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__MMISSIONERS
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Executive Director

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ARIZONA CORPORATION COMMISSION

Memo

To: Docket Control

From: Maureen A. Scott
Deputy Chief of Litigation & Appeals
Legal Division

Date: March 20, 2020

Re: Docket No. RE-00000A-07-0609
Notice of Final Rulemaking
Interconnection of Distributed Generation Facilities.

Attached is the *Arizona Adiministrative Register,* 26 A.A.R. 473, Notice of Final Rulemaking regarding the Interconnection of Distributed Generation Facilites Rules, A.A.C. R14-2-2601 through R-14-2-2628. The rules became effective, February 25, 2020.

ACC - Docket Control - Received 3/20/2020 3:02 PM
ACC - Docket Control - Docketed 3/20/2020 3:50 PM

NOTICES OF FINAL RULEMAKING

This section of the *Arizona Administrative Register* contains Notices of Final Rulemaking. Final rules have been through the regular rulemaking process as defined in the Administrative Procedures Act. These rules were either approved by the Governor's Regulatory Review Council or the Attorney General's Office. Certificates of Approval are on file with the Office.

The final published notice includes a preamble and text of the rules as filed by the agency. Economic Impact Statements are not published.

The Office of the Secretary of State is the filing office and publisher of these rules. Questions about the interpretation of the final rules should be addressed to the agency that promulgated them. Refer to Item #5 to contact the person charged with the rulemaking. The codified version of these rules will be published in the Arizona Administrative Code.

NOTICE OF FINAL RULEMAKING

TITLE 14. PUBLIC SERVICE CORPORATIONS; CORPORATIONS AND ASSOCIATIONS; SECURITIES REGULATION

CHAPTER 2. CORPORATION COMMISSION FIXED UTILITIES

[R20-37]

PREAMBLE

1. Article, Part, or Section Affected (as applicable) — Rulemaking Action

Article, Part, or Section Affected (as applicable)	Rulemaking Action
Article 26	New Article
R14-2-2601	New Section
R14-2-2602	New Section
R14-2-2603	New Section
R14-2-2604	New Section
R14-2-2605	New Section
R14-2-2606	New Section
R14-2-2607	New Section
R14-2-2608	New Section
R14-2-2609	New Section
R14-2-2610	New Section
R14-2-2611	New Section
R14-2-2612	New Section
R14-2-2613	New Section
R14-2-2614	New Section
R14-2-2615	New Section
R14-2-2616	New Section
R14-2-2617	New Section
R14-2-2618	New Section
R14-2-2619	New Section
R14-2-2620	New Section
R14-2-2621	New Section
R14-2-2622	New Section
R14-2-2623	New Section
R14-2-2624	New Section
R14-2-2625	New Section
R14-2-2626	New Section
R14-2-2627	New Section
R14-2-2628	New Section

2. Citations to the agency's statutory rulemaking authority to include both the authorizing statute (general) and the implementing statute (specific):

Authorizing statute: Arizona Constitution, Art. 15, §§ 3 and 13 and A.R.S. §§ 40-202 through 40-204, 40-321, 40-322, 40-332, 40-336, 40-361, and 40-374

Implementing statute: Arizona Constitution, Art. 15, §§ 3 and 13 and A.R.S. §§ 40-202 through 40-204, 40-321, 40-322, 40-332, 40-336, 40-361, and 40-374

3. The effective date of the rule:

February 25, 2020

a. If the agency selected a date earlier than the 60 day effective date as specified in A.R.S. § 41-1032(A), include the earlier date and state the reason or reasons the agency selected the earlier effective date as pro-

vided in A.R.S. § 41-1032(A)(1) through (5):

Not applicable

b. If the agency selected a date later than the 60 day effective date as specified in A.R.S. § 41-1032(A), include the later date and state the reason or reasons the agency selected the later effective date as provided in A.R.S. § 41-1032(B):

Not applicable

4. Citations to all related notices published in the *Register* as specified in R1-1-409(A) that pertain to the record of the final rulemaking package:

Notice of Rulemaking Docket Opening: 25 A.A.R. 376, February 15, 2019

Notice of Proposed Rulemaking: 25 A.A.R. 355, February 15, 2019

Notice of Supplemental Proposed Rulemaking: 25 A.A.R. 2033, August 9, 2019

5. The agency's contact person who can answer questions about the rulemaking:

Name:	Patrick LaMere, Executive Consultant
Address:	Arizona Corporation Commission Utilities Division 1200 W. Washington St. Phoenix, AZ 85007
Telephone:	(602) 542-4382
E-mail:	PLaMere@azcc.gov
Or	
Name:	Maureen Scott, Deputy Chief of Litigation and Appeals
Address:	Arizona Corporation Commission Legal Division 1200 W. Washington St. Phoenix, AZ 85007
Telephone:	(602) 542-3402
Fax:	(602) 542-4780
E-mail:	MScott@azcc.gov
Web site:	www.azcc.gov

6. An agency's justification and reason why a rule should be made, amended, repealed or renumbered, to include an explanation about the rulemaking:

With this rulemaking, the Commission adds a new Article 26, entitled "Interconnection of Distributed Generation Facilities" to 14 A.A.C. 2, the Chapter containing the Commission's rules for fixed utilities, with the new Article 26 including 28 new rules. The rules for Interconnection of Distributed Generation Facilities ("DGI Rules") establish mandatory technical standards, processes, and timelines for utilities to use for interconnection and parallel operation of different types of distributed generation ("DG") facilities; customer and utility rights and responsibilities; provisions for disconnection of DG facilities from the distribution system; specific safety requirements; more flexible standards for electric cooperatives; a reporting requirement; and a requirement for each utility to create, submit for initial approval and submit for approval periodically and when revised, and implement and comply with a Commission-approved Interconnection Manual.

On June 28, 2005, Congress passed the Energy Policy Act of 2005, published as Public Law 109-58 ("EPACT 2005"), which, *inter alia*, amended Section 111(d) of the Public Utility Regulatory Policies Act of 1978, published as Public Law 95-617 ("PURPA"), codified at 16 U.S.C. 2621(d), by adding the following:

> (15) Interconnection.--Each electric utility shall make available, upon request, interconnection service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term "interconnection service" means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and procedures shall be established whereby the services are [sic] offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential.

EPACT 2005 also added, *inter alia*, the following language to PURPA Section 112(b), codified at 16 U.S.C. 2622(b):

> (5)(A) Not later than 1 year after the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated utility shall commence the consideration referred to in section 111, or set a hearing date for consideration, with respect to the standard established by paragraph (15) of section 111(d).
>
> (B) Not later than two years after the date of the enactment of the this [sic] paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall complete the consideration, and shall make the determination, referred to in section 111 with respect to each standard established by paragraph (15) of section 111(d).

The consideration and determination to be made by each state regulatory authority was contained in Section 111(a) of PURPA, which provided:

(a) CONSIDERATION AND DETERMINATION.—Each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall consider each standard established by subsection (d) and make a determination concerning whether or not it is appropriate to implement such standard to carry out the purposes of this title. For purposes of such consideration and determination in accordance with subsections (b) and (c), and for purposes of any review of such consideration and determination in any court in accordance with section 123, the purposes of this title supplement otherwise applicable State law. Nothing in this subsection prohibits any State regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to implement any such standard, pursuant to its authority under otherwise applicable State law.

In Decision No. 69674 (June 28, 2007), the Commission adopted a modified version of the PURPA standard on interconnection:

Each electric utility shall make available, upon request, interconnection service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term 'interconnection service' means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the Arizona Corporation Commission's rules for interconnection when such rules are adopted and become effective. Until such rules are adopted and become effective, the Interconnection Document shall serve as a guide for interconnection unless otherwise ordered by the Commission.

The Commission also approved an Interconnection Document and ordered Commission Staff to begin a rulemaking process to convert the Interconnection Document into rules.

The DGI Rules are designed to fulfill the requirements of PURPA and EPACT 2005, as the ultimate culmination of the Commission's consideration and determination regarding the implementation of the 16 U.S.C. 2621(d)(15) standard for interconnection, because the DGI Rules establish standards and procedures concerning how regulated utilities must handle requests for interconnection and parallel operation of DG facilities. The DGI Rules build upon the Interconnection Document adopted in Decision No. 69674, and are designed to promote the three purposes of PURPA: "to encourage— (1) conservation of energy supplied by electric utilities; (2) the optimization of the efficiency of use of facilities and resources by electric utilities; and (3) equitable rates to electric consumers." (PURPA § 101.). In Decision No. 69674, the Commission found that having interconnection standards might facilitate the installation of DG, thus reducing the amount of energy to be supplied by electric utilities, and further found that the presence of DG might improve the efficiency of utility electric facilities and thus reduce costs for electric consumers.

Commission Staff has determined that DG systems provide benefits in the form of greater grid reliability, greater grid stability because of voltage support along transmission lines, increased system efficiency due to decreased transmission line losses, increased diversity of resources, decreased demand and cost pressures on natural gas and oil, and sustainability. Commission Staff further has determined that adoption of the DGI Rules, which establish explicit and consistent standards and procedures for interconnection and parallel operation of DG facilities, should prevent increases in monetary and transaction costs for Commission-regulated utilities and their customers that can result from uncertainty. Additionally, Commission Staff has determined that the DGI Rules adopt standards that promote current best practices of DGI for utilities, utility distribution systems, utility customers, and customers' generating facilities and that will help to ensure the continued safe and reliable operation of the distribution systems while also enhancing long-term system planning.

The Commission has determined that the Interconnection Document is insufficient to establish the standards and processes that the Commission considers necessary to adequately address DGI and that the adoption of the DGI Rules is necessary to ensure that all utilities use DGI best practices for interconnection and that applicants for interconnection and parallel operation of DG facilities are subjected to the same technical standards, have their applications handled according to the same standardized processes and timelines based on the DG facilities for which interconnection is requested, and are required to pay only the costs authorized by the Commission's rules for DGI or in Commission-approved utility tariffs. The Commission has determined that failure to adopt rules for DGI could increase the risk of unsafe interconnection and parallel operation of DG facilities, which could result in conditions posing a risk to people and property, particularly in light of the technological changes in and increased adoption of generating facilities.

7. A reference to any study relevant to the rule that the agency reviewed and either relied on or did not rely on in its evaluation of or justification for the rule, where the public may obtain or review each study, all data underlying each study, and any analysis of each study and other supporting material:

Not applicable

8. A showing of good cause why the rulemaking is necessary to promote a statewide interest if the rulemaking will diminish a previous grant of authority of a political subdivision of this state:

Not applicable

9. A summary of the economic, small business, and consumer impact:

The persons most affected by the DGI Rules ("stakeholders") include:

a. Utilities that are under the Commission's jurisdiction and are providing electric utility service in Arizona ("regulated electric utilities"),

b. Customers receiving electric service in Arizona from regulated electric utilities and who seek to have generating facilities interconnected ("applicants"),

c. Customers receiving electric service in Arizona from regulated electric utilities and who do not seek to have generating facilities interconnected ("other customers")

d. Entities engaging in commerce directly related to DG technology and services ("industry participants"),

e. The general public, and

f. The Commission.

In many ways, the DGI Rules maintain the processes and standards by which regulated electric utilities have been guided pursuant to the Interconnection Document adopted by the Commission in Decision No. 69674 (June 28, 2007). To the extent that the provisions of the DGI Rules are the same or substantially similar to those in the Interconnection Document, the Commission considers the DGI Rules to maintain the status quo and thus not cause stakeholders an economic impact. However, the DGI Rules include the following major differences from the Interconnection Document adopted in Decision No. 69674, which have the potential to impact different stakeholders as noted in parentheticals:

a. They expand the scope of the Interconnection Document by establishing standards that:
   i. Apply to all generating facilities operated in electrical parallel, regardless of maximum capacity, that are interconnected with the distribution system of a regulated electric utility (benefitting all stakeholders by establishing technical and safety standards for systems previously excluded and benefitting industry participants by increasing business opportunities);
   ii. Do not prohibit "islandable systems" (benefitting all stakeholders by establishing technical and safety standards for systems previously excluded and benefitting industry participants by increasing business opportunities); and
   iii. Address energy storage systems (benefitting all stakeholders by establishing technical and safety standards for systems previously excluded and benefitting industry participants by increasing business opportunities);
b. They allow a customer to designate a representative to act on the customer's behalf regarding the interconnection and parallel operation process, to sign and submit documents electronically, to request a one-time 90-day extension from the utility with simple notice, and not to have an extension unreasonably withheld for circumstances beyond the customer's control (primarily benefitting applicants, but also benefitting regulated electric utilities);
c. They rely upon the utility's Interconnection Manual to establish the codes, guides, and standards applicable to qualify generating facility equipment as certified equipment (benefitting regulated electric utilities, applicants, other customers, and the Commission);
d. Except when disconnection is done to make immediate distribution system repairs to prevent a danger, they require a utility to provide notice to a customer at least three days before disconnecting the customer's generating facility and to include in the notice the timing and estimated duration of the disconnection (benefitting applicants, burdening regulated electric utilities);
e. They establish a process and timeline for restoring interconnection when a generating facility was disconnected for failure to meet technical requirements (benefitting applicants, burdening regulated electric utilities);
f. They establish requirements for when there is a change of ownership of an interconnected generating facility (benefitting regulated electric utilities, burdening applicants);
g. They eliminate the dispute resolution process required by the Interconnection Document (benefitting regulated electric utilities and applicants);
h. They increase the maximum capacity for inverter-based generating facilities eligible to use the Level 1 Super Fast Track process from 10 kW to 20 kW (benefitting applicants, regulated electric utilities, and industry participants);
i. They add a Supplemental Review process that must be offered by a utility and can be requested by an applicant when interconnection of a generating facility cannot be approved under the Level 1, 2, or 3 Tracks (benefitting applicants and industry participants, burdening regulated electric utilities);
j. They increase the flexibility of one Screen for generating facilities, adapting it for higher capacity generating facilities, and include exceptions from three Screens for non-exporting systems and certain inadvertent export systems (benefitting applicants and regulated electric utilities);
k. They allow an applicant to request a Pre-Application Report from a utility and establish a process and timeline for completion of a Pre-Application Report (benefitting applicants and regulated electric utilities, burdening regulated electric utilities;
l. They establish timelines using calendar days rather than business days (benefitting all stakeholders), deem an application incomplete rather than denied (and eliminate the requirement for an applicant to start over with a new application) if a generating facility design does not satisfy an applicable Screen for the Level 1 Track or does not meet the utility's Interconnection requirements (benefitting applicants), and allow an applicant to request an extension of the 30-day period to submit additional information to the utility if an application is deemed incomplete (benefitting applicants);
m. They require a customer to submit to the utility a copy of final electrical clearance for the generating facility issued by the authority having jurisdiction, if required (benefitting all stakeholders, burdening applicants);
n. They require a utility to verify compliance with specific requirements during a site inspection, if one is completed, rather than suggesting what the utility should verify (benefitting all stakeholders, burdening regulated electric utilities);
o. They impose a 30-day deadline after a failed site inspection for an applicant to correct any outstanding issues and provide notice of corrections to the utility (benefitting regulated electric utilities, burdening applicants), allow the utility a few additional days to complete reinspection (benefitting regulated electric utilities), and eliminate the reinspection fee unless a utility has a Commission-approved tariff authorizing such a fee (benefitting applicants);
p. They eliminate the provision that operating a generator in parallel without utility approval may result in immediate termination of electric service (benefitting applicants);
q. They allow a customer whose generating facility is processed under the Level 2 Fast Track or the Level 3 Study Track to modify the generating facility's operating characteristics, as agreed upon by the customer and utility, in order to reduce or

eliminate improvements to the distribution system that would otherwise be necessary to accommodate interconnection (benefitting applicants);

r. They standardize the timing requirements for Feasibility Studies, System Impact Studies, and Facilities Studies (benefitting applicants);

s. They establish permanent standards and requirements for interconnection to secondary spot network systems, with a larger size limit for inverter-based units, replacing the pilot effort included in the Interconnection Document (benefitting all stakeholders by establishing technical and safety standards for systems previously excluded and benefitting industry participants by increasing business opportunities);

t. They establish a new Expedited Interconnection Process for non-exporting or inadvertent export generating facilities that have a maximum capacity of 20 kW or less and meet specified requirements (benefitting applicants and industry participants);

u. They allow a utility to require a customer to install and maintain a disconnect switch that meets specified standards and to impose additional requirements for disconnect switches in the utility's Interconnection Manual (benefitting regulated electric utilities, other customers, the general public, and the Commission, and burdening applicants);

v. They establish advanced grid support features for generating facilities utilizing inverter-based technology (benefitting regulated electric utilities, other customers, the general public, and the Commission);

w. They allow proposed revisions to a utility's Interconnection Manual to go into effect immediately if made to enhance health or safety, although the revisions are subject to subsequent review and approval by the Commission (benefitting regulated electric utilities, applicants, other customers, the general public, and the Commission); allow Staff to contest and seek suspension of a proposed revision to a utility's Interconnection Manual (benefitting the Commission, burdening regulated electric utilities); and require a utility to file an updated Interconnection Manual with Docket Control within 10 days after the effective date of the decision approving the Interconnection Manual (benefitting applicants, the Commission, and industry participants, and burdening regulated electric utilities);

x. They add fields of information to be included in a utility's annual Interconnection Report to be filed with the Commission (benefitting the Commission and burdening regulated electric utilities);

y. They allow an electric cooperative's Commission-approved Interconnection Manual to impose substitute timelines with which the cooperative must comply in lieu of complying with the timelines in R14-2-2614 and R14-2-2616 through R14-2-2623 and require an electric cooperative to employ best reasonable efforts to comply with the deadlines established in the applicable provisions of the DGI Rules (benefitting regulated electric utilities that are cooperatives);

z. They require a regulated electric utility's Interconnection Manual to contain detailed technical, safety, and protection requirements necessary to interconnect a Generating Facility to the Distribution System in compliance with the DGI Rules and Good Utility Practice; and to specify by date, either in its main text or an appendix, the version of each standard with which an applicant's generating facility must comply to be eligible for interconnection and parallel operation (collectively benefitting applicants, industry participants, the general public, and the Commission, and burdening regulated electric utilities); and

aa. They require a regulated electric utility to submit its Interconnection Manual to the Commission for review and approval as necessary to ensure compliance with Good Utility Practice (benefitting the Commission, applicants, other customers, and the general public, and burdening regulated electric utilities and the Commission).

The Commission expects the potential costs identified above to be minimal for all stakeholders, although the safety-related benefits may be significant.

A regulated electric utility may be able to obtain Commission approval for a tariff that would allow the utility to pass its additional reasonable and prudent costs through to applicants and possibly other customers.

The Commission expects establishment of a consistent standard that explicitly establishes procedures for interconnection and parallel operation to increase investment certainty for regulated electric utilities, applicants, and industry participants.

The Commission expects the DGI Rules to result in safer and more reliable DG and grid operation and in more consistent and predictable processing of DGI applications, using the most up-to-date technical standards currently available.

The Commission has incurred costs from the rulemaking process, including many hours of personnel time as well as the expense of purchasing the four electric industry standards incorporated by reference in the DGI Rules. The Commission anticipates that the DGI Rules will result in increased costs to the Commission because of the personnel time that will be spent reviewing Interconnection Manuals to ensure compliance with Good Utility Practice.

The Commission does not anticipate that other agencies or political subdivisions will be directly impacted by the DGI Rules unless they become applicants.

The Commission does not currently expect the DGI Rules to have more than a minimal impact on private and public employment in businesses, although that impact will increase as more applications for interconnection are submitted to regulated electric utilities.

The Commission does not currently anticipate that state revenues will be impacted by the DGI Rules.

The Commission expects small businesses to be impacted by the DGI Rules either as applicants, as industry participants, or as cooperative regulated electric utilities.

10. A description of any changes between the proposed rulemaking, to include supplemental notices, and the final rulemaking:

No changes have been made between the supplemental rulemaking and final rulemaking.

11. An agency's summary of the public or stakeholder comments made about the rulemaking and the agency response to the comments:

The following table includes prefatory information necessary to understand the formal comments concerning the Notice of Supplemental Proposed Rulemaking; a summary of the written and oral comments received by the Commission concerning the Notice of Supplemental Proposed Rulemaking; and the Commission's response to each formal comment received.

Prefatory Information

On June 18, 2019, Commissioner Boyd Dunn filed a letter in the docket for this rulemaking ("the Dunn letter") that, *inter alia*, identified the following three options for the definition of "Maximum Capacity":

Option 1:

"Maximum Capacity" means:

a. The nameplate AC capacity of a Generating Facility; or

b. If the Operating Characteristics of the Generating Facility limit the power transferred across the Point of Interconnection to the Distribution System, only the power transferred across the Point of Interconnection to the Distribution System, not including Inadvertent Export.

Option 2:

"Maximum Capacity" means the nameplate AC capacity of a Generating Facility.

Option 3:

"Maximum Capacity" means the nameplate AC capacity of a Generating Facility or if a Utility and Customer reach an agreement regarding the operating characteristics of the Generating Facility that limits the power transferred across the Point of Interconnection to the Distribution System, only the power transferred across the Point of Interconnection to the Distribution System.

On August 14, 2019, Chairman Robert Burns filed a letter in the docket for this rulemaking ("the Burns letter") stating, *inter alia*, that he was considering an amendment to the definition of "Maximum Capacity" included in the Notice of Supplemental Proposed Rulemaking (which was Option 1). Chairman Burns stated that the amendment under consideration would modify the definitions of "Maximum Capacity" and "Operating Characteristics" as follows:

"Maximum Capacity" means:

a. The nameplate AC capacity of a Generating Facility, or

b. The AC capacity of the Generating Facility established by its Operating Characteristics.

"Operating Characteristics" means the mode of operation of a Generating Facility (Exporting System, Non-Exporting System, or Inadvertent Exporting System) that controls the amount of power delivered across the Point of Interconnection to the Distribution System, as established by the Generating Facility manufacturer in accordance with Section 204.3.2(a) of the Underwriters Laboratories Inc. Certification Requirement Decision on Power Control Systems for UL 1741, issued on March 8, 2019, with no future editions or amendments, which is incorporated by reference; on file with the Commission; and published by and available from Underwriters Laboratories Inc., 151 Eastern Avenue, Bensenville, IL, 60106-3072 and through https://standardscatalog.ul.com.

Chairman Burns requested that stakeholders provide responses addressing how the definitions shown above ("Burns definitions") would improve or detract from the DGI Rules included in the Notice of Supplemental Proposed Rulemaking, specifically as to safety.

Written Comments on Notice of Supplemental Proposed Rulemaking

Public Comment	Commission Response
Tesla, Inc. ("Tesla") opposed the Burns definitions. Tesla stated that the Burns definitions would only allow operating characteristics to be considered when calculating maximum capacity for a system if the power control system has its settings locked by the manufacturer so that the settings are unchangeable in the field. Tesla stated that this restriction would impede the adoption of distributed energy storage, making it more expensive and less likely to be installed, because maximum capacity would be calculated based on the false assumption that energy storage systems ("ESS") will be exporting at full nameplate capacity. Tesla stated that the restriction would force customers to pay for unnecessary system upgrades or not to adopt energy storage. Tesla also stated that there are currently more than 150,000 distributed generation ("DG") systems in Arizona and millions in the U.S. and that even though each DG system currently is equipped with an inverter that has 6 to 11 adjustable settings, and that could have a negative impact on the grid if set incorrectly or altered, Tesla is not aware of even one instance of an end user intentionally altering inverter settings with negative impacts.	The Commission appreciates the information provided and agrees that it is appropriate to adopt the definition of "Maximum Capacity" included in the Notice of Supplemental Proposed Rulemaking, as it strikes an appropriate balance between the needs of the regulated utilities and the DG industry, and no evidence has been produced to indicate that it compromises safety. No change is needed as a result of the comment.

Tesla asserted that having field adjustable settings is beneficial to the grid because different utilities and jurisdictions require inverters to support their systems in different ways, and the adjustability ensures that one product can be configured to meet the different requirements. Tesla also stated that this flexibility keeps costs lower for the end user, with little risk to the grid, and that the March 8, 2019, Underwriters Laboratories Inc. Certification Requirement Decision on Power Control Systems for UL 1741 ("UL CRD") adds a level of protection to ensure that once an ESS is installed, the settings are difficult to reconfigure, because UL CRD § 204.3.2 allows for a certified system's power control system settings to be selected in only four ways: (1) UL CRD § 204.3.2.a, supported in the Burns letter, provides for the settings to be set and locked at the time of manufacturing and to be unchangeable in the field; (2) UL CRD § 204.3.2.b provides for the use of configuration files, which require a sophisticated interface designed to be used by trained installers, as the sole means of making changes in the field; (3) UL CRD § 204.3.2.c provides for power control system setting changes to be made in the field only through password-restricted access available to the manufacturer or the manufacturer's authorized representatives, not to end users; and (4) UL CRD § 204.3.2.d provides for power control system settings to be established at the time of installation as part of the interconnection process, through a single-use password, preventing post-installation alterations without manufacturer involvement. Tesla asserted that the Commission should move forward with the DGI Rules as included in the Notice of Supplemental Proposed Rulemaking.	
Arizona Public Service Company ("APS") asserted that the safest and most accurate definition of "Maximum Capacity" is the nameplate AC capacity of a Generating Facility (Option 2). APS stated that Option 2 provides the greatest assurance of customer safety and system reliability because it allows utilities to accurately determine the potential impact of a Generating Facility on the distribution system. APS stated that it is important for utilities to have a comprehensive understanding of the potential generation that can be exported to feeders to ensure that the distribution system can be operated and maintained safely. APS also asserted that Option 2 will allow utilities to approve future changes to the operational settings of a customer's system as more facilities are interconnected to the grid, directly benefitting customers. APS stated that defining "Maximum Capacity" as the operational settings of a Generating Facility does not allow insight into the potential exports of the Generating Facility, either unintentional exports or exports caused by a change in operational settings. APS stated that the UL CRD minimizes the risk that an installer or customer can unintentionally change operational settings, but does not address the potential impacts on the distribution system if a change to operational settings is made without utility approval or evaluation. APS also stated that adopting Option 2 would not cause customers to incur unnecessary costs to upgrade the distribution system because R14-2-2617 and R14-2-2618 both allow for modification of a Generating Facility's operating characteristics, upon agreement between the customer and utility, to eliminate or minimize the need for improvements to the distribution system. APS stated that these provisions provide customers the flexibility to select beneficial operating settings while preserving the safety, reliability, and flexibility of the distribution system.	The Commission appreciates the information provided, but has determined that the definition of "Maximum Capacity" included in the Notice of Supplemental Proposed Rulemaking is the appropriate definition to adopt at this time. The Commission believes that the recent adoption of the UL CRD, with which manufacturers will comply to ensure UL certification, reduces the risk of unauthorized field changes to operational settings. The Commission also notes that no evidence has been provided to show that unauthorized field changes to Generating Facility settings have created safety issues or other problems for customers, utilities, or the grid. Should the Commission receive evidence in the future that unauthorized field changes to Generating Facility settings are creating safety issues or other problems for customers, utilities, or the grid, the Commission will evaluate the situation and determine whether additional rulemaking is necessary at that time. No change is needed as a result of the comment.

Tucson Electric Power Company and UNS Electric, Inc. ("TEP/UNSE") stated that they continue to support Option 2 and to oppose Option 1, as stated in their previous comments filed in the docket (responding to the recommended language for the Notice of Supplemental Proposed Rulemaking and to the Dunn letter). TEP/UNSE attached their previous comments. TEP/UNSE asserted that Option 2 allows a utility to evaluate and approve a Generating Facility based on its nameplate capacity and thus ensures that system reliability and safe operation of the distribution system can be maintained, whereas Option 1 requires a utility to evaluate and approve a Generating Facility based on its operating capacity, which is likely less than its nameplate capacity. TEP/UNSE stated that the operating capacity could be altered after installation, up to the nameplate capacity, because a third party can adjust factory settings without utility knowledge or approval, and that this would result in increased risk to safety and system reliability. TEP/UNSE stated that Tesla's comments about the changeability of inverter settings confirmed TEP/UNSE's concerns. TEP/UNSE stated that the Burns definitions may provide some additional safety and control regarding the power control system, but does not address the concerns regarding the potential changes to inverter settings and the resulting safety and reliability risk. TEP/UNSE requested that the Commission adopt Option 2, but stated that if Option 2 is not adopted, the Burns definitions would be an improvement to Option 1, although they do not fully address concerns for altering capacity, and it is unknown how the UL CRD will be applied or realized at this time. In its attached prior comments, TEP/UNSE stated that adoption of Option 2 is critical because the Notice of Supplemental Proposed Rulemaking eliminated the provision included in the Notice of Proposed Rulemaking that would have made an installer liable for the loss of or damage to property arising from interconnection of a Generating Facility that was inadvertently or intentionally operated at a higher capacity than the operating characteristics reviewed and approved by the utility. TEP/UNSE stated that this deleted provision was an incentive for proper operation to reduce risk. Additional comments in attached letters: TEP/UNSE opposed use of the UL CRD in the rules and stated that it would not alleviate concerns regarding the use of operating characteristics as maximum capacity. TEP/UNSE stated that the UL CRD language related to operating modes provides for a hazardous variance in how equipment can be operated, allowing variability in how an ESS can charge from and discharge to the grid as well as in how operating modes can be selected. TEP/UNSE also stated that the UL CRD is a manufacturing certification standard that does not represent how an installer and consumer will use a product and, further, that it would be improper for the Commission's rules to incorporate the UL CRD because it has not yet been adopted as a UL standard. TEP/UNSE also stated that Tesla had mischaracterized the comments of a TEP representative regarding TEP's use of operating characteristics to evaluate interconnection. Finally, TEP/UNSE stated that it could support Option 3, which would provide a utility the opportunity to reach an agreement with customers regarding operating characteristics and enable the utility to verify the maximum power transfer.	The Commission appreciates the information provided, but has determined that the definition of "Maximum Capacity" included in the Notice of Supplemental Proposed Rulemaking is the appropriate definition to adopt at this time. The Commission believes that the recent adoption of the UL CRD, with which manufacturers will comply to ensure UL certification, reduces the risk of unauthorized field changes to operational settings. The Commission also notes that no evidence has been provided to show that unauthorized field changes to Generating Facility settings have created safety issues or other problems for customers, utilities, or the grid. Should the Commission receive evidence in the future that unauthorized field changes to Generating Facility settings are creating safety issues or other problems for customers, utilities, or the grid, the Commission will evaluate the situation and determine whether additional rulemaking is necessary at that time. The Commission notes that the rules do not incorporate the UL CRD and, further, that the Commission eliminated the liability provision due to a lack of legal authority. No change is needed as a result of the comment.

The Grand Canyon State Electric Cooperative Association, Inc. ("GCSECA") filed comments on behalf of Duncan Valley Electric Cooperative, Inc; Graham County Electric Cooperative, Inc.; Mohave Electric Cooperative, Inc.; Navopache Electric Cooperative, Inc.; Sulphur Springs Valley Electric Cooperative, Inc.; and Trico Electric Cooperative, Inc. GCSECA stated that GCSECA's earlier concerns regarding the timelines for processing interconnection applications and a potential conflict between a liability insurance restriction and a requirement for Rural Utilities Service funding had been resolved through changes made in the Notice of Supplemental Proposed Rulemaking. GCSECA stated that it supports those changes. GCSECA stated that it still has concerns about the definition of "Maximum Capacity," which requires the utility to evaluate the generating facility based solely on the facility's operating characteristics (rather than nameplate capacity) if the operating characteristics are set to limit the power transferred across the point of interconnection to the distribution system. GCSECA stated that because the definition does not include inadvertent export, the interconnection design criteria must exclude any portion of capacity that is not planned to be transferred to the distribution system. GCSECA stated that this does not account for the possibility that the operating characteristic settings could malfunction or be changed after interconnection, allowing more power than originally planned to flow to the distribution system. GCSECA stated that it supports Option 3 as a reasonable compromise that ensures the utility has an opportunity to review and consent to the overall design, including proposed safeguards when a system is designed to operate at less than nameplate capacity. GCSECA stated that it joined in the concerns expressed by TEP and APS. GCSECA also stated that allowing installers unilaterally to design DG facilities based solely on operating characteristics creates a potential safety hazard for the customer for whom the DG facility is installed due to the possibility that the connected electrical hardware will be undersized. GCSECA stated that if the power control system fails, is incorrectly programmed, or is modified, generator output could exceed the initial operating characteristic limit. GCSECA stated that to ensure safety when a home has both a photovoltaic solar system and ESS, the wiring and breakers from the solar panels and the ESS should be separate and sized to handle the full independent output of each system. GCSECA stated that if an installer programs the power control system so that both systems will not discharge at the same time, Option 1 limits the evaluation of the output capacity to the nameplate rating of either the solar inverter or the battery inverter, not both, potentially creating a mismatch and allowing for a residential service panel insufficient to carry the electrical current of both systems. GCSECA stated that if the power control system fails or functions other than as intended, both solar and ESS output could be fed into the service panel simultaneously, creating an overload and fire risk. GCSECA conceded that the utility is not responsible for ensuring that a customer's premises are designed to avoid such risks, it believes that evaluating each facility based on nameplate capacity provides an extra level of protection for the customer. GCSECA opposes Option 1 in the rules because it allows installers complete discretion to establish the operating characteristics of a DG facility and requires interconnection based solely upon those characteristics, thereby creating an unnecessary and unreasonable potential risk to the utility, the customer, and the public. GCSECA supports either Option 2 or, as a compromise, Option 3. GCSECA stated that Burns definitions may eliminate the risk of initial or subsequent programming error, but do not alleviate the potential for a device failure and resulting safety risk. GCSECA also stated that there are potential practical limitations with a manufacturer-set operating characteristics power control system, which may not be configured to the requirements of a particular installation.	The Commission appreciates the information provided, but has determined that the definition of "Maximum Capacity" included in the Notice of Supplemental Proposed Rulemaking is the appropriate definition to adopt at this time. The Commission believes that the recent adoption of the UL CRD, with which manufacturers will comply to ensure UL certification, reduces the risk of unauthorized field changes to operational settings. Additionally, the Commission believes that even in the absence of a Commission rule attributing liability to an installer, an installer has a strong incentive to meet industry best practices when designing DG facilities for installation at a customer's home, as the installer could be subject to civil liability for damages resulting from the installer's failure to meet industry standards. The Commission also notes that no evidence has been provided to show that unauthorized field changes to Generating Facility settings, failures of power control systems, or incorrect programming of power control systems have created safety issues or other problems for customers, utilities, or the grid. Should the Commission receive evidence in the future that any of these potential issues are creating safety issues or other problems for customers, utilities, or the grid, the Commission will evaluate the situation and determine whether additional rulemaking is necessary at that time. No change is needed as a result of the comment.
Oral Comments on Notice of Supplemental Proposed Rulemaking, Oral Proceeding 9/13/19	
Public Comment	**Commission Response**

Brandon Cheshire of AriSEIA stated that the type of batteries being used for grid support have seamless control systems that are programmed and that, once programmed, safely and reliably control how the system will function. Mr. Cheshire stated that adopting the Burns definitions would only make battery installation more expensive by requiring upgrades to the system that are not needed or, more likely, would disincentivize the installation of batteries. Mr. Cheshire stated that some utilities seem less inclined to make it easy for their customers to use battery storage, and AriSEIA believes that is why some utilities have pushed back on the definition of "Maximum Capacity." Mr. Cheshire stated that UL has issued certification procedures to allow manufacturers to certify these power control systems. Mr. Cheshire stated that a utility can verify operating characteristics at the standard inspection and commissioning. Mr. Cheshire also stated that no one will reprogram a battery and characterized utilities' assertions that people might reprogram batteries as a "scare tactic." Mr. Cheshire stated that there are tens of thousands of inverters in Arizona that could have their settings altered to the detriment of the grid, but he is unaware of even one such occurrence. Mr. Cheshire also stated that operating at maximum capacity is not a normal operating characteristic of this technology. Mr. Cheshire stated that the technology is safe, that other states are allowing this, and that the Commission should encourage the efficient adoption of solar paired with storage. AriSEIA encouraged the Commission to continue supporting the definition included in the Notice of Supplemental Proposed Rulemaking (Option 1).	The Commission appreciates the information provided and agrees that it is appropriate to adopt the definition of "Maximum Capacity" included in the Notice of Supplemental Proposed Rulemaking, as it strikes an appropriate balance between the needs of the regulated utilities and the DG industry, and no evidence has been produced to indicate that it compromises safety. No change is needed as a result of the comment.
Sarah Walinga of Tesla stated that the Burns definitions would allow use of only one of the four UL CRD options for battery storage settings, the option that is least likely to be used by manufacturers when creating their systems. Ms. Walinga stated that the Burns definitions could limit the availability of products for use in Arizona and prohibit the use of non-export storage. Ms. Walinga stated that to comply with the Burns definitions, manufacturers would need to create dedicated product lines for non-export products, which would restrict how the products could be used. Ms. Walinga stated that only one or two settings make the difference between an exporting and a non-exporting system because the systems are not physically different. Ms. Walinga stated that inverters and control systems are configurable, and that the UL CRD has other methods that allow for not having dedicated product lines, allowing for systems to be configured at install or for manufacturers to set up systems. Ms. Walinga stated that each of the four methods available in the UL CRD would ensure that it is very difficult for a customer or installer to change an inverter from non-exporting to exporting after it is installed. Ms. Walinga also stated that by creating the need for a new dedicated product line, adoption of the Burns definitions would increase manufacturer overhead and make it unlikely that manufacturers will produce systems to be used in Arizona.	The Commission appreciates the information provided. No change is needed as a result of the comment.
Steven Rymsha of Sunrun stated that he supports the existing Option 1 definition and that the Burns definitions are problematic. Mr. Rymsha stated that requiring the setting to be made by the manufacturer is inconsistent with what is happening, and he has not heard of any manufacturer doing that. Mr. Rymsha stated that the systems are manufactured to have operational flexibility and certified to be used in North America. Mr. Rymsha stated that the Burns definitions would cause many supply chain issues if systems were being programmed at the factory for a specific mode—non-exporting or exporting. Mr. Rymsha stated that there are also export-limiting operating characteristics that can be used to reduce the output of the system. Mr. Rymsha indicated that there are additional operating characteristics available for customers to use for their systems and noted that utilities will be able to inspect the systems before operation. Mr. Rymsha stated that the Burns definitions have a lack of clarity and flexibility and that Sunrun supports the existing Option 1 definition.	The Commission appreciates the information provided and agrees that it is appropriate to adopt the definition of "Maximum Capacity" included in the Notice of Supplemental Proposed Rulemaking, as it strikes an appropriate balance between the needs of the regulated utilities and the DG industry, and no evidence has been produced to indicate that it compromises safety. No change is needed as a result of the comment.

Mark Holohan of AriSEIA stated that the rules should be passed as currently written (with Option 1) and urged the Commission to adopt them without further delay. Mr. Holohan stated that the rules are consistent with the Commission's interest in increasing use of renewables, Mr. Holohan stated that customers now are building smaller solar systems than they should be or are abandoning projects because of the lack of Commission rules to change utility practices and policies, such as policies that impose higher costs if a system exceeds a certain size, even if the size is within the Fast Track process under the proposed rules. Mr. Holohan stated that solar sales people help their customers decide the right system for them based on how much electricity they need, how much space they have, and utility rule limitations. Mr. Holohan urged the Commission to adopt the rules and review utilities' Interconnection Manuals so that the Commission can decide if that is how they want the utilities to operate. Mr. Holohan also stated that the rating of systems matters for safety because we do not want main circuits in the distribution system to be running backwards all the way to the switchyard when there are minimal demands from customers. Mr. Holohan also stated that customers will not want to change the programming on their systems to do anything other than provide electricity for their own use on site, especially because exported power has been devalued. Mr. Holohan questioned how a customer's solar system and ESS would ever lead to that much power being exported to the distribution system because the customer will never have zero load. Mr. Holohan also stated that due to the types of inverters that are required to be used, a customer cannot run a solar system without having a grid connection. Mr. Holohan asserted that the Burns definitions would artificially and unnecessarily limit the amount of solar and batteries customers could put on the grid due to an unrealistic scenario.	The Commission appreciates the information provided and agrees that it is appropriate to adopt the definition of "Maximum Capacity" included in the Notice of Supplemental Proposed Rulemaking, as it strikes an appropriate balance between the needs of the regulated utilities and the DG industry, and no evidence has been produced to indicate that it compromises safety. No change is needed as a result of the comment.
Court Rich, on behalf of Tesla, stated that Tesla is in favor of the rules as published in the Notice of Supplemental Proposed Rulemaking (Option 1). Mr. Rich stated that there is no reason to make the changes in the Burns definitions. Mr. Rich stated that many states look at operating characteristics, as shown in filings previously made in the docket. Mr. Rich also stated that California, the largest market in the U.S. for distributed rooftop solar and energy storage, has passed rules that recognize the UL CRD and that, because of this, manufacturers will be manufacturing to the California standards. Mr. Rich stated that there are approximately 150,000 systems in Arizona with inverters that have settings that can be manipulated. Mr. Rich stated that it is unrealistic and unfounded to believe that customers will "hack" their systems or that harm would result if they did, as this has not occurred. Mr. Rich stated that Option 3 is also unrealistic because of the administrative overhead and burden of utilities from having to negotiate with every customer, which is likely to result in utilities simply using nameplate capacity. Because of this, Mr. Rich stated, upgrades would be needed, even though the system will never be sending power at nameplate capacity to the grid. Mr. Rich also stated that from a policy perspective, solar with ESS is better. Mr. Rich asserted that adoption of the Burns definitions would be a disincentive to the installation of ESS, would make ESS more expensive, and would likely result in many people not installing ESS at all. Mr. Rich also stated that because different settings work in different parts of the country, different utilities have different needs, and different states have different requirements, it is most efficient to allow for ESS settings to be made on site. Mr. Rich also asserted that creation of an Arizona-specific line of batteries is unrealistic and that the UL CRD setting included in the Burns definitions is the least likely to be used by manufacturers. Regarding liability, Mr. Rich stated, courts can hold individual customers responsible for damages caused. Additionally, Mr. Rich asserted, interconnection agreements between customers and utilities will undoubtedly require customers not to change system settings, so utilities will have recourse if any customers do.	The Commission appreciates the information provided and agrees that it is appropriate to adopt the definition of "Maximum Capacity" included in the Notice of Supplemental Proposed Rulemaking, as it strikes an appropriate balance between the needs of the regulated utilities and the DG industry, and no evidence has been produced to indicate that it compromises safety. No change is needed as a result of the comment.

Jennifer Cranston, on behalf of GCSECA, stated that written comments would be filed the same day and that GCSECA supports the changes made to R14-2-2607 and R14-2-2627 in the Notice of Supplemental Proposed Rulemaking to address the concerns of the cooperatives. Ms. Cranston stated that GCSECA is still concerned about the definition of "Maximum Capacity" because it excludes consideration of inadvertent export, and does not contemplate that operating characteristic settings could be changed after interconnection or that systems could malfunction. Ms. Cranston stated that GCSECA believes now is the time to add safeguards against imperfect systems. Ms. Cranston stated that the Burns definitions would eliminate the risk of programming error, but do not protect against damage from malfunction or device failure, which creates a safety concern on the customer side as well as the utility side. Ms. Cranston further stated that there are practical limitations that could arise from the Burns definitions. Ms. Cranston asserted that GCSECA would like to see the Commission adopt Option 2 or Option 3 to add extra protections by allowing utilities to use the most conservative position of nameplate capacity.	The Commission appreciates the information provided, but has determined that the definition of "Maximum Capacity" included in the Notice of Supplemental Proposed Rulemaking is the appropriate definition to adopt at this time. The Commission believes that the recent adoption of the UL CRD, with which manufacturers will comply to ensure UL certification, reduces the risk of unauthorized field changes to operational settings. Additionally, the Commission believes that even in the absence of a Commission rule attributing liability to an installer, an installer has a strong incentive to meet industry best practices when designing DG facilities for installation at a customer's home, as the installer could be subject to civil liability for damages resulting from the installer's failure to meet industry standards. The Commission also notes that no evidence has been provided to show that unauthorized field changes to Generating Facility settings, failures of power control systems, or incorrect programming of power control systems have created safety issues or other problems for customers, utilities, or the grid. Should the Commission receive evidence in the future that any of these potential issues are creating safety issues or other problems for customers, utilities, or the grid, the Commission will evaluate the situation and determine whether additional rulemaking is necessary at that time. No change is needed as a result of the comment.
Don McAdams of TEP stated that TEP appreciated the Burns letter because it is safety oriented. However, Mr. McAdams stated, TEP is now and will always be in favor of only Option 2 because the definition applies to all DG and is not flexible. Mr. McAdams stated that the Super Fast Track rule allows for rapid review and approval, and TEP intends to comply. Mr. McAdams stated that TEP is concerned about the wide swath of projects that fit under the Fast Track review. Mr. McAdams stated that TEP does not have a lot of experience with ESS and that TEP plans based on worst case scenarios. Mr. McAdams stated that Option 2 would allow TEP to continue performing its review and analysis in that way. Mr. McAdams also stated that TEP can cautiously support the Burns definitions because the UL CRD is essentially an official document, although TEP is concerned that the UL CRD is not readily available and that it may not be adopted in the UL 1741 standard when it is revised. Mr. McAdams stated that the only official standard currently is the UL 1741 standard, not the UL CRD. In response to installers' statements concerning the 150,000 inverters in Arizona, none of which have caused negative impacts due to field changes to their settings, Mr. McAdams stated that 99.9 percent of those inverters are in solar photovoltaic systems that are intended to export because of net metering and, further, that TEP has always been able to evaluate those inverters based on nameplate capacity. Mr. McAdams stated that TEP prefers the Burns definitions to Option 1.	The Commission appreciates the information provided, but has determined that the definition of "Maximum Capacity" included in the Notice of Supplemental Proposed Rulemaking is the appropriate definition to adopt at this time. The Commission believes that the recent adoption of the UL CRD, with which manufacturers will comply to ensure UL certification, reduces the risk of unauthorized field changes to operational settings. The Commission also notes that no evidence has been provided to show that unauthorized field changes to Generating Facility settings have created safety issues or other problems for customers, utilities, or the grid. Should the Commission receive evidence in the future that unauthorized field changes to Generating Facility settings are creating safety issues or other problems for customers, utilities, or the grid, the Commission will evaluate the situation and determine whether additional rulemaking is necessary at that time. No change is needed as a result of the comment.

Daniel Haughton of APS stated that the Burns definitions are a good step toward safety and reliability but are not flexible enough. Mr. Haughton stated that APS does not support Option 1 or the Burns definitions. Mr. Haughton stated that APS only supports Option 2. Mr. Haughton stated that APS believes that "Maximum Capacity" and "Operating Characteristics" should be defined independently because operating characteristics go to application rather than capacity. Mr. Haughton asserted that because R14-2-2617 and R14-2-2618 allow for modifications to generating facility operating characteristics to reduce the need for improvements to the distribution system, the rules already provide the flexibility desired. Mr. Haughton stated that APS has serious concerns for safety, such as for electrical workers and the general public, that are not a scare tactic. Mr. Haughton also stated that if APS were forced to choose between Option 1 and the Burns definitions, APS would choose the Burns definitions. Mr. Haughton added that the Burns definitions are too rigid, however, because by allowing only one of the UL CRD ESS operating mode setting options, they do not allow for field changes to operating characteristics, which Mr. Haughton said need to be available.	The Commission appreciates the information provided, but has determined that the definition of "Maximum Capacity" included in the Notice of Supplemental Proposed Rulemaking is the appropriate definition to adopt at this time. The Commission believes that the recent adoption of the UL CRD, with which manufacturers will comply to ensure UL certification, reduces the risk of unauthorized field changes to operational settings. The Commission also notes that no evidence has been provided to show that unauthorized field changes to Generating Facility settings have created safety issues or other problems for customers, utilities, or the grid. Should the Commission receive evidence in the future that unauthorized field changes to Generating Facility settings are creating safety issues or other problems for customers, utilities, or the grid, the Commission will evaluate the situation and determine whether additional rulemaking is necessary at that time. No change is needed as a result of the comment.

12. All agencies shall list other matters prescribed by statute applicable to the specific agency or to any specific rule or class of rules. Additionally, an agency subject to Council review under A.R.S. §§ 41-1052 and 41-1055 shall respond to the following questions:

Not applicable

a. Whether the rule requires a permit, whether a general permit is used and if not, the reasons why a general permit is not used:

Not applicable

b. Whether a federal law is applicable to the subject of the rule, whether the rule is more stringent than federal law and if so, citation to the statutory authority to exceed the requirements of federal law:

Not applicable

c. Whether a person submitted an analysis to the agency that compares the rule's impact of the competitiveness of business in this state to the impact on business in other states:

Not applicable

13. A list of any incorporated by reference material as specified in A.R.S. § 41-1028 and its location in the rule:

R14-2-2601(46): UL 1741: Underwriters Laboratories Inc. Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources (February 15, 2018)

R14-2-2614(E)(1): IEEE 1547-2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces (April 6, 2018)

R14-2-2620(E)(2)(b): IEEE 1453, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems (October 30, 2015)

R14-2-2620(E)(2)(c): IEEE 519 limits, IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems (June 11, 2014)

14. Whether the rule was previously made, amended or repealed as an emergency rule. If so, cite the notice published in the *Register* as specified in R1-1-409(A). Also, the agency shall state where the text was changed between the emergency and the final rulemaking packages:

The rule was not previously made as an emergency rule.

15. The full text of the rules follows:

TITLE 14. PUBLIC SERVICE CORPORATIONS; CORPORATIONS AND ASSOCIATIONS; SECURITIES REGULATION

CHAPTER 2. CORPORATION COMMISSION
FIXED UTILITIES

ARTICLE 26. INTERCONNECTION OF DISTRIBUTED GENERATION FACILITIES

Section

ARTICLE 26. INTERCONNECTION OF DISTRIBUTED GENERATION FACILITIES

R14-2-2601. Definitions

In this Article, unless otherwise specified:

1. "AC" means alternating current.
2. "Applicant" means a Customer or Representative who submits an Interconnection Application pursuant to this Article.
3. "Application" means the standard form or format for an Applicant to apply to a Utility for Interconnection of a Generating Facility with the Distribution System.
4. "Backfeed" means to energize a section of a Utility electric system with a Generating Facility.
5. "Calendar Day" means any day including Saturday, Sunday, or a Federal or State Holiday.
6. "Certified Equipment" means a specific generating and protective equipment system or systems certified as meeting the requirements in R14-2-2611 relating to testing, operation, safety, and reliability by an NRTL.
7. "Clearance" means documentation from a Utility stating that a line or equipment is disconnected from all known sources of power and tagged; that for safety purposes all proper precautionary measures have been taken; and that workers may proceed to inspect, test, and install ground on the circuit.
8. "CFR" means Code of Federal Regulations.
9. "Commission" means the Arizona Corporation Commission.
10. "Customer" means an electric consumer applying to connect a Generating Facility on the consumer's side of the Utility meter, whether an Exporting System, a Non-Exporting System, or an Inadvertent Export System.
11. "DC" means direct current.
12. "Disconnect Switch" means a device that:
    a. Is installed and maintained for a Generating Facility by the Customer;
    b. Is a visible-open, manual, gang-operated, load break disconnect device;
    c. Is capable of being locked in a visible-open position by a standard Utility padlock that will completely isolate the Generating Facility from the Distribution System; and
    d. If the voltage of the Generating Facility is over 500 volts, is capable of being grounded on the Utility side.
13. "Distributed Generation" means any type of Customer electrical generator, solid-state or static inverter, or Generating Facility interconnected with the Distribution System that either can be operated in electrical parallel with the Distribution System or can feed a Customer load that can also be fed by the Distribution System.
14. "Distribution System" means the infrastructure constructed, maintained, and operated by a Utility to deliver electric service at the distribution level (69 kV or less) to retail consumers.
15. "Electric Cooperative" means a Utility that is:
    a. Not operated for profit;
    b. Owned and controlled by its members; and
    c. Operating as a public service company in this state.
16. "Exporting System" means any type of Generating Facility that is designed to regularly Backfeed the Distribution System.
17. "Facilities Study" means a comprehensive analysis of the actual construction needed to take place based on the outcome of a System Impact Study.
18. "Fault Current" means the level of current that can flow if a short circuit is applied to a voltage source.
19. "Feasibility Study" means a preliminary review of the potential impacts on the Distribution System that will result from a proposed Interconnection.

20. "Generating Facility" means all or part of a Customer's electrical generator(s), energy storage system(s), or any combination of electrical generator(s) and storage system(s), together with all inverter(s) and protective, safety, and associated equipment necessary to produce electric power at the Customer's facility; this includes solid-state or static inverters, induction machines, and synchronous machines.
21. "Good Utility Practice" means any of the practices, methods, and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods, and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimal practice, method, or act to the exclusion of all others, but rather to include practices, methods, or acts generally accepted in the region at the relevant time.
22. "IEEE" means the Institute of Electrical and Electronics Engineers, Inc.
23. "Inadvertent Export" means the unplanned, uncompensated transfer of electrical energy from a Generating Facility to the Distribution System across the Point of Interconnection.
24. "Interconnection" means the physical connection of a Generating Facility to the Distribution System.
25. "Interconnection Agreement" means an agreement, signed between the Utility and the Customer, covering the terms and conditions governing the Interconnection and operation of the Generating Facility with the Utility, and includes any appendices to the agreement.
26. "Interconnection Facilities" means the electrical wires, switches, and related equipment that are required, in addition to the facilities required to provide electric distribution service to a Customer, to allow Interconnection. Interconnection Facilities may be located on either side of the Point of Interconnection as appropriate to their purpose and design.
27. "Interconnection Manual" means a separate document developed and maintained by a Utility as required under R14-2-2628.
28. "Interconnection Study" means a study that may be undertaken by a Utility (or a Utility-designated third party) in response to the Utility's receipt of a completed Application. An Interconnection Study may include:
    a. A Feasibility Study;
    b. A System Impact Study;
    c. A Facilities Study; and
    d. Any additional analysis required by the Utility.
29. "Islanding" means a condition in which a portion of the Distribution System is energized solely by one or more local electric power systems throughout the associated Point of Interconnection while that portion of the Distribution System is electrically separated from the rest of the Distribution System. Islanding can be either intentional (planned) or unintentional (unplanned).
30. "Jurisdictional Electric Inspection Agency" means the governmental authority having jurisdiction to inspect and approve the installation of a Generating Facility.
31. "kW" means kilowatt.
32. "Maximum Capacity" means:
    a. The nameplate AC capacity of a Generating Facility; or
    b. If the Operating Characteristics of the Generating Facility limit the power transferred across the Point of Interconnection to the Distribution System, only the power transferred across the Point of Interconnection to the Distribution System, not including Inadvertent Export.
33. "MW" means megawatt.
34. "Non-Exporting System" means a system in which there is no designed, regular export of power from the Generating Facility to the Distribution System.
35. "NRTL" means a Nationally Recognized Testing Laboratory recognized by the U.S. Occupational Safety and Health Administration.
36. "Operating Characteristics" means the mode of operation of a Generating Facility (Exporting System, Non-Exporting System, or Inadvertent Exporting System) that controls the amount of power delivered across the Point of Interconnection to the Distribution System.
37. "Parallel Operation" means the operation of a Generating Facility that is electrically interconnected to a bus common with the Distribution System, either on a momentary or continuous basis.
38. "Protective Functions" means the equipment, hardware, or software in a Generating Facility that protects against Unsafe Operating Conditions.
39. "Point of Interconnection" means the physical location where the Utility's service conductors are connected to the Customer's service conductors to allow Parallel Operation of the Generating Facility with the Distribution System.
40. "Relay" means an electric device that is designed to interpret input conditions in a prescribed manner and, after specified conditions are met, to respond and cause contact operation or similar abrupt change in associated electric control circuits.
41. "Representative" means an agent of the Customer who is designated by the Customer and is acting on the Customer's behalf.
42. "RUS" means the U.S. Department of Agriculture Rural Utilities Service.
43. "Scoping Meeting" means an initial review meeting between a Utility and a Customer or Representative during which a general overview of the proposed Generating Facility design is discussed, and the Utility provides general information on system conditions at the proposed Point of Interconnection.
44. "Secondary Spot Network System" means an AC power Distribution System meeting the criteria in R14-2-2622.
45. "System Impact Study" means a full engineering review of the impact on the Distribution System from a Generating Facility, including power flow, Utility system protective device coordination, generator protection schemes (if not Certified Equipment), stability, voltage fluctuations, frequency impacts, and short circuit study. A System Impact Study may consider total nameplate capacity of the Generating Facility.
46. "UL 1741" means the Underwriters Laboratories Inc. Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources (February 15, 2018), with no future editions or amendments, which

is incorporated by reference; on file with the Commission; and published by and available from Underwriters Laboratories Inc., 151 Eastern Avenue Bensenville, IL 60106-3072 and through https://standardscatalog.ul.com.

47. "UL 1741SA" means the approved supplemental amendment of UL 1741 that defines the manufacturing (including software) and product testing requirements for advanced inverters.
48. "Unsafe Operating Conditions" means conditions that, if left uncorrected, could result in any of the following:
    a. Harm to personnel;
    b. Damage to equipment;
    c. An adverse effect to the safe operation of the Distribution System; or
    d. Operation of the Generating Facility outside pre-established parameters required by the Interconnection Agreement.
49. "Utility" means an electric distribution company that constructs, operates, and maintains its Distribution System for the receipt and delivery of electricity and that is a public service corporation under Arizona Constitution, Article 15, § 2.

R14-2-2602. Applicability

These rules apply to a Generating Facility operating (or to be operated) in parallel with a Distribution System of a Utility, subject to Commission jurisdiction after the effective date of this Article.

R14-2-2603. Types of Generating Facilities

A. A Customer may operate a Generating Facility as an Exporting System, a Non-Exporting System, or an Inadvertent Export System.
B. An Applicant shall declare the Maximum Capacity of a Generating Facility in its Application.
C. If an Applicant claims a Generating Facility is a Non-Exporting System:
1. The Utility may require an independent third-party certification ensuring that the system meets the following standards:
    a. Is able to supply part or all of the Customer's load continuously or during a Utility power outage;
    b. Is sized such that the export of power is not possible or includes control functions to prevent the export of power; and
    c. Has control functions that are listed by an NRTL for the purpose as used and are also inspected and approved by the Customer's Jurisdictional Electric Inspection Agency; and
2. The Applicant shall ensure that the Generating Facility utilizes any combination of equipment, hardware, or software, as specified by the Utility in its Interconnection Manual, to prevent the transfer of electrical energy to the Distribution System.

D. If an Applicant claims a Generating Facility is an Inadvertent Export system that does not utilize only UL 1741-certified or UL 1741SA-listed grid support non-islanding inverters:
1. The Utility may require additional protective functions and equipment to detect Distribution System faults;
2. The amount of Inadvertent Export to the Distribution System shall be limited to the lesser of the following values:
    a. 50% of the Generating Facility's Maximum Capacity;
    b. 10% of the continuous conductor rating in watts at 0.9 power factor for the lowest rated feeder conductor upstream of the Generating Facility; or
    c. 500 kW; and
3. The expected frequency of Inadvertent Export events shall be less than two occurrences per 24-hour period.

E. If an Applicant claims a Generating Facility is an Inadvertent Export system that utilizes only UL 1741-certified or UL 1741SA-listed grid support non-islanding inverters, the Generating Facility shall:
1. Utilize control functions that limit the export of electrical power to the Distribution System;
2. Have a Maximum Capacity of 500 kVA or less;
3. Have a magnitude of Inadvertent Export no more than 100 kVA;
4. Have a duration of Inadvertent Export of power of less than 30 seconds for any single event;
5. Monitor that its total energy export per month is maintained to be no more than its Maximum Capacity multiplied by 0.1 hours per day over a rolling 30-day period (e.g., a 100 kVA gross nameplate capacity Generating Facility would have a maximum energy export per 30-day month of 300 kWh);
6. Disconnect the Generating Facility from the Distribution System in the event of an Inadvertent Export, ceasing to energize the Distribution System or halting energy production, within two seconds after the period of uninterrupted export exceeds 30 seconds or the magnitude of export exceeds 100 kVA; and
7. Enter a safe operation mode, where Inadvertent Export events cannot occur, upon failure of the control or inverter system for more than 30 seconds, whether from loss of control signal, loss of control power, or a single component failure or related control sensing of the control circuitry.

R14-2-2604. Customer Rights and Responsibilities

A. A Customer has the following rights:
1. To designate a Representative to act on the Customer's behalf;
2. To submit an Application to interconnect a Generating Facility with a Distribution System;
3. To expect prompt and professional responses from a Utility during the Interconnection process;
4. To expect detailed and itemized good faith estimates of cost from the Utility;
5. To expect outlines, supporting data, and justification for proposed work before the Utility undertakes any studies or system upgrades to accommodate the Generating Facility;
6. To sign documents using an electronic (e-signature) method if the Customer has the technical capability to sign electronically and is submitting the documents electronically; and
7. To request a one-time 90-day extension from the Utility using a simple notification process and not to have an extension unreasonably withheld for circumstances beyond the Customer's control.

B. A Customer shall ensure that:
1. The Generating Facility meets or exceeds all minimum Interconnection, safety, and protection requirements outlined in this Article and the Utility's Interconnection Manual;

2. The Generating Facility meets all applicable construction codes, safety codes, electric codes, laws, and requirements of government agencies having jurisdiction;
3. The Generating Facility's Certified Equipment is installed and operated in a manner that protects the Generating Facility, Utility personnel, the public, and the Distribution System from harm;
4. The Generating Facility design, installation, maintenance, and operation minimize the likelihood of causing a malfunction in, damaging, or otherwise impairing the Distribution System;
5. The Generating Facility does not adversely affect the quality of service to other Utility consumers;
6. The Generating Facility does not hamper efforts to restore a feeder to service when a Clearance is required;
7. The Generating Facility is maintained in accordance with applicable manufacturers' maintenance schedules; and
8. The Utility is notified of any emergency or hazardous condition or occurrence involving the Generating Facility that could affect safe operation of the Distribution System.

C. A Customer shall pay for; lease or own; and be responsible for designing, installing, and operating all Interconnection Facilities located on the Customer's side of the Point of Interconnection.

D. A Customer shall ensure that Interconnection Facilities:
1. Are located on the Customer's premises; and
2. To enable delivery of power from the Generating Facility to the Distribution System at the Point of Interconnection, include:
   a. Necessary equipment for:
      i. Connection,
      ii. Transformation,
      iii. Switching,
      iv. Protective relaying,
      v. Metering,
      vi. Communication, and
      vii. Safety requirements;
   b. A Disconnect Switch; and
   c. Any other requirements outlined in this Article or specified by the Utility in its Interconnection Manual.

E. A Customer interconnecting a Generating Facility with the Distribution System shall:
1. Sign an Interconnection Agreement and all other applicable purchase, supply, and standby agreements; and
2. Comply with all applicable tariffs, rate schedules, and Utility service requirements.

F. A Customer shall not interconnect or cause Interconnection of a Generating Facility to the Distribution System without first executing an Interconnection Agreement with the Utility that operates the Distribution System.

R14-2-2605. Utility Rights and Responsibilities

A. A Utility shall interconnect a Generating Facility to the Distribution System, subject to the requirements of this Article and of the Utility's Interconnection Manual.

B. A Utility has the right to expect prompt, reasonable, and professional responses from a Customer during the Interconnection process.

C. A Utility shall require that an interconnected Generating Facility:
1. Not present any hazards to Utility personnel, other Utility consumers, or the public;
2. Minimize the possibility of damage to the Utility and to other Utility consumers' equipment;
3. Not adversely affect the quality of service to other Utility consumers; and
4. Not hamper efforts to restore a feeder to service when a Clearance is required.

D. A Utility shall notify a Customer if there is reason to believe that operation of the Customer's Generating Facility has caused disruption or deterioration of service to other Utility consumers served from the Distribution System or that such operation has caused damage to the Distribution System.

E. A Utility shall make its Interconnection Manual, standard Application, and Interconnection Agreements readily available to an Applicant in print and online formats.

F. Following the receipt of an Application, a Utility shall review the Generating Facility to ensure it complies with the applicable screens in R14-2-2615. If the Generating Facility design does not comply with the applicable screens in R-14-2-2615, an Interconnection Study may be required. Before the Utility undertakes any Interconnection Study or system upgrades that will be charged to the Applicant, the Utility shall provide the Applicant a detailed estimate of the cost, an outline of the proposed work, supporting data, and justification for the proposed work. If the results of an Interconnection Study necessitate additional Interconnection Facilities or upgrades, the Utility shall provide written notice to the Applicant of the Utility's intent to install the Interconnection Facilities or upgrades. The Applicant shall pay the Utility for Interconnection Facilities or upgrades identified in the Interconnection Study except for those unrelated to the Generating Facility installation. The Utility shall provide the results of the Interconnection Study to the Applicant.

G. A Utility may not disapprove Interconnection of a Generating Facility that satisfies the requirements of this Article and the Utility's Interconnection Manual.

H. If additional Interconnection Facilities or upgrades are needed to accommodate a Generating Facility, and the Interconnection Facilities or upgrades will benefit the grid, the Utility shall reduce the charge of the Interconnection Facilities or upgrades to the Customer by the amount of benefits to the grid that are readily quantifiable by the Utility. A Utility shall not reject an Application on the basis of existing Distribution System conditions that are deficient, or charge a Customer for Interconnection Facilities or upgrades that are overdue or that will soon be required to ensure compliance with Good Utility Practice.

I. A Utility shall process each Application on a nondiscriminatory basis.

R14-2-2606. Easements and Rights-of-Way

A. Where an easement or right-of-way does not exist, but is required by a Utility to accommodate Interconnection, a Customer shall provide a suitable easement or right-of-way, in the Utility's name, on the premises owned, leased, or otherwise controlled by the Customer. If the required easement or right of way is on another's property, the Customer shall obtain and provide to the Utility a suitable easement or right-of-way, in the Utility's name, at the Customer's expense and in sufficient time to comply with Interconnection Agreement requirements.

B. A Utility shall use reasonable efforts to utilize existing easements to accommodate Interconnection.

C. A Utility shall use reasonable efforts to assist a Customer in securing necessary easements at the Customer's expense.

R14-2-2607. Insurance

A. Except as provided in subsection (D), a Utility shall not require a Customer to maintain general liability insurance coverage as a condition for Interconnection.

B. A Utility shall not require a Customer to negotiate any policy or renewal of any policy covering any liability through a particular insurance provider, agent, solicitor, or broker.

C. The provision in subsection (A) does not waive or otherwise foreclose any rights a Utility may have to pursue remedies at law against a Customer to recover damages.

D. A Utility that obtains financing from RUS may require a Customer to maintain liability insurance, to the extent necessary to meet the Utility's obligations to RUS.

R14-2-2608. Non-Circumvention

A. A Utility shall not directly or through an affiliate use knowledge of proposed Distributed Generation projects submitted to the Utility for Interconnection or study to initiate competing proposals to the Customer that offer discounted rates in return for not installing the Distributed Generation, or to offer the Customer competing Distributed Generation projects.

B. A Customer may share with a Utility or its affiliates information in the Customer's possession regarding a potential Distributed Generation project and may use such information to negotiate a discounted rate or other mutually beneficial arrangement with a Utility or its affiliate.

C. A Utility may inform a Customer of any existing or pending (awaiting approval by the Commission) rate schedule that may economically benefit, economically disadvantage, or otherwise affect the Customer's Distributed Generation project.

R14-2-2609. Designation of Contact Persons

A. Each Utility shall:
1. Designate a person or persons who will serve as the Utility's contact for all matters related to Distributed Generation Interconnection;
2. Identify to the Commission in its Interconnection Manual each designated Distributed Generation Interconnection contact person or persons; and
3. Provide convenient access through its website to the name, telephone number, mailing address, and email address for each Distributed Generation Interconnection contact person.

B. Each Applicant applying for Interconnection shall designate a contact person or persons and provide to the Utility the name, telephone number, mailing address, and email address for each contact person.

R14-2-2610. Minor Modifications

A Utility shall not reject or declare incomplete and require resubmission of a submitted Application if minor modifications must be made to the design of the Generating Facility or to other information on the Application (including ownership of Generating Facility) while the Application is being reviewed by the Utility or prior to completing the Interconnection of the Generating Facility.

R14-2-2611. Certification

A. To qualify as Certified Equipment, Generating Facility equipment proposed for use separately or packaged with other equipment in an Interconnection system shall:
1. Comply with all applicable codes and standards required by this Article and referenced in the Utility Interconnection Manual;
2. Comply with all applicable codes and standards used by an NRTL to test and certify Interconnection equipment; and
3. Be labeled and publicly listed as certified by the NRTL at the time of Application submission.

B. If Certified Equipment includes only interface components (switchgear, inverters, or other interface devices), a Customer shall show, upon request from the Utility, that the Generating Facility is compatible with the interface components and consistent with the testing and listing specified for the Interconnection equipment.

C. A Customer is not required to ensure that equipment provided by the Utility is Certified Equipment.

R14-2-2612. No Additional Requirements

If a Generating Facility complies with all applicable requirements of R14-2-2611, complies with the screens listed in R14-2-2615, and complies with the Utility's Interconnection Manual, a Utility shall not require the Customer to install additional controls, or to perform or pay for additional tests, in order to obtain approval to interconnect, unless the Customer agrees to do so or the Commission so requires. A Utility may install additional equipment or perform additional testing at its own expense.

R14-2-2613. Disconnection from or Reconnection with the Distribution System

A. A Utility may disconnect a Generating Facility from the Distribution System under the following conditions:
1. Upon expiration or termination of the Interconnection Agreement with a Customer, in accordance with the terms of the Interconnection Agreement;
2. Upon determining that the Generating Facility is not in compliance with the technical requirements found within the Utility's Interconnection Manual;
3. Upon determining that continued Interconnection of the Generating Facility will endanger system operations, persons, or property, for the time needed to make immediate repairs on the Distribution System;
4. To perform routine maintenance, repairs, and system modifications; and
5. Upon determining that an Interconnection Agreement is not in effect for the Generating Facility.

B. A Utility and a Customer shall cooperate to restore the Generating Facility and the Distribution System to their normal operating states as soon as practicable.

C. A Customer may temporarily disconnect the Generating Facility from the Distribution System at any time. Such temporary disconnection shall not constitute a termination of the Interconnection Agreement unless the Customer has so specified in writing.

D. Except in the case of a disconnection under subsection (A)(3), a Utility shall provide notice to a Customer before disconnecting the Generating Facility. The Utility shall provide the Customer notice at least three calendar days prior to the impending disconnection and shall include in the notice the date, time, and estimated duration of the disconnection.

E. When a Generating Facility is disconnected under subsection (A)(2):
1. The Customer shall notify the Utility when the Generating Facility is restored to compliance with technical requirements;
2. The Utility shall, within five calendar days after receiving the Customer's notice, have an inspector verify the compliance; and
3. Upon verifying the compliance, the Utility shall, in coordination with the Customer, reconnect the Generating Facility.

F. A Utility shall reconnect a Generating Facility as quickly as practicable after determining that the reason for disconnection is remedied.

G. An Interconnection Agreement shall continue in effect after disconnection or termination of electric service to the extent and for the period necessary to allow or require the Utility or Customer to fulfill rights or obligations that arose under the agreement, notwithstanding subsection (H)(4). An Interconnection Agreement cannot be for a term less than the expected life of the Generating Facility, unless mutually agreed upon by the Customer and the Utility.

H. An Interconnection Agreement shall become effective on the effective date specified in the Interconnection Agreement and shall remain in effect thereafter unless and until:
1. It is terminated by mutual agreement of the Utility and Customer;
2. It is replaced by another Interconnection Agreement, with mutual consent of the Utility and Customer;
3. It is terminated by the Utility or the Customer due to a breach or default of the Interconnection Agreement; or
4. The Customer terminates Utility electric service, vacates or abandons the property on which the Generating Facility is located, or terminates or abandons the Generating Facility, without the Utility's agreement.

I. An Interconnection Agreement shall not be terminated in the event of the sale or lease of the property owned by the Customer. If the ownership of a Generating Facility changes, the Interconnection Agreement will remain in effect so long as the operation of the Generating Facility, as specified in the Interconnection Agreement, remains unchanged. The Customer shall provide notice to the Utility within seven calendar days in the event of a change in the ownership of the Generating Facility.

J. Upon termination of an Interconnection Agreement:
1. The Customer shall ensure that the electrical conductors connecting the Generating Facility to the Distribution System are immediately lifted and permanently removed, to preclude any possibility of interconnected operation in the future; and
2. The Utility may inspect the Generating Facility to verify that it is permanently disconnected.

R14-2-2614. Application and Generating Facility General Requirements

A. A Customer desiring to interconnect to the Distribution System a Generating Facility that is not a Non-Exporting inverter-based energy storage Generating Facility or an Inadvertent Export Generating Facility with a Maximum Capacity of 20 kW or less shall apply to the Utility for Interconnection as provided in this Section.

B. An Applicant shall submit an Application on a form provided by the Utility, or according to a format provided by the Utility, along with the following:
1. All supplemental information and documents required by the Utility, which shall be noted on the Utility's Application or Application instructions;
2. An executed Interconnection Agreement, if required by the Utility; and
3. An initial Application or processing fee, if a tariff containing such a fee is approved for the Utility by the Commission.

C. Upon request, a Utility shall provide an Applicant with sample diagrams that indicate the preferred level of detail and type of information required for a typical inverter-based system.

D. Within seven calendar days after receiving an Application, a Utility shall review the Application and provide the Applicant notice:
1. That the Application satisfies all requirements under subsection (B); or
2. That the Application does not satisfy one or more requirements under subsection (B), in which case:
   a. The Utility shall specify the additional information or documents required;
   b. The Applicant shall submit the specified information or documents; and
   c. The Application may be deemed withdrawn if the Applicant does not submit the required information or documents within 30 calendar days.

E. A Generating Facility shall comply with the following general requirements:
1. If inverter based, each inverter shall meet the shutdown protective functions (under/over voltage, under/over frequency, and anti-Islanding) specified in IEEE 1547-2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces (April 6, 2018), with no future editions or amendments, which is incorporated by reference; on file with the Commission; and published by and available from IEEE, 3 Park Avenue, 17th Floor, New York, New York 10016, and through http://ieeexplore.ieee.org;
2. The Generating Facility shall meet all applicable codes and standards required by this Article and referenced in the Utility Interconnection Manual; and
3. The Generating Facility shall comply with the Utility's Interconnection Manual and Interconnection Agreement requirements.

R14-2-2615. Screens

A. For Interconnection of a proposed Generating Facility to a distribution circuit, the aggregated generation on the circuit, including the proposed Generating Facility, shall not exceed 15% of the total circuit annual peak load as most recently measured at the substation or on the line section (if available), or the circuit hosting capacity limit; whichever is greater. Non-Exporting Systems, regardless of system size, and Inadvertent Export systems with a Maximum Capacity of 20 kW and under shall not be subject to this subsection.

B. A proposed Generating Facility shall not contribute more than 10% to a distribution circuit's maximum fault current at any point on the Distribution System, including during normal contingency conditions that may occur due to reconfiguration of the feeder or the distribution substation.

C. The proposed Maximum Capacity of a Generating Facility, in aggregate with the Maximum Capacity of other generation on a distribution circuit, shall not cause any distribution protective devices and equipment (including but not limited to substation breakers, fuse cutouts, and line reclosers), or consumer equipment on the system, to exceed 90% of the short circuit interrupting capability. Interconnection shall not be proposed for a circuit that already exceeds 90% of the short circuit interrupting capability.

D. A proposed Generating Facility shall be interconnected to the Distribution System as shown in the table below:

Primary Distribution Line Configuration	**Interconnection to Primary Distribution Line**
Three-phase, three wire	If a three-phase or single-phase Generating Facility, Interconnection shall be phase-to-phase
Three-phase, four wire	If a three-phase (effectively grounded) or single-phase Generating Facility, Interconnection shall be line-to-neutral

E. If a proposed Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Maximum Capacity of the Generating Facility, shall not exceed 75% of the service transformer rating. Non-Exporting Systems and Inadvertent Export systems shall not be subject to this subsection.

F. If a proposed Generating Facility is single-phase and is to be interconnected on a transformer center tap neutral of a 240-volt service, its addition shall not create an imbalance between the two sides of the 240-volt service of more than 20% of the nameplate rating of the service transformer.

G. A proposed Generating Facility, in aggregate with other generation interconnected to the distribution low-voltage side of a substation transformer feeding the distribution circuit where the Generating Facility would interconnect, shall not exceed 10 MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission voltage level busses from the Point of Interconnection). Non-Exporting Systems, regardless of system size, and Inadvertent Export systems with a Maximum Capacity of 20 kW and under shall not be subject to this subsection.

H. A proposed Generating Facility's Point of Interconnection shall not be on a transmission line.

I. A proposed Generating Facility shall not exceed the capacity of the Customer's existing electrical service unless there is a simultaneous request for an upgrade to the Customer's electrical service or the Generating Facility is configured never to inject onto the feeder power that exceeds the capacity of the electrical service.

J. If a proposed Generating Facility is non-inverter based, the Generating Facility must comply with the Protective Function requirements and any additional Utility Interconnection requirements, which shall be specified by the Utility in its Interconnection Manual.

R14-2-2616. Pre-Application Report

A. An Applicant requesting a Pre-Application Report shall submit to a Utility:
1. The Applicant's contact information (name, address, phone, and email);
2. A proposed Point of Interconnection, sufficiently identified by latitude and longitude, site map, street address, meter number, account number, or some combination of those sufficient to identify the location of the Point of Interconnection;
3. A description of the proposed generation technology and fuel source; and
4. A non-refundable processing fee, if a tariff containing such a fee is approved for the Utility by the Commission.

B. An Applicant requesting a Pre-Application Report shall understand that:
1. The existence of "available capacity" does not mean that the Interconnection of a Generating Facility with a nameplate capacity that is equivalent to the available capacity may be completed without impacts, because the Pre-Application Report does not address all of the variables studied as part of the Interconnection review process;
2. The Distribution System is dynamic and subject to change; and
3. Data provided in the Pre-Application Report may become outdated and may not be useful at the time an Application is submitted.

C. Within 21 calendar days of receipt of a completed Pre-Application Report request, a Utility shall provide a Pre-Application Report, which shall include the following information, as available:
1. The total capacity (MW) of the substation/area bus or bank and circuit likely to serve the proposed site;
2. The allocated capacity (MW) of the substation/area bus or bank and circuit likely to serve the proposed site;
3. The queued capacity (MW) of the substation/area bus or bank and circuit likely to serve the proposed site;
4. The available capacity (MW) of the substation/area bus or bank and circuit most likely to serve the proposed site;
5. Whether the proposed Generating Facility is located on an area, spot, or radial network;
6. The substation nominal distribution voltage or nominal transmission voltage, if applicable;
7. The nominal distribution circuit voltage at the proposed site;
8. The approximate circuit distance between the proposed site and the substation;
9. The peak load estimate and minimum load data of each relevant line section, when available;
10. The number of protective devices and voltage regulating devices between the proposed site and the substation/area;
11. Whether three-phase power is available at the site and, if not, the distance of the site from three-phase service;
12. The limiting conductor rating from the proposed Point of Interconnection to the distribution substation; and

13. Based on the proposed Point of Interconnection, any 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.

D. A Utility shall not be required to generate data for a Pre-Application Report and may include only pre-existing data. An Applicant request for a Pre-Application Report does not obligate the Utility to conduct a study or other analysis of the proposed project in the event that pre-existing data is not available. If a Utility cannot complete all or some of a Pre-Application Report due to lack of available data, the Utility shall provide the Applicant a Pre-Application Report that includes the information that is available and identifies the information that is unavailable. Notwithstanding any provisions of this Section, a Utility shall, in good faith, provide Pre-Application Report data that represents the best available information at the time of reporting.

E. A Utility may charge a fee for a Pre-Application Report if a tariff containing such a fee is approved for the Utility by the Commission.

R14-2-2617. Level 1 Super Fast Track

A. A Customer interconnecting an inverter-based Generating Facility with a Maximum Capacity of 20 kW or less, which only uses Certified Equipment, shall apply for Interconnection under the Level 1 Super Fast Track Application process.

B. To qualify for Level 1 Super Fast Track, the Generating Facility shall comply with R14-2-2615(A), (E), and (F).

C. The Level 1 Super Fast Track shall proceed as follows:

1. Within 14 calendar days following provision of notice under R14-2-2614(D)(1), the Utility shall review the Application and notify the Applicant of one of the following determinations:
   a. The Generating Facility design satisfies R14-2-2615(A), (E), and (F) and meets all Interconnection requirements and the Application is therefore deemed complete and approved for Interconnection; or
   b. The Generating Facility design does not satisfy one or more of the requirements listed in R14-2-2615(A), (E), or (F) or does not meet one or more of the Utility's Interconnection requirements, which shall be specified, and the Application is therefore deemed incomplete and not approved for Interconnection.
2. If the Utility's determination falls under subsection (C)(1)(b), the Applicant shall notify the Utility within 30 calendar days whether it wishes to proceed with the Interconnection.
   a. Except as provided in subsection (D), if the Applicant does not provide notice within 30 calendar days that it wishes to proceed with the Interconnection, the Application may be considered withdrawn.
   b. If the Applicant wishes to proceed with the Interconnection, the Applicant shall submit to the Utility, within 30 calendar days, any Utility-specified additional information or modifications to the Generating Facility, along with one of the following:
      i. A request that the Utility continue to process the Application under this section; or
      ii. A request that the Utility process the Application in accordance with R14-2-2620.
3. Once an Application is approved, the Generating Facility shall be subject to R14-2-2621.

D. An Applicant may, within 30 calendar days after receiving notice under subsection (C)(1)(b), submit a request for an extension of the 30-day period allowed for submissions under subsection (C)(2)(b).

E. After receiving a submission under subsection (C)(2)(b), a Utility shall again follow the process of subsection (C).

F. A Utility may not charge a fee for an additional review under subsection (C), unless a tariff containing such a fee is approved for the Utility by the Commission.

G. A Customer shall be responsible for any costs of Utility facilities and equipment modifications necessary to accommodate the Customer's Interconnection.

H. If the Generating Facility's operating characteristics can be modified such that improvements to the Distribution System are reduced or not required, and both the Utility and Customer agree on the operating characteristics, the Customer shall have the opportunity to modify the Generating Facility's operating characteristics to reduce facility costs.

R14-2-2618. Level 2 Fast Track

A. A Customer interconnecting a Generating Facility with a Maximum Capacity of less than 2 MW, excluding a Generating Facility processed in accordance with R14-2-2617, shall apply for Interconnection under the Level 2 Fast Track Application process.

B. To qualify for the Level 2 Fast Track, the Generating Facility shall comply with R14-2-2615(A) through (J).

C. The Level 2 Fast Track shall proceed as follows:

1. Within 21 calendar days following provision of notice under R14-2-2614(D)(1), the Utility shall review the Application and notify the Applicant of one of the following determinations:
   a. The Generating Facility design satisfies R14-2-2615(A) through (J) and meets all Interconnection requirements and the Application is therefore deemed complete and approved for Interconnection; or
   b. The Generating Facility design does not satisfy one or more of the requirements listed in subsections R14-2-2615(A) through (J) or does not meet one or more of the Utility's Interconnection requirements, which shall be specified, and the Application is therefore deemed incomplete and not approved for Interconnection.
2. If the Utility's determination falls under subsection (C)(1)(b), the Applicant shall notify the Utility within 30 calendar days whether it wishes to proceed with the Interconnection.
   a. Except as provided in subsection (D), if the Applicant does not provide notice within 30 calendar days that it wishes to proceed with the Interconnection, the Application may be considered withdrawn.
   b. If the Applicant wishes to proceed with the Interconnection, the Applicant shall submit to the Utility, within 30 calendar days, any Utility-specified additional information or modifications to the Generating Facility, along with one of the following:
      i. A request that the Utility continue to process the Application under this section;
      ii. A request that the Utility process the Application in accordance with R14-2-2619; or
      iii. A request that the Utility process the Application in accordance with R14-2-2620.
3. Once an Application is approved, the Generating Facility shall be subject to R14-2-2621.

D. An Applicant may, within 30 calendar days after receiving notice under subsection (C)(1)(b), submit a request for an extension of the 30-day period allowed for submissions under subsection (C)(2)(b).
E. After receiving a submission under subsection (C)(2)(b), a Utility shall again follow the process under subsection (C).
F. A Utility may not charge a fee for an additional review under subsection (C), unless a tariff containing such a fee is approved for the Utility by the Commission.
G. A Customer shall be responsible for any costs of Utility facilities and equipment modifications necessary to accommodate the Interconnection.
H. If the Generating Facility's operating characteristics can be modified such that improvements to the Distribution System are reduced or not required, and both the Utility and Customer agree on the operating characteristics, the Customer shall have the opportunity to modify the Generating Facility's operating characteristics to reduce facility costs.

R14-2-2619. Level 3 Study Track

A. A Customer interconnecting a Generating Facility with a Maximum Capacity of 2 MW or greater, or a Generating Facility that does not meet the screening requirements for Level 1 Super Fast Track, Level 2 Fast Track, or Supplemental Review, shall apply for Interconnection under the Level 3 Study Track Application process.
B. An Applicant may request a pre-application meeting with the Utility to discuss the proposed design, installation, and operation of the Generating Facility prior to submission of an Application.
C. The Level 3 Study Track shall proceed as follows:
1. Within 14 calendar days after transfer from Level 1 Super Fast Track, transfer from Level 2 Fast Track, or transfer from Supplemental Review, a Utility shall review the Application and provide the Applicant notice:
   a. That the Application satisfies all requirements under R14-2-2614(B); or
   b. That the Application does not satisfy one or more requirements under R14-2-2614(B), in which case:
      i. The Utility shall specify the additional information or documents required;
      ii. The Applicant shall submit the specified information or documents; and
      iii. The Application may be deemed withdrawn if the Applicant does not submit the required information or documents within 30 calendar days.
2. Within 30 calendar days following provision of notice under (C)(1)(a) or R14-2-2614(D)(1), the Utility shall review the Application and notify the Applicant of one of the following determinations:
   a. The Generating Facility design appears to meet all of the applicable Interconnection requirements; no further studies, special protective requirements, or system modifications are required; and the Application is deemed complete and approved for Interconnection; or
   b. The Generating Facility does not meet one or more of the Utility's Interconnection requirements, which shall be specified, and cannot be interconnected without further information, data, engineering studies, or modifications to the Distribution System or Generating Facility; the Interconnection shall proceed according to a meeting and study process deemed necessary by the Utility; itemized costs and timelines for the studies will be disclosed and agreed upon by the Utility and Applicant prior to the start of each one; and all studies will be made available to the Applicant.
3. Within 21 calendar days after notice is provided under subsection (C)(2)(b), a Scoping Meeting may be conducted to discuss which studies are needed, and the Utility shall provide to the Customer at the Scoping Meeting an acknowledgement letter describing the project scope and including a good faith estimate of the cost.
4. If requested by the Customer, the Utility shall undertake a Feasibility Study. The Utility shall provide the Customer, within 14 calendar days after the Scoping Meeting, a Feasibility Study agreement including an outline of the scope of the study and a non-binding, good faith estimate of the cost of the materials and labor needed to perform the study. The Utility shall conduct the Feasibility Study after the Customer executes the Feasibility Study agreement, provides all requested information necessary to complete the Feasibility Study, and pays the estimated costs.
   a. The Feasibility Study shall be completed within 45 calendar days.
   b. The Feasibility Study:
      i. Shall include review of short circuit currents, including contribution from the proposed generator, as well as coordination of and potential overloading of distribution circuit protection devices;
      ii. Shall provide initial details and ideas on the complexity and likely costs to interconnect prior to commitment of costly engineering review; and
      iii. May be used to focus or eliminate some or all of the more intensive System Impact Study.
5. If deemed necessary by the Customer or the Utility, the Utility shall undertake a System Impact Study. The Utility shall provide the Customer, within 14 calendar days after completing the previous study or meeting, a System Impact Study agreement including an outline of the scope of the study and a non-binding, good faith estimate of the cost of the materials and labor needed to perform the study. The Utility shall conduct the System Impact Study after the Customer executes the System Impact Study agreement, provides all requested Customer information necessary to complete the System Impact Study, and pays any required deposit of the estimated costs.
   a. The System Impact Study shall be completed within 45 calendar days.
   b. The System Impact Study shall reveal all areas where the Distribution System would need to be upgraded to allow the Generating Facility to be built and interconnected as designed and may include discussions with the Customer about potential alterations to generator design, including downsizing to limit grid impacts, as well as operational limits that would limit grid impacts if implemented.
   c. If the Utility determines, in accordance with Good Utility Practice, that the Distribution System modifications required to accommodate the proposed Interconnection are not substantial, the System Impact Study shall identify the scope and detailed cost of the modifications.
   d. If the Utility determines, in accordance with Good Utility Practice, that the system modifications to the Distribution System are substantial, a Facilities Study shall be performed.

e. Each Utility shall include in its Interconnection Manual a description of the various elements of a System Impact Study it would typically undertake pursuant to this Section, including:
   i. Load flow study;
   ii. Short-circuit study;
   iii. Circuit protection and coordination study;
   iv. Impact on system operation;
   v. Stability study, and the conditions justifying inclusion; and
   vi. Voltage collapse study, and the conditions justifying inclusion.

6. The Utility shall undertake a Facilities Study if needed based on the outcome of the System Impact Study. The Utility shall provide the Customer, within 14 calendar days after completing the previous study or meeting, a Facilities Study agreement including an outline of the scope of the study and a non-binding, good faith estimate of the cost of the materials and labor needed to perform the study. The Utility shall conduct the Facilities Study after the Customer executes the Facilities Study agreement, provides all requested Customer information necessary to complete the study, and pays the estimated costs.
   a. The Facilities Study shall be completed within 45 calendar days.
   b. The Facilities Study shall delineate the detailed costs of construction and milestones. Construction may include new circuit breakers, relocation of reclosers, new Utility grid extensions, reconductoring lines, new transformers, protection requirements, and interaction.
7. If the Generating Facility meets all of the applicable Interconnection requirements, all items identified in any meeting or study have been resolved and agreed to, and the Utility has received the final design drawings, then:
   a. The Utility shall send to the Customer, within seven calendar days, an executable Interconnection Agreement, which shall include as an exhibit the cost for any required Distribution System modifications;
   b. The Customer shall review, sign, and return the Interconnection Agreement and any balance due for Interconnection studies or required deposit for facilities; and
   c. The Customer shall then complete installation of the Generating Facility, and the Utility shall complete any Distribution System modifications, according to the requirements set forth in the Interconnection Agreement. The Utility shall employ best reasonable efforts to complete such system upgrades in the shortest time practical.
8. Once an Application is approved, the Generating Facility shall be subject to R14-2-2621.

D. A Utility may not charge a fee for an additional review under subsection (C), unless a tariff containing such a fee is approved for the Utility by the Commission.

E. A Customer shall have the responsibility for any costs of Utility facilities and equipment modifications necessary to accommodate the Customer's Interconnection.

F. If the Generating Facility's operating characteristics can be modified such that improvements to the Distribution System are reduced or not required, and both the Utility and Customer agree on the operating characteristics, the Customer shall have the opportunity to modify the Generating Facility's operating characteristics to reduce facility costs.

R14-2-2620. Supplemental Review

A. If a Utility determines that an Application for Interconnection cannot be approved without conducting a Supplemental Review, or if requested by the Applicant:
1. The Utility shall, within seven calendar days of making the determination or receiving the request, provide the Applicant a good faith estimate of the cost of the Supplemental Review and a written agreement setting forth the terms of the Supplemental Review; and
2. If the Customer desires to proceed with the Application, the Customer shall, within 14 calendar days of receipt of the good faith estimate and written agreement, sign the written agreement and submit to the Utility a deposit for the full estimated cost of the Supplemental Review.

B. The Applicant may specify the order in which the Utility will complete the screens in subsection (E).

C. The Applicant shall be responsible for the Utility's actual costs for conducting a Supplemental Review and must pay any review costs exceeding the deposit amount within 30 calendar days of receipt of an invoice for the balance, or resolution of any dispute as to those costs. If the deposit amount exceeds the actual costs of the Supplemental Review, the Utility shall return such excess to the Customer, without interest, within 30 calendar days of completing the Supplemental Review.

D. Within 21 calendar days following receipt of the deposit for a Supplemental Review, the Utility shall:
1. Perform a Supplemental Review by determining compliance with the screens in subsections (E)(1), (2), and (3);
2. Unless the Applicant has previously provided instructions for how to respond to the Generating Facility's failure to meet any of the Supplemental Review screens:
   a. Notify the Applicant following the failure of any of the screens; and
   b. If the Utility is unable to determine compliance with the screen in subsection (E)(1), notify the Applicant within two calendar days of making such determination and request the Applicant's permission to:
      i. Continue evaluating the Interconnection under subsection (E);
      ii. Terminate the Supplemental Review and continue evaluating the Generating Facility under R14-2-2619; or
      iii. Terminate the Supplemental Review upon withdrawal of the Interconnection request by the Applicant; and
3. Notify the Applicant of the results of the Supplemental Review along with copies of the analysis and data underlying the Utility's determinations of compliance with the screens.

E. A Utility shall apply the following screens in its Supplemental Review:
1. A minimum load screen:
   a. If 12 months of line section minimum load data (including onsite load but not station service load served by the Generating Facility) are available, can be calculated, can be estimated from existing data, or can be determined from a power flow model, the aggregate Generating Facility Maximum Capacity on the line section shall be less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the Generating Facility.

b. If 12 months of line section minimum load data are not available, or cannot be calculated, estimated, or determined, the Utility shall include in its Supplemental Review results notification under subsection (D) each reason that it is unable to calculate, estimate, or determine minimum load.
c. In making its determination of compliance with subsections (E)(1)(a) and (b), the Utility shall:
i. Consider the type of generation used by the Generating Facility when calculating, estimating, or determining the circuit or line section minimum load, using daytime minimum load for solar photovoltaic generation systems with no battery storage (i.e., 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for solar photovoltaic generation systems utilizing tracking systems), and using absolute minimum load for all other generation;
ii. For a Generating Facility that serves some station service load, consider only the net injection into the Utility's electric system as part of the aggregate generation; and
iii. Not consider as part of the aggregate generation Generating Facility capacity known to be reflected already in the minimum load data.
2. A voltage and power quality screen: In aggregate with existing Maximum Capacity on the line section:
a. Voltage regulation on the line section shall be maintained in compliance with relevant requirements under all system conditions;
b. Voltage fluctuation shall be within acceptable limits as defined by IEEE 1453, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems (October 30, 2015), with no future editions or amendments, which is incorporated by reference; on file with the Commission; and published by and available from IEEE, 3 Park Avenue, 17th Floor, New York, New York 10016, and through http://ieeexplore.ieee.org; and
c. Harmonic levels shall meet IEEE 519 limits, IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems (June 11, 2014), with no future editions or amendments, which is incorporated by reference; on file with the Commission; and published by and available from IEEE, 3 Park Avenue, 17th Floor, New York, New York 10016, and through http://ieeexplore.ieee.org.
3. A safety and reliability screen: The location of the Generating Facility and the aggregate Maximum Capacity on the line section shall not create impacts to safety or reliability that cannot be adequately addressed without application of the Interconnection Study process. In making this determination regarding potential impacts to safety and reliability, the Utility shall give due consideration to the following, and any other relevant factors:
a. Whether the line section has significant minimum loading levels dominated by a small number of customers (e.g., several large commercial customers);
b. Whether the loading along the line section is uniform or even;
c. Whether the Generating Facility is located in close proximity to the substation (i.e., within less than 2.5 electrical circuit miles);
d. Whether the line section from the substation to the Point of Interconnection is a main feeder line section rated for normal and emergency ampacity;
e. Whether the Generating Facility incorporates a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time;
f. Whether operational flexibility is reduced by the Generating Facility, such that transfer of the line section(s) of the Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues; and
g. Whether the Generating Facility employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, Islanding, reverse power flow, or voltage quality.

F. If the Interconnection satisfies subsection (E), the Application shall be approved for Interconnection, and the Utility shall provide the Applicant notice of the Supplemental Review results.

G. If Interconnection Facilities or minor modifications to the Utility's system are required for the Interconnection to meet the screens in subsection (E), the Utility shall notify the Applicant and request for the Applicant to pay for the modifications. If the Applicant agrees to pay for the modifications to the Utility's electric system, the Utility shall provide an Interconnection Agreement, along with a non-binding good faith estimate of the cost for the Interconnection Facilities and minor modifications, to the Applicant within seven calendar days after the Applicant agrees to pay for the modifications.

H. If more than Interconnection Facilities or minor modifications to the Utility's system would be required for the Interconnection to meet the screens in subsection (E), the Utility shall notify the Applicant, at the same time it notifies the Applicant of the Supplemental Review results, that the Interconnection request shall be evaluated under R14-2-2619, unless the Applicant withdraws its Application.

I. If the Interconnection fails any of the screens in subsection (E), and the Applicant does not withdraw its Application, the Utility shall continue to evaluate the Application under R14-2-2619.

R14-2-2621. Utility Site Inspection; Approval for Parallel Operation

A. Once an Application is approved for Interconnection:
1. If the Utility has not received an executed Interconnection Agreement, the Utility shall send to the Customer, within seven calendar days after the notice of Application approval, the appropriate Interconnection Agreement for review and signature;
2. If required, the Customer shall submit to the Utility a copy of the final electrical clearance for the Generating Facility issued by the authority having jurisdiction;
3. The Customer shall submit all necessary supplemental documents as specified by the Utility; and
4. A site inspection shall be performed if deemed necessary by the Utility or requested by the Customer.

B. Within seven calendar days after a site inspection is deemed necessary by the Utility, or requested by the Customer, the Utility shall perform a site inspection for which it may charge a fee, if a tariff containing such a fee is approved for the Utility by the Commission. During a site inspection, the Utility shall verify at least the following:
1. The Generating Facility is in compliance with all applicable Interconnection and code requirements;
2. All Generating Facility equipment is properly labeled;
3. The Generating Facility system layout is in accordance with the plant location and site plans submitted to the Utility;

4. The inverter nameplate ratings are consistent with the information submitted to the Utility;
5. The Utility has unrestricted 24-hour access to the Utility-owned production meter and Disconnect Switch, and the Disconnect Switch meets all applicable requirements;
6. The inverter shuts down as required upon simulated loss of Utility voltage; and
7. To the extent visible, the Generating Facility appears to be wired in accordance with the electrical diagrams submitted to the Utility.

C. The Utility shall install appropriate metering equipment, if required. The Utility may require the Customer to pay for the metering equipment, if a tariff containing such a fee is approved for the Utility by the Commission.

D. Within three calendar days of the completion of the site inspection and the receipt of all final applicable signed Interconnection documents, the Utility shall determine whether the Generating Facility meets all applicable requirements and shall notify the Customer that:
1. The Generating Facility is approved for Parallel Operation with the Distribution System per the agreed terms and conditions; or
2. The Generating Facility has failed the site inspection because it does not meet one or more of the applicable requirements, which shall be specified; the Generating Facility is not approved for Parallel Operation; and specified actions must be taken by the Customer to resolve the issue and to obtain approval for Parallel Operation.

E. If the Generating Facility fails the initial Utility site inspection:
1. The Applicant shall, within 30 calendar days of the initial site inspection, correct any outstanding issues and notify the Utility that all corrections have been made, or the Application may be deemed withdrawn unless alternative arrangements have been made by the Customer with the Utility; and
2. The Utility shall, within 14 calendar days of the Applicant notice of correction, perform a repeat inspection of the Generating Facility, for which the Utility may charge a fee, if a tariff containing such a fee is approved for the Utility by the Commission.

F. A Utility may take any reasonable actions, including locking open a Disconnect Switch, to prevent Parallel Operation for:
1. A Generating Facility that fails a site inspection; or
2. A Customer who operates a Generating Facility in parallel without Utility approval.

G. If a Customer does not interconnect a Generating Facility within 180 calendar days after Application approval, the Customer's Application may be considered withdrawn.

R14-2-2622. Interconnection to a Secondary Spot Network System

A. A Secondary Spot Network System is a system that:
1. Simultaneously serves a Customer from three-phase, four-wire, low-voltage (typically 480V) circuits supplied by two or more network transformers which have low-voltage terminals that are connected to the low-voltage circuits through network protectors without ties to adjacent or nearby secondary network systems;
2. Has two or more high-voltage primary feeders that are either dedicated network feeders that serve only other network transformers, or non-dedicated network feeders that serve radial transformers in addition to the network transformers, depending on network size and design; and
3. Has automatic protective devices and fuses intended to isolate faulted primary feeders, network transformers, or low-voltage cable sections while maintaining uninterrupted service to the consumers served from the low-voltage circuits.

B. Because interconnecting a Generating Facility to a Secondary Spot Network System implicates technical requirements that are particular to the design and operational aspects of network protectors that are not required on radial systems, the Utility shall determine the process for interconnecting to a Secondary Spot Network System, subject to the following:
1. A Generating Facility shall not be interconnected to the load side of spot network protectors unless the Generating Facility uses an inverter-based equipment package and, together with the aggregated other inverter-based generation, does not exceed the smaller of 5% of the Secondary Spot Network System's maximum load or 50 kW; and
2. Interconnection of a Generating Facility shall not result in a Backfeed of a Secondary Spot Network System or cause unnecessary operation of any Secondary Spot Network System protectors.

R14-2-2623. Expedited Interconnection Process

A. A Customer interconnecting a Non-Exporting inverter-based energy storage Generating Facility or an Inadvertent Export Generating Facility with a Maximum Capacity of 20 kW or less may apply for Interconnection under the Expedited Interconnection Process. In order to qualify for the Expedited Interconnection Process, the Customer's Generating Facility must meet the applicable conditions specified in subsections (B) and (C).

B. For a Customer interconnecting a Non-Exporting Generating Facility:
1. The Generating Facility shall utilize only UL 1741- and UL 1741SA-listed equipment;
2. The Generating Facility shall meet all applicable codes and standards required by this Article and referenced in the Utility Interconnection Manual;
3. The Generating Facility shall comply with Utility Interconnection and contractual requirements;
4. The Generating Facility shall be a Non-Exporting inverter-based energy storage device with an aggregate maximum nameplate rating no greater than 500 kW;
5. No other Generating Facilities, other than isolated back-up Generating Facilities, may be at the same Point of Interconnection as the Generating Facility;
6. The Generating Facility shall comply with R14-2-2615(F); and
7. The Generating Facility shall comply with one of the following:
   a. The system capacity shall be less than 25% of the electrical service entrance ampere rating, and less than 50% of the service transformer rating; or
   b. The system output rating shall be less than 50% of the verifiable Customer minimum load as measured over the past 12 months.

C. For a Customer interconnecting an Inadvertent Export Generating Facility with a Maximum Capacity of 20 kW or less:

1. The Generating Facility shall utilize only UL 1741- and UL 1741SA-listed equipment;
2. The Generating Facility shall meet all applicable codes and standards required by this Article and referenced in the Utility Interconnection Manual;
3. The Generating Facility shall comply with Utility Interconnection and contractual requirements;
4. The Generating Facility shall comply with R14-2-2603(E)(1) and (E)(4) through (7);
5. No other Generating Facilities, other than isolated back-up Generating Facilities or Generating Facilities that are already subject to an executed Interconnection Agreement, may be at the same Point of Interconnection as the Generating Facility; and
6. The Generating Facility shall comply with R14-2-2615(E) and (F).

D. The Expedited Interconnection Process shall proceed as follows:

1. An Applicant shall complete an Application provided by the Utility and submit the Application to the Utility along with all required supplemental information and documents, which shall be noted on the Application, as well as an executed Interconnection Agreement, if required by the Utility, and with an initial application fee or processing fee only if a tariff containing such a fee is approved for the Utility by the Commission.
2. Within seven calendar days of receipt of the Application, the Utility shall notify the Applicant whether the Application is complete or incomplete.
   a. When the Utility notifies the Applicant that an Application is incomplete, the Utility shall specify what additional information or documentation is necessary to complete the Application.
   b. Within 30 calendar days after receipt of notification that an Application is incomplete, an Applicant shall withdraw the Application or submit the required information or documentation. If an Applicant does not submit the required information or documentation within 30 calendar days, the Application may be considered withdrawn.
3. Within seven calendar days following the receipt of a complete Application, the Utility shall review the Application and notify the Applicant of one of the following determinations;
   a. The Generating Facility meets the requirements of subsections (B) and (C), and the Application is approved as submitted; or
   b. The Generating Facility does not meet the requirements of subsections (B) and (C), in a manner specified by the Utility; the Application is no longer eligible for processing under the Expedited Interconnection Process; and the Applicant has the option to select Application processing in accordance with R14-2-2620.
4. If the Application is not accepted as submitted, the Applicant shall notify the Utility within 30 calendar days whether it wishes to proceed with the Interconnection.
   a. If the Applicant does not wish to proceed with the Interconnection, or the Utility is not notified within the specified timeframe, the Application may be considered withdrawn.
   b. If the Applicant wishes to proceed with the Interconnection, the Utility shall begin processing the Application in accordance with R14-2-2620.
5. Once an Application is approved:
   a. If the Utility has not received an executed Interconnection Agreement, the Utility shall send to the Customer, within three calendar days after the notice of Application approval, the appropriate Interconnection Agreement for review and signature; and
   b. Within three calendar days of the receipt of all final applicable signed Interconnection documents, the Utility shall notify the Customer that the Generating Facility is approved for Parallel Operation.

R14-2-2624. Disconnect Switch Requirements

A. If required by a Utility, a Customer shall install and maintain a visual-open, manually operated, load break Disconnect Switch that completely opens and isolates all ungrounded conductors of the Generating Facility from the Distribution System. For multi-phase systems, the Disconnect Switch shall be gang-operated.

B. A Utility may impose additional requirements for a Disconnect Switch in its Interconnection Manual.

R14-2-2625. Advanced Inverter Requirements

A. If interconnected after the effective date of this Article, a Generating Facility utilizing inverter-based technology shall be interconnected via advanced inverter(s) that are capable of, at minimum, the advanced grid support features specified in subsection (B).

B. At a minimum, an advanced inverter shall be capable of the following grid support features:

1. Volt/VAR Mode – Provide voltage/VAR control through dynamic reactive power injection through autonomous responses to local voltage measurement;
2. Volt/Watt Mode – Provide voltage/watt control though dynamic active power injection through autonomous responses to local voltage measurement;
3. Fixed Power Factor – Provide reactive power by a fixed power factor;
4. Anti-Islanding – Support anti-Islanding to trip off under extended anomalous conditions;
5. Low/High Voltage Ride-through (L/HVRT) – Provide ride-through of low/high voltage excursions beyond normal limits;
6. Low/High Frequency ride-through (L/HFRT) – Provide ride-through of low/high frequency excursions beyond normal limits;
7. Soft-Start Reconnection – Reconnect after grid power is restored; and
8. Frequency/Watt Mode – Provide Frequency/Watt control to counteract frequency excursions beyond normal limits by decreasing or increasing real power.

C. The grid support features listed in subsections (B)(1), (2), (3), (7), and (8) shall only be activated upon mutual consent between the Customer and the Utility.

D. The grid support features listed in subsections (B)(4), (5), and (6) shall always be operational.

E. Advanced inverters shall meet the shutdown protective functions (under/over voltage, under/over frequency, and anti-Islanding) specified in IEEE 1547-2018, which is incorporated by reference in R14-2-2614(E)(1).

R14-2-2626. Utility Reporting Requirements

A. Each Utility shall maintain records concerning each received Application for Interconnection and shall include in its records:
1. The date the Application was received;
2. Any documents generated in the course of processing the Application;
3. Any correspondence regarding the Application;
4. The final disposition of the Application; and
5. The final disposition date.

B. By March 30 of each year, each Utility shall file with the Commission a Distributed Generation Interconnection Report, with data for the preceding calendar year that shall include:
1. The number of complete Applications denied by track level, including the reasons for denial;
2. A list of special contracts, approved by the Commission during the reporting period, that provide discounted rates to Customers as an alternative to self-generation;
3. Pre-Application Report:
   a. Total number of reports requested;
   b. Total number of reports issued;
   c. Total number of requests withdrawn; and
   d. Maximum, mean, and median processing times from receipt of request to issuance of report;
4. Interconnection Application:
   a. Total number received, broken down by:
      i. Primary fuel type (e.g., solar, wind, biogas, etc.); and
      ii. System size (<20 kW, 20 kW-2 MW, >2MW);
   b. Expedited Interconnection Process:
      i. Total number of applications approved;
      ii. Total number of applications denied;
      iii. Total number of applications withdrawn; and
      iv. Maximum, mean, and median processing times from receipt of complete Application to execution of Interconnection Agreement;
   c. Level 1 Super Fast Track Process:
      i. Total number of applications approved;
      ii. Total number of applications denied;
      iii. Total number of applications withdrawn; and
      iv. Maximum, mean, and median processing times from receipt of complete Application to execution of Interconnection Agreement;
   d. Level 2 Fast Track Process:
      i. Total number of applications approved;
      ii. Total number of applications denied;
      iii. Total number of applications withdrawn; and
      iv. Maximum, mean, and median processing times from receipt of complete Application to execution of Interconnection Agreement;
   e. Supplemental Review:
      i. Total number of applications approved;
      ii. Total number of applications denied;
      iii. Total number of applications withdrawn; and
      iv. Maximum, mean, and median processing times from receipt of complete Application to execution of Interconnection Agreement; and
   f. Level 3 Study Process:
      i. Total number of System Impact Studies completed;
      ii. Maximum, mean, and median processing times from receipt of signed System Impact Study agreement to provision of study results;
      iii. Total number of Facilities Studies completed;
      iv. Maximum, mean, and median processing times from receipt of signed Facility Study agreement to provision of study results;
      v. Maximum, mean, and median processing times from receipt of complete Application to execution of Interconnection Agreement.

R14-2-2627. Electric Cooperatives

A. Upon Commission approval of an Electric Cooperative's Interconnection Manual, its provisions shall substitute for the timeline requirements set forth in R14-2-2614 and R14-2-2616 through R14-2-2623 for the Electric Cooperative and its Customers.

B. Each Electric Cooperative shall employ best reasonable efforts to comply with the deadlines set forth in the applicable provisions of this Article or, if unable to meet those deadlines, shall process all Applications and conduct all inspections and tests in the shortest time practical.

R14-2-2628. Interconnection Manuals

A. No later than 90 calendar days after the effective date of this Article, each Utility shall file with Docket Control, for Commission review and approval, an Interconnection Manual that:
1. Contains detailed technical, safety, and protection requirements necessary to interconnect a Generating Facility to the Distribution System in compliance with this Article and Good Utility Practice; and
2. Specifies by date, either within its main text or in an appendix, the version of each standard, code, or guideline with which an Applicant's Generating Facility must comply to be eligible for Interconnection and Parallel Operation.

B. A Utility shall revise its Interconnection Manual as necessary to ensure compliance with Good Utility Practice.

C. A Utility shall file each revision to its Interconnection Manual with Docket Control, for Commission review and approval, at least 60 calendar days prior to the proposed effective date of the revision.

D. A revision to an Interconnection Manual that a Utility has determined is necessary to enhance health or safety shall become effective immediately, subject to subsequent review and approval by the Commission.

E. The Commission's Utilities Division may contest a Utility's proposed revision to its Interconnection Manual and may seek a suspension of the effective date of the revision to allow for further review.

F. A Utility shall file with Docket Control, within 10 calendar days after the effective date of a decision approving any revisions to its Interconnection Manual, an updated Interconnection Manual conforming to the Commission's decision.

G. A Utility shall make its Interconnection Manual available on the Utility's website.

H. A Utility shall implement and ensure compliance with its Commission-approved Interconnection Manual.