Lessons from the Front Line:

Principles and Recommendations for Large-scale and Distributed Energy Interconnection Reform

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I. EXECUTIVE SUMMARY

The United States solar industry continues to rapidly expand, but outdated interconnection policies pose a major threat to solar and storage deployment across the nation. Because solar power is one of the lowest-cost resources for electricity and because solar paired with storage is also a way for customers to supply their own clean power and save money when compared with distribution utility costs, applications to interconnect solar and energy storage projects have skyrocketed.

Interconnection policies in regional transmission organizations ("RTOs"), vertically integrated utilities, and distributed utilities have not kept pace with the demands of this new energy marketplace. Interconnection procedures designed for the by-gone thermal generation era are not aligned with today's advanced technologies, and interconnection delays now constitute a major threat toward meeting state and national clean energy goals.

This paper advances a series of reform principles, as well as near-term and longer-term interconnection reform recommendations. With respect to general reforms that impact large-scale and distributed projects SEIA recommends that utilities and RTOs:

- Add staff, adhere to interconnection timelines, and advance needed policies related to planning, forecasting, and standards to ensure progress is made toward state and national clean energy goals;
- Automate and standardize processes where appropriate; and
- Collect more information about infrastructure upgrade costs for all types of projects and make them accessible to developers.

With respect to interconnection reform for large-scale projects, SEIA recommends that the Federal Energy Regulatory Commission ("FERC") standardize queue management requirements across RTOs and require each RTO to:

- Make better transmission system operating information more accessible to interconnection customers; and
- Explore alternate models for paying for network upgrade costs.

With respect to interconnection reforms for distribution level projects, SEIA recommends that state regulators require each distribution utility to:

- Improve and open the black box of distribution system planning and perform proactive forecasting and scenario development to meet state clean energy goals; and
- Provide greater transparency and accuracy of interconnection estimates of infrastructure upgrade costs using hosting capacity maps, through the study process, or through preapplication processes.

State regulators should also:

- Reform cost sharing for infrastructure upgrades and split costs between interconnection customers and other system beneficiaries; and
- Increase project maturity requirements for projects to enter the interconnection queues.

Finally, as smart grid technologies continue to be deployed, RTOs, vertically integrated utilities, and distribution utilities should stop solving for grid constraints that only exist in the system under limited conditions and start providing more flexible interconnection solutions that take the use of these technologies into account.

II. Inadequate Interconnection Policies Pose a Major Threat to State and Federal Decarbonization Goals

Encouraged by state and federal policies, solar markets across the nation have seen tremendous growth. The solar industry installed more than 20 gigawatts ("GW") of capacity in 2021, with utility scale projects accounting for 17 GW.[1] Distribution level projects have also been growing steadily as well, and now nearly 5 percent of viable homes for solar have residential solar systems.[2] Even with expected headwinds for many clean energy projects around the country with an average annual growth rate of 33 percent over the past several years, analysts still forecast increasing solar deployments, and solar paired with energy storage resources, for some time to come.[3] Because solar is now one of the lowest cost sources of electricity, and because customers can supply their own power with on-site solar resources, applications to interconnect large-scale and small-scale solar projects have skyrocketed.

In the PJM Interconnection L.L.C. ("PJM") alone, a large-scale power market that includes 13 states and the District of Columbia, approximately 153 GW worth of energy projects are waiting for interconnection agreements.[4] Based on the backlog, PJM has stopped accepting new interconnection applications for a year to focus on processing existing requests.

At the distribution utility level, companies building rooftop solar for customers and on-site projects for commercial customers have also increasingly seen interconnection delays. And the attractive sites capable of interconnecting larger distributed projects, such as community solar projects, without the need for major technology upgrades have dwindled. For example, despite an ambitious solar incentive program and aggressive

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[1] *See* U.S. Solar Market Insight Report, 2021 Year in Review. Wood Mackenzie, SEIA. March 2022. p 5.

[2] Ibid.

[3] Ibid. These headwinds also include a very damaging trade petition at the U.S. Department of Commerce that would impose punitive solar import tariff and has temporarily frozen the solar market.

[4] *See* https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

clean energy goals, initially 900 megawatts ("MW") worth of Massachusetts solar projects were delayed in 2020 due to various interconnection study processes by the distribution utilities as well as the RTO. For some of these projects, there is no clear timeline for resolution.[5] Similar issues have emerged in Maine. Together, more than 1,300 MW worth of distributed solar projects remain stymied by interconnection bottlenecks in Massachusetts and Maine.[6]

Furthermore, large-scale solar projects are interconnecting to an aging transmission system built for fossil fuel-fired, central station power plants. Clean energy projects are coming online to replace these fossil fuel plants, but the retirement of a single centralized coal plant typically results in multiple solar projects, in different areas, coming on-line to meet system needs. And as a result, new transmission facilities are needed to allow those new projects to interconnect to the grid. This, and the fact that the transmission system is aging and requires the replacement of many transmission assets, has resulted in prohibitively high infrastructure upgrade costs. In other words, increasingly expensive improvements to the grid are needed to connect projects.

High upgrade costs are also now emerging on the distribution system as the number of less constrained interconnection points are dwindling in key states and bi-directional power flows are becoming the norm. These smaller-scale projects must also rely on an older, less functional grid, that was only designed only to transmit power from generators to end users, and not from multiple customer generators across the system.

If distribution utilities, vertically integrated utilities, and RTOs are going to reach state and national clean energy and greenhouse gas ("GHG") reduction goals, such as SEIA's goal to supply 30 percent of the nation's electric power by the year 2030, or the Biden Administration's goal to reduce economy-wide GHG levels approximately 50 percent by 2030, then legislators, regulators, and utility operators must adopt key interconnection reforms as soon as possible.

This paper explains principles that should guide reform, proposes near-term reforms to encourage the faster connection of distributed and large-scale projects, and lays the foundation for longer-term interconnection changes.

Failing to adopt meaningful interconnection reforms will slow progress toward efforts such as transitioning to electric vehicle fleets, switching to electric heating sources for buildings, and cleaning up the national electric generation fleet. Without more carbon-free sources of energy such as solar and storage to power these cars, buildings and homes, decision-makers will see many of their decarbonization goals go unrealized.

[5] There are also examples of approved distribution utility projects that have been subject to further study by the RTO leaving some projects in permanent limbo and without any clear timeframe for resolution.
[6] *See* U.S. Solar Market Insight Report, 2021 Year in Review. Wood Mackenzie, SEIA. March 2022. p 31.

III. THREE INTERCONNECTION REFORM PRINCIPLES

Based on extensive discussion with leading SEIA member companies, outside interconnection experts, and SEIA's on-the-ground experience, the following three principles should guide all interconnection reform discussions at both the RTO and utility level.

a. Interconnection Processes Must be Detailed, Transparent, and Clear

Any entity that oversees the interconnection of solar and storage projects must establish rules with clear, enforceable timelines for key activities. Regulators must establish detailed timeframes for the utilities or RTOs to process applications, complete project impact analyses, ensure the timely construction of interconnection infrastructure and conduct final inspections before energizing the project. Further, utilities and RTOs should provide infrastructure upgrade cost estimates that are as accurate as possible and estimates for infrastructure upgrades needed before interconnection, as soon as practicable in the interconnection process.

Relatedly, distribution utilities, vertically integrated utilities, and RTOs should publish more information about areas on the bulk power grid, and on the distribution utility grids, where power projects of all sizes could help meet system needs. This information should be available upon request to any interested stakeholder, as well as updated regularly. Not only is this information useful to energy project developers, but it would also help regulators, customers, and businesses seeking clean electricity.

b. Interconnection Rules Must Be Rigorously Enforced

The rules regarding tasks, timelines, and responsibilities should be rigorously enforced by oversight entities. Policies to improve performance, including penalties, should be used to ensure utilities are meeting and conducting timely studies and interconnecting large and small generators. To avoid penalties, based on our interviews and experience, too often distribution utilities will unilaterally "stop the clock," for a variety of reasons, resetting interconnection timelines with little explanation of delays or transparency regarding new targeted dates. At the large-scale level, long delays in RTOs processing requests based on lack of staff create a vicious cycle when large numbers of projects unable to stay in the queue for three to four years, withdraw from the queue, creating cascading restudies from those withdrawals, and further delay the processing of interconnection requests. Tariffs set timelines for processing interconnection applications, but then only hold utilities and RTOs to the "reasonable efforts" standard, a standard that FERC has never found to be violated.[7] Distribution utilities often rely on the outdated practice of conducting studies sequentially without following industry best practices to manage multiple applications at once in a timely and efficient manner. As a

[7] *See Tenaska Clear Creek Wind, LLC v. Southwest Power Pool, Inc.*, 177 FERC ¶ 61,200 (2021) (Clements Dissent at p 1).

result, an interconnection application can remain on hold for a long time before a study is commenced.

Utilities should not be able to simply reset interconnection timelines based on updating analysis that is only indirectly relevant to the project, or simply because they have too many applications to consider. Regulators must hold utilities and RTOs to a higher standard for processing interconnection applications, and provide the adequate incentives, or disincentives, for utilities and RTOs to process interconnection requests in a transparent and timely manner.

c. Infrastructure Upgrade Cost Estimates Must Be Reasonable, Directly Related to the Connecting Project, and Durable

When an infrastructure upgrade is needed to connect a project, either on the distribution system or the transmission system, the cost estimate that is provided to the interconnecting customer must be reasonable, transparent, and reflect the costs needed to connect safely to the grid. Such upgrade costs must also be commensurate with the project in terms of size and geography.

For example, for a distributed project grid upgrade costs should not be based on assumptions that the project and the accompanying upgrade would result in complete protection against total transformer and system failure. This kind of over-protection and system gold plating only drives up cost and kills projects.

Furthermore, for large-scale projects, analyses related to system impacts of connecting a project should be limited to areas on the transmission system that are most likely to be affected by the new resource, not distant RTO zones or utilities that would only be affected during a widespread system failure.

Lastly, for both large-scale and distributed projects, in cases where preliminary assessments of costs are provided, the final costs must be “durable,” or in other words, within a reasonable range of the initial estimate. Too often, developers run into issues where an infrastructure upgrade cost is identified, but final cost estimates or actual installation costs balloon to several times the initial estimate with little oversight; significantly impacting the economics of the project and in many cases causing the project to drop out of the queue.

IV. General Recommendations for Interconnection Reform

The following reforms are applicable to both transmission and distribution interconnections.

a. Encourage RTOs and Utilities to Recruit and Maintain Staff

The RTOs and utilities need to add staff to process applications, work through issues, conduct studies, and move projects through the queue faster than ever before.[8] RTOs and utilities need to forecast resourcing needs proactively in response to climate goals and regulatory programs and hire adequate interconnection support and engineering staff, redeploy existing staff, and generally prioritize this work. RTOs and utilities need to ensure there is adequate capability to deal with increased interconnection requests to the distribution and transmission system, in addition to evolving transmission and distribution planning needs that may require additional or shared functional staff to support the climate goals of the state and/or region.

b. Require Adoption of State-of-the-Art Study Processing Methods

Utilities and RTOs should create automated, web-based portals for submitting interconnection requests and for rapid information exchange. These web portals should include centralized, searchable databases for commonly asked questions, lessons learned, and standardized data collection and entry. To the extent possible, utilities and RTOs should develop automated processes for application intake, studies, and project modification submissions, to reduce delays associated with lags in information exchange and review between interconnection process stakeholders.

Relatedly, the RTOs and distribution utilities should move toward publishing interconnection queues that provide *real-time* updated information on the queue itself, so the market has insight into project status as well as metrics that show how quickly or slowly projects are moving through the interconnection process. This real-time information would help developers and customers and allow stakeholders to more accurately forecast construction timelines for new resources on the system. Regulators should require utilities and RTOs to report these data to track and monitor their progress and for use in measuring performance and for enforcement.[9]

c. Collect Infrastructure Upgrade Cost Data

Although a number of states collect information on interconnection upgrade costs for completed projects, to our knowledge no state or RTO is systematically collecting information on interconnection project estimates for *all* complete project applications or the corresponding *estimated* costs to interconnect those projects.

High interconnection costs can be the difference between a project moving forward or being withdrawn. Furthermore, monopolistic utilities have historically no incentive to provide accurate or transparent costs to better inform customers throughout the interconnection process. Based on our members' experience, utility cost estimates do not often correspond to market prices for materials or labor and therefore transparency into additional utility "adders" or "overheads" would provide needed insight into how

[8] State regulatory agencies should also dedicate more staff to providing oversight of utility interconnection work.

[9] *See Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043 (2018), *errata notice*, 167 FERC ¶ 61,123, *order on reh'g*, Order No. 845-A, 166 FERC ¶ 61,137, *errata notice*, 167 FERC ¶ 61,124, *order on reh'g*, Order No. 845-B, 168 FERC ¶ 61,092 (2019).

utilities arrive at their cost estimates. More comprehensive data should be collected and reported that shows interconnection infrastructure upgrade costs assigned to pending, active or withdrawn projects in the queue, including:

- The estimated cost of interconnection facilities and/or network upgrades associated with the project;
- The actual cost of interconnection facilities and/or network upgrades associated with the project; and
- A breakdown of the interconnection delays by transmission zone, or feeder line, to determine whether there is a particular transmission owner or utility associated with the interconnection delays.

These data points would be tremendously useful to interconnection customers and would help educate the market about system needs, as well as provide more useful information to regulators about the state of the grid itself.

d. Consider Interconnection Reforms Alongside Updated Clean Energy Policies

Based on our direct experience in key states, policymakers and regulators should ensure that interconnection policies evolve and keep pace with changing clean energy goals. For instance, when a state enacts policies to: create a community solar program, adopt incentives to encourage distributed solar, increase renewable energy procurements, or increase its renewable or clean energy portfolio standard obligations, decision-makers should also be thinking about the needed changes to interconnection to make achieving the goal possible.

Too often states have passed ambitious laws and watched their implementation timelines slip and programs run into trouble because policymakers failed to consider outdated interconnection rules. These delays have serious consequences, including freezing development capital, increasing project transaction and financing costs, and slowing the deployment of clean energy. At the very least, policymakers should always direct regulators to review interconnection rules when they are making any major changes to clean energy policy, if not outright direct specific additional reforms with hard timelines for implementation.

V. NEAR-TERM LARGE-SCALE INTERCONNECTION REFORMS

For large-scale solar and storage projects, the following recommendations apply to needed interconnection changes in RTO and vertically integrated transmission utilities.[10]

a. Provide System Operating Data and Study Assumptions to Project Developers

More transparent and more granular transmission system information is an important element to improving the large-scale interconnection processes. The transmission planning process should provide more information to generation developers on points of interconnection with the lowest likely interconnection costs. Generation developers suffer from information asymmetry with respect to project siting. Project developers do not know how costly network upgrades will be until they are far along in the interconnection process—so to obtain this information, projects need to enter the interconnection queue. This is inefficient for project developers and for transmission providers.

Instead, transmission providers should make available, on a secured website, the following:

- Study models and assumptions that will be used for each cluster of projects to be studied;
- A list of the transmission lines that are currently capacity-constrained and a list of lines expected to be constrained once certain projects in the queue come online;
- Information on transfer capability and points of interconnection of planned transmission; and
- A database of FERC jurisdictional distribution and sub-transmission lines to clarify the interconnection rules to which the interconnection customer would need to follow.

This information, coupled with the requirement to provide interconnection customers with the option of using third-party consultants to produce required studies, would help unclog interconnection queues by encouraging better project planning by developers and eliminating the need for these "exploratory" requests. [11]

b. Standardize Queue Management Requirements

The slow pace of completing interconnection studies is increasingly becoming a major roadblock to bringing large-scale resources online. Study timelines vary by RTO, but

[10] Reforms related to large-scale interconnection reforms were first proposed by SEIA, along with American Clean Power and Advanced Energy Economy in comments submitted to FERC on February 14, 2022. *See* Comments of the Clean Energy Coalition, FERC Docket No. RM21-17 (Feb. 14, 2022). This whitepaper elaborates on several proposals in the February FERC comments.

[11] *See* section V.c. infra. p 10.

large-scale projects are often forced to spend significant upfront capital and then wait sometimes up to five years, in the case of PJM, for studies to be completed.

While FERC Order No. 2003 and Order No. 845 show that there is a need for independent entity variations in certain instances, there are certain queue management practices that are unrelated to geographical and market differences that could be standardized across the regions. These include:

- Standardizing interconnection milestone requirements for receiving applications, maintaining progress through the application process, or suspending queue positions.
- Establishing a "first-ready, first-served" process, and requiring projects to demonstrate project readiness earlier in the process. These demonstrations would include:
    - site control;
    - a demonstration of permitting progress, either filed applications or received permits;
    - an executed power purchase agreement or other significant financial agreement to show project viability; and
    - the payment of "gated" deposits that increase as the project moves through the review period.
- Standardizing interconnection study deposits from developers, as well as procedures and penalties for project withdrawal.
- Requiring that utilities use the same assumptions for interconnection studies that they use in their transmission planning studies.

c. Explore New Models for Paying for Network Upgrade Costs

There are several proposals before FERC today involving revisiting the question of who pays for the required network upgrades to interconnect large-scale projects. Under most tariffs, the interconnection customer pays 100 percent, or nearly 100 percent, of these costs. So called "participant funding" was intended to address certain concerns, including the efficient siting of resources.[12] Consumer advocates often view participant funding as a way to protect retail ratepayers from the cost of network upgrades.

However, with the change in resource mix, and the lack of significant upgrades to the transmission system, those concerns are not as prevalent as they once were. The efficient siting of renewable resources not only includes access to transmission, but also siting in areas that would provide optimal access to solar and wind injections.

[12] *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, P 695 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

Going forward, FERC should do away with the participant funding and crediting mechanism entirely, instead requiring transmission providers to establish a fee, separate from any interconnection deposit, based on project size, to be charged for submitting an interconnection request.[13] For projects that require network upgrades, the fee would be applied towards the cost of the network upgrades. The remaining cost of the network upgrade would be allocated to the load zone served by the project.[14]

d. Reform the Transmission Planning Process

While reforming the interconnection process is necessary, the queue backlogs generators currently face are just symptoms of a flawed transmission planning process. On April 21, 2022, FERC issued a Notice of Proposed Rulemaking that would require RTOs and transmission utilities in non-RTO regions to engage in long-term, forward-looking planning that incorporates factors, such as federal, state, and local laws and regulations that affect the future resource mix and demand; trends in technology and fuel costs; resource retirements; generator interconnection requests and withdrawals; and extreme weather events.[15] The demand for clean energy will continue to grow. States will continue to set clean energy goals. Large, sophisticated customers will continue to demand clean energy.[16] Better transmission planning that encourages new transmission to serve growing demand from a diverse set of resources will help address many of issues causing the interconnection queue delays.

e. RTO/Utilities Can Head Off Affected Systems Problems

Furthermore, the RTOs and utilities should proactively engage affected parties to find proactive solutions when affected system issues arise. Project developers occasionally run into roadblocks when, upon analysis, their project is projected to have an impact on a neighboring transmission system. RTOs/utilities, however, can come up with solutions to these kinds of problems without waiting for FERC or another utility to act. When RTOs/utilities work together to plan for seams issues triggered by a large-scale project ultimately more clean energy projects can be interconnected to the grid based upon joint

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[13] *See* Comments of the Solar Energy Industries Association, Docket No. RM21-17 (Oct. 12, 2021).

[14] Should a fee structure not be implemented, FERC should adopt a methodology that encourages developer certainty for any cost allocation of upgrade costs, such as cost cap.

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

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

transmission projects.[17] By working collaboratively with developers, grid managers can unlock tremendous value for customers.

VI. Near-Term Distributed Utility Reforms

a. Improve Distribution System Planning and Prioritize Climate Goals

Any discussion of interconnection reform by distribution utilities must begin with the need for better, more transparent, distribution system planning. Even leading states that have put effort into improving the distribution planning process, such as New York, have a long way to go toward making the distribution planning process more in-line with the needs of a modern utility system.

Planners must look at the exercise through the lens of envisioning a decarbonized grid, maintaining reliability and promoting grid resilience. Transparent and proactive distribution system planning would provide project developers insight into utility operations, steer projects to locations on the grid that would help improve resiliency, support future electrification, or defer massive infrastructure upgrades. Thoughtful planning can ensure that infrastructure is built to serve the needs of the state instead of becoming a bottleneck on the pathway to decarbonization.

Ideally, through the distribution planning process the utility would forecast distributed energy resource ("DER") growth, identify saturation points on their systems, and then plan a combination of cost-effective solutions to improve reliability and increase hosting capacity. Solutions such as installing more DER and energy storage to offset or delay grid infrastructure and improve ratepayer benefits should also be considered.

Too often the distribution planning process is a "black box" which provide market participants very little input or insight.[18] Regulators should require utilities to open this box and include the industry and other distribution-system users in early discussions regarding forecasts, scenarios, market trends, and technology and technical assumptions. Too often utilities simply retreat behind closed doors, produce their plans, and drop them on the stakeholder community, as well as regulators with very little explanation or opportunity to meaningfully engage. Although better system planning will not solve every interconnection problem, better planning will help improve the accuracy of estimating interconnection upgrade costs and would be helpful when considering changes to cost sharing.

[17] Michael Goggin, Rob Gramlich, Michael Skelly, Transmission Projects Ready to Go: Plugging in to America's Untapped Renewable Resources, at 4 (April 2021), https://cleanenergygrid.org/wp-content/uploads/2019/04/Transmission-Projects-Ready-to-Go-Final.pdf

[18] *See* https://www.seia.org/sites/default/files/resources/SEIA-GridMod-Series-2_2017-July-FINAL_0.pdf

b. Provide Accurate Estimates of Infrastructure Upgrade Costs Up Front Or Use a Preapplication Report

Ideally, enough system information and accurate hosting capacity maps would be available to allow developers to make informed decisions about whether to pay the required interconnection upgrade costs. If a developer knows upgrade costs will run from $500,000 - $1,500,000 they may choose to avoid a full application process, saving the need for more exhaustive studies and analysis.

However, where that information is not yet available distribution utilities should establish a low-cost, pre-application process for DER project developers that may be used as a screen to understand potential interconnection upgrade costs. Project developers should be able to submit a pre-application proposal to the utility that scopes out the project location, size, configuration, and interconnection point. The proposal should yield a durable estimate of the interconnection upgrade cost needed at that site to safely connect the project. This is a no-regrets approach, employed by at least 12 states, that could save project developers and utilities considerable time and effort later in the interconnection process.[19]

These initial estimates, while they can be transmitted in ranges of likely costs, should also be reasonable. The final costs should not be significantly higher than the initial estimate. Too often, projects receive the final cost estimate near the end of the development process that is orders of magnitude greater than the initial estimate, resulting in the developer withdrawing the project from the queue. Establishing a pre-screening process can prevent the inefficiencies resulting from late-stage withdrawals.

c. Reform Cost Sharing for Infrastructure Upgrades

A major issue in distribution utility upgrades involves the problem of sharing costs among multiple DERs that benefit from an infrastructure upgrade. Under the current practice, the project developer, not the utility, pays for any upgrade needed to connect their project. This practice sometimes results in benefits not just to the interconnection project owner, but also to the customers of the utility. But these benefits also accrue to subsequent interconnection customers as well, often creating a free-ridership issue that is becoming a critical barrier to renewable energy deployment. There are several issues with this model that need to be revisited.

1. First Mover Problem

Under the first mover problem, one project developer makes an initial investment in interconnection network upgrades that ultimately results in benefits to several, subsequent interconnection customers. For example, developer A pays $1 million for an infrastructure upgrade to connect their project, which results in additional capacity for connection on the distribution grid. Then developer B connects their project to the same

[19] *See* Zachary Peterson and Eric Lockhart, Evaluating the Role of Pre-Application Reports in Improving Distributed Generation Interconnection Processes, https://www.nrel.gov/docs/fy19osti/71765.pdf.

location, without incurring these costs, instead benefiting from the upfront investment made by developer A.

Unless a developer agrees to pay the infrastructure upgrade costs, much needed clean energy capacity is unlikely to be installed on the grid in the first place. With upgrade costs increasing on a year-to-year basis, significant amounts of DERs are not being developed because no developer is willing to pay interconnection upgrade costs that are higher than project returns. Given the magnitude of the challenge at hand, regulators need to come up with a better way to unlock areas on the grid that accommodate more distributed resources.[20]

To solve the first mover problem, first state regulators should consider revising who pays the costs for infrastructure upgrades. Additionally, regulators should establish a set amount of interconnection upgrade costs developers should pay and split remaining costs with the broader class of utility ratepayers who are also benefiting from the upgrade. Although establishing the developer contribution would require more technical analysis, this approach would help unlock much more clean energy potential on the grid and is under consideration in some jurisdictions. For example, Massachusetts is considering a model where developer contributions would be set on a $/kW basis that is known in advance of applying for interconnections, with a portion of potentially being socialized among utility ratepayers. This proposal has considerable promise and should be replicated in other states.

2. Unfair Cost Allocation Problem

The second issue involves fairness and we return to our example. Developer B benefits from the grid improvement paid for by developer A. Unless developer A paid in the first instance, any remaining projects wouldn't even be able to interconnect at all, let alone serve the need for their customers. Let's call this the "unfair allocation" problem. There are drawbacks to this approach. The first interconnection firm is still responsible for the entire cost of the upgrade, placing all the risk on the first developer. And some upgrade costs are so large that virtually no project by itself or jointly, can pay for the needed improvement.

To solve the "unfair allocation" problem, a few states have experimented with different approaches. Going back to our example, New York authorized developer A to collect a portion of the paid upgrade costs from developer B on a pro-rata basis. Connecting firms would be required to pay the firm making the initial upgrade, and any subsequently interconnecting firm would reimburse the first two firms. To date, however, this collection method was seldom used. As a result, in a second round of interconnection reforms, New York then authorized utilities to pay for the cost of upgrades in the first instance, and then collect from developers their pro rata share.

[20] Note that this problem will happening more frequently in utility territories as the low-hanging fruit of easy interconnection sites are taken.

Now Massachusetts is considering a similar approach. However, with the Massachusetts model, the utility pays the upgrade costs in the first instance and the utility charges firms on a pro-rata basis their share of the cost upgrade after interconnection, with ratepayers paying for the costs in the interim and being reimbursed as new projects pay their pro-rata fee.

d. Increase project maturity requirements for large DG

Finally, similar to our recommendation for transmission system projects, distribution utilities should establish a "first-ready, first-served" process, requiring projects to demonstrate project readiness earlier in the process. To enter the distribution utility queues after the preapplication stages, projects should be required to show a) site control, b) detailed design specifications, and c) the developing firm should be required to pay up front deposits.

These maturity requirements ensure that serious projects enter the queue and have a better chance toward reaching commercial operation, instead of more speculative projects that would waste the utility's time conducting studies when they have very little chance of reaching fruition.

VII. Long-Term Interconnection Reforms

The recommendations considered above should be considered near-term objectives for reform and will help RTOs and utilities improve their processes and make progress toward achieving state and federal policy goals. These are immediate steps that will help speed up the connection of clean energy resources.

But in the long run, even these common-sense improvements will be insufficient to drive the rapid interconnections that will be needed to completely decarbonize the electric system and meet the demands of growing electric load. After quickly executing on the near-term reforms, regulators should begin considering more systemic changes for both RTOs, vertically integrated utilities, and distribution utilities.

One concept that regulators should consider is providing "flexible" interconnection options to large-scale and small-scale clean energy resources. A flexible interconnection agreement connects the resource without major infrastructure upgrade cost but uses controls to monitor the state of the grid at any given time and adjust the project's output to respond to changing conditions.

While flexible interconnection has become standardized in some European countries, only a variety of small demonstrations have taken place in the US. New York stakeholders are potentially the furthest along, where Avangrid worked with Smarter Grid Solutions to connect large-scale solar to constrained distribution feeders. Their Spencerport solar projects were initially approved for only a combined 2.6 megawatts of firm connection. Using the flexible interconnection framework enabled 15 megawatts to connect.[21] As these projects demonstrate, providing flexible interconnection choices, coupled with smart grid technology investments, can provide interconnections solutions when typical approaches are cost prohibitive. New York stakeholders are now actively considering demonstration options from all the other utilities and are considering revisions to add flexible interconnection to their standardized interconnection requirements.

Today's interconnection procedures are organized around the concept that headroom or hosting capacity is limited based on static, snapshot of worst-case conditions. Regulators must keep in mind, however, that most parts of the grid have approximately 50% utilization annually. To a great degree, grid constraints are rare operating conditions compared to annual availability of most transmission or distribution lines. Instead, more aggressive deployment of smart grid technologies and grid management tools could avoid the need for many infrastructure upgrades.

In brief, in thinking through long-term interconnection reforms, regulators and utilities should be looking at the entire range of options to modernize that grid, not simply infrastructure upgrades, reconductoring lines, or building new substations, and come up with options for interconnecting projects that take customer flexibility and these newer technologies into account.

The same concept applies on the distribution grid. Market choice for firm versus flexible interconnection is equally applicable for in front of the meter large, distributed generation, and even for large behind the meter systems too. Small, distributed generation, less than 25 kilowatts, for residential and small business should aim to be further streamlined by moving to a "connect and notify" approach. This way controllable generation and storage are treated fairly with small customers connecting new controllable loads like electric vehicle charging or heat pumps.

With a more actively managed grid, RTOs and utilities would prioritize smart grid and customer flexibility solutions as the most affordable ways to modernize the electric system. Therefore, providing developers with the choice between firm versus flexible interconnection options on how to connect to "constrained" networks may lead to better outcomes, and potentially significant savings for ratepayers.

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[21] *See* Renewable energy generation boosted by more than 100% in US-first demonstration project (Dec. 8, 2021). https://www.powermag.com/press-releases/renewable-energy-generation-boosted-by-more-than-100-in-us-first-demonstration-project/