STATE OF VERMONT
BEFORE THE PUBLIC UTILITIES COMMISSION

Proposed revisions to Vermont Public Utility Commission Rule 5.500	Case No. 19-0856-RULE

COMMENTS OF THE INTERSTATE RENEWABLE ENERGY COUNCIL, INC. ON CHANGES TO VERMONT'S INTERCONNECTION RULES

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I. Introduction

On December 20, 2021, the Vermont Public Utilities Commission (Commission) issued the Order Requesting Comments on Draft Rule (Order). The Order provided a draft of changes to the Commission's Rule 5.500 (Commission Draft) and asked stakeholders to provide comments on specific questions regarding the changes. On January 20, 2022, the Interstate Renewable Energy Council, Inc. (IREC) requested an extension to the deadline to file comments to February 11, 2022. The Commission granted this extension via a procedural order issued on January 21, 2022. Pursuant to the Commission's orders, IREC respectfully submit the following comments.

IREC is a 501(c)(3) non-partisan, non-profit organization working nationally to build the foundation for rapid adoption of clean energy and energy efficiency to benefit people, the economy and our planet. In service of our mission, IREC advances scalable solutions to integrate distributed energy resources (DERs), e.g., renewable energy, energy storage, electric vehicles, and smart inverters, onto the grid safely, reliably, and affordably. IREC supports the creation of robust, competitive clean energy markets, though IREC does not have a financial stake in those markets. IREC works across numerous diverse states to improve the rules, regulatory policies and technical standards that enable the streamlined, efficient and cost-effective interconnection of DERs.

A. The Commission should consider the best practices established by FERC and IREC for state interconnection procedures.

In 2005, FERC published the first Small Generator Interconnection Procedures (SGIP), which are now intended to "serve as a model for state rules."[1] The SGIP approach incorporates a number of screens that use defined mathematical calculations to determine when a particular DER can be interconnected quickly and safely via the Fast Track process or a more comprehensive study process will be necessary to safely accommodate the Project. The defined screens embedded in SGIP enable applicants and utilities to avoid expensive and lengthy studies in situations where they are unnecessary. In its last major revision in 2013, FERC updated SGIP to incorporate many new best practices, including a Supplemental Review process with specific technical screens, that improve the interconnection process for higher levels of distributed generation.[2] Many states use SGIP as a model for their own interconnection standards, encouraged by provisions in the Energy Policy Act of 2005 that required state regulators to "consider" adopting interconnection standards based on "current best practices."[3]

In addition to SGIP, IREC publishes Model Interconnection Procedures (IREC Model) that compile the best practices developed by states across the country into one set of procedures.[4] The IREC procedures have been used as a model by numerous states, including Arizona, Illinois,

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[1] *See* FERC Order 2006 at ¶ 502 ("Standardization of Small Generator Interconnection Agreements and Procedures") (May 12, 2005); FERC Order 792, 145 FERC ¶ 61,159 (adopting revised SGIP).

[2] *See* FERC Order 792.

[3] *See* 16 U.S.C. § 2621 *et seq.* For example, Colorado, Connecticut, Minnesota, North Carolina, and Ohio are just some of the states that have based their state procedures on SGIP.

[4] Interstate Renewable Energy Council, *Model Interconnection Procedures* (2019), https://irecusa.org/resources/irec-model-interconnection-procedures-2019/.

Maryland, Ohio, and Oregon.[5] IREC's procedures are updated more frequently than SGIP (most recently in 2019) and include a number of additional innovations that have proven highly effective for distribution-level interconnections. These include features such as eliminating the Feasibility Study, allowing more Projects to access the Simplified Process, and establishing rules concerning the interconnection of limited export Projects.

IREC is currently engaged in a three-year initiative funded by the Department of Energy to develop a comprehensive toolkit and guidance document for the interconnection of energy storage and solar-plus-storage technologies. The Building a Technically Reliable Interconnection Evolution for Storage (BATRIES) initiative is a collaboration between IREC, the Electric Power Research Institute, and several other DER industry associations and utilities.[6] Together the BATRIES team has developed model rule language for energy storage interconnection. Though the final Toolkit will not be publicly available until the end of March 2022, IREC has included certain recommended definitions, export control criteria, and screen and study language from this initiative in our recommendations for the Commission. For example, many developers design solar and energy storage systems to control or manage export, so interconnection rules need to identify the difference between the amount a Project can export to the distribution system and the Project's Nameplate Rating. The BATRIES Toolkit will use a pair of defined terms, "Export

[5] *See* AZ Admin. Code § R14-2-2601 *et seq*; IL Admin. Code, tit. 83, pt. 466; Code MD Regs. § 20.50.09; OH Admin. Code § 4901:1-22; OR Admin. Rule § 860-082.

[6] The BATRIES initiative partners are the: California Solar and Storage Association; Electric Power Research Institute; Energy Storage Association; New Hampshire Electric Cooperative; PacifiCorp; Solar Energy Industries Association; and Shute, Mihaly & Weinberger LLP.

Capacity" and "Nameplate Rating," to identify this difference, and IREC encourages Vermont to adopt these terms and definitions as well.[7]

IREC recommends certain revisions to the Commission Draft of Rule 5.500 based on national best practices. A redline of these revisions is available in Attachment A (IREC Proposal). Throughout these comments, IREC notes where its proposed revisions are based on best practices established by SGIP, the IREC Model, BATRIES, or an evolution found in leading state rules.

B. Executive Summary

In order for interconnection processes to efficiently evaluate the safety and reliability impacts of proposed Projects, SGIP and the IREC Model use a tiered review approach that offers multiple review paths that increase in complexity and duration depending on the Project's size, characteristics, and potential distribution system impacts. The three paths available to customers in almost every state include:

- a Simplified Process with a quick screening process for the smallest Projects[8];
- a Fast Track Process with a robust screening process[9]; and
- a full study process for large or complex Projects unlikely to pass the Fast Track screens.[10]

As the Commission modifies Rule 5.500 to include net energy metering (NEM) Projects, it is important for the interconnection procedures to efficiently review small Projects. IREC recommends Vermont use a Simplified Process to allow for the safe and quick evaluation of

[7] Capitalized terms in these comments are defined in Rule 5.500.

[8] Also known as Level 1 in the IREC Model and some states, and the 10 kW Inverter Process in SGIP.

[9] Also known as Level 2 in the IREC Model in some states.

[10] Also known as Level 4 in the IREC Model and some states.

small inverter-based Projects. Alternatively, IREC would also support allowing some small Projects to skip the screening process entirely because their impact on the distribution system is likely insignificant. However, the IREC Proposal, based on the IREC Model and BATRIES, applies a limited set of screens for Projects with a Nameplate Rating of 50 kW or less, and an Export Capacity of 25 kW or less.

Incrementally larger Projects usually require incrementally more review and the Fast Track screening process defines the rules by which these Projects can be quickly approved. The Fast Track screens are typically designed to use readily available utility data in defined mathematical calculations. IREC recommends that Vermont's Fast Track process use such defined screens, including a penetration screen designed to evaluate most distribution system impacts, and modify or remove ambiguous screens.

When a Project fails a Fast Track screen, the Supplemental Review process provides the utility an opportunity to apply several additional screens to determine the if the Project can be interconnected without a detailed study. IREC recommends that Vermont follow the lead of several states with industry-leading solar markets by eliminating the Feasibility Study and instead using a Supplemental Review process with standard screens and a fixed fee.

Unavoidably, some Projects will require a full System Impact Study. Establishing eligibility requirements for the Fast Track process will ensure that Projects that could not conceivably pass the Fast Track screens do not unnecessarily linger in the Fast Track process, using utility resources and customer time. The Commission should also consider standardizing the System Impact Study timeline so that most Projects are evaluated in 60 calendar days. Group studies offer the potential of cost and time savings, but achieving these benefits requires navigating complex set of design decisions. IREC cautions against authorizing group studies

without a formal proceeding that fully considers their potential to result in additional delays and disputes.

Distributed energy resources, including Projects with energy storage systems, can optimize their output by limiting their export. Following the Order's instructions to pay "detailed attention to" the use of export limitations in the Commission Draft,[11] IREC suggests aligning the rule with the best practice recommendations from the BATRIES Toolkit by using:

- more straightforward language to describe how certified power control systems limit export in Section 5.521(5);
- the defined terms Export Capacity instead of Generation Capacity, and Nameplate Rating instead of Nameplate Capacity;
- separate Nameplate Rating and Export Capacity size limit in the Simplified Process;
- Nameplate Rating when screening for impacts on spot networks;
- a new inadvertent export screen to avoid system impacts; and
- Operating Profiles and Export Capacity to evaluate a Project's impact in the study process.

Even the best designed interconnection rule produces disputes. Vermont can prepare for this eventuality by describing a more robust dispute resolution procedure that requires parties to make certain good faith efforts at reconciliation before bringing the dispute to the Commission. In addition, Vermont should appoint an independent interconnection ombudsperson to track and help mediate disputes.

Increasing transparency will aid utilities, the Commission, and policymakers in tracking the effectiveness of the reforms required by Public Act No. 54 (2021). IREC suggests that the rules require a more robust set of data be included in regularly updated public queues and annual interconnection reports. In addition, utilities and customers would benefit from better-designed

[11] Order at 3.

Projects if pre-application reports included more data, e.g., hourly load profiles, and the screening process produced standardized written reports for screen failures.

Finally, IREC supports the Commission's inclination to swiftly adopt IEEE 1547-2018 because it will allow Vermont to take advantage of the capabilities of inverters to mitigate grid impacts and thereby allow potentially higher penetrations of DERs at a lower cost. The Commission should first convene a working group to provide recommendations on implementation timelines and technical implementation decisions and then adopt this latest revision to IEEE 1547-2018.

II. The Commission should establish a quick and efficient interconnection review process that reduces the administrative burden for both utilities and applicants.

The first question in the Order requests comments on "how the interconnection process could be simplified" for energy storage Projects under 100 kW and 1 MW.[12] IREC encourages the Commission to use the same rules to evaluate all types of Projects regardless of their technology (e.g., solar, energy storage, etc.). The eligibility criteria for the Simplified and Fast Track processes can be designed so the technical attributes of the Project that impact distribution system operations determine how the Project is screened. For example, a customer could use a certified Power Control System (PCS, described in more detail in Section V below) to limit a Project's export to a fixed amount. Provided that the PCS meets the requirements set in Section 5.521, the Export Capacity of the Project would be a limited amount and not the full Nameplate Rating. PCS on the market today can limit export with or without an energy storage device. Therefore, using a limited export system pursuant to Section 5.521 to meet the eligibility

[12] Order at 2-3.

requirements for the Simplified or Fast Track processes should not be dependent on the presence of an energy storage system.

A. The Commission should establish a Simplified Process for small Projects.

The sixth question in the Order requests comments on how to design a shorter interconnection process for small Projects.[13] IREC suggests establishing a Simplified Process to allow for the safe and quick evaluation of all small inverter-based Projects to the distribution system. It is reasonable to use a different and shorter process for small Projects because:

- small inverter-based Projects typically have fewer and less severe distribution systems impacts;
- such impacts can typically be evaluated via review screens in an expedited manner; and
- utilities typically process more Applications for small inverter-based Projects, so having a quicker process for them helps avoid creating a backlogged interconnection queue with lots of small Projects.

Almost all states, as well as SGIP and the IREC Model, use a Simplified Process for small Projects. To design the Simplified Process, IREC suggests the Commission answer the following three questions: 1) what screens should the process use, 2) what is the size limit, and 3) how long should screening take?

As the Commission modifies Rule 5.500 to include NEM Projects, it is important for the interconnection procedures to allow for the efficient review of small Projects. Thus, the IREC Proposal includes a Simplified Process for Projects with a Nameplate Rating of 50 kW or less and an Export Capacity of 25 kW or less that uses a limited set of screens and expedited timeline for the review process.

[13] Order at 4.

1. The Simplified Process should allow small Projects to interconnect using a limited set of screens.

IREC recommends that the Simplified Process use a limited set of screens. Green Mountain Power stated in its April 9, 2021 presentation that Projects up to 15 kW do not require review.[14] As an alternative, IREC supports designing the rule so that some small Projects using certified inverters skip the screening process entirely because their impact on the distribution system is likely insignificant. However, the IREC Proposal, based on the IREC Model, uses an abbreviated set of screens compared to the Fast Track process.[15]

This limited set of screens adequately addresses the most relevant impacts of small Projects, in aggregate with previously-installed DER, on the distribution system. The penetration screen can identify the risk of voltage violations or protection miscoordination due to the aggregate amount of DER, while other screens review the local impacts of the individual Project. Those are namely the single-phase shared secondary screen[16] and the single-phase imbalance screen.[17]

The Fast Track protection screens[18] are unnecessary in the Simplified Process since such small inverter-based Projects will contribute very little fault current. For example, the likely worst-case scenario that could arise would be a 50 kW Nameplate Capacity single-phase system on a 4160V primary. This would equate to about 25 amps of fault current. When screened

[14] Green Mountain Power, Distributed Energy Resources Interconnection, at 9 ("Power Output <= 15 kW ► No review required") (April 9, 2021); Order at 2.

[15] IREC Proposal, New Section for Simplified Process (C).

[16] Commission Draft Section 5.511(C)(6) (Fast Track screen 6).

[17] Commission Draft Section 5.511(C)(7) (Fast Track screen 7).

[18] Commission Draft Section 5.511(C)(3)-(4) (Fast Track screens 3 and 4).

against an equipment short circuit interrupting capability of 10,000 amps, the 50 kW system would contribute 0.25% of the capability. For a more typical primary voltage of 12.47 kV, a single-phase 50 kW system would contribute a mere 0.08% of the 10,000 amp equipment rating. Omitting these fault current screens reduces the time the utility must spend gathering distribution system data and making calculations that would show a negligible effect. Similar arguments can be made regarding the risks that the line configuration screen and transient stability screens address. Small Projects will simply have negligible effect, especially at the lower level of aggregate size allowed by the penetration screen.

To maintain speed and efficiency, IREC recommends that Vermont follow the lead of states like Illinois, Iowa, Massachusetts, New Mexico, and California,[19] and use fewer screens in the Simplified process than in the Fast Track process.

2. Certified inverter-based Projects with a 25 kW Export Capacity and 50 kW Nameplate Rating should use the Simplified Process.

In order to adopt a Simplified Process, the Commission must determine what size Projects will be eligible for this expedited review. The Commission's Rule 5.100, which governs the interconnection of small NEM Projects today, uses a quicker process for Projects under 15

[19] IREC Model § III.A.2., III.B.2 (Level 1 uses fewer screens than Level 2); IL Admin. Code, tit. 83, § 466.90; 199 IA Admin. Code 45.8-45.9 (Level 1 uses fewer screens than Level 2); MA Dept. of Public Util., Eversource Energy, Standards for Interconnection of Distributed Generation, at p. 47 (Sept. 15, 2021) (Figure 1 shows that the Simplified Process uses fewer screens than expedited process), https://www.eversource.com/content/docs/default-source/rates-tariffs/55.pdf; NM Pub. Reg. Comm., New Mexico Interconnection Manual § 8.6(A) (July 29, 2008) (using a limited set of screens in the Simplified Process), https://kitcarson.com/wp-content/uploads/2019/01/NM-Interconnection-Manual-2008.pdf; CA Pub. Util. Comm., Dkt. R.17-07-007, Interconnection of Distributed Energy Resources and Improvements to Rule 21, Decision 20-09-035, Decision Adopting Recommendations from Working Groups Two, Three, and Subgroup, at 43-44 (Sept. 30, 2020) (Decision 20-09-035) (approving proposals 8f, 8g, 8h, and 8j, which increase the size limit for Projects that can bypass certain screens from 11 kVA to 30 kVA).

kW.[20] SGIP includes a Simplified Process with a 10 kW size limit for certified inverter based Projects,[21] however, recently the trend across the country is for states to use a larger size threshold because utilities have demonstrated that they can quickly evaluate small Projects larger than 10-15 kW. The rationale for supporting a higher size threshold is to capture greater process efficiency by routing larger, but still straight-forward, Projects through the Simplified Process. Importantly, there is no increased risk in using a larger size threshold because the Applications must pass the Simplified Process screens. Any Project that fails a screen, regardless of size, will be routed to further study.

Using a larger size threshold allows more small Projects that pass the screens to interconnect to the grid efficiently. This efficiency and cost reduction is beneficial for both customers and utilities.

NREL identified increased size limits for small inverter-based systems as a best practice,[22] and many states have followed this advice. Iowa uses a 20 kVA threshold for its Simplified Process[23]; Arizona, Maryland, Minnesota, North Carolina, and South Carolina use 20 kW[24]; Illinois, Massachusetts, Ohio, Oregon, Utah, and West Virginia set their thresholds at 25

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[20] Section 5.105.

[21] SGIP Attachment 5.

[22] Kevin Fox et al., *Updating Small Generator Interconnection Procedures for New Market Conditions*, National Renewable Energy Laboratory, at 15-16 (Dec. 2012), http://www.nrel.gov/docs/fy13osti/56790.pdf.

[23] 199 IA Admin. Code § 45.7(1).

[24] AZ Admin. Code § R14-2-2623(A); Code MD Regs. 20.50.09.08(B); MN Pub. Util. Comm., Dkt. E-999/CI-16-521, MN Distributed Energy Resources Interconnection Process § 2.1.1 (MN DIP) (April 19, 2019), https://mn.gov/puc/assets/MN%20DIP_tcm14-431769.pdf; NC Util. Comm., Dkt. No. E-100, Sub 101, North Carolina Interconnection Procedures, Forms, and Agreements for State-Jurisdictional Generator Interconnections, § 2.1 (Aug. 20, 2021); SC Pub. Util. Comm., Dkt. No. 2015-362-E, Order No. 2016-191, Exhibit 1, § 2.1 (April 26, 2016).

kW[25]; California raised the threshold to 30 kVA[26]; while New York uses 50 kW.[27] The IREC model uses 25 kW.[28] IREC recommends that Vermont open its Simplified Process to certified inverter-based Projects with up to 25 kW of Export Capacity.

IREC also recommends that the Simplified Process include a higher eligibility limit for Projects that limited their Export Capacity to 25 kW, but have up to 50 kW of total Nameplate Capacity. This is a reasonable approach because the majority of potential impacts from Projects are a result of exported energy. If a Project's export is limited, the only increased distribution system impact that could occur from the Project's higher Nameplate Rating are those related to fault current. However, as explained above, the fault current contribution from Projects as small as 50 kW is likely to be insignificant. Thus, it is reasonable to allow Projects with up to 50 kW of Nameplate Capacity to proceed through Simplified Review so long as their total Export Capacity is below 25 kW. This will enable more Projects with energy storage to take advantage of the Simplified Process and can be particularly important for solar plus storage systems which have multiple inverters and thus higher Nameplate Ratings.

For the reasons described in this section, the Commission should set the size threshold for the Simplified Process at an Export Capacity of 25 kW and a Nameplate Rating of 50 kW.

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[25] IL Admin. Code, tit. 83, § 466.80; MA Dept. Pub. Util. Dkt. No. DPU 11-75, Order 11-75-E, Appendix A: MA Interconnection Standards, § 3.1; OH Admin. Code 4901:1-22-06(A)(2); OR Admin. Rule 860-082-025(2)(a); UT Admin. Code R746-312-8(1)(b); WV Code R. § 150-33, Form No. 2: Interconnection Standards, § 1.2.1.

[26] CPUC Decision 20-09-035 at 43-44 (approving proposals 8f, 8g, 8h, and 8j, which increase the size limit for Projects that can bypass certain screens from 11 kVA to 30 kVA).

[27] NY State Pub. Serv. Comm., Dkt. No. 15-E-0557, Order Modifying Standardized Interconnection Requirements, Mar. 18, 2016.

[28] IREC Model § III.A (the IREC Model and many states label the Simplified Process Level 1).

3. The Simplified Process should use shorter timelines than the Fast Track Process.

One common feature of the Simplified Process is shorter timelines. For example, SGIP's Simplified Process provides utilities 15 business days to apply all of the Fast Track screens.[29] The IREC Model, on the other hand, provides seven business days for utilities to apply a smaller set of screens.[30] Under Section 5.105, utilities have been evaluating the interconnection impacts of inverter-based Projects under 15 kW in 11 business days. Since the Commission and utilities in Vermont have many years of experience meeting this 11 business day review timeline for small Projects, IREC recommends that the Commission allow 15 calendar days (approximately the same as 11 business days) for utilities to complete screening in the Simplified Process. Fifteen calendar days is more than enough for a utility to apply a limited set of screens to a small Project; for example, in California, Pacific Gas & Electric Company recently reported that, on average, it can screen Projects under 30 kW in just 2.7 business days.[31]

Moreover, the Simplified Process normally features an expedited process for the signing of an Interconnection Agreement.[32] The fourth question in the Order asks if Projects under 150 kW need to sign Interconnection Agreements.[33] IREC does not take a position on the need for an

[29] SGIP Attachment 5 § 4.0.

[30] IREC Model § III.A.3.

[31] CA Pub. Util. Comm., Rule 21 Interconnection Program Evaluation, p. 54 (Mar. 2021), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/rule21/rule-21-interconnection-program-eval_2021.pdf.

[32] Where an Interconnection Agreement is required, the Simplified Process uses a combined Interconnection Application and Agreement form. This enables the customer to sign the Agreement upon submitting the Application, and then the utility can simply counter sign after review is complete instead of sending it back to the customer for signature. SGIP Attachment 5; IREC Model Attachment 3.

[33] Order at 3-4.

Interconnection Agreement. However, if the Commission decides to require Interconnection Agreements for small Projects, it should use the well-established process found in SGIP and the IREC Model that reduces the amount of back-and-forth paperwork. By creating a combined Application and agreement, the applicant will sign the agreement when it submits the Application and the utility counter signs and returns the agreement if the Project passes the screen.

B. The Fast Track Process should not be used for large Projects that are likely to require interconnection studies.

To make the interconnection process more efficient for utilities and customers, certain Projects over 1 MW should bypass the Fast Track process and go directly to study. As Green Mountain Power noted in its April 9, 2021 presentation, the size of a Project is often closely related to the need for a System Impact Study.[34] Large Projects that are certain to fail the screens should bypass the Fast Track Process entirely, freeing up utility resources to screen other Projects and allowing customers to start the study process more expeditiously.

IREC recommends sending all Projects with an Export Capacity over 5 MW, and some Projects between 1-5 MW, directly to the study process. In addition, IREC recommends modifying the Application to allow customers to elect to go straight to study even if they are eligible for the Simplified or Fast Track process.[35]

SGIP originally limited the Fast Track process to Projects below 2 MW, but in 2013 FERC updated SGIP to vary the eligibility by size for certified-inverter based systems depending

[34] Green Mountain Power, Distributed Energy Resources Interconnection, at 9 ("Inverter Output Power Rating Dictates Interconnection Study Requirements") (April 9, 2021).

[35] IREC Proposal Section 5.506(A).

on the "voltage of the line and the location of and the type of line at the Point of Interconnection."[36] The size limits selected were intended to reflect the largest size Project that could theoretically pass the screens based on those conditions. Many states and the IREC Model follow the updated approach and use a varying eligibility limit.[37] Vermont should use the updated approach to Fast Track eligibility because it strikes a reasonable balance between taking into account factors that could limit the safe and reliable interconnection of a Project without upgrades, while ensuring the maximum number of small Projects receive faster review. Specifically, the technical screening process is the ultimate arbiter of whether or not a system can proceed under Fast Track or requires additional study. Thus, the Fast Track size limit should allow the largest sized Project that could potentially pass the interconnection screens on the particular line size to use the Fast Track procedures. If the Project is too large, the screens will prevent the Project from interconnecting without study. Thus, Section 5.511(A) of the IREC Proposal uses the updated approach to Fast Track eligibility standards based on the IREC Model. This would also replace the fixed 23 kV line voltage limit in screen 1 with a more nuanced approach that varies the size limit as the distribution system line voltage changes.[38]

Like with the Simplified Process, it is reasonable to apply the size limit to the Export Capacity instead of the Nameplate Rating. Export limited Projects are likely to pass the screens that evaluate if a Project is likely to cause safety or reliability impacts on the distribution grid,

[36] SGIP § 2.1; FERC Dkt. RM13-2-000, FERC Order No. 792, at ¶¶ 112-118 (Nov. 22, 2013) (describing why FERC raised the size limit for Fast Track eligibility).

[37] *See*, e.g., MN DIP, § 3.1.1; IL Admin. Code, tit. 83, § 466.80(b)(2).

[38] Commission Draft Section 5.511(C)(1). This screen would continue to prevent the Fast Track process for being used by a Project interconnecting to a transmission line. IREC Proposal Section 5.511(D)(1).

even if their Nameplate Rating is higher than their Export Capacity. A Project whose higher Nameplate Rating causes significant system impacts will not pass the Fast Track screens that evaluate the Nameplate Rating, including a new screen designed specifically to check for system impacts resulting from inadvertent export (as explained further below). If a Project passes the screens, it can be safely interconnected without the need for further study. Enabling the greatest number of Projects to take advantage of this process is an important way to improve the efficiency and lower the costs of interconnection.

C. The Fast Track process should use defined screens.

The typical Fast Track screens found in SGIP and the IREC Model were designed as an indicator of whether there is any significant likelihood for a Project to cause any system impacts based on an objective review of utility data. The Fast Track screens are not designed to pass Projects that approach the limit of how much DER the distribution system can handle; rather, they represent a conservative approach to quickly approving Projects that are extremely unlikely to cause any safety or reliability concerns.

Moreover, the typical Fast Track screens have the following attributes:

- Use readily available utility data and information in the Application to perform defined mathematical calculations.
- Are clearly defined so that any two people, or any two utilities, examining the same data will reach the same conclusion, i.e., no engineering judgement or discretion required to apply the screens.
- Do not require detailed studies or power flow simulations.
- Often do not require a licensed engineer to perform the defined calculations.

As noted above in section II.B, IREC proposes to modernize the line voltage limits in Fast Track screen 1 and move those limits to the new eligibility table. Below, IREC describes modifications to the other Fast Track screens.

1. The Commission should replace screen 10 with a defined penetration screen using 100% of minimum load.

Most states' interconnection rules use a penetration calculation to screen for the possibility of encountering the types of impacts that screen 10 evaluates. Screen 10 is not appropriate for Fast Track because it is not an objective review of utility data and requires considerable engineering judgement. Additionally, it could require significant effort for the utility while a penetration screen can be applied more quickly.

In the Commission Draft, screen 10 evaluates whether the aggregate Export Capacity will compromise the rating or settings of distribution circuit equipment. While it is important to ensure safety and reliability by using equipment within its rating, the penetration level at which this type of equipment would be compromised is much higher than the penetration level at which other issues, such as voltage concerns, would arise. Given that circuit equipment will always be designed for at least maximum load, generation at minimum load and with no reverse power could not compromise the equipment ratings or settings. Thus, IREC recommends replacing screen 10 with a more traditional penetration screen. This screening approach may be slightly more conservative, but it also provides customers greater transparency and the ability to independently evaluate if the Project is likely to pass the screen (with the load profile provided in the Pre-Application Report).

Penetration screens evaluate the aggregate Export Capacity of generation that could cause reverse power flow over a significant portion of a circuit. When generation is below minimum load, reverse power will not occur over a line section, and thus will not raise voltage to potentially problematic levels. The penetration screen does not directly evaluate the presence of voltage issues, but it is a conservative proxy for those issues. Projects that fail the screen and

could potentially cause voltage issues are sent to Supplemental Review or full study for a more detailed evaluation of potential voltage impacts. Since a penetration screen can identify virtually every voltage problem and all equipment ratings issues, the Commission should replace the open-ended screen 10 with a defined penetration calculation.

The IREC Proposal replaces Fast Track screen 10 with a defined penetration screen using 100% of minimum load when that data is available, or 15% of peak load if minimum load data is not available. SGIP, the IREC Model, the Commission's current interconnection rules, and almost every state interconnection procedure have a penetration screen in the Fast Track process.[39]

The 15% of peak load limit was set over twenty years ago as a conservative, low penetration level at which detailed impacts, such as those due to higher penetration levels, are not analyzed.[40] The idea is that those impacts, like "unintentional islanding, voltage aberrations, protection miscoordination, and other potentially negative impacts are unlikely if the amount of D[istributed] G[eneration] capacity is significantly smaller than feeder capacity and always less than feeder load."[41] Distribution systems would certainly avoid those impacts if the aggregated DER does not feed more power into the grid than 100% of the minimum load (the time of lowest demand on the relevant line section).

[39] SGIP § 2.2.1.2; IREC Model § III(B)(2)(b); Section 5.505(B)(3); *see*, e.g., MN DIP § 3.2.1.2; Admin. R. MT 35.8.8410(2)(a).

[40] SGIP § 2.2.1.2; FERC Dkt. RM02-12-000, FERC Order No. 2006 (May 12, 2005).

[41] Robert J. Broderick & Abraham Ellis, *Evaluation of Alternatives to the FERC SGIP Screens for PV*, Interconnection Studies, Photovoltaic Specialists Conference (PVSC), 2012 38th IEEE, 10.1109/PVSC.2012.6317712.

However, at that time few utilities recorded minimum load data, and most utilities recorded peak load. Because minimum load data was not available, 15% of peak load was used. Fifteen percent of peak load was intended to serve as a proxy for 50% of minimum load because, for typical distribution circuits in the United States, minimum load is approximately 30% of peak load.[42] Using an approximation of 50% of the minimum load provides a very high likelihood that there will be no unintentional islanding, voltage deviations, protection miscoordination, or other potentially negative impacts because the combined DER on a line section is always less than the minimum load. Using this approximation means that the 15% of peak load screen is likely much more conservative than is necessary to ensure safety and reliability. However, it was developed at a time when there was less data available about load and less familiarity with DERs, and thus its crafters selected a highly conservative metric.

Today, most utilities have access to minimum load data, and some are installing advanced meters that record loads at frequencies not contemplated when the first penetration screen was crafted. Therefore, when minimum load data is available, the Fast Track penetration screen should use 100% of relevant minimum load, rather than an estimation of minimum load based on measured peak load. When minimum load data is not available, utilities can perform the traditional penetration screen using a 15% of peak load. Other jurisdictions, including Montana and Minnesota,[43] have evolved their Fast Track screens to use 100% of minimum load. In addition, Illinois recently decided to require all utilities to measure and use minimum load in

[42] Michael Coddington, et al., *Updating Interconnection Screens for PV System Integration*, National Renewable Energy Laboratories, p. 2 (Feb. 2012), https://www.nrel.gov/docs/fy12osti/54063.pdf.

[43] Admin. R. MT 35.8.8410(2)(a) (using minimum load or 15% of peak load); MN DIP § 3.2.1.2.

the Fast Track penetration screen within one year.[44] If the Commission wishes for all utilities to use the more precise minimum load calculation, it could follow Illinois' lead and require utilities to measure and use minimum load data within the next year or two.

2. The Commission should use Nameplate Rating instead of Export Capacity when screening Projects interconnecting to a spot network.

Screen 2 evaluates the ratio of DER penetration to a spot network's maximum load.[45] IREC recommends that the Commission modify this screen to use Nameplate Rating instead of Export Capacity. The time necessary for the export control methods identified in Section 5.521 to respond may be insufficient due to the sensitivity of spot networks' network protectors. To avoid the need to reconfigure the network protection on spot networks, this screen should use Nameplate Rating.

3. The Commission should remove ambiguity in the line configuration screen.

Screen 5, commonly called the line configuration screen, is designed to ensure that the Project will not contribute to ground-fault overvoltage. However, the language in the Commission Draft is ambiguous because it does not describe if the connection is on the primary or secondary side of the interconnecting transformer. This could be problematic depending on

[44] IL Commerce Comm., Dkt. 20-0700, Amendment of 83 Ill. Adm. Code 466 and 83 Ill. Adm. Code 467, Illinois Second Notice Order, Appx. A, § 466.100(a)(1) (8-12-21) (Until December 31, 2023, using 100% of minimum load where available, and 15% of peak load if not available; in 2024 and beyond, requiring the use of 100% of minimum load.). After the Commission issued the Second Notice Order, the Illinois Legislature passed a law that required further revisions to the state's interconnection procedures, and the Commission withdrew this order to issue a new one to add the new state law requirements. However, the Commission has not indicated any intent to change the cited recommendations.

[45] IREC Proposal Section 5.511(D)(2).

the winding configuration, e.g., a Wye-Delta. Similar with the approach taken by Illinois, the IREC Proposal clarifies that connection is on the primary side of the transformer.[46]

Further, it can be challenging for customers or utility engineers to determine whether inverter-based systems are "effectively grounded," since they are physically very different from rotating machines for which effective grounding concepts are well known. Unlike rotating machines, inverters can maintain effective grounding through the line-to-neutral load on the distribution system, rather than the use of grounding at the Project site. IEEE 1547-2018 and IEEE 1547.1-2020 contain requirements and tests that can give engineers better information about the ability of inverters to contribute to overvoltage, while IEEE 62.92.6[47] gives more guidance about the unique attributes important for effectively grounding inverters.

When Projects fail this screen, utilities determine the need for additional grounding requirements via further study. Inverter-based systems may avoid supplemental grounding (such as the use of grounding banks) in situations where rotating machines would not. As such, implementing this screen requires a clear understanding of an inverter-based Project's impact on effectively grounded distribution systems so that the Project does not unnecessarily fail the screen. Therefore, IREC recommends further revisions to this screen as part of the IEEE 1547-2018 adoption process described in section VIII below. The BATRIES Toolkit,[48] expected to be

[46] Illinois Second Notice Order, Appx. A, § 466.100(a)(6) ("When a customer-generator facility is to be connected to 3-phase, 4-wire 1150 primary EDC distribution lines, a 3-phase or single-phase generator shall 1151 use a grounded line-to-neutral primary connection. This screen does not 1152 apply to DER facilities with a nameplate capacity below 11 kVA.").

[47] Guide for Application of Neutral Grounding in Electrical Utility Systems, Part VI - Systems Supplied by Current-Regulated Sources

[48] Interstate Renewable Energy Council, *BATRIES: Storage Interconnection Reform* https://irecusa.org/programs/batries-storage-interconnection/.

published in March 2022, will contain guidance on revising the line configuration screen and Supplemental Review to adequately address effective grounding for inverter-based DER.

4. The Commission should exclude substation areas with less than 10 MVA of aggregate DER from the transient stability screen.

Screen 8 restricts interconnection in areas with known transient stability limitations but does not differentiate between Projects connecting to areas with few other DER, and areas where the penetration of DERs could affect stability. As a result, a relatively small Project could fail the screen when it would have a negligible effect on transient stability. In SGIP, the IREC Model, and most state interconnection rules[49] this screen excludes interconnections in substation areas with less than 10 MVA of aggregate DER connected. Some states, such as Minnesota and New York, omit the screen from Fast Track altogether,[50] while others, like California, exclude Projects under a certain size from this screen.[51] IREC recommends Vermont follow SGIP, the IREC Model, and most states by excluding from this screen interconnections in substation areas with less than 10 MVA of aggregate DER connected.

[49] *See*, e.g., IL Admin. Code, tit. 83, § 466.100(a)(9); MA Dept. of Public Util., Eversource Energy, Standards for Interconnection of Distributed Generation, at p. 50; Code MD Regs. 20.50.09.10(A)(8).

[50] MN DIP § 3.2.1; NY Pub. Serv. Comm., Standardized Interconnection Requirements and Application Process for New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems, Appendix G: Preliminary Screening (March 2021), http://www.dps.ny.gov/distgen.htm.

[51] CA Pub. Util. Comm., Pacific Gas and Electric Company, Electric Rule 21: Generating Facility Interconnections, § G.1.k-l (CA Rule 21) (Projects under 500 kW skip the stability test, screen L), https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_21.pdf.

5. The Commission should require that all Projects meet applicable codes and standards, not just those using the Fast Track process.

All Projects should be certified or meet applicable standards unless the utility agrees otherwise. Because this requirement should be applied more broadly, the IREC Proposal moves screen 12 to Section 5.519, where it applies to all Projects.

6. If the Commission moves the evaluation of voltage fluctuation to Supplemental Review, it should set a 21 calendar day timeline for the Fast Track process.

IREC suggests that the Commission consider whether utilities should perform the time-intensive process of screening for voltage fluctuation in Fast Track or Supplemental Review. If the Commission elects to screen for voltage fluctuation in Supplemental Review, it should commensurately shorten the Fast Track review timeline.

a. IREC believes the intent of screen 13 is to model voltage fluctuation.

IREC recommends against using the term "flicker" in screen 13 because it does not clearly describe the electrical impact that utilities evaluate. Flicker is typically a phenomenon that can be observed or measured in the field, not one that DER models used in the interconnection process are designed to evaluate (without making several assumptions which are not stated). For example, IEEE 1453.1-2012 defines flicker as:

> impression of unsteadiness of visual sensation induced by a light stimulus whose luminance or spectral distribution fluctuates with time.
>
> NOTE
>
> Flicker is the effect on the incandescent lamps while the electromagnetic phenomenon causing it is referred as voltage fluctuations.

Further, SGIP's Supplemental Review includes a Voltage and Power Quality Screen that, like screen 13, requires compliance with IEEE 1453 but uses the term voltage fluctuation. For these reasons, IREC recommends that Vermont use the term voltage fluctuation and not flicker.

In addition, when the Commission revises these rules to adopt IEEE 1547-2018 (see section VIII), it should also revise this screen. References to IEEE 1453 and IEEE 519 are out of date and should be replaced with IEEE 1547-2018 once the Commission adopts that version of the standard. IEEE 1547-2018 directly addresses the acceptable voltage fluctuation limits (and harmonic limits) for DER and requires less interpretation and engineering judgement than IEEE 1453. Using IEEE 1547-2018 will reduce the potential for engineers to interpret the screen differently, increasing certainty and transparency for customers.

b. The Commission should consider adopting a short Fast Track review timeline and moving the evaluation of voltage fluctuation to Supplemental Review.

The evaluation of voltage fluctuation requires more detailed information and calculations than the typical Fast Track screens. Performing these calculations is very time-consuming, so much so that some engineers prefer computer modeling instead of making the calculations manually. In order to ensure that the Fast Track process remains an expedited process, FERC, the IREC Model, and most states design the Fast Track screens to avoid the need for detailed calculations. This allows utilities to avoid the administrative burden of screening for voltage fluctuations when Projects pass the other screens (including the penetration screen, meaning the Project is unlikely to cause voltage fluctuations). On the other hand, the Supplemental Review screening process provides the time necessary for utilities to perform a detailed calculations and check for this and other types of voltage problems.

In addition, screening for voltage fluctuation requires using engineering judgment to determine what calculations will be performed. As noted above, FERC and IREC designed the Fast Track screens to use defined mathematical calculations with fixed values explicitly because such calculations avoid the controversy that can surround the use of utility discretion and engineering judgment and provide an applicant a greater ability to assess whether a Project will pass the Fast Track screens in advance. Screens that require extensive engineering judgement, like the voltage fluctuation screen, are more appropriate in the Supplemental Review process.

Under today's Section 5.505(A), SGIP and the IREC Model, utilities do not perform detailed voltage fluctuation calculations and complete Fast Track screening within 15 business days of receiving a complete Application.[52] Many states take the same approach; for example Minnesota screens Projects in 15 business days, while Arizona uses a Fast Track timeline of 21 calendar days, roughly equivalent to 15 business days.[53] The Commission Draft, however, extends the Fast Track timeline to 30 calendar days and requires detailed voltage fluctuation calculations.[54]

For the reasons described in this section, IREC prefers moving voltage fluctuation screening to Supplemental Review (or the Feasibility Study, if the Commission does not rename it Supplemental Review) so all Projects benefit from the quicker Fast Track timeline of 21 calendar days.[55] However, if the Commission does not wish to adopt IREC's recommendation to

[52] IREC Model § III.B.3; SGIP § 2.2.

[53] AZ Admin. Code § R14-2-2618(C)(1); MN DIP § 3.2.

[54] Commission Draft Section 5.511(A); Commission Draft Section 5.511(C)(13).

[55] IREC Proposal Section 5.522(B).

use a shorter Fast Track timeline, it is reasonable to keep the voltage fluctuation screen in Fast Track, as 30 calendar days is adequate time to perform the required calculations.

7. The Commission should delete screen 14 because the penetration screen will fail Projects with voltage concerns and screen 14 inappropriately creates a higher threshold for smaller Projects.

SGIP, the IREC Model, and typical state interconnection rules do not use a stiffness ratio screen in Fast Track because the penetration screen is designed to fail Projects with voltage concerns.[56] The penetration screen is a better fit for the Fast Track process than the stiffness ratio screen because the penetration screen is designed as a proxy to identify a broader set of steady-state voltage issues. When a Project fails the penetration screen, it goes to Supplemental Review where the Voltage and Power Quality screen is designed to identify the types of concerns identified by the stiffness ratio screen, among other voltage and power quality issues.

However, if the Commission decides to include a stiffness ratio screen, it should not use a higher threshold for small Projects. It is unclear to IREC why the Commission Draft's screen 14 uses a more conservative threshold for smaller Projects. Smaller Projects are much less likely to have voltage effects on the distribution system and therefore should not be screened using a higher ratio than is used for larger systems.[57] IREC acknowledges that smaller Projects often interconnect to shared secondaries, which could create voltage issues. For this reason, screen 6 is designed to fail any Projects that could cause voltage issues on shared secondaries. Thus, it would be redundant to use a higher ratio in screen 14 to screen for this type of voltage issue.

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[56] Screen 14 is a stiffness ratio screen.

[57] *See* Tom Key, *Independent Assessment of Duke Energy's Fast Track Review Process for DER Interconnection,* Electric Power Research Institute, at 4-10 (Oct. 2019) (Chapter 4, page 10, recommendation 6 suggests using a stiffness ratio of 25, for all Projects regardless of size, in Supplemental Review), https://tinyurl.com/2f6nx4fu.

8. The Commission should adopt a new inadvertent export screen.

Finally, an important issue related to the review of export-controlled Projects is how to evaluate the "inadvertent export" from those Projects. Inadvertent export is power that is unintentionally exported from a DER when load drops off suddenly, such as when an electric water heater switches off, before the export control system responds to the signal to limit or stop export. Inadvertent export events occur when using relays or PCS and the duration and magnitude of the events will vary to some extent based on the device and the load behavior at the DER site.[58] As more DERs use export controls, utilities need to be assured that these inadvertent export events will not impact the grid and, therefore need a way to identify where problems may arise.

The IREC Model identified this as an area that lacked a clear best practice at the time it was published in 2019,[59] and even today this issue has been treated in varying ways by states.[60] One of the primary goals of the BATRIES research was to conduct further time-series analysis and modeling to better understand the potential impacts of inadvertent export and to provide states with guidance on their evaluation. The research largely concluded that the potential impacts of inadvertent export are likely insignificant for small Projects. For larger Projects, however, there may be some potential for voltage impacts depending on the size, response time of the export control device, and the configuration of the distribution circuit. Thus, IREC

[58] Inadvertent export events do not arise when using either the configured power rating or the relative DER rating options identified in the Section 5.521.

[59] *See* IREC Model at 11, footnote 11.

[60] *See* e.g., AZ Admin. Code § R14-2-2603; CA Rule 21 § G.1.i; NV Energy Rule 15 § I.4.b; Hawaiian Elec. Co., Rule No. 22: Customer Self-Supply, Appendix II at 44B-1–44B-2 (Feb. 5, 2018).

(through our collaboration with the BATRIES team) is proposing to use a new screen in the Fast Track process to help determine when further evaluation of inadvertent export may be required in Supplemental Review or the study process. Again, like all the Fast Track screens, this screen is conservatively designed and failure should not be interpreted as an indication that a Project's inadvertent export will cause system impacts or require upgrades, but rather simply that further review is necessary to rule out that risk.

The proposed screen, found in IREC Proposal Section 5.511(D)(14), consists of two parts. The first is a size threshold. If the Nameplate Rating minus the Export Capacity of the Project is below 250 kW, the BATRIES research found that it is safe to assume that inadvertent export from acceptable export control systems will not cause voltage violations. For Projects above this threshold, a further test was devised that evaluates whether the voltage change at the primary level nearest the DER's point of interconnection is less than 3%. The reasoning behind this approach is that inadvertent export events are akin to the rapid voltage change (RVC) events described in IEEE 1547-2018.[61] To ensure RVC is limited to no more than 3%, in line with the standard, utilities can estimate voltage change using the primary grid impedance values from the circuit model, in addition to the Nameplate Rating and Export Capacity. This calculation gives a close estimate of the actual voltage change and thus can adequately screen for potential impacts from inadvertent export.

The Commission should adopt this new screen along with the other changes IREC recommends to the existing interconnection screens. Together these changes will ensure that the potential impacts of export limited Projects (like energy storage) are accurately screened.

[61] IEEE 1547-2018 subclause 7.2.2 limits rapid voltage changes at medium voltage to 3% of nominal voltage and 3% per second averaged over a period of one second.

D. Projects that fail Fast Track should have the opportunity to interconnect without the time and expense of a System Impact Study.

IREC supports the Commission and Green Mountain Power's decision to evolve the interconnection process so that Projects that fail the Fast Track have an alternative to the full study process.[62] The Commission Draft incorporates this process into the Feasibility Study. Providing such a process is a best practice that IREC encourages. In SGIP, the IREC Model, and most states,[63] the process that allows further review but not a full System Impact Study is called Supplemental Review. IREC recommends that Vermont's interconnection rules include such a process designed to:

- allow the utility additional time to perform a more detailed analysis than is allowed by the short timeline in Fast Track;
- take significantly less time than the full study process;
- use standard screens; and
- use a fixed fee.

IREC prefers that this process use its typical name, Supplemental Review. However, more important than a name is adopting a process designed to provide customers that fail the Simplified and Fast Track screens a path to interconnection after an efficient review process that includes a fixed fee and standard screens.

[62] *See* Green Mountain Power Comments on Proposed Revisions to Vermont Public Utility Commission Rule 5.500, at 3 (June 17, 2019) ("the Feasibility Study process can accomplish precisely what the Supplemental Review process is designed to do making inclusion of the Supplemental Review process redundant.").

[63] *See*, e.g., FERC Order No. 792, 145 FERC ¶ 61,159 (Nov. 22, 2013); AZ Admin. Code § R14-2-2620; IA Admin. Code § 45.9(6) (Jan. 18, 2017); IL Admin. Code, tit. 83, § 466.100(f); MN DIP § 3.4; Kevin Fox et al., *Updating Small Generator Interconnection Procedures for New Market Conditions*, National Renewable Energy Laboratory, at 22-23.

1. In the interest of this efficiency, IREC recommends using a fixed fee for Supplemental Review.

In order to expedite the process, IREC recommends using a flat fee of $1,000 instead of the existing process in which the utility prepares a cost estimate, the customer pays a deposit, and at the end the utility reconciles actual costs with the amount paid by the customer.[64] Switching from the existing process to flat fee could save up to 28 calendar days in the interconnection process because utilities will not have to estimate the deposit amount and customers would not have to sign a customized study agreement[65]; further, utility staff would no longer need to spend time reconciling actual costs to deposit amounts.

The $1,000 deposit amount included in the Commission Draft is a reasonable starting point for a fixed Supplemental Review fee (or the Feasibility Study, if the Commission uses that name). Ultimately, IREC recommends that the Commission design the fixed fee to recover the utility's actual cost by using the historical average of the utility's actual cost to perform Supplemental Review. If utilities document that the actual cost of Supplemental Review regularly exceeds $1,000, they should provide this data to the Commission in a petition requesting to increase the Supplemental Review fee.

2. The Supplemental Review process, including the typical Supplemental Review screens, are designed to evaluate similar concerns identified by the Commission Draft's Feasibility Study.

IREC recommends using the typical Supplemental Review screens so that utilities make a more precise evaluation of minimum load and the potential for backfeed. The typical Supplemental Review screens use more precise language to identify similar concerns as

[64] Commission Draft Section 5.512(A) (Seven calendar days for Feasibility Study agreement and cost estimate plus 21 calendar days to sign agreement and submit deposit).

[65] *Id*.

contemplated in the Commission Draft's Feasibility Study. As the aggregate export on the line section approaches 100% of minimum load, it is appropriate for the utility to spend more time considering potential distribution system impacts.

IREC proposes that Supplemental Review include a more detailed 100% of minimum load screen, that if failed, would send Projects to a System Impact Study. Most Supplemental Review processes, including those found in SGIP and IREC Model, include a detailed 100% of minimum load screen.[66]

This 100% of minimum load screen is different from the penetration screen in the IREC Proposal for Fast Track because it requires a more precise calculation. First, the Fast Track screen only requires use of minimum load where it is already available, however the Supplemental Review screen requires utilities to calculate, estimate, or determine minimum load, even when it is not already available. Second, while the Fast Track screen simply instructs a utility to evaluate the "relevant minimum load," which the engineer can use her judgement to define, the Supplemental Review screen includes more explicit instructions in subsections (i)-(iii). Most importantly, subsection (i) requires engineers to use daytime minimum load for PV systems with no energy storage.

Supplemental Review also provides utilities additional time to evaluate the specific concerns (enumerated in the Voltage and Power Quality Screen and the Safety and Reliability Screen) that, as explained above, the penetration screen was designed as a proxy to identify. In addition, utilities can use the Supplemental Review process to further investigate concerns raised by the failure any of the Fast Track screens.

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[66] *See*, e.g., AZ Admin. Code § R14-2-2620(E)(1)(c); IL Admin. Code, tit. 83, § 466.100(f)(4)(A); MN DIP § 3.4.4.1.

In sum, no matter what this process is named, it should include a fixed fee and standard screens.

3. If the Commission retains the Feasibility Study, it should be optional.

Recently, many jurisdictions have found the Feasibility Study process unnecessary. The sum of the Feasibility Study timelines in the Commission Draft is 73 calendar days,[67] and after that time customers are typically provided only a rough idea of the potential system impacts and required upgrades. In addition, the cost of the study is significant and it uses valuable engineering resources. The IREC Model and a report by NREL recommend elimination of the Feasibility Study as an effective method of shortening the study process. [68] Several states, including California, Massachusetts, and North Carolina rely on just two studies, and this efficient process is especially important in these high penetration states.[69] Accordingly, if the Commission retains the Feasibility Study, it should only be performed at the customer's request, as is the practice in Illinois.[70]

[67] Commission Draft Section 5.512(A) (Seven calendar days for Feasibility Study agreement and cost estimate plus 21 calendar days to sign agreement and submit deposit); Commission Draft Section 5.512(F)(1) (45 calendar days to complete Feasibility Study and provide results).

[68] Kevin Fox et al., *Updating Small Generator Interconnection Procedures for New Market Conditions*, at 31-37, http://www.nrel.gov/docs/fy13osti/56790.pdf.

[69] These jurisdictions use only a System Impact Study and a Facilities Study. CA Rule 21 at 52-120; MA Dept. of Public Util., Eversource Energy, Standards for Interconnection of Distributed Generation, at p. 16-68; NC Util. Comm., Dkt. No. E-100, Sub 101, North Carolina Interconnection Procedures, Forms, and Agreements for State-Jurisdictional Generator Interconnections, § 4 (Aug. 20, 2021).

[70] IL Commerce Comm., Dkt. 20-0700, Amendment of 83 Ill. Adm. Code 466 and 83 Ill. Adm. Code 467, Illinois Second Notice Order, Appx. A, § 466.120(e)(1) (allowing the customer to waive the Feasibility Study).

E. The Commission can further streamline Vermont's interconnection process by changing certain timelines.

IREC applauds the Commission's efforts to streamline the interconnection Application process, for example by allowing utilities to provide an interconnection or study agreement without a notification to proceed from the customer.[71] The Commission can further streamline the process by providing Interconnection Agreements earlier and setting a shorter timeline to notify customers that their Application was received.

When a Project passes all the Fast Track or Supplemental Review screens and no construction of facilities is required, utilities can provide standardized Interconnection Agreements at the same time as providing screening results. The Commission Draft provides seven calendar days for this task.[72] However, if the Project passes the screens, and no additional study or construction of facilities is required, the preparation of the Interconnection Agreement should be a simple task based on data in the Application. Because this a routine and straightforward task, the Commission should require utilities to provide the Interconnection Agreement at the same time as the screen results.[73]

Moreover, when preparing the Interconnection Agreement after the study process, utilities can draft the Interconnection Agreement in a timely manner. The Commission Draft allows utilities 21 calendar days to provide an Interconnection Agreement after completing the study process.[74] SGIP, the IREC Model, and many states use significantly less time: seven

[71] Section 5.507(E)(6)(c); Section 5.507(E)(7)-(9); Section 5.507(F)(4)(c); Section 5.507(F)(8)-(9). Each of these sections requires customers to provide approval before utilities can send an interconnection or study agreement.

[72] Commission Draft Section 5.511(D); Section 5.512(G).

[73] IREC Proposal Section 5.511(E); Section 5.512(D).

[74] Commission Draft Section 5.513(H); Section 5.514(E).

calendar days or five business days.[75] Consistent with SGIP, the IREC Model, and many states, IREC recommends that utilities provide the Interconnection Agreements with seven calendar days of completing the study process.[76]

Next, ensuring that customers know the utility received their Application in a timely manner is important because utilities assign queue positions when an Application is deemed complete. SGIP, the IREC Model, and many states require utilities to notify customers of receipt within three business days.[77] Some utilities use an automated email notification to satisfy this requirement, which is sent immediately upon receipt. Other states have further expedited this process by removing the notice of receipt and only notifying customers if the Application is complete.[78] Under Commission Draft Section 5.510(A), utilities send the notice of receipt within seven calendar days of submission. IREC recommends that the Commission shorten the timeline to three calendar days so that customers are sure that their Application is under review.

[75] IREC Model § III(F)(6)(a); SGIP §§ 2.2.2, 3.2.9. 3.3.4, 3.5.7; *see*, e.g., AZ § 14-2-2619(C)(7)(a) (utility provides Interconnection Agreement in seven calendar days); MD 20.50.09.12(E)(3)(d) (utility provides Interconnection Agreement in five business days).

[76] IREC Proposal Section 5.513(H); Section 5.514(E).

[77] SGIP § 1.3; IREC Model § I.C.2; MN Pub. Util. Comm., Dkt. E-999/CI-16-521, MN DIP § 1.5.2; UT Admin. Code, Rule 312: Electrical Interconnection, R746-312-8(2)(b); R746-312-9(2)(b); R746-312-10(2)(b).

[78] Arizona, Maryland, Illinois, Ohio, and Oregon combine the process into one notice of completeness that has a shorter timeline than states with two notifications. *See* AZ Admin. Code § R14-2-2614(D); Code MD Regs. § 20.50.09.09(B), 20.59.09.10(B), 20.59.09.12(B); IL Admin. Code, tit. 83, § 466.90(b)(2); OH Admin. Code § 4901:1-22-04(C)(3); OR Admin. Rule § 860-082-025(7)(a).

III. The Commission should harmonize its rules so that utilities cannot revoke an interconnection approval issued under This Rule in the certificate of public good process.

The Commission should establish that there is only one set of interconnection rules. The Commission's Order indicates that the "interconnection process described in the draft rule would apply to all net-metering systems" and "be completed before a net-metering system applies for a certificate of public good."[79] In addition, Rule 5.100, concerning the process for approving a certificate of public good, currently allows utilities to raise objections to interconnections.[80] IREC is concerned that a utility could approve a Project for interconnection under This Rule and subsequently object to the Project's interconnection in the certificate of public good process. To avoid this, IREC recommends that the Commission add the following language to Section 5.501(C) to prevent utilities from subsequently objecting to a Project approved under This Rule:

> An Interconnecting Utility that, pursuant to This Rule, notifies an Interconnection Requester that its Project is approved for interconnection may not, pursuant to a certificate of public good process (e.g., Rule 5.100), subsequently raise any interconnection concerns or interconnection objections about the Project as studied.

Eventually, IREC recommends that the Commission harmonize these rules by removing from Rule 5.100 the ability of a utility to object to an interconnection, and instead require the customer to apply for interconnection pursuant to Rule 5.500. In the interim, IREC Proposal Section 5.501(C) provides the Interconnection Requester certainty that an approval via the interconnection rule cannot be undermined in the certificate of public good processes.

[79] Order at 1.

[80] Section 5.105(E); 5.106(H); 5.107(C)(10).

IV. The study process should fairly evaluate Projects without delays.

A. System Impact Studies can be completed in 60 calendar days.

The Commission Draft requires utilities to complete System Impact Studies within 60 calendar days, however, when no Feasibility Study is performed the timeline extends to 90 calendar days.[81] As explained in section II.D above, several states streamlined their rules by eliminating the Feasibility Study and IREC recommends that Vermont follow their lead. In Illinois, where the Feasibility Study is optional, the timeline for a System Impact Study is 25 business days.[82] SGIP allows 30 business days for a distribution system impact study or 45 days for the transmission system impact study, and does not provide additional time when skipping the Feasibility Study.[83] In the IREC Model, where there is no Feasibility Study, the timeline for the System Impact Study is 40 business days.[84] Therefore, IREC recommends that the Commission set the timeline for all System Impact Studies at 60 calendar days, which is approximately 43 business days.

B. Vermont's interconnection rules should allow parties to initiate a proceeding where the Commission may authorize a group study process.

The eighth question in the Order asks for comments on authorizing group studies.[85] IREC supports using group studies because they can play an important role in managing high volume queues and also offer a more efficient process with the potential for cost sharing amongst applicants. However, group studies are complex and, if not designed appropriately, can result in

[81] Commission Draft Section 5.513(D)(1).

[82] IL Admin. Code, tit. 83, § 466 Appendix F(7).

[83] SGIP Attachment 7 § 9.0.

[84] IREC Model § III.(F)(4)(d).

[85] Order at 4.

delays and disputes. Ensuring that customers are treated fairly in a group study process requires careful consideration of the process's impacts on all customers in the queue. Vermont Electric Power Company's (VELCO's) proposal, which the Commission implements in its draft rules, fails to adequately address how group studies would be established, how they would impact the proposed study timelines, and how they would impact later queued Projects. These are key issues that must be resolved before group studies move forward. Therefore, the Commission should not at this time authorize utilities to unilaterally conduct group studies.

IREC recommends that This Rule allow a party to propose using group studies by filing a formal petition that considers the impact on all customers of switching to group studies. The Commission should invite VELCO to participate in this process and help design the group study process. As shown in the IREC Proposal Section 5.504, IREC recommends that the petition directly address, and Commission consider in the subsequent proceeding, the following key decisions for group study processes:

(1) Group formation, including timing, geographic scope, and requirements for participation (e.g., interrelated Projects, exclusion of small Projects, and single-applicant groups);
(2) How to conduct group studies, including phases, duration, group vs. individual impact assessments, and distribution vs. transmission impacts;
(3) Group retention, including managing group attrition, (e.g., phases, deposits, site control) and the impact of Project modifications;
(4) Cost allocation, including study costs and upgrade costs; and
(5) Transitioning to a group study process, including impact on Projects already in the queue.

More detail regarding these decisions can be found in Attachment C to these comments.

Failing to fully consider these key decisions will likely cause negative impacts to customers. For example, the petition and Commission should consider if group studies should be mandatory (both for utilities and customers) for certain capacity-constrained areas or feeders.

Failing to properly designate the time at which participating customers are irrevocably assigned the costs of the study and associated upgrades could derail all Projects in the group if one drops out after others are committed and costs must be redistributed. If group studies are voluntary, customers may not commit to a group, resulting in smaller groups than are needed to realize benefits from the group study process.[86] Further, if a customer can opt out at any time, a group could be stuck with an incomplete and useless study, forfeiting the cost and time efficiencies of the group process.

Similarly, the petition and the Commission should consider the impact of Project changes and prohibit changes that inappropriately impact others in the group. Without anticipating such changes at the outset, the entire group will face uncertainty and delays when Projects are modified, removed, or added.

The petition should also have a clearly defined process for sharing study and upgrade costs. Allocation of study costs among participants is complicated because the "group study" may include Project-specific studies that should not be allocated to the entire group. Likewise, the petition should address the allocation of upgrade costs, as system-wide and Project-specific upgrade costs should be treated differently. Finally, the Commission should consider how small Projects will be treated if they are applying on a queue where a group study is being conducted.

Considering the significant detail and complications associated with using a group study process, the Commission should not prematurely authorize its use. Instead, the Commission

[86] When only one or two Projects are in the group, group studies are rarely more cost or time efficient than serial studies. The Commission should consider the exact quantity of Projects needed to make group studies worth their cost.

should allow parties interested in using a group study to submit a well-considered proposal for the Commission's consideration via a formal regulatory process.[87]

V. Vermont's interconnection rules should reflect current best practices for the efficient interconnection of limited export Projects, including energy storage systems.

The Order notes that the Commission Draft includes "standards, modeled on the IREC Model Interconnection Procedures, to account for limited export systems and the operational characteristics of storage," and requests comments on this topic.[88] In addition to adopting a new inadvertent export screen (as explained in section II.C.8 above), IREC recommends that Vermont's rules clarify the terms used to describe limited export systems' size, include updated and simplified language to describe export limitations for PCS, and clarify that interconnection studies must evaluate limited export Projects using their Export Capacity.

A. The Commission should clarify the terms used to identify limited export systems.

Many solar and energy storage systems can be designed to control or manage export. The Commission Draft takes an important step in facilitating the interconnection of these export limiting DERs by describing the difference between the amount a Project can export to the distribution system and the Project's Nameplate Rating. The IREC Model in 2019 defined a pair of terms, "Generating Capacity" and "Nameplate Rating," to identify this difference.

[87] *See*, e.g., MA Dept. of Public Util., Eversource Energy, Standards for Interconnection of Distributed Generation, at 32-39, 169-177 (group study consent form, group study agreement, timeframe, explanation of risks and benefits, and other details about the group study process).

[88] Order at 2-3.

Since then, IREC has participated in various states' interconnection rulemakings[89] and launched the BATRIES initiative. As a result of these conversations, IREC's thinking about the best practices for energy storage interconnection has evolved since 2019, and we now recommend that interconnection rules define the terms "Export Capacity" and "Nameplate Rating" to describe these concepts.

The Commission Draft use the terms "Generation Capacity" and "Nameplate Capacity."[90] IREC prefers the term "Export Capacity" over "Generation Capacity" because the word "export" identifies the primary attribute of the value—its ability to export—that differs from the Nameplate Rating. IREC prefers the term "Nameplate Rating" to "Nameplate Capacity" because a reader is more likely to confuse the pair of terms if both use the word "capacity." Accordingly, IREC recommends using entirely different words when defining the pair.

Whether the Commission uses the term "Export Capacity" or "Generation Capacity," IREC recommends clarifying edits to the definition. As a result of our work with the BATRIES project, IREC now recommends the following definition for Export Capacity:

> Export Capacity – The amount of power that can be transferred from the Project to the distribution system. Export Capacity is either the Nameplate Rating of a Project in alternating current (AC), or a lower amount if limited using an acceptable means identified by in Section 5.521.

IREC does not intend this definition to change the meaning of the term compared to the definition provided in the Commission Draft. Instead, we offer it as an alternative that is more

[89] *See* CA Pub. Util. Comm., Dkt. R.17-07-00; IL Commerce Comm., Dkt. 20-0700; MA Dept. of Pub. Util, Dkt. D.P.U. 19-55.

[90] Commission Draft Section 5.502(21), Commission Draft Section 5.502(33).

straightforward and easier to understand. Similarly, IREC suggests clarifying that the definition of Nameplate Rating references the value identified on the manufacturer nameplate.

B. To avoid confusion, Vermont's interconnection rules should defer to the technical certification standards for power control systems.

Many DERs, including those with energy storage, are likely to use a device called a Power Control System, or PCS, to limit the export of energy to the distribution system. A PCS may be used alone or in conjunction with other means of controlling export, such as a utility grade relay. In order to capture the advanced capabilities of energy storage, the interconnection procedures should describe the requirements and use of PCS.

The Commission Draft's Section 5.521 includes language from the IREC Model. As a result of work with the BATRIES project, IREC now recommends replacing proposed Section 5.521(5) with the following language:

> Certified Power Control Systems: Projects may use certified power control systems to limit export. Projects using this option must use a power control system and inverter certified per UL 1741 by a Nationally Recognized Testing Laboratory ("NRTL") with a maximum open loop response time of no more than 30 seconds. NRTL testing to the UL power control system certification requirements decision shall be accepted until similar test procedures for power control systems are included in a standard. This option is not available for interconnections to area networks or spot networks.

This new language improves upon the 2019 IREC Model in several ways. First, the heading uses "Certified," which clearly indicates that the devices must be tested and certified. Second, the industry now uses the term "Power Control System" to reference both inverters and other control systems, therefore the title uses "Power Control Systems" instead of separately listing inverter and control systems.

Third, the language used in the IREC Model includes specific technical requirements because it is based on how California and Hawaii authorized the use of PCS prior to the

publication of a UL certification. Now that UL published its PCS certification requirements decision (PCS CRD), some of the IREC Model language is not in perfect alignment with the certification. This can be problematic for the evaluation of equipment since the certification will not match the interconnection rule's technical requirements. In addition, UL anticipates incorporating the PCS CRD's test requirements into UL 1741 in the next year. As a part of that process, UL may further revise the certification requirements. To avoid confusion as to the applicable requirements and maintain alignment with the UL standards, IREC now recommends that the interconnection procedures should not contain detailed technical requirements and instead simply cite to the UL standards.

C. The Commission should clarify that interconnection studies must account for the Project's Export Capacity, rated fault current, and Operating Profile.

IREC recommends modifying Commission Draft Section 5.503(A)-(B) to clarify that if a Project uses one of the acceptable means of export control in Section 5.521, then interconnection studies must evaluate impacts to the distribution system using the Project's Export Capacity, except when evaluating fault current. In addition, the screening and study processes should take into account the ways that Projects can be controlled to mitigate impacts that may occur only during certain hours of the day (e.g., when peak or minimum loads exist) or during different months of the year.

1. It is appropriate for the Commission and utilities to rely on verified export controls.

When a Project follows Section 5.521, the Commission Draft allows the utility the option to study "some other reasonable and expected capacity determined by the Interconnecting

Utility" instead of the Export Capacity.[91] This provision could inappropriately allow a utility to study a Project at more than its Export Capacity when the Project uses one of the six options described in Section 5.521. All six options use equipment configurations recognized by utilities across the country or a standards organization.

For example, IREC expects most smaller Projects to select option 5 and use a PCS, which can be trusted because its functionality has been tested and certified by a Nationally Recognized Testing Laboratory (NRTL). Interconnection standards and guidance documents, such as the suite of UL 1741 standards, play a crucial role in ensuring that devices used to interconnect to the grid operate safely, reliably, and according to their specifications. NRTLs subject manufacturers' equipment to a battery of tests before granting certification. Some equipment fails the testing and are denied certification. The certification process, in conjunction with the evaluations performed in the interconnection process as well as any commissioning tests, provides utilities and regulators with adequate assurances that the PCS will effectively limit export to the distribution system in all relevant circumstances. Therefore, it is appropriate for the Commission and utilities to rely on the nationally-recognized testing and standards process to accept the use of verified export controls. It is inappropriate for interconnection rules to allow a utility to study a Project that complies with Section 5.521 as exporting more than its Export Capacity.

2. The screening and study process should evaluate fault current contribution using the Nameplate Rating or manufacturer test data.

When evaluating potential fault current impact, utilities typically use the Nameplate Rating of the Project to calculate its contribution to fault current. For this reason, IREC

[91] Commission Draft Section 5.503.

recommends that the Commission modify Fast Track screens 3 and 4[92] to evaluate fault current instead of Export Capacity. IREC recommends that the Commission make this change to ensure that Vermont's interconnection rules fully evaluate the safety and reliability impacts on distribution system fault current.

In addition, IEEE 1547.1-2020 clause 5.18 describes a fault current test that can be used to establish that equipment contributes less to fault current than would be expected based on the equipment's Nameplate Rating. Therefore, as shown in the IREC Proposal Section 5.503, if the customer provides the utility manufacturer test data demonstrating that the fault current is independent of the Nameplate Rating, then utilities should use that rated fault current in the study process.

3. The study process should evaluate Projects according to their Operating Profile rather than assuming unrealistic scenarios.

A solar Project without energy storage can only export power when the sun shines, i.e., its Operating Profile, and a Project with energy storage can select the specific hours and days it elects to export, i.e., its Operating Schedule.[93] Because many system impacts have a temporal aspect due to daily or seasonal changes in the load curve, the Commission's rules should establish that the study process must consider the Operating Profile, and may consider an Operating Schedule.

Due to the prevalence of solar Projects (without energy storage) that only generate in daylight hours and have seasonal output variations, the Commission should require studies to account for temporal changes to electric grid outside of the Project's control. For example, if a

[92] IREC Proposal Section 5.511(D)(3)-(4).

[93] The IREC Proposal includes definitions for Operating Profile and Operating Schedule.

solar Project without energy storage proposes to interconnect to circuit on which a system impact study shows that constraints only occur at night, that Project should be able to interconnect without limitation because it does not export at night. The Commission Draft recognizes that interconnection studies should "consider the operational characteristics unique to Energy Storage Devices that can minimize impacts to system stability and reliability,"[94] but omits consideration of the same for Projects without energy storage. Therefore, IREC proposed to modify the first sentence of Section 5.503(A) to read:

> All screens and studies conducted pursuant to this Rule must consider the Project's design, including but not limited to the applicant's proposed Operating Profile, and study the Project according to how the Application proposes to operate it.

National standards organizations and several states are evaluating ways that customers can communicate predefined Operating Schedules to utilities, and what technologies can provide utilities adequate assurances that energy storage Projects will export only according to their Operating Schedule.[95] However, no one standard or technology is mature enough to require its use today. Therefore, more work needs to be done before regulators can require the use of Operating Schedules in the screening and study processes. Accordingly, we urge the Commission to future-proof its interconnection rules by allowing customers to designate an Operating Schedule in the Interconnection Application,[96] and to allow utilities to consider the Operating Schedule in the study process.[97] After a national standard organization publishes

[94] Commission Draft Section 5.503(B).

[95] See, e.g., CA Pub. Util. Comm. Dkt. R17-07-007; MA Dept. of Pub. Util. Dkt. 19-55.

[96] IREC Proposal Section 5.502 (definition of Operating Schedule allows a customer to designate the Operation Schedule in the Interconnection Application).

[97] IREC Proposal Section 5.503(A) ("The Supplemental Review and System Impact Study may consider an Operating Profile proposed in the Application.").

requirements for equipment that sets Operating Schedules, the Commission should require utilities to consider the Operating Schedule of a Project that uses equipment that complies with that standard.

VI. Vermont's rules should include a more robust dispute resolution process, including an Interconnection Ombudsperson.

IREC recommends including in This Rule a more detailed dispute resolution process based on the IREC Model, which includes an Interconnection Ombudsperson. A more detailed dispute resolution process will aid the efficient resolution of interconnection disputes, and ideally, prevent many disputes from reaching the Commission's formal processes.

To accomplish this, the IREC Proposal requires parties to first attempt to resolve the dispute among themselves, without outside assistance.[98] In most cases, the parties would be required to send written notices detailing the problem, and to respond to such notices in writing in a timely manner.[99] In IREC's experience, this written process helps the parties better understand both their position and the other's response, which aids the efficient resolution of disputes. Most importantly, the parties should be required to meet and use good faith and best efforts to resolve the dispute.[100]

The IREC Proposal also envisions the Commission appointing an Interconnection Ombudsperson to track and oversee disputes. The Ombudsperson, typically an employee of the Commission or another independent third party, would receive a copy of all notices regarding disputes, gain insight into the details of interconnection disputes, and maintain availability to

[98] IREC Proposal Section 5.515(E)(1)-(2).

[99] IREC Proposal Section 5.515(E)(4).

[100] IREC Proposal Section 5.515(E)(4).

serve as a mediator. Staffing the role in-house would also provide the Commission detailed knowledge about the nature and frequency of disputes, as well as the underlying issues that drive them. In recent years, several states have created a role for a staff Ombudsperson to assist with the resolution of disputes between applicants and utilities.[101] Vermont should follow suit.

VII. The Commission should modify its rules to increase transparency surrounding the interconnection process.

A. Publishing more information about the queue and timelines will enable utilities, the Commission, and policymakers to track the effectiveness of the interconnection process.

Lack of a robust public queue or regular interconnection reports often results in a dearth of information about the actual implementation of the interconnection process. This lack of transparency inhibits the Commission and policymakers from using unbiased data to evaluate the effectiveness of the interconnection process and utilities' progress towards meeting the state's distributed energy resource goals. Therefore, IREC recommends that the Commission modify its rules to require utilities to track various metrics surrounding the interconnection process, and to publish that data online in a public queue and annual report.

The Commission proposes for the first time to require utilities to provide a public interconnection queue. IREC fully supports this requirement, however, the Commission should make this requirement more effective by specifying a minimum frequency of queue updates and requiring utilities to provide more information, consistent with the recommendations in the IREC

[101] *See*, e.g., MA Dept. Pub. Util., Interconnection Dispute Resolution Guidance, https://www.mass.gov/info-details/interconnection-dispute-resolution-guidance ("If the dispute is not resolved after 8 days of discussions, you may request dispute resolution help from the DPU's Ombudsperson."); New York Interconnection, https://tinyurl.com/32jzmpsd ("Ombudsman services are now available to provide coordination between DG applicants and utilities."); NY Dept. of Pub. Serv., Interconnection Ombudsman Effort, https://tinyurl.com/5cytwkvk.

Model. Providing greater transparency into timeline compliance and the failure rate for screens is particularly important because IREC has found that these areas are most likely to produce problems.

When utilities publish timeline compliance and screen failure data, customers, the utility, the Commission, and policymakers benefit. When queue data is published regularly (such as weekly or monthly) in a sortable spreadsheet, customers can determine how many Projects are ahead in the queue, if a study has begun or not, how long the utility's study process typically takes, what sorts of Projects are likely to fail screens, and if certain geographic areas have seen more distribution system impacts. The Commission and policymakers likewise benefit by gaining access to unbiased data that provides insight into how the interconnection process is proceeding, both in terms of utility and customer responsiveness. This information can provide insight in whether additional revisions to the procedures to improve the process are warranted. In Massachusetts, regulatory require and the Department of Energy Resources closely monitors a detailed monthly public queue and annual report.[102]

As the Commission transitions to the new Simplified Process and Fast Track Process, this type of tracking could be especially helpful to identify challenges associated with this transition, including the Application of the new screens. In other states without tracking and public reporting requirements, problems with the implementation of interconnection screens can go unacknowledged for years. For example, Duke Energy did not report on its Fast Track screen results, so customers, policymakers, and the Commission had no way to discover why Duke

[102] MA Dept. Energy Resources, *Interconnection in Massachusetts*, https://sites.google.com/site/massdgic/home/interconnection (accessed Jan. 30, 2022) (queue data available under "Utility Reporting & Circuit Analysis for Locational Value," timeline compliance data available under "Timeline Enforcement").

Energy's interconnection queue was severely backlogged and customers faced extensive delays waiting to be studied. Many years later, after the discovery process in a contested docket, it emerged that an unusual number of Projects were failing one screen in particular. It then came to light that the utility was applying the screen in an unconventional, and ultimately overly conservative, manner.[103] This could have been remedied sooner with more transparent reporting requirements. Vermont should plan ahead, avoid the need for a discovery process in a contested docket, and provide public access to this data.

In addition to simply publishing raw data in a queue spreadsheet, IREC's proposed annual report provides a vehicle for utilities, stakeholders, the Commission, policymakers to track Vermont's DER deployment goals and take a big-picture look at interconnection processing trends. If the report reveals a pattern of impediments to interconnection in a certain aspect of the interconnection process, policymakers or the Commission could request an analysis of the root cause of the problem and then evaluate changes to fix the problem. It is reasonable to require utilities to track this data because it is information that is readily available to the utilities in their ordinary course of business. Such reporting is required in Massachusetts, as well as in California and Minnesota.[104] Utilities should track metrics about implementation of the interconnection process and publish that data online in a public queue and in an annual report.

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[103] NC Util. Comm., Dkt. E-100 Sub. 101, Post-Hearing Brief of the Interstate Renewable Energy Council, Inc., at 12-13 (March 25, 2019).

[104] MA Dept. Energy Resources, *Interconnection in Massachusetts;* MN Pub. Util. Comm., Dkt. E999/CI-01-1023, MN DIP Interconnections Annual Report (March 15, 2021); CA Pub. Util. Comm., *Quarterly IOU Interconnection Data Reports*, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/rule-21-interconnection/quarterly-iou-interconnection-data-reports (accessed Feb. 2, 2022); CPUC Decision 20-09-035 (Ordering Paragraph 22 requires utilities to additionally report on interconnection timeline tracking every quarter).

B. Utilities should provide load profiles in pre-Application reports.

IREC recommends the Commission revise the data provided in the pre-Application report to include load profiles and several clarifications that reflect national best practices. Utilities' distribution system information is typically available to customers only through mechanisms that interconnection procedures require. Vermont's current interconnection rules include an informal pre-Application report process without a defined set of data for utilities to provide customers. IREC applauds the Commission's proposed rules for moving beyond this informal process and instead defining the data that should be included in a formal pre-Application report.

However, in order to maximize the value of the pre-Application report for developers of energy storage systems, pre-Application reports should include load profiles. Customers and developers use load profiles to strategically locate storage Projects to provide energy during peak load hours and to minimize export during low load/high generation hours. For example, a customer seeking to site a new solar Project with energy storage could use a load profile that avoids expensive distribution system upgrades by designing a system that accommodates daily or seasonal variations in minimum load with voluntary seasonal or hourly export limits. In addition, a customer seeking to site a standalone energy storage Projects can use the peak load on a feeder to understand the magnitude of the proposed new load compared to the existing peak loads.

The Commission should require that utilities provide the most specific granularity of profile available. Ideally, utilities would provide a full 8,760 hour profile including the load in every hour of the year. If an 8,760 hour profile is not available, the utility should provide a 576 hour profile, including the monthly minimum and peak load that occurs during each of the 24 hours in the day (24 hours x 12 months x 2 load values (peak and minimum load)). For developers to take advantage of load data to strategically avoid trigging upgrades at peak or

minimum load hours, as well estimate if their Project can pass the penetration screens, the data must include at the very least a 24 hour load profile for the peak load day, and a 24 hour load profile for the minimum load day, in each season. Customers similarly have access to hourly load profiles in California, Nevada, and New York.[105]

In addition, IREC recommends that the pre-Application report provide "any other information the utility deems relevant to the Project."[106] This catch-all provision ensures that the utility provides customers other data that will help inform the design and siting of the Project. As with the other pre-Application report data, this is not a requirement for the utility to perform a new study or develop new data. Rather, it is a requirement to disclose other relevant data the utility identifies when preparing the pre-Application report.

The IREC Proposal in Section 5.505(B) also recommends clarifying the type of data to be provided. These clarifications include specifying that the provision of aggregate Export Capacity instead of Nameplate Rating, among others.

Finally, IREC recommends that customers include in the Pre-Application Report Request the Project's Nameplate Rating, Export Capacity, single or three-phase, whether the Project is stand-alone or will service on-site load, and whether new service is requested. Providing this information will allow the utility to return more specific and relevant data as a part of the pre-Application report.

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[105] Joint Utilities of New York, *Historical Load Data*, https://jointutilitiesofny.org/utility-specific-pages/system-data/historical-load-data (accessed Feb. 3, 2022); Southern California Edison, *Integrated Capacity Analysis User Guide*, at 13-14 (Aug. 30, 2021), https://ltmdrpep.sce.com/drpep/downloads/ICAUserGuide.pdf; *NV Energy Distributed Resources Plan Web Portal User Guide*, at 16-19 (June 24, 2021), https://tinyurl.com/2p8k67mv.

[106] IREC Proposal Section 5.505(13).

C. If a Project fails one of the Simplified, Fast Track, Supplemental Review screens, the utility should provide a standardized written report of the specific system threshold or limitation.

When a Project fails a screen, utilities should explain to the customer in writing which screen failed and why. The Commission Draft requires utilities to provide customers "copies of the analysis and data underlying the Interconnecting Utility's determinations."[107] IREC strongly supports this requirement, and encourages the Commission to further require that this notification use a standardized format and be in writing.

Ideally, the standardized format would include full information about each screen failed so that the customer would be able to ascertain exactly what changes to the Project could allow it to pass the screen (and thereby avoid the need for upgrades). The Commission Draft gives utilities leeway to determine how much information to provide in the notification, and in jurisdictions with similar language in their interconnection procedures, this results in different utilities providing varying levels of information to customers.

With the BATRIES team, IREC recently reviewed screening results from utilities in Hawaii, Illinois, Minnesota and North Carolina to determine the range of data currently provided. The type and amount of data provided varied significantly, with some utilities providing a simple "pass" or "fail" for each screen and others providing more detailed data. Given the likelihood of data being available to the utility during the screening process, the BATRIES team developed a standardized format for the provision of certain screen results based on data provided in one or more of the examples we reviewed. IREC recommends that the

[107] Commission Draft Section 5.511(A).

Commission require utilities to provide standardized screen results that follow the template provided in Attachment B.

D. The Commission's rules should reference—not restate—reporting requirements set by transmission utilities or independent system operators.

The ninth question in the Order asks for comments on the VELCO reporting requirement.[108] VELCO requested that the "rule should put developers on notice of ISO-NE's notification and study requirements for Projects greater than 1 MW. Doing so will avoid having developers needlessly surprised by the transmission study requirement with its associated costs and potential delays."[109] IREC agrees that the distribution utilities should notify VELCO when requested to do so. However, such notification requirements are typically set by transmission utilities or independent system operators through processes not under the Commission's jurisdiction. Since those requirements can change independently of This Rule, IREC recommends that the rule reference—not restate—the reporting requirements. As we explained in section V.B above, problems have occurred when interconnection rules restate requirements set by other organizations, and then those requirements change. To avoid that situation, IREC recommends This Rule reference VELCO's requirement. Utilities can restate the reporting criteria in their Applications, which will provide customers the notice requested by VELCO.

[108] Order at 4.

[109] Vermont Electric Power Company, Response to Request for Information Re: 19-0856-RULE Proposed Revisions to Vermont Public Utility Commission Rule 5.500, at 2 (July 30, 2021).

VIII. The Commission should establish a working group to adopt IEEE 1547-2018 and specify in the rule the version of each standard the Commission adopts.

The seventh question in the Order asks for comments concerning a process for adopting additional standards for communications protocols and suggests a working group process.[110] IREC agrees that the Commission should convene a working group; we recommend that the working group broadly address the adoption of IEEE 1547-2018, a standard that provides the foundation for the review of DER. In addition, IREC recommends that Section 5.519 identify the specific version of each standard the Commission adopts.

A. IREC supports the Commission's inclination to swiftly adopt IEEE 1547-2018, allowing Vermont to take advantage of the capabilities of inverters to mitigate grid impacts and allow potentially higher penetrations of DERs at a lower cost.

The Commission should amend Rule 5.500 to include the new 2018 version of IEEE 1547, but the adoption process is not as simple as stating that new standards are automatically adopted six months after their publication.[111] 1547-2018 includes many new requirements compared to 1547-2003, including voltage and frequency ride-through, voltage regulation, frequency regulation, interoperability (communications), power quality, intentional islands (microgrids) and new concepts including the Reference Point of Applicability. The utility and applicant should have the same understanding of how these requirements apply to a particular Project such that it can be interconnected successfully, and thus the requirements should be spelled out clearly in a technical interconnection requirements document.

Unlike the previous 2003 version, in two areas 1547-2018 requires that the implementing body choose from a defined set of options regarding which level of capability of the DER it will

[110] Order at 4.

[111] *See* Commission Draft Section 5.519.

require. The selection of the Normal Operating Performance Category and the Abnormal Operating Performance Category must be defined clearly, and they may apply differently to different technologies. Equipment manufacturers and developers will need to know which categories must be supported. Additionally, the regional reliability coordinator should have input into the selection of the Abnormal Operating Performance Category, as the capabilities of aggregated DER can have effects on the bulk electric grid. ISO-NE has also created guidelines for 1547-2018 implementation.[112] The standard defers to the Authority Governing Interconnection Requirements, i.e., the Commission, to determine the applicability of the category assignment.

Besides the performance categories, whether to use voltage regulation by default, as well as whether and how to implement standardized monitoring and control, will have broad implications for the deployment of DER and its effect on the distribution system as penetration grows. Without attempting to provide an exhaustive list, the evaluation of rapid voltage changes, the configuration setting for power, fault current characterization, and evaluation/commissioning are further issues to address when adopting the updated requirements.

In its Order, the Commission expresses a desire for "more flexibility to adapt to rapid changes in technology and interconnection standards from governing bodies like IEEE."[113] To accomplish this and address the adoption of IEEE 1547-2018, IREC recommends the Commission implement the basic process laid out below:

1) Identify the stakeholder working group to engage in the adoption discussions, including, but not limited to, Commission staff, utilities, DER developers, regional

[112] ISO New England, Default New England Bulk System Area Settings Requirement (Aug. 18, 2021), https://drive.google.com/file/d/10iB8_x91g_J1PEsZiOugn2JwkK8HSSRh.

[113] Order at 2.

reliability coordinators, DER advocates, consumer advocates, 1547 standard experts, and technical assistance providers.[114]

2) Plan a schedule for addressing all 1547 adoption topics within the working group, including, but not limited to, those described above.
3) Engage the working group to discuss the conceptual topics and decision points, with the goal of gaining consensus on which decisions will be addressed by formal guidance.
4) Determine the suitable location for formal guidance, whether within the interconnection rules, another tariff, Commission guidance document, or utility documentation.
5) Determine the timeline for implementation. For example, IREC recently surveyed inverter manufacturers and many expect availability of 1547-2018 compliant equipment in April 2023.
6) Identify and engage a writing group to formalize conceptual agreement and decision points within the draft guidance document(s).
7) Distribute the draft guidance document(s) to the working group for one or more rounds of comment and revision.
8) Shepherd the guidance document(s) through any necessary regulatory process for final inclusion in the appropriate rules, tariffs, or other documentation, as envisioned by Commission Draft Section 5.520.

Items 4 and 5 would not necessarily occur in sequential order, and likely should be discussed throughout the process.

IREC commends the Commission for supporting the use of voltage and frequency ride-through in Section 5.515(C). However, the Commission should first establish a process to fully develop detailed technical guidance before requiring voltage and frequency ride-through. Without that detail, such as which Abnormal Operating Performance Categories Projects should use, implementing the requirements would be confusing. IREC recommends that the Commission avoid requiring voltage and frequency ride-through until detailed technical guidance makes clear to the utility and customer exactly which requirements are in effect. IREC supports allowing the utility and customer to mutually agree to use voltage and frequency ride-

[114] Experts and technical assistance may potentially be provided by the National Renewable Energy Laboratory, Sandia National Laboratory, Electric Power Research Institute, IREC or others.

through at this time. Alternatively, reference could be made to the Inverter Source Requirement Document of ISO New England (ISO-NE),[115] such as "The Interconnection Agreement shall require that inverters comply with the requirements of the Inverter Source Requirement Document of ISO New England (ISO-NE) dated February 6, 2018."

B. Section 5.519 should include the version number of each standard adopted.

Updates to standards other than IEEE 1547 should follow similar processes in order to determine if the updates call for the Commission to make decisions in implementation, if equipment meeting the new certification is available, the timeline for implementation, and any necessary additions or changes to tariffs and/or guidelines. It is likely that for most standards a rather abridged version of this process may be utilized, given that the Application may not be as complex as the update to IEEE 1547-2018.

After a new version of a standard is released, it takes time for manufactures to develop equipment certified to meet the new standard. Given the lag in certified equipment availability, the Commission should establish a date on which each updated standard goes into effect. While manufacturers may bring equipment to market within six months for some updates, others will take longer. Accordingly, a blanket six month adoption requirement could leave customers without any certified equipment to purchase and utilities unprepared to integrate necessary changes into the interconnection process. For example, as of February 2022, little equipment

[115] ISO New England, Inverter Source Requirement Document of ISO New England (ISO-NE) (Feb. 6, 2018), https://tinyurl.com/2p98593c.

exists today that is certified to IEEE 1547-2018, almost four years later (and over eighteen months after publication of IEEE 1547.1-2020).[116]

Therefore, IREC recommends that the Commission clarify in Section 5.519 which version of each standard is in effect now.[117] When adopting updated standards in the future, IREC recommends that the Commission's interconnection rules, tariff, or technical guidance document indicate the date on which new Applications must comply with each updated standard so that utilities and customers understand the exact date new requirements apply.

IREC Proposal Section 5.519 includes the suggested format for standards citations, including version numbers. IREC notes that IEEE 1547, 1547.1 and UL 1741 should be updated as part of 1547 adoption efforts, while references in the rule to IEEE 519 and 1453 may be replaced with references to IEEE 1547-2018. Amendments (e.g., IEEE 1547a-2020) may also be added to the list as needed for clarity.

IX. Interconnection rules can address vehicle-to-grid discharging and the simultaneous evaluation of system impacts from grid exports and imports.

The Order's second question asks if "the rule should address the interconnection of electric vehicles or fleets of electric vehicles."[118] Interconnection rules can address two facets of

[116] As UL 1741 was updated to include reference to IEEE 1547.1-2020 testing protocols, a number of inconsistencies and issues were noted, requiring UL 1741 to updated again with clarifications and a new Third Edition in September 2021. Regardless of the unanticipated certification challenges, updates to UL 1741 have typically been implemented over the course of eighteen months to allow manufacturers time to adapt. Moving forward, UL's intention is to let market acceptance of certification requirements lead the way in terms of requirement transitions. This means that regulators will take on a larger role in determining when new requirements must go into effect.

[117] IREC Proposal Section 5.519 includes suggested version numbers for each standard.

[118] Order at 3.

electric vehicle interconnection: exporting power from a vehicle to the grid, and the simultaneous review of systems impacts from energy storage exports and imports.

Exporting power from a vehicle to the grid (vehicle-to-grid or V2G) is still in the early stages of development. While some states are beginning to explore the capabilities of V2G, and V2G-enabled equipment is currently being developed and commercialized, the technology is not yet in widespread use, and several challenges must be addressed in order to scale this technology.[119] One of the initial hurdles for states is determining how to safely and cost-efficiently interconnect new V2G technologies given that technical standards essential to certifying the equipment as safe and reliable to operate are new. While different standards organizations authored a number of V2G-applicable standards, there is disagreement over which entity should be responsible for testing equipment and how to fill in gaps not covered by these standards.[120] For more information, please see *Paving the Way*, a series of papers from IREC discussing the opportunities and challenges associated with V2G.[121]

Next, states could evolve interconnection rules to simultaneously evaluate the system impacts of a battery DER exporting to the grid, as well as more traditional grid-to-battery

[119] The list of states with V2G pilots or ongoing regulatory discussions on V2G includes California, Michigan, Minnesota, New York, North Carolina, South Carolina, and Virginia. Mafazy, Midhat, *Paving the Way: Vehicle-to-Grid Standards for Electric Vehicles*, Interstate Renewable Energy Council, at 2 (Jan. 2022) (note 2), https://irecusa.org/resources/paving-the-way-vehicle-to-grid-standards-for-electric-vehicles/.

[120] *See* CPUC Docket 17-07-007, Final Report of the Vehicle to Grid Alternating Current Interconnection Subgroup – Gaps Analysis and Recommendations (Dec. 11, 2019).

[121] Interstate Renewable Energy Council, *Electric Vehicles*, https://irecusa.org/our-work/electric-vehicles/.

charging.[122] As is typical in most states, Vermont's interconnection rule is designed to simply address a DER's export of power and does not contain any guidance on how to study the additional load. Eventually, the Commission could develop rules to ensure that utilities evaluate the charging and discharging aspects of energy storage Projects simultaneously.

When the Commission embarks on drafting rule language to accomplish this, one important thing to consider is the concept of an Operating Schedule for charging. When developing rules for the interconnection of energy storage Projects, the Commission should ensure that the controllable nature of the charging behavior is accounted for through the concept of an Operating Schedule for imports from the grid.[123] In addition, to the extent there are different rules for allocating costs for upgrades required for new load sources versus new generation sources, those rules should be harmonized to ensure energy storage Projects are treated fairly.

X. Conclusion

IREC thanks the Commission for the opportunity to comments on the draft rules.

[122] IREC suggests opening this process to all energy storage systems, not just batteries in vehicles.

[123] The IREC Proposal adds a definition of Operating Schedule to Rule 5.500.

DATED: February 11, 2022

By: /s/ Yochanan Zakai

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ATTACHMENT A

5.500 INTERCONNECTION PROCEDURES FOR PROPOSED Distributed Energy ~~ELECTRIC~~ ~~GENERATION~~ RESOURCES

Commented [A1]: The title ideally would encompass more than generators, i.e., independent energy storage system are not a generation resource.

5.501 Applicability

(A) This Rule applies to all proposed interconnections of Projects within the State of Vermont that are not lawfully subject to ISO-NE interconnection rules or successor rules approved by FERC. The interconnection of all net-metering systems is governed by This Rule. This Rule applies to all Applications filed on or after the effective date of this Rule.

(B) This rule establishes minimum requirements. The Commission may adopt additional requirements for the interconnection of Projects by order pursuant to Public Act No. 61, § 7 (2006 Vt., Adj. Sess.).

(C) An Interconnecting Utility that, pursuant to This Rule, notifies an Interconnection Requester that its Project is approved for interconnection may not, pursuant to a certificate of public good process (*e.g.*, Rule 5.100), subsequently raise any interconnection concerns or interconnection objections about the Project as studied.

Commented [A2]: Provides the Interconnection Requester certainty that using this process will allow for interconnection under the certificate of public good processes.
IREC recommends that after these changes to Rule 5.500 are adopted, the Commission remove the interconnection provisions from Rule 5.100.

5.502 Definitions

(1) Affected System – any electric system that is either directly or indirectly connected to the Interconnecting Utility's electric system that could be adversely affected by the interconnection and parallel operation of the Interconnection Requester's Project ~~Generation Resource~~.

(2) Application – a request for interconnection initiated by the submission of a completed Application form provided by the Commission for the interconnection of Projects, the ~~$300~~ Application fee, and any other information required by this Rule.

(3) Application Fee – the fee paid to the interconnecting utility to review an Application. The fee shall be $300 or the amount specified in an approved utility tariff. The Application Fee is non-refundable, unless the Application is withdrawn within 7 days of submittal. The Interconnecting Utility may require electronic payment of the Application Fee.

(4) Application Form – the form adopted by the Commission for Projects to request interconnection with the Interconnecting Utility. The Application Form may be amended by the Commission from time to time. Application Forms must be submitted electronically to the Interconnecting Utility.

(5) Automatic Disconnect Device – an electronic or mechanical switch used to isolate a circuit or piece of equipment from a source of power without the need for human intervention.

(6) Commission – the Vermont Public Utility Commission.

(7) Disconnect (verb) – To isolate a circuit or equipment from a source of power. If isolation is accomplished with a solid-state device, "disconnect" shall mean to cease the transfer of power.

(8) Disconnection – the state of a circuit or equipment being disconnected from a source of power.

(9) Distribution Level Study – a System Impact Study conducted at the distribution level.

(10) Emergency – a situation in which continued interconnection of a Project is imminently likely to result in significant disruption of service or endanger life or property.

(11) Energy Storage Device means a device that captures energy produced at one time, stores that energy for a period of time, and delivers that energy as electricity for use at a future time.

(12) Facilities Study – a study to determine which Interconnection Facilities or System Upgrades are necessary for interconnection of the Project.

(13) Facilities Study Report – contains the results of the Facilities Study and is transmitted to the Interconnection Requester in accordance with Section 5.514.

(14) Fast Track – the process for establishing an interconnection for certain qualifying Projects in accordance with Section 5.511 of this Rule.

(15) Fast Track Screening Criteria – the screening criteria for Projects set forth in ~~i~~this Rule.

(16) ~~Feasibility Study~~Supplemental Review – the process defined in Section 5.512 of This Rule~~a study consisting of initial engineering analyses regarding the feasibility of interconnecting the Project, if the Project is not eligible for Fast Track~~.

(17) ~~Feasibility Study Report – contains the results of the Feasibility Study, and other information required by this Rule.~~

(18) FERC – the Federal Energy Regulatory Commission.

(19) ~~Flicker – voltage fluctuations caused by rapid changes in Project output.~~

Commented [A3]: The Rule's definition of flicker is inconsistent with the definition of flicker found in IEEE 1453.1-2012. See IREC's comments. To avoid confusion, we recommend deleting this definition and simply using voltage fluctuation.

(20) Frequency Ride Through – the ability of a Project to stay connected to and synchronized with the system or equipment of the Interconnecting Utility and any Affected Systems during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other Projects in the Interconnecting Utility's service territory on a comparable basis.

(21) ~~Generation~~Export Capacity – The amount of power that can be transferred from the Project to the distribution system. Export Capacity is either the ~~maximum~~ Nameplate Rating of a Project in alternating current (AC), or a lower amount if ~~except that where such capacity is~~ limited using an acceptable means identified by ~~any of the methods of limiting electrical export in~~ Section 5.521~~, the Generating Capacity shall be the net capacity as limited through the use of such methods (not including Inadvertent Export)~~.

Commented [A4]: Modified to reflect best practices developed since IREC's 2019 model rules were published. See comments for more detail.

(22) Generation Resource – a facility that produces electric energy from other energy sources.

(23) Good Utility Practice – Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric industry operating a comparable electric system

during the relevant time period, or any of the practices, methods, and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

(24) IEEE – Institute of Electrical and Electronics Engineers, Inc.

(25) Interconnecting Utility – Electric utility with which the Interconnection Requester proposes to interconnect a Project.

(26) Inadvertent Export - The unscheduled export of active power from a Project, exceeding a specified magnitude and for a limited duration, generally due to fluctuations in load-following behavior.

(27) Interconnection Agreement – an agreement between an Interconnecting Utility and Interconnection Requester regarding the interconnection and parallel operation of a Project. The Interconnection Agreement is accompanied by or includes Technical Requirements and Operator Protocols.

(28) Interconnection Facilities – all facilities and equipment between the Project and the Point of Interconnection, including any modification, additions, or upgrades that are necessary to physically and electrically interconnect the Project to the Interconnecting Utility's distribution or transmission system. Interconnection Facilities are sole-use facilities and shall not include System Upgrades.

(29) Interconnection Queue – the list of Applications for the interconnection of Projects, in order based upon the date-and-time-stamp of complete Applications, maintained by each Interconnection Utility.

(30) Interconnection Requester – person or entity who proposes to interconnect a Project with an Interconnecting Utility.

(31) ISO-NE – ISO New England, Inc.

Line Section - means that portion of the Interconnecting Utility's System connected to a Project that is bounded by automatic sectionalizing devices[1] or the end of the line.

Commented [A5]: Definition of a line section provided because the term is used in the penetration screens.

(32) Material Modification – means a modification that has a material impact on the cost or timing of processing an Application with a later queue priority date or a change in the Point of Interconnection. A Material Modification does not include, for example, (a) a

[1] Automatic sectionalizing device means an interrupting device like a line recloser. A fuse must be manually replaced and is not an automatic sectionalizing device.

change of ownership of a Project, (b) a change or replacement of ~~generating~~ equipment that is a like-kind substitution in size, ratings, impedances, efficiencies, or capabilities of the equipment specified in the original Application, or (c) a reduction in the output of the Project of 10% or less.

(33) Nameplate Rating~~Capacity~~ – means the sum total capacity of all of a Project's constituent units as identified on the manufacturer nameplate, regardless of whether it is limited by any of the methods in Section 5.521.

Commented [A6]: Modified to reflect best practices developed since IREC's 2019 model rules were published. See comments for more detail.

Operating Profile - means the manner that the Project is designed to be operated, based on the generating prime mover and operational characteristics. The operating profile includes any limitations set on power imported or exported at the Point of Interconnection and the resource characteristics, *e.g.*, solar output profile.

Operating Schedule - means the time of year, time of month, and hours of the day designated in the Application for the import or export of power.

(34) Operator Protocols - an agreement between the Interconnection Requester and the Interconnecting Utility pertaining to the operation and maintenance of the Project.

(35) Point of Interconnection – the point on the Interconnecting Utility's existing system to which the Interconnection Requester proposes to interconnect.

(36) Pre-Application Fee – a Pre-Application Request includes a Pre-Application Fee. The fee shall be $300 or the amount specified in an approved utility tariff.

(37) Pre-Application Report – information about the application process and the point of proposed interconnection to the utility system.

(38) Pre-Application Request – a request from the Interconnection Requester for a Pre-Application Report.

(39) Project – a Generation Resource or Energy Storage Device or an electrically-connected combined Generation Resource and Energy Storage Device.

(40) Radial Feeder – a distribution line that branches out from a substation and is normally not connected to another substation or another circuit sharing a common supply of electric power.

(41) Scoping Meeting – an optional meeting between the Interconnecting Utility and the Interconnection Requester to discuss the results of the review of the Fast Track Screening Criteria, and how to proceed with the interconnection request.

Simplified Process – the process for establishing an interconnection for small inverter-based Projects in accordance with Section [NEW] of This Rule.

(42) Site Control – the ability of the Applicant to control the Project site documented by one of one of the following: (1) fee simple title to such real property; (2) valid written leasehold or easement interest for such real property; (3) a legally enforceable written option with all terms stipulated including "option price" and "option term," unconditionally exercisable by the proponent or its assignee, to purchase or lease such real property or hold an easement for such property; or (4) a duly executed contract for the purchase and sale of such real property.

(43) ~~Smart Inverter – a Project's inverter that performs functions that, when activated, can autonomously contribute to grid support during excursions from normal operating voltage and frequency system conditions by providing dynamic reactive/real power support, Voltage Ride Through, Frequency Ride Through, ramp rate controls, communication systems with ability to accept external commands, and other functions.~~

Commented [A7]: IREC recommends deleting the term "smart inverter" where it was used in This Rule, so the definition is not needed.

(44) Study Agreement – an agreement between the Interconnecting Utility and Interconnection Requester regarding the terms and conditions of the conduct of a study proposed by the Interconnecting Utility in order to proceed with the interconnection review process.

(45) System Impact Study – any study or studies performed by an Interconnection Utility or a designated third party to ensure the safety, reliability, and stability of the electric power system with respect to the interconnection of Projects.

(46) System Impact Study Report - contains the results of the System Impact Study, and other information required by this Rule.

(47) System Upgrades – the additions, modifications, and upgrades to the distribution system and/or transmission system at or beyond the Point of Interconnection to facilitate interconnection of the Project. System Upgrades do not include Interconnection Facilities.

(48) Technical Requirements - an agreement between the Interconnection Requester and the Interconnecting Utility designed to provide protection to the public and to the personnel and equipment of the Interconnection Requester and Interconnecting Utility from the physical and financial risks associated with the interconnection and parallel operation of the proposed Project. The interconnection Technical Requirements accomplish this task through including, but not limited to, ensuring the installation of proper protective devices and metering equipment, and establishing performance criteria to minimize the probability that the Project will reduce the quality of service on the Interconnecting Utility's system.

(49) This Rule –Commission Rule 5.500: Interconnection Procedures for Proposed Electric Projects.

(50) Transmission Level Study – a System Impact Study conducted at the transmission level.

(51) Voltage Ride Through – the ability of a Project to stay connected to and synchronized with the system or equipment of the Interconnecting Utility and any Affected Systems during system disturbances within a range of under-voltage and over-voltage conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other Projects in the Interconnecting Utility's service territory on a comparable basis.

(52) VELCO – Vermont Electric Power Company who operates the transmission system in Vermont.

5.503 General Procedures

(A) All studies conducted pursuant to this Rule must consider the Project's design, including but not limited to the Operating Profile, and study the Project according to how the Application proposes to operate it. If the Project limits export pursuant to Section 5.521, the Supplemental Review and System Impact Study must use Export Capacity instead of the Nameplate Rating, except when assessing fault current contribution. To assess fault current contribution, the Supplemental Review and System Impact Study must use the Rated Fault Current; for example, the Interconnection Requester may provide manufacturer test data (pursuant the fault current test described in IEEE 1547.1-2020 clause 5.18) showing that the fault current is independent of the Nameplate Rating. The Supplemental Review and System Impact Study may consider an Operating Profile proposed in the Application.~~shall model all such Projects at their Generation Capacity including any limitations on export imposed by means identified in Section 5.521 or at some other reasonable and expected capacity determined by the Interconnecting Utility~~.

(B) ~~For Projects that include an Energy Storage Device, all studies conducted pursuant to this rule shall consider the operational characteristics unique to Energy Storage Devices that can minimize impacts to system stability and reliability. The Interconnecting Utility may impose inverter settings or operating regimes relating to Energy Storage Devices that ensure system stability and reliability.~~

(C) All studies shall consider all Projects that:
(1) Are directly interconnected to the Interconnecting Utility's electric transmission or distribution system;
(2) Are interconnected to Affected Systems and may have an impact on the Interconnection Requester's Application; and
(3) Have a pending Application with an earlier position in the Interconnection Queue to interconnect to the electric transmission and/or distribution systems.

(D) After providing an opportunity for comment to the Department of Public Service, electric utilities, and other affected parties, the Commission may provide model documents, which may be used by the Interconnecting Utility and Interconnection Requester, for the following: Pre-Application Report Request, any Study Agreement, Interconnection Agreement, Technical Requirements, and Operator Protocols. However,

Commented [A8]: IREC has participated in various states' interconnection rulemakings and launched the BATRIES project to address the barriers to storage interconnection and help pave the way for rapid deployment of storage on the distribution grid. As a result of this work, we developed the language included here. This represents IREC's most recent thinking about how study processes should reflect Operating Profiles and Export Capacity.

Commented [A9]: Not appropriate to allow utilities to ignore a system's Export Capacity when set using an acceptable method identified in Section 5.521. See comments for more detail.

Commented [A10]: The concept is covered by the revised section (A)

Commented [A11]: Permissible utility settings for power control systems are covered in Section 5.521.

the Interconnecting Utility and Interconnection Requester may also voluntarily enter into different arrangements. In the event that these parties are unable to agree upon the terms of an agreement to be reached under this Rule, either party may petition the Commission for resolution of the dispute.

(E) The time deadlines specified in this Rule are maximum times. To avoid unnecessary delay of the, the Interconnecting Utility is encouraged to complete each task in less time than allotted, to the extent feasible.

(F) The Interconnecting Utility may contract with consultants, including contractors acting on behalf of the Interconnecting Utility, to perform the activities required under a Study Agreement. The third-party entities contracted with shall be licensed appropriately for each area of study.

5.504 Group and Serial Studies

~~(A)~~ The Interconnecting Utility or Interconnection Requestor(s) may~~, on its own initiative,~~ submit a formal petition to the Commission proposing to use a group study process. The Commission may authorize or reject the proposal at its discretion. The proposal shall, at a minimum, address the following aspects of the group study process:

(1) Group formation, including timing, geographic scope, and requirements for participation (*e.g.*, interrelated projects, exclusion of small projects, and single applicant groups);
(2) How to conduct group studies, including phases, duration, group vs. individual impact assessments, and distribution vs. transmission impacts;
(3) Group retention, including managing group attrition, (*e.g.*, phases, deposits, site control) and project modifications;
(4) Cost allocation, including study costs and upgrade costs; and
(5) Transitioning to a group study process, including impact on projects already in the queue.

~~Applications to be studied together in order to minimize the cost of studies or System Upgrades through economies of scale~~.

~~(B) An Interconnection Requestor or several Interconnection Requestors may request that the Interconnecting Utility group multiple Projects for study, provided all Interconnection Requestors involved agree to their Projects being reviewed as a group.~~

~~(C) If the number and timing of interconnection requests for a specific area is such that interconnection requests directly affect each other, the Interconnecting Utility may study Projects serially. In the case of serial review, the Interconnecting Utility will notify the Interconnection Requester that its review of the Project will be on hold until the Interconnecting Utility has completed its study or review of Projects ahead of the Interconnecting Requester in the Interconnection Queue.~~

5.505 Optional Pre-Application Report

(A) Upon receipt of a completed Pre-Application Report Request and the Pre-Application Fee, the Interconnecting Utility shall provide pre-application data described in this section within 14 days of receipt. The Pre-Application Report Request shall include a proposed Point of Interconnection, generation technology, storage technology, Nameplate Rating, Export Capacity, single or three-phase, whether Project is stand-alone or will service on-site load, whether new service is requested, and fuel source. The proposed Point of Interconnection shall be defined by latitude and longitude, site map, street address, utility equipment number (e.g., pole number), meter number, account number, or some combination of the above sufficient to clearly identify the location of the Point of Interconnection.

Commented [A12]: Additional information that the customer should provide to ensure that the utility responds with all relevant data.

(B) The Pre-Application Report will include the following information if available:

(1) Total ~~Generation~~Export Capacity (MW) of substation or bank and circuit likely to serve proposed site;

(2) ~~Allocated Generation~~Aggregate existing Export Capacity (MW) interconnected to the ~~of~~ substation or bank and circuit likely to serve proposed site;

(3) Aggregate Queued ~~Generation~~Export Capacity (MW) proposing to interconnect to the ~~of~~ substation or bank and circuit likely to serve proposed site;

(4) Available ~~Generation~~Export Capacity (MW) of substation or bank and circuit most likely to serve proposed site. Available Export Capacity is the Total Export Capacity less the sum of existing and queued Export Capacity, accounting for all load served by existing and queued generators;

(5) Nominal distribution circuit voltage at ~~of~~ the ~~circuit most likely to serve~~ proposed site;

(6) Approximate circuit distance between the proposed site and the substation;

~~(6)~~(7) Hourly load profile by substation and transformer, at the most specific granularity available (e.g., if an 8760 hour profile is not available, provide a 576 hour profile);

~~(7)~~(8) Relevant ~~l~~Line ~~s~~Section(s) actual or estimated peak load ~~estimate~~, and minimum load data, when available.;

~~(8)~~(9) Number and rating of protective devices and number and type of voltage regulating~~,~~ devices between the proposed site and the substation;

~~(9)~~(10) Whether or not three-phase power is available at the site and/or distance from three-phase service;

~~(10)~~(11) Limiting conductor rating from proposed Point of Interconnection to the substation; and

(12) Based on proposed Point of Interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.

~~(11)~~(13) Any other information the utility deems relevant to the Project.

(C) The Pre-Application Report need only include pre-existing data. A Pre-Application Report request does not obligate the utility to conduct a study or other analysis of the proposed Project in the event that data are not available. If the utility cannot complete all or some of a Pre-Application Report due to lack of available data, the utility will provide

the applicant with a Pre-Application Report that includes the information that is available.

(D) In requesting a Pre-Application Report, the Interconnection Requester understands that:
(1) The existence of "Available ~~Generating~~Export Capacity" in no way implies that an interconnection up to this level may be completed without impacts because there are many variables studied as part of the interconnection review process;
(2) The utility system is dynamic and subject to change;
(3) Data provided in the Pre-Application Report may be outdated and not useful at the time of submission of the complete Interconnection Request; and
(4) Pre-Application Report Requests are not placed in the Interconnection Queue.

(E) Notwithstanding any of the provisions of this Section, the utility shall, in good faith, provide Pre-Application Report data that represents the best available information at the time of reporting.

5.506 Application

An Application must include the following:

(A) A completed Application Form specifying the process (Simplified, Fast Track, or Study) the Interconnection Requester elects for the Application;

Commented [A13]: Allows the customer to select which process to use. To use the simplified or fast track process, the Project must meet the eligibility requirements, e.g., size.

(B) The Application Fee;

(C) For systems with a Nameplate Rating larger than 150 kW, documentation of Site Control;

(D) Information regarding certification or Underwriters Laboratory listing of the Interconnection Requester's Project;

(E) Information regarding anti-islanding equipment and/or inverter settings;

(F) For a Project with a Nameplate ~~Capacity~~ Rating of greater than 150 kW or for a Project of any capacity, using a Generation Resource and Energy Storage Device, a one-line diagram; and

(G) For a Project with a Nameplate ~~Capacity~~ Rating of greater than 150 kW, a site plan.

5.507 Interconnection Queue and Reporting Requirements

(A) Interconnection Queue. Each interconnecting utility must maintain an Interconnection Queue of all proposed Projects.

(B) Interconnection Queue Position. The Interconnecting Utility shall assign each Project a position in the Interconnection Queue based ~~up~~on when the Application is deemed

~~the date and time stamp of the Interconnection Requester's~~ complete ~~Application~~.

(C) Certain Interconnection Queue Information Available Online. The Interconnecting Utility shall make a public ~~its~~ Interconnection Queue available online in sortable, tabular format, *e.g.*, a spreadsheet. The public Interconnection Queue shall be updated at least monthly and ~~, redacted to~~ include: ~~only the Project type~~queue number, ~~location by~~ town, zip code~~interconnection point~~, substation, feeder, primary fuel type, secondary fuel type, ~~and Generation~~Export Capacity ~~of proposed Projects~~, Nameplate Rating, status (active, withdrawn, interconnected, ect), date Application deemed complete, date of notification of Fast Track screen results, screen results (pass or fail, if fail, identify screens failed), date of notification of Supplemental Review screen results, screen results (pass or fail, if fail, identify screens failed), date of notification of System Impact Study results, date of notification of Facilities Study results and/or construction estimate, date interconnection agreement is provided to customer, date Interconnection Agreement is signed by bother parties, date of grant of permission to operate, final interconnection cost paid to utility.

(D) Interconnecting Utility Reporting Requirement. Each Interconnecting Utility shall annually submit to the Commission and make available to the public on its website an interconnection report. The report shall contain information described in this section, including relevant totals for both the year and the most recent reporting period.

(1) Pre-Application Reports
- (a) Total number of reports requested
- (b) Total number of reports in process
- (c) Total number of reports issued
- (d) Total number of requests withdrawn
- (e) Maximum, mean, and median processing times from receipt of request to issuance of report
- (f) Number of reports processed in more than the 14 days allowed in Section 5.505.

(2) Interconnection Applications:
- (a) Total number received, broken down by:
  - (i) Primary fuel type (e.g., solar, wind, bio-gas, etc.)
  - (ii) Export Capacity (e.g., <25 kW, <1 MW, <5MW, >5MW)
  - (iii) Nameplate Capacity (e.g., <25kW, <1 MW, <5MW, >5MW)
- (b) Simplified Review Process
  - (i) Total number of applications processed
  - (ii) Maximum, mean, and median processing times from receipt of complete Application to notification of result.
- (c) Fast Track Review Process
  - (i) Total number of applications that passed the screens in Rule 5.511(D)
  - (ii) Total number of applications that failed the screens in Rule 5.511(D)
  - (iii)Maximum, mean, and median processing times from receipt of complete Application to notification of result and issuance of Interconnection Agreement

Commented [A14]: Clarifying that the queue position is based on when the utility deems the application complete.

Commented [A15]: Modified to include the information in IREC's Model Rule, Attachment 8, Public Queue Requirement. Transparently providing this data will allow VELCO, customers, stakeholders, and regulators to track project's progress through the queue. This allows customers to understand the status of projects ahead in the queue, VELCO to understand the distribution of projects in the queue, and for regulators and stakeholders to have more visibility into each utility's current interconnection challenges.

(d) Supplemental Review
(i) Total number of applications that passed the screens in Rule 5.512(A)(B).
(ii) Total number of applications that failed the screens in Rule 5.512(A)(B).
(iii)Maximum, mean, and median processing times from receipt of complete Application to notification of results and issuance of Interconnection Agreement
(e) System Impact Studies
(i) Total number of System Impact Studies completed under Rule 5.513.
(ii) Maximum, mean, and median processing times from receipt of signed Interconnection System Impact Study Agreement to provision of study results
(f) Facilities Studies
(i) Total number of Facilities Studies completed under Rule 5.514.
(ii) Maximum, mean, and median processing times from receipt of signed Interconnection Facilities Study Agreement to provision of study results
(iii) Maximum, mean, and median processing times for projects undergoing the study process from receipt of complete Application to issuance of Interconnection Agreement.
(g) Construction: Number of Projects where final construction milestone was not reached by time specified in the Interconnection Agreement
(h) Number of Projects that achieved Commercial Operation, by:
(i) Primary fuel type (e.g., solar, wind, bio-gas, etc.)
(ii) Export Capacity (e.g., <25 kW, <150 kW, <1 MW, <5MW, >5MW)
(i) Total process time from receipt of complete Application to signed Interconnection Agreement (or notification of approval if no Interconnection Agreement required), by Export Capacity (e.g., <25 kW, <150 kW, <1 MW, <5MW, >5MW)
(j) Total process time from receipt of complete Application to permission to operate, by Export Capacity (e.g., <25 kW, <150 kW, <1 MW, <5MW, >5MW)

5.508 Notice of Applications

(A) Notice to Affected Systems. The Interconnecting Utility shall notify the Affected Systems in accordance with the same interconnection notification protocols that would apply if the Application were subject to FERC jurisdiction.

(B) Notification to VELCO. To assess any transmission level impacts and to coordinate any needed transmission-level interconnection studies, the Interconnecting Utility shall report to VELCO a~~ll~~ proposed Projects ~~greater than or equal to 1 MW in nameplate capacity and Projects smaller than 1 MW nameplate capacity if requested~~

Commented [A16]: IREC agrees that the distribution utilities should notify VELCO when requested to do so. However, because transmission utility study standards can change independently of this rule, this rule should not require notification, as notification for projects at a certain size that is required today may be not be required in the future. Instead, this rule should require notification when requested by VELCO,. Interconnecting Utilities can state in their Applications the criteria used to determine if a project is referred to VELCO.

that meets certain criteria set by VELCO. Interconnection Utilities shall state in their Applications the criteria used to refer a Project to VELCO. In consultation with the Vermont System Planning Committee, VELCO may prescribe the format in which interconnection queue data should be submitted.

Commented [A17]: IREC does not object to this language, but notes that it is likely unnecessary if the Commission adopts IREC's proposal for the public queue. Under IREC's proposal any person can download a spreadsheet with detailed queue data from the utility's website.

5.509 Cost Allocation

(A) The date-and-time-stamp of the Application will be used to determine the cost responsibility for any interconnection studies or System Upgrades necessary to accommodate the interconnection, unless the Commission authorizes the use of a group study under Rule 5.504.

(B) ~~For group review of multiple Applications, the Interconnecting Utility may allocate costs based on a *pro rata* share of Generation Capacity of the grouped Projects or a methodology specified in an approved utility tariff.~~

5.510 Completeness Review~~Procedure for Initial Review of Applications~~

(A) The Interconnecting Utility shall notify the Interconnection Requester of receipt within ~~7~~3 days of receiving the Interconnection Requester's Application.

(B) The Interconnecting Utility shall notify the Interconnection Requester within 14 days of the receipt of the Application as to whether the Application is complete or incomplete.

(1) If the Application is incomplete, the Interconnecting Utility shall provide, along with the notice that the Application is incomplete, a written list detailing all information that must be provided to complete the Application. An Application will be complete upon submission to the Interconnecting Utility of a revised Application containing the listed information. The Interconnecting Utility will have 14 days to review the revised Application for completeness.

(2) Complete Applications reviewed pursuant to this Subsection will be reviewed using the procedures specified in this Rule.

[NEW SECTION] Simplified Process for Small Inverter-based Projects

(A) Time to process screens: Within 15 days after the Interconnecting Utility notifies the Interconnection Requester that the Application is complete, the Interconnecting Utility shall notify the Interconnection Requester whether the Project meets all of the applicable Simplified Process screens.

Commented [A18]: Similar timeline as allowed for review of small NEM projects currently.

(B) Screens failure:

(1) Despite the failure of one or more screens, the Interconnecting Utility, at its sole option, may approve the interconnection provided such approval is consistent with safety and reliability.

(2) If the Interconnecting Utility cannot determine that the Project may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the Interconnecting Utility shall provide the Interconnection Requester with specific information on the reason(s) for failure in writing. The written notification shall include the specific screens that the Application failed, including the technical reason for failure and copies of the analysis and data underlying the Interconnecting Utility's determinations. The Interconnecting Utility shall provide standardized information and detail about the specific system threshold or limitation causing the Application to fail the screen.

(3) In addition, the Interconnecting Utility shall allow the Interconnection Requester to procced to Supplemental Review or System Impact Study at the Interconnection Requester 's option. The Interconnection Requester must notify the Interconnecting Utility of its selection within 14 days or the Application will be deemed withdrawn.

(C) Simplified Process Screening Criteria:

(1) The Project has an Export Capacity of not greater than 25 kW, a Nameplate Rating not greater than 50 kW, and uses a UL 1741 Certified inverter.

(2) The proposed interconnection point is not on a transmission line.

(3) Penetration Screen.

(a) For interconnection to a radial distribution circuit: Where 12 months of Line Section minimum load data (including onsite load but not station service load served by the proposed Project) are available, the aggregate Export Capacity on the Line Section is less than 100% of the relevant minimum load for all Line Sections bounded by automatic sectionalizing devices upstream of the proposed Project. If minimum load data are not available, the Export Capacity of the Project, aggregated with the Export Capacity of other Projects on the Line Section, is less than 15% of the peak load for all Line Sections bounded by automatic sectionalizing devices upstream of the proposed Project.

(b) For interconnection to a Spot Network or Area Network: The aggregate Nameplate Rating, including the Project's Nameplate Rating, may not exceed 50 percent of the Spot Network or Area Network's anticipated minimum load. If solar energy Generating Resources are used exclusively, only the anticipated daytime minimum load shall be considered. The Utility may select any of the following methods to determine anticipated minimum load:

(i) the Spot Network or Area Network's measured minimum load in the previous year, if available;

(ii) five percent of the Spot Network or Area Network's maximum load in the previous year;

(iii) the Applicant's good faith estimate, if provided; or

(iv) the Utility's good faith estimate if provided in writing to the Applicant along with the reasons why the Utility considered the

other methods to estimate minimum load inadequate.

(4) If the proposed Project is to be interconnected on a single-phase shared secondary, the aggregate Export Capacity on the shared secondary, including the proposed Project, shall not exceed 20 kW.

(5) If the Project is single-phase and is to be interconnected on a center tap neutral of a 240-volt service, its addition will not create an imbalance between the two sides of the 240 volt service of more than 20% of the service transformer nameplate.

5.511 Fast Track Screening Process

(A) Eligibility. Projects with an Export Capacity within the limits identified in the table below (which vary according to the voltage of the line at the proposed Point of Interconnection) are eligible for the Fast Track process. Projects not eligible for fast track go directly to study pursuant to Rule 5.512 to 5.514. Generating Facilities located within 2.5 miles of a substation and on a main distribution line with minimum 600-amp capacity are eligible for the Fast Track process under higher thresholds.

Line Voltage	**Export Capacity for Fast Track Eligibility**	
	Regardless of location	**On > 600 amp line and < 2.5 miles from substation**
< 5 kV	< 1 MW	< 2 MW
5 kV – 14 kV	< 2 MW	< 3 MW
15 kV – 30 kV	< 3 MW	< 4 MW
31 kV – 69 kV	< 4 MW	< 5 MW

~~(A)~~(B) Within ~~30~~ 21 days after an Application is determined to be complete, the Interconnecting Utility shall perform a review of the Application under all of the Fast Track Screening Criteria set forth below~~,~~ and shall notify the Interconnection Requester of the results in writing. ~~, and~~ If one or more screens are not passed, the written notification shall include the specific screens that the Application failed, including the technical reason for failure and ~~with the notification~~ copies of the analysis and data underlying the Interconnecting Utility's determinations ~~under the applicable Fast Track Screening Criteria~~. The Interconnecting Utility shall provide standardized information and detail about the specific system threshold or limitation causing the Application to fail the screen.

~~(B)~~(C) The results of a Fast Track analysis shall be provided to the Interconnection Requester. The results will not only document the pass or fail of the Fast Track screening but also document any agreed-to resolution(s) of a failed item by its number in the Fast Track criteria.

~~(C)~~(D) Fast Track Screening Criteria

Commented [A19]: IREC recommends sending all projects with an Export Capacity over 5 MW, and some projects between 1-5 MW, directly to the study process. This "table-based" eligibility approach is used in many states, SGIP, and the IREC Model.

Bypassing the Fast Track process for these large projects will make the process more efficient for utilities, which will not need to screen projects that will certainly fail the screens, and customers, who will start the study process faster.
In addition, IREC recommends modifying the Application to allow customers to elect to go straight to study even they are eligible for the simplified or fast track process. See Section 5.506(A).

Commented [A20]: Utilities should complete all the screens, even if one fails. It is instructive to know the results of each screen so the customer can evaluate if the Project should 1) continue to supplemental review (where the issue could potentially be resolved) or 2) be modified in a way that addresses the failure.

Commented [A21]: Attached to IREC's comments are examples of standardized data that can provided in response to screen failures.

(1) The proposed interconnection point is not on at transmission linevoltage (i.e., not over 23 kV line to line or 13.28 kV line to neutral).

(2) For interconnection of a Project to the load side of spot network protectors, the proposed Project must utilize an inverter-based equipment package and, together with the aggregated other inverter-based Nameplate Rating Generation Capacity, shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW.

(3) The fault current of the proposed Project, in aggregation with the fault current of other Generation CapacityProjects on the distribution circuit, shall not contribute more than 10% to the circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed Project.

(4) The fault current of the proposed Project, in aggregation with the fault current of other Generation CapacityProjects on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers) or Interconnection Requester equipment on the system to exceed 87.5% of the short-circuit interrupting capability; nor shall the Project be proposed for a circuit that already exceeds 87.5% of the short-circuit interrupting capability.

(5) For interconnection of a proposed single-phase or effectively grounded three-phase Project where the primary distribution system is three-phase, four-wire, the Project shall use a groundedbe connected line-to-neutral primary connection. For interconnection of a proposed single-phase or three-phase Project where the primary distribution system is three-phase, three-wire, the Project shall use a be connected line to line primary connection.

(6) If the proposed Project is to be interconnected on a single-phase shared secondary, the aggregate GenerationExport Capacity on the shared secondary, including the proposed Project, shall not exceed 20kW.

(7) If the Project is single-phase and is to be interconnected on a center tap neutral of a 240-volt service, its addition will not create an imbalance between the two sides of the 240 volt service of more than 20% of the service transformer nameplate.

(8) The Nameplate Rating of a proposed Project, in aggregate with other Projects' Nameplate Rating interconnected to the distribution side of a substation transformer feeding the circuit where the Project proposes to interconnect, may

Commented [A22]: This screen, as designed in SGIP (Section 2.2.1.1) and IREC's Model (Section III.B.2.i), simply requires that the line be a distribution line, or conversely, not a transmission line. Line voltage limits are typically included in the Fast Track eligibility table, see subsection (A) above.

Commented [A23]: IREC and the BATRIES project recommend using Nameplate Rating.

Commented [A24]: Clarifying that the evaluation is of fault current, not capacity.

Commented [A25]: Clarifying that the evaluation is of fault current, not capacity.

~~is~~ not exceed 10 MVA ~~located~~ in an area where there are known or posted transient stability limitations to ~~generating units~~ Projects located in the general electric vicinity~~, including but not limited to known harmonic issues~~.

(9) No system modifications, in excess of limited preparations that do not necessitate a Facilities Study, are required to facilitate the interconnection of the Project.

(10) ~~The aggregated Generation Capacity, including the proposed Project, on a distribution circuit will not cause any distribution protective devices and equipment, including but not limited to conductors, substation transformers, line stepdown transformers, substation breakers, fuse cutouts, and line reclosers, or customer equipment on the system, to compromise the device's continuous duty ratings and protection settings as determined by the Interconnecting Utility.~~ Penetration Screen:

(a) Where 12 months of Line Section minimum load data (including onsite load but not station service load served by the proposed Project) are available, the aggregate Export Capacity on the Line Section is less than 100% of the relevant minimum load for all Line Sections bounded by automatic sectionalizing devices upstream of the proposed Project.

(b) If minimum load data are not available, the Export Capacity of the Project, aggregated with the Export Capacity of other Projects on the Line Section, is less than 15% of the peak load for all Line Sections bounded by automatic sectionalizing devices upstream of the proposed Project.

(11) Voltage drop caused by starting generation is within acceptable limits, meaning that inrush current caused by the startup of the proposed Project up to once per hour, is not greater than 3% of the available fault current or does not cause greater than a 3% voltage deviation at the Point of Interconnection as modeled in an unbalanced load flow. Voltage drop due to starting the proposed Project more than once per hour meets a tighter inrush-current tolerance to be determined by the Interconnecting Utility. This criterion is applicable only to synchronous or induction Projects.

(12) ~~The Interconnection Requester affirms that the proposed Project meets the applicable codes and standards of Section 5.519 or is a certified equipment package under Section 5.518.~~

Commented [A26]: This requirement should apply to all projects (not just those using fast track) unless waived by the utility. Moved to Section 5.519.

(13) ~~Flicker caused by the proposed Project shall comply with IEEE Standard 1453.~~

(14) ~~For any single Project, the available utility short circuit current at the Point of Interconnection divided by the rated output current of the Project is no less than:~~

~~(a) 50 for Projects of less than 100 kW;~~
~~(b) 40 for Projects from 100 kW to less than 500 kW; and~~
~~(c) 20 for Projects equal to or greater than 500 kW.~~

For interconnection of a Project that can introduce inadvertent export, where the Nameplate Rating minus the Export Capacity is greater than 250 kW, use the following inadvertent export screen limit. With a power change equal to the Nameplate Rating minus the Export Capacity, the change in voltage at the point on the medium voltage (primary) level nearest the PCC does not exceed 3%. Voltage change will be estimated applying the following formula:

Formula	$$\frac{(R_{SOURCE} \times \Delta P) - (X_{SOURCE} \times \Delta Q)}{V^2}$$
Where: $\Delta P = (\text{DER Nameplate Apparent Power Rating} - \text{Export Capacity}) \times PF$, $\Delta Q = (\text{DER Nameplate Apparent Power Rating} - \text{Export Capacity}) \times \sqrt{(1 - PF^2)}$ is the grid resistance, X_{SOURCE} is the grid reactance, V is the Grid voltage	

~~(D)~~(E) If the proposed interconnection passes all of the applicable Fast Track Screening Criteria, the Interconnection Request shall be approved and the Application shall not require additional study. Approval of an application must be provided to the Applicant in writing. For Projects with a Nameplate Rating greater than 150 kW ~~in capacity~~, the Utility shall provide the Interconnection Requester with an executable interconnection agreement at the same it provides the notification of the screen results~~within 7 days after the completion of the Fast Track Screening~~. Projects with a Nameplate Rating ~~capacity~~ of less than 150 kW may interconnect without an interconnection agreement.

~~(E)~~(F) If the proposed interconnection fails one or more of the Fast Track Screening Criteria, but the Interconnecting Utility determines that the Project may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the

Commented [A27]: Moved to supplemental review. To avoid confusion, we recommend using "voltage fluctuation" here instead of "flicker".

Commented [A28]: When the Commission adopts 1547-2018, it should update this to reference the rapid voltage change requirements of 1547-2018 section 7.2.2.

Commented [A29]: This screen is not necessary because the penetration screen will fail projects with voltage concerns and it inappropriately creates a higher threshold for smaller projects.

Commented [A30]: If the project passes the screens, then no additional study or construction of facilities is required. In this case, a standard Interconnection Agreement can be provided at the same time as the screen results.

Interconnecting Utility shall notify the Interconnection Requester that the Application is approved in writing and, if the Projects has an Export Capacity ~~is~~ greater than 150 kW ~~in capacity~~, provide an executable Interconnection Agreement within ~~7~~5 days. The Interconnecting Utility shall provide, for each failed criterion, a technical justification in the Fast Track results regarding why the proposed Project may nevertheless be interconnected consistent with safety, reliability, and power quality standards.

~~(F)~~(G) If the proposed interconnection fails the Fast Track Screening Criteria, and the Interconnecting Utility does not or cannot determine from the initial review that the Project may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Requester is willing to consider minor modifications or further study, the Interconnecting Utility shall provide the Interconnection Requester with the opportunity to attend a Scoping Meeting. If the Interconnection Requester indicates in response to this opportunity that it does not want to hold a Scoping Meeting or proceed to additional study, the Application will be considered withdrawn.

~~(G)~~(H) If mutually agreed upon, a Scoping Meeting to discuss available options may be scheduled and held within 14 days of the Interconnecting Utility notifying the Interconnection Requester of the results of the review of the Fast Track Screening Criteria. The purpose of the Scoping Meeting may be to review existing studies relevant to the Interconnection Requester's Interconnection Application.

~~(H)~~(I) At the time of notification of the Interconnecting Utility's determination, or at the Scoping Meeting, the Interconnecting Utility shall:

(1) Offer to perform limited and low-cost modifications to the Interconnecting Utility's electric system (e.g., changing meters, fuses, relay settings) and provide a non-binding good-faith estimate of the cost to make such modifications to the Interconnecting Utility's electric system. If the Interconnection Requester agrees to pay for the modifications to the Interconnecting Utility's electric system, the Utility will provide the Interconnection Requester with an executable interconnection agreement within 14 days of the Scoping Meeting or, if there is no Scoping Meeting, within 14 days of the notification of the Interconnecting Utility's determination; or

(2) Offer to perform a Supplemental Review in accordance with Section 5.512~~Provide a non-binding good-faith estimate of the costs of such review~~; or

(3) Obtain the Interconnection Requester's agreement to continue evaluating the Interconnection Request under the Study Processes described in Section 5.513~~this Rule~~.

~~(I)~~(J) If mutually agreed upon by the Interconnection Requester and the Interconnecting Utility, the ~~Feasibility,~~ System Impact, and~~/or~~ Facilities Studies may be combined for the purpose of achieving cost and/or time savings.

Commented [A31]: Modified to require utilities to offer to perform supplemental review.

5.512 Supplemental Review~~Feasibility Study~~

(A) ~~In cases where the Interconnecting Utility determines that a Feasibility Study is necessary, the Interconnecting Utility shall provide the Interconnection Requester an executable Feasibility Study agreement including an outline of the scope of the study and a good-faith estimate of the cost to perform the study. The executable Feasibility Study agreement will be provided by the Interconnecting Utility within 7 days after the close of the Scoping Meeting, or the date of the decision not to hold a Scoping Meeting. In order to remain in the Interconnecting Utility's Interconnection Queue, the Interconnection Requester must return, within 21 days, an executed Feasibility Study agreement along with a deposit of the lesser of 50 percent of estimated Feasibility Study costs or $1,000.~~ To accept the offer of a Supplemental Review, the Interconnection Requester shall agree in writing and pay a Supplemental Review fee of $1,000, both within 21 days of the offer. If the written agreement and fee have not been received within that timeframe, the Interconnection Request shall continue to be evaluated under the Section 5.513 Study Process unless it is withdrawn by the Interconnection Requester.

Commented [A32]: In order to expedite this process, IREC recommends using a flat fee of $1,000 instead of the existing estimate-deposit-reconcile costs approach. If utilities document that actual cost of supplemental review regularly exceeds $1,000, the fee amount should be raised to reflect an average of actual costs.

(B) Supplemental Review Screens. ~~A Feasibility Study~~Supplemental Review shall include the following analyses:

(1) ~~Initial identification of any instances where the short-circuit capability limits of any protective device (circuit breaker, recloser, fuse, etc.) would be exceeded as a result of the interconnection~~ Supplemental Review Penetration Screen: Where 12 months of Line Section minimum load data (including onsite load but not station service load served by the proposed Project) are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate Export Capacity on the Line Section is less than 100% of the gross minimum load for all Line Sections bounded by automatic sectionalizing devices upstream of the proposed Project. If minimum load data is not available, or cannot be calculated, estimated, or determined, the Export Capacity of the Project, aggregated with the Export Capacity of other Projects on the Line Section, is less than 30% of the peak load for all Line Sections bounded by automatic sectionalizing devices upstream of the proposed Project.

(i) The type of Project used by the proposed Project will be taken into account when calculating, estimating, or determining circuit or Line Section minimum load relevant for the application this screen. Solar photovoltaic (PV) Projects with no battery storage use daytime minimum load (*i.e.* 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems), while all other Projects use absolute minimum load.

(ii) Load that is co-located with load-following, non-exporting or export-

limited Projects should be appropriately accounted for.

(iii) The Interconnecting Utility will not consider as part of the aggregate Export Capacity for purposes of this screen Project Export Capacity, including combined heat and power (CHP) facility capacity, known to be already reflected in the minimum load data.~~;~~

~~(1)~~(2) ~~Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;~~Voltage and Power Quality Screen: In aggregate with existing generation on the Line Section:

(i) The voltage regulation on the Line Section can be maintained in compliance with relevant requirements under all system conditions;

(ii) The voltage fluctuation is within acceptable limits as defined by IEEE Standard 1453;

(iii) Harmonic levels meet IEEE Standard 519 limits at the Point of Interconnection.

If the Project limits export pursuant to Section 5.521, the Export Capacity must be included in any analysis including power flow simulations.

(3) Safety and Reliability Screen: The location of the proposed Project and the aggregate Export Capacity on the Line Section do not create impacts to safety or reliability that cannot be adequately addressed without application of the Study Process. If the Project limits export pursuant to Section 5.521, the Export Capacity must be included in any analysis including power flow simulations, except when assessing fault current contribution. To assess fault current contribution, the analysis must use the Rated Fault Current; for example, the Interconnection Requestor may provide manufacturer test data (pursuant the fault current test described in IEEE 1547.1-2020 clause 5.18) showing that the fault current is independent of the Nameplate Rating. The Interconnecting Utility may consider the following factors and others in determining potential impacts to safety and reliability in applying this screen:

(i) Whether the Line Section has significant minimum loading levels dominated by a small number of customers (e.g., several large commercial customers).

(ii) Whether the loading along the Line Section is uniform or even.

(iii) Whether the Project is located in close proximity to the substation (i.e., less than 2.5 electrical circuit miles), and whether the Line Section from the substation to the Point of Interconnection is a Mainline rated for normal and emergency ampacity.

Commented [A33]: Fast Track Screen 12 moved here, minor modification to use standard language from SGIP.

To avoid confusion we recommend using "Voltage fluctuation" here instead of "Flicker," intending the same meaning.

Commented [A34]: When the Commission adopts 1547-2018, it should update this to reference the rapid voltage change requirements of 1547-2018..

Commented [A35]: When the Commission adopts 1547-2018, it should update this to reference the harmonic level requirements of 1547-2018.

(iv) Whether the Project incorporates a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time.

(v) Whether operational flexibility is reduced by the Project, such that transfer of the Line Section(s) of the Project to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

(vi) Whether the Project employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, islanding, reverse power flow, or voltage quality.

~~(2)~~(4) ~~Initial review of grounding requirements and system protection; and~~

~~(3)~~(5) ~~Description and non-binding estimated cost of facilities required to interconnect the facility to an electric distribution power system or directly to a transmission system and to address the identified short-circuit and power-flow issues.~~

~~(C) A Feasibility Study shall model the impact of the Project regardless of purpose, in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Requester later changes the purpose for which the Project is being installed.~~

~~(D) A Feasibility Study shall include the feasibility of any interconnection at a proposed Project site where there could be multiple potential Points of Interconnection, as requested by the Interconnection Requester.~~

~~(E) In performing the Feasibility Study, the Interconnecting Utility shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Requester shall not be charged for such existing studies; however, the Interconnection Requester shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the Feasibility Study.~~

~~(F)~~(C) ~~Feasibility Study Report~~

~~(1) Once a Feasibility Study is completed, the Interconnecting Utility shall prepare a Feasibility Study Report, which describes the results of the Feasibility Study, and transmit it to the Interconnection Requester. Barring unusual circumstances outside of the Interconnecting Utility's control, the Interconnecting Utility shall complete a Feasibility Study, and transmit the Feasibility Study Report to the Interconnection Requester, w~~Within 45 days of the Interconnecti~~o~~ng Utility's receipt of ~~an executed Feasibility Study agreement~~ written acceptance of the offer of Supplemental Review and the Supplemental Review fee ~~deposit as~~ described in Section 5.512(A), the

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Interconnecting Utility shall: (1) perform a Supplemental Review using all of the screens set forth above; (2) notify in writing the Interconnection Requester of the results; and (3) include the specific screens that the Application failed, including the technical reason for failure and copies of the analysis and data underlying the Interconnecting Utility's determinations. The Interconnecting Utility shall provide standardized information and detail about the specific system threshold or limitation causing the Application to fail the screen.

~~(2) The Feasibility Study Report shall also include cost estimates for the Distribution Level System Impact Study, Transmission Level System Impact Study, and Facilities Study, to the extent that any of these studies are determined by the Feasibility Study to be required.~~

~~(3) The Interconnecting Utility shall provide the applicable Study Agreement or Interconnection Agreement.~~

~~(G)~~(D) If the proposed interconnection passes the Supplemental Review screens ~~a Feasibility Study shows no potential adverse impacts on the electric system,~~ and no additional facilities are required, the Interconnecting Utility shall send the Interconnection Requester written approval of the Application and, in the case of Projects~~Generation Facilities~~ with an Export ~~e~~Capacity greater than 150 kW, an executable Interconnection Agreement ~~within 7 days after delivery of~~ at the same time as the Supplemental Review screen results~~Feasibility Study Report~~.

~~(H)~~(E) If the proposed interconnection passes the Supplemental Review screens ~~a Feasibility Study shows no potential adverse impacts on the electric system,~~ but additional facilities are required, the Interconnecting Utility shall send the Interconnection Requester an executable Facilities Study agreement, including an outline of the scope of the study and a good-faith estimate of the cost to perform the study within 7 days after delivery of the Supplemental Review screen results~~Feasibility Study Report~~.

~~(I)~~(F) If the proposed interconnection fails the Supplemental Review screens ~~a Feasibility Study shows the potential for adverse impacts on either the distribution system or the transmission system~~, the review process shall proceed to the System Impact Study, and the Interconnecting Utility shall send the Interconnection Requester an executable System Impact Study agreement, including an outline of the scope of the study and a good-faith estimate of the cost to perform the study within 7 days of the delivery of the ~~Feasibility Study~~Supplemental Review screen results. The executable System Impact Study agreement shall specify whether it and the cost estimate are for a Distribution Level Study, Transmission Level Study, or both. Additional study is not required if the adverse impacts are minor, routine in nature, or easily mitigated.

5.513 System Impact Study

(A) In order to remain in the Interconnecting Utility's Interconnection Queue, the Interconnection Requester must return, within 21 days, an executed System Impact

Commented [A36]: Clarifies provision screens failed, the technical reason for failure, and details of the system threshold or limitation.

Attached to IREC's comments are examples of data that can provided in response to screen failures.

Commented [A37]: Here the project passes the screens and no additional study or construction of facilities is required. In this case, a standard Interconnection Agreement can be provided at the same time as the screen results.

Study agreement along with a deposit equivalent to the estimated cost of the study.

(B) A System Impact Study includes two sub-studies: a Transmission Level Study and a Distribution Level Study. One or both of the sub-studies may be performed, depending on the specific circumstances of the Application and the findings of the screening processes (i.e., Fast Track and Supplemental Review), and Scoping Meeting~~, and/or Feasibility Study~~. If the ~~Fast Track,~~ screening processes or Scoping Meeting~~, or Feasibility Study~~ identifies potential adverse impacts on the distribution system, a Distribution Level Study shall be performed. If the screening processes, Scoping Meeting, ~~Feasibility Study, or~~ Distribution Level Study identifies potential adverse impacts on the transmission system, a Transmission Level Study shall be performed.

(1) The Distribution Level System Impact Study shall consist of a distribution load-flow study, an analysis of equipment-interrupting ratings, protection coordination study, voltage drop and ~~flicker~~ fluctuation studies, protection and set point coordination studies, and grounding reviews, and the impact on system operation, as necessary.

(2) The Transmission Level System Impact Study shall consist of a short-circuit analysis, a stability analysis, a power-flow analysis, voltage-drop and ~~flicker~~ fluctation studies, protection and set-point-coordination studies, and grounding reviews, as necessary.

(C) The purpose of the System Impact Study shall be to identify and specify the impacts on electric transmission and/or distribution system stability and reliability that would result if the proposed Project were interconnected without Project modifications or system modifications, focusing on the adverse impacts identified in the ~~Fast Track,~~ screening processes or Scoping Meeting~~, or Feasibility Study~~, and to identify and study any additional potential impacts.

(D) System Impact Study Report

(1) Once a System Impact Study is completed, the Interconnecting Utility shall prepare a System Impact Study Report and transmit it to the Interconnection Requester. Barring unusual circumstances outside of the Interconnecting Utility's control, the System Impact Study ~~determined to be necessary by the Feasibility Study or Scoping Meeting~~ shall be completed and transmitted to the Interconnection Requester within 60 days from receipt of the System Impact Study agreement ~~and deposit if a Feasibility Study was performed, and 90 days from receipt of the System Impact Study agreement and deposit if a Feasibility Study was not performed~~.

Commented [A38]: Neither SGIP nor IREC's model provide for additional time without supplemental review or a feasibility study. Recently, many states that revise their interconnection procedures have omitted the feasibility study entirely, and instead offer supplemental review.

(2) The System Impact Study Report shall state the assumptions upon which the System Impact Study is based, state the results of the analyses, and provide the requirements for, or potential impediments to, providing the requested interconnection service, including a preliminary indication of the cost and

length of time that would be necessary to correct any problems identified in those analyses and to implement the interconnection. The System Impact Study shall provide a list of facilities that are required as a result of the Interconnection Requester's Application and a non-binding good-faith estimate of cost responsibility and a non-binding good-faith estimate of time to construct. The System Impact Study Report shall also include a Facilities Study agreement or Interconnection Agreement.

(E) If, while conducting the Distribution Level ~~System Impact~~ Study ~~outlined in the executed System Impact Study agreement~~, the Interconnecting Utility determines that ~~studies beyond those contained in the executed System Impact Study Agreement are required (for instance, if the Feasibility Study recommended that a Distribution Level Study be conducted, and, during the course of conducting the Distribution Level Study, the Interconnecting Utility determined that~~ a Transmission Level Study is also required~~)~~, the Interconnecting Utility shall, within 7 days of making that determination, send the Interconnection Requester a supplemental System Impact Study agreement, including an outline of the scope of the supplemental study and a good-faith estimate of the cost to perform the supplemental study. In order to remain in the Interconnection Queue, the Interconnection Requester must return an executed supplemental System Impact Study Agreement within 21 days with a deposit equivalent to the estimated cost of the supplemental study. Barring unusual circumstances outside of the Interconnecting Utility's control, a supplemental System Impact Study shall be completed and transmitted to the Interconnection Requester within 60 days of the receipt of the supplemental System Impact Study agreement.

Commented [A39]: Clarifies that the utility should, at the outset, properly scope the study of all distribution system impacts. Only transmission system impacts that could not have been anticipated at the outset of the study process should trigger this process.

(F) In instances where ~~a Feasibility Study or~~ a System Impact Study shows potential impacts on the transmission system, within 7 days following transmittal ~~of the Feasibility Study Report or~~ System Impact Study report, the Interconnecting Utility shall notify the Affected Systems.

(G) Where transmission systems and electric power distribution systems have separate owners, such as is the case with transmission-dependent utilities, whether investor-owned or not, the Interconnection Requester or Interconnecting Utility may apply to the nearest transmission utility providing transmission service to the transmission-dependent utility to request Project coordination. Affected Systems shall participate in the study and provide all information necessary to prepare the study.

(H) If a System Impact Study shows that no additional facilities are required, or that the only additional facilities are not transmission voltage equipment or are of a routine nature for the utility, the Interconnecting Utility shall send the Interconnection Requester written approval of the Application and, in the case of ~~Generation Facilities~~ Projects with an Export ~~c~~Capacity greater than 150 kW, an executable Interconnection Agreement within 7~~21~~ days after delivery of the System Impact Study Report.

Commented [A40]: IREC suggests a shorter timeline here. The IREC Model § III(F)(6)(a) and SGIP §§ 2.2.2, 3.2.9. 3.3.4, 3.5.7 use 5 business days, which is approximately 7 calendar days. Therefore, IREC recommends using 7 calendar days.

(I) If a System Impact Study shows that additional facilities are required, the Interconnecting Utility shall send the Interconnection Requester an executable Facilities

Study agreement, including an outline of the scope of the study and a good-faith estimate of the cost to perform the study within 7 days after delivery of the System Impact Study Report.

5.514 Facilities Study

(A) In order to remain in the Interconnecting Utility's Interconnection Queue, the Interconnection Requester must return, within 30 days, an executed Facilities Study agreement along with a deposit equivalent to the estimated cost of the study.

(B) Facilities Study Preparation. Transmission-system and/or distribution-system interconnection design for any required Interconnection Facilities and/or System Upgrades shall be performed under a Facilities Study agreement between the Interconnection Requester and the Interconnecting Utility.

(C) In some cases, the Interconnection Requester and the Interconnecting Utility may reach agreement allowing the Interconnection Requester to separately arrange for the design of some of the required Interconnection Facilities and/or System Upgrades. In such cases, facilities design shall be reviewed, and modified as necessary by the Interconnecting Utility, prior to acceptance under the provisions of the Facilities Study agreement. If the parties agree to separately arrange for design and construction, the Interconnecting Utility shall make sufficient information available to the Interconnection Requester to permit the Interconnection Requester to obtain an independent design and cost estimate for any necessary facilities. This provision shall not prohibit the Interconnecting Utility and the Interconnection Requester from reaching agreement to protect information that one or the other deems confidential, and shall not require the Interconnecting Utility to disclose information that it is otherwise obliged not to disclose or affect the Commission's authority to compel or restrict disclosure of information.

(D) System Upgrades. In cases where System Upgrades are required, the Facilities Study shall be completed and a Facilities Study Report transmitted to the Interconnection Requester within 60 days of the receipt of the Facilities Study agreement. In cases where no System Upgrades are required, and the required facilities are limited to Interconnection Facilities, the Facilities Study shall be completed and a Facilities Study Report transmitted to the Interconnection Requester within 30 days. The Facilities Study Report shall include a good-faith estimate of the cost of any recommended System Upgrades or Interconnection Facilities.

(E) The Interconnecting Utility shall send the Interconnection Requester an executable Interconnection Agreement within ~~21~~7 days after delivery of the Facilities Study Report.

Commented [A41]: IREC suggests using a shorter timeline here. The IREC Model § III(F)(6)(a) and SGIP §§ 2.2.2, 3.3.4, 3.5.7 use 5 business days, which is approximately 7 calendar days. Therefore, IREC recommends using 7 calendar days.

5.515 Terms Applicable to All Interconnection Applications

(A) The Interconnection Requester is responsible for meeting all applicable codes

and standards of Section 5.519 unless interconnection is accomplished by a certified equipment package under Section 5.518.

(B) Interconnection Agreement. Except in the case of Projects that are allowed under this Rule to interconnect without a written agreement, upon completion of the necessary studies, if any, the Application shall be approved and the Interconnecting Utility shall provide the Interconnection Requester an executable Interconnection Agreement with necessary attachments within the time limits identified in the portions of this Rule detailing the study processes used for the proposed Project. The Interconnection Requester's Application shall be deemed withdrawn and the Interconnection Requester shall lose its Interconnection Queue position unless the Interconnection Requester returns the executed Interconnection Agreement by the later of (1) three months after provision of the executable Interconnection Agreement or (2) 30 days after the issuance of the Certificate of Public Good for the Project but in no case later than one year after provision of the executable Interconnection Agreement. The Interconnection Requester bears all risk if, during the period between completion of Studies and the return of the executed Interconnection Agreement, (i) network conditions change such that the Studies' results are no longer valid and the Studies need to be revisited and updated at the Interconnection Requester's cost and (ii) the cost estimate for System Upgrades and Interconnection Facilities is no longer valid, except to the extent that these changed circumstances are known or could reasonably have been foreseen by the Interconnecting Utility.

(C) ~~The Interconnection Agreement shall require that Voltage Ride Through capability, Frequency Ride Through capability, and Smart Inverter functionality comply with the standards required by this Rule.~~ If mutually agreed upon by the Interconnecting Utility and Interconnection Requester, the Interconnection Agreement shall require enhanced Voltage Ride Through, Frequency Ride Through, or other ~~Smart Inverter~~ functionality, consistent with the standards required by the Rule and with Good Utility Practice.

(D) Reasonable Efforts. The Interconnecting Utility shall make reasonable efforts to meet all time frames provided in this Rule unless the Interconnecting Utility and the Interconnection Requester agree to a different schedule. If an Interconnecting Utility cannot meet a deadline provided herein, it shall notify the Interconnection Requester, explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure. The Interconnecting Utility shall maintain records, subject to audit, of all Project Applications received, the times required to complete Application approvals and disapprovals, and justification for the actions taken on the Applications. If costs arise from delay despite reasonable efforts of the Interconnecting Utility, these costs shall be borne by the Interconnection Requester. If costs arise from delay resulting from a lack of reasonable efforts on the part of the Interconnecting Utility, such costs shall be borne by the Interconnecting Utility.

Commented [A42]: Incorporation of IEEE 1547-2018 will require additional process and a subsequent order with technical requirements. See IREC's comments for more information.

Commented [A43]: IEEE 1547-2018 is not technology specific and some ride-through requirements and advanced features may apply to any type of DER, including rotating machines. As "Smart Inverter" is defined but used only in this section, the definition could be deleted as well, until such a time it may be necessary to include technology-specific requirements in the interconnection rule.

(E) Dispute Resolution.

(1) The Parties agree to attempt to resolve all disputes arising out of the interconnection process and associated study and interconnection agreements according to the provisions of this Section.

(2) In the event of a dispute, the disputing Party shall provide the other Party a written Notice of Dispute containing the relevant known facts pertaining to the dispute, the specific dispute and the relief sought, and express notice by the disputing Party that it is invoking the procedures under this Section. The notice shall be sent to the non-disputing Party's email address and physical address set forth in the Interconnection Agreement or Application, if there is no Interconnection Agreement. A copy of the notice shall also be sent to Interconnection Ombudsperson. The non-disputing Party shall acknowledge the notice within 3 days of its receipt and identify a representative with the authority to make decisions for the non-disputing Party with respect to the dispute.

(3) If the dispute is principally related to one or both Parties' compliance with timelines specified in these Interconnection Procedures or associated agreements, the Parties shall seek assistance from Interconnection Ombudsperson if the Parties cannot mutually resolve the dispute within 8 days.

(4) If the dispute is not principally related to one or both Parties' compliance with a timeline, then the non-disputing Party shall provide the disputing Party with all relevant regulatory and/or technical details and analysis regarding any Utility interconnection requirements under dispute within 10 Business Days of the date of the notice of dispute. Within 20 Business Days of the date of the notice of dispute, the Parties' authorized representatives shall meet and confer to try to resolve the dispute. Parties shall operate in good faith and use best efforts to resolve the dispute.

(5) If a resolution is not reached in 30 days from the date of the notice of dispute, either (1) a Party may request to continue negotiations for an additional twenty 20 days, or (2) the Parties may by mutual agreement make a written request for mediation to the Interconnection Ombudsperson. Alternatively, both Parties by mutual agreement may request mediation from an outside third-party mediator with costs to be shared equally between the Parties.

(6) If the results of the mediation are not accepted by one or more Parties and there is still disagreement, the dispute shall proceed to the formal petition process.

(7) ~~If a dispute arises a~~At any time ~~during these procedures,~~ either Party ~~the Interconnection Requester or the Interconnecting Utility~~ may seek immediate resolution by written petition to the Commission, with copies to the other party and the Vermont Department of Public Service, stating the issues in dispute.

(8) If neither Party elects to seek assistance from the Commission, or if the attempted dispute resolution fails, then either Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of these procedures.

(9) Pursuit of dispute resolution shall not affect an Interconnection Requester's Application with regard to consideration for interconnection, nor position in an

Commented [A44]: Adding the dispute resolution procedure from IREC's Model Rule.

Commented [A45]: An Interconnection Ombudsperson can be designated by the Commission (typically Commission staff) to help track and facilitate the efficient and fair resolution of disputes.

Commented [A46]: The duration of the typical dispute resolution process is generally considered to be too long to be effective in assisting parties with timeline disputes. Thus, it is helpful to engage an Ombudsperson earlier on to facilitate disputes related to timelines where possible.

Interconnection Queue.

(F) Interconnection Metering. Any metering necessitated by the interconnection of the Project shall be installed at the Interconnection Requester's expense in accordance with the Interconnecting Utility's reasonable specifications.

(G) Commissioning. Commissioning tests of an Interconnection Requester's installed equipment shall be performed pursuant to applicable codes and standards as identified by the parties in the Interconnection Agreement. The Interconnecting Utility shall be given 14 days' written notice, or as otherwise mutually agreed by the parties, of the tests and may have one or more of its representatives present to witness the commissioning tests.

(H) As Built Drawings. In the case of Projects with an Export ~~e~~Capacity of greater than 150 kW, the Interconnection Requester shall, within 30 days of the Project in-service date, supply to the Interconnecting Utility "As Built" drawings depicting the details of what was installed during the construction process. This drawing shall be stamped by a professional engineer. Any deviation from the Application not previously approved by the Interconnecting Utility shall be addressed pursuant to the Interconnection Agreement.

(I) Notification Prior to Exceeding Cost Estimate. For any study, Interconnection Facilities, or System Upgrades for which this Rule requires the Interconnection Requester to bear costs, the Interconnecting Utility shall, prior to exceeding a previously provided cost estimate, promptly notify the Interconnection Requester if such costs are likely to exceed the previously provided estimate and shall provide the Requester with a revised total estimated cost for the study. The Interconnecting Utility shall proceed with completing the study, Interconnection Facilities, or System Upgrades unless and until requested to cease processing the Application by the Interconnection Requester, in which case the Requester shall be responsible for all such costs incurred to date and the Application shall be deemed withdrawn.

(J) For those portions, if any, of the study fees for the ~~Feasibility,~~ System Impact~~,~~ and Facilities Studies that the Interconnecting Utility bills to the Interconnection Requester and for which the Interconnecting Utility could also recover in its rates, the Interconnecting Utility shall book this income separately.

(K) Where additional facilities, Interconnection Facilities, or System Upgrades are required to permit the interconnection of a Project, the Interconnection Requester shall bear the entire cost of such facilities. Within 30 days of final collection of all material, labor, contractor, permitting, and other costs incurred by the Interconnecting Utility in construction, testing, and commissioning of the Interconnection Facilities and System Upgrades, the Interconnecting Utility shall provide the Interconnection Requester with an invoice. The Interconnection Requester must pay all such costs that exceed the deposit within 30 business days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the Interconnecting Utility shall return such

excess, without interest, within 30 business days of receipt of the invoice or resolution of any dispute

(L) Market Participation – As part of the Application, Interconnecting Requestor shall notify the Interconnecting Utility whether the Project will be participating in the wholesale electricity markets, including whether the Project will be aggregated with other resources to participate.

5.516 Cost Responsibility and Cost Reconciliation

(A) Costs of Facilities and Cost Responsibility. Where additional facilities, Interconnection Facilities, or System Upgrades are required to permit the interconnection of a Project, the Interconnecting Utility shall provide a detailed good-faith estimate of the costs, and the Interconnection Requester shall pay the full amount of the estimate or, if such costs are covered by an Interconnection, Line Extension, or other tariff, said charges shall be billed and paid pursuant to the tariff.

(B) Within 21 days of submittal of a Study Report, the Interconnecting Utility shall provide to the Interconnection Requester an invoice that includes a breakdown of the actual cost to perform the Study. The Interconnection Requester must pay the full cost of the Study. The Interconnecting Utility shall base all study fees on actual costs, which include, but are not limited to, salaries, overheads, and out-of-pocket costs including costs billed by other entities for new studies or portions thereof that the Interconnecting Utility does not itself perform. If the cost of the Study exceeds the deposit, the Interconnection Requester must pay the invoiced amount (cost of the Study minus the deposit), without interest, within 30 days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the cost of the Study, the Interconnecting Utility shall refund such excess, without interest, within 21 days of submittal of the Study Report.

5.517 Disconnection

(A) The following requirements shall govern disconnection from the electrical system of a Project that was interconnected under these procedures. These requirements apply to such Projects only and do not supplant Commission Rules 3.300 and 3.400 relating to utility disconnection in general.

(B) The Interconnection Requester retains the option to disconnect temporarily from the Interconnecting Utility's system at any time. Such temporary disconnection shall not be a termination of any Interconnection Agreement unless the Interconnection Requester exercises its termination rights under such agreement.

(C) In the event an Interconnecting Utility needs to perform an Emergency disconnection of a Project, the Interconnecting Utility shall notify the Interconnection Requester within 24 hours after the disconnection.

(1) If the Emergency is not caused by the Project, the Interconnecting Utility shall assist the Interconnection Requester with reconnecting the Project upon cessation of the Emergency.

(2) If the Emergency is caused by the Project, the Interconnecting Utility shall communicate the nature of the problem to the Interconnection Requester within 5 days and shall work with the Interconnection Requester to resolve the problem. If the problem has not been resolved within 30 days of an Emergency disconnection, the Interconnecting Utility shall file a disconnection petition with the Commission. In any proceeding on such a petition, the Interconnecting Utility shall bear the burden of proof to demonstrate the reasonableness of disconnection.

(D) Non-Emergency disconnections shall follow the same procedure as Emergency disconnections outlined above, except that the Interconnecting Utility shall give written notice of the disconnection no earlier than 10 days and no later than 7 days prior to the first date on which disconnection of the Project may occur. Such notice shall communicate the reason for disconnection to the Interconnection Requester and the expected duration of the disconnection. An Interconnecting Utility may obtain, at the discretion of the Interconnection Requester, an Interconnection Requester's written agreement to notice requirements for non-Emergency disconnections that are different from those set forth in these procedures, provided that the Interconnecting Utility first advises the Interconnection Requester of its rights under this Rule.

(E) An Interconnection Requester whose Project is involuntarily disconnected may file a complaint with the Commission at any time following disconnection. The Commission may hold a hearing to determine whether the Project should be reconnected to the Interconnecting Utility. In the event of the filing of such a complaint, the Interconnecting Utility shall bear the burden of proof to demonstrate the reasonableness of disconnection.

(F) An Project may be disconnected for exceeding the ~~generation~~Export ~~c~~Capacity applied for and studied during the interconnection process, if such excess ~~generation~~Export ~~c~~Capacity is not remedied within a reasonable time, after notice of such excess generation is given by the Interconnecting Utility.

5.518 Certification of Project Equipment Packages

(A) A Project equipment package shall be considered certified for interconnected operation to an electric power distribution system if it has been approved under the certification process described below.

(B) An equipment package shall be considered certified for interconnected operation if it has been submitted, tested, and listed by a nationally recognized testing and

certification laboratory or approved by the U.S. Department of Energy for continuous utility interactive operation in compliance with the applicable Codes and Standards listed in Section 5.519, below. An "equipment package" shall include all interface components including switchgear, inverters, or other interface devices and may include an integrated Project. If the equipment package has been tested and listed as an integrated package that includes a Generation Resource, it shall not require further design review, testing, or additional equipment to meet the certification requirements. If the equipment package includes only the interface components (switchgear, inverters, or other interface devices), then an Interconnection Requester must demonstrate to the Interconnecting Utility that the Generation Resource being utilized with the equipment package is compatible with the equipment package and consistent with the testing and listing specified for the package. If the Generation Resource combined with the equipment package is consistent with the testing and listing performed by the nationally recognized testing and certification laboratory, no further design review, testing, or additional equipment shall be required to meet the certification requirements. A certified equipment package does not include equipment provided by the Interconnecting Utility, nor does certification necessarily exempt an equipment package or Generation Resource from commissioning testing required for installation and operation.

5.519 Codes and Standards

Unless waived by the Interconnecting Utility, a Project must meet the applicable codes and standards of this Section or be a certified equipment package under Section 5.518.~~When any listed version of the following codes and standards is superseded by a revision approved by the standards-making organization, then the revision shall be applied where these codes and standards are referenced in this Rule. Applications that are date-and-time-stamped on or before six months after the revision date may follow the previous version of the standard, unless an immediate threat to safety and reliability exists that requires the retrofit of all similarly situated equipment. Applications that are date-and-time-stamped later than six months after the revision date must follow the revised standard.~~

(1) IEEE 1547-2003 ~~Series of~~ IEEE Standard~~s~~ for Interconnecting Distributed Resources with Electric Power Systems ~~as adopted~~;

(2) IEEE 1547.1-2005 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems;

~~(2)~~(3) UL 1741 Standard for Safety for Inverters, Converters, ~~and~~ Controllers and Interconnection System Equipment for Use With Distributed Energy Resources, Second Edition, January 28, 2010~~in Independent Power Systems~~;

~~(3)~~(4) NFPA 70 National Electrical Code, 2017 Edition;

~~(4)~~(5) IEEE Standard C37.90.1-2012 IEEE Standard Surge Withstand Capability

Commented [A47]: Incorporation of IEEE 1547-2018 will require additional process and subsequent order with technical requirements Implementing automatic updates to standards will likely cause confusion and should be avoided. See IREC's comments for more information.

(SWC) Tests for Protective Relays and Relay Systems;

(5)(6) IEEE Standard C37.90.2-2004 IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers;

(6)(7) IEEE Standard C37.108-2021 IEEE Guide for the Protection of Network Transformers;

(7)(8) IEEE Standard C57.12.44-2014 IEEE Standard Requirements for Secondary Network Protectors;

(8)(9) IEEE Standard C62.41.2-2002 IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits;

(10) IEEE Standard C62.45-2002 IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits;

(9)(11) IEEE C62.92.6-2017 IEEE Guide for Application of Neutral Grounding in Electrical Utility Systems, Part VI - Systems Supplied by Current-Regulated Sources

(10)(12) ANSI C84.1-2020 Electric Power Systems and Equipment - Voltage Ratings (60 Hertz);

(11)(13) IEEE Standards ~~100 IEEE Standard~~ Dictionary Online, https://ieeexplore.ieee.org/browse/standards/collection/ieee~~of Electrical and Electronic Terms.~~;

(12)(14) NEMA MG 1-2016 Motors and Small Resources;

(13)(15) IEEE Standard 519-2015 IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems;

(14)(16) IEEE Standard 1453-2015 IEEE Recommended Practice--Adoption of IEC 61000-4-15:2010, Electromagnetic compatibility (EMC)--Testing and measurement techniques--Flickermeter--Functional and design specifications;

(15)(17) IEEE Standard 1453.1-2012 IEEE Adoption of IEC TR 61000-3-7 2008 Assessment of emission limits for the connection of fluctuating installations to MV, HV, and EHV power systems; and

(16)(18) Any other code or standard ordered by the Commission.

5.520 Communications Protocols

The Commission may adopt by order inverter settings and other controls related to communications protocols that will facilitate communication between Projects and Interconnecting Utilities and Transmission Utilities.

5.521 Limited-Export and Non-Exporting Projects

If a Project uses any configuration or operating mode listed below to limit the export of electrical power across the Point of Interconnection, then the ~~Generating~~ Export Capacity shall be only the amount capable of being exported (not including any Inadvertent Export). To prevent impacts on system safety and reliability, any Inadvertent Export from a Project must comply with the limits in paragraphs (5) or (6), below. The ~~Generating~~ Export Capacity specified in the Application will subsequently be included as a limitation in the Interconnection Agreement. Other means not listed in in this section may be used to limit export if mutually agreed upon by the Utility and Applicant.

(1) Reverse Power Protection: To ~~ensure power is never exported~~limit export of power across the Point of Interconnection, a reverse power Protective Function may be provided. The default setting for this Protective Function shall be 0.1% (export) of the service transformer's rating, with a maximum 2.0 second time delay to limit inadvertent export.

(2) Minimum Power Protection: To ~~ensure at least a minimum amount of power is imported~~limit export of power across the Point of Interconnection ~~at all times (and, therefore, that power is not exported)~~, an under-power Protective Function may be provided. The default setting for this Protective Function shall be 5% (import) of the Project total Nameplate Rating, with a maximum 2.0 second time delay to limit inadvertent export.

~~(2)~~(3) Directional Power Protection: To limit export of power across the point of interconnection, a directional power protective function is implemented using a utility grade protective relay. The default setting for this protective function shall be the Export Capacity value, with a maximum 2.0 second time delay to limit inadvertent export.

~~(3)~~(4) Relative Distributed Energy Resource Rating: This option requires the Nameplate Rating of the Project, minus any auxiliary load, to be so small in comparison to its host facility's minimum load that the use of additional Protective Functions is not required to ensure that power will not be exported to the Electric Delivery System. This option requires the Project capacity to be no greater than 50% of the Interconnection Customer's verifiable minimum Host Load over the past 12 months. This option is not available for interconnections to area networks or spot networks.

~~(4)~~(5) Configured Power Rating: A reduced output rating utilizing the power rating configuration setting may be used to ensure the DER does not generate power beyond a certain value lower than the Nameplate Rating.[2]~~24~~

[2] The configuration setting corresponds to the active or apparent power ratings in Table 28 of IEEE Std 1547™-2018, as described in subclause 10.4. A local DER communication interface is not required to utilize the configuration setting as long as it can be set by other means.

Commented [A48]: Relay systems and PCS can introduce inadvertent export and should be screened via the new inadvertent export screen. This language makes it more clear that these systems can introduce inadvertent export.

Commented [A49]: Relays may also provide limited export capability

Commented [A50]: It is appropriate to require controls to ensure network protectors are not inadvertently tripped

Commented [A51]: The draft failed to include footnote 24 when copied from the IREC Model. We add it back in.

~~(5)~~(6) ~~Limited Export Utilizing Inverters or~~ Certified Power Control Systems: Projects may ~~utilize~~use certified power control systems to limit export. Projects using this option must use a power control system and inverter certified per UL 1741 by~~,~~ a Nationally Recognized Testing Laboratory ("NRTL") ~~Certified Power Control~~ with a maximum open loop response time of no more than 30 seconds to limit inadvertent export. NRTL testing to the UL power control system certification requirements decision shall be accepted until similar test procedures for power control systems are included in a standard. This option is not available for interconnections to area networks or spot networks.~~System and inverter system that results in the Project disconnecting from the Electric Delivery System, ceasing to energize the Electric Delivery System or halting energy production within 2 seconds if the period of continuous Inadvertent Export exceeds 30 seconds.25 Failure of the control or inverter system for more than 30 seconds, resulting from loss of control or measurement signal, or loss of control power, must result in the Project entering an operational mode where no energy is exported across the Point of Interconnectoin to the Electric Delivery System.~~

~~(6)~~(7) Limited Export Using Mutually Agreed-Upon Means: Project may be designed with other control systems and/or Protective Functions to limit export and Inadvertent Export to levels mutually agreed upon by the Applicant and the Utility. The limits may be based on technical limitations of the Interconnection Customer's equipment or the Electric Delivery System equipment. To ensure Inadvertent Export remains within mutually agreed-upon limits, the Interconnection Customer shall use an internal transfer relay, energy management system, or other customer facility hardware or software.

Commented [A52]: Simplified and updated language can be used now that the Certification Requirements Decision for Power Control Systems is out. See IREC's comments for more details.

ATTACHMENT B

Attachment B
BATRIES Project Standardized Screen Results

Standardized 100% minimum load result

Where 12 months of line section minimum load data (including onsite load but not station service load served by the proposed DER) are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate Export Capacity on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed DER. If minimum load data is not available, or cannot be calculated, estimated or determined, the Distribution Provider shall include the reason(s) that it is unable to calculate, estimate or determine minimum load in its Supplemental Review results notification.

Export Capacity of DER Application		kW
Export Capacity of DER Active on Feeder		kW
Export Capacity of DER ahead in Queue		kW
Relevant time period	__ am/pm to __ am/pm	
Minimum Load		kW
Aggregate Export Capacity, including proposed DER		kW
DER as % of Load		%
Passes Screen	No	

Standardized 15% screen result

For interconnection of a proposed DER to a radial distribution circuit, the aggregated Export Capacity, including the proposed DER, on the circuit shall not exceed 15% of the line section annual peak load as most recently measured. A line section is that portion of a Distribution Provider's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

Export Capacity of DER Application		kW
Export Capacity of Active DER on Feeder		kW
Export Capacity of DER ahead in Queue		kW
15% of Peak Load		kW
Aggregate Export Capacity, including proposed DER		kW
Export Capacity of DER, as % of Load		%
Passes Screen	No	

Attachment B
BATRIES Project Standardized Screen Results

Standardized shared transformer screen result		
If the proposed DER is to be interconnected on single-phase shared secondary, the aggregate Export Capacity on the shared secondary, including the proposed DER, shall not exceed 20 kW or 65% of the transformer Nameplate Rating.		
Export Capacity of DER Application		kW
Export Capacity of DER Active on Feeder		kW
Export Capacity of DER ahead in Queue		kW
Export Capacity of Aggregate DER on Shared Secondary:		kW
Transformer Nameplate Rating:		kW
Export Capacity of Aggregate DER, as a % of Transformer Nameplate Rating:		%
Passes Screen	No	

Standardized protection screen result		
The fault current of the proposed DER, in aggregate with the fault current of other DERs on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.		
Nameplate Rating of DER Application		kW
Nameplate Rating of DER Active on Feeder		kW
Nameplate Rating of DER ahead in Queue		kW
Lowest short circuit interrupting rating of equipment in-line with DER:		Amps
Aggregate DER fault current contribution:		Amps
Distribution Circuit Maximum Fault Current nearest the PCC:		Amps
Total available short circuit current		Amps
% of short circuit interrupting rating:		%
Passes Screen	No	

IREC has not developed a template for standardized results of the other screens. However, IREC reviewed the each screen in SGIP developed a description of data that utilities should be required to provide when a Project fails that screen. This information is provided in the following table.

SGIP Screen		Description	Data to provide
2.2.5 Initial Review	2.2.1.2	15% of annual section peak load (or 100% min load)	Load (peak or min), aggregate generation (or Export Capacity), and percentage of load. For interconnection rules that integrate time-based load data into the screening process, provide the minimum load time window.
	2.2.1.3	Spot network (5% of network peak load or 50 kW)	Peak load, aggregate generation on network, and percentage of load.
	2.2.1.4	10% of maximum fault current	Aggregate generation fault current on circuit, distribution circuit max fault current, percentage of max fault current, assumptions for customer's DER (e.g., fault current = 1.2x inverter Nameplate Rating).
	2.2.1.5	87.5% of short circuit interrupting capability	Short circuit interrupting rating at limiting (lowest rated) equipment in-line with DER, aggregate DER fault current contribution, distribution circuit max fault current nearest PCC, total short circuit current, percentage of short circuit interrupting rating.
	2.2.1.6	Line configuration	Distribution line type, interconnection (customer service) type.
	2.2.1.7	Shared secondary transformer 20 kW	Aggregate DER rating (or export) on shared secondary, for screens that use 65% of transformer rating instead of 20 kW provide transformer rating and percentage of rating.
	2.2.1.8	Single-phase imbalance	Transformer rating, imbalance as percentage of rating.
	2.2.1.9	10 MVA transient stability	Aggregate generation, whether there are known transient stability limitations.
2.2.27 Supplemental	2.4.4.1	100% minimum load	Min load, aggregate generation (or export), percentage of load, time period under consideration (e.g., hours of the day based on fixed vs. tracking PV).
	2.4.4.2	Voltage and power quality	This list is not exhaustive and would be dependent on the applied criteria. E.g., if non-bidirectional regulators experiencing reverse flow: maximum reverse power at regulator; If overvoltage is flagged at minimum load: maximum reverse power with customer's DER, maximum reverse power before triggering voltage limit violation.
	2.4.4.3	Safety and Reliability	This list is not exhaustive and would be dependent on the applied criteria. E.g., conductor loading: limiting conductor ampacity, total current, loading as a percentage of ampacity.
	Covering all screens		kW of existing DER in-line section and DER ahead in queue.

ATTACHMENT C

Attachment C: Informal Outline of Group Study Considerations
Interstate Renewable Energy Council, Inc.

1. Group Formation – The core component of a group study process is determining when and how a group will be formed.
    a. Timing – The process will need to establish a mechanism for determining when a group study will be conducted and what projects will be included in the group(s). Though Massachusetts and California differ on the details of formation, the principle elements are a triggering event (i.e. two or more electrically interrelated projects entering the queue near the same time) and a window of some sort for adding projects to the group.
    b. Geographical Scope – Whether projects need to be studied in a group depends on whether they will impact each other. In addition to timing, the process will need to determine how projects are "grouped" based upon the electrical infrastructure they share or other relationship.
    c. Requirements for Participation – In order for groups to function well and result in time and cost sharing benefits it is typically necessary that all interrelated projects be required to participate. However, there can be various ways to implement this and to break up group formation.
        i. Excluding small projects – An exception to this rule of required participation is an acknowledgement that it would be detrimental for small projects to be required to participate. Thus, the process needs to define what size (or other characteristic) projects need to participate and how excluded projects will be processed.
        ii. Single Applicant groups – Another concept on the table is whether single-developer groups can be formed and whether/how they will interact with the broader group study process.
2. How Group Studies are Conducted – Once groups have been formed, it will need to be determined how they are conducted.
    a. Study Phases – How many studies will be conducted and if there is more than one, how will they vary from each other? Often groups and cluster studies are conducted in two phases, with the first study being used to determine initial scope of impacts and costs, followed by a more detailed second phase. Between the two phases is often an opportunity for members of the group to drop out (i.e. if their estimated cost share was too great or the timeline for completing the upgrades was too significant).
    b. Duration of Study – Timelines will need to be defined for each phase in the process, they can be universal or vary in length based upon the size of the group, complexity, or other factors so long as those are clearly identified.
    c. Group vs. Individual Impact Assessments – Typically there is one study conducted of the collective impacts of the projects, but there may also need to be some individual impact assessments (typically for project specific interconnection facilities). These are usually conducted at the same time as the broader group assessment, but should be clearly identified.
    d. Distribution vs. Transmission Impacts – If it is anticipated or possible that there will be transmission system impacts the process for evaluating and assessing those impacts along with the distribution system impacts should be considered and defined.

3. Group Retention
    a. Managing Group Attrition – Project development is complex and there can be multiple different factors that cause projects to withdraw during the interconnection process. While a group study process can help minimize project withdrawals by providing more efficient timelines, process clarity, and cost sharing opportunities, there should be a clear set of rules that define when a project can drop out and what the consequences of this are as it can significantly impact other projects in the group.
        i. Phases (see discussion above)
        ii. Deposits – In order to deter projects from exiting late in the process, there could be payments or financial security deposits required at various steps in the process for both study and upgrade costs. How and when those will go into effect, the amounts and the method of payment should be defined and be reasonable at both deterring withdrawals while also being realistic about the development cycle.
        iii. Site Control – In addition to the financial mechanisms, there may be other elements to require that assure that projects are likely to be able to continue. Requiring evidence of site control is one common feature, but when it must be demonstrated and how can vary.
    b. Project Modifications – In addition to managing project withdrawal the process should also clearly define how and when projects may make modifications to their project.
4. Cost Allocation – There are two aspects of cost allocation in a group: study costs and upgrade costs.
    a. Study Costs – In addition to defining when study costs are paid (see above) the process will need to define how the costs are allocated across the participating parties (i.e. on the basis of size, equally, or other factors). There may need to be group study costs and also individual study components.
    b. Upgrade Costs – Similarly, a transparent and fair process for allocating upgrade costs across the participants will need to be defined. Like with the study costs, there may be upgrades costs that are appropriate to share across all participants, while there are some project-specific upgrades.
5. Transitioning to a Group Study Process – Perhaps the final element to consider is when to transition to the use of a group study process, and in particular, what happens with projects that are already in the queue? It is important to define a process that keeps projects moving and does not result in further delays.