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Independent Assessment of Duke Energy's Fast Track Review Process for DER Interconnection

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EPRI Project Manager
T. Key

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

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The Electric Power Research Institute (EPRI), prepared this report:

Principal Investigator
T. Key
N. Enbar

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ABSTRACT

Duke Energy is among the growing number of electric utilities working to update their interconnection procedures. Among other things, Duke is attempting to improve upon the technical review process it currently employs to safeguard against reliability concerns caused by distributed energy resource (DER) grid connections. It is also endeavoring to address perceived uncertainties in why, when, and how it applies the multiple screens associated with the technical review process, as enforced by the North Carolina Interconnection Procedures (NCIP).

This report presents results from an independent, third-party review conducted by the Electric Power Research Institute of Duke Energy's Fast Track Review process as well as the accompanying technical criteria specified in the NCIP. A stipulation of the North Carolina Utilities Commission under Docket E-100 Sub 101 (Order Approving Revised Interconnection Standard and Requiring Reports and Testimony), this assessment evaluates both the need and grounds for implementing potential modifications to the existing Fast Track process.

Keywords
Interconnection
Fast Track
Supplemental Review
Distributed Energy Resources
Duke Energy
Engineering Review

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PROJECT BACKGROUND AND OBJECTIVES

Rising U.S. demand to interconnect distributed energy resources (DERs) – predominately solar photovoltaics (PV) – on the distribution system is driving change within the electric utility segment. Specifically, utilities are increasingly exploring opportunities to better manage their DER grid interconnection processes in ways that can more fully leverage technology advances, enable procedural transparency, and recognize evolving technical standards, including the recently published IEEE Std 1547-2018—the primary model used to inform DER interconnection technical requirements in North America.

Duke Energy Carolinas and Duke Energy Progress (Duke) are among the growing number of electric utilities that are working to update their interconnection procedures. Among other things, Duke is attempting to improve upon the technical review process it currently employs to safeguard against reliability concerns caused by DER grid connections. It is also endeavoring to address perceived uncertainties in why, when, and how it applies the multiple screens associated with the technical review process, as enforced by the North Carolina Interconnection Procedures (NCIP).

To aid in this effort, the Electric Power Research Institute (EPRI) has conducted an independent, third-party review of Duke's Fast Track and Supplemental Review process as well as the accompanying technical criteria specified in the NCIP. A stipulation of the North Carolina Utilities Commission (NCUC) under Docket E-100 Sub 101 (Order Approving Revised Interconnection Standard and Requiring Reports and Testimony[1]), this assessment – the results of which are presented in this report – evaluated both the need and grounds for implementing potential modifications to the existing Fast Track and Supplemental Review process.

The EPRI evaluation, as further described below, broadly considered the NCIP's current technical review criteria and screens relative to other jurisdictional and industry norms. This industry benchmarking, paired with EPRI's prior project experience examining the technical issues and challenges associated with DER interconnection, served as the basis for suggesting further changes to the NCIP as well as clarifications to Duke's prevailing technical review practices. Among the issues that were scrutinized, five were specifically called out for independent review:

1. Whether Fast Track eligibility limits in the NCIP can be raised to allow more projects that may not have system impacts to be processed through the Fast Track process;
2. Whether Duke's application of Screen 3.2.1.2 (aggregate generation not to exceed 15% of the line section peak load) is (1) consistent with other utilities' determination of "line section"; and (2) necessary to protect system safety and reliability considering the desired efficiency of the interconnection process (i.e., whether other screens may fulfill similar objectives);

[1] North Carolina Utilities Commission (NCUC), Docket E-100 Sub 101, Order Approving Revised Interconnection Standard and Requiring Reports. https://starw1.ncuc.net/NCUC/page/docket-docs/PSC/DocketDetails.aspx?DocketId=b8c5f6f2-943d-4504-8cdf-718f5ca434de

3. Whether all projects failing Fast Track are given the option to go to Supplemental Review;
4. How Duke's existing Supplemental Review process compares to that of other utilities and whether further transparency could be provided to facilitate customer understanding and predictability of the process; and
5. How other states (New York, Massachusetts, California, and others facing increasing penetration and queue challenges) conduct the Fast Track review process considering interdependencies.

Independent Review: Scope and Approach

To comply with the NCUC's stipulation, EPRI conducted its review and evaluation over a roughly three-month period, spanning late June to early September 2019. The scope of EPRI's assessment encompassed issues specified in Section 3 of the 2019 redline of the NCIP, which surrounds the Optional Fast Track Process for Certified Generating Facilities. In addition to examining the criteria laid out in Section 3 of the NCIP, EPRI also investigated the way Duke Energy Carolina applies Section 3 criteria in its technical review practices and protocols. EPRI's technical review assessment specifically included 10 Fast Track screens from the NCIP E-100 Sub 101 (2019), and six Supplemental Review tests developed by Duke.

To complete its analysis, EPRI leveraged multiple sources to gather sufficient perspective and insight. Information was derived via a combination of detailed in-person interviews as well as secondary research. EPRI worked closely with Duke to comprehensively review the NCIP redline and the utility's associated technical criteria, screens, and processes. Multiple in-person meetings were convened between EPRI and Duke staff to assess the utility's Fast Track and Supplemental Review approach, and to solicit input from Duke's technical team.[2]

These meetings were supplemented by telephone, webinar, and email communications. Discussed subject matter included the utility technical review practices, protocols, and timelines; staff responsibilities and infrastructure, and planned improvements. Throughout, Duke staff shared a significant amount of external and internal documentation – including pass/fail data by screen, Supplemental Review internal criteria, review flow charts and approval results, and voltage quality specifications and criteria – to provide EPRI with a robust understanding of the utility's screening procedures as well as the rationales governing them.

With a firm grasp of both the NCIP screening criteria and Duke's related practices, EPRI next examined technical review criteria used by Duke and compared them to other jurisdictions.[3] This comparative review included all Federal Energy Regulatory Commission (FERC) Small Generator Interconnection Procedures (SGIP) criteria, additional criteria based on EPRI's experience in other jurisdictions, and new criteria based on IEEE Std 1547-2018. In all, 52 criteria were examined, each of which fall into one of eight specific categories of evaluation, including basic (size, type, certification, locations), voltage tests, capacity and export limits, thermal limits, protection, power quality, immunity, and safety. (Note: EPRI's evaluation of the

[2] Face-to-face meetings between EPRI and Duke staff were facilitated on June 27 and 28, July 29, and August 29 and 30.

[3] In addition to the FERC SGIP, other jurisdictions considered were California, Illinois, Louisiana, Massachusetts, Michigan, Minnesota, New York, Ontario (Canada), and Pennsylvania.

Fast Track criteria used by Duke is discussed in Chapter 2.) The comparative analysis noted differences between the NCIP and the other jurisdictions, and gleaned learnings were leveraged to suggest both modifications and clarifications to the most recent NCIP update as well as to Duke's latest technical review practices (i.e., with proposed clarifications and new Supplemental Review criteria).

All told, EPRI performed the following core tasks as part of its consultation with Duke:

- A point-by-point review of the technical requirements delineated in Sections 3.1 to 3.4 in the stipulated NCIP redline (June 2019) relative to the FERC SGIP Fast Track process and those of nine other jurisdictions.
- Identification of divergences between the Fast Track process stipulated in the NCIP and in comparative documentation from other jurisdictions.
- Identification of technical criteria and review procedures that may benefit from better technical definition and clarification based on EPRI experience with industry practices and related challenges in other jurisdictions outside of North Carolina.
- The development of specific recommendations regarding the NCIP Fast Track process and proposed clarification in Duke's application procedures.

Report Contents

This summary report provides project background and results of EPRI's independent assessment of the Fast Track review process in North Carolina. Findings include commentary as well as proposed recommendations and clarifications for modifying the NCIP and aspects of Duke's existing Fast Track and Supplemental Review process. They were shared at the September 17, 2019 DER Interconnection Technical Standards Review Group (TSRG) meeting,[4] and are ultimately to be provided to the NCUC for its review and adjudication.

The contents of EPRI's assessment effort are organized within the remaining chapters of this report as follows:

- *Chapter 2 – Characterizing the Fast Track Process.* Defines the Fast Track and Supplemental Review process, providing a brief history of its origins, as well as a high-level summary of the process and criteria used in several jurisdictions including North Carolina; conveys recent outcomes from Duke Energy Carolina's application of its Fast Track and Supplemental Review process.
- *Chapter 3 – Review and Assessment: North Carolina's Fast Track Process.* Provides a review of the Fast Track process currently in use in North Carolina and included in the Docket No. E-100, Sub 101, 6-2019 Stipulated North Carolina Interconnection Procedures Redline. Compares the eligibility and screening criteria (Sections 3.1 to 3.4 in the stipulated redline) with those used in the FERC SGIP and in other jurisdictions, noting discrepancies and identifying technical review criteria and procedures that are recommended for better

[4] The TSRG was initiated by Duke in early 2018 to bridge open dialog between Duke engineers and DER developers and installers actively involved in interconnection projects in the service areas of Duke Energy Carolinas and Duke Energy Progress. The TSRG currently serves as a forum for discussing a range of interconnection issues and for addressing voiced challenges.

definition and clarification. Provides the groundwork for further discussion in Chapter 4, which presents EPRI's formal recommendations for enhancing the Fast Track process in North Carolina.

- *Chapter 4 –EPRI Recommendations for Fast Track and Supplemental Review.* Provides a descriptive accounting of EPRI's proposed recommendations for clarifying or modifying 1) the North Carolina Fast Track process and criteria, and 2) Duke's technical review criteria and procedures as they relate to the NCIP E-100. The recommendations are accompanied by supporting rationales and commentary, based on industry knowledge and experiences concerning the technical issues and challenges associated with interconnection.

2
CHARACTERIZING THE FAST TRACK PROCESS

Technical screening is a fundamental means for evaluating the potential grid impacts of proposed projects and, in turn, ensuring safe, reliable, and cost-effective interconnection. Interconnection procedures such as those included in the FERC SGIP[5] and California Rule 21[6] have suggested initial screens and Supplemental Review criteria to address technical concerns and enable a Fast Track approval process. Using screens to support Fast Track processing of interconnection requests has since evolved to be a broadly accepted practice. Screening also provides for some standardization of technical review criteria informing expectations and supporting future planning for new connections.

As depicted in Figure 2-1, once a completed application for interconnection is submitted, and based on its specified size threshold, a project is subjected to a series of initial or Fast Track screens (as a series of quick-check questions). If all screens are passed, approval to interconnect may be granted immediately or conditionally. However, if the application does not pass Fast Track review, many states will apply Supplemental Review tests to determine the need for a detailed impact study involving modeling and mitigation. If any negative system impacts – for example on voltage, power quality, or protection – are identified during the screening process, strategies for mitigating those impacts are identified by the utility and presented to the applicant.

Ultimately, the Fast Track and detailed Supplemental Review process is designed to expedite the interconnection of mid-sized projects without compromising grid reliability or safety. Rather than requiring all projects to undergo a full study, the integrated approach employs a two-tier screening process that streamlines technical review. This approach, which increases procedural efficiency, is expected to become more widely adopted as DER penetrations rise across North America and beyond.

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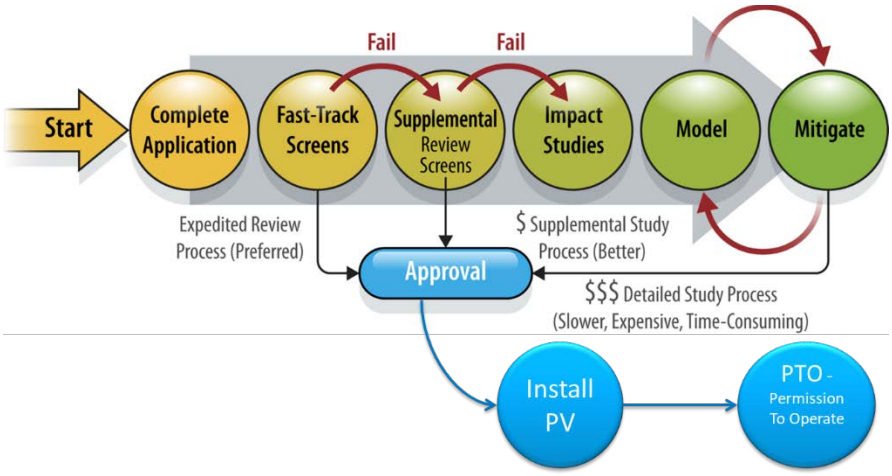
[5] Federal Energy Regulatory Commission, FERC, Doc No. RM13-2-000**,** May 12, 2005, *Standardization of Small (<20 MW) Generator Interconnection Agreements and Procedures.* Under FERC jurisdiction, this docket also provided suggested procedures for DER in distribution.

[6] California Public Utilities Commission, https://www.cpuc.ca.gov/Rule21/.



Source: National Renewable Energy Laboratory (NREL)
Note: Systems above a certain size may skip the Fast Track Screening Process and go straight to more detailed impact studies.

Figure 2-1
Typical Utility Interconnection Process

Historical Context

The first known screening procedure for interconnecting generating facilities to the distribution grid was adopted by California Rule 21 in 1999.[7] However, most technical screens used in utility interconnection procedures are an outgrowth of FERC's SGIP, first published in 2005, and originally developed for transmission-connected generating facilities. Many jurisdictions have since adapted the FERC SGIP for distribution and implemented or encouraged it as part of their rules for regulated utilities. In turn, numerous utilities that engage in DER interconnection have either outright adopted or modified all or most of the FERC-recommended technical screens.

The FERC SGIP makes recommendations for technical review (screening and studies) of certified equipment using a "fast track process" that applies to low voltage up to 69kV. A series of 10 initial reviews or Fast Track screens is applied to all DER connections, of any size, from 0 to 20 MW. If any of the technical screens are triggered (or tripped or failed), the DER interconnection application may be required to go through supplemental screens, as specified in FERC Order No. 792 in 2013. To date, however, only a handful of states have adopted these supplemental screens, including California, Illinois, Iowa, Massachusetts, Minnesota, New York, and Ohio.

At the time of their publication, the screens associated with FERC SGIP were considered sound technical guidance for identifying DER systems that might have negative impacts on the grid. However, there are ongoing efforts to further refine and improve the technical screens in multiple jurisdictions. Key factors driving reforms to the original screens include increasing DER aggregate capacity, evolving opportunities for DER (including energy storage) to provide

[7] Today, California Rule 21 fast track eligibility depends on interconnection tariff and relative system size. All DER and energy storage connections are now screened in the state, and systems less than 11 kW, or non-exporting systems, may be approved after passing eight initial screens.

grid support, growing utility interconnection experience, and the availability of better tools for understanding specific grid impacts and mitigations.

Ongoing and future changes to preliminary screens will intend to clarify the technical basis and purpose of each screen. But depending on the circumstances, the relevance of any screen will often change with site conditions and with shifting deployment penetration. In general, screening is a process without a single correct solution and there are always necessary tradeoffs. For example, preliminary screens will tend to be conservative to enable simplicity and speed of review, while supplemental screens will typically be more involved to enable interconnection without further study. Generally, reform efforts are likely to be better served by seeking to inform the "art" of screening rather than attempting to conclusively resolve each screen.

Defining the Optional Fast Track Process for Certified Generating Facilities

The Fast Track Process involves the application of a set of established, standardized screens to evaluate if a proposed project can be interconnected safely, with or without upgrades, or whether a more comprehensive full study is required to make the determination. Fast Track screens utilize conservative limits that are defined to filter out projects that have any potential for safety or reliability impacts. These screens have been used successfully across the country to efficiently interconnect most new DERs.

If a project fails one or more of the Fast Track screens, it is then directed to Supplemental Review or to a full study process. The Fast Track process is intended to increase the efficiency of the interconnection review process by allowing eligible projects to avoid the multi-month (or potentially longer) study process on the condition that they pass a set of technical screens. Without an effective Fast Track and Supplemental Review process, all proposed projects would go through full study.

In 2015, North Carolina revised its state interconnection standard to adopt the SGIP, including its Fast Track and Supplemental Review process. Interim modifications were subsequently approved in October 2018, and further updates were included in a stipulated redline of the NCIP (E-100 Sub 101) in June 2019. As a result, the optional Fast Track process is available within Duke's service territory to select applicants seeking to interconnect their certified generating facilities to the utility's distribution system. Eligible generating facilities must be UL-certified and have a capacity below the size limits stipulated in Table 2-1; eligibility is further determined by generator type and size, line voltage, and the location of and type of line at the Point of Interconnection (POI). Size limits vary according to the voltage of the line at the proposed POI.

As indicated in the table, generating facilities connecting to lines greater than or equal to 35 kV do not qualify for the Fast Track process regardless of size, unless mutually agreed to by the applicant and Duke. Meanwhile, those located within 2.5 electrical circuit miles of a substation and on a mainline are eligible under the higher thresholds delineated in the table. In addition to the size threshold, the interconnection applicant's proposed generating facility must meet the requisite codes, standards, and certification requirements of the Fast Track procedures. Else, following design review and/or testing of a proposed generating facility, Duke must be satisfied that the system is safe to operate.

Table 2-1
Fast Track Eligibility for Inverter-Based Systems

Line Voltage	Fast Track Eligibility Regardless of Location	Fast Track Eligibility on a Mainline[1] and ≤ 2.5 Electrical Circuit Miles from Substation[2]
< 5 kV	≤ 100 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 1 MW	≤ 2 MW
≥ 15 kV and < 35 kV	≤ 2 MW	≤ 2 MW

Notes:
[1] For purposes of the table, a mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 336.4 kcmil, 397.5 kcmil, 477 kcmil, and 795 kcmil.
[2] An interconnection customer can determine this information about its proposed interconnection location in advance by requesting a pre-application report.

For eligible systems, Fast Track review occurs within 15 business days of Duke notifying the interconnection applicant that it has received a complete application, and the utility has preliminarily determined that the application is independent of other interconnection requests. An initial review is then performed using 10 Fast Track screens to determine whether a proposed system is safe to interconnect to the utility distribution system, or if additional technical study is required to discern if the proposed interconnection is consistent with safety, reliability, and power quality standards. Following is a list of the current Fast Track screens employed by Duke (the first four delineated bullets convey Fast Track eligibility criteria):

- 3.1 – Screening not required for ≤ 20 kW (Fast Track eligibility)
- 3.1 – Fast Track applicable to certified inverters only (Fast Track eligibility)
- 3.1 – kW & kV requirements (Fast Track eligibility)
- 3.1.1 – Grounds for skipping Fast Track and proceeding directly to Supplemental Review (Fast Track eligibility)
- 3.2.1.1 – POI located on Duke's distribution system
- 3.2.1.2 – Aggregate generation not to exceed 15% of the line section peak load
- 3.2.1.3 – Aggregate generation not to exceed 90% of circuit/bank minimum load
- 3.2.1.4 – On spot or LV networks, aggregate generation not to exceed 5% of a spot network's maximum load or 50 kW
- 3.2.1.5 – Aggregate generation not to contribute more than 10% of the circuits maximum fault current (short circuit contribution)
- 3.2.1.6 – Aggregate generation not to cause protection devices or interconnection equipment on the system to exceed 87.5% of the short circuit interrupting capability
- 3.2.1.7 – Interconnection type and service to enable effective grounding
- 3.2.1.8 – Aggregate capacity not to exceed 65% of the secondary transformer rating
- 3.2.1.9 – Generation facility not to create an imbalance of more than 20% of the service transformer rating

- 3.2.1.10 – Aggregate generation not to exceed 10 MW in areas with known transient stability limitations

If the proposed interconnection passes the Fast Track screens and requires no system upgrade to enable interconnection, it is approved, and an executable interconnection agreement is provided by Duke within 10 business days. In cases where the proposed interconnection passes the Fast Track screens but requires minor modifications, the applicant receives approval to interconnect (along with an interconnection agreement) that is conditional to paying the estimated modification costs. Where a proposed interconnection passes the Fast Track screens but the costs of interconnection, including system upgrades, must still be determined, Duke notifies the applicant of the need to complete a Facilities Study.

Several outcomes are, meanwhile, possible when the application fails one or more Fast Track screens: 1) Duke may approve the interconnection outright if it determines it to be safe, 2) Duke may provide conditional approval based on the applicant's agreement to cover the costs of minor construction, and 3) Duke may propose a customer options meeting to discuss next steps (i.e., perform facility modifications, proceed with Supplemental Review or technical study, etc.).

Table 2-2 provides a comparative overview of the NCIP's initial and supplemental screens, Duke Energy Carolina's review practices, and industry norms. For each defined technical issue, the table indicates the associated criteria type, typical review level, and application to the individual or aggregate plant on a feeder. It then maps these elements to the NCIP Section 3 redline and compares the screens and Supplemental Review criteria to industry norms and Duke's current practices. References to new criteria in IEEE Std 1547-2018 are also indicated.

Table 2-2
Comparative Overview of NCIP Initial Screens, Duke Review Practices, and Industry Norms

Specific Technical Issue	Type of Review	NC E-100 Screens	Duke's Current Practice	Industry Norms	EPRI Observation Duke/Industry	Review Type/Level	Applies to DER	IEEE 1547-2018 Reference
Screening not required	Basic	**3**	<20 kW	<10 to 50kW	**Within Industry norm**	Preliminary	Individual	
Certification required	Basic	**3**	Yes	Yes	**Same practice**	Fast Track	Individual	11.1-4
Monitoring capacity	Basic	**3**	Yes	Yes	**Same practice**	UL Tested	Individual	10
Relative size concern	Basic	**3.1.1**	Preapprove SR	Options Vary	**May save process time**	Supplemental	Individual	4.6.2
Qualifies for Fast Track	Basic	**3.1-table**	Per NC kW/kV	Per SGIP	**More conservative**	Preliminary	Individual	
Confirm service availability	Basic	**3.2.1.1**	Yes	Yes	**Same practice**	Fast Track	Individual	
Unintended islanding % peak	Protection	**3.2.1.2**	15%	15% or min.	**Opportunity to clarify**	Fast Track	Aggregate	8.1
Unintended islanding % min	Protection	**3.2.1.3**	90% in FT	100% in SR	**Within Industry norms**	FT or SR	Aggregate	8.1
On spot or LV network	Basic	**3.2.1.4**	5%	5% or 50 kW	**Within Industry norms**	Fast Track	Individual	9.2 and 9.3
Short circuit contribution	Protection	**3.2.1.5**	90% /10%	90%/10%	**Same practice**	Fast Track	Aggregate	11.4
Interrupting capability	Protection	**3.2.1.6**	87.5% Limit	87.5% limit	**Within Industry norms**	Fast Track	Aggregate	6.2.
GFO/effective grounding	Protection	**3.2.1.7**	Inverter exception	Varies	**Recommended practice**	Fast Track	Individual	4.12
Exceeds secondary ratings	Thermal	**3.2.1.8**	65%	20kW 65%	**Within Industry norm**	Fast Track	Aggregate	
Secondary imbalance	Voltage	**3.2.1.9**	20%	20%	**Same practice**	Fast Track	Individual	
Transient stability	Penetration	**3.2.1.10**	depends on HV	10 MW limit	**Within Industry norms**	Fast Track	Aggregate	
Safety/Reliability	Penetration	**3.2.2.4-6**	Six tests	Tests Vary	**Better defined than norm**	Supplemental	Aggregate	4.6.2
Flicker	PQ	**3.2.2.4-6**	By exception	Pst <.35	**Recommended practice**	Supplemental	Individual	7.2
Rapid Voltage Change	PQ	**3.2.2.4-6**	MV 3% ΔVpeak	MV-3%/second	**Conservative inrush test**	Supplemental	Individual	7.2
Aggregate RVC Limit	PQ	**3.2.2.4-6**	MV 4% ΔV	Not used	**Not a recommended test**	Supplemental	Aggregate	7.2-appendix E
Harmonics	PQ	**3.2.2.4-6**	By exception	I_{THD}<5%	**Within Industry norm**	UL Tested	Individual	7.3
Stiffness at PCC	Voltage / PQ	**3.2.2.4-6**	>25 times	20 - 50	**Recommended practice**	Supplemental	Individual	

Notes: EPRI examined 52 technical review criteria and specific issues in 9 different jurisdictions, including FERC SGIP and sections in the new IEEE Std 1547-2018. EPRI's assessment is based on red line updates to the NCIP, proposed clarifications, and new Supplemental Review criteria. PCC = the point of common coupling, or the point in the electrical system where multiple customers or multiple electrical loads may be connected. IEEE 1547-listed sections indicate that the attribute is also described in the standard and likely tested during certification.

Defining Supplemental Review

The Supplemental Review option is composed of additional tests and criteria for determining whether a proposed project can be safely interconnected to distribution. It applies to interconnections for customers who have either opted out of Fast Track or did not pass Fast Track screening.

As currently stipulated in the NCIP, applicants may choose to pursue Supplemental Review if their proposed DER systems fail one or more of the Fast Track screens, and Duke concludes that Supplemental Review can determine the systems' ability to safely and reliably interconnect. (Note: To minimize overall processing time in cases where an application fails the initial review screens and Supplemental Review appears appropriate, applicants may choose to pre-authorize Supplemental Review, and skip a customer options meeting to discuss next steps.) Duke is responsible for providing a non-binding good faith estimate to the applicant reflecting the costs of the review, and the applicant subsequently has 10 business days to 1) accept the utility's offer to perform the Supplemental Review, and 2) post any associated deposit requirements covering the estimated costs.[8]

Following receipt of the deposit, Duke has 10 business days to determine if the generating facility can be interconnected safely and reliably. Possible outcomes include approval with an executable interconnection agreement, conditional approval based on implementation of required facility modifications, conditional approval based on the results of a Facilities Study to determine the costs of mitigation that are required for interconnection or recommended further evaluation via a technical study.

Supplemental Review currently comprises multiple, undefined screens that are broadly intended to consider grid safety, power quality, and reliability issues.[9] An application must satisfy all the criteria in the applied supplemental screens to interconnect. (Note: Duke does not cease its Supplemental Review at the first failure; it accounts for all possible failures). If any criterion is not satisfied by minor modifications a more detailed Study Process is the next step to determine interconnection and/or system upgrade requirements.

The current NCIP provides that Duke need only offer Supplemental Review if it concludes that review might determine a project could interconnect without a full study; all the discretion of whether the process is available is left to the utility. Moreover, the Supplemental Review process is somewhat open-ended and does not explicitly define how Duke shall determine if a project can be interconnected safely and reliably. As such, the utility is not obligated to specify what technical issues warrant further study. An EPRI assessment of the Supplemental Review criteria Duke employs, along with the associated screens it applies, is provided in Chapters 3 and 4 of this report.

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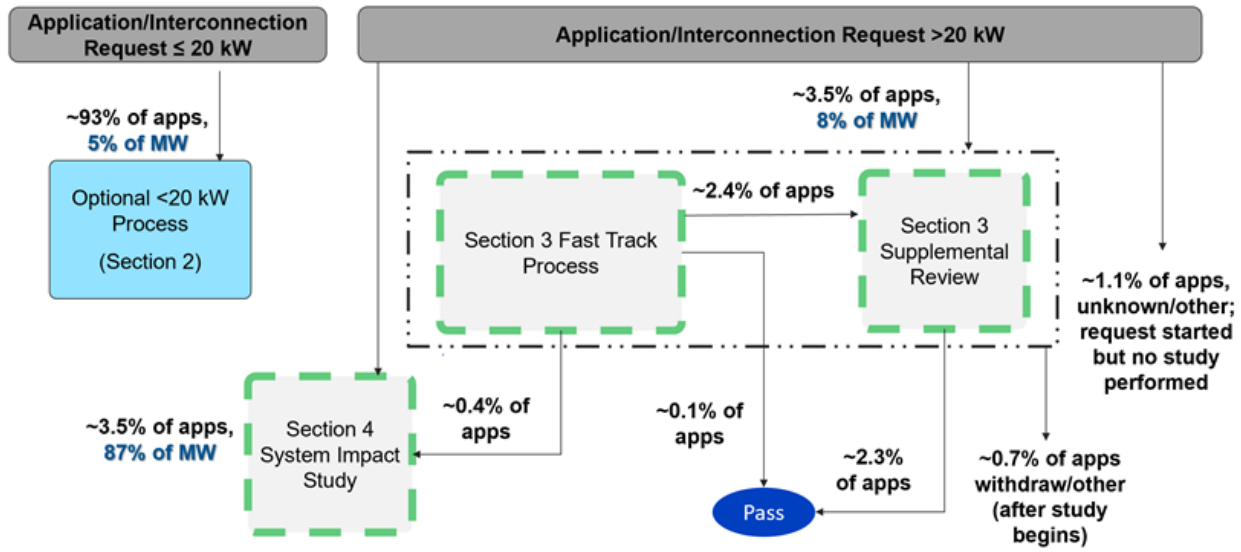
[8] The applicant must pay any review costs that exceed the deposit within 20 business days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, Duke will return the balance within 20 business days of the invoice without interest.

[9] For Supplemental Review, some stakeholders advocate for three screens: 1) 100% minimum load screen, 2) voltage and power quality screen, and 3) safety and reliability screen.

Outcomes from Duke's Fast Track and Supplemental Review Process

Duke currently employs the North Carolina Fast Track screening process for projects sized >20 kW to 2 MW. Figure 2-2 provides an overview of the way the interconnection applications submitted to Duke Energy were processed in North and South Carolina (includes DEC and DEP) from May 2015 to August 2019.

As illustrated, roughly 93% of the applications received during that time frame, totaling 5% of the megawatt capacity, were processed through Duke's optional inverter process for certified inverter-based generating facilities no larger than 20 kW. Meanwhile, 3.5% of received applications, totaling 8% of the megawatt capacity, were eligible for the Fast Track process. Also, another 3.5% of the received applications, representing 87% of the megawatt capacity, proceeded through the utility's system impact study process. A small number of applications, about 1%, are initiated but are not reviewed for a variety of reasons.



Source: Duke Energy

Figure 2-2
DER Interconnection Application Processing for Duke Energy in North and South Carolina, May 2015 - Aug. 2019

Of the 3.5% of total applications eligible for the Fast Track process, most were approved via Supplemental Review. The total Fast Track eligible applications approved was 69% (2.4% of the total submitted applications). Most of these Fast Track eligible applications (2.3% of total applications) passed Supplemental Review and were granted approval to interconnect—in some cases, pending system or facility upgrades. Another 11% were approved after a required system impact study (0.4% of the total).

All told, 80% of the applications that qualified for Fast Track review were approved for interconnection. The other 20% (0.7% of total) either withdrew or were otherwise abandoned at some point after the review was started. Of the 80% of approved applications, the majority required either Supplemental Review or System Impact Study and related upgrades for approval to interconnect. Only 3% of applications eligible for Fast Track (0.1% of the total) were approved for interconnection by screening alone.

According to Duke staff, Screen 2 (if aggregate generation exceeds 15% of peak load) and screen 6 (if aggregate short-circuit current exceeds 87.5% of device interrupting rating) have the highest "no pass" rate. Difficulty in passing aggregate screens can be directly linked to higher DER penetration levels, and increased screen failures are not unexpected. As a result, many of the Fast Track-eligible projects evaluated by Duke were required to go through the Supplemental Review process. Those applications that failed Fast Track and opted for Supplemental Review experienced a high pass rate.

It is not unusual that most Fast Track eligible applications are failing aggregate generation screen limits. In many jurisdictions, rising DER penetration levels in the distribution system have significantly reduced the number of interconnection applications that can connect by screening alone. This is an important trend that is beginning to reshape Fast Track processes, and it is leading to modifications of both qualifying limits and screens. Also, high failure rates via screening is increasing the focus and importance of Supplemental Review in the Fast Track process.

With this chapter's background information in mind, the following report sections will explore whether there are potential opportunities to improve screening, technical review criteria, Fast Track eligibility, and application of the North Carolina Fast Track process.

3
REVIEW AND ASSESSMENT: NORTH CAROLINA FAST TRACK PROCESS

In this chapter, EPRI provides a review of the North Carolina Fast Track process. The review is based on Docket No. E-100, Sub 101, Stipulated NC Procedures Redline (June 2019), and its application by Duke in North and South Carolina. A point-by-point assessment is conducted by comparing the Fast Track process defined in the NCIP E-100 with the Fast Track process laid out in the FERC SGIP.[10] The scope of the review and assessment encompasses Sections 3.1 to 3.4 in the stipulated redline. It is, furthermore, based on the following:

- EPRI's understanding and experience addressing the technical issues and challenges associated with DER interconnection, screen types and levels, related standards, and industry trends.
- The 2019 Redline of the Stipulated NCIP, Section 3, Optional Fast Track Process for Certified Generating Facilities.
- Pass/fail criteria currently being applied by Duke to determine eligibility for Fast Track screening, NCIP Section 3.1.
- Pass/fail criteria currently being applied by Duke to determine the outcome of each initial screen identified in the NCIP Section 3.2.
- Supplemental Review requirements, assessment criteria, and expected outcomes described in the NCIP Section 3.4 and proposed by Duke to pass the Supplemental Review.

Based on noted exceptions when comparing the NCIP and the FERC SGIP Fast Track processes, as well as EPRI's understanding and experience with interconnection processes, several modifications to the published NCIP Fast Track screens are recommended. In addition, any specific technical review procedures that may benefit from better technical definition and clarification are identified. Conveyed findings are intended to provide the groundwork for further discussion in Chapter 4, which presents EPRI's formal recommendations for enhancing the Fast Track process in North Carolina. For convenience, issues to be further discussed in Chapter 4 are highlighted in the Chapter 3 text. The presented review and assessment are based on EPRI's experience with industry practices as well as related challenges in jurisdictions outside of North Carolina.

Assessment: Fast-Track Process/Eligibility (Sections 3 and 3.1)

Certified inverter-based DER less than 20 kW and on radial service receive expedited approval if basic review criteria are met. This review typically includes availability/compatibility of existing service and completeness of project information, consideration for service existing transformer

[10] As a matter of convenience, the FERC SGIP is used as a baseline reference. This approach is not intended as an endorsement of the SGIP as the correct, or the only, way to conduct a Fast Track review process. Several suggested changes to FERC's Fast Track screens are, in fact, also suggested with respect to distribution applications.

size and loading, and the addition of a visible disconnect switch (if not otherwise covered by the National Electric Code).

Duke receives many small, under 20 kW interconnection applications. As discussed in Chapter 2, applications for systems less than 20 kW amounted to 93% of the total applications received by the utility in North and South Carolina between May 2015 to August 2019 (equal to 5% of reviewed DER capacity). There is a simplified application and agreement provided for these smaller systems.

Fast-Track Process

A Fast Track process is designed to address applications larger than 20 kW that are typically simple enough to avoid the need for detailed review and facility study. The NCIP includes several factors to determine if an interconnection application qualifies for the Fast Track review process. Certification of the plant is a basic requirement for Fast Track. Generally, synchronous machines are not certified and would not qualify for the Fast Track process.

When eligible, an initial review is conducted using 10 screens. Passing the screens leads to an interconnection approval, while failure leads to a customer options meeting that is convened to discuss review options and identify any additional site or utility requirements. When additional technical review is required, the customer can authorize a Supplemental Review within the Fast Track process (if applicable) or submit to a more detailed study process, as described in Section 4 of the NCIP.

- **NCIP Exceptions with SGIP regarding the overall process** – *None noted.*

Discussion – Several other jurisdictions are currently using the SGIP Fast Track process template, including Illinois, Maryland, Massachusetts, Minnesota, South Carolina, and Virginia. Meanwhile, Michigan is in the process of adopting a Fast Track process based on the SGIP's. And in other states with relatively high levels of DER – Georgia, New Jersey, and New York – there are similar screens and technical review levels defining a Fast Track process. Across the U.S. this process is being broadly applied, providing both consistency and familiarity for stakeholders. (Note: California Rule 21 preceded and influenced the 2005 SGIP, although both have evolved since that time to consider more grid support functionality in DER.)

Differences between jurisdictions continue to evolve with deployment experience, changes in interconnection standards, and increasing penetration levels. EPRI is not aware of any jurisdiction that is applying a Fast Track process in the exact same way as suggested by the FERC SGIP, principally because of the FERC's natural focus on larger, transmission-connection DER. That said, EPRI's assessment is that the North Carolina process is very similar to the Fast Track review process recommended in SGIP and used in other jurisdictions.

Looking ahead, Fast Track processes are expected to continue to evolve and to incorporate DER-specific analysis tools. For example, further application of DER communication and control, such as real and reactive power control, may help define a "flexible" interconnection agreement where DER output limits may vary with time and feeder conditions. Such flexible interconnection approaches may expand Fast Track eligibility for larger DER. Separately, the growing availability of data and development of novel tools are expected to help improve Fast

Track review by informing both the initial and Supplemental Review processes and bringing opportunities for more automated reviews.

Fast-Track Eligibility

SGIP Fast Track eligibility is determined based upon the generator type and size, the voltage of the line, the location of the Point of Interconnection (POI), and the type of line at the POI. In addition, Fast Track is typically only available to DERs that have been certified by a National Accredited Testing Laboratory, and is usually limited or excluded in the case of utility network-connected DER.

This same approach is used in the NCIP Fast Track process, with several exceptions relative to size eligibility and feeder voltage. Other jurisdictions apply the same or similar criteria. Specific differences noted between the kW limits specified in the NCIP and SGIP are as follows:

- On feeders <5kV –
  NCIP limit: 100 kW (anywhere on the circuit);
  SGIP recommended: 500 kW (anywhere on the feeder)
- On feeders ≥5kV to <15kV –
  NCIP limits: 1 MW (anywhere on feeder) and 2 MW (within 2.5 circuit miles);
  SGIP recommended: 2 MW (anywhere on feeder) and 3 MW (within 2.5 circuit miles)
- On feeders ≥15kV to <35kV (note that the FERC uses a <30kV high limit) –
  NCIP limits: 2 MW (anywhere on feeder) and 2 MW (within 2.5 circuit miles);
  SGIP recommended: 3 MW (anywhere on feeder) and 4 MW (within 2.5 circuit miles)
- On feeders ≥35kV, interconnections are not eligible for Fast Track in the NCIP

■ **NCIP Exceptions with SGIP on Eligibility** – *The kW limits stipulated in the NCIP are lower on several feeder voltage levels; this observation is further addressed in Chapter 4.*

Discussion – Reviewing the numbers, types, and success rate of interconnection applications from time-to-time is a recommended practice. Some factors for consideration:

- Eligibility guidance in the SGIP and the NCIP can be informed by review results that depend on aggregate deployments, electric system- and feeder-specific considerations.
- Pass/fail results in the existing Fast Track process—for example, if a high level of Fast Track applications is passing or failing technical review.
- Future changes in feeder-available capacity with changing loads, potential upgrades, and increases in DER penetration levels.

In addition to these factors, Duke is likely to leverage growing interconnection experience to enhance criteria, procedures, and analytical tools used in technical review.

Although lower than recommended by FERC SGIP, EPRI's assessment is that the NCIP's size eligibility requirements are not out of line with industry practices. Appropriate limits depend on, among other things, the available feeder capacity, distribution of load, feeder lengths, in-line regulators, and options for reconfiguration. 4,160V circuits represent a very small portion of Duke's energy delivery capacity and would therefore support a limited number of DERs. The

100-kW limit used by Duke applies to the portion of the circuit further than 2.5 miles from the substation. These areas have limited capacity for DER other than residential.

In the 5-15kV circuit class, the requirement to study 2- and 3-MW plants that may otherwise have been eligible for Fast Track is reasonable. In most cases, it saves the time and effort to enter and fail Fast Track review. Given these considerations, it is unclear if changing MW limits would materially affect the review, approval, and interconnection process.

Pre-Approval for Supplemental Review

The NCIP provides an option for developers to pre-approve the Supplemental Review process. For larger DER and/or locations with relatively high aggregate DER this may be a time saver compared to other jurisdictions applying Fast Track review.

- ***NCIP Exceptions with SGIP in Process –*** *North Carolina offers applicants an option to pre-authorize Supplemental review; this observation is further addressed in Chapter 4.*

Discussion – Currently, FERC SGIP does not offer an option to pre-approve any of the more detailed reviews. A customer options meeting is required by SGIP to proceed to the next step. This practice is becoming somewhat outdated in jurisdictions with significant experience interconnecting larger commercial/industrial and utility-scale PV plants. In the updated North Carolina Fast Track process, eligible applicants are offered the unique option to go immediately into Supplemental Review where experience indicates that they are likely to fail Fast Track screens. This feature is expected to reduce the overall timeline for technical review by at least two weeks and is supported by the addition of more specific review criteria in Supplemental Review.

EPRI's assessment is that the NCIP's pre-authorization option is appropriate based on the accumulated experience and number of interconnection applications thus far received in North Carolina. Related, further definition of Supplemental Review technical criteria, with visibility on pass/fail requirements, is likely to support the NCIP approach. Improved definition of Supplemental Review criteria somewhat contrasts with other jurisdictions where criteria are broadly specified (i.e., safety, reliability, and power quality). Defining the criteria and their rationales is considered a good approach that is likely to further enhance the Supplemental Review process.

Assessment: Initial Review (Section 3.2)

Initial review screens in North Carolina are very similar – or in some cases identical – to those recommended in the SGIP and used in other jurisdictions. Two exceptions are noted below. Based on EPRI's assessment, modification or alignment of these two screens with FERC SGIP is not proposed.

- **NCIP Exceptions with SGIP Initial Screens** – *Two screens are materially different from those in the SGIP; no changes to these criteria are recommended in Chapter 4.*

- NCIP Screen 3 addresses substation bank or circuit loading not to exceed 90% minimum load;

  - SGIP does not cover this topic. Some other jurisdictions have screens related to not exceeding the rating of any MV equipment.
- SGIP has an initial review, Screen 2.2.1.10, which stipulates no construction of facilities by the Transmission Provider on its own system shall be required to accommodate the Small Generating Facility;
  - NCIP omits this initial screen.

Discussion – The objective of screening is to identify applications that do not require further review. Depending on the specific circumstances, some screens will be more applicable than others. Both art, for making the screens broadly useful, and engineering, to identify potential technical issues, are incorporated into the screens. Screens and related criteria are likely to evolve with experience and with changing DER penetration levels and performance requirements.

EPRI's assessment is that the individual screens discussed below (and encompassed in NCIP Section 3.2) are quite like those in the SGIP. In EPRI's experience, there can be important differences in the way screens are interpreted and applied, and in the specific criteria considered. As such, any material differences in these initial screens are identified in the following assessment. For clarity, a rationale is included with each screen stating EPRI's understanding of the screen's purpose, as well as the expected procedure for completing the screening. Where applicable, discussion is also provided to describe usage and application experience and some issues identified in other jurisdictions.

North Carolina Screens (3.2.1)

3.2.1.1 – The proposed Generating Facility's Point of Interconnection must be on a portion of the Utility's Distribution System.

Rationale – Service territories and available service need to be confirmed for jurisdiction.

Procedure – Identify available service or right-of-way that is adjacent or otherwise accessible to applicant's property.

Discussion – None

3.2.1.2 – For interconnection of a proposed Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Generating Facility, on the circuit shall not exceed 15% of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Utility's System connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

Rationale – Interconnections should be managed so as not to exceed minimum load on a line section without a protection review or study. The 15% of peak is used as a proxy for the minimum because minimum values are typically not known. The primary concern is the potential for unintended islanding in cases where DER generation approximately matches the islanded load during a grid outage. The screen is also used to calibrate if the relative size and operation of DER may impact voltage regulation, power quality, protection, or restoration procedures.

Procedure – Identify the aggregate DER and peak load on the next upstream automatic sectionalizing device (ASD). Alternatively, if the minimum load is known, it may substitute for the 15% of peak. To better recognize solar generation, SGIP revisions and several jurisdictions have further defined load minimum as between the daytime hours of 9 a.m. and 3 p.m. This approach to estimating daytime minimum load is explicit in the SGIP screen.

- **Proposed modification to Duke review procedure for Screen 3.2.1.2** – *In addition to using peak daytime load for solar PV plants to determine the 15% limit, also consider if the minimum daytime load is known and can be used as the limit; this recommendation is further addressed in Chapter 4.*

Discussion – Although widely employed, the "15% rule" screen has been controversial, particularly given increasing DER deployments and penetration levels. Issues related to the screen include the lack of clear definition and its application of "line-sections," cases of multiple automatic sectionalizing devices on a circuit, and different opinions surrounding the reasoning behind a 15% limit (i.e., that it may be a conservative limit or a conservative estimate of minimum load).

For the purposes of islanding prevention, EPRI's assessment is that only line sections that can be islanded by a single device should be considered in the screen. That is, the screen should be applied from the next upstream ASD and considering aggregate total of the generation and load to the end of the feeder. This limited definition of line section is to remove from consideration line-sections that would require simultaneous opening of two devices. This determination is based on field experience and assessment that creation of an island on a radial-fed system by simultaneously opening two ASD poses little to no risk involving DER.

The National Renewable Energy Laboratory (NREL), Sandia National Laboratories, and EPRI provided a report via the Department of Energy with additional descriptions and recommended practices related to this screen.[11] In addition to using the daytime minimum load, the report suggests that improvements in analytical methods and tools could better define the available safe capacity for DER at medium voltage connection points. Duke currently uses a min daytime load between the hours of 9 a.m. and 5 p.m.

This screen is also used as a proxy for potential voltage impact from DER—for example, voltage rise and power quality, as well as exceeded ratings on any power delivery equipment. Otherwise, there is currently no initial screen that address voltage or voltage quality.

3.2.1.3 – For interconnection of a proposed Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Generating Facility, on the circuit shall not exceed 90% of the circuit and/or bank minimum load at the substation.

Rationale – At the substation bank or feeder head, this screen limits the aggregate DER capacity to 90% of minimum load. It intends to prevent backfeed at the substation where the voltage regulator and/or ongoing efforts to optimize voltage levels for conservation or peak limiting may not be designed for reverse power.

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[11] *Alternatives to the 15% Rule: Modified Screens and Validation*. EPRI, Palo Alto, CA: 2015. 3002005791.

Procedure – Determine aggregate DER on the feeder and minimum load at the substation bank or individual feeder head.

Discussion – To EPRI's knowledge this preliminary screen is not used in most jurisdictions. In New York, there is an initial screen that asks, "Is any Electric Power System Rating exceeded by aggregate DER?". The technical basis for the New York screen is not to exceed ratings of the power delivery system (primary or secondary) as it may be unsafe or contribute to reduction in power quality and reliability. In North Carolina and New York, the screen is intended to consider worst case conditions for both generation and loading using two different calculations.

Identifying possible grid or DER changes to avoid overloads is normally beyond the scope of preliminary screening. When available, and as approved by the EPS operator, changes in DER settings and export limiting may be applied to pass this screen (e.g., smart inverter grid support, energy storage charge/discharge, or reverse power limiting relays to limit backfeed).

3.2.1.4 – For interconnection of a proposed Generating Facility to the load side of spot network protectors, the proposed Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW.

Rationale – Allow DER on spot networks (usually 480V) with sufficient headroom to avoid the need for protection studies or costly control upgrades; assure that cascading reverse power and network outages are avoided.

Procedure – Look at aggregate total of all inverter-based DER downstream on any network protectors and at the reverse power setting on the protectors in a spot network.

Discussion – The issue with network systems is that the protectors are designed to open with a small amount of reverse power. In services with multiple protectors, the overriding concern is the likelihood that opening protector will cause others to follow suit and create a cascading power outage. DERs on spot networks are, therefore, highly limited. This limit is typical and sufficient for most jurisdictions using 480V, spot-network service to large commercial or industrial customers.

Typically, in the case of area networks such as a 208V city network, DERs are highly limited or not allowed without study. DERs large enough to cause backfeed would require significant changes in protection settings and to predict load flows. Consequently, area network-connected DER are not eligible for Fast Track. Related, there is an ongoing effort by Consolidated Edison of New York to develop new Fast Track screens that are applicable to the utility's LV (208V) city network. It is a work in progress and in the future the State of New York may adopt these network screens for trial use in early 2020.

3.2.1.5 – The proposed Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.

Rationale – If the Generating Facility passes this screen, it can be expected that it will have no significant impact on the distribution system's short circuit duty, fault detection sensitivity, relay coordination, or fuse-saving schemes.

Procedure – Assume that existing levels are known and estimate aggregate fault contributions; consider type and related peak currents measured at the primary point of connection.

Discussion – The screen may also identify cases in which higher fault currents leave little margin for additional fault current and for coordination with added DER. If margins are too low or uncertain, then a protection coordination study is required. This can be a limiting factor for circuits with small margins. Fuses may be employed where fuse replacement is a low-cost option.

3.2.1.6 – The proposed Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.

Rationale – If the Generating Facility passes this screen, it can be expected that it will not cause any of the distribution provider's equipment to be overstressed during fault events.

Procedure – If the fault level at a protective device, without DER, exceeds the screen limit of 87.5%, then Supplemental Review is required.

Discussion – Typically, this screen serves to verify interrupting capability for protective devices such as fuses, reclosers, or circuit breakers and the need to limit DER or to consider a larger device rating. The most common upstream protective device limiting capacity is a fused lateral connection of the DER. Protection upgrades to increase ratings may be considered in Supplemental Review.

3.2.1.7 – Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service to be provided to the Interconnection Customer, including line configuration and the transformer connection for limiting the potential for creating over-voltages on the Utility's System due to a loss of ground during the operating time of any anti-islanding function.

Primary distribution Line Type	Type of Interconnection to Primary Distribution Line	Result/Criteria
Three-phase, three wires	3-phase or single phase, phase-to-phase	Pass Screen
Three-phase, four wires	Effectively-grounded three-phase or single phase, line-to-line Neutral	Pass Screen

Rationale – This screen aims to consider if the transformer connection of the DER is compatible with the feeder connection configuration and feeder system grounding. The main concern is limiting ground fault overvoltage (GFO) on medium voltage (MV) if the grid source ground is lost during a ground fault. Momentary backfeed from the DER can cause GFO unless it is connected according to distribution system standards defining "effectively grounded systems." ANSI C62.92.1 and .3 define these requirements for conventional synchronous generators. Other limiting factors for transformer interconnections to the medium voltage are feeder design, number of wires, and coordination of protective devices for different fault scenarios.

Procedure – Identify the primary distribution line configuration that will serve the Generating Facility. Based on the type of connection to be used for the Generating Facility, determine from the screen table if the proposed Generating Facility passes the screen.

- **Proposed modification to NCIP Screen 3.2.1.7 –** *Update this screen to include criteria that are appropriate for inverter-connected DER; this recommendation is further addressed in Chapter 4.*

Discussion – This screen, as written, applies to synchronous machines and is not applicable to inverter-based DER. Current utility industry practices and requirements for grounding inverter-connected DER vary widely for a number of reasons. One issue for three-phase inverter-connected plants is that they are usually not grounded sources, which leads to questions about acceptable transformer connections or if supplemental grounding is needed. In the case of a Yg-Yg transformer connection, as is currently applied by Duke in North Carolina, an ungrounded generator would raise questions and likely fail this screen as written.

An important issue with grounding for distributed generation is the need to review feeder protection coordination not covered in initial review screens. In the case of synchronous machines, which normally require local grounding, their addition would also require checking protection coordination to consider the effects of the additional ground source on the circuit. This is beyond the scope of initial Fast Track screening. In the past, synchronous machines have not been certified where the grid-side protection has usually involved a separate protection package.

The new IEEE 1547.1 expects synchronous generators to be type tested and synchronous generator manufacturers have been active participants in the standard's updating. The old IEEE 1547.1-2005 also required type testing of all "DER interconnection systems". In the case of synchronous generators, this generally involved a relay and switchgear package that could provide compliance. Pending 1547.1's revision, synchronous machines do not qualify for the Fast Track process.

Review of inverter-connected DER that are eligible for Fast Track would benefit from clarification of this screen. Recognition that inverters are different than synchronous machines with respect to compatible interconnection may be addressed by adding a note in screen 7. Updating the table to separately cover synchronous machines and inverters is more difficult as industry practices for inverters are a work in progress. Also, depending on the distribution system, some utility protection practices do not allow the addition of ground sources without study.

Simply recognizing differences with inverters would be an improvement to the screen and make it more applicable to typical DER eligible for the Fast Track process. Additional updates to the screen are needed to address criteria for inverter-connected DER and to note exceptions where effective grounding is not allowed. New criteria are supported by the recent addition of ANSI C62.92.6 addressing inverter connections. Creation of new criteria is, however, beyond the scope of this review.

3.2.1.8 – If the proposed Generating Facility is to be interconnected on a single-phase shared secondary, the aggregate Generating Facility capacity on the shared secondary, including the proposed Generating Facility, shall not exceed 65% of the transformer nameplate rating.

Rationale – To address concerns related to voltage rise on a shared secondary, limit or allocate the LV capacity in case backfeeding power through the transformer impedance causes the service (secondary) voltage to exceed ANSI steady state limits.

Procedure – Look at the transformer capacity relative to maximum backfeed and calculate the percent of nameplate rating. Estimated minimum daytime loading on the same transformer may also be factored into the calculation for solar PV systems.

Discussion – This is a very common criterion. SGIP indicates a 20-kW limit on shared single-phase secondaries. In some jurisdictions, such as in Minnesota, both the 65% and the 20-kW limits are applied.

3.2.1.9 – If the proposed Generating Facility is single-phase and is to be interconnected on a 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.

Rationale – Avoid imbalance on shared single-phase 240V service.

Procedure – Base the 20% limit test on the kVA of the service transformer.

Discussion – This limit is expected to result in minimum voltage imbalance (2-3%) in most cases, which is within the recommended voltage balance in the voltage ratings standard, ANSI C84.1.

3.2.1.10 – The Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Generating Facility proposes to 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 busses from the point of interconnection).

Rationale – Depending on the substation and transmission service capacity a large deployment of DER can impact grid operations and transient stability.

Procedure – Evaluate stability at the substation and on sub-transmission.

- **Proposed modification to NCIP Screen 3.2.1.10 –** *Remove from required initial review screens; this recommendation is further addressed in Chapter 4.*

Discussion – This screen would typically be applied where there are known stability limits on transmission or sub-transmission. Special consideration must be given to those areas identified as having current or future (due to queued interconnection requests) transient stability concerns. In rare cases this screen may have been used to limit the total DER on a feeder. However, other screens also address aggregate total DER on a feeder. For example, screens 3.2.1.2 and 3.2.1.3 address challenges of aggregate DER on a feeder.

As written, this screen is more appropriate for large wind energy plants and qualifying DER facilities with large synchronous machines that would not normally qualify for Fast Track. The issue of transient stability on the transmission side of a substation is normally not a consideration in "first-level" initial screening at the distribution level. An alternative to address transient stability is to include it in Supplemental Review for locations interconnected in areas of limited transmission capacity.

Assessment: Customer Options Meeting (Section 3.3)

When an application cannot be approved without modifications or additional study a customer options meeting is offered to determine what further steps are needed to permit the interconnection. Customer options include:

- Facility modifications or minor modifications to the utility system (includes a good faith cost estimate for modifications)
- Supplemental review (includes a good faith cost estimate for the review).
- Continued evaluation under the Section 4 study process (includes a good faith cost estimate for the study).

- **NCIP Exceptions with SGIP on Customer Options** – *None noted.*

Assessment: Supplemental Review (Section 3.4)

A supplemental, or second level, review process is defined in the FERC SGIP and is a common step – whether required or optional – in all Fast Track processes EPRI is aware of. The three criteria identified in the FERC SGIP address aggregate DER. These criteria range from a very specific minimum load screen, to standard references for grid voltage and power quality, to a much less well-defined screen regarding grid safety and reliability.

Supplemental Review in North Carolina is like the SGIP's, however the criteria in Section 3.4 of the NCIP is less specific than in the SGIP. The Supplemental Review described in North Carolina refers to interconnections that are consistent with safety, reliability, and power quality standards, but specific criteria and scope for Supplemental Review are not defined.

- SGIP defines a minimum load screen for line sections as one of three Supplemental Review criteria. In North Carolina, the aggregate DER to minimum load screen is in the initial review

screen 3.2.1.3. This NCIP screen refers to aggregate DER on a circuit or transformer bank. Line-section is not identified as a criterion for this initial screen.

- SGIP includes criteria for power quality and contains fewer specific criteria for safety and reliability.

- **NCIP Exceptions with SGIP on Supplemental Review** – *The SGIP is somewhat more specific on Supplemental Review than the NCIP; this is noted but is not included as a recommendation in Chapter 4.*

Discussion – In many jurisdictions, Supplemental Review is effectively a mini-study that requires feeder analytical tools and engineering judgement to determine pass/fail. Additional analytics are needed to consider facility or feeder upgrade requirements. The criteria used are typically thermal limits, voltage regulation, power quality, and protection. Engineering judgement can also play an important role in Supplemental Review. As such, specific pass/fail criteria are usually not published beyond the broad guidelines provided in documents such as the NCIP or SGIP.

In some cases outside North Carolina, Supplemental Review is viewed as both a cost and a delay that may not culminate in an approved interconnection. One reason for this perception: requirements for achieving approval are typically not well defined and grid upgrade options may be limited. Another reason: Fast Track processes with the highest eligibility limits invite applications that will need to be studied. Increasing aggregate DER may also complicate Fast Track approval and consequently require detailed study. All told, the decision to perform a Supplemental Review versus a detailed study is evolving as utilities accrue DER interconnection experience.

Similar to the SGIP, the general criteria in the NCIP Supplemental Review description is broad. In North Carolina, the passing rate for applications undergoing Supplemental Review is relatively high. In reviewing the Supplemental Review process with Duke, EPRI found that internal check lists, flow charts, technical bulletins, and related criteria are being applied. An important step in the future will be for Duke to provide transparency to the process by publishing criteria in an interim bulletin and in an update to Duke's Method of Service (technical interconnection requirements [TIR] for paralleling DER with the grid).

The following six Supplemental Review criteria have been proposed by Duke and reviewed by EPRI. They are considered to provide reasonable clarity and transparency to the detail and scope of the utility's Supplemental Review technical requirements. For each Supplemental Review requirement EPRI's understanding of the rationale behind the criteria is provided.

1. **Upstream Voltage Regulator** – Refers to line and substation regulators and considers minimum load reduction.
   - *Criteria* – Does the project comply with the Duke's Method of Service Guidelines, Section 3.2? Does the addition of the exempt Generating Facility cause backfeed of power through a line-voltage regulator?

     The review applies to the aggregate generation downstream of all existing and any planned line-voltage regulators. The estimated minimum load is considered as a reduction

to potential backfeed. If backfeed is indicated, the Generating Facility fails Supplemental Review and requires additional study.

- *Rationale* – Regulators are usually not configured for backfeed. Changing LVR configuration is typically a major modification requiring detailed review. There is added difficulty as Duke is required to maintain specific peak reduction capabilities utilizing voltage reduction. Any change would have to consider voltage optimization, regulator device upgrades, as well as other grid modernization and reconfiguration issues. Also considered is the future application of electronic regulation equipment to improve conservation voltage reduction for the purposed of load reduction. The criterion is that any DER >250 kVA is required to connect upstream of any voltage regulator. The rationale is based on experience with large DER causing voltage regulation issues and/or increased regulator operation in cases of changing PV plant output with moving clouds.

2. **Voltage Regulation Limits** – Refers to ANSI C84.2 Range A limits using MV load flow analysis and calculation of service LV.
   - *Criteria* – Is the Generating Facility expected to cause any voltage violations such as exceeding ANSI C84.2 Range A limits? A circuit load flow analysis is conducted to calculate voltage changes on the feeder. Using these results, the service voltage to customers is estimated. If no violations are indicated, the Generating Facility meets the criteria. If the Generating Facility causes violations, then it fails Supplemental Review and requires additional study.
   - *Rationale* – Voltage rise is the most common outcome of higher DER penetration; either ANSI limits relative to rated or relative to moving average are typically considered. Results should inform if any and what specific additional detail reviews are needed.
3. **Power Quality Limits** – Refers to IEEE 1547-established power quality criteria for DERs and considers impacts on other customers.
   - *Criteria* – Is the Generating Facility expected to cause any power quality limit violations when interconnected? Site-specific power quality assessments such as inrush, RVC, or resonance are performed for the proposed interconnection. The generation facility and/or the rest of the circuit are included. The power quality requirements specified in IEEE Std 1547-2018, Section 7 are considered in the review. If violations are indicated by the addition of the Generating Facility, then it fails Supplemental Review and requires additional study.
   - *Rationale* – Power quality impacts depend mostly on circuit strength at the Point of Common Coupling (PCC). Certification verifies DER performance in a laboratory setting without regard for the PCC. In Supplemental Review, the existing loading conditions, the circuit strength at the PCC, and the relative size of the DER are considered along with an assumption that the DER passed the other PQ certification tests. (Note that there are no certification type tests related to RVC in either IEEE Std 1547 or 1547.1.) In the case of unforeseen interactions related to harmonics, EMC, and other PQ phenomena,

contingency options should be included in all interconnection agreements; otherwise, these phenomena are difficult to predict via studies. Maintaining a stiffness ratio greater than 25 is another good way to reduce potential power quality impacts.

- **Proposed modification to the Supplemental Review criteria for RVC** – *Update limits used for RVC considering new criteria in IEC 61000-4-30, Ed. 3, 2015, language describing the use of RVC limits in IEEE-1547 2018 and in the Draft 2 update to IEEE-1453; this recommendation is further addressed in Chapter 4.*

4. **Distribution Protection** – Addresses fault current limits, protection coordination and uses short-circuit analysis tools to conduct the Supplemental Review.
   - *Criteria* – Will the addition of the Generating Facility and its related fault current contributions exceed interrupting capability, cause miscoordination or nuisance tripping on the circuit? A short circuit analysis is used to determine any impacts on protection coordination. Plant characteristics, circuit characteristics, and point of interconnection are used to determine if there are any other issues. If protection issues are indicated by the addition of the Generating Facility, it fails Supplemental Review and requires additional study.
   - *Rationale* – Protection needs to be examined at the Supplemental Review level. Results will inform if specific additional detail reviews are needed. Also, limitations in a planning tool's capability to address protection issues with mixed DER types and high penetration should be factored into review; tool improvements should also be pursued based on identified limitations.

- **Define changes to Supplemental Review criteria for Distribution Protection** – *Identify cases where an exception to the 87.5% interrupting capacity limit may be applied; this recommendation is further addressed in Chapter 4.*

5. **Substation Available Capacity** – Addresses any limits in power systems capacity to support generation and load.
   - *Criteria* – Does the aggregate generation connected downstream of the substation transformer bank exceed available capacity? Nameplate rating (ONAN) of the transformer bank is used to determine available capacity. Consideration can be given to the bank minimum load for generation that is co-located with load. If adding the Generating Facility may exceed the substation capacity, then it fails Supplemental Review and requires additional study.
   - *Rationale* – Allocating circuit capacity is a recommended practice as is maintaining reasonable spare capacity. There is no standard way to determine these capacities. Duke may want to document the method and rationale for internal use.
6. **Unintentional Islanding Risk** – Considers aggregate generation type, configuration, protection, and potential to support load.

- *Criteria* – Does the addition of the Generating Facility, in aggregate with other queued Generating Facilities, create a concern for unintentional islanding? A review of the Generating Facility's inverter detection capability, service configuration, and transformation is performed in conjunction with the substation and/or circuit load demands. Should the Generating Facility create a concern, remediation or further analysis is required.
- *Rationale* – Although inverters are tested for islanding detection in the laboratory, the mix of DER and detection methods in the field is relevant to risk. Several detection methods work better than others. EPRI is currently evaluating effectiveness and risk assessment methods. Duke should consider these results in the future and potentially require larger DER to declare what method they use.

The overall assessment of the above Supplemental Review criteria used in the Fast Track process is that they provide appropriate transparency and clarity. EPRI expects that maintaining well-defined technical criteria and rationales, and making them available to inform developers, will enhance the review process. This could support planning and decision-making regarding whether to pre-authorize Supplemental Review or pursue detailed facility study. One practical consideration, broadly applied, is to include the review criteria in Duke's existing technical interconnection requirement document or in an amendment.

Supplemental Review can be an effective path to interconnection if a process and supporting criteria are clearly spelled out. Making the process and technical requirements more transparent to the developer can support the decision to use Supplemental Review. Meanwhile, applying analytical tools, often used in distribution planning, to the Supplemental Review process is a good way to increase efficiency. For applications that qualify for Fast Track, some standard mitigations may be pre-estimated, especially as DER penetration levels rise. Both the utility and developer benefit if detailed studies can be avoided. Also, the new performance requirements published in IEEE Std 1547-2018 should be considered and incorporated into the Supplemental Review process and criteria.

4
EPRI RECOMMENDATIONS FOR FAST TRACK AND SUPPLEMENTAL REVIEW

This chapter presents EPRI's recommendations for improving the Fast Track process specified in the North Carolina Interconnection Procedures, E-100, Sections 3.1 to 3.4. It addresses the screens and procedures identified by the NCUC as needing third-party review, and provides specific recommendations to Duke's technical review criteria and procedures as they relate to the NCIP E-100. Coverage encompasses Fast Track eligibility, technical screening, and Supplemental Review.

Two types of recommendations are presented:

1. Recommended *modification* to the Fast Track process or technical criteria, and
2. Recommended *clarification* of the Fast Track process or technical criteria.

What follows is a descriptive accounting of EPRI's recommendations. An in-depth explanation is provided for each recommendation, along with supporting commentary. The recommendations are based on the comparative review detailed in Chapter 3, EPRI experience with the Fast Track processes in other jurisdictions, and related DER grid integration research completed by EPRI.

Recommendations: Eligibility Requirements (Section 3.1)

Fast Track eligibility is based on the feeder kV and the distance to the serving substation. The kW limits for several feeder voltage levels are lower in North Carolina than those in the FERC SGIP. In addition, FERC SGIP stipulates connections up to 69kV are eligible.

Although lower than suggested in the FERC SGIP, NCIP eligibility requirements are not out of line with industry practices. Appropriate limits depend on the available feeder capacity, distribution of load, feeder lengths, in-line regulators, options for reconfiguration, among other things. In looking specifically at the 100-kW eligibility limit (<5kV and more than 2.5 miles from the substation), it becomes apparent that a very small percentage of interconnection applications submitted to Duke are affected. Based on recent history, the current limits only apply to roughly 8% of applications submitted to Duke within the last several years (see Chapter 2 for more details).

As discussed in Chapter 3, and given the small number of requests on 5kV circuits beyond 2.5 miles, it is not clear that changing limits would materially affect the review, approval, and interconnection process.

In prior testimony and review of eligibility limits,[12] the NCUC recognized that larger plants have dominated interconnection and adoption of a more conservative approach in North Carolina was acknowledged. Considering the growing DER penetration levels in the state, changing eligibility

[12] North Carolina Utilities Commission, "Order Approving Revised Interconnection Standard and Requiring Reports and Testimony," June 14, 2019.

at this time is not expected to enhance the process. Table 4-1 provides a summary of EPRI's observations and recommended next steps related to the eligibility requirements and options in NCIP, Section 3.1.

Table 4-1
Summary of EPRI Observations and Recommended Next Steps for Fast Track Eligibility

Technical Consideration & Criteria	NCIP E-100 Section	Review Type/Level	Observations	Recommended Next Steps
Expedited process, limited screening ≤ 20 kW	3.1	Fast Track Eligibility	Expedited interconnection for small, typically residential, PV has become widely accepted practice. The expedited range is ~10-50 kW for certified inverter DER connections (not addressed in current FERC-SGIP).	None
Certified inverters only	3.1	Fast Track Eligibility	Certification is a key requirement in Fast Track, both screens and Supplemental Review depend of it. Non-inverter certification is possible and may require future changes to Fast Track processes.	None
Fast Track Eligibility, kW level for feeder kV level	3.1-table	Fast Track Eligibility	NC is currently more conservative on Fast Track size eligibility than is recommended in FERC-SGIP. It is not clear that changing eligibility limits would enhance interconnection process in North Carolina (~10 projects/year, 85% of 5kV within 2.5 mi.).	**Recommendation 1:** Periodically monitor if applications that are not Fast Track-qualified are connected without mitigations. Consider if more experience and better tools will address larger DER.
Pre-authorize Supplemental Review	3.1.1	Fast Track Eligibility	Pre-authorization for Supplemental Review looks like a practical time saving option. Data support the practice.	**Recommendation 2**: Continue to evaluate Supplemental Review criteria. Consider success rate with/without Supplemental Review.

Statistics related to the current Fast Track process, described in Chapter 2 and 3, indicate that eligibility is generally at the right level. It is not clear that expanding eligibility will improve outcomes. Given changing conditions in grid hosting capacity and in the types of DER interconnection applications, EPRI recommends the following two actions:

Recommendation 1 – Periodically review Fast Track eligibility relative to the size range and the number of applications submitted and consider if adjusting the limits is warranted. A potential

benefit of raising the limit is to simplify the review process for larger plants proposed in areas with available capacity or in cases where export limiting and/or sufficient local load can mitigate some integration issues. Additional experience and improvements in the Supplemental Review process could provide relief for any backlog in detailed studies.

Recommendation 2 – Inform developers, during the TSRG and like meetings, about the option to pre-approve Supplemental Review for larger projects eligible for Fast Track. Publish the technical criteria used in Supplemental Review. Where possible, apply analytical tools that can consider the point of connection, aggregate impacts, and protection coordination and mitigation recommendations in Supplemental Review.

Recommendations: Fast Track Initial Screening (Section 3.2)

A summary of EPRI's observations and recommended next steps related to the NCIP's 10 designated Fast Track screens is provided in Table 4.2. Included in the table is EPRI's understanding of each screen's criteria and its application to either individual DER or aggregate DER on a feeder or substation.

What follows are EPRI comments on and suggested clarifications to Duke's application of three of 10 initial review screens stipulated in the NCIP. The clarifications are based on EPRI's understanding of the pass/fail criteria applied by Duke to determine pass or fail results. EPRI suggests that each of its proposed clarifications be addressed in documents, such as technical interconnection requirements (TIR) documents, that describe parallel connection requirements to customers and developers. To this end, the TIR documents produced by Duke Energy Carolina and Duke Energy Progress should be updated and harmonized as much as is possible.

Table 4-2
Summary of EPRI Observations and Recommended Next Steps for Fast Track Screening

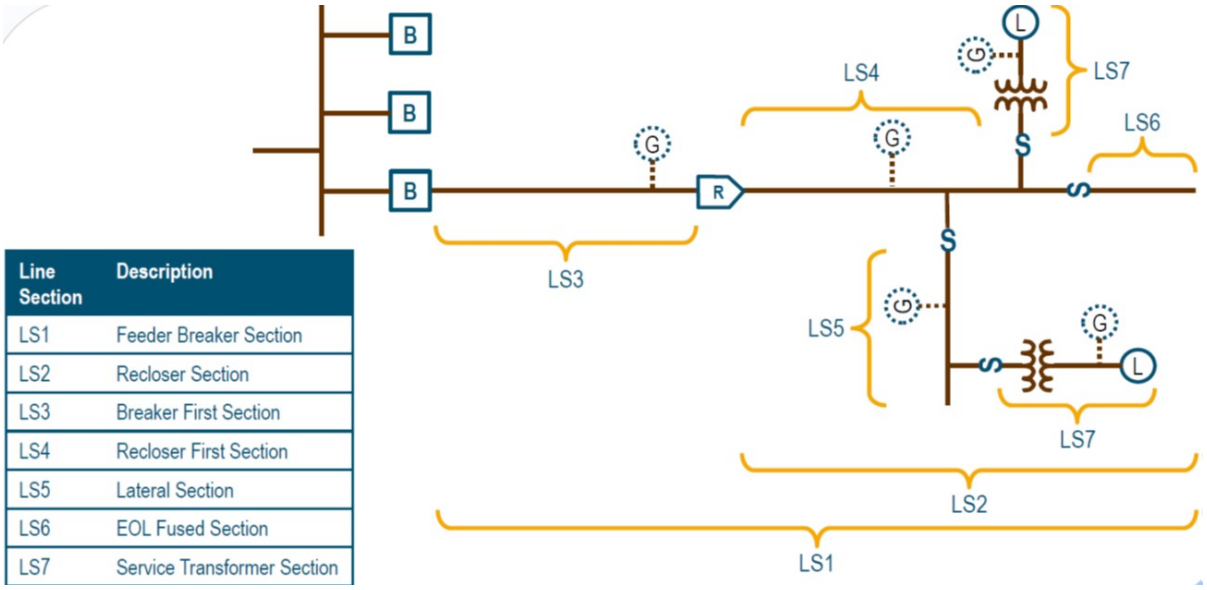
Technical Consideration & Criteria	NC E-100 Section	Review Type	Observations	Recommended Next Steps
POI location on Duke system	**3.2.1.1**	Individual	Application PCC to be in service territory	None
Line section generation is <15% of peak load	**3.2.1.2**	Aggregate	15% of peak is used as an estimate for minimum load on line sections. SGIP and several jurisdictions with higher penetration of solar use day-time minimum load.	**Recommendation 3:** Either estimate or, if known, use daytime minimum load in case of solar PV.
<90% of min load	**3.2.1.3**	Aggregate	SGIP screens do not address min load. This screen could enhance first level review if the rationale and relationship to 3.2.1.2 are clarified. Indicator of high penetration on feeders.	None
On spot or LV networks	**3.2.1.4**	Aggregate	Consistent with SGIP, some jurisdictions do not allow network connections based on screening.	None

Technical Consideration & Criteria	NC E-100 Section	Review Type	Observations	Recommended Next Steps
SC contribution <10%	**3.2.1.5**	Aggregate	Consistent with SGIP, failure indicates a protection issue	None
Interrupting <87.5%	**3.2.1.6**	Aggregate	Consistent with SGIP, failure indicates a protection issue	None
DER effective grounding	**3.2.1.7**	Individual	Duke uses recommended practice, not clear in SGIP	**Recommendations 4:** Clarify inverter requirements in methods of service and in the NCIP E-100
Secondary transformer 65%	**3.2.1.8**	Aggregate	Addresses voltage on shared LV, consistent with SGIP	None
Secondary imbalance 20%	**3.2.1.9**	Individual	Addresses voltage on shared LV, consistent with SGIP	None
Transient stability limits	**3.2.1.10**	Aggregate	A transmission-level issue; may not be needed for Fast Track	**Recommendation 5:** Remove as required initial screen.

Recommended Clarification: 15% of Peak Load DER Aggregate Limit per Line Section (3.2.1.2)

As described in the NCIP, the existing screen is consistent with industry practices and other jurisdictions. “Aggregate generation on any line-section, downstream of the next automation sectionalizing device,” is typical language used. The concept of “line section” can be a point of confusion because a wide variety of feeder configurations and “line sections” occur in many different forms.

As illustrated in Figure 4-1, there are line sections that encompass the entire feeder, sections in the middle of a feeder, and sections near the end of the feeder. Sectionalizing enables the utility to isolate faulted sections of a feeder. In many cases, power can be re-routed, and service restored to sections affected by a fault using alternative routes, sectionalizing, and access to other feeders. The general definition of a line section is between two automatic sectionalizing devices.



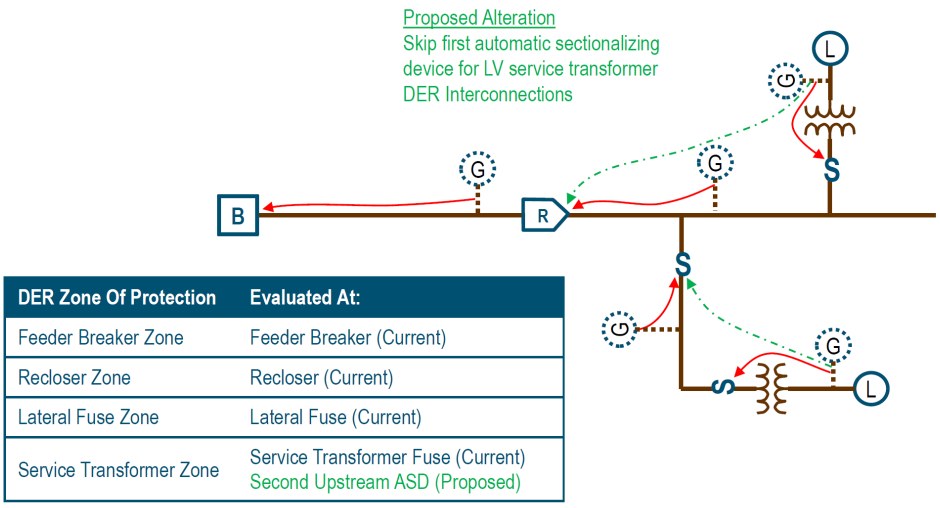
Line Section	Description
LS1	Feeder Breaker Section
LS2	Recloser Section
LS3	Breaker First Section
LS4	Recloser First Section
LS5	Lateral Section
LS6	EOL Fused Section
LS7	Service Transformer Section

Source: Duke Energy

Figure 4-1
Defined Line Sections on a Typical Feeder

As discussed in Chapter 3, the main objective of this screen is to avoid the possibility of islanding. A secondary objective for limiting DER to 15% of peak load is to avoid any impact on voltage regulation and quality. Regarding the unintended islanding objective, line sections of concern should only involve the one upstream automatic sectionalizing device and all downstream load and generation (only LS1, LS2, LS6, and LS7 in Figure 4-1).

Further, there are updates and simplifications to Duke's current Supplemental Review shown in Figure 4-2. The figure illustrates two implementations of line sections. In the first case, the first sectionalizing device is a service transformer fuse and the second is a lateral fuse. In the second case, the first sectionalizing device is a service transformer fuse and the second is a recloser device on the mainline. In these cases, the second sectionalizing device is used to evaluate if the DER exceeds the 15% limit and if the protection is adequate.



DER Zone Of Protection	Evaluated At:
Feeder Breaker Zone	Feeder Breaker (Current)
Recloser Zone	Recloser (Current)
Lateral Fuse Zone	Lateral Fuse (Current)
Service Transformer Zone	Service Transformer Fuse (Current) Second Upstream ASD (Proposed)

Source: Duke Energy

Figure 4-2
Unique Cases of Feeder Line-Sections where the Second Upstream Sectionalizing Device Defines the Aggregate Load and Generation on the Section

This proposed alteration, in effect, excludes the service transformer and the next upstream protection device as a separate line section for this screen. There are pros and cons to defining the service transformer as a line section. In the case of the 15% limit, using the second upstream device is likely to allow more DERs to pass the screen. Most other protection-related reasons for limiting to a service transformer line section are addressed by other screens and Supplemental Reviews. Duke will determine if secondary studies are warranted on a case-by-case basis and if actions should be taken based on results.

Recommendation 3 – Duke should clarify how line sections are defined in screen 3.2.1.2 in its Method of Service and/or TIR document. This may be useful for informing customers and developers. When applying this screen in areas where the actual minimum load on the related section can be estimated, EPRI recommends using the estimate rather than the 15% proxy; this would need to include any load that may be masked by generation on a line section.

Recommended Modification: Effective Grounding and Transformer Configuration Requirements (3.2.1.7)

This screen addresses a basic design objective in medium and high voltage utility delivery systems for the system effective grounding to limit line-to-ground voltage during ground faults. The criterion is a system coefficient of 80% of grounding. It is related to limiting the potential for ground fault overvoltage that is voltage line to ground to 0.8 times the line-to-line voltage (0.8 x 1.73 = 1.39 of the voltage line-line voltage). The limit protects equipment-connected line to ground, such as lightning arrestors, from damaging momentary overvoltages during ground faults.

An issue with synchronous distributed generation is that effective grounding may be lost when a line section is islanded. As a result, the local generator may momentarily cause overvoltage if backfeeding the faulted three-phase line section. This can occur after an upstream device opens

and islands the remainder of the feeder. Screening criteria were originally developed for rotating machines in this scenario. Figure 4-3 illustrates ground fault overvoltage for an islanded feeder and the exposed grounded loads.

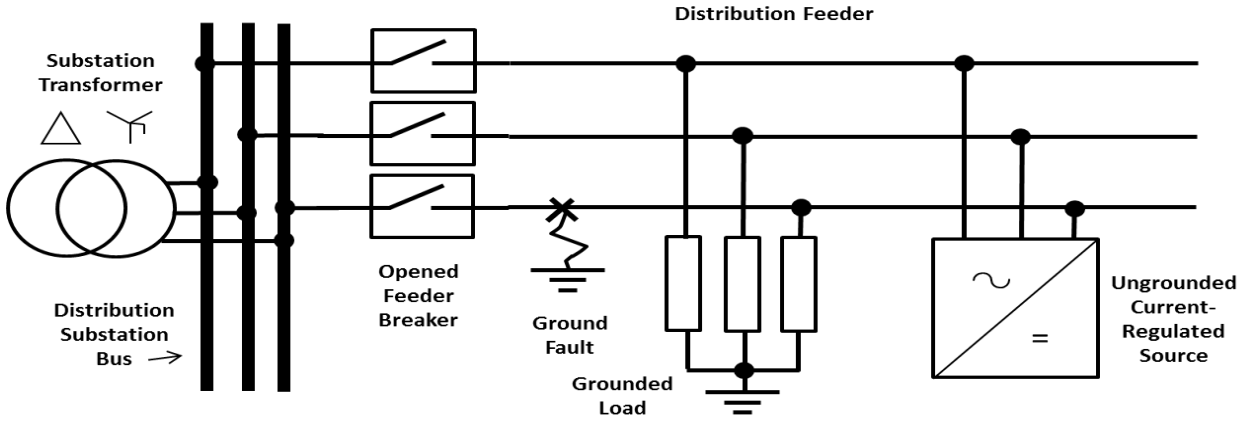


Figure 4-3
Ground Fault Overvoltage when a DER Backfeeds into a Ground Fault

In the case of three-phase inverters, the issue of ground fault overvoltage is significantly mitigated, often reducing or eliminating the need to provide for effective grounding in the DER interconnection. On the other hand, if additional grounding is added with DER, there is a concern regarding side effects on protection coordination. Consequently, many distribution feeder designs require, and utility protection engineers prefer, interconnections that are not excessively grounded and/or the grounding is well-defined and can be considered in coordination of fault protection.

Currently, the NCIP screen implies that a three phase 4-wire feeder configuration, as is common in the Duke service territory, requires effective grounding to pass the screen. Duke's current practice for inverter-connected DER does not require or allow additional grounding in the plant interconnection or supplemental grounding in the plant. Depending on how it is interpreted, the existing screen may be inconsistent with the practice that developers see in other jurisdictions. That is, plants connected Yg-Yg require supplemental grounding or they will fail this screen.

Duke has recognized that supplemental grounding is likely not necessary for inverter connections. This is because a sufficient amount of line-to-ground connected load can effectively ground the system in the case of inverter-based DER. Just because the inverter does not itself provide the grounding does not mean that the condition does not exist. Effective grounding is a system characteristic, not a source characteristic.

Realizing this point is nontraditional, somewhat esoteric, and not easily understood, EPRI recommends making it clearer in the screen's pass/fail criteria. It should be clarified in applying screen 3.2.1.7 that PV inverters may be treated as exceptions to the need for local effective grounding. Again, effective grounding is a system issue, not a DER plant characteristic. The desired effective grounding comes about in a different way due to the strong effect of loads when considered relative to a current-regulated source, that is, in the case of inverters sources.

Currently, the NCIP screen implies that a three phase 4-wire feeder configuration, as is common in Duke service territory, requires effective grounding to pass the screen. Duke's current practice for inverter-connected DER does not require or allow additional grounding in the plant interconnection or supplemental grounding in the plant. The existing screen is inconsistent with the current practice. As such, it should be clarified that in applying the screen, PV inverters may be treated as exceptions to local effective grounding, and that effective grounding is a system issue and not a plant characteristic.

Recommendation 4 – Update inverter grounding requirements in both Duke's public technical interconnection requirements and in the NCIP changes to Screen 3.2.1.7.

- Document Duke's preferences and technical requirements for grounding both synchronous machines and inverter-based DER in its Method of Service Guidelines. Include both interconnection configurations and any supplemental grounding requirements. This document is currently referenced on the TSRG website and available as a public document covering technical interconnection requirements. It should lay out general technical requirements for grid interconnection as well as specific requirements depending on the feeder characteristic, the point of interconnection, the DER plant size and type, as well as the aggregate on a feeder.
- Update the NCIP Screen 3.2.1.7 to distinguish existing requirements for synchronous machine-connected DER and new requirements for inverter-connected DER. The recommended replacement language is as follows.

  Proposed revision to Screen 3.2.1.7 **- Is DER interconnection prone to support ground-fault overvoltage at the PCC?**

  Procedure: Determine the type of interconnection to a primary distribution line, then review the type of electrical service to be provided to the Interconnection Customer. The purpose of this screen is to consider the potential for creating a ground fault over-voltage on the utility's system after loss of the grid source and during the detection time delay of any islanding prevention protective functions. Considerations for passing this screen include the line configuration, the transformer connection, the type of DER, and the nature of the load.

  References: If the DER is a synchronous machine, then the requirements for effective grounding in IEEE/ANSI C62.92-1 and 3 will apply. If the DER is an inverter, then the requirements in IEEE/ANSI C62.92-1 and 6 will apply.

Recommendation 5 – Remove the existing NCIP Screen 3.3.1.10 as it is not an expected Fast Track initial review consideration.

Recommendations: Supplemental Review (Section 3.4)

As previously discussed, FERC SGIP and most jurisdictions identify three general Supplemental Review criteria: penetration level, voltage and power quality, and safety/reliability. The NCIP refers to all these criteria except penetration level. As described in Chapter 3, Screen 3.2.1.6 addresses penetration level as a percentage of minimum load. Although there are some

differences in the way the SGIP and NCIP describe Supplemental Review, these differences appear to be immaterial to the current effectiveness and planned enhancements to Supplemental Review.

With higher DER penetration levels and larger application volumes, Supplemental Review is likely to become increasingly important in the future. In addition, analytical tools like load flow and protection coordination software are being upgraded to do a better job of addressing special DER cases; even automated review using these tools is being considered and used in California, Connecticut, Maryland, Massachusetts, New York, and other jurisdictions.[13] On the other hand, in some jurisdictions, unclear Supplemental Review criteria have discouraged use of the review.

EPRI's observations and recommendations related to Supplemental Review process are provided in Table 4.4. Additional discussion regarding recommended next steps follows the table.

Table 4-3
Summary of EPRI Observations and Recommended Next Steps for Supplemental Review

Technical Consideration & Criteria	NC E-100 Section	Review Type	Observations	Recommended Next Steps
Line Voltage Regulator Upstream	3.4.1	Individual	>250 kVA DER downstream of any regulator needs to connect above regulator	None
Voltage Regulation Limits	3.4.1	Aggregate	Steady state voltage review criteria follow expected industry practices	None
Power Quality Reviews	3.4.1	Individual	Relies on IEEE Std 1547-2018	**Recommendation 6:** A Circuit Stiffness Ratio (CSR) limit should be considered as a test to avoid PQ issues
Flicker – Pst <.3	3.4.1	Individual	Certification is sufficient unless exceptional case is identified	This is a recommended practice
Distortion – I_{TDD} <5%	3.4.1	Individual	Certification is sufficient unless exceptional case is identified	This is a recommended practice.
RVC – ΔV_{RMS} <3%	3.4.1	Individual	Limits transformer in-rush to a max voltage dip of 3%; this is conservative.	**Recommendation 7:** Increase the RVC limit to 10-12% for the peak V_{RMS} or use an average ΔV over 1-2 seconds.
Distribution Protection	3.4.1	Individual	Review criteria and rationale follow expected industry practices	**Recommendation 8:** Address exceptions in the 87.5% of interrupting rating in supplemental review criteria.

[13] *The Role of Automation in Distributed Energy Resources (DER) Interconnection*. EPRI, Palo Alto, CA: 2018. 10254237.

Technical Consideration & Criteria	NC E-100 Section	Review Type	Observations	Recommended Next Steps
Substation Available Capacity	3.4.1	Individual	Review criteria and rationale follow expected industry practices	None
Unintentional Islanding	3.4.1	Individual	Review criteria and rationale follow expected industry practices	None

Recommended Addition: Supplemental Review Power Quality, Stiffness Ratio Test (3.4.1)

A circuit stiffness ratio test may be a good indicator of issues, such as RVC, flicker, or harmonic interactions, when the DER point of connection is defined. The data needed to make this calculation – short circuit capacity at the PCC – is typically available from a load flow analysis conducted for voltage regulation. An x/r ratio adjustment may be considered for installations near the end of the feeder. For x/r ratios of less than 3-5, resistance is typically the main factor affecting power quality and likely a better indicator than the impedance.

Recommendation 6 – Supplemental Review criteria for power quality may be more effective if a stiffness ratio calculation at the PCC is included with the limits currently used. In cases where a stiffness ratio (already defined in Duke's Method of Service) is less than 25, additional power quality evaluation may be warranted in Supplemental Review.

Recommended Modification: Supplemental Review Power Quality, Rapid Voltage Change (3.4.1)

Updated power quality limits specific to DER interconnections are provided in IEEE Std 1547-2018. These are intended to supersede previous IEEE recommended practices that were directed at end-use equipment and/or generators. The two standards referenced in IEEE Std 1547-2018 that convey power quality limits are IEEE 519 (for harmonics) and IEEE 1453 (for fluctuations).

Several other power quality requirements added in the 2018 update of IEEE Std 1547 include specific limits for DER-caused overvoltages, called load rejection overvoltage (LRO) and rapid voltage change (RVC). Both are important additions addressing power quality events that can be related to DER and are considered improvements to previous IEEE Std 1547 power quality limits stipulated in 2003 and 2014. Other power quality standards in IEC and IEEE address measurement and acceptable limits. However, appropriate limits for transient analysis, prediction, and mitigation with DER are still evolving.

LRO has been a very localized issue for inverters in that worst case is seen when there is nothing else connected, hence the name Load Rejection Overvoltage. LRO is not an issue until disconnection and is most often recorded during DER commissioning disconnection tests. The event is a characteristic or malfunction of the inverter control and can be mitigated at the inverter. In the future, LRO, along with dc injection and harmonic current distortion in an inverter's output, are expected to be adequately addressed as part of certification tests.

Note that type tests for harmonics performed while connected to the factory or test lab power system will not completely determine harmonic currents when interconnected to any specific system. This is because the source (voltage-source inverter or rotating generator) is a harmonic voltage source behind an impedance, and the harmonic current when interconnected is determined by that source voltage magnitude divided by the total circuit impedance. In the field tests, the circuit impedance includes the Area EPS impedance.

RVC is a relatively new name for a power quality measurement related to classic transients in power systems.[14] Note that switching surges in power systems are not RVCs and refer to the super-synchronous system oscillations caused by switching (e.g., "ring wave"). In contrast, RVC pertains to the RMS or fundamental-frequency voltage change. It is related to sudden changes in voltage that may occur with large fluctuating changes in generation. Moving clouds with PV would not constitute an RVC event. The most common output variation causing an RVC would be tripping due to grid events or load events such as motor starting, switching of a capacitor bank, or transformer inrush when energized.

Power quality standards that have defined RVC include IEC,[15] IEEE Std 1547-2018 and IEEE 1453.[16] The IEC standard defines the characteristics including duration, ΔV_{MAX}, and $\Delta V_{STEADYSTATE}$ of an RVC event, but does not offer a limit. IEEE 1547 indicates a DER limit of 3% ΔV on medium voltage but is unclear about maximum, average, or steady state change. It states, "step or ramp changes in the RMS voltage at the PCC exceeding 3% of nominal and exceeding 3% per second averaged over a period of one second." Events in IEEE 1547 may include transformer inrush and should be infrequent.

The current draft of IEEE 1453 clarifies both the frequency and the limits specifically for infrequent RVC from DER. A table is provided indicating a ΔV limit of 5-6% if occurring less than four time per day. It references IEEE Std 1547 and notes the 5-6% limit should not be applied for infrequent transformer energization events due to commissioning, fault restoration, or maintenance typically not planned for more than once per year. The limits recommended for transformer inrush are ΔV_{MAX} of 12% for up to 4 cycles and 10% for the remainder of 1 second.

RVC is not tested during DER certification because it depends substantially on the utility point of connection. Further, plant inrush depends on the step-up transformers at the site and any related switching upstream of the transformer. Aggregation of inrush RVC may be considered in the case of multiple transformers at a plant site.

Applied to DER, RVC is intended for individual plants, not for aggregate DER on a feeder. The idea is that aggregate or simultaneous changes are expected in cases of utility system events, such as a system fault or switching events. Application guidance is described in IEEE Std 1547-2018, Section 7 and in informative appendix G.

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[14] A Greenwood, "Electric Transients in Power System." New York: John Wiley and Sons, Inc. 1971.

[15] Electromagnetic Compatibility (EMC) – Part 4-30: Testing and measurement techniques. Power quality measurement methods, IEC 61000-4-30, Ed. 3, 2015.

[16] P1453™/D2, Draft Voltage Fluctuations\Flicker Standard for the Analysis of Fluctuating Power Installations on Power Systems, September 2019.

Recommendation 7 – Change the RVC peak limit criteria from 3% ΔV currently used in Duke's Supplemental Review, to 10-12% during the first few cycles, and not to exceed an average of 3% ΔV over a 1-second moving window during the simulated event. Consider that a stiffness ratio of not less than 25 may be an adequate safety margin for the effects of DER transformer inrush.

Recommended Clarification: Distribution Protection Supplemental Review, Interrupting Capacity (3.4.1)

The 87.5% of the rated fault interrupting limit is a common and accepted practice. Exceeding 87.5% fails the initial review screen 3.2.1.6. In some cases, existing fault current interrupting limits may be at or above 87.5% in locations where additional DER are proposed; this becomes a limiting factor to passing initial screening.

Duke currently screens for fault current exceeding 87.5% of any device rating. Applications that fail this screen can be further considered during a Supplemental Review. Depending on the circumstances, an application may be allowed to connect, by exception, and up to 95% of clearing capacity after Supplemental Review.

Recommendation 8 – Document the existing Fast Track screen and the Supplemental Review processes and any possible exceptions relative to fault clearing practices described above.

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Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com