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Interconnection: Connecting Generation Resources and Energy Storage Systems to the Electric Grid

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Status: **Maintained** | Jurisdiction: **United States**

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A Practice Note discussing the process of connecting an energy generating or battery storage facility to the electric grid and the legal and regulatory framework applicable to the interconnection process. This Note also discusses key issues that developers and investors should consider when connecting to the electric grid, including site location, timing, and financing.

Interconnection presents important issues and considerations for developers, whether the energy project involves new solar panels mounted to the roof of a home, a five megawatt (MW) community solar project, an 80 MW small power production qualifying facility, or a 600 MW natural gas generating station. It is one of the major challenges developers face to bring their projects online and to integrate more renewable energy resources in the power grid.

This Practice Note is a high-level overview of the nature and process of interconnecting commercial or utility-scale electric generating facilities to the electric grid. It discusses:

- The interconnection process, including how a developer can initiate the process.
- The legal and regulatory framework applicable to the interconnection process.
- Key issues developers and investors should consider when connecting to the electric grid.

Interconnection Overview

When a project developer builds a new electric generating facility or battery energy storage system (an energy facility), it must connect that facility to the electric or power grid to allow the produced electricity to be transmitted, distributed, and consumed by end users (whether residential or commercial). Interconnection refers to:

- The administrative procedures, rules, and technical standards grid owners and operators (collectively referred to in this Note as grid operators) use to evaluate potential effects associated with the connection of an energy facility to a larger electric power system. The larger electrical system may be the interstate high voltage transmission system or a local distribution system, depending on the location of the energy facility and other factors.
- Contractual agreements that set out operational and cost responsibilities between the owner or operator of a transmission or distribution system to which the energy facility is connecting and the owner of the energy facility.

Jurisdiction Over the Interconnection Process

Under the Federal Power Act (16 U.S.C. §§ 791a to 828c), the Federal Energy Regulatory Commission (FERC or the Commission) has jurisdiction over the wholesale electricity markets, the interstate transmission system, and the rules and procedures involved to interconnect generating and energy storage facilities to the transmission system (16 U.S.C. § 824(b)). The states have jurisdiction over retail electricity sales, local distribution systems, and the processes involved to connect an energy facility to a local distribution system. This division of regulatory authority applies even if the energy facility is interconnecting to a local distribution

system to participate in FERC-jurisdictional wholesale electricity markets. FERC maintains and courts have upheld that FERC has jurisdiction over all aspects of the wholesale electricity markets. In theory, FERC could exercise jurisdiction over distribution level interconnections to the extent they affect access to the wholesale electricity markets, but FERC has so far declined to exercise that jurisdiction (see, for example, *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations & Independent System Operators*, 172 FERC ¶ 61,247, at P 90 (2020)).

Role of the Grid Operator

To connect to the electric grid, a project developer initiates the interconnection process by submitting an interconnection request to the applicable grid operator. The grid operator may be:

- A utility.
- A regional transmission organization (RTO) or an independent system operator (ISO).
- A federal power system.

Most transmission infrastructure (lines, poles, and other equipment) to which a project developer is looking to connect their energy facility is owned by utilities. Depending on their location, the utilities may also operate this infrastructure. However, in much of the US, utilities have transferred operational control of their transmission infrastructure to ISOs and RTOs. Utilities that have transferred operational control of such infrastructure are often referred to as participating transmission owners.

ISOs grew out of FERC efforts to ensure independent power producers (IPPs) had access to utility-owned transmission facilities on a non-discriminatory basis (see Order No. 888, 75 FERC ¶ 61,080 (Apr. 14, 1996) and Order 889, 75 FERC ¶ 61,078 (Apr. 24, 1996)). FERC also encouraged the voluntary formation of RTOs to administer the transmission grid on a regional basis throughout North America (including parts of Canada) (see Order No. 2000; Transmission Planning & Cost Allocation by Transmission Owning & Operating Public Utilities, 136 FERC ¶ 61,051 (2011)).

The seven RTOs and ISOs, covering about two-thirds of the electricity consumed in the US, are:

- The Midcontinent Independent System Operator (MISO).
- The Pennsylvania New Jersey Maryland Interconnection (PJM).
- ISO New England (ISO-NE).
- The New York Independent System Operator (NYISO).
- The California Independent System Operator (CAISO).
- The Southwest Power Pool (SPP).
- The Electric Reliability Council of Texas (ERCOT) (though ERCOT, which operates entirely within Texas, is not subject to FERC regulation).

Sales of electricity (even on a wholesale basis) within the ERCOT area are considered intrastate and outside of FERC's regulatory authority because the Texas Interconnection, which covers the ERCOT area, is separate from any other transmission network.

In certain cases, the transmission infrastructure is owned by a federal power system that sells electricity generated from federally owned energy facilities. These federal agencies are:

- The Bonneville Power Administration, which operates transmission systems in the Pacific Northwest.
- The Western Area Power Administration, which operates transmission systems in the Southwest.
- The Tennessee Valley Authority, which operates transmission systems in the Southeast.

Transmission Versus Distribution Interconnections

One of the most significant decisions a project developer must make for their energy project is siting. Distance to the existing electric grid, the character of that existing infrastructure, and whether there remains unused transfer capacity on that transmission system can make a huge difference in the cost required to interconnect and whether the site is a feasible location for the project (see Practice Notes, Wind Energy Project Development Issues: Preliminary Considerations: Site Analysis and Solar Energy Project Development Issues: Preliminary Considerations: Site Identification and Solar Resource Analysis).

How the energy facility interconnects to the electrical grid is also an important component of the siting equation. Whether an energy facility seeks to interconnect to the distribution grid or the transmission grid dictates many aspects of the interconnection process, including:

- The regulator that has jurisdiction (see Regulatory Authority).
- The time it takes to secure an interconnection agreement (see Duration of the Interconnection Process).
- The costs the interconnection customer can realistically expect to incur (see Costs Associated with Interconnection).

Regulatory Authority

One main difference between transmission lines and distribution lines is voltage. Transmission lines are generally higher voltage, while local distribution lines are lower voltage (typically 100 kilovolts or less). FERC employs a seven-factor analysis to evaluate whether infrastructure is transmission or distribution.

FERC exercises jurisdiction over the rates, terms, and conditions regarding interconnection to and usage of interstate transmission infrastructure in the US. By contrast, distribution infrastructure is subject to state public utility commission (PUC) or public service commission (PSC) oversight.

Duration of the Interconnection Process

The time it takes to secure an interconnection agreement depends largely on the size of the energy facility and the operator of the electric system to which the energy facility is connecting. Project developers may submit an interconnection request either to an RTO/ISO or, if none exists, directly to the relevant transmission owner, which may be a utility or a federal power system.

RTO-administered regions typically have the longest queue processing times (duration from interconnection request to executed interconnection agreement), particularly for large projects (those greater than 20 MW). According to the Lawrence Berkeley National Laboratory (Berkeley Lab)'s 2024 analysis of national transmission interconnection queues, PJM and NYISO have the longest median queue times at about 40 months, with the other ISOs faring marginally better but with medians still exceeding 30 months (see Berkeley Lab: Queued Up: 2024 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 (Apr. 2024)). The median queue processing times in non-RTO regions are shorter by several months, with ERCOT reported to have the shortest processing time at around 20 months. These queue processing times are expected to be substantially improved following the full implementation of new regulations governing interconnections (see Practice Note, Understanding FERC Order No. 2023: Framework for Connecting to the Electric Grid).

Projects with a nameplate capacity of 20 MW or less typically experience much faster processing times, with a median processing time of 18 months for projects between 5 MW and 20 MW, decreasing further to 11 months for projects sized five MW or smaller.

Distribution-level interconnections are largely regulated at the state level. As a result, there can be significant variation in processes, timelines, and costs from state to state and even between distribution utilities in the same state. However, as a general proposition, distribution-level interconnections, if feasible, tend to be faster and cheaper than interconnecting to a high-voltage transmission system.

Costs Associated with Interconnection

Interconnection costs typically consist of application fees, study costs, interconnection facilities, and network upgrades (if required) (see Box, Summary of *Pro Forma* Large Generator Interconnection Procedure Milestones Post-Order No. 2023). Depending on where the energy facility is delivering its electricity, additional costs may be incurred to deliver or wheel the electricity to its delivery point. Project developers and their advisors should ascertain and consider all costs associated with interconnecting and operating the energy facility. These costs may determine whether the project developer:

- Can develop the project and bring it online.
- May need to secure third-party funding (whether in the form of debt or equity) to pay these costs (see Financing Issues).
- Can negotiate pricing under an offtake agreement (whether a power purchase agreement or hedge) to generate sufficient revenue to pay for these costs (see Practice Notes, Power Purchase Agreements: Key Issues and Provisions and Introduction to Renewable Energy Power Purchase Agreements).

There may also be cost implications during the service life of the project. For example, a distribution-interconnected project that is selling into an organized wholesale market (also referred to as a deregulated electricity market) (for example, the PJM or MISO) may have to pay the distribution utility periodic charges for wholesale distribution service to transmit

energy across the distribution system to reach the transmission system. Depending on the distribution utility, these charges could be nominal, zero, or significant enough to affect the financial feasibility of the project.

FERC Order No. 2023: Improvements to Procedures for Transmission Interconnections

In 2003, FERC issued Order No. 2003, in which the Commission required all public utilities that own, control, or operate facilities used for transmitting electric energy in interstate commerce to file standard procedures (*pro forma* Large Generator Interconnection Procedures (LGIP)) and a standard agreement for interconnecting generating facilities larger than 20 MW (a Large Generator Interconnection Agreement (LGIA)) (see *Standardization of Generator Interconnection Agreements & Procs.*, 104 FERC ¶ 61,103, at P 2 (2003) (Order No. 2003), *order on reh'g*, 106 FERC ¶ 61,220 (2004), *order on reh'g*, 109 FERC ¶ 61,287 (2004), order on reh'g, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007)).

On July 28, 2023, FERC issued Order No. 2023 to reform these interconnection procedures to address interconnection queue backlogs, improve certainty and predictability, and prevent undue discrimination for new technologies (see *Improvements to Generator Interconnection Procedures & Agreements*, 184 FERC ¶ 61,054 (2023) (Order No. 2023), *order on reh'g*, 186 FERC ¶ 61,199 (2024)).

In issuing this order, FERC stated that:

> "[t]he electricity sector has transformed significantly since the issuance of Order Nos. 2003 and 2006. The growth of new resources seeking to interconnect to the transmission system and the differing characteristics of those resources have created new challenges for the generator interconnection process. These new challenges are creating large interconnection queue backlogs and uncertainty regarding the cost and timing of interconnecting to the transmission system, increasing costs for consumers. . . . While the Commission recognized these issues and sought to address them in Order No. 845 . . . it is clear that further action is needed."

(Order No. 2023, 186 FERC ¶ 61,054, at P 3.)

The Berkeley Lab's 2024 analysis of interconnection queue data from all seven ISOs and RTOs, alongside 44 non-ISO utilities, which collectively represent over 95% of the currently installed electric generating capacity, found that more than 1,480 GW of zero-carbon generating capacity is currently seeking transmission access, with solar (1,086 GW) and wind (366 GW) accounting for the largest share of generation capacity in the queues (see Berkeley Lab: Queued Up: 2024 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 (Apr. 2024)).

The order requires:

- Grid operators to restructure queues from the current serial study procedures to a more efficient cluster study process with more enforceable study deadlines.
- Public utilities to adopt revised *pro forma* LGIPs, LGIAs, Small Generator Interconnection Procedures, and Small Generator Interconnection Agreements to ensure that interconnection customers can interconnect to the transmission system in a reliable, efficient, transparent, and timely manner and to prevent undue discrimination.

Order No. 2023, as amended, went into effect on November 6, 2023, and transmission providers had until May 16, 2024, to file compliance filings with FERC setting out how they would implement the requirements of the new rule. For a more detailed discussion of the changes, see Practice Note, Understanding FERC Order No. 2023: Framework for Connecting to the Electric Grid.

Issues to Consider

Developers must consider several issues to facilitate a smoother interconnection process, including:

- Identifying an appropriate location for the site (see Site Analysis).
- Conducting an initial assessment of interconnection costs (see Contingent Facilities).
- Identifying how to finance the deposits developers must pay at various points during the interconnection process (see Financing Issues).

Site Analysis

To maximize efficiency, project developers should use all tools available to identify sites that can accommodate generation while minimizing the

need for network upgrades. The tools available for this vary depending on the location and situation. As part of the Order No. 2023 reforms, FERC directed RTOs and ISOs to develop and make available interconnection heatmaps (interactive visual representations of available interconnection capacity) so developers can see where excess transmission capacity already exists and identify ideal points of interconnection. These heatmaps must be updated within 30 calendar days after the completion of each cluster study and cluster restudy.

While this type of information is not currently freely available for all RTOs and non-RTO systems, engineering consultants can often help a developer identify locations where capacity is or is likely to be available, which can minimize the likelihood that network upgrades will be required to interconnect.

Contingent Facilities

Contingent facilities are unbuilt transmission upgrades that are necessary for a project's interconnection but are the cost responsibility of prior queued projects. If those prior queued projects drop out of the queue and cancel construction, this could necessitate restudies and result in significant changes to the overall interconnection costs for a project (for example, cost responsibility for the contingent facilities could be reassigned to the project at issue). Contingent facilities are typically identified in the LGIA and can result in changes to interconnection costs after the developer has secured a mutually executed interconnection agreement.

It is rarely possible to know the costs to interconnect and operate a project without any investment at all. As system impact and facilities studies are performed during the relevant interconnection process, these costs come into focus and become increasingly firm until the execution of the LGIA. If contingent facilities are identified, the project developer may not have complete cost certainty even after execution of the LGIA.

Developers and investors must therefore be diligent to analyze and understand the full scope of costs and potential costs associated with a project's interconnection and delivery of products, including the level of certainty that exists at the time the evaluation is taking place. Doing so will maximize the likelihood of successful funding (if any) and completion of the project.

Financing Issues

Order No. 2023 sought to address concerns that interconnection practices have permitted project developers to proceed through the process without having to show sufficient financial evidence of ability to develop its project, which was clogging the interconnection queue with speculative projects. To remedy this issue, Order No. 2023 added financial security requirements, including that project developers pay deposits at various phases of the interconnection process, which may be a challenge for some developers (see Box, Summary of *Pro Forma* Large Generator Interconnection Procedure Milestones Post-Order No. 2023).

While some larger developers may have sufficient funds to post these deposits, other developers may need to secure the funds from third-party sources (whether in the form of debt or equity).

Project developers may:

- Sell all or a portion of the project to raise the funds needed to post the required deposits.
- Enter into a development facility to finance these costs. Traditional project finance lenders do not typically provide these loans because of their greater risk. Because the project is at the development stage, there is a greater likelihood that the project may not be completed (for example, the developer may withdraw from the queue). The project developer also has fewer assets available to secure this loan. Where commercial banks provide this financing, they typically require:
  - a higher interest rate;
  - more restrictive covenants; and
  - a guarantee from the project developer's parent or affiliate or another form of credit support.

However, there are companies (including institutional lenders and private credit providers) that provide early-stage development financing. These facilities tend to be more expensive and bespoke, reflecting the project's specific risks and the lenders' risk tolerance.

Summary of *Pro Forma* Large Generator Interconnection Procedure Milestones Post-Order No. 2023

The chart below sets out the schedule for completing certain milestones, the amounts payable by project developers as part of their application to connect to the grid, and the penalties payable by project developers and grid operators for not complying with this schedule. This data comes from the pro forma LGIP and details may differ in the relevant RTO or transmission owner LGIP. The currently effective version of the relevant tariff should always be consulted for definitive information.

For more detailed information on these steps, see Practice Note, Understanding FERC Order No. 2023: Framework for Connecting to the Electric Grid.

Step in Interconnection Process	Timing for Completion	Amounts Payable by the Project Developer	Penalties for Grid Operator Review Delays	Project Developer Withdrawal Penalties
Opening of cluster request window	Annual 45-day period starting on date provided by the grid operator.	N/A	N/A	N/A
Submission of interconnection request	Before close of the cluster request window.	• A non-refundable application fee of $5,000. • A study deposit based on the size of the facility ($35,000 plus $1,000 per MW; $150,000; or $250,000). • A commercial readiness deposit equal to 2X the study deposit.	N/A	N/A
Customer engagement window	60-day window beginning after the close of the request window.	N/A	N/A	N/A
Initial cluster study	150 calendar days from close of customer engagement window.	Included in study deposit.	$1000 per business day, subject to a cap.	The greater of the study deposit and two times its actual allocated cost of all studies for the cluster up until the point of withdrawal.

Step in Interconnection Process	Timing for Completion	Amounts Payable by the Project Developer	Penalties for Grid Operator Review Delays	Project Developer Withdrawal Penalties
Cluster restudy (if necessary)	150 days after cluster study period.	Within 20 calendar days of the cluster study report, an additional deposit that brings the commercial readiness deposit to 5% of the customer's network upgrade costs.	$2000 per business day, subject to a cap.	The greater of the study deposit and 5% of estimated network upgrade costs.
Interconnection facilities study	To be delivered within 30 days of receipt.	An additional deposit that brings the commercial readiness deposit to 10% of the customer's network upgrade costs.	$2500 per business day, subject to a cap.	The greater of the study deposit and 10% of estimated network upgrade costs.
Optional interconnection study	• May be requested by project developer after receipt of cluster study results. • Grid operator will use reasonable efforts to complete the study within the period agreed by the parties in the optional interconnection study agreement.	$10,000, but any difference between the initial payment and the actual cost of the study will be paid by or refunded to project developer.	N/A	N/A
Affected system study	Within 150 days after the receipt of the affected system study agreement and deposit.	• Unspecified deposit amount. • The actual cost of the affected system study once results are received. • Any difference between the deposit and the actual cost of the study will be paid by or refunded to project developer.	$2000 per business day, subject to a cap.	N/A

Step in Interconnection Process	Timing for Completion	Amounts Payable by the Project Developer	Penalties for Grid Operator Review Delays	Project Developer Withdrawal Penalties
Executed LGIA	N/A	LGIA deposit equal to 20% of the project developer's estimated network upgrade costs minus the total amount of commercial readiness deposits made to date.	N/A	The greater of the study deposit and 20% of estimated network upgrade costs.