BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES

IN THE MATTER OF MODERNIZING NEW JERSEY'S INTERCONNECTION RULES, PROCESSES, AND METRICS	**Docket No. QO2110085**

COMMENTS OF THE INTERSTATE RENEWABLE ENERGY COUNCIL, INC. ON THE PROPOSED AMENDENTS AND NEW RULES AT NJAC 14:8

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On June 4, 2024, the New Jersey Board of Public Utilities (BPU) issued a Notice of Proposed Rulemaking (NOPR) that contained proposed revisions to New Jersey Administrative Code (NJAC) § 14:8 (proposed rules). The NOPR is the culmination of a process that commenced three years ago and included input from various stakeholders. The BPU issued a draft rule for comment on March 2, 2023 and received opening, but no reply, comments on the proposed revisions. In the NOPR, the BPU invited stakeholders to comment on the proposed rule by August 2, 2024. Pursuant to the BPU's orders, the Interstate Renewable Energy Council, Inc. (IREC) respectfully submits the following comments on the proposed rules along with a redline showing recommended revisions (Attachment A).

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's team includes policy experts, lawyers, and electrical engineers who are well versed in the procedures and technical standards for interconnecting DERs to the electric power system. Drawing on that knowledge, 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. IREC has extensive experience with state interconnection procedures and has helped to refine and improve interconnection procedures across the United States. IREC closely monitors and tracks the development of best practices in interconnection policy, with a focus on both the procedural and technical aspects of interconnection.[1]

I. Introduction

New Jersey was an early leader in the adoption of solar and has recently adopted new programs to encourage continued growth in clean, distributed energy resources (DERs) to transition the Garden State away from fossil fuels. Despite this positive focus on clean energy, New Jersey's small generator interconnection procedures have remained woefully out-of-date. In 2023, IREC released its "Freeing the Grid" tool, which grades the interconnection procedures of individual states based on their adoption of widely-implemented national best practices.[2] New Jersey received a D, demonstrating the need for a significant overhaul of the interconnection rules.

The proposed rules make some significant improvements to bring New Jersey's procedures into alignment with modern procedures. IREC strongly supports the adoption of some valuable best practices, including the pre-application report (PAVE), concrete timelines for the preparation of System Impact Studies and Facilities studies, and a dispute resolution process. The inclusion of modern tools for submitting applications and tracking progress, combined with quality interconnection timeline tracking, will improve customer progress and provide visibility into what is working and where the process is still falling short.

However, the proposed rules do not go nearly far enough. If adopted as is, New Jersey will barely improve its Freeing the Grid interconnection grade from a D to a C. The proposed

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[1] IREC publishes and regularly updates Model Interconnection Procedures, along with other resources help states update their interconnection rules. IREC also closely monitors the development of relevant interconnection standards, such as IEEE 1547, and publishes resources to help states with adoption of these standards. These resources can all be accessed at no cost on IREC's website: www.irecusa.org.

[2] IREC & Vote Solar, *Freeing the Grid*, available at www.freeingthegrid.org.

rules lack crucial improvements and bungle the attempt to move toward more advanced concepts crucial for grid modernization, such as the incorporation of export limited systems. This is a missed opportunity that fails to capitalize on the multi-year process that culminated in this rulemaking. Particularly disappointing is the BPU's adoption of redline edits submitted jointly by the utilities in 2023, without any opportunity for reply comments by stakeholders to identify the significant problems with the utilities' edits.

Specifically, while the proposed rules take the first steps toward integrating energy storage and recognizing the export control capabilities of DERs, the rules need to be supplemented to provide clarity and certainty to utilities and applicants. The rules also fail to adopt core best practices for initial review screens and supplemental review that have been adopted by nearly every state that has modified their procedures in the last decade. Principally, this includes transitioning to the use of a minimum load metric in penetration screens, amending the size limits for Level 2 to better reflect the conditions that determine whether a project can safely pass through the screens, and adopting a defined supplemental review process that is automatically available when a DER fails Level 1 or 2 review. These changes are now well-tested and have been relied on to connect millions of solar projects across the country. These changes are a basic way of ensuring that existing grid capacity is utilized and can be accessed in a safe and effective manner.

The proposed rules also contain significant organizational issues and terminology that are likely to cause considerable confusion and dispute. The rules propose to require the adoption of Hosting Capacity Analyses (HCA), but fail to include critical details that are imperative if the information is to be at all informative. Without these, and other improvements highlighted herein and in the enclosed redlines, New Jersey's interconnection process will remain unnecessarily time and cost intensive, tying up utility and developer resources without improving safety or reliability.

Fortunately, many of the necessary changes can be adopted easily by following existing models. IREC recognizes that the momentum at this point will be towards adopting these rules without significant changes, but we strongly urge the BPU to consider if that is in the best interest of the state. If the BPU declines to adopt the more significant changes, it should consider immediately opening another, better designed, process to do a more comprehensive clean-up and update of the rules.

In these comments, IREC outlines the major opportunities the BPU has to make meaningful and achievable changes to the proposed rules. IREC offers specific language for most of the recommendations and illuminates the benefits of making these changes. In addition, IREC is including a redlined version of the proposed rules in Attachment A that show how these concepts can be integrated.[3] Included in the redline edits are comments explaining the need for many of the highlighted changes. IREC also identifies a list of additional best practices that the state may want to consider to help ensure that New Jersey's rules for connecting clean energy resources to the grid are at the top of their class. By adopting these rules, New Jersey will ensure the timely and cost-effective deployment of DERs across the state, while enhancing grid safety and reliability. Key recommendations are as follows:

- Adopt and/or refine defined terms to incorporate critical concepts that have emerged since New Jersey last updated the rules. This requires repairing some significant

[3] Although IREC requested one, there was no redlined version of the rules available to facilitate an easy redline. IREC worked with what was available from the publication in the register but notes that the formatting was difficult to replicate and that the section references throughout the rule will need to be corrected if some or all of the changes are adopted.

oversights that could limit the applicability of the rules.

- Amend the rules to fully embrace the capabilities of export controls by:
  - Adding a list of definitions related to export controls that provide clarity to developers and utilities;
  - Including a list of the accepted means by which to control export;
  - Introducing a new screen to evaluate inadvertent export;
  - Ensuring the screens used by utilities clearly identify where export capacity or nameplate capacity will be used.
- Bring the screening process in line with national best practices by:
  - Using a minimum load metric, instead of peak load, in penetration screens;
  - Updating the effective grounding screen;
  - Clearly-defining a supplemental review process that is automatically offered when a DER fails Level 2 review.
- Ensure that the state takes the necessary and required steps to properly adopt Institute of Electrical and Electronics Engineers (IEEE) Standard 1547-2018 and enable the use of smart inverters.
- Improve the requirements for the preparation of HCAs to ensure that the results provide meaningful and useable information to potential interconnection applicants.

II. The proposed rules should be improved with additional and/or refined definitions.

BPU proposes to add and revise numerous terms in the definitions sections that govern interconnection (Proposed Rules § 14:8-5.1) and Net Metering ("NEM") (*id.* § 14:8-4.2). Quality definitions are key to avoiding disputes and ensuring the procedures are easy to follow and streamlined. IREC's proposed edits to the definition section are focused in two areas.

First, the proposed interconnection rules currently lack crucial definitions of the most commonly used terms. In particular, the interconnection rules lack a definition of "customer-generator" and "customer-generator facility," despite these terms being used consistently throughout the rules. A definition for these terms is proposed in the NEM rules, but therein the term customer-generator refers only to generation or energy storage "on the customer's side of the meter."[4] This may be appropriate for the NEM rules. However, if these definitions were meant to be incorporated into the interconnection rules, they would severely limit the applicability of the interconnection rules, excluding community solar facilities and other front-of-the-meter projects.

While there are various ways to resolve this, IREC recommends using different terms between the interconnection and NEM rules. For the definition of "customer-generator," IREC recommends simply using the already defined term "applicant" in the body of the rule.[5] In place of the term "customer-generator facility," IREC recommends using Distributed Energy Resources, or DERs, and offers an improved definition of DER that is inclusive of all types of systems that should be able to apply under the rules. The definition of DER that is proposed in the rules currently is limited to "inverter-based" systems, which leaves out some generating classes that may need interconnection access. Using "DER" instead of "customer-generator facility" is also clearer since energy storage is not a "generator." Thus, IREC proposes this definition:

"Distributed energy resource**"** or "DER**"** means the equipment used by an

[4] Proposed Rules § 14:8-4.2 (defining "Customer-generator" as "an electricity customer that generates electricity *on the customer's side of the meter*" and "Energy storage device" as a "device that is capable of absorbing energy from the grid or from a generation source *on the customer's side of the meter*") (emphasis added).

[5] NJAC § 14:8-5.1 ("'Applicant'" means a person who has filed an application to interconnect a customer-generator facility to an electric distribution system").

> interconnection customer to generate and/or store electricity that operates in parallel with the electric distribution system. A DER may include but is not limited to an electric generator and/or energy storage system, a prime mover, or combination of technologies with the capability of injecting power and energy into the electric distribution system, which also includes the interconnection equipment required to safely interconnect the facility with the distribution system.

IREC also recommends using "Energy storage system" instead of the term "Energy storage device" in the interconnection rules to be clearer about the configurations of those systems and exclude the limitation that it be behind the customer's meter.

> "Energy storage system" or "ESS" means a mechanical, electrical, or electrochemical means to store and release electrical energy, and its associated interconnection and control equipment. For the purposes of these interconnection procedures, an energy storage system can be considered part of a DER or a DER in whole that operates in parallel with the distribution system.

IREC also suggests the BPU swap the term "energy storage device" with "energy storage system" or "ESS" to remove any confusion as to whether the NEM definitions govern interconnection and to clearly provide that energy storage can stand alone or be part of a DER system. IREC proposes additional definitions to include concepts vital to export control, discussed in detail in Section III.A.

The other category of revisions to the definitions that IREC recommends is inclusion of numerous terms that are necessary to better review DERs that can control their export to the grid, that reflect current terminology used in standards such as IEEE 1547, and that clean up erroneous limitations from other terms. Some of these additions are discussed in later sections and all the changes can be seen in IREC's enclosed redline. The definitions used are generally sourced from IREC's Model Interconnection Procedures which are regularly updated to reflect the best use of terminology across the United States.[6]

[6] IREC's 2023 Model Interconnection Procedures can be downloaded at no cost here: https://irecusa.org/resources/irec-model-interconnection-procedures-2023/ Note that the Model (footnote continued on next page)

III. The BPU should prioritize amending the proposed rules to fully embrace the capabilities of export controls.

IREC is pleased to see that the proposed rules take initial steps towards integrating the important capabilities of export limiting systems, such as energy storage. The capabilities of DERs have evolved significantly since the rules were last updated and incorporating export limiting is vital to ensure those capabilities, and their reduced grid impacts, are recognized. While the rules start down this path, they do it in an incomplete manner that leaves out crucial concepts necessary to ensure safety and reliability. IREC recommends the BPU adopt a clearer, more thorough approach to addressing how projects with export limiting capabilities, particularly energy storage, are evaluated. While making these necessary changes requires substantial revisions, clear models exist and the BPU can easily incorporate these changes to better accomplish the goals of the rulemaking.

How much power a project exports to the grid is a key factor in determining whether, and to what extent, that project will require upgrades. Power that is not exported does not contribute to certain types of distribution system impacts, including voltage and thermal impacts, making it inappropriate to use a resource's nameplate capacity to determine whether it will cause such impacts.[7] Thus, when a project safely and reliably limits the amount of power it exports to the grid, the manner in which the utility evaluates the impact of the project should change. For energy storage projects, the primary factor that needs to be taken account in evaluating a project's grid impacts is the controllable nature of the technology, which can allow different

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includes a number of other terms that are used in the New Jersey rules but not defined, we recommend the BPU consider adopting a more comprehensive set of definitions to improve rule clarity.

[7] For other grid impacts, such as fault current, it is necessary to use a resource's nameplate capacity.

export amounts, and at different times, in a way not common with traditional generators. It is also important to recognize and evaluate whether inadvertent export from export controlled facilities will impact the grid.

On March 28, 2022, the Building a Technically Reliable Interconnection Evolution for Storage (BATRIES) project issued the Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage (Toolkit).[8] The BATRIES project was funded by the Department of Energy's Office of Energy Efficiency and Renewable Energy. The project partners and Toolkit co-authors are IREC, the Electric Power Research Institute, Shute, Mihaly & Weinberger LLP, the New Hampshire Electric Cooperative, the Solar Energy Industries Association, the California Solar and Storage Association, and PacificCorp. The BATRIES project convened utility and energy storage stakeholders from across the country to identify the key barriers to energy storage interconnection and develop consensus based recommendations for how to address those barriers in interconnection procedures.

A central focus of BATRIES was how interconnection rules can be changed so that utilities can accurately evaluate the impacts of a project that purports to limit the export of power to the electric grid. The following changes are essential to facilitating the timely and cost-effective deployment of energy storage and other DER resources across the State: (1) adding a list of definitions related to export controls that provide clarity to developers and utilities; (2) including a list of the accepted means by which to control export; (3) introducing a new screen to evaluate inadvertent export; and (4) ensuring the screens used by utilities clearly identify where export capacity or nameplate capacity will be used. The Toolkit includes model language the

[8] Interstate Renewable Energy Council, et. al, *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage* (March 2022) (Toolkit), downloadable at https://energystorageinterconnection.org.

BPU can use to make each of these changes, which are reflected in IREC's redlines. The Toolkit also includes important detail on the integration of new aspects of the IEEE 1547-2018 standard, such as the use of the Reference Point of Applicability. The recommendations herein are derived from the BATRIES report and each is explained in further detail therein if the BPU desires additional orientation to the concepts and the reasoning behind the following proposals. Since BATRIES was published, states such as Oregon and New Mexico have modeled their procedures off the Toolkit.[9] New Jersey has the opportunity to make major improvements to its rules by doing so as well.

A. The BPU should add definitions related to export controls that provide clarity to developers and utilities.

The foundation of a comprehensive review process for DERs purporting to limit their export is a list of detailed definitions that accurately explain each of the concepts vital to export control. The proposed rules do not define export capacity or nameplate rating, two concepts which are essential for utilities to properly evaluate DERs' grid impacts. The proposed rules also fail to define "Power control system," which refers to the technology most commonly used to control export. Also excluded from the proposed rules is any mention of inadvertent export, another key consideration in evaluating the potential grid impacts of export limiting DERs—discussed in detail in Section II.C.

The proposed rules include two new terms in the interconnection definitions section:

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[9] Or. Pub. Util. Com., Dkt. AR-659, *In the Matter of Rulemaking to Update Division 82 Small Generator Interconnection Rules, and Division 39 Net Metering Rules*, Order No. 24-068 (March 8, 2024); Or. Admin. Code §§ 860-082-0005 *et seq*; NM. Pub. Reg. Com., Dkt. No. 21-002660-UT, *In the Matter of a Commission Rulemaking Regarding NMPRC Rule 17.9.568 NMAC Interconnection of Generating Resources with a Nameplate Capacity Rating Up to and Including 10 MW Connecting to a Utility System*, Final Order (Dec.8, 2022); NM Admin. Code §§ 17.9.568.1 *et seq*. In addition, many of the recommendations in BATRIES were modeled after the interconnection rules adopted by Illinois in 2022. Il. Com. Comm., Dkt. 20-0700, Final Order (May 25, 2022); Ill. Admin. Code §§ 466.10 *et seq*.

"Non-exporting customer-generator facility" and "Non-exporting technology." While IREC appreciates the BPU acknowledging the potential for DERs to control their export, these terms do not clearly differentiate between non-export controls and limited export controls. This distinction is crucial for determining which means of export control a DER should use, as well as for evaluating a resource's potential grid impacts.

BATRIES includes numerous terms related to export controls, each of which is included in IREC's redlines. IREC proposes the rule be amended to include each of the following terms:

> "Export capacity" means the amount of power that can be transferred from the DER to the distribution system. Export capacity is either the nameplate rating, or a lower amount if limited using an acceptable means identified in Section __.
>
> "Nameplate rating" means the sum total of maximum rated power output of all of a DER's constituent generating units and/or ESS as identified on the manufacturer nameplate, regardless of whether it is limited by any approved means.
>
> "Non-Export" or "Non-Exporting" means when the DER is sized, designed, and operated using any of the methods in Section __, such that the output is used for host load only and no electrical energy (except for any inadvertent export) is transferred from the DER to the distribution system.
>
> "Host load" means electrical power, less the DER auxiliary load, consumed by the customer at the location where the DER is connected.
>
> "Limited export" means the exporting capability of a DER whose generating capacity is limited by the use of any configuration or operating mode described in Section __.
>
> "Inadvertent export" means the unscheduled export of active power from a DER, exceeding a specified magnitude and for a limited duration, generally due to fluctuations in load-following behavior.
>
> "Power control system" or "PCS" means systems or devices which electronically limit or control steady state currents to a programmable limit.

The importance of these terms, and the concepts they illuminate, is discussed in detail in Sections II.B-II.D.

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B. The proposed rules should be amended to include a list of the widely-accepted means to control export.

In order for utilities to determine how to evaluate the impacts of a project that purports to limit the export of power to the electric grid, they must have confidence that the means used are safe and reliable. There are a variety of different methods that can be used to control export. It is beneficial for interconnection procedures to clearly define what means are acceptable so that applicants know going into the application process and can design their systems accordingly. This approach improves transparency and minimizes the amount of back and forth and customized review that would otherwise be needed in the interconnection review process. It also helps applicants better understand how their project will be reviewed. However, the proposed rule does not identify ***any*** means by which export from a DER can be controlled.

BATRIES identified six specific export control means that utilities can confidently rely on. These means are either certified or use well-established methods that have been accepted by utilities for decades. The BATRIES report explains what each method is, why they are safe and reliable, and pays particular attention to why power control systems (PCS), certified under the UL standard, should be allowed.[10] These include technologies that can be used to completely restrict and/or simply limit export from DERs. BATRIES also includes a seventh option for other means that can be used upon mutual agreement of an applicant and utility. It is crucial for the interconnection rules to make explicit that, where any of the acceptable means are utilized, the export amount selected by the applicant will determine the export capacity of the project to be used by utilities in the review process. IREC's redlines include a section that identifies these accepted export control means and delineates the criteria for their application, reproduced here:

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[10] Toolkit, at 45-55.

Export Control Methods for Non-Exporting DER

Reverse Power Protection (Device 32R[11]): To limit export of power across the Point of common coupling, a reverse protective function is implemented using a utility grade protective relay. The default setting for this protective function shall be 0.1% export of the service transformer's nominal base Nameplate Rating, with a maximum 2.0 second time delay to limit Inadvertent Export.

Minimum Power Protection (Device 32F): To limit export of power across the Point of common coupling, a minimum import protective function is implemented using a utility grade protective relay. The default setting for this protective function shall be 5% (import) of the DER's total Nameplate Rating, with a maximum 2.0 second time delay to limit Inadvertent Export.

Relative Distributed Energy Resource Rating: This options requires the DER's Nameplate Rating 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 distribution system. This options requires the DER's Nameplate Rating to be no greater than 50% of the interconnection customer's verifiable minimum host load during relevant hours over the past 12 months. This option is not available for interconnections to area networks or spot networks.

Export Control methods for Limited-Export DER

Directional Power Protection (Device 32): To limit export of power across the Point of common coupling, 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.

Configured Power Rating: A reduced output power 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. 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. The reduced power rating may be indicated by means of a Nameplate Rating replacement, a supplemental adhesive Nameplate Rating tag to indicate the reduced Nameplate Rating, or a signed attestation from the customer confirming the reduced capacity.

[11] Device numbers are enumerated in the American National Standards Institute/IEEE, *IEEE Standard Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

Export Control Methods for Non-Exporting DER or Limited-Export DER

Certified Power Control Systems: DER may use certified Power Control Systems to limit export. DER utilizing this options must use a Power Control System and inverter certified per UL 1741[12] by a nationally recognized testing laboratory (NRTL) 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 Requirement Decision shall be accepted until similar test procedures for power control systems are included in a standard. This option is not available for interconnection to area network or spot networks.

Agreed-Upon Means: DER may be designed with other control systems and/or protective functions to limit export and Inadvertent Export if mutual agreement is reached with the Distribution Provider. The limits may be based on technical limitations of the interconnection customer's equipment or the electric distribution system equipment. To ensure Inadvertent Export remains within mutually agreed-upon limits, the interconnection customer may use an uncertified Power Control System, an internal transfer relay, energy management system, or other customer facility hardware or software if approved by the Distribution Provider.

BPU should recognize the use of all of these means, which have been incorporated into interconnection procedures by numerous states, including Oregon, New Mexico, and Illinois.[13] The consequence of not doing so is that interconnection applicants will not have clear visibility before they apply on what system design is acceptable, and there will be the need for more back and forth with the utility than is necessary. In addition, utilities may seek to add additional requirements or not allow the use of means that are widely accepted, all of which can lead to costly disputes that are preventable with the right set of interconnection rules.

C. The BPU should add a new screen into the interconnection rules to evaluate inadvertent export.

One of the important evolving issues related to the review of export-controlled

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[12] When BATRIES was written the UL certification was being incorporated into UL 1741 via a Certification Requirement Decision. Since that time, UL has adopted a new standard, UL 3141, that now includes the certification requirements for PCS.

[13] Or. Admin. Code § 860-082-0033; NM Admin. Code § 17.9.568.12; Ill. Admin. Code tit. 83, § 466.75.

projects is how "inadvertent export" from those projects should be evaluated.[14] Inadvertent export is power that is unintentionally exported from a DER when load drops off suddenly and the export control system does not immediately respond to the signal to limit or stop export. Inadvertent export events occur when using relays or PCS; the duration and magnitude of the events will vary to some extent based on the device and the load behavior at the DER site.[15] As more systems utilize export control means, utilities need to be assured that these inadvertent export events will not impact the grid and, therefore, need a way to screen for where they might become a problem. The proposed rules do not acknowledge inadvertent export, let alone include a process by which utilities can evaluate whether inadvertent export from a DER has the potential to cause grid impacts.

One of the primary goals of the BATRIES project was to conduct power flow simulations and modeling to better understand what the potential impacts of inadvertent export could be, if any, and to help provide states with greater guidance on how it should be evaluated based on those potential impacts. The research largely concluded that the potential impacts of inadvertent export were non-consequential for small projects. For larger projects, however, there may be some potential for voltage impacts depending on the size (nameplate rating), response time of the export control device, and the configuration of the circuit. Thus, the BATRIES team developed a new screen for use in the interconnection process to help determine when further evaluation of inadvertent export may be required in supplemental review or the study process. Again, similar to all of the interconnection screens, this proposed screen is designed to be conservative. Utilities should not interpret a project failing the inadvertent export screen as a definitive indication that

[14] *See* Toolkit, at 78-93.

[15] Inadvertent export events do not arise when using either the configured power rating or the relative DER rating options identified in IREC's redlines and discussed in Section II.B.

the 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 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 it is safe to assume that inadvertent export from acceptable export control systems will not cause voltage violations.[16] 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.[17] To ensure RVC is limited to no more than 3% in line with the standard, an estimate of voltage change can be made using the primary grid impedance values from the circuit model in addition to the DER nameplate apparent power rating and export capacity. This calculation gives a conservative estimate of the actual voltage change and thus can adequately screen for potential impacts from inadvertent export.

The BPU should adopt this new screen along with the other changes IREC recommends to the existing interconnection screens in Section II.D. Together, these changes will ensure that the potential impacts of export limited projects are accurately screened for, and not over- or under-estimated as would occur under the proposed rules.

D. The screens in the interconnection rules should clearly identify where export capacity or nameplate capacity will be used.

Once the interconnection rules have clearly defined acceptable means of export and what

[16] Note this is why this screen is also not needed for Level 1. Level 1 systems are sized such that they are well below the threshold where additional review may be necessary to rule out system impacts.

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

constitutes a project's nameplate and export capacity, the final critical element is to then apply these concepts in the screening and study process. Specifically, each of the interconnection screens should identify whether the potential impact it is screening for should be evaluated using export capacity, nameplate rating, or neither (in the case of screens that relate to system configuration or other factors not related to the amount of electric energy from the project). The proposed rules do not clearly delineate when export capacity, nameplate rating, or neither should be used in discrete segments of the review process.

The proposed rules provide that, for a resource to qualify for Level 1 review, it must have a "power rating of 25 kW or less, as measured in alternating current."[18] However, the proposed rules do not plainly specify whether the threshold is determined based on a resource's export capacity or nameplate capacity. The proposed rules should be amended to clarify that resources with a nameplate rating of 50kW are eligible for Level 1 review, as long as their export capacity is no greater than 25 kW. 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 impacts that could occur from the project's higher nameplate rating are those related to fault current. However, the fault current contribution from projects as small as 50 kW is likely to be insignificant. All inverter-based projects contribute very little fault current to the system relative to rotating machines, and projects below 50 kW are therefore very unlikely to meaningfully impact the amount of fault current on the distribution system.[19] Thus, it is reasonable to allow projects with up to 50 kW of nameplate capacity to proceed through Level 1 review so long as their total export capacity is below 25 kW. This approach will enable more

[18] Proposed Rules §§ 14:8-5.2(a)(1), 14:8-5.4(a)(2).

[19] Toolkit, at 60-61.

projects with energy storage to take advantage of the simplified process.

Similarly, the proposed rules do not modify the threshold for resources to be eligible for Level 2 review, which is simply defined as "two megawatts or less," (Proposed Rules § 14:8-5.2(a)(2)(i)), but does not delineate whether this threshold is calculated using export capacity or nameplate rating. Moreover, the rules' Level 2 threshold is out of step with the interconnection procedures recommended by IREC and the Federal Regulatory Energy Commission (FERC)[20], and adopted by numerous states[21]. Common practice is to delineate a threshold for Level 2 eligibility that varies based on line voltage and proximity to substations, as follows:

Line Voltage	**Level 2 Eligibility**	
	Regardless of location	**On ≥ 600-amp line and ≤ 2.5 miles from substation**
≤ 5 kV	< 1 MW	< 2 MW
5 kV – ≤ 15 kV	< 2 MW	< 3 MW
15 kV – ≤ 30 kV	< 3 MW	< 4 MW
30 kV – 69 kV	≤ 4 MW	≤ 5 MW

What this results in is a lower eligibility threshold of 1 MW for low voltage lines that ratchets up to 5 MW as the voltage of the line increases or distance from the substation decreases. This allows large, non-exporting systems to be processed efficiently, since their impacts will largely be limited to fault current—impacts which are already accounted for in the

[20] Interstate Renewable Energy Council, Inc., Model Interconnection Procedures at § III.B.2.a. (2019) ("IREC Model"), available at https://irecusa.org/resources/irec-model-interconnectionprocedures-2019/; FERC Order 2006 at ¶ 502, § 2.1 ("Standardization of Small Generator Interconnection Agreements and Procedures") (May 12, 2005).

[21] *See, e.g.,* Iowa Admin. Code, r. 199-45.7(2); Ill. Admin. Code tit. 83, pt. 466.80(b); Ohio Admin. Code, r. 4901:1-22-07(A); 4 Code of Colorado Regulations 723-3 § 3855(a).

screening process. A static size threshold of 2 MW will unnecessarily slow the review process for projects that do not have significant grid impacts. The interconnection rules' technical screens are robust enough to identify projects needing study; the rules do not also need to further restrict access through overly conservative eligibility limits. Size eligibility limits should simply be used to improve administration of the rules, not function as a safety or reliability limit. As with Level 1 review, the proposed rules should clearly state that export capacity is used to determine a project's eligibility for Level 2 review. Following from this, the Level 3 language should be modified to correspond to the changes above.

Looking to the screens themselves, each one that evaluates capacity must distinguish between export or nameplate capacity. First, the BPU proposes to update the penetration screen (i.e., where a resource is connected to a radial line section) for Level 1 (Proposed Rules § 14:8-5.4(e)) and Level 2 (*id.* § 14.8-5.5(f)) to provide that a resource's "aggregate capacity" is "reduced by any export limited capacity achieved through non-exporting technology." IREC strongly supports the BPU providing explicitly that a resource's export capacity is used in the penetration screen, but suggests the BPU amend the relevant sections to provide more clarity. Additionally, IREC strongly recommends the BPU amend the penetration screen to rely on minimum load, instead of peak load, as discussed at length in Section IV.B.

Second, the transformer rating screen (i.e., where a resource is connected to a single-phase shared secondary) for Level 1 (Proposed Rules § 14:8-5.4(f)) and Level 2 (*id.* § 14:8-5.5(i)) review provides that a resource may not exceed 30 kVA, but again fails to specify whether this is calculated using export capacity or nameplate rating. Because the transformer rating screen is designed to evaluate the potential for reverse power flow to cause impacts, only export past the point of common coupling is relevant to consider.[22] The proposed rules should therefore be amended to clarify that the threshold for this screen is determined using export capacity.

Finally, just like it is important to ensure the above two screens are evaluated by looking at the export capacity of the proposed and already connected DERs, it is also important to be clear that the screens that evaluate fault current must use nameplate capacity.[23] Typically export controls do not alter the transient behavior of DERs and thus the fault current contribution from DER sites is therefore an aggregate contribution of the individual DER nameplates. The short circuit interrupting capability screen (Level 2 screen (c)) and the fault current screen (Level 2 screen (e)) should both be revised to clearly use nameplate capacity instead of simply "generation capacity."

IV. The proposed levels of review lack detail and are significantly out of step with national best practices, which will likely lead to costly and unnecessary study unless revisions are made.

Although the proposed rules include several amendments that will improve the interconnection process, significant revisions are needed to clarify procedures in the review process and align New Jersey with national best practices. To improve the screening and study process, IREC recommends that the final rule include several significant revisions, discussed below.

A. The BPU should clarify that alternating current, not direct current, is used

[22] Toolkit, at 65-66.

[23] Toolkit, at 66. ("While the export control methods… may act to limit the steady state export from a site, they do not alter the transient behavior of the DER. During faults and other transient conditions, export controls are not typically fast enough to change the behavior of an export-controlled system. The fault current contribution from DER sites is therefore an aggregate contribution of the individual DERs. Thus, during the screening and study process, utilities must still evaluate the fault current contribution from export-controlled projects.")

when evaluating a resource's grid impacts.

In the proposed rules, the BPU clarified that a resource's capacity will be evaluated in alternating current.[24] IREC strongly supports this proposed amendment. Alternating current is a much more accurate metric for determining an inverter based resource's grid impacts than direct current. However, in the Level 2 interconnection review section (Proposed Rules § 14:8-5.5(a)(1)), the proposed rule states a resource's capacity is measured in direct current. IREC believes this is simply a mistake and requests the BPU amend the final rule to consistently state that a resource's capacity is measured in alternating current.

B. The BPU should update the penetration screens to use 100% of relevant minimum load to more accurately screen for potential impacts.

The proposed rules make two changes to the penetration screen used in Level 1 and Level 2 review: increasing the percentage of peak load a resource cannot exceed to qualify for expedited review, and specifying that export capacity should be used for this screen.[25] While IREC appreciates BPU amending the screen to account for export capacity, the screen remains widely out of step with the common practice across the country[26] to use 100% of minimum load,

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[24] Proposed Rules §§ 14:8-5.2(a).

[25] Proposed Rules §§ 14:8-5.4(e), 14:8-5.5(f).

[26] States and FERC started to transition to using 100% of minimum load over a decade ago in supplemental review. *See* Federal Energy Regulatory Commission, Dkt. RM13-2-000, *Small Generator Interconnection Agreements and Procedures*, Order No. 792, at 81-85 (November 22, 2013); CA Pub. Util. Com., Dkt. 11-09-011, Decision Adopting Settlement Agreement Revising Distribution level Interconnection Rules and Regulations – Electric Tariff Rule 21 and Granting Motions to Adopt the Utilities' Rule 21 Transition Plans, at 69 (Sep. 13, 2012); MA Dept. of Pub. Util., Dkt. 11-75, *Department Investigation on Distributed Generation Interconnection*, Order on the Model Interconnection Tariff, at Attachment A (May 4, 2015); NY Pub. Service Com., Standardized Interconnection Requirements and Application process for New Distribution Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems (revised February 2024). With a decade of experience with this, utilities have now recognized the value of this approach and many states are now adopting 100% of minimum load in the initial screens for Level 1 and 2 equivalent processes. *See, e.g.* Ill. Ill.
(footnote continued on next page)

instead of a percentage of peak load, to evaluate whether a resource passes the penetration screen. The incorporation of export capacity should also extend to the already connected DERs used in the aggregate calculation.

The purpose of the penetration screen is to ensure that the additional capacity does not cause the total capacity on a circuit to cause backfeed. While backfeed does not necessarily cause grid impacts, it is a useful proxy for when additional review of voltage or thermal impacts might arise and require further study. Negative grid impacts are avoided if the DER does not feed more power into the grid than the feeder's minimum load—that is, the time of lowest demand on the relevant line section. 100% of minimum load is thus the most accurate metric to use for a penetration screen. The use of a percentage of peak load instead is a relic of the late 1990s and early 2000s, when minimum load data was not widely available to utilities. Because minimum load data was not readily available at the time that the screen was developed, but peak load data was, the 15% of peak load screen was designed to function as a proxy for minimum load.[27] Utilities now generally have access to feeder minimum load and feeder peak load data via Supervisory Control and Data Acquisition (SCADA) systems; use of this less accurate proxy is no longer a best practice.[28]

To adequately account for the minimum load of all types of DERs, it is also important to incorporate the concept of "relevant" minimum load into interconnection procedures. Since

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Admin. Code tit. 83, pts. 466.90(a)(1), 466.100(a)(1); Or. Admin. Code §§ 860-082-0045(c), 860-082-0050(b); New Mex. Code R. §§ 17.9.568.15(B), 17.9.568.16(B); MN Pub. Util. Comm., Dkt. E-999/CI-16-521, Distributed Energy Resources Interconnection Process at § 3.2.1.2 (April 19, 2019).

[27] *See* M. Coddington, et al., *Updating Interconnection Screens for PV Systems Integration*, National Renewable Energy Laboratories (Feb. 2012), at 2, *available at* https://www.nrel.gov/docs/fy12osti/54063.pdf.

[28] *Id*. at 7.

stand-alone solar systems only generate electricity during the day, it is appropriate to use minimum daytime load when screening those systems (not absolute minimum which often occurs at night). However, solar paired with a battery and other types of DER that can generate beyond daylight hours should use the absolute minimum load. IREC therefore proposes the addition of the following definition:

> "Relevant minimum load" means the lowest measured circuit or substation load coincident with the DER's production. For solar photovoltaic DERs 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 systems utilizing tracking).

Adopting "relevant minimum load" also allows the rules to evolve as more technical capabilities, such as the scheduling of export, are recognized and utilized. For example, if in the future a project proposes to only export between 9 am and 9 pm, the minimum load for those hours would be used in application of the penetration screens.

In sum, the BPU should adopt 100% relevant minimum load as the metric for penetration screens used in Level 1 and Level 2 review, as well as in a defined supplemental review process, measured in export capacity, consistent with national best practices. The penetration screens are typically the most commonly failed screen and as proposed in the rules they are excessively conservative. Altering the screen to evaluate 100% of relevant minimum load will increase the ability of projects to undergo expedited review while maintaining safety and reliability.

C. The screen that evaluates effective grounding is out of date and should be updated to reflect current thinking on grounding review for inverter based systems.

The understanding of inverters' effect on ground fault overvoltage, as it relates to effective grounding, has been expanding in the last ten years.[29] The industry is still catching up to new information and concepts related to inverters that differ from the well-understood

[29] *See* Toolkit, at 132-35.

effective grounding rules for rotating machines, and New Jersey's existing rule does not make any distinction. Not only are the existing screens (NJAC § 14:8-5.5(g), (h)) out of date , but they are also imprecise in their wording, potentially leading to confusion. Similar wording has been improved in Illinois' interconnection rule. The following shows the changes New Jersey should make to the current screens to reflect this evolution:

> (g) If a customer-generator facility is to be connected to three-phase, three wire primary EDC distribution lines, a three-phase or single-phase generator shall ~~be connected~~use a phase-to-phase primary connection.
>
> (h) If a customer-generator facility is to be connected to three-phase, four wire primary EDC distribution lines, a three-phase or single phase generator shall ~~be connected~~use a grounded line-to-neutral primary connection~~and shall be effectively grounded~~.

This screen allows utilities to continue to maintain safety, reliability, and power quality by identifying generators that pose over-voltage concerns and mitigating them through a technical solution. At the same time, it avoids a full study when one is not needed. In some states this screen appears in a table format, while in other states it may appear in sentences/paragraph format as it does here. Several iterations of the screen exist around the country and attempts have been made to refine it considering the differences in over-voltage behavior between inverters and rotating machines, and the screen may evolve further. The proposed version of the screen is based off Illinois part 466.100 which omits considerations of effective grounding for rotating machines.[30] When adopting the screen in this format, the BPU should consider whether and how "effective grounding" should be specified for rotating machines, since the primary interconnection type is not the only determining factor for whether a rotating machine is effectively grounded. The important fact to note is that the term "effective grounding" as historically used to apply to rotating machines can be misinterpreted when applied to inverters.

[30] Ill. Admin. Code § 466.100(a).

For example, the phrase "rotating machines shall be effectively grounded" could be appended to the proposed text in screen (h), but this was not seen as necessary in Illinois. We propose an additional Supplemental Review grounding screen that can more accurately determine the grounding needs for rotating machines compared to inverter-based systems as discussed in Section IV. D. Oregon's interconnection rules adopt the Supplemental Review grounding screen, but take a table-based approach for initial review that is significantly more complicated than Illinois, but still make the appropriate distinction between inverters and rotating machines:

> Line Configuration Screen. Using Table 2 attached, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the project, including line configuration and the transformer connection to limit the potential for creating over-voltages on the interconnecting public utility's electric power system due to a loss of ground during the operating time of any anti-islanding function.[31]

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line Required To Pass Screen
Three-phase, three-wire	Interface connection transformer high side is phase-to-phase
Three-phase, four-wire	For single phase generation, the interface connection transformer high side is phase-to-neutral; For three-phase inverter-based generation, the interface connection transformer is (1) Yg-yg, or (2) Yg-delta with a relay on the transformer high side that can detect faults; or, For three-phase rotating generation, the small generator facility high side is connected phase-to-neutral and effectively grounded.
Three-phase, four-wire or mixed three-wire and four-wire	The public utility will extend the neutral wire to the point of interconnection and treat the small generator facility as an interconnection to a three-phase, four-wire system.

For further information on the differences between grounding needs of inverters and

[31] Or. Admin. Code § 860-082-0050(g).

rotating machines, see IEEE C62.92.6-2017 IEEE Guide for Application of Neutral Grounding in Electrical Utility Systems, Part VI—Systems Supplied by Current-Regulated Sources.

D. The BPU should adopt a supplemental review process with defined screens and transparent results that is automatically available to applicants.

The proposed rules are missing another widely used and valuable concept: supplemental review. The current rules provide the utilities the option of doing additional review, but do not require it. Nor do the rules define the process or expectations for that review.

A clearly defined supplemental review process that is automatically triggered when a project fails Level 2 review is a basic and widely used practice to avoid sending projects unnecessarily to lengthy and costly studies. By design, the initial review screens are conservative; many projects which fail the initial review screens can be safely connected without upgrades or a multi-month study process. A clearly defined supplemental review process—that is available automatically to projects that fail Level 2 review—provides utilities additional time (and compensation) to more closely evaluate whether a project requires further study. The definition of the process forces utilities to identify specific reasons for further study, rather than relying on undefined judgment calls.

A defined supplemental review process was first adopted in California in 2011; FERC subsequently adopted its analogous process in 2013, and since then, many states, including Arizona, Iowa, Illinois, Minnesota, and Ohio, have adopted a structured supplemental review process.[32] These procedures all include a defined set of standard screens, along with clear timelines and fees and/or deposits for the review. Those rules ensure that supplemental review is

[32] FERC Order No. 792, 145 FERC ¶ 61,159 (Nov. 22, 2013); IA Admin. Code, ch. 45.9(6) (Jan. 18, 2017); MN Distributed Energy Resources Interconnection Process § 3.4 (MN DIP) (April 19, 2019); AZ Admin. Code § R14-2-2620; IL Admin. Code, tit. 83, § 466.100(f); OH Admin. Code Chapter 4901:1-22-07(E) .

utilized appropriately by utilities, while also giving customers much-needed clarity concerning the steps, timeline, and expense of undergoing supplemental review. In state after state, IREC has seen this process increase the number of projects that can safely be interconnected without detailed studies.

Here, where a DER fails Level 2 review, the proposed rules require utilities to "offer to perform additional review" if "the initial review indicates that additional review may enable to EDC to determine that the" resource can be interconnected safely.[33] The proposed rules do not specify which party determines whether "initial review indicates that additional review may enable the EDC to determine" the resource can be interconnected safely. If the utilities have the discretion to make this determination, then developers functionally do not have an automatic right to supplemental review. The proposed rules should be amended to instead state explicitly that applicants have a right to proceed to supplemental review after failing Level 2 review.

The proposed rules also fail to define the precise manner in which utilities must conduct "additional review." If left as is, applicants who fail Level 2 review will not have sufficient information to determine whether to proceed with "additional review" or go straight to study. Additionally, applicants have no assurance that utilities will apply "additional review" in a way that prevents unnecessary study. To remedy this, IREC proposes the BPU adopt the following standard screens for supplemental review derived from IREC's Model Rules:[34]

> Minimum load screen[35]: Where twelve (12) months of line section minimum load data (including onsite load but not station service load served by the proposed DER) are

[33] Proposed Rules § 14:8-5.5(o)(3).

[34] In the enclosed redline, the capitalization and numbering format have been changed to reflect the format of the New Jersey Rules which are slightly different than those used in IREC's Model Rules. The section references will need to be updated when the final rule is adopted.

[35] The minimum load screen IREC proposes as a component of supplemental review relies on more defined data than the minimum load metric IREC proposes to be used for the penetration screen.

available, can be calculated, estimated from existing data, or determined from a power flow model, the DER's export capacity aggregated with all other generation capable of exporting energy on the line section is less than one hundred percent (100%) of the relevant minimum load for all Line Sections bounded by automatic sectionalizing devices upstream of the proposed DER. If the minimum load data are not available, or cannot be calculated or estimated, the DER's export capacity aggregated with all other generation capable of exporting energy on the line section is less than 30 percent of the peak load for all line sections bounded by automatic sectionalizing devices upstream of the proposed DER.

i. Load that is co-located with load-following, non-exporting or export-limited generation should be appropriately accounted for.

ii. The EDC will not consider as part of the aggregate export capacity for purposes of this screen DER export capacity, including combined heat and power (CHP) facility capacity, known to be already reflected in the minimum load data.

b. Voltage and power quality screen. If the DER limits export pursuant to Section [reference the section IREC proposed to define acceptable export controls], the export capacity instead of nameplate rating must be utilized in any analysis done for this screen, including power flow simulations. 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 Std 1547; and

iii. The harmonic levels meet IEEE Std 1547 limits at the reference point of applicability.

c. Supplemental grounding screen. If the DER failed the line configuration screen (Section [insert reference to screens g and h in the current rules, as amended by IREC):

i. For DERs with a rotating machine, effective grounding must be maintained.

ii. For DERs with a three-phase inverter, the utility shall apply one of the following screens to evaluate whether the DER is effectively grounded:

> (a) The line-to-neutral connected load on the feeder or line section is greater than thirty-three percent (33%) of peak load on the feeder or line section.
>
> (b) If using a supplemental grounding software tool:
>
>> (1) The tool determines that supplemental grounding is not required to maintain effective grounding.
>>
>> (2) If the tool determines that supplemental grounding is required, the applicant must agree to modify the DER to include supplemental

grounding.

(c) If using a detailed hosting capacity analysis that incorporates evaluation of temporary overvoltage risk for inverters, the nameplate rating of the DER is below the available hosting capacity at the point of common coupling.

d. Safety and reliability screen. The location of the proposed DER and the aggregate export capacity on the line section do not create impacts to safety or reliability that cannot be adequately addressed without detailed study review. If the DER limits export pursuant to Section [insert reference to the section IREC proposed adding to define acceptable export controls], the export capacity must be included in any analysis including power flow simulations, except when assessing fault current contribution. To assess fault current contribution, use the rated fault current; for example, the applicant may provide manufacturer test data (pursuant to the fault current test described in IEEE Std 1547.1-2020 clause 5.18) showing that the fault current is independent of the nameplate rating. The EDC shall give due consideration to 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 (i.e., several large commercial customers).

ii. Whether there is an even or uneven distribution of loading along the feeder.

iii. Whether the proposed DER is located in close proximity to the substation (i.e., < 2.5 electrical circuit miles), and whether the distribution line from the substation to the Point of common coupling is composed of large conductor/feeder section (i.e., 600A class cable).

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

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

vi. Whether the proposed DER utilizes certified anti-islanding functions and equipment.

IREC further recommends that the Commission adopt a $2,500 fixed fee for conducting supplemental review. The interconnection rules solely require utilities to provide a "good faith estimate of the cost of [] additional review."[36] The process of estimating and doing the back and forth associated with it is not needed for supplemental review and $2,500 is a widely accepted

[36] Proposed Rule § 14:8-5.5(o)(3)(i).

cost. A fixed fee will give applicants who fail Level 2 review vital information to determine whether supplemental review is worth the cost, or whether it would be more efficient to go straight to study. It will also prevent utilities from requiring unreasonable costs for conducting supplemental review.

V. The BPU should amend the Level 3 review process to provide more clarity to applicants and utilities.

IREC generally supports the BPU's proposed changes to the Level 3 review, which, among other changes, add concrete timelines for the preparation of System Impact Studies and Facilities studies. However, the Level 3 review process delineated in the proposed rules is quite confusing and difficult to follow. IREC suggests the BPU re-organize the section sequentially in a manner that mirrors the actual review process. In addition, IREC recommends the BPU make specific changes to the Level 3 review section to provide more certainty to utilities and applicants, and effectively streamline the review process.

A. Utilities should be required to finish completeness review within 10 business day of receiving an application for Level 3 review.

The proposed rules include a section (Proposed Rules § 14:8-5.6(b)) requiring utilities to notify applicants whether an application for Level 3 review is complete or incomplete within 15 business days of receiving the application. Allowing 15 business days for simple completeness review is unreasonable. The BPU should amend the rules to require utilities to finish completeness review within 10 business days.

B. Applicants should not be required to pay a fixed fee in addition to actual study costs.

The proposed rules include a section requiring applicants seeking Level 3 review to pay an application fee of up to $2,000, in addition to actual time spent by the utility on studies and facilities (Proposed Rules § 14:8-5.6(j)). However, the proposed rules also contain a conflicting provision in § 14:8-5.7(c) which includes no maximum fee and would result in application fees of $10,000 or more. It does not appear that either provision needs to exist. Preferably, the proposed rules would be amended to solely require applicants to pay actual costs, but not an additional fee. In lieu of an application fee, applicants can be required to pay a deposit for each study phase that is credited toward the applicant's obligation to pay actual costs, with reconciliation above or below when the process is complete. However, if the BPU intends to keep one of the existing, conflicting provisions, the BPU should adopt the provision limiting the application fee to $2,000.

C. The proposed rules should identify precisely how utilities must break out individual components of an itemized quote for necessary facilities.

Upon the completion of a facilities study, the proposed rules require utilities to provide an interconnection agreement that includes "an itemized quote, including overheads, for any required electrical power system modifications" (Proposed Rules § 14:8-5.6(e)). To provide greater clarity, IREC suggests the proposed rules use a more specific description of how the cost estimate shall be itemized. The rules should be amended to require utilities to provide "an itemized quote, <u>breaking out equipment, labor, operation and maintenance, and other costs, including overheads</u>, for any required electrical power system modifications or interconnection facilities."

D. The 50% cost envelope for transmission upgrades included in the proposed rules should be reduced.

IREC strongly supports the adoption of a cost envelope that limits the amount an applicant is required to pay for cost upgrades to a specified amount above the estimate provided by the utility. However, IREC opposes the proposed rules' inclusion of a 50% threshold for the cost envelope (Proposed Rules § 14:8-5.6(q)), which is widely out of step with the cost envelopes adopted by other states.[37] IREC recommends the BPU amend the proposed rules to include a maximum limit of 30% above the cost estimate provided by the utility. In addition, the rules should specify that the utility shareholders, not the ratepayers, are responsible for any costs over the cap. It is important to incentivize utilities to improve the accuracy of their estimations. Finally, we recommend that the reporting requirements track the estimates and final costs closely to ensure that the adoption of the cost envelope does not result in inflated estimates.

VI. The BPU should add additional detail to the hosting capacity analysis requirements to ensure the modeling effort produces meaningful results.

The proposed rules require the utilities to submit a tariff filing to implement a common Hosting Capacity Analysis (HCA) mapping process. Adoption of HCA requirements is one of the major advancements of these proposed rules and IREC is strongly supportive of the direction the rule is heading in. IREC has extensive experience with HCA development and utilization and has published multiple reports that lay out important considerations to ensure HCAs are actually functional.[38] In line with those considerations, there are some specific flaws in the current requirements that, if not fixed, are likely to make the HCAs of very limited value to customers. It is vital that the BPU ensure that the actual HCA results are useful if it is going to require the utilities to invest the time and resources in the modeling effort.

A. For HCA results to provide meaningful information for siting of projects, they must be published at the nodal, not circuit or substation, level.

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[37] *See, e.g.,* Pacific Gas & Electric, Electric Rule No. at 20 (May 2, 2024) (25% cost envelope adopted in CA); Massachusetts Electric Company, *Standards for Interconnection of Distributed Generation*, at 27 (25% cost envelope adopted in MA).

[38] IREC & National Renewable Energy Laboratory, *Data Validation for Hosting Capacity Analysis* (April 14, 2022), https://irecusa.org/resources/hosting-capacity-analysis-data-validation/; IREC, *Key Decisions for Hosting Capacity Analyses* (Se. 16, 2021), https://irecusa.org/resources/key-decisions-for-hosting-capacity-analyses/; IREC, *Optimizing the Grid: A Regulators Guide to Hosting Capacity Analyses for Distributed Energy Resources* (Dec. 2017), https://irecusa.org/wp-content/uploads/2021/07/IREC-Optimizing-the-Grid-2017-1.pdf.

The most significant flaw in the proposed HCA rules is that utilities are not required to model the HCA, and provide results, at the nodal or line section level.[39] Proposed Rules section 14:8-5.11(b) requires the utilities to post maps that "include both circuit and substation level data in the maps." Hosting capacity can vary by multiple MWs on a single circuit depending on where the DER is interconnected. What this means is that, by only requiring results at the circuit and substation level, they will be published using a range (i.e., a minimum and maximum HCA value). This range can be so vast as to essentially render the results meaningless for anything above the minimum value. For example, Xcel Energy in Colorado publishes an HCA and has a downloadable report that provides the HCA values for each feeder. One can see that it is common for the minimum HCA for the feeder to be at or near 0 kW, while the maximum is 10 MW.[40] A developer can make little, if any, use of this information. Thus, the rules should be revised to require that the utilities utilize an HCA methodology/software that is capable of modeling the results at the nodal level. Utilities should be required to display the results on the map at the nodal level, and make those results available for download. This will enable potential applicants to select the exact site they are evaluating and see what the hosting capacity is at that point. Such requirements will provide vital information to applicants. Utilities can comply with these requirement by using off-the-shelf software available today.

B. HCA results should be published for each limiting criteria.

The proposed rules require the utilities to identify the "recommended and maximum" amount of export capacity that can be accommodated "without violating any reliability criteria,

[39] The terms line section and node are often used interchangeably in this context.

[40] The Xcel map can be located here: https://co.my.xcelenergy.com/s/renewable/developers/interconnection/hosting-capacity-map (in the pop-up box for feeders the user can see the Minimum (MW) and Maximum (MW) HCA and also the Min Limiting Factor and the Max Limiting Factor).

including, but not limited to, thermal, steady-state voltage, voltage fluctuation, and voltage protection criteria."[41] However, the rules do not require that the results be published in a manner that identifies the limitations for each of those criteria. Again, providing results at this more granular level is considerably more informative because it indicates to a customer what type of upgrade may be necessary, and its possible expense. For example, if the primary limiting criteria is thermal, the customer will know that the cost to upgrade the circuit is likely to be very significant. On the other hand, if the limitation is for a violation of a voltage criteria, there is a possibility of mitigating impacts through the use of smart inverter capabilities; the costs of a distribution upgrade to resolve voltage concerns are likely to be relatively low. Thus, the rules should require the utilities to publish the HCA limit for each of the technical criteria evaluated. They should not only identify what the most limiting criteria is, but also show the specific limit for each of the criteria (e.g. 3 MW thermal, 2.7 MW for steady state voltage, 5 MW for protection, etc.). To adequately identify the limitations as required by the proposed rules, the utilities must have this capability in their models. Requiring them to publish the full results will not be considerably more onerous.

C. To enable future scheduling of DERs and to illustrate how constraints change on a monthly and hourly basis, the HCA should be run, and results provided, on at least a 288 hour basis for both load and generation.

Another crucial gap in the current requirements is that the proposed rules do not specify the temporal granularity of the model or published results. Hosting capacity varies substantially throughout the day and year. For DERs to effectively respond to this variability, by exporting more power during periods of high demand and avoiding exporting during periods with low demand, the HCA results should be run and published on at least a 288 hour basis for both load

[41] Proposed Rules § 14:8-5.11(c)(2).

and generation. In other words, the utilities should be required to model 24 hours for each of the 12 months, once for the minimum load hours (for generation) and once for the peak load hours (for load). While this level of granularity cannot easily be shown on the map, the results should be available for download in a .csv file or other format (and ideally available through the use of an Application Programming Interface, or API).

Publishing results for both load and generation is also key to enabling the state to facilitate the use of scheduled DERs, a direction that the state will certainly want to head to fully capture the benefits of energy storage and to avoid the need for unnecessary grid upgrades. The proposed rules do not clearly specify whether utilities are required to publish HCA results for both load and generation. In light of the state's policies on electrification and the fact that energy storage systems that charge from the grid will also need to know the ability for the grid to host additional load as well as generation, the BPU should require that the utilities publish results for both load and generation.

D. The HCA results should be updated at least on a monthly, not quarterly, basis.

The proposed rules should also increase the frequency with which the HCAs are required to be updated. Currently, the proposed rules require the HCA to be updated on a quarterly basis.[42] In an active DER market such as New Jersey, the hosting capacity of certain feeders is likely to change much more frequently than once a quarter. Thus, IREC recommends the data be updated at least once a month, with a goal of increasing the frequency over time. Importantly, this does not mean that the utility has to run the entire distribution system through the model each month. Rather, the utilities should develop a system to identify which feeders and substations have had changes in the previous month (namely, feeders with newly submitted interconnection

[42] Proposed Rules § 14:8-5.11(b).

applications, known changes to load, or distribution system changes) and run only those feeders that have changed each month. The maps should also show when the data was last updated so the potential customer knows how current they are. Failure to require monthly updates will seriously reduce the effectiveness of the proposed HCA rules. An outdated HCA is the same as an inaccurate HCA.

E. The BPU should carefully evaluate any claims that HCA data cannot be published for physical or cybersecurity reasons.

Proposed Rules section 14:8:5.11(c) requires that the HCA results be integrated with a GIS system that will present the data on a map. However, the rules contain a significant caveat proposed by the utilities, that requires this to be done only to the "greatest extent permitted pursuant to the North American Electric Reliability Council standards, applicable Federal and State laws, rules, and regulations, and internal EDC physical and cybersecurity policies." While protecting grid assets from physical and cyber attacks is critical, this language is overly broad and places too much discretion in the hands of the utilities to interpret the laws and adopt policies that may unnecessarily hinder grid transparency. To the extent the utilities want to limit publication of HCA data, they should be required to identify the specific concern, supporting law or policies, and explain in detail why publication of the data would result in a risk. IREC has participated in multiple proceedings on HCAs where these concerns are raised vaguely without sufficient support or analysis. HCA data should be air-gapped from a utilities system and thus unlikely to raise cybersecurity issues. IREC has yet to see a utility identify a specific state or federal law, including FERC and NERC standards, that prevents publication of HCA results or display of those results on a map.

VII. The proposed rules need additional refinements to appropriately incorporate the use of the latest standards, including IEEE 1547-2018 and the associated UL testing standards for inverters.

While the proposed rules incorporate IEEE 1547-2018 by reference, the BPU should take further steps to ensure that the standard is fully adopted in a structured manner. IEEE 1547-2018 certified devices come with smart features and functions, offering: voltage regulation, voltage and frequency ride-through, ramp rate control, ability to respond autonomously to set points, ability to respond to communication signals, and more. Additionally, certified devices can have certain functions activated or deactivated depending on grid needs. In general, though, IEEE 1547-2018 specifies technical capabilities, but it is silent on utilization. It is up to the BPU to determine appropriate utilization with input from utilities and stakeholders.

IEEE 1547-2018 indicates that selecting performance categories is the BPU's responsibility,[43] and is something that needs to be established quickly because many smart inverter capabilities are dependent on it. By not specifying the performance categories, the proposed rules skip a fundamental step towards 1547-2018 adoption. The normal operating performance category, designated within IEEE 1547-2018 as category A (Cat A) or category B (Cat B), is used for voltage regulation and reactive power requirements. Cat A sets a minimum performance capability that is easily met by any DERs (including rotating and inverter-based) and is deemed adequate for low penetration. Cat B sets a higher performance capability that can only be met by some DER types (such as inverter-based) and is preferred for high penetration markets.[44] Notably, DER types certified to Cat B can meet Cat A requirements, but not vice versa. It is important to understand that Cat B DERs have all the voltage regulation functions using reactive power (such as constant power factor, volt-var, watt-var, constant var) and voltage

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[43] Per 1547-2018, the authority governing interconnection requirements (AGIR) is the entity tasked with making this selection.

[44] Annex B of IEEE 1547-2018 provides guidance to the AGIR regarding the assignment of performance categories.

regulation by active power (volt-watt), but Cat A DERs are not required to have watt-var or volt-watt. The rule should be explicit on what is required for the categories.

Similarly, abnormal performance categories must also be selected. Such categories, designated in 1547-2018 with Cat I, Cat II or Cat III, are used for ride-through disturbances and reliability needs. Here, Cat I provides the lowest level of disturbance ride-through, and Cat II and Cat III provide the medium and highest levels, respectively. Notably, inverter-based DERs can meet any of the abnormal performance categories, while rotating DERs can generally only meet Cat I.

In light of these considerations, IREC recommends that the BPU adopt a more concrete framework for 1547-2018 adoption to ensure the state realizes the full potential of smart inverter capabilities. The BPU should take the following steps in the rules to ensure this outcome.[45]

A. The BPU must establish category assignment.

As explained above, category assignment (normal Cat A or Cat B and abnormal Cat I, Cat II, Cat III) should be completed by the BPU upfront. IREC recommends such assignment be specified in the interconnection rules, while details on functional settings can be included in a Technical Interconnection and Interoperability Requirements (TIIR) document after discussion in a working group, such as the Grid Modernization Forum. Assignment of both categories is essential to providing clear guidance to manufacturers and developers operating in New Jersey. Currently, the proposed rules are silent on normal and abnormal category assignments. The rule should state that IEEE 1547-2018/UL 1741 SB compliance is required and identify which categories are expected of inverter based DERs and rotating DERs. Please note

[45] Further guidance is provided by IREC's Decision Options Matrix for IEEE 1547-2018 Adoption, https://irecusa.org/resources/decision-options-matrix-for-ieee-1547-2018-adoption-3/

that while UL 1741 Supplement SB does confirm that the inverter has been tested to the requirements of IEEE 1547-2018, Supplement SA does not, and thus reference to SA should be struck.

Interconnection rules should guide the selection of "normal category A (Cat A)" or "normal category B (Cat B)." By specifying what is expected of inverters vs. rotating machines in terms of normal category assignment, the rules would set a clear and transparent expectation for manufacturers and developers. IREC's view is that most inverter manufactures have certified to Cat B, because such DER types are not limited to Cat A capabilities. As such, the rule should make it clear that Cat B is required for inverter based DERs.

The rule should also explicitly state how Cat I, Cat II, or Cat III apply to various DER types. Per the standard, it is up to the BPU to assign abnormal performance categories. Without such assignment, manufacturers cannot determine which ride-through capability they must certify their device to. IREC's view is that most inverter manufacturers have certified to Cat III, because such DER types are not limited to Cat I or Cat II capabilities (compared to rotating DERs).

PJM has issued guidance on the selection of categories in its *PJM Guideline for Ride Through Performance of Distribution-Connected Generators*.[46] The transmission operator states that DERs "should have the capability to ride through abnormal frequency and voltage events according to either Category II or Category III of IEEE Std 1547™-2018, as specified by the electric distribution company, except that generators using technology types that are generally incapable of meeting Category II or Category III performance should instead meet the ride

[46] PJM, *PJM Guideline for Ride Through Performance of Distribution-Connected Generators* (2019), https://www.pjm.com/-/media/planning/plan-standards/pjm-guideline-for-ride-through-performance.ashx.

through requirements specified by the electric distribution company."[47] The document also provides suggested voltage and frequency trip limits which could be specified in a TIIR.[48]

B. The BPU must establish a process for adoption of default inverter settings.

While establishment of the normal and abnormal categories sets the minimum capability requirements for different technologies, implementation is still left open. To gain the most benefits from smart inverters and DERs, voltage regulation and appropriate settings need to be deployed. If voltage regulation is not implemented for all DER systems, its effectiveness at regulating voltage and thus potentially increasing DER hosting capacity is reduced. If voltage regulation is turned on for future DER installations when distribution circuits are already at high penetration, those installations will not be able to correct for the voltage effects of all previously-installed systems. Thus, it is critically important that the BPU direct the implementation of voltage regulation and other DER settings to ensure New Jersey can reach its DER deployment goals. To ensure this goal is achieved, the following steps are encouraged:

1) Establish a stakeholder working group to engage in implementation discussions, made up of, but not limited to, BPU staff, EDCs, DER developers, DER advocates, consumer advocates, 1547 standard experts, and technical experts.

2) Plan a schedule for addressing all 1547 settings topics within the working group, including, but not limited to, those described in the proposed rule language in the following section.

3) Engage the working group to discuss the conceptual topics and decision points,

[47] *Id*. at 2.

[48] *Id*. at 3.

with the goal of gaining consensus on how decisions will be addressed by the formal guidance document.

4) Determine the suitable location for the formal guidance, such as a Technical Interconnection and Interoperability Requirements document as well as a companion spreadsheet in EPRI's Common File Format[49].

5) Identify and engage a writing group to formalize conceptual agreement and decision points within the draft guidance document(s).

6) Distribute the draft guidance document(s) to the working group for one or more rounds of comment and revision.

7) Shepherd the guidance document(s) through any necessary regulatory process for final inclusion in the document.

C. The BPU should include interconnection rule language guiding IEEE 1547-2018 adoption.

The rules should provide simple, accurate, and direct guidance on 1547-2018 adoption to avoid any confusion in the industry. IREC recommends that the BPU include three simple specifications in the rule: (1) the implementation date and transition period should be clearly communicated, (2) the normal performance category should be specified, and (3) the abnormal performance category should be indicated based on the DER type. By specifying these three capabilities, the rule would coherently communicate requirements and set expectations that can be built upon in the working group scope. Below is proposed language that can be inserted into the rule:

> 1. Beginning on [insert effective date] DERs shall be required to comply with IEEE Std 1547-2018, and shall conform with the following minimum requirements:

[49] *Common File Format for DER Settings Exchange and Storage, Version 2.0*, Electric Power Research Institute (September 2022)

a. Abnormal operating performance category: Inverter-based DERs shall meet Category III capabilities and rotating DERs shall meet Category I capabilities.
b. Normal operating performance category: Inverter-based DERs shall meet Category B capabilities and rotating DERs shall meet Category A capabilities.

Inverter-based interconnection equipment may be certified to UL 1741 Third Edition, Supplement SB in order to demonstrate compliance with IEEE Std 1541-2018. Equipment that is not certified to Supplement SB may require additional evaluation and commissioning testing to confirm compliance with IEEE Std 1547-2018.

2. The above assignment of categories is expected to cover the vast majority of interconnections. Any instances that do not fall within the above assignment shall be:
a. Reviewed on a case-by-case basis, with the EDC making the determination for requiring the specific category; or
b. Specified in the EDC's TIIR.
The EDC should consider Annex B of IEEE Std 1547-2018 when making these determinations on a case-by-case basis or in a TIIR.

3. Each EDC shall post its preferred settings in its TIIR. As applicable the following shall be identified in the TIIR:
a. Voltage and frequency trip settings;
b. Frequency droop settings;
c. Activated reactive power control function and settings;
d. Voltage-active power mode activation and settings;
e. Enter service settings; and
f. Communication protocols and ports requirements.

4. TIIRs shall be created through a technical advisory group process and submitted to the BPU for approval with opportunity for public comment. Subsequent changes to TIIRs shall also be submitted to the BPU for approval with opportunity for public comment.

D. The BPU should maintain authority over technical interconnection requirements.

Utilities generally post additional technical interconnection requirements in a document that is not overseen by the BPU, sometimes referred to as an interconnection handbook, "blue book," or technical service manual. These extraneous requirements can have significant impact on the financial viability of DER systems, and could potentially limit DER deployment if overly-conservative or arbitrary requirements are set in place that usurp the technical evaluations in the interconnection rules. For example, ACE's Criteria Limits for Distributed Energy Resource

Connections[50] only allow a maximum of 3 MW of DER sized over 250 kW on a 12-12.8 kV circuit, regardless of whether or not a Level 2 system passes the initial review screens or any other review. While the TIIRs recommended above should at minimum contain the information needed to fully implement IEEE 1547-2018, IREC recommends that all relevant utility technical requirements be housed in the same document and receive BPU oversight. It would be worthwhile for the BPU to convene a yearly workshop on the TIIR to review the existing requirements and determine if any updates are needed based on field experience to date with the settings and other requirements.

E. The BPU should remove any limitations of applicability at the 10 MVA size threshold.

We note that in IEEE 1547-2018 there is no longer a limitation of applicability to DER sized 10 MVA or less, as there was in IEEE 1547-2003. Therefore, requirements of the interconnection rules can apply equally to DER sized over 10 MVA.

F. The BPU should remove any references to "smart inverters."

Finally, in a couple instances, the term "smart inverter" is used in the proposed rule, though it is never defined. There does not appear to be an express need to utilize the term, since the certification requirements define the requirements on inverters and other DER. In general, a DER (inverter or otherwise) that complies with IEEE 1547-2018 could be deemed "smart," and reference to the standard is sufficient to establish the necessary capabilities.

G. The rules should adopt the Reference Point of Applicability (RPA) concept and incorporate a process for identification of the RPA in the rules.

The proposed rules should be amended to require utilities and applicants to agree to a

[50] Criteria Limits for Distributed Energy Resource Connections to the ACE, DPL, and Pepco Distribution Systems (less than 69kV) Rev 10/18/2023, https://azure-na-assets.contentstack.com/v3/assets/bltbb7c204688a1a6a8/blt7c4c6f1e1fe1121d/658dc269e77a32000a55b6db/TIR_Summary_as_of_10-18-23_Rev._4.pdf.

Reference Point of Applicability (RPA) early in the screening process.[51] IEEE 1547 defines an RPA so that it is clear at what physical point in the configuration of the system, the requirements of the standard need to be met for testing, evaluation, and commissioning. The RPA location can be at the point of common coupling, point of DER connection, or a point between those two. There could also be multiple RPAs for different DER units or different requirements. It is crucial that the utility and developer agree on the location of the RPA as early as possible to determine the DER system design, equipment, and certification needs. IREC recommends supplementing the interconnection rules with a defined RPA review process for each of the interconnection review levels. IREC proposes revisions in the enclosed redline to demonstrate how to integrate the RPA review into the existing Level 1 to 3 procedures in a relatively seamless manner. The basic process is also described below.

The process for identifying RPA for each system should be integrated with the review process such that it does not unnecessarily add additional time to the evaluation process. This is best done by having the utility review the RPA concurrently with the timeline for the evaluation of the screens in Level 1 and 2. Thus, after the application is deemed complete, the utility should review whether the RPA denoted in the application is appropriate. If the RPA is not appropriate, the utility should notify the applicant within 5 business days and provide the applicant 5 business days to provide a corrected application. This time period should run concurrently with the time provided for the utility to evaluate the project under the Level 1 or 2 screens. For Level 1, the utility may need to be provided with an additional 2 days for application of the screen *if* the RPA had to be amended.

For the Level 3 study process, the RPA can be evaluated after the application is deemed

[51] *See* Toolkit, at 22-23.

complete and can be discussed in the scoping meeting. If inappropriate, the utility should specify why and require the application to be updated within 10 business days to include the revised RPA. This can be completed before the study begins within the existing timelines in the proposed rules.

VIII. The proposed rules should eliminate problematic language that provides the utilities too much discretion to require additional controls or utilize overly conservative technical thresholds.

In Proposed Rules section 14:8-5.2, utilities are granted the authority to require a DER to "install additional controls or external disconnect switches not included in the interconnection equipment, to perform or pay for additional tests, or to purchase additional liability insurance" at the utility's discretion when required to maintain the safety, power quality, or reliability of the EDC's EPS. This language is fraught with the potential to introduce excessively conservative requirements and potentially untenable costs. For instance, a utility could require Direct Transfer Trip (DTT) for systems of a certain size regardless of whether the interconnection evaluation determines that islanding is a possibility. In fact, ACE today requires DTT, an incredibly expensive islanding mitigation, for systems above 750 kW regardless of whether or not they present significant risk of islanding. Despite many utilities across the US moving away from requiring DTT except in corner cases where some risk of islanding is identified, and despite growing literature and field experience that islanding is an extremely rare occurrence with likely low risk, ACE considers DTT required to maintain safety and reliability.[52] An interconnection

[52] *See, e.g.,* The Joint Utilities of New York, *Unintentional Islanding Protection Practice for Generation Connected to the Distribution System*, at 2 (Feb. 9, 2017), https://dps.ny.gov/system/files/documents/2022/11/islanding-risk-requirements-2-09-2017.pdf; Massachusetts Technical Standards Review Group, *Common Technical Standards Manual*, at 5-10 (Dec. 22, 2022), https://www.mass.gov/doc/tsrg-common-guideline-2022-12-22/download; Commonwealth Edison, *DER Interconnection Guidelines for Customers – Interconnection for Parallel Generation*, at 11 (July 20, 2018),
(footnote continued on next page)

customer cannot be sure that a utility will not determine that arbitrary additional controls or other requirements are necessary to maintain safety and reliability, thus decreasing transparency in the interconnection process and increasing risk for interconnection customers. If utilities believe the interconnection rules do not provide for safe and reliable interconnection, then they should propose specific revisions to screens or evaluations where they believe they fall short. However, given the long history of interconnection with similar screening processes, there is no reason to believe that the screens cannot provide adequate assurance of safety and reliability.

IREC has similar concerns about the language proposed in Proposed Rules section 14:8-5.5 which would allow the utility to utilize the results of a "power flow analysis" to determine whether a project "poses no adverse impacts to the EPS," instead of relying on the screen results. IREC does not oppose utilities utilizing power flow models in place of screens if they are able to do so in the expedited timeframes of the Level 2 process. In fact, this may have significant benefits and can move away from relying on screening heuristics. Utilization of hosting capacity analysis results might be one example of this. However, IREC is concerned that the thresholds used to determine impacts in the power flow analysis must not be more conservative than those that would be used in the screens. In other words, the utilities should not be able to require projects to go to a Level 3 study if a power flow model is used that has unreasonably, or unvetted, thresholds for determining impacts. This would be an appropriate topic to discuss in the forthcoming grid modernization working groups.

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https://www.comed.com/SiteCollectionDocuments/MyAccount/MyService/DER_Interconnection_Guidelines_for_Customers.pdf; Pacific Gas & Electric, *Distributed Generation Protection Requirements*, at 1 (Feb. 15, 2023), https://www.pge.com/content/dam/pge/docs/about/doing-business-with-pge/094681.pdf; VA State Corp. Com., Case No. PUR-2023-00097, Petition of Virginia Distributed Solar Alliance for Injunctive Relief against Virginia Electric and Power Company (June 28, 2023) (see Exhibit B for discussion of research literature and island screening practices).

IX. The proposed rules should be amended to provide further clarity and certainty to applicants and utilities.

In addition to the changes IREC recommends the BPU make to the proposed rules, IREC suggests the BPU consider adopting the following concepts now or in the very near future:

- The proposed rule should specify precisely what information utilities must include in public interconnection queues (Proposed Rules § 14:8-5.9(a)), including queue number, nameplate rating, export capacity, and each category delineated in IREC's Model Interconnection Rules. The full list of fields is included in IREC's redline.
- Utilities should be required to include detailed cost data in quarterly reports (Proposed Rules § 14:8-5.9(c)), including study costs, facility upgrade costs, and data showing how often actual costs exceed utility estimates and by how much.
- Replace the "reasonable efforts" standard utilized in Proposed Rules section 14:8-5.2(p) with binding requirements for adherence to the timelines in the rules. The BPU should adopt a framework to hold utilities accountable for compliance with the timelines. FERC recently made this change, noting that the reasonable efforts standard "does not provide adequate incentive for transmission providers to complete interconnection studies on time" and instead adopting a penalty structure that "reasonably incentivizes transmission providers to ensure the timely processing of interconnection requests."[53]
- The rules should define a timeline for customers to remedy deficiencies in the application if the utility determines it is incomplete. In addition, the BPU may want to consider establishing a clear statement about how queue positions are established and

[53] FERC Order 2023, 184 FERC ¶ 61,054 at ¶ 966 (July 28, 2023).

maintained. Typically a customer does not obtain a queue position until the application is deemed complete.

- On a related note, currently if a customer fails Level 1 or Level 2, the rules require the applicant to resubmit the application under the next review level.[54] Instead, the rules should allow customers to "roll" into the next available study process if they submit the necessary fee for that level. This allows applicants to avoid needing to go through completeness review again and to maintain their queue position.
- IREC recommends, as shown in the enclosed redline, that the language in the proposed rules specifying the information to be provided in the PAVE report be made consistent with other recommended changes to reflect the differences between nameplate capacity and export capacity. Requiring the utilities to provide information about both the aggregate nameplate and the aggregate export capacity already connected will make the results more meaningful.

X. Conclusion

IREC thanks the BPU for consideration of these comments. IREC appreciates that a lot of work has gone into developing the proposed changes and recognizes that the scope of changes proposed here may come as a surprise. Nonetheless, it is vital for New Jersey to ensure the changes to the interconnection rule are clear, represent current technical capabilities and understanding, and are designed to facilitate safe, reliable and efficient interconnection of the clean energy resources the state needs. If the BPU does not commit to a more thorough revision, New Jersey's interconnection rules will remain deeply out of step with national best practices and unnecessarily increase costs and limit the state's ability to meet its clean energy goals.

[54] Proposed Rules §§ 14:8-5.4(p), 14:8.5-5(o)(4)(ii).

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Attachment A

SUBCHAPTER 4. NET METERING FOR CLASS I RENEWABLE ENERGY SYSTEMS

14:8-4.2 Net metering definitions

The following words and terms, when used in this subchapter, shall have the following meanings, unless the context clearly indicates otherwise. Additional definitions that apply to this subchapter can be found at N.J.A.C. 14:3-1.1 and 14:8-1.2.

. . .

"Community solar facility" shall have the same meaning as set forth at N.J.A.C. 14:8-9.2.

"Community solar project" shall have the same meaning as set forth at N.J.A.C. 14:8-9.2.

"Customer-generator" means an electricity customer that generates electricity on the customer's side of the meter[,] using **one or more** class I renewable energy source**s and/or stores energy on the customer's side of the meter using an energy storage device. An electricity customer that meets these criteria is a customer-generator regardless of whether the customer's generation source(s) and/or energy storage device are unaggregated or part of an aggregated resource.** The Board may deem a pair of entities acting together - that is, a net metering generator and a net metering customer - to constitute one customer- generator for the purpose of net metering.

"Customer-generator facility" means the equipment used by a customer-generator to generate, **store,** manage, and/or monitor electricity. A customer-generator facility typically includes an electric generator**, energy storage device, vehicle-to-grid device,** and/or interconnection equipment that connects the customer-generator facility directly to the customer**, whether the equipment is aggregated or not**.

. . .

"Energy storage device" means a device that is capable of absorbing energy from the grid or from a generation source on the customer's side of the meter, storing it for a period of time using mechanical, chemical, or thermal processes, and thereafter discharging the energy back to the grid or directly to an energy-using system. ~~to reduce the use of power from the grid.~~

Commented [SCS1]: Recommend striking this language because it is unnecessary and fails to capture the many reasons and ways an energy storage device might be used. In many cases they will be used to shift energy use and not necessarily to reduce energy use.

. . .

"Net metering generator" means an entity that owns and/or operates a **class I** renewable energy generation facility, the electricity from which is delivered to a net metering customer**; provided that only the electricity produced by the class I renewable energy sources shall be eligible for net metering treatment**. The net metering generator may or may not be the same entity as the net metering customer; and may or may not be located on the same property as the net metering customer.

SUBCHAPTER 5. INTERCONNECTION OF CLASS I RENEWABLE ENERGY SYSTEMS

14:8-5.1 Interconnection definitions

The following words and terms, when used in this subchapter, shall have the following meanings, unless the context clearly indicates otherwise. Additional definitions that apply to this subchapter can be found at N.J.A.C. 14:3-1.1 and 14:8-1.2.

. . .

"Area network" means a type of electric distribution system served by multiple transformers interconnected in an electrical network circuit, which is generally used in large metropolitan areas that are densely populated, in order to provide high reliability of service. This term has the same meaning as the term "secondary grid network" as defined in IEEE [standard] **Standard** 1547 Section 4.1.4, which is incorporated herein by reference [as amended and supplemented.]**, or in any subsequent standard as identified in a Board order.** [IEEE standard 1547 can be obtained through the IEEE website at www.ieee.org.]

"Authority governing interconnect requirements" or "AGIR" means the agency that has authority for setting interconnection rules to the State-jurisdictional electric system, as set forth in IEEE Standard 1547 or a subsequent standard as identified in a Board order. The term AGIR is functionally equivalent to the term "Relevant Electric Retail Regulatory Authority" as used in FERC's Order No. 2222.

"Common interconnection agreement process" or "CIAP" means a common EDC application that allows ~~customer-generator~~DERs to apply for and manage the interconnection process electronically through a portal-based software application platform capable of tracking key information throughout the subsequent interconnection application process, documenting generation type and capacity, and incorporating schedules and budgets for upgrade commitments and construction timelines.

"Community energy system" means a community solar facility and/or energy storage device that is located in geographical proximity to an energy-consuming community and connected to the distribution grid for delivery of power to that designated community through an approved EDC tariff.

"Community solar facility" shall have the same meaning as set forth at N.J.A.C. 14:8-9.2.

"Community solar project" shall have the same meaning as set forth at N.J.A.C. 14:8-9.2.

"DER aggregation" means a grouping of discrete interconnected ~~customer-generator~~DER facilities or behind the meter load-modifying resources working as a combined or coordinated group for purposes of providing energy, grid services, or other value streams, on an aggregated basis, for the purposes of participating in either retail or wholesale markets.

~~"Distributed energy resource" or "DER" means an inverter-based, electricity-producing resource, an energy storage device, or a controllable load that is connected to an electric public utility's distribution infrastructure.~~"Distributed energy resource" or "DER" means the equipment used by an interconnection customer to generate and/or store electricity that operates in parallel with the electric distribution system. A DER may include but is not limited to an electric generator and/or energy storage system, a prime mover, or combination of technologies with the capability of injecting power and energy into the electric distribution system, which also includes the interconnection equipment required to safely interconnect the facility with the distribution system.

"Distribution system upgrade" means a required addition or modification to the electric distribution system to accommodate the safe and reliable interconnection of the distributed energy resource (DER) facility and to enable grid flexibility service calls to the facility during its operation. Distribution upgrades do not include interconnection facilities.

"Energy storage system" or "ESS" means a mechanical, electrical, or electrochemical means to store and release electrical energy, and its associated interconnection and control equipment. An Energy storage system can be considered part of a DER or a DER in whole that operates in parallel with the distribution system.

"EDC grid flexibility services" are control capabilities procured from a ~~customer-generator~~DER, which may be compensated by the EDC, that help to maintain distribution system reliability and safety, whether separately or as part of a DER aggregation.

"Electrical power system" or "EPS" **means facilities that deliver electric power to a load and** has the same meaning as is assigned to this term in IEEE [standard] **Standard** 1547[. As of June 4, 2012, IEEE standard 1547 defined EPS as a facility that delivers electric power to a load.]**, which is incorporated herein by reference, or any subsequent standard as identified in a Board order.**

"Enhanced PAVE process" is a real-time meeting between an EDC and a prospective community solar facility or community energy system applicant in which the EDC reviews and walks through a PAVE report. The enhanced PAVE process is an optional addition to the normal PAVE process.

"Export capacity means the amount of power that can be transferred from the DER to the distribution system. Export capacity is either the nameplate rating, or a lower amount if limited using an acceptable means identified in Section __."

"Facilities study" means a study that determines the cost and timeline associated with upgrading the EDC's electrical power system to safely and reliably accommodate a proposed ~~customer-generator~~DER facility.

"Generating facility means the equipment used by an interconnection customer to generate, store, manage, interconnect, and monitor electricity. A generating facility includes the interconnection equipment required to safely interconnect the facility with the distribution system."

"Good utility practice" has the same meaning as assigned to this term in the Amended and Restated Operating Agreement of PJM Interconnection, which is incorporated herein by reference**,** as amended and supplemented, **or in any subsequent standard, as identified in a Board order.** The Operating Agreement can be obtained on the PJM Interconnection website at [http://www.pjm.com/documents/downloads/agreements/oa.pdf] **https://agreements.pjm.com/oa/4534**. As of [October 23, 2008] **December 14, 2023**, the Operating Agreement defines this term as "any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices,

Commented [SCS2]: Recommend replacing with this improved and more comprehensive definition from the BATRIES Toolkit. Critically, the currently proposed definition should not limit DERs to "inverter based" resources. There are non-inverter based distributed resources, such as natural gas generators that might be used in a microgrid or elsewhere as needed.

Commented [SCS3]: Currently the proposed rules lack a definition for energy storage. IREC recommends adopting this definition for Energy Storage System and changing the references through the document from "energy storage device" to "energy storage system" to capture that they can be a part of a DER or a DER on their own.

Commented [SCS4]: It is valuable to separately define export capacity to distinguish it from the systems total nameplate capacity. The section reference should be to a section, proposed below, that clearly identified acceptable means of export control.

Commented [SCS5]: Currently the proposed rules lack a definition of generating facility. The term customer-generator is used instead, but as defined in the NEM rules above, this term only includes behind the meter systems and thus is too restrictive and does not capture community solar facilities and other front of the meter systems that will need to utilize these rules.

IREC recommends using DER instead of customer-generator, but proposed this definition which could be used instead of customer-generator instead if desired.

methods and acts which, 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] **utility practice** is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region**; including those practices required by Federal Power Act Section 215(a)(4)**."

"Hosting capacity" means the amount of ~~aggregate generation~~DER capacity that can be accommodated on the electrical power system, or a specific electrical power system circuit, without requiring distribution system upgrades.

"Hosting capacity analysis" means the methodology used to calculate, publish, and evaluate ~~the ability to increase the available hosting capacity of a given circuit.~~ability of the distribution system to host additional DER without requiring distribution system upgrades."

"Host load means electrical power, less the DER auxiliary load, consumed by the customer at the location where the DER is connected."

"IEEE Standard 1547" means IEEE Standard [1547-2003] **1547-2018**, which was approved in [2003] **2018** and [reaffirmed in 2008] **amended in 2020, or any future updated version of the IEEE Standard 1547, as may be identified in a Board order**.

. . .

"Inadvertent export means the unscheduled export of active power from a DER, exceeding118 a specified magnitude and for a limited duration, generally due to fluctuations in load-following behavior."

"Interconnection agreement" means an agreement between an interconnection customer ~~customer- generator~~ and an EDC, which governs the connection of the ~~customer- generator~~DER ~~facility~~ to the electric distribution system, as well as the ongoing operation of the ~~customer-generator~~DER ~~facility~~ after it is connected to the system**, whether the ~~facility~~ DER operates singly, or as part of a DER aggregation**. An interconnection agreement shall follow the standard form agreement developed by the Board and available from each EDC.

"Interconnection equipment" means a group of components connecting an electric generator with an electric distribution system and includes all interface equipment**,** including switchgear, inverters**,** or other interface devices. Interconnection equipment may include an integrated generator**, energy storage device,** or electric source.

"Interconnection Ombudsman" means a member of Board staff designated to address interconnection issues and work with applicants and EDCs to ensure a fair and transparent interconnection process.

"Non-Export or Non-Exporting means when the DER is sized, designed, and operated using any of the methods in Section __, such that the output is used for host load only and no electrical energy (except for any inadvertent export) is transferred from the DER to the distribution system."

~~"Non-exporting customer-generator facility" means a customer- generator facility that is designed to prevent or limit export of electricity past the point of common coupling from the customer-generator facility to the EDC's electrical power system.~~

~~"Non-exporting technology" means an electric device that is designed to ensure that a customer-generator facility is a non- exporting customer-generator facility or that limits the amount of injection past the point of common coupling.~~

"Limited export means the exporting capability of a DER whose export capacity is limited by the use of any configuration or operating mode described in Section __."

"Nameplate rating means the sum total of maximum rated power output of all of a DER's constituent generating units and/or ESS as identified on the manufacturer nameplate, regardless of whether it is limited by any approved means."

"Party" or "parties" means the interconnection applicant/customer~~customer-generator~~, the EDC, or both.

["Point of common coupling" has the same meaning as assigned to this term in IEEE Standard 1547 Section 3.0, which is incorporated herein by reference as amended and supplemented. IEEE standard 1547 can be

Commented [SCS6]: This definition is problematic because it suggests the HCA is to determine the ability to "increase" hosting capacity. Typically an HCA is just an assessment of the available capacity, not the ability to increase it. IREC recommends revising to simply reference the definition of hosting capacity.

Commented [SCS7]: This definition is necessary to support a proper definition of non-export.

Commented [SCS8]: In order to safely connect systems using various types of export controls it is important to define inadvertent export and, elsewhere in the rules, how it will be screened for and managed.

Commented [SCS9]: As discussed in more detail in IREC's comments, we recommend separately defining non-export from limited-export and recommend this definition which would reference a list of the acceptable means for controlling export. This also eliminates the need for the definition of "non-exporting technology."

Commented [SCS10]: IREC recommends separately defining limited export.

Commented [SCS11]: It is valuable to separately define export capacity and nameplate rating to clearly distinguish the power exported from the total nameplate of the system in screens and elsewhere.

obtained through the IEEE website at www.ieee.org. As of June 4, 2012, IEEE standard 1547 Section 3.0 defined this term as "the point where a Local EPS is connected to an Area EPS."]

"Point of common coupling" means the point in the power system at which the EDC and the customer interface occurs and has the same meaning as assigned to this term in IEEE Standard 1547, or any future updated version of the IEEE Standard 1547, as may be identified in a Board order. Point of common coupling has the same meaning as point of interconnection.

"Power control system" or "PCS" means systems or devices which electronically limit or control steady state currents to a programmable limit."

"Pre-application verification/evaluation process" or "PAVE process" means a process designed to provide a prospective ~~customer- generator~~applicant an opportunity to receive actionable feedback from the EDC about the technical aspects of an interconnection request, including electrical feasibility, processing timeline, and other technical and procedural matters at the beginning of the interconnection process.

"Reference Point of Applicability" or "RPA" means a location proximate to the DER where the interconnection and interoperability performance requirements, as specified by IEEE Std 1547-2018, apply.

"Relevant minimum load" means the lowest measured circuit or substation load coincident with the DER's production. For solar photovoltaic DERs with no energy 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 systems utilizing tracking).

"Solar permitting application software" is a scalable software platform designed by a national lab or other entity designed to be deployed in a municipality or other local entity to significantly automate and compress solar/storage permit application and processing times. One example of solar permitting application software is the SolarAPP+, developed by the National Renewable Energy Laboratory.

"Spot network" [has the same meaning as assigned to the term under IEEE Standard 1547 Section 4.1.4, (published July, 2003), which is incorporated herein by reference as amended and supplemented. IEEE standard 1547 can be obtained through the IEEE website at www.ieee.org. As of June 4, 2012, IEEE Standard 1547 defined "spot network" as "a type of electric distribution system that uses two or more inter-tied transformers to supply an electrical network circuit."] **means a portion of an electric distribution system that uses two or more inter-tied transformers to supply an electrical network circuit and has the same meaning as assigned to the term pursuant to IEEE Standard 1547- 2018, or any future updated version of the IEEE Standard 1547, as may be identified in a Board order.** A spot network is generally used to supply power to a single customer or a small group of customers.

"System impact study" means an engineering analysis of the probable impact of a ~~customer-generator~~DER ~~facility~~ on the safety and reliability of the EDC's electric distribution system.

"Technical Interconnection and Interoperability Requirements" or "TIIR" means Board-approved public documents, often utility-specific, which include requirements for interconnection, interoperability, DER capabilities and their utilization (settings), and grid integration (e.g., protection coordination, telemetry).

14:8-5.2 General interconnection provisions

(a) **These interconnection rules are applicable to all state-jurisdictional interconnections of DERs.**

~~(a)~~(b) Each EDC shall provide the following three review procedures for applications for interconnection of ~~customer-generator~~DERs ~~facilities~~:

1. Level 1: An EDC shall use this review procedure for [all] applications to connect inverter-based ~~customer-generator facilities~~DERs which have a nameplate rating, as measured in alternating current, of 50 kilowatts (kW) or less and an export capacity of 25 kW or less~~power rating of [10] **25** kW or less , **as measured in alternating current**~~, and which meet the certification requirements at N.J.A.C. 14:8-5.3. Level 1 interconnection review procedures are set forth at N.J.A.C. 14:8-5.4;

2. Level 2: An EDC shall use this review procedure for applications to connect ~~customer-generator facilities~~DERs that have an export capacity, measured in alternating current, that does not exceed the limits identified in the table below, which vary according to the voltage of the line at the proposed point of common coupling. DERs located within 2.5 miles of a substation and on a main distribution line with minimum 600-amp

Commented [SCS12]: Recommend adding to clearly define this important export control technology which will be referenced in the section we recommend adding that defines acceptable means of export control.

Commented [SCS13]: Addition of this term makes it easier to determine the appropriate minimum load measurement to refer to in the remainder of the rule.

Commented [SCS14]: Having a clear statement of applicability that includes all state jurisdictional projects regardless of size is a standard best practice.

Commented [SCS15]: As explained in IREC's comments, recommend adopting a limit for level 1 that allows more nameplate capacity so long as the export capacity does not exceed 25 kW. The level 1 screens can safely evaluate whether these projects will require further review.

capacity are eligible for Level 2 interconnection under higher thresholds.

Line Voltage	Level 2 Eligibility	
	Regardless of location	On > 600-amp line and < 2.5 miles from substation
< 5 kV	< 1 MW	< 2 MW
5 kV – < 15 kV	< 2 MW	< 3 MW
15 kV – < 30 kV	< 3 MW	< 4 MW
30 kV – 69 kV	< 4 MW	< 5 MW

~~2.~~3. ~~[with a power rating of two MW or less] which meet the certification requirements at N.J.A.C. 14:8-5.3[.]~~ **and that:**

~~i. **Are two MW or less, as measured in alternating current;**~~

~~ii.~~i. **Do not qualify for level 1 interconnection review procedures; or**

~~iii.~~ii. **Did not pass a level 1 process**. Level 2 interconnection review procedures are set forth at N.J.A.C. 14:8-5.5; and

~~3.~~4. Level 3: An EDC shall use this review procedure for applications to connect ~~customer-generator facilities~~DERs that [do]**:**

~~i. **Are greater than two MW, as measured in alternating current;**~~

~~ii.~~i. **Do** not qualify for either the level 1 or level 2 interconnection review procedures; **or**

~~iii.~~ii. **Did not pass a level 2 process.** Level 3 interconnection review procedures are set forth at N.J.A.C. 14:8-5.6.

~~(b)~~(c) (No change.)

~~(c)~~(d) Upon request **of an applicant**, the EDC shall meet with an applicant who qualifies for level 2 or level 3 interconnection review [to assist them in preparing the application].

[(d) An application for interconnection review shall be submitted on a standard form, available from the EDC. The application form will require the following types of information:

1. Basic information regarding the ~~customer-generator~~DER and the electricity supplier(s) involved;
2. Information regarding the type and specifications of the ~~customer- generator facility~~DER;
3. Information regarding the contractor who will install the ~~customer- generator facility~~DER;
4. Certifications and agreements regarding utility access to the ~~customer-generator's~~interconnection customer's property, emergency procedures, liability, compliance with electrical codes, proper operation and maintenance, receipt of basic information; and
5. Other similar information as needed to determine the compliance of a particular applicant with this chapter.]

[(e)] **(d)** (No change in text.)

[(f)] **(e)** An EDC shall not require **an applicant** ~~or a customer- generator~~ whose facility meets the criteria for interconnection approval [under] **pursuant to** the level 1 or level 2 interconnection review procedure at N.J.A.C. 14:8-5.4 and 5.5 to install additional controls or external disconnect switches not included in the interconnection equipment, to perform or pay for additional tests**,** or to purchase additional liability insurance except ~~[~~if agreed to by the applicant.~~]~~ ~~**at the EDC's discretion when required to maintain the safety, power quality, or reliability of the EDC's EPS.**~~

[(g)] **(f)** If the interconnection of a ~~customer-generator facility~~DER is subject to interconnection requirements of FERC or PJM, **whether in compliance with rules governing DER aggregations pursuant to FERC's Order No. 2222 or otherwise**, the provisions of this subchapter that apply to interconnection apply to that facility only to the extent that they do not conflict with the interconnection requirements of FERC or PJM.

[(h) If an applicant for interconnection disagrees with an EDC's determination of fact or need regarding

Commented [SCS16]: A 2 MW limit for Fast Track is severely outdated and should be modified to reflect the widespread approach, adopted by FERC, of varying the limit based upon the voltage of the line and the distance from the substation. In addition, it should be based upon a project's export capacity.

Commented [SCS17]: This is unnecessary since the other Levels define their size limits and all others should proceed through Level 3. This also aligns with our recommendation above to increase the capacity for Level 2.

Commented [SCS18]: IREC opposes this alteration to the rules. The EDCs should not be provided with unfettered ability to add costs and requirements. See IREC's comments for a discussion of why this language is problematic.

matters covered in this subchapter, or if any person has a complaint regarding matters covered in this subchapter, the applicant or other person may file an informal complaint with the Board under N.J.A.C. 14:1-5.13, or may file a petition with the Board under N.J.A.C. 14:1-5.]

[(i)] **(g)** Once a ~~customer-generator~~DER has met the [the level 1 interconnection requirements at N.J.A.C. 14:8-5.4, or has met the level 2 interconnection requirements at N.J.A.C. 14:8-5.5,] **requirements of the relevant interconnection review,** the EDC shall notify the ~~customer- generator~~applicant [in writing that the customer-generator is authorized to energize the customer-generator facility, as follows:

1. The EDC shall send the authorization to the e-mail address, and to the U.S. Postal Service mailing address that is listed on the customer- generator's submitted interconnection application form.; and

2. The EDC shall not condition the authorization to energize on the EDC's replacement of the customer-generator's meter.] **through the CIAP-compliant automated portal and a message to all applicant-associated email address(es) on file. The EDC shall not condition the authorization to energize on the EDC's replacement of the customer~~- generator~~'s meter.**

[(j)] **(h)** (No change in text.)

(i) Potential applicants with systems over 500 kW capacity shall qualify for a Pre-Application Verification/Evaluation (PAVE) report as set forth at N.J.A.C. 14:8-5.10. The CIAP portal shall allow for the initial request and payment for a PAVE report prior to formal application.

(j) Prospective community solar facility or community energy system applicants shall have the right to request an enhanced PAVE process meeting to discuss the PAVE report prior to application filing, and the EDC shall grant such a request upon a prospective community solar facility or community energy system applicant's payment of the required fee.

(k) In determining the appropriate interconnection level and performing the related studies, the EDC shall allow a prospective generator to limit its ability to export power to the grid to less than its nameplate rating per the subsection (l), ~~including the utilization of non-exporting technology that prevents the export of electricity past the point of common coupling, either in whole or in part,~~ or by enrolling in a Board-approved EDC grid flexibility services program. The net export capacity of the ~~customer-generator facility~~DER shall form the basis for the appropriate screens and studies~~, unless the EDC determines, using good utility practice, that the applicant's proposal would potentially harm the integrity of the EDC system and documents such findings to the Board~~.

(l) Export Controls

1. If a DER uses any configuration or operating mode in subsection 14:8-5.6(l)(3) to limit the export of electrical power across the point of common coupling, then the 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 DER must comply with the limits identified in this Section. The export capacity specified by the interconnection customer in the application will subsequently be included as a limitation in the interconnection agreement.

2. An application proposing to use a configuration or operating mode to limit the export of electrical power across the point of common coupling shall include proposed control and/or protection settings.

3. Acceptable Export Control Methods

i. Export Control Methods for Non-Exporting DER

- **Reverse Power Protection (Device 32R): To limit export of power across the point of common coupling, a reverse power protective function is implemented using a utility grade protective relay. The default setting for this protective function shall be 0.1% (export) of the service transformer's nominal base nameplate rating, with a maximum 2.0 second time delay to limit inadvertent export.**
- **Minimum Power Protection (Device 32F): To limit export of power across the point of common coupling, a minimum import protective function is implemented utilizing a utility grade protective relay. The default setting for this protective function shall be 5% (import) of the DER's total nameplate rating, with a maximum 2.0 second time delay to limit inadvertent export.**
- **Relative Distributed Energy Resource Rating: This option requires the DER's nameplate rating 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 distribution system.**

Commented [SCS19]: IREC's comments explain in full why it is crucially important to define the types of export controls that are allowed and to provide the associated technical limits and process details.

This option requires the DER's nameplate rating to be no greater than 50% of the interconnection customer's verifiable minimum host load during relevant hours over the past 12 months. This option is not available for interconnections to area networks or spot networks.

ii. Export Control Methods for Limited Export DER

- Directional Power Protection (Device 32): To limit export of power across the point of common coupling, 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.
- Configured Power Rating: A reduced output power 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. 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. The reduced power rating may be indicated by means of a nameplate rating replacement, a supplemental adhesive nameplate rating tag to indicate the reduced nameplate rating, or a signed attestation from the customer confirming the reduced capacity.

iii. Export Control Methods for Non-Exporting DER or Limited Export DER

- Certified Power Control Systems: DER may use certified power control systems to limit export. DER utilizing 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 to limit inadvertent export. NRTL testing to the UL Power Control System Certification Requirement 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.

~~(k)~~• Agreed-Upon Means: DER may be designed with other control systems and/or protective functions to limit export and inadvertent export if mutual agreement is reached with the EDC. The limits may be based on technical limitations of the interconnection customer's equipment or the electric distribution system equipment. To ensure inadvertent export remains within mutually agreed-upon limits, the interconnection customer may use an uncertified power control system, an internal transfer relay, energy management system, or other customer facility hardware or software if approved by the EDC.

~~(l)~~(m) **By (120 days of the Board's effective date of this rulemaking), each EDC shall make a compliance filing to allow existing ~~customer- generator facilities~~DERs to add an energy storage device and/or upgrade to a UL 1741-compliant ~~smart~~ inverter without additional study through the appropriate interconnection process on all circuits that can host greater distributed energy storage capacity.**

~~(m)~~(n) **By (one year of the effective date of this rulemaking), each EDC shall establish a secure common interconnection agreement process (CIAP) that will provide a structured approach for submitting interconnection applications, tracking key information throughout the interconnection application process, and monitoring the interconnection process electronically. Each EDC's CIAP-compliant portal shall be developed based on the needs of the EDC and its applicants and maintain a consistent customer experience for applicants across EDC service territories. The cost of implementing the CIAP portal and related costs shall be recovered by each EDC as part of its base rates or through an approved Infrastructure Investment Program pursuant to N.J.A.C. 14:3-2A.2. Each CIAP shall, at a minimum:**

1. **Include a portal-based application form that requires the following:**

i. **Basic information regarding the ~~customer-generator~~DER involved;**

ii. **Information regarding the type and specifications of the ~~customer-generator facility~~DER;**

iii. **Information regarding the contractor who will install the ~~customer-generator facility~~DER;**

iv. **Certifications and agreements regarding utility access to the ~~customer-generator~~DER's property, emergency procedures, liability, compliance with electrical codes, proper operation and maintenance,**

and receipt of basic information;

v. **Include a check box to indicate whether the applicant has previously requested the PAVE process;**

vi. **Include a check box to indicate whether the applicant has previously requested the Enhanced PAVE process and has been granted an Enhanced PAVE process meeting; and**

vii. **Other similar information, as needed to determine the compliance of a particular applicant with this chapter;**

2. **Include standardized online forms for required applicant information, the ability to save all work in progress for application completion at a later time, a visual "thermometer bar" indicator of progress through the full process, options for email and phone/text status change notifications, and other such administrative requirements that the Board may establish through Board order either following a joint EDC proposal or on its own initiative;**

3. **Integrate with a solar permitting application software platform, such as SolarAPP+, or other similar solar permitting tool selected and implemented jointly by the EDCs, and approved by the Board;**

4. **Document generation type and capacity, timelines, schedule, and budget for upgrade commitments, when upgrade payments or deposits are due or have been paid, and construction timelines, and other comparable requirements that the Board may establish through Board order either following a joint EDC proposal or on its own initiative;**

5. **Provide automatic email and online notifications to the applicant with the goal of enforcing clearly defined tariff timelines and reducing the turnaround time for missing data. The software should be designed to improve the accuracy and consistency of data entry and facilitate cross-department intake of application information and to identify missing data upon submission or as soon as practicable after submission to minimize the number of incomplete applications;**

6. **Enable each EDC to customize the forms while maintaining a consistent customer experience;**

7. **Enable each EDC to provide key performance indicators regarding interconnection processing, including the number of applications with missing data, applications with complete information, and achieved timelines for all interconnection applications at all interconnection levels;**

8. **Allow for a fully virtual interconnection process, including allowing for the upload of files and documents and electronic payment of fees; and**

9. **Include a Frequently Asked Questions (FAQ) webpage to provide guidance useful to interconnection customers engaging in the interconnection process that clearly presents context and instructions for interacting with the electronic application tracking system.**

~~(n)~~(o)**Each EDC shall develop an interconnection dispute resolution process as set forth at N.J.A.C. 14:8-5.12, to be included on the EDC FAQ webpage. As part of a dispute resolution process, the EDCs should identify an ombudsman to handle customer interconnection complaints. If an applicant disagrees with an EDC's determination of fact or need regarding matters covered in this subchapter, or if any person has a complaint regarding matters covered in this subchapter, the applicant or other person may file an initial informal complaint with the Board's interconnection ombudsman pursuant to N.J.A.C. 14:1-5.13, or may file a formal petition with the Board pursuant to N.J.A.C. 14:1-5.**

~~(o)~~(p)**Any applicant may request that the EDC take into account any significant anticipated changes in load associated with contemporaneous installation of the ~~customer-generator facility~~DER and any of the following:**

1. **Electric vehicle charging infrastructure, including any vehicle- to-grid bidirectional capabilities;**
2. **Building electrification upgrades;**
3. **Deployment of energy efficiency upgrades; or**
4. **Verifiable increases in load, which the EDC shall not unreasonably refuse to consider. The EDC may require the applicant to delay energization or re-start the interconnection process if the contemplated contemporaneous changes are not completed prior to the planned energization of the system.**

~~(p)~~(q) **In administering the deadlines in this chapter, the EDC shall make reasonable efforts to meet all established timelines. If the EDC cannot meet a timeline, the EDC shall notify the applicant and Board staff, in writing, within three business days after the missed deadline by email or another**

Commented [SCS20]: As FERC recently did in Order 2023, the BPU should consider eliminating the reasonable efforts standard in place of a system that holds utilities accountable for meeting timelines.

methodology established by Board order. The notification shall explain the reason for the EDC's failure to meet the deadline and provide an estimate of when the step will be completed. The EDC shall keep the applicant and Board staff updated of any changes in the expected completion date.

~~(q)~~(r) **The applicant may request, in writing, the extension of a deadline established pursuant to this chapter. The requested extension may be for up to one-half of the time originally allotted (for example, a 10-business-day extension for a 20-business-day timeframe). The EDC shall not unreasonably refuse this request. If further deadline extensions are necessary, the applicant may request an extension through the CIAP portal or from the EDC's interconnection ombudsman, who shall grant the request, if it is reasonable, or otherwise, deny it, within three business days, and notify the applicant on the CIAP-compliant automated portal and a message to all associated email address(es) on file.**

~~(r)~~(s) **By (120 days of the effective date of this rulemaking), each EDC shall file a compliance tariff that sets forth standardized protocols governing the conduct of system impact studies, facility studies, related agreements, and a pro forma interconnection agreement, as well a detailed description of the various elements of a system impact study it would typically undertake pursuant to N.J.A.C. 14:8-5.6, along with, and including:**

1. A load-flow analysis;

2. A short-circuit analysis;

3. A circuit protection and coordination analysis;

4. Information regarding the impact on system operation of the electric distribution system;

5. A stability analysis (and the conditions that would justify including this element in the system impact study);

6. A voltage-collapse analysis (and the conditions that would justify including this element in the system impact study); and

7. Any additional analyses the EDC would undertake prior to or as part of the system impact study.

14:8-5.3 Certification of ~~customer-generator~~ interconnection equipment

(a) In order to qualify for the level 1 and the level 2 interconnection review procedures described at N.J.A.C. 14:8-5.4 and 5.5, a ~~customer- generator~~applicant's interconnection equipment shall have been tested and listed by an OSHA-approved nationally recognized testing laboratory for continuous interactive operation with an electric distribution system**, except as provided in this section,** in accordance with the following standards, as applicable:

1. IEEE [1547] **1547-2018**, Standard for Interconnecting Distributed Resources with Electric Power Systems (published July [2003] **2018, amended April 2020**) **or any future updated version of the IEEE Standard 1547 as may be identified by Board order,** which is incorporated herein by reference[, as amended or supplemented]. IEEE Standard 1547 can be obtained through the IEEE website at www.ieee.org; and

2. UL [1741] **1741** ~~**Supplement SA or SB**~~ Inverters, Converters, ~~and~~ Controllers and Interconnection System Equipment for Use With Distributed Energy Resources ~~in Independent Power Systems~~ ([November 2005] **September 2021**) **or any future updated version of the UL 1741 Standard as may be identified by Board order**, which is incorporated herein by reference [as amended or supplemented]. UL 1741 can be obtained through the Underwriters Laboratories website at www.ul.com.

Commented [BL21]: Recommend using the updated title of Edition 3. Note that SA and SB are a sub-part of 1741. As SB certification would be called out with an effective date in proposed language (see IREC's comments and (e) below) it shouldn't be necessary to include here.

(b) Interconnection equipment shall be considered certified for interconnected operation if it has been submitted by a manufacturer to an OSHA-approved nationally recognized testing laboratory[,] **or alternative testing protocols permitted pursuant to this chapter** and has been tested and listed by the laboratory for continuous interactive operation with an electric distribution system in compliance with the applicable codes and standards listed [in] **at** (a) above.

(c) If the interconnection equipment has been tested and listed in accordance with this section as an integrated package[, which] **that** includes [a generator or other electric source] **an electrical power system facility or a** ~~**customer-generator facility**~~**DER**, the interconnection equipment shall be deemed certified and the EDC shall not require further design review[,] **or** testing [or additional equipment].

(d) If the interconnection equipment includes only the interface components (switchgear, inverters**, non-exporting technology,** or other interface devices), an [interconnection] applicant shall show that the generator or other electric source being utilized with the interconnection equipment is compatible with the interconnection equipment and consistent with the testing and listing specified for the equipment. If the generator or electric source being utilized with the interconnection equipment is consistent with the testing and listing performed by the OSHA-approved nationally recognized testing laboratory **or alternative testing protocols permitted pursuant to this section**, the interconnection equipment shall be deemed certified and the EDC shall not require further design review, testing**,** or additional equipment.

(e) IEEE 1547-2018 Adoption

1. Beginning on [insert effective date] DERs shall be required to comply with IEEE Std 1547-2018, and shall conform with the following minimum requirements:

a. Abnormal operating performance category: Inverter-based DERs shall meet Category III capabilities and rotating DERs shall meet Category I capabilities.

b. Normal operating performance category: Inverter-based DERs shall meet Category B capabilities and rotating DERs shall meet Category A capabilities.

Inverter-based interconnection equipment may be certified to UL 1741 Third Edition, Supplement SB in order to demonstrate compliance with IEEE Std 1541-2018. Equipment that is not certified to Supplement SB may require additional evaluation and commissioning testing to confirm compliance with IEEE Std 1547-2018.

2. The above assignment of categories is expected to cover the vast majority of interconnections. Any instances that do not fall within the above assignment shall be:

a. Reviewed on a case-by-case basis, with the EDC making the determination for requiring the specific category; or

b. Specified in the EDC's TIIR.

The EDC should consider Annex B of IEEE Std 1547-2018 when making these determinations on a case-by-case basis or in a TIIR.

3. Each EDC shall post its preferred settings in its TIIR. As applicable the following shall be identified in the TIIR:

a. Voltage and frequency trip settings;

b. Frequency droop settings;

c. Activated reactive power control function and settings;

d. Voltage-active power mode activation and settings;

e. Enter service settings; and

f. Communication protocols and ports requirements.

~~(d)~~4. TIIRs shall be created through a technical advisory group process and submitted to the BPU for approval with opportunity for public comment. Subsequent changes to TIIRs shall also be submitted to the BPU for approval with opportunity for public comment.

14:8-5.4 Level 1 interconnection review

(a) Each EDC shall adopt a level 1 interconnection review procedure. The EDC shall use the level 1 review procedure only for an application to interconnect a ~~customer-generator facility~~DER that meets all of the following criteria:

1. The facility is inverter-based ~~**and has smart inverter capability**~~;
2. The facility has a nameplate rating, as measured in alternating current, of 50 kilowatts (kW) or less and an export capacity of [10] **25** kW or less; and
3. (No change.)

(b) For a ~~customer-generator facility~~DER described at (a) above, the EDC shall approve interconnection under the level 1 interconnection review procedure **upon payment of a fee, not to exceed $100.00 or other value established by Board order**, if all of the applicable requirements at (c) through (g) below are met. An EDC shall not impose additional requirements not specifically authorized [under] **pursuant to** this section.

(c) (No change.)

(d) A ~~customer-generator~~DER [facility's point of common coupling shall not be on a transmission line, a spot network, or an area network.] ~~**facility**~~ **does not qualify for interconnection as level 1 if the point of common coupling is on a transmission line, a spot network, or an area network; provided that the EDC will use good utility practice to allow interconnection of a** ~~**customer-generator facility**~~**DER to such**

Commented [SCS22]: As explained in IREC's comments, to properly adopt and incorporate IEEE 1547-2018 further work needs to be done to identify the categories and settings that will be required.

Commented [SCS23]: This reference is not needed since subsection 3 (not shown since there is no change) references the certification section which requires the use of "smart inverters"

Commented [SCS24]: This limit should be expanded as explained above and in IREC's comments.

facilities, where feasible.

(e) If a ~~customer-generator facility~~DER is to be connected to a radial line section, the aggregate ~~generation~~ export capacity connected to the circuit, including the export capacity~~at~~ of the proposed ~~customer-generator facility~~DER~~,~~ ~~**reduced by any export limited capacity achieved through non-exporting technology,**~~ shall not exceed ~~[10] **15** percent ([15] **25** percent for solar electric generation)~~ 100% of the circuit's relevant ~~total annual peak~~ minimum load, as most recently measured at the substation.

(f) If a ~~customer-generator facility~~DER is to be connected to a single-phase shared secondary, the aggregate ~~generation~~ export capacity connected to the shared secondary, including the export capacity of the ~~customer-generator facility~~proposed DER, shall not exceed [20] **30** kilovolt-amps (kVA).

(g) (No change.)

(h) An applicant shall submit an Interconnection Application/ Agreement Form for level 1 interconnection review **through the CIAP portal**. The standard form is available from the EDC and includes a Part 1 (Terms and Conditions) and a Part 2 (Certificate of Completion).

(i) Within three business days after receiving an application for level 1 interconnection review, the EDC shall [provide written or e-mail notice to] **notify** the applicant**, in writing, through email and through the CIAP portal** that it received the application and [whether] **that** the application is **either** complete **or incomplete**. If the application is incomplete, the written notice shall include a list of all of the information needed to complete the application. The applicant must provide the requested information within 10 business days, or the Application will be deemed withdrawn.

(j) Within 5 business days after the EDC notifies the applicant that the application is complete, it shall notify the applicant if the RPA denoted in the application is inappropriate and should provide the applicant 5 business days to revise the application to amend the RPA location. If the RPA is not appropriately identified the application will be withdrawn.

~~(j)~~(k) Within 10 business days after the EDC notifies the applicant that the application is complete (or 12 business days if the RPA needs to be amended per (j)) [under] **pursuant to** (i) above, the EDC shall notify the applicant that:

1. The ~~customer-generator facility~~DER meets all of the criteria at (c) through (g) above that apply to the facility, and the interconnection will be finally approved upon completion of the process set forth at (k) through (o) below; [or]
2. The ~~customer-generator~~DER ~~facility~~ has failed to [meet] **pass** one or more of the applicable [criteria] **screens** at (c) through (g) above, and the interconnection application is denied[.]**, subject to the resubmittal options set forth at (p) below; or**
3. **That the ~~customer-generator facility~~DER is proposing to connect to a spot network or an area network, and the EDC requires additional time to determine whether the interconnection is technically feasible.**

~~(k)~~(l) If the EDC notifies the ~~customer-generator~~applicant [under] **pursuant to** (j)1 above that the facility will be approved, the EDC shall, within three business days after sending the notice [under] **pursuant to** (j)1 above, do both of the following:

1. Notify the applicant **through the CIAP portal and** by [e-mail] **email** or other writing of whether an EDC inspection of the ~~customer- generator facility~~DER is required prior to energizing the facility; or that the EDC waives inspection; and
2. Return to the applicant Part 1 of the original application, signed by the appropriate EDC representative**, through the CIAP portal and by email or other writing**.

~~(l)~~(m) Once an applicant receives Part 1 of the application with the EDC signature in accordance with (k) above, and has installed and interconnected the ~~customer-generator facility~~DER, the applicant shall obtain approval of the facility [by] **from** the appropriate construction official, as defined at N.J.A.C. 5:23-4.1.

~~(m)~~(n) The ~~customer-generator~~applicant shall submit documentation of the construction official's [approval] **successful inspections and permit closing** to the EDC, along with a copy of Part 2 of the application, signed by the ~~customer-generator~~applicant.

~~(n)~~(o) If inspection of the ~~customer-generator facility~~DER was waived [under] **pursuant to** (k)1 above, the EDC shall, within five business days after receiving the submittal required [under] **pursuant to** (m) above,

Commented [SCS25]: The use of peak load is outdated and should only be used where minimum load data does not exist or cannot be calculated or estimated. In 2024 having minimum load data should be the norm. Adoption of 100% of minimum load is now widely accepted and a standard best practice that should be used in New Jersey. This change reflects more accurate screening and can significantly reduce the number of projects requiring additional review.

Commented [SCS26]: This screen should only consider export capacity, not the nameplate rating. Only exported power will impact the transformer that is the equipment of concern for this screen.

Commented [SCS27]: Recommend adding this language to make it clear how long the applicant has to resolve the deficiencies and provide the complete information.

notify the ~~customer-generator~~applicant [of authorization] **that it is authorized** to energize the facility. The notice to the ~~customer-generator~~applicant shall be provided [in the format required under N.J.A.C. 14:8-5.2(i).] **through the CIAP portal and by email or other writing.**

~~(o)~~(p)If inspection of the ~~customer-generator facility~~DER was not waived [under] **pursuant to** (k)1 above, the following process shall apply:

1. The ~~customer-generator~~applicant shall submit **documentation of** the construction official's [approval and] **successful inspections and permit closing, as well as a** signed Part 2 **of the application** as required at (m) above, and inform the EDC that the ~~customer-generator facility~~DER is ready for EDC inspection;
2. Within five business days after the ~~customer-generator~~applicant notifies the EDC [under] **pursuant to** (o)1 above that the facility is ready for inspection, the EDC shall offer the ~~customer-generator~~applicant two or more available four-hour inspection appointments (for example, February 4th from noon to 4:00 P.M. or February 6th from 10:00 A.M. to 2:00 P.M.);
3. The appointments offered [under] **pursuant to** (o)2 above shall be no later than 10 business days after the EDC offers the appointments (that is, within 13 business days after the ~~customer-generator~~applicant submittal [under] **pursuant to** (m) above);
4. (No change.)
5. Within five business days after successful completion of the EDC inspection, the EDC shall notify the ~~customer-generator~~applicant that it is authorized to energize the facility [. The notice shall be provided in the format required under N.J.A.C. 14:8-5.2(i)] **through the CIAP portal and by email**; [and]
6. The applicant shall not begin operating the ~~customer-generator facility~~DER until after the inspection and testing is completed[.]**; and**
7. **Unauthorized system interconnection or operation will result in no payment for excess generation credits. The EDC has the right to disconnect unauthorized interconnections, and must notify the ~~customer-generator facility~~DER operator within four hours of such action being taken.**

~~(p)~~(q)If an application for level 1 interconnection review is denied because it does not meet one or more of the applicable requirements in this section, [an applicant may resubmit the application under the level 2 or level 3 interconnection review procedure, as appropriate.] **the EDC shall provide, in writing, the specific screens that the application failed, including the technical reason for failure. The EDC shall provide information and detail about the specific system threshold or limitation causing the application to fail the screen.~~the EDC shall provide direct evidence of which screens were failed and why~~. In response, an applicant may either:**

1. **Resubmit an amended level 1 application for expedited review with appropriate mitigation measures that either reduce the ~~customer-generator facility~~DER's capacity or restrict its ability to export past the point of common coupling through the addition of ~~non- exporting~~export controls ~~technology~~. The EDC shall also allow an applicant to address a failed screen by adding energy storage or increasing its proposed load, provided that such mitigation measures are paired with ~~non-exporting technology~~ export controls and/or a reduction in the ~~customer- generator facility's~~DER's nameplate capacity; or**
2. **Resubmit the application pursuant to the level 2 or level 3 interconnection review procedure, as appropriate.**
~~2.~~3. **The applicant shall notify the EDC of how it wants to proceed within 10 business days after receipt of the screen results. If no response is received, the application will be deemed withdrawn.**

14:8-5.5 Level 2 interconnection review

(a) Each EDC shall adopt a level 2 interconnection review procedure. The EDC shall use the level 2 interconnection review procedure for an application to interconnect a ~~customer-generator facility~~DER that meets [both of] the following criteria:

~~1.~~ The facility has an export capacity, measured in alternating current, that does not exceed the limits identified in the table below. ~~of two megawatts or less~~**~~, as measured in direct current~~**~~; [and]~~

Line Voltage	**Level 2 Eligibility**

Commented [SCS28]: In order for an applicant to resubmit their application with mitigation measures, they need to have sufficient information about the exact thresholds used. This information is also helpful to inform the client on whether it is worth proceeding to Level 2 or 3 should mitigations not be possible.

Commented [SCS29]: It is inefficient and problematic to require an applicant to resubmit the application. Projects should be able to roll through the process if they submit the updated fees without losing their queue position. In addition, Level 1 projects should be provided the opportunity to proceed directly to Supplemental Review instead of going through the Level 2 screens which are largely parallel. The screens that are in Level 2 are unlikely to reveal additional insights for projects in the Level 1 size range.

Commented [SCS30]: Currently the process is not clear with respect to what happens if the applicant wants to revise the project per 1, or to proceed to Level 2 or 3. So that the project is not reserving capacity, it is a best practice to define a clear timeline for the customer to respond.

	Regardless of location	**On > 600-amp line and < 2.5 miles from substation**
< 5 kV	< 1 MW	< 2 MW
5 kV – < 15 kV	< 2 MW	< 3 MW
15 kV – < 30 kV	< 3 MW	< 4 MW
30 kV – 69 kV	< 4 MW	< 5 MW

~~2.~~1. The facility has been certified in accordance with N.J.A.C. 14:8- 5.3[.]**; and**

~~**3.**~~**2. The facility does not qualify for the level 1 interconnection review procedure or an applicant that qualifies for the level 1 interconnection review opts to use the level 2 interconnection review procedure.**

(b) For a ~~customer-generator facility~~DER described at (a) above, the EDC shall approve interconnection [under] **pursuant to** the level 2 interconnection review procedure if **the** ~~**customer-generator facility**~~**DER meets** all of the applicable **screening** requirements at (c) through (l) below [are met]. An EDC shall not impose additional requirements not specifically authorized [under] **pursuant to** this section.

(c) The aggregate ~~generation~~ nameplate capacity on the line section to which the ~~customer-generator facility~~DER will interconnect, including the nameplate capacity of the ~~customer-generator facility~~DER, shall not cause any distribution protective equipment (including, but not limited to, substation breakers, fuse cutouts**,** and line reclosers) or customer equipment on the electric distribution system, to exceed [90] **95** percent of the short circuit interrupting capability of the equipment. In addition, a ~~customer-generator facility~~DER shall not be connected to a circuit that already exceeds [90] **95** percent of the short circuit interrupting capability, prior to interconnection of the facility.

(d) (no change)

~~(c)~~(e) The aggregate nameplate ~~generation~~ capacity connected to the line section, including the ~~customer-generator facility~~DER, shall not contribute more than 10 percent to the line section's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of common coupling.

~~(d)-(e) (No change.)~~

(f) If a ~~customer-generator facility~~DER is to be connected to a radial line section, the aggregate export ~~generation~~ capacity connected to the electric distribution system by non-EDC sources, including the export ~~customer-~~ capacity of the ~~generator facility~~DER, ~~**reduced by any export limited capacity achieved through non-exporting technology,**~~ shall not exceed 100% of the circuit's relevant minimum load ~~[10] **15** percent (or [15] **25** percent for solar electric generation) of the total circuit annual peak load~~. For the purposes of this subsection, annual relevant minimum~~peak~~ load shall be based on measurements taken over the 12 months prior to the submittal of the application, measured at the substation nearest to the ~~customer- generator facility~~DER.

(g) For interconnection of a proposed DER that can introduce inadvertent export, where the nameplate rating minus the export capacity is greater than 250 kW, the following inadvertent export screen is required. 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 point of common coupling does not exceed 3%. Voltage change will be estimated applying the following formula:

Formula	$\frac{(R_{SOURCE} \times \Delta P) - (X_{SOURCE} \times \Delta Q)}{V^2}$

Commented [SCS31]: For Level 2, the screens are capable of safely evaluating the interconnection of projects larger than 2 MW. Utilization of the table based approach, combined with a penetration screen that uses minimum load and a defined supplemental review process, narrows the applicability to the maximum size that is likely to be able to pass the screens while also allowing larger, well-sited systems to take advantage of the more expedited review process. The systems should be evaluated using the export capacity (not the nameplate capacity) measured in AC *not* DC as proposed.

Commented [SCS32]: IREC supports the changes to this screen, but recommends clarifying that the nameplate capacity (not export capacity) should be used.

Commented [SCS33]: The proposed rule makes no changes to this screen, it is added here with the proposed redlines shown. These changes are necessary to ensure that the full nameplate capacity should be used for this screen.

Commented [SCS34]: Recommend adding this screen to ensure that the amount of inadvertent export is not likely to cause grid impacts.

Where:
ΔP = (DER apparent power nameplate rating – export capacity) × PF,
ΔQ = (DER apparent power nameplate rating – export capacity) × $\sqrt{(1 - PF^2)}$,
R_{SOURCE} is the grid resistance, X_{SOURCE} is the grid reactance,
V is the grid voltage, PF is the power factor

(h) If a DER is to be connected to three-phase, three wire primary EDC distribution lines, a three-phase or single-phase generator shall ~~be connected~~ use a phase-to-phase primary connection.

~~(f)~~(i) If a DER is to be connected to three-phase, four wire primary EDC distribution lines, a three-phase or single phase generator shall ~~be connected~~use a grounded line-to-neutral primary connection~~and shall be effectively grounded~~.

~~(g)-(h) (No change.)~~

(i) If a ~~customer-generator~~DER ~~facility~~ is to be connected to a single-phase shared secondary, the aggregate export ~~generation~~ capacity on the shared secondary, including the ~~customer-generator~~export capacity of the DER ~~facility~~, shall not exceed [20] **30** kilovolt-amps (kVA).

(j)-(k) (No change.)

(l) If a ~~customer-generator facility~~DER's proposed point of common coupling is on a spot or area network, the interconnection shall meet all of the following requirements that apply, in addition**,** to the requirements [in] **at** (c) through (k) above:

1. For a ~~customer-generator facility~~DER that will be connected to a spot network circuit, the aggregate generation capacity connected to that spot network from ~~customer-generator facilities~~DERs, including the ~~customer- generator facility~~DER, shall not exceed [five] **10** percent of the spot network's maximum load; **provided that the EDC will use good utility practice to allow interconnection of a ~~customer-generator facility~~DER to such facilities at higher percentages where technically feasible, and if solar energy ~~customer-generator facilities~~DERs are used exclusively, only the ~~anticipated~~ relevant minimum load during an off-peak ~~daylight~~ period shall be considered;**

2. For a ~~customer-generator facility~~DER that utilizes inverter based protective functions, which will be connected to an area network, the ~~customer-generator facility~~DER, combined with other exporting ~~customer-generator facilities~~DER on the load side of network protective devices, shall not exceed [10] **50** percent of the minimum annual load on the network, or 500 kW, whichever is less, **or a future standard proposed by IEEE and approved by the Board by order; provided that the EDC will use good utility practice to allow interconnection of a ~~customer-generator facility~~DER to such facilities at higher percentages where technically feasible.** For the purposes of this paragraph, the percent of minimum load for [solar] **an** electric generation ~~customer-generator facility~~DER **that exclusively generates electricity from solar energy, including a ~~customer-generator facility~~DER that incorporates an energy storage device,** shall be calculated based on the minimum load occurring during an off-peak daylight period; and/or

3. For a ~~customer-generator facility~~DER that will be connected to a spot or an area network that does not utilize inverter based protective functions, or for an inverter based ~~customer-generator facility~~DER that does not meet the requirements [of] **at** (l)1 or 2 above, the ~~customer-generator facility~~DER shall utilize **non-exporting technology, such as** reverse power relays or other protection devices that ensure no export of power from the ~~customer- generator facility~~DER, including inadvertent export (under fault conditions) that could adversely affect protective devices on the network.

(m) An applicant shall submit an Interconnection Application/Agreement Form for level 2 interconnection review **through the CIAP portal**. The standard form [is] **shall be** available from the [EDC,] **EDC's CIAP portal** and **shall** include[s] a Part 1 (Terms and Conditions) and a Part 2 (Certificate of Completion).

(n) Within three business days after receiving an application for level 2 interconnection review, the EDC shall [provide written or e-mail notice to] **notify** the applicant **through the CIAP portal and by email** that it received the application and [whether] **that** the application is **either** complete **or incomplete**. If the

Commented [SCS35]: As discussed in IREC's comments, these two screens are out of date with current understanding of effective grounding. The redlines show the revisions to the existing screens.

Commented [BL36]: While the change to 30 kVA is likely to decrease the unnecessary flagging of transformer/secondary issues, an approach that evaluates the aggregate export relative to the size of the transformer would be more accurate (i.e. X% of the secondary transformer rating). Secondary transformers are not all the same size and can be sized up to 100 kVA. A 100% of transformer rating threshold could be supported if voltage regulation functions are turned on. We recommended that this threshold be revisited as part of 1547-2018 adoption once it is clear what DER voltage regulation practices will be put in place.

application is incomplete, the [written] notice shall include a list of all of the information needed to complete the application. The applicant must provide the requested information within 10 business days, or the application will be deemed withdrawn.

~~(n)~~(o)Within 5 business days after the EDC notifies the applicant that the application is complete, it shall notify the applicant if the RPA denoted in the application is inappropriate and should provide the applicant 5 business days to revise the application to amend the RPA location. If the RPA is not appropriately identified the application will be withdrawn.

~~(o)~~(p)Within 15 business days after the EDC notifies the applicant that the application is complete [under] **pursuant to** (n) above, the EDC shall notify the applicant [by e-mail or in writing] **through the CIAP portal and by email** of one of the determinations at (o)1 through 4 below, as applicable. During the 15 business days provided [under] **pursuant to** this subsection, the EDC may, at its own expense, conduct any studies or tests it deems necessary to evaluate the proposed interconnection, but may not use more restrictive thresholds than those in the screens. ~~and arrive at one of the following determinations:~~

1. The ~~customer-generator facility~~DER [meets] **passes** the applicable **screening** requirements [in] **at** (c) through (l) above **or passes an EDC- conducted power flow analysis that demonstrates the interconnection poses no adverse impacts to the EPS**. In this case[, the EDC shall]:

i. [Notify] **The EDC shall notify** the applicant, [by e-mail or other writing] **through the CIAP portal and by email**, that the interconnection will be finally approved upon completion of the process set forth at (p) [through]**, (q), and** (r) below; and

ii. Within three business days after the notice [in] **at** (o)1i above, **the appropriate EDC representative shall sign Part 1 of the original application and** the EDC shall return [to the applicant] **the signed** Part 1 [of the original application, signed by the appropriate EDC representative] **to the applicant through the CIAP portal and by email or other writing**;

2. The ~~customer-generator facility~~DER has failed to meet one or more of the applicable **screening** requirements at (c) through (l) above, but the EDC has nevertheless determined that the ~~customer-generator facility~~DER can be interconnected consistent with safety, reliability**,** and power quality. In this case[, the EDC shall]:

i. [Notify] **The EDC shall notify** the applicant [by e-mail or other writing] **through the CIAP portal and by email** that the interconnection will be finally approved upon completion of the process set forth at (p) [through]**, (q), and** (r) below; and

ii. Within five business days after the notice [in] **at** (o)2i above, **the appropriate EDC representative shall sign Part 1 of the original application and** the EDC shall return [to the applicant] **the signed** Part 1 [of the original application, signed by the appropriate EDC representative] **to the applicant through the CIAP portal and by email or other writing**;

3. The ~~customer-generator facility~~DER has failed to meet one or more of the applicable **screening** requirements at (c) through (l) above, ~~but the initial review indicates that additional review may enable the EDC to determine that the customer-generator facility can be interconnected consistent with safety, reliability, and power quality. In such a case[, the EDC shall]:~~, the EDC shall provide the applicant with the screen results through the CIAP portal and by email. If one or more screens are not passed, the EDC shall provide, in writing, the specific screens that the application failed, including the technical reason for failure. The EDC shall provide information and details about the specific system threshold or limitation causing the application to fail each of the screens. In addition, the EDC shall allow the applicant to select one of the following, at the applicant's option. The applicant must notify the EDC of its selection within 10 business days or the application will be deemed withdrawn:

4. Resubmit an amended level 2 application with appropriate mitigation measures that either reduce the DER's capacity or restrict its ability to export past the point of common coupling through the addition of export controls. The EDC shall also allow an applicant to address a failed screen by adding energy storage or increasing its proposed load, provided that such mitigation measures are paired with export controls and/or a reduction in the DER's nameplate capacity; or

~~3.~~i.

~~i.~~ [Notify] Undergo supplemental review in accordance with section XXX, after submittal of a $2,500 fee

Commented [SCS37]: Recommend adding this language to make it clear how long the applicant has to resolve the deficiencies and provide the complete information.

Commented [SCS38]: IREC supports enabling EDCs to run actual power flow models in place of screens if the capability exists to do so in the time provided for the screening process. However, this should not allow the EDC the opportunity to add additional requirements that would be more conservative than those identified in the screens. See IREC's comments for discussion of the potential issues that could arise here.

Commented [SCS39]: As explained further in IREC's comments, there need to be boundaries put around this to prevent application of unreasonable technical thresholds.

Commented [SCS40]: Like for Level 1, we recommend giving the customer the option to revise their application to mitigate impacts.

for the review; or ~~The EDC shall notify the customer-generator, through the CIAP portal, of[,] which screening requirements were not met and offer to perform[,] additional review to determine whether minor modifications to the electric distribution system (for example, changing meters, fuses, or relay settings) would enable the interconnection to be made consistent with safety, reliability, and power quality. The EDC notice shall provide to the applicant a nonbinding, good faith estimate of the costs of such additional review, and/or such minor modifications, at the +25 percent/-25 percent level, as well as the expected timeline for the additional analysis;~~

ii. Continue evaluating the application under Level 3 after submittal of the Level 3 application fee.

~~ii. [If the customer-generator notifies the EDC that the customer- generator consents to pay for the review and/or modifications, the] **Within 15 business days after the EDC offers to perform additional review and/or modifications, the customer-generator shall notify the EDC if the customer-generator consents to pay for the review and/or modifications. The** EDC shall undertake the review and/or modifications within 15 business days after this notice from the customer-generator[; and]**, or within a longer period agreed to by the customer-generator and the EDC in writing. Any required payments for the additional review shall be received within 30 days after invoicing. If such deposits or payments are not made, the EDC may make the interconnection capacity available to other potential customer-generators and may require the applicant to re-start the interconnection process; and** Within 15 business days after the **additional** review or modifications are complete, **the appropriate EDC representative shall sign Part 1 of the original application and** the EDC shall return [to the customer-generator] **the signed** Part 1 [of the original application, signed by the appropriate EDC representative] **to the customer-generator through the CIAP portal and by email or other writing**; or~~

~~4. The customer-generator facility has failed to meet one or more of the applicable [requirements] **screening criteria** at (c) through (l) above, and the initial review indicates that additional review would not enable the EDC to determine that the customer-generator facility could be interconnected consistent with safety, reliability, and power quality. In such a case, the EDC shall[:] **notify the customer-generator that its facility has failed one or more screening criteria. The EDC shall further include a written explanation of which screens were failed and why within the notice, and provide the following options for the applicant to choose from:**~~

~~[i. Notify the customer-generator in writing that the interconnection application has been denied; and~~

~~ii. Provide a written explanation of the reason(s) for the denial, including a list of additional information and/or modifications to the customer-generator's facility, which would be required in order to obtain an approval under level 2 interconnection procedures.]~~

~~i. **Receive a list of additional information and/or modifications to the customer-generator's facility that would be required to obtain an approval pursuant to level 2 interconnection procedures. The EDC shall further provide guidance to the customer-generator on submission of an amended level 2 application with appropriate mitigation measures that may include:**~~

~~(1) **Reduction in the size of the proposed customer-generator facility that would allow the EDC to interconnect the facility;**~~

~~(2) **Addition of energy storage or active demand management that would allow the EDC to interconnect the facility; and**~~

~~(3) **Elimination of injections onto the grid through addition of non- exporting technology, power relays, or other comparable means.**~~

~~ii.~~iii. ~~**Resubmit the application pursuant to the level 3 interconnection review procedure.**~~

(q) If the applicant chooses to proceed to supplemental review, within 20 business days of an applicant's election and payment of the fee, the EDC shall perform supplemental review using the screens set forth below, notify the applicant of the results, and include with the notification a written report of the analysis and data underlying the utility's determinations under the screens, including information about the specific system threshold or limitation causing the result.

1. Minimum Load Screen: 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, estimated from existing

data, or determined from a power flow model, the DER's export capacity aggregated with all other generation capable of exporting energy on the line section is less than one hundred percent (100%) of the relevant minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed DER. If the minimum load data are not available, or cannot be calculated or estimated, the DER's export capacity aggregated with all other generation capable of exporting energy on the line section is less than 30 percent of the peak load for all line sections bounded by automatic sectionalizing devices upstream of the proposed DER.

i. Load that is co-located with load-following, non-exporting or export-limited generation should be appropriately accounted for.

ii. The EDC will not consider as part of the aggregate export capacity for purposes of this screen DER export capacity, including combined heat and power (CHP) facility capacity, known to be already reflected in the minimum load data.

2. Voltage and Power Quality Screen: If the DER utilizes acceptable means of export control, the export capacity instead of nameplate rating must be utilized in any analysis done for this screen, including power flow simulations. 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 1547; and

iii. The harmonic levels meet IEEE Standard 1547 limits at the Reference Point of Applicability.

3. Supplemental Grounding Screen: If the DER failed the line configuration screen section XXX:

i. For DERs with a rotating machine, effective grounding must be maintained.

ii. For DERs with a three-phase inverter, the Utility shall apply one of the following screens to evaluate whether the DER is effectively grounded:

- The line-to-neutral connected load on the feeder or line section is greater than thirty-three percent (33%) of peak load on the feeder or line section.
- If using a supplemental grounding software tool: (1) The tool determines that supplemental grounding is not required to maintain effective grounding. (2) If the tool determines that supplemental grounding is required, the Applicant must agree to modify the DER to include supplemental grounding.

iii. If using a detailed hosting capacity analysis that incorporates evaluation of temporary overvoltage risk for inverters, the nameplate rating of the DER is below the available hosting capacity at the point of common coupling.

4. Safety and Reliability Screen: The location of the proposed DER and the aggregate export capacity on the line section do not create impacts to safety or reliability that cannot be adequately addressed without Detailed Study review. If the DER limits export pursuant to Section IV.B, the export capacity must be included in any analysis including power flow simulations, except when assessing Fault Current contribution. To assess Fault Current contribution, use the rated Fault Current; for example, the Applicant may provide manufacturer test data (pursuant to the Fault Current test described in IEEE Std 1547.1-2020 clause 5.18) showing that the Fault Current is independent of the nameplate rating. The EDC shall give due consideration to 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 (i.e., several large commercial customers).

ii. Whether there is an even or uneven distribution of loading along the feeder.

iii. Whether the proposed DER is located in close proximity to the substation (i.e., < 2.5 electrical circuit miles), and whether the distribution line from the substation to the point of common coupling is composed of large conductor/feeder section (i.e., 600A class cable).

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

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

vi. Whether the proposed DER utilizes Certified Anti-Islanding functions and equipment.

5. If the application fails one or more of the supplemental review screens, the EDC shall provide the applicant with the screen results through the CIAP portal and by email. The EDC shall provide, in writing, the specific screens that the application failed, including the technical reason for failure. The EDC shall provide information and details about the specific system threshold or limitation causing the application to fail each of the screens. The EDC shall provide the applicant the option to:

i. Resubmit an amended level 2 application with appropriate mitigation measures that either reduce the DER's capacity or restrict its ability to export past the point of common coupling through the addition of export controls. The EDC shall also allow an applicant to address a failed screen by adding energy storage or increasing its proposed load, provided that such mitigation measures are paired with export controls and/or a reduction in the DER's nameplate capacity; or

ii. Withdraw the application or proceed to Level 3. The applicant must notify the EDC of its selection within 10 business days or the application will be deemed withdrawn.

6. If the application passes the supplemental review screens, the EDC shall notify the applicant through the CIAP portal and by email that the interconnection will be finally approved upon completion of the process set forth at (q) , (r), and (s) below; and

7. Within five business days after the notice at (p)6 above, the appropriate EDC representative shall sign Part 1 of the original application and the EDC shall return the signed Part 1 to the applicant through the CIAP portal and by email or other writing.

~~(p)~~(r) (No change.)

~~(q)~~(s) At least 10 business days prior to starting operation of the ~~customer- generator facility~~DER (unless the EDC does not require 10 days notice), the ~~customer-generator~~applicant shall**, through the CIAP portal**:

1.-3. (No change.)

~~(r)~~(t) The EDC may require an EDC inspection of a ~~customer-generator facility~~DER prior to operation, and may require and arrange for witness of commissioning tests as set forth [in] **at** IEEE [standard] **Standard** 1547 [(published July 2003)] in accordance with the following:

1. The ~~customer-generator~~applicant shall submit the construction official's approval and the signed Part 2 [under] **of the application pursuant to** (q) above and inform the EDC that the ~~customer-generator facility~~DER is ready for EDC inspection;

2. (No change.)

[3. The appointments offered under (r)2 above shall be no later than 15 business days after the EDC offers the appointments, (that is, within 20 business days after the ~~customer-generator~~applicants submittal under (r)1 above);]

3. The inspection times offered pursuant to (r)2 above shall be based on the EDC's scheduling process, and shall not be unreasonably delayed;

4. (No change.)

5. Within five business days after successful completion of the EDC inspection, the EDC shall notify the ~~customer-generator~~applicant that it is authorized to energize the facility. The notice shall be provided in the format required [under] **pursuant to** N.J.A.C. 14:8-5.2(i); [and]

6. The applicant shall not begin operating the ~~customer-generator facility~~DER until after the inspection and testing is completed[.]**; and**

7. Unauthorized system interconnection or operation will result in no payment for excess generation credits. The EDC has the right to disconnect unauthorized interconnections, but must notify a ~~customer-generator facility~~DER operator within four hours of taking such action.

[(s) If an application for level 2 interconnection review fails to meet the requirements as described at (*o*)3 or 4 above, or is denied because it does not meet one or more of the requirements in this section, the applicant may resubmit the application under the level 3 interconnection review procedure.]

14:8-5.6 Level 3 interconnection review

~~(a)~~ [Each] **By (120 days of the effective date of this rulemaking), each** EDC shall adopt **a common set of** level 3 interconnection review procedures. ~~[procedure]~~ ~~**screens**~~. [The EDC shall use the level 3 review procedure for an application to interconnect a ~~customer-generator facility~~DER that does not qualify for the level 1 or level 2 interconnection review procedures set forth at N.J.A.C. 14:8-5.4 and 5.5.] **An EDC shall use ~~the~~ level 3 ~~review screens~~ for applications to connect ~~customer-generator facilities~~DERs that:**

Commented [SCS41]: It should be clear that if an applicant fails Level 1, 2, or Supplemental Review that it can proceed on to Level 3 without losing its queue position or needing to resubmit the application. The applicant should be provided the opportunity to pay the Level 3 fees within 10 business days and then proceed.

Commented [SCS42]: This entire section needs a major revision. The processes set forth in the newly added sections (j) through (t) need to be organized and better integrated with the remaining sections not yet deleted herein that set forth the system impact study and facilities study. Generally, the subsections should proceed in the sequential order the steps would be taken. For example, the application fee and process for payment should bet set forth first, then the process for the scoping meeting, followed by the system impact study, facilities study, and signing of the interconnection agreement. As is, this section is deeply confusing.

Commented [SCS43]: There are no screens for this process as set forth below, rather it relies on studies.

~~1.~~**(a)** ~~**Are greater than two MW, as measured in direct current;**~~

~~2.~~1. **Do not qualify for either the level 1 or level 2 interconnection review procedures; or**

~~3.~~2. **Did not pass the level 1 or level 2 interconnection review procedures set forth at N.J.A.C. 14:8-5.4 and 5.5.**

[(b) The EDC shall conduct an initial review of the application and shall offer the applicant an opportunity to meet with EDC staff to discuss the application. At the meeting, the EDC shall provide pertinent information to the applicant, such as the available fault current at the proposed interconnection location, the existing peak loading on the lines in the general vicinity of the ~~customer-generator facility~~DER, and the configuration of the distribution lines at the proposed point of common coupling.]

(b) Within 1~~0~~5 business days after receiving an application for level 3 interconnection review, the EDC shall notify the applicant through the CIAP portal and by email that it received the application and that the application is either complete or incomplete. If the application is incomplete, the notice shall include a list of all of the information needed to complete the application. The applicant must provide the requested information within 10 business days, or the application will be deemed withdrawn.

(c) [The EDC shall provide an impact study agreement to the applicant, which shall include a good faith cost estimate for an impact study to be performed by the EDC. An impact study is an engineering analysis of the probable impact of a ~~customer-generator facility~~DER on the safety and reliability of the EDC's electric distribution system. An] **A system** impact study shall be conducted in accordance with good utility practice, as defined at N.J.A.C. 14:8-5.1**,** and shall:

1.-3. (No change.)

(d) If the proposed interconnection may affect electric transmission or delivery systems[, other than] that **are not** controlled by the EDC, operators of these other systems may require additional studies to determine the potential impact of the interconnection on these systems. If such additional studies are required, the EDC shall coordinate the studies[, but shall not be responsible for their timing] **and shall ~~use best efforts to~~ complete those studies within 60 business days of being notified of the need for an affected system study**. The applicant shall be responsible for the costs of any such additional studies required by another affected system. Such studies shall be conducted only after the applicant has provided written authorization **to the EDC**.

[(e) After the applicant has executed the impact study agreement and has paid the EDC the amount of the good faith estimate required under (c) above, the EDC shall conduct the impact study and shall notify the applicant of the results as follows:

1. If the impact study indicates that only insubstantial modifications to the EDC's electric distribution system are necessary to accommodate the proposed interconnection, the EDC shall send the applicant an interconnection agreement that details the scope of the necessary modifications and an estimate of their cost; or

2. If the impact study indicates that substantial modifications to the EDC's electric distribution system are necessary to accommodate the proposed interconnection, the EDC shall provide an estimate of the cost of the modifications, which shall be accurate to within plus or minus 25 percent. In addition, the EDC shall offer to conduct a facilities study at the applicant's expense, which will identify the types and cost of equipment needed to safely interconnect the applicant's ~~customer-generator facility~~DER.

(f) If an applicant requests a facilities study under (e)2 above, the EDC shall provide a facilities study agreement. The facilities study agreement shall describe the work to be undertaken in the facilities study and shall include a good faith estimate of the cost to the applicant for completion of the study. Upon the execution by the applicant of the facilities study agreement, the EDC shall conduct a facilities study, which shall identify the facilities necessary to safely interconnect the ~~customer-generator facility~~DER with the EDC's electric distribution system, the cost of those facilities, and the time required to build and install those facilities.]

[(g)] **(e)** [Upon completion of a facilities study] **Within five business days of the completion of the facilities study**, the EDC shall provide the applicant with the results of the study and an executable **Part I** interconnection agreement. The **interconnection** agreement shall list the conditions and facilities necessary for the ~~customer-generator facility~~DER to safely interconnect with the EDC's electric distribution system, [the cost of those facilities, and the estimated time required to build and install those facilities] **incorporate**

Commented [SCS44]: Per the above suggestions, there is no need for this section. Any project that either does not qualify for Level 1 or 2, or does not pass either, should be able to proceed to Level 3.

Commented [SCS45]: This is unnecessarily long, this two weeks should be more than sufficient to simply review the completeness of an application.

Commented [SCS46]: Recommend adding this language to make it clear how long the applicant has to resolve the deficiencies and provide the complete information.

the milestones (if any) from the facilities study, and include an itemized quote breaking out equipment, labor, operation and maintenance, and other costs, including overheads, for ~~**, including overheads, for**~~ **any required electrical power system modifications** **or interconnection facilities**, **subject to the cost limit set by the facilities' study cost estimate.**

[(h) If the applicant wishes to interconnect, it shall execute the interconnection agreement, provide a deposit of not more than 50 percent of the cost of the facilities identified in the facilities study, complete installation of the ~~customer-generator facility~~DER, and agree to pay the EDC the amount required for the facilities needed to interconnect as identified in the facilities study.]

[(i)] **(f)** Within [15] **10** business days after notice from the applicant that the ~~customer-generator facility~~DER has been installed, the EDC shall inspect the ~~customer-generator facility~~DER and shall arrange to witness any **required** commissioning tests [required under] **pursuant to** IEEE Standard 1547. The EDC and the applicant shall select a date by mutual agreement for the EDC to witness commissioning tests**.** ~~**For systems greater than 10 MW, IEEE Standard 1547 may be used as guidance.**~~ **If the** ~~**customer-generator facility**~~**DER passes the inspection, the EDC shall provide written notice of the results within three business days. If a** ~~**customer-generator facility**~~**DER initially fails an inspection, the EDC shall offer to redo the inspection at the applicant's expense at a time mutually agreeable to the parties within 30 business days of the** ~~**customer-generator**~~**applicant requesting a retest. If the EDC determines that the** ~~**customer-generator facility**~~**DER fails the inspection, it must provide a written explanation detailing the reasons and any standards' criteria violated.**

[(j)] **(g)** Provided that the ~~customer-generator facility~~DER passes any required commissioning tests satisfactorily, the EDC shall notify the applicant in writing **through the CIAP portal**, within three business days after the tests, of one of the following:

1. (No change.)
2. The facilities study identified necessary construction that has not been completed, the date upon which the construction will be completed**,** and the date when the ~~customer-generator facility~~DER may begin operation. **The EDC shall promptly notify the** ~~**customer-generator**~~**applicant through the CIAP portal of any changes in the construction schedule.**

[(k)] **(h)** If the commissioning tests are not satisfactory, the ~~customer- generator~~applicant shall repair or replace the unsatisfactory equipment and reschedule a commissioning test pursuant to [(i)] **(f)** above.

[(l)] **(i)** (No change in text.)

(j) An application fee not to exceed $100.00 plus $10.00 per kW of the nameplate rating up to a maximum of $2,000 shall accompany any application and an application shall not be deemed complete until the application fee is received. The application fee shall be in addition to charges for actual time spent on analyzing the proposed interconnection. Costs for EDC studies and facilities necessary to accommodate the applicant's proposed ~~**customer-generator facility**~~**DER shall be the responsibility of the applicant.**

(k) Within 1~~3~~0 business days of a completed application, the EDC shall conduct an initial review that includes a scoping meeting with the applicant. The scoping meeting shall take place in person, by telephone, or electronically, by a means mutually agreeable to the parties. At the scoping meeting, the EDC shall provide additional relevant and non-confidential information to the applicant that was not already provided as part of the PAVE report, including items such as the available fault current at the proposed interconnection location, the existing peak loading on the lines in the general vicinity of the ~~**customer-generator facility**~~**DER, and the configuration of the distribution lines at the proposed point of common coupling. The EDC shall also identify if the RPA denoted by the application is appropriate. If not, the EDC should specify why and require the utility to update the application with the proper RPA within 10 business days. By mutual agreement of the parties, the scoping meeting or system impact study may be waived in writing.**

(l) Within five business days of the completion of the scoping meeting (or five business days after the EDC receives a completed application if the scoping meeting is waived), the EDC shall provide a draft system impact study agreement to the applicant, which shall include a good faith cost estimate of the cost and time for an impact study to be performed by the EDC. The applicant shall execute the

Commented [SCS47]: Recommend using a more specific description of how the cost estimate shall be itemized.

Commented [SCS48]: IEEE 1547-2018 is now applicable to systems above 10 MW and should thus be used for all DERs.

Commented [SCS49]: This is inconsistent with the language below in 14:8-5.7(c). Here the fee has a maximum of $2,000, but below there is no max. Further, it is not clear what the Level 3 study fee is intended to compensate the utility for if it is also responsible for the EDC's time spend on the studies. For Level 3 we recommend just having the costs tracked and compensated directly through the study process.

Commented [SCS50]: This seems like a long period of time to just conduct the scoping meeting. IREC recommends shortening this to 10 business days.

impact study agreement within 10 business days, along with any deposit required by the EDC; provided that the applicant may request that the EDC hold the draft agreement in abeyance for up to 60 calendar days to allow for negotiation of the scope of the system impact study or to engage in dispute resolution procedures as specified at N.J.A.C. 14:8-5.12.

(m) Once an applicant delivers to the EDC an executed system impact study agreement and payment in accordance with that agreement, the EDC shall conduct the system impact study. The system impact study shall be completed within 30 business days of the applicant's delivery of the executed system impact study agreement; provided that if system upgrades are required, the EDC may elect to extend the study process by an additional 20 business days. The system impact study provided to the applicant shall include a description of the EDC's analysis, conclusions, and the reasoning supporting those conclusions.

(n) If the EDC determines that the system upgrades required to accommodate the proposed ~~customer-generator facility~~DER are not substantial, the system impact study will state the scope and cost of the modifications identified in its results, and no facilities study shall be required. Modifications are considered not substantial if:

1. **The total cost is below $200,000, or such other value as the Board shall establish by Board order; or**
2. **The EDC, in its reasonable judgement, determines the modifications are not substantial.**

(o) If the EDC determines that necessary modifications to the electrical power system are substantial, the results of the system impact study will include an estimate of the cost of a facilities study and an estimate of the modification costs and timeline. If the applicant chooses to proceed, the EDC shall complete a facilities study that identifies the detailed costs of any electrical power system modifications necessary to interconnect the applicant's proposed ~~customer-generator facility~~DER, unless the parties agree to waive the facilities study.

(p) If the parties do not waive the facilities study, then within five business days of the completion of the system impact study, the EDC shall provide a facilities study agreement, which shall include a good faith estimate of the cost and the time needed to undertake the facilities study.

(q) Once the applicant executes the facilities study agreement and pays the EDC pursuant to the terms of that agreement, the EDC shall conduct the facilities study. The facilities study shall include a detailed list of necessary electrical power system upgrades and an itemized cost estimate, breaking out equipment, labor, operation, maintenance, and other costs, including overheads, for completing such upgrades. If the EDC commences construction of actual upgrades, the EDC may not charge the applicant for any portion of cost overruns that exceed 50 percent of the total estimated upgrade cost. The facilities study shall also indicate the milestones for completion of the applicant's installation of its ~~customer-generator facility~~DER and the EDC's completion of any electrical power system modifications, and the milestones from the facilities study (if any) shall be incorporated into the interconnection agreement. The facilities study shall be completed within 45 business days of the applicant's delivery of the executed facilities study agreement and receipt of any necessary deposits. If the applicant fails to execute the facilities study agreement or make the required deposits within 60 business days after receipt of the facilities study agreement from the EDC, the EDC may make the interconnection capacity available to other potential ~~customer-generators~~applicants and may require the applicant to re-start the interconnection process. Within 40 business days of the receipt of an interconnection agreement, the applicant shall execute and return the interconnection agreement and notify the EDC of the anticipated date on which the ~~customer-generator facility~~DER expects to commence commercial operation. Unless the EDC agrees to a later date or requires more time for necessary modifications to its electrical power system, the applicant shall identify an anticipated start date that is within 36 months of the applicant's execution of the interconnection agreement. However, the parties may mutually agree to an extension of this time, if needed, which shall not be unreasonably withheld. The applicant shall notify the EDC, in writing, and through the CIAP portal if there is any change in the anticipated start date of interconnected operation of the ~~customer-generator facility~~DER.

(r) The EDC shall bill the applicant for the design, engineering, construction, and procurement costs of the EDC-provided interconnection facilities and upgrades on a monthly basis, or as otherwise

Commented [SCS51]: Waiver of the facilities study should be at the customers option, not solely the determination of the EDC.

Commented [SCS52]: IREC strongly supports the adoption of this cost envelope, but a 50% increase is unacceptable and out of line with what other states have adopted. IREC recommends a maximum limit of 30%, which is 5% above the general guide for estimate accuracy.

agreed by the parties. The ~~customer-generator~~applicant shall pay each bill within 30 calendar days of receipt, or as otherwise agreed by the parties and memorialized in writing. At least 20 calendar days prior to the commencement of the design, procurement, installation, or construction of a discrete portion of any EDC facilities or upgrades, the applicant shall provide the EDC with a deposit equal to 50 percent of the cost estimated for its interconnection facilities prior to its beginning design of such facilities.

(s) Within 60 calendar days of completing the construction and installation of the modifications to the EDC's system, the EDC shall provide the applicant with a final accounting report of any difference between the actual cost incurred to complete the construction and installation and the budget estimate provided to the applicant in the interconnection agreement and the applicant's previous deposit and aggregate payments to the EDC for such modifications. The EDC shall provide a written explanation for any actual cost exceeding a budget estimate by 25 percent or more. If the applicant's cost responsibility exceeds its previous deposit and aggregate payments, the EDC shall invoice the applicant for the amount due and the applicant shall make payment to the EDC within 30 calendar days. If the applicant's previous deposit and aggregate payments exceed its cost responsibility, the EDC shall refund to the applicant an amount equal to the difference within 30 business days of the final accounting report.

14:8-5.7 Interconnection fees

[(a) An EDC or supplier/provider shall not charge an application or other fee to an applicant that requests level 1 interconnection review. However, if an application for level 1 interconnection review is denied because it does not meet the requirements for level 1 interconnection review and the applicant resubmits the application under another review procedure in accordance with N.J.A.C. 14:8-5.4(p), the EDC may impose a fee for the resubmitted application, consistent with this section.]

(a) An EDC or supplier/provider shall charge an application fee, not to exceed $100.00, or other value established by Board order, to an applicant that requests level 1 interconnection review.

(b) For a level 2 interconnection review, the EDC may charge **initial application** fees of up to $50.00 plus $1.00 per kilowatt of the ~~customer- generator facility's~~DER's [capacity] **~~nameplate rating~~export capacity**, [plus] **or any alternative value established by Board order. In addition to the initial application fee, the EDC may charge the applicant for** the cost of any minor modifications to the electric distribution system or additional review, if required [under] **pursuant to** N.J.A.C. 14:8-5.5[(o)3 or 4]. Costs for such minor modifications or additional review shall be based on EDC estimates and shall be subject to case-by-case review by the Board**,** or its designee. [Costs for] **~~The EDC shall bill an applicant only for the actual costs, including reasonable overhead, of~~** ~~engineering work done as part of any additional review [shall not exceed $100.00 per hour].~~**For supplemental review, the EDC may charge a $2,500 fee. An application shall not be deemed complete until the EDC receives the initial application fee.**

1. **For a level 2 interconnection review of a community solar facility or community energy system for which an applicant is granted an Enhanced PAVE process, the EDC may charge another fee of $700.00, in addition to the normal fee for a level 2 PAVE report.**

(c) For a level 3 interconnection review, the EDC may charge **initial application** fees of up to $100.00 plus [$2.00] **$10.00** per kilowatt of the ~~customer-generator facility~~DER's [capacity, as well as charges] **nameplate rating. In addition to the initial application fee, the EDC may charge the applicant** for actual time spent on any impact and/or facilities studies required [under] **pursuant to** N.J.A.C. 14:8-5.6. [Costs for] **The EDC shall bill an applicant only for the actual costs, including reasonable overhead, of** engineering work done as part of a system impact study or facilities study [shall not exceed $100.00 per hour]. If the EDC must install facilities in order to accommodate the interconnection of the ~~customer-generator facility~~DER, the cost of such facilities shall be the responsibility of the applicant. **An application shall not be deemed complete until the initial application fee is received.**

1. **For a level 3 interconnection review of a community solar facility or community energy system for which an applicant requests an Enhanced PAVE process, the EDC may charge another fee of $700.00, in addition to the normal fee for a level 2 PAVE report.**

(d) (No change.)

(e) ~~A customer-generator shall pay for the cost of any additional equipment the EDC reasonably~~

Commented [SCS53]: This is inconsistent with the language above in 14:8-5.6(j). As worded, this fee is outrageously high (e.g. $10,100 for a 1 MW project), particularly if the customer is also responsible for the actual study costs. As noted above, the rules should require a deposit for the system impact study and the facilities study and no application fee. Applicants should be responsible for the EDC's actual costs, but nothing more.

~~**determines is necessary to interconnect a customer-generator facility in a manner that maintains the safe and reliable operation of the EPS.**~~

14:8-5.8 Testing, maintenance**,** and inspection after interconnection approval

(a) Once a net metering interconnection has been approved [under] **pursuant to** this subchapter, the EDC shall not require an applicant ~~customer- generator~~ to test or perform maintenance on its facility except for the following:

1.-2. (No change.)

3. Any post-installation testing necessary to ensure compliance with IEEE **Standard** 1547 or to ensure safety.

(b) When a ~~customer-generator facility~~DER approved through a level 2 or level 3 review undergoes maintenance or testing in accordance with the requirements of this subchapter, the ~~customer-generator~~applicant shall retain written records documenting the maintenance and the results of testing **for three calendar years**. No recordkeeping is required for maintenance or testing performed on a ~~customer-generator facility~~DER approved through a level 1 review.

(c) An EDC shall have the right to inspect an applicant's ~~customer-generator's~~ facility after interconnection approval is granted, at reasonable hours and with reasonable prior notice to the ~~customer-generator~~applicant. If the EDC discovers that the ~~customer-generator's facility~~DER is not in compliance with the requirements of this subchapter, and the noncompliance adversely affects the safety or reliability of the electric distribution system, the EDC may require the ~~customer-generator~~applicant to disconnect the ~~customer-generator facility~~DER until compliance is achieved. **The EDC shall notify the ~~customer-generator~~applicant of any noncompliance requiring disconnection of the ~~customer-generator facility~~DER through the CIAP.**

(d) The EDC shall notify the ~~customer-generator~~applicant through the CIAP, if it identifies any issue with customer-owned equipment during any required commissioning tests that requires de-energizing the ~~customer-generator facility~~DER, or preventing the ~~customer- generator facility~~DER from energizing, in order to maintain the safety or reliability of the electric distribution system. The EDC shall notify the ~~customer-generator facility~~DER operator within four hours of such action being taken. The ~~customer-generator~~applicant and the EDC shall then determine a mutually agreeable timeframe in which to resolve the issue. The EDC shall also notify the ~~customer-generator~~applicant through the CIAP of any changes in the construction schedule.

14:8-5.9 Interconnection reporting requirements for EDCs

(a) Each EDC with one or more ~~customer-generators~~DERs connected to its distribution system shall**:** [submit two interconnection reports per year, one covering January 1 through June 30 and one covering July 1 through December 31. The EDC shall submit the reports by August 1 and February 1, respectively.]

1. Track key performance indicators, including those listed at (c) and (d) below, as well as any other performance indicator established by Board order, on the EDC's website and update this information at least once every month;Maintain a publicly available~~n~~ interconnection queue that includes all level 2 and level 3 interconnection requests currently pending before the EDC that includes the following information for each project~~, at a level of detail that reasonably preserves customer confidentiality;~~:

i. **Queue number**
ii. **Nameplate Rating (kW)**
iii. **Export Capacity (kW)**
iv. **Primary fuel type (e.g., solar, wind, bio-gas, etc.)**
v. **Secondary fuel type (if applicable)**
vi. **Exporting (including limited export) or Non-Exporting**
vii. **City**
viii. **Zip code**
ix. **Substation**
x. **Feeder**
xi. **Status (active, withdrawn, interconnected, etc.)**
xii. **Date application deemed complete**

Commented [SCS54]: It is unclear why this is needed, the above sections lay out the process for paying for upgrade costs. IREC is concerned this opens the door for the EDCs to arbitrarily charge for equipment not identified in the study process.

Commented [SCS55]: IREC recommends requiring a specific list of fields for the interconnection queue. Attachment 7 to IREC's model rules includes a list of the information that should be required.

xiii. **Date of notification of level 2 screen results (if applicable)**
xiv. **Level 2 screen results (pass or fail, and if fail, identify the screens failed) (if applicable)**
xv. **Date of notification of Supplemental Review results (if applicable)**
xvi. **Supplemental Review results (pass or fail, and if fail, identify the screens failed) (if applicable)**
xvii. **Date of notification of System Impact Study results (if applicable)**
xviii. **Date of notification of Facilities Study results and/or construction estimates (if applicable)**
xix. **Date final Interconnection Agreement is provided to Customer**
xx. **Date Interconnection Agreement is signed by both parties**
xxi. **Date of grant of permission to operate**
~~1.~~xxii. **Final interconnection upgrade cost paid to utility**

2. **Conduct customer satisfaction surveys and post those results on its website and provide them to the Board; and**
3. **Submit interconnection reports to the Board on a quarterly basis, by the first day of each quarter.**

(b) The EDC shall submit [the reports required by this section electronically, in PDF format, to oce@bpu.state.nj.us] **any interconnection reports to the Board Secretary in a docket and in a form specified by the Board Secretary**. [In addition, the EDC may, at its discretion, submit a paper copy of the reports by hand delivery or regular mail to the Secretary, Board of Public Utilities, 44 South Clinton Avenue, 9th Floor, PO Box 350, Trenton, New Jersey 08625-0350. The EDC may, at its discretion, submit the interconnection report together with the net metering report required under N.J.A.C. 14:8-4.5.

(c) Each report shall contain the following information regarding ~~customer-generator facilities~~DERs that interconnected with the EDC's distribution system for the first time during the reporting period, listed by type of renewable energy technology:

1. The number of ~~customer-generators~~DERs that interconnected;
2. The estimated total nameplate ~~rated generating capacity~~and export capacity of all ~~customer- generator facilities~~DER that interconnected; and
3. The total cumulative number of ~~customer-generators~~DERs that interconnected between June 15, 2001 and the end of the reporting period, including the ~~customer-generators~~DERs in (c)1 above.

(d) The information required under (c) above shall be listed by type of class I renewable energy, as set forth at N.J.A.C. 14:8-2.5(b), as follows:

1. Solar PV technology;
2. Wind technology;
3. Biomass; or
4. A renewable energy technology not listed at (d)1 through 3 above. In such a case, the report shall include a description of the renewable energy technology.]

(c) Each report shall contain the following key performance indicators and information, as may be adjusted by Board order, regarding ~~customer-generator facilities~~DERs that interconnected with the EDC's distribution system or attempted to interconnect during the reporting period, for each interconnection level, based on the nameplate capacity of the ~~customer-generator facility~~DER:

1. The number and total nameplate capacity of ~~customer- generator~~DERs that applied for interconnection;
2. The number and total nameplate capacity of ~~customer- generator~~DERs that successfully interconnected;
3. The number and total nameplate capacity of ~~customer- generator~~DERs ~~facilities~~ that withdrew or were removed from the interconnection queue;
4. The number of applications submitted with missing information that were not automatically addressed as part of the CIAP process;
5. Number, total nameplate capacity, and type of all proposed ~~customer-generator facilities~~DERs that undertook a PAVE process;
6. Number, total nameplate capacity, and type of ~~customer- generator~~ DER applications processed within the timelines established by this chapter;
7. Length of time each ~~customer-generator~~applicant waited for system impact and facilities studies;

Commented [SCS56]: IREC recommends adding information to the list below on costs. Specifically, the reports should include information on the costs for system impact studies and facilities studies, the cost for upgrades, and the deviation between cost estimates and final costs for upgrades. Monitoring the difference between cost estimates and final costs is important to ensure the utilities are not inflating the estimates to get around the cost envelope.

8. Number, total nameplate capacity, and type of ~~customer- generator~~DER applications not processed within the timelines established in this chapter, the length of time taken to complete processing delayed applications, and the reasons for any delay in processing applications;

9. Data on Enhanced PAVE requests covering all key performance indicators described at (c)1 through 8 above, presented clearly and conspicuously in a dedicated section of the report;

10. The number and total nameplate capacity of ~~customer- generator~~DERs of each technology type, broken out by class I renewable energy technologies (for example, solar, wind, or fuel cell technologies), energy storage devices, electric vehicle-to-grid projects, and hybrid systems involving multiple behind-the-meter technologies;

11. Data on quantity, nameplate capacity, type, and processing times for DER aggregation requests;

12. Data on the number of times applicants requested formal or informal dispute resolution, the timeline for resolution, whether the Board's interconnection ombudsman was involved, and how each dispute was resolved; and

13. A statement regarding whether the EDC believes it has the resources and capabilities needed to timely process current interconnection applications, as well as a trend analysis that assesses the EDC's capability to timely process interconnection applications if the volume of applications increases.

(d) Each EDC shall maintain a current summary status on its website, and present it in a graphical format that is common to all EDCs, of all active interconnection applications showing the following performance indicators for active level 1, 2, and 3 interconnections:

1. The number of and total nameplate capacity represented by new applications received during the reporting period;

2. The number of and total nameplate capacity represented by currently active applications;

3. The number and total nameplate capacity of ~~customer- generator~~DER facilities approved for interconnection during the reporting period, as well as the percent of active applications and nameplate capacity approved during the reporting period; and

4. The percent of active applications and total nameplate capacity approved year to date.

(e) Each EDC shall annually report to the Board the full results of all recurring testing performed on legacy interconnected customer/generators, segmented by levels 2 and 3, pursuant to N.J.A.C. 14:8-5.8(a)1, which shall include:

1. Number and percentage of total interconnected systems that were tested;

2. Number and percentage of waivers that were granted for exemption from testing; and

3. Number and percentage of total interconnected systems that failed testing and required remediation.

14:8-5.10 Pre-Application Verification/Evaluation (PAVE) process

(a) A Pre-Application Verification/Evaluation (PAVE) process shall be offered by each EDC for any qualified level 2 or level 3 projects upon payment of a $300.00 fee, or such alternative fee as the Board shall establish by Board order.

1. Community solar facilities or community energy systems that are eligible for PAVE reports may elect to have an Enhanced PAVE process upon payment of a $700.00 fee, which shall be additional to the fee for the standard PAVE process.

(b) The PAVE process shall be initiated through the CIAP. To facilitate the PAVE process, the CIAP shall include an easy-to-use PAVE screening/configurator tool with data field entries into which a potential applicant can input basic parameters about their potential ~~customer-generator facility~~DER.

(c) Within 15 business days of the potential applicant providing a complete PAVE request, the EDC should provide information about relevant parts of its EPS through the CIAP, or other means agreed to by the EDC and the potential applicant, to the potential applicant regarding the interconnection of a proposed project, which may include the following items, as they may be modified by Board order:

1. Total capacity (MW) of substation/area bus or bank and circuit;

2. Aggregate queued ~~generating~~ nameplate and export capacity (MW) proposing to interconnect to the substation/area bus or bank and circuit;

3. Available hosting capacity (MW) of the substation/area bus or bank and circuit, which is the total capacity less the sum of existing and queued ~~generating~~ nameplate and export capacity, accounting

Commented [SCS57]: Recommend requiring that both the nameplate and export capacity be provided as this will be more useful. For example, if there is a 2 MW non-exporting project on a circuit but only the nameplate capacity is reported, the customer will not be able to accurately assess whether the feeder is at or near capacity for thermal or voltage constraints.

for all load served by existing and queued generators. In calculating available hosting capacity and how much of it a potential ~~customer-generator facility~~DER may utilize, the EDC shall account for non-exporting technology, including non-exporting technology used in combination with increased on-site load or an energy storage device, that limits or will limit the maximum amount of power a ~~customer-generator facility~~DER can export to less than its nameplate capacity rating; Whether the proposed ~~customer-generator facility~~DER is located on an area, spot, or radial network;

4. **Substation nominal distribution voltage or transmission nominal voltage, if applicable;**
5. **Nominal distribution circuit voltage at the proposed site;**
6. **Approximate circuit distance between the proposed site and the substation;**
7. **Relevant line section(s) and substation actual or estimated peak load and relevant minimum load data, including the time the peak and minimum load occurs, when available;**

Commented [SCS58]: This information will be helpful to better inform customers who are installing solar only projects and will be useful for future scheduled systems.

8. **Whether or not three-phase power is available at the site and/or the distance from three-phase service;**
9. **Limiting conductor rating from the proposed point of common coupling to the distribution substation;**
10. **Based on the proposed point of common coupling, 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; or**
11. **Any other information that the EDC deems relevant to the applicant.**

(d) Within 10 business days of providing the potential applicant with a PAVE report, or at a time mutually agreeable to the parties, the EDC shall offer to have a meeting with the potential applicant to review the findings.

(e) In preparing a PAVE report, the EDC need only include pre- existing data. A PAVE request does not obligate the EDC to conduct a study or other analysis of the proposed project in the event that data is not available. If the EDC cannot complete all or some of a PAVE report due to a lack of available data, the EDC will provide the potential applicant with a report that includes the information that is available and identify any information that is unavailable. The EDC shall, in good faith, provide PAVE report data that represents the best available information at the time of reporting.

(f) Each EDC shall provide an FAQ page on its website that clearly explains what the PAVE process is and provides instructions for using and completing the process. At a minimum, the EDC shall provide the following:

1. **A clear statement of the purpose and intent of the PAVE process;**
2. **An overview and explanation of the specific data potential applicants need to provide to utilize the PAVE process, including instructions on how to use the CIAP's PAVE screening/configurator tool;**
3. **Any fee schedules, terms, and conditions associated with the PAVE process;**
4. **Simplified case studies or examples that illustrate successful handling and outcomes of the PAVE process; and**
5. **A designated contact point (email and phone) for handling more detailed questions and/or resolving issues.**

(g) An EDC shall inform a potential applicant who requests a PAVE report that:

1. **The existence of "available hosting capacity" does not imply 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 distribution system is dynamic and subject to change, and the results of the PAVE report do not represent binding interconnection cost quotes; and**
3. **Data provided in the PAVE report may become outdated and not useful by the time a potential applicant submits a complete application.**

14:8-5.11 Hosting capacity maps

(a) By (120 days of the effective date of this rulemaking), each EDC shall make a tariff filing to implement a common hosting capacity mapping process to aid applicants. Hosting capacity maps shall indicate locations on each EDC's distribution system with spare capacity and locations which are likely

to require additional upgrades if a ~~customer-generator facility~~DER interconnects there. If the EDC identifies rules, regulations or physical cyber security policies that limit the ability to publish the maps or otherwise limit sharing of hosting capacity data, the EDC must identify the policy in its tariff filing and explain why it restricts the sharing of data and propose a way to address the restriction without unduly limiting grid transparency.

(b) An EDC shall post distribution system hosting capacity maps on its website, update them at least once every ~~quarter~~month, and publish the results for each line section ~~include both circuit and substation level data~~ in the maps. The data should also be made available in a downloadable format such as a .csv file or equivalent. The available hosting capacity values for each circuit shall be calculated using common methodology and presented in a consistent manner across all EDCs' websites. The hosting capacity analysis should be conducted on at least a 288 hour basis (24 hours a day for each of the 12 months) for generation and for load, such that the results show how limitations vary throughout the day and year. An EDC shall post a written summary of all significant changes to hosting capacity maps on its website and simultaneously distribute them to a subscriber email listserv at least once every quarter. Each EDC shall clearly label its maps with detailed legends explaining what the data means and ensure its map legends use a nomenclature common to all EDCs.

(c) ~~To the greatest extent permitted pursuant to the North American Electric Reliability Council standards, applicable Federal and State laws, rules, and regulations, and internal EDC physical and cybersecurity policies, all hosting capacity maps shall be integrated with GIS systems, V~~Visually present all system data for substations, feeders, line sections, and related distribution assets, and allow potential applicants to easily determine, based on an entered street address, the following information:

1. Whether the nearby distribution circuit(s) are closed, have limited available surplus capacity, or are fully open to interconnecting additional generation;
2. A recommended and maximum amount of additional export ~~capable generating~~ and load capacity, defined as the maximum amount of power ~~customer-generator facilities~~DERs can export or import, after accounting for any ~~non-exporting technology~~export controls, that can be accommodated on each nearby open circuit without violating any reliability criteria, including, but not limited to, thermal, steady-state voltage, voltage fluctuation, and ~~voltage~~ protection criteria;
3. A quantified indication of interest level from other projects (and their aggregate capacity) along the same circuit;
4. A built-in function enabling users to filter sites based on available hosting capacity above a certain threshold;
5. A range of budgetary cost estimates for anticipated upgrades required to make additional hosting capacity available, based on high-level estimates (for example, +/- 25 percent);
6. Uniform load on a circuit segment;
7. Preliminary information on the circuit segment and if the segment has a known transient/dynamic stability limitation, if a transmission ground fault overvoltage is possible, if a proposed facility has any transmission interdependencies, and if all islanding conditions are met based on the utility's screening policies;
8. Identification of potentially limiting equipment requiring a system upgrade on the hosting capacity maps (for example, voltage controllers, protective relays, communication systems, conductor ampacity, etc.); and
9. For each feeder, the available hosting capacity, as well as existing energy storage nameplate capacity, PV nameplate capacity, and any non-PV distributed generation nameplate capacity, each labeled individually. Minimum and peak load data should also be made available for each location.

(d) Each EDC shall ensure that its hosting capacity mapping process includes a documented methodology for validating models, publishing hosting capacity maps, and enabling the collection and compilation of customer feedback.

14:8-5.12 Dispute resolution

(a) By (120 days of the effective date of this rulemaking), each EDC shall make a tariff filing to implement a standardized dispute resolution process to govern disputes between the EDC and a ~~customer-generator~~applicant, including, but not limited to, disputes involving issues with

Commented [SCS59]: IREC recommends this language instead of that proposed below. The utilities should not be given sole authority over interpreting law and policies in this area and they should have to justify any physical or cyber security concerns they have.

Commented [SCS60]: This should be on a monthly basis. Quarterly is too slow to provide timely information.

Commented [SCS61]: Providing information only at the circuit and substation levels makes these maps largely useless. The amount of hosting capacity can vary on a circuit by multiple MWs depending on where a project is interconnected. Quality hosting capacity analysis are done a the nodal or line section level and the results should be published as such as well.

Commented [SCS62]: This improves the ability to view the more granular data and to sort and filter for potential sites and constraints.

Commented [SCS63]: This language is vague and leaves the door open to unecessary redactions or exclusion of information. If the BPU believes that there are laws or policies that limit the publication of data for cybersecurity reasons it should specifically identify those rather than leaving it up to the utility to apply non-transparent "internal policies." IREC added similar language above that requires the utility to affirmative identify the policy and justify its applicability subject to BPU approval or rejection.

Commented [SCS64]: What does it mean for a circuit to be "closed" and why would it be if a customer can pay for upgrades? Recommend eliminating this concept. The point of the HCA is to identify what constraints exist.

Commented [BL65]: We're assuming this means fault protection

Commented [SCS66]: In line with the comment above, the data should be provided at the nodal level with a specific value not a "range." The data should also show the limit by reliability criteria so the customer understand the nature of the constraint.

Commented [SCS67]: IREC's experience with this is that these values are hard to develop and of little use without further analysis. The BPU should ensure it understands whether the utilities are able to produce useful values for this.

Commented [SCS68]: It is not clear what this means. IREC strongly encourages the BPU to require publication of HCA results for both load and generation, but it is not clear if this is what is intended by this.

interconnection studies, cost estimates for necessary upgrades, queue priority, the development of the interconnection agreement, billing, fees, or any related matters. The Board shall accept a standardized dispute resolution tariff filing upon a finding that the proposed dispute resolution process conforms to the requirements of this section and will enable the EDC to fulfill its duties pursuant to this section.

(b) **An applicant may initiate the informal dispute resolution process by making a request through the CIAP portal or to the EDC's interconnection ombudsman, and an EDC may initiate the process by notifying an applicant through the CIAP portal and by sending a written message to the applicant's email address. The parties shall make good faith efforts to resolve any dispute, including by making subject matter experts available, within 10 business days of its initiation or such longer time as the parties agree to in writing.**

(c) **If the informal dispute resolution process is unsuccessful, the applicant shall provide the EDC a written notice of dispute, setting forth the nature of the dispute, the relevant known facts pertaining to the dispute, and the relief sought. The applicant shall submit the notice through the CIAP portal or send it to the EDC and the Board's interconnection ombudsman by email. If the applicant submits the notice through the CIAP portal, the EDC shall send a copy of the notice to the interconnection ombudsman by email.**

(d) **The EDC shall acknowledge the notice within three business days of its receipt and identify a representative with the authority to make decisions for the EDC with respect to the dispute.**

(e) **The EDC shall provide the applicant with all relevant regulatory and/or technical details and analysis regarding any EDC 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. The parties shall operate in good faith and use best efforts to resolve the dispute.**

(f) **If the parties do not resolve their dispute within 30 business days of the date the applicant sent the notice of dispute, then:**

1. **Either party may request to continue negotiations for an additional 20 business days;**
2. **The parties may refer the dispute to the Board's interconnection ombudsman by mutual agreement; or**
3. **The parties may request mediation from an outside third-party mediator by mutual agreement, with costs to be shared equally between the parties.**

(g) **If the parties still do not reach an agreement after attempting to resolve their dispute by one or more of the methods listed at (f) above, then the applicant is strongly encouraged to proceed to the Board's formal complaint resolution process by filing a petition with the Board pursuant to N.J.A.C. 14:1-5.**

(h) **At any time, either party may file a complaint before the Board pursuant to its rules or exercise whatever rights and remedies it may have at equity or law.**