load to better access the benefits provided by the new generation. This will likely provide at least partial granting of these Higher Services to most new generators. During this stage, the generators would need to evaluate the financial merits of increasing their Higher Service levels against any transmission upgrade costs associated with that service.

Study specifics

The TSR study determines if additional upgrades are needed to meet the IC’s requested interconnection service. Because the TSR study occurs after the Regional Study, the model’s baseline should include any upgrades related to the IC from the Screening Study and the Regional Study. This assures any additional interconnection service is additive and not duplicative. This will assist in meeting the generator’s deliverability needs. This gives the highest likelihood of generators receiving at least some critical capacity revenues and/or qualifying to meet resource adequacy requirements. It is possible that the upgrades identified in the previous study rounds could cover some or all the needed upgrades (and cost) to meet the IC’s TSR. This reduction in costs partially off-set the risk to generators of making investment decisions to enter regional planning window without prior knowledge of the likelihood of obtaining Higher Service.

Results

Like the Screening Study, we propose using a TDF threshold to identify any additional upgrades specific to the generator’s TSR. Using the same process in the Screening Study to allocate the cost of upgrades, the IC would be responsible for upgrade costs for facilities where the IC’s TDF exceeds a fixed TDF threshold such as 3% or 5%, which are commonly used today. Constraints below this TDF threshold would be ignored due to the minimal impact of the new Higher Service request on the constraint, as is done today.

Additional Considerations

For the purpose of this proposal, the timing of submittal for transmission service requests (TSR) is set at the conclusion of the Regional Study phase, step 3, as it is possible that available transmission capacity may arise from the selection of certain transmission projects at the Screening Study or Regional Study

[28] Types of interconnection service and the need for transmission service are addressed in the relevant TP’s OATT. Nothing in this proposal is intended to change the types of OATT service or interconnection service needed by a generator in any RTO/ISO or non-RTO/ISO control area. As noted previously, certain RTO/ISO regions have included levels of interconnection service within the GIP/GIA process such that the deliverability requirements of energy and capacity would have been studied with the initial IC request.

[29] Further consideration to the structure of this proposal related to NITS in non-RTO markets may be necessary.

phases. Requests for increased levels of non-ERIS interconnection service (e.g., NRIS or CIR) from generators which entered the regional study in a previous cycle would be required on a similar timeline. This proposal does not intend to preclude requests for transmission service at a point earlier in the process. However, in regions that follow the pro-forma OATT, the IC may benefit from submission of a TSR as the Regional Study is wrapping up as beneficial transmission paths may have been identified for upgrade or enhancement, thus allowing for more transmission capacity for the term requested.

Conclusion

There is an urgent need for reforming the generation interconnection process and for integrating the process with transmission planning. The need is becoming more extreme as the volume of projects wishing to construct and interconnect steadily rises. Across TPs, there are lengthy queue delays, uncertain timelines and upgrade costs, and insufficient transmission capacity preventing the timely development of new generation projects.

This proposal provides a mechanism that creates a level of certainty for queued projects for transmission planning purposes. By clustering necessary network upgrades from highly viable queued projects, these IC needs can be incorporated into the system planning process to identify economically beneficial and reliability enhancing transmission solutions that might only far later be identified under present planning processes. By adopting these mechanisms, the proposed process provides the opportunity to bring new renewable generation online that might otherwise not be built and assist in reaching public policy goals without increasing costs to ratepayers.

Collaborate with Enel Green Power

Enel welcomes feedback and suggestions for how to improve this proposal. Please contact the primary authors of this paper with any questions or recommendations.

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Appendix A - Frequently Asked Questions

1. Who is responsible for paying for which type of upgrades?
    a. This proposal does not address cost allocation principles such as participant funding or crediting. The proposal can function under either existing cost allocation methods or new cost allocation methods. Our proposal assumes that current cost allocation methods continue, but we support cost allocation reform as proposed by the Clean Energy Trades.

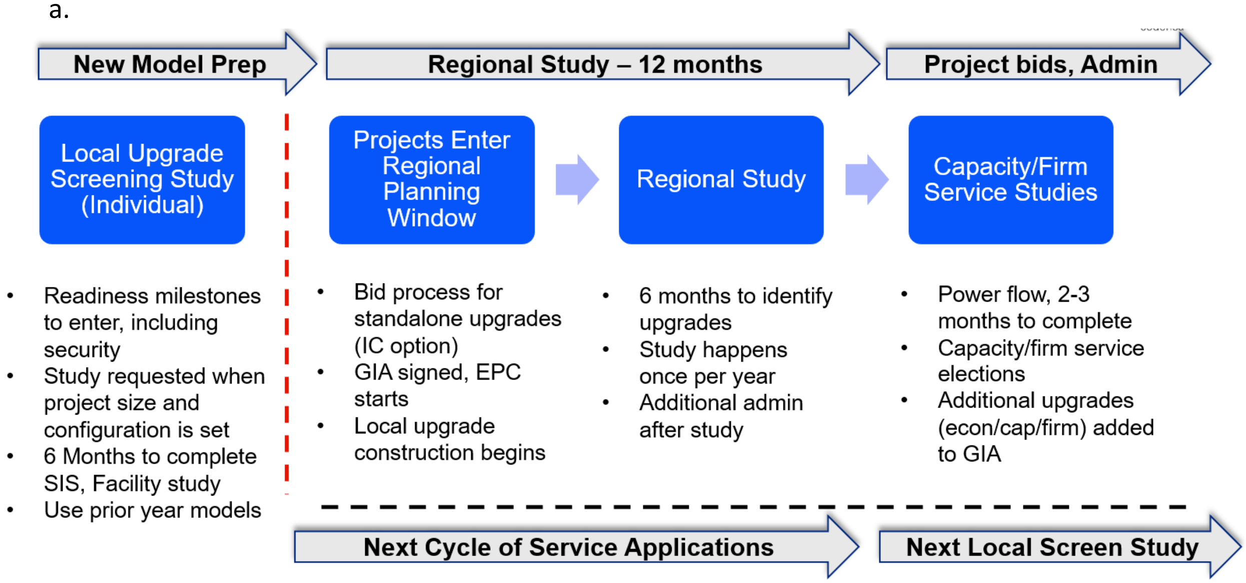
2. Regional transmission lines take years to build. Do generators looking to interconnect have to wait for the new lines to be built before they can come online?
    a. No, they do not need to wait until new lines are built before they can come online. Transmission Providers provide a variety of options for Interconnection Customers to bring their generators online before completion of the upgrades through various

regional processes, such as MISO's provisional and/or conditional interconnection agreements and quarterly operating limits studies, SPP's interim service process and limited operation studies, and PJM's interim deliverability process. However, until all upgrades are complete, generators continue to bear the risk of new assigned upgrade costs and/or their generator output being capped.

3. How do you differentiate between "local" and "regional"?
    a. This paper considers electrical distance to be a more accurate assessment than geographical distance of whether a transmission facility is local versus regional. The TDF metric, which calculates the percentage of a generator's output which flows on a specific transmission facility, is a good metric of the electrical proximity of a generator to the transmission facility as it involves the physics of electrical power flow on a transmission system.

4. What happens to transmission constraints with a TDF less than 20%?
    a. If no generators meet the 20% TDF criteria for a constraint, Transmission Providers would not assign any upgrades associated with resolving the constraint. This is similar to current practices in many parts of the country. The constraint would not be assigned to the Transmission Owner. The regional study process would evaluate whether the constraint meets the region's criteria for reliability or economic mitigation and what upgrades to build.

5. What would the timeline for the new process look like?
    a.



The diagram above represents an estimated timeline for our proposed process. Further consideration is needed to ensure an expedited but robust process.

As a first step, we propose to eliminate queue entry deadlines which can incentivize generators to rush to submit prospective projects that are not yet matured. These underdeveloped projects are more likely to fail on the development side. However, due to the tremendous delays in interconnection queue processing, ICs often pursue any avenue possible to try to make a queue position work before withdrawing it, knowing that a new submittal could take multiple years of additional time to wait for studies. Those additional years result in increased costs for maintaining site control or even loss of site control due to expiring terms, expiration of permits and other approvals obtained, and delay the construction of new generation which helps businesses meet growth targets and increases competition in the market which reduces cost to load. Thus, while queue backlogs are partly caused by developer behavior in flooding queues and sitting on queue positions with low likelihood of success, it must also be recognized that queue processing delays and the tremendous uncertainty involved in the interconnection process triggers much of that behavior. Eliminating queue entry "windows" or deadlines will lessen the sense of urgency to enter by a certain date and will allow interconnection customers to prepare their projects properly before entering the interconnection study process.

Once studies are done, regular entry points into the Regional Study should be established. It is highly recommended that these entry points be scheduled on a relatively frequent basis, such as quarterly, to minimize the impact of missing an entry window. Upon entry, the Transmission Provider would immediately kick off the facility study phase, which would be followed by the GIA and EPC work. The Transmission Provider would also specify which entry windows would be used to feed interconnection projects into a specific annual Regional Study.

ERCOT again provides an excellent framework for this approach. ERCOT has no queue entry deadlines and simply processes new requests as they are received. Interconnection projects must achieve certain milestones related to study completion, security posting, and site control to achieve various process milestones. These milestones ultimately lead to the Quarterly Stability Assessment (QSA), which involves a quarterly entry deadline. The entry deadline determines the earliest date the generator can begin synchronizing generating equipment to the grid.

Appendix B – Examples of problematic upgrade assignments using a low TDF

In Step 1, we discuss the use of a Transfer Distribution Factor (TDF), which measures the percentage of the electricity produced by a generator which travels on a given transmission facility. Our proposal uses a TDF threshold of 20% or greater and a voltage impact of 3% or greater by an individual project to identify network upgrades. The TDF concept is commonly used in interconnection processes today, but low TDF thresholds trigger regional upgrades and create a large degree of interdependency between projects. The following real-life example illustrates this point and the importance of using reasonable TDF threshold that is commensurate with the product of "as available" ERIS service.

Example - SPP Interconnection Request GEN-2017-048

Interconnection request GEN-2017-048 in the SPP queue is located in northwest North Dakota, roughly 35 miles from the Canadian border and 50 miles from the Montana border. GEN-2017-048 is requesting 300 MW of ERIS service and is not requesting NRIS service. It is clustered in SPP's DISIS-2017-001 cycle. In the second phase of its interconnection studies it was assigned about $3.9MM (~60% of the total cost, with the other ~40% allocated to a generator in southwest North Dakota) to mitigate a system intact constraint on an SPP transformer approximately 350 miles away in South Dakota, with a TDF range of approximately 9% to 13% depending on the system conditions. It was also assigned a Contingent Facility for a transmission line located over 450 miles away in Nebraska[30]. For identification of both network upgrades[31] and contingent facilities[32], SPP applies a 20% TDF for outage-based constraints, but only a 3% TDF for system intact constraints. SPP also has group impact criteria that assigns mitigations if the cluster of interconnection requests collectively increases the flow on a line by 20% of the facility's emergency rating and at least one generator has a TDF of at least 5%.

GEN-2017-048 was also assigned cost allocation for eight 69 kV thermal upgrades in Missouri on the Associated Electric Cooperative (AECI) transmission system (an Affected System), around 1000 miles away. Request GEN-2017-048 had an impact ranging from 0.4 MW to 1.2 MW on these eight constraints, or a TDF range from 0.1% to 0.4%.[33] Per the report, upgrades are assigned if the entire study group has a collective loading contribution to a facility of more than 3% of the facility's rating[34].

On top of the SPP and AECI assigned upgrades and contingent facilities, MISO assigned this same generator cost allocation for seven reactive devices (capacitors and SVC/statcoms) spread across eastern North Dakota, Minnesota, and Iowa, distances ranging from 280 miles to nearly 700 miles away.[35] Per the report, reactive power upgrades are assigned if the entire study group has a collective voltage impact on a facility of more than 1%[36].

The fifteen MISO and AECI upgrades were each shared by up to fourteen different SPP generation interconnection requests interconnecting in a region stretching from North Dakota to Kansas, creating a very tight interdependency between the projects and a high sensitivity to withdrawals and need for restudies in spite of the very significant geographic diversity between the projects. In total, GEN-2017-048 was assigned $17.6MM of upgrades to obtain ERIS interconnection service from SPP, with only $3MM of that amount (the project's facilities for physically connection to the grid) related to upgrades within 280 miles of the project's Point of Interconnection. Not only are there thirteen other generators which could withdraw and trigger re-studies, but there are also sixteen different transmission constraints which will require facility studies, multi-party facility construction agreements, and recurring limited operation studies by three transmission providers as various generators go in service prior to completion of the upgrades. Not only are these projects dependent on these upgrades, but future clusters of SPP, MISO, and AECI interconnection requests will also be constrained by these same

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[30] SPP's "DISIS-2017-001 Phase Two Power Flow" report/results spreadsheet, dated 4/28/2021, located at https://opsportal.spp.org/documents/studies/files/2017_Generation_Studies/DISIS_Results_Workbook_DIS1701P2-Power_Flow-Final-Reposting_v2.xlsx

[31] SPP's "Open Access Transmission Tariff Business Practices" section 7250, located at https://www.spp.org/documents/64300/spp%20oatt%20business%20practices%2020210724.pdf

[32] SPP's Open Access Transmission Tariff Attachment V Generation Interconnection Procedures section 3.8.1.

[33] AECI's "SPP DISIS 2017-001 AFR Study Report", dated 4/16/2021, located at https://opsportal.spp.org/documents/studies/files/2017_Generation_Studies/AECI%20AFS%20for%20DIS1701P2_V2.pdf

[34] Id. Page 4

[35] "Midcontinent ISO (MISO) Affected System Studies for Southwest Power Pool (SPP) Projects Phase II" dated April 2021, posted at https://opsportal.spp.org/documents/studies/files/2017_Generation_Studies/FinalReport-MISO_AFS-2017-DISIS_v2.0.pdf

[36] Id. Page 2-5

upgrades, either through identification as contingent facilities or because the upgrades eventually fall from cycle to cycle as interconnection requests are withdrawn and re-studies are performed.

As can be clearly seen from this example, stringent impact criteria thresholds create an excessive assignment of regional and even interregional upgrade costs for generators. These criteria dramatically increase the interdependency of queued projects both within and between interconnection queues, triggering an ongoing dependency on re-studies by both the host Transmission Provider and by Affected Systems. Independent entity variations are clearly allowing Transmission Providers to study interconnection service with overreaching criteria that places regional and interregional transmission needs on the backs of remote generation. The regional and interregional transmission upgrades are developed hastily and without adequate diligence by stakeholders, without regard to the feasibility of the solution (e.g. if right of way is available for new transmission), and are not evaluated using economic studies to refine the scope of the upgrades or compare between alternatives. All these outcomes point to the need for higher distribution factor and voltage impact criteria thresholds for assignment of upgrades so that the transmission system can be design thoughtfully and efficiently in regional (and interregional) planning processes.