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1 DEC and DEP obligations
DEC and DEP (Companies) comply with their interconnection obligations under PURPA\(^1\) and applicable state laws by adhering to the North Carolina Interconnection Procedures approved by the North Carolina Utilities Commission (effective May 15, 2015, Docket No. E-100, Sub 101, the “NCIP”)) and the South Carolina Generator Interconnection Procedures approved by the South Carolina Public Service Commission (effective April 24, 2016, Case No. 2015-362-E, the “SCGIP”). Consistent with those standards and procedures, the Companies determine and apply technical interconnection guidelines through the administration of Good Utility Practice.\(^2\)

DEC and DEP consider all necessary system upgrades to the general electrical system that are required in order to provide distributed energy resources (DER) reasonable and non-discriminatory access to the DEC and DEP distribution systems, the primary purpose of which is to serve existing and future retail customers. As firm retail electric providers, DEC and DEP seek to interconnect DER in a manner that allows each resource to operate within its contractual parameters without negatively impacting existing utility customers’ quality of service or cost of service. DEC and DEP are not, however, obligated under the NCIP or SCGIP to make modifications that are, or reasonably could be determined to be, detrimental to the operation of its system or detrimental to DEC’s and DEP’s public service obligations as regulated public utilities or retail electric service providers.

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\(^2\) Good Utility Practice is defined in the NCIP and SCGIP as any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.
2 Interconnection to the transmission system or distribution system

2.1 Interconnection method as dictated by DER capacity

2.1.1 Consideration of individual DER capacity

In most cases, the electrical size (in MW) of a generator interconnection is the primary consideration, all factors considered, as to whether it makes sense to interconnect to the distribution system or to the transmission system. This section’s guidelines are intended to more quickly guide interconnection projects to the proper method of interconnection and system at which to interconnect, based on a consideration of the factors involved: (1) impacts to transmission & distribution system reliability/power quality, (2) operational ease and flexibility for the utility, and (3) overall cost (in general, project developers bear all or most up-front costs). Exceptions can be made, but only when a specific project’s characteristics and impacts do not fit well into these guidelines, and the optimal balance of factors are the primary consideration.

Table 1 provides general guidance as to the proper method of interconnection.
### TABLE 1: Interconnection method based on size of facility

<table>
<thead>
<tr>
<th>Interconnection method</th>
<th>Interconnection facility (MW) (lower limit)</th>
<th>Interconnection facility (MW) (higher limit)</th>
<th>Guideline for system/interconnection point</th>
</tr>
</thead>
<tbody>
<tr>
<td>T³</td>
<td>&gt; 20 MW</td>
<td>--</td>
<td>transmission system</td>
</tr>
<tr>
<td>S</td>
<td>&gt; 10 MW (25 kV or 35 kV class)</td>
<td>≤ 20 MW</td>
<td>direct connection to a retail substation⁴</td>
</tr>
<tr>
<td></td>
<td>&gt; 6 MW (15 kV class)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>&gt; 3 MW (where local retail distribution substation is served from 44 kV sub-transmission)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>D</td>
<td>--</td>
<td>≤ 10 MW (25 kV or 35 kV class)</td>
<td>general distribution circuit</td>
</tr>
<tr>
<td></td>
<td></td>
<td>≤ 6 MW (15 kV class)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>≤ 3 MW (where local retail distribution substation is served from 44 kV sub-transmission)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>≤ 2 MW (5 kV class)⁵</td>
<td></td>
</tr>
</tbody>
</table>

³ Method “T” interconnections are specifically guided by DEC’s or DEP’s appropriate FCR (Facility Connection Requirements) documents, which are accessible at DEC’s and DEP’s OASIS sites (oasis.oati.com/duk/ and oasis.oati.com/cpl/).

⁴ In general, due to the existence of legacy terminology across operating areas, a “retail substation” is the term used within DEC to describe a substation which serves general retail distribution loads from circuits connected to the substation’s distribution bus. In this document, the term “retail substation” will be used to describe this type of substation, which in DEP is often called a “T/D” or “T to D” substation.

⁵ Interconnections at 5 kV, above 2 MW, are not permitted. Such facilities must interconnect at a higher voltage class.
2.1.2 Consideration of aggregate utility-scale DER capacity (per distribution circuit and per retail substation)

Aggregate capacity of distribution-connected utility-scale projects, per distribution circuit, shall not exceed the planning capacity of that circuit. Aggregate capacity of distribution-connected utility-scale projects, per retail substation, shall not exceed the capacity of that substation, as defined by the (1) nameplate capacity of the substation transformer bank or (2) the capacity of other substation components, whichever is less.

Calculation of aggregate capacity of DER on a substation or a circuit shall not include the types of facilities shown in Table 2, nor shall interconnection of the following facilities be subject to aggregate capacity limitations on the circuit or substation.

This requirements may change in the future as DER planning guidelines further mature.

TABLE 2: DERs exempt from aggregate capacity limitations on the circuit or substation

| Exemption #1 | Net Metered | Up to 1 MW | The aggregate DER capacity for the first regulated zone of the circuit (substation bus regulation or circuit exit regulation) is limited to the circuit planning capacity or other lesser value as determined in the Supplemental Review or System Impact Study. |
| Exemption #2 | Sell Excess | Up to 1 MW | The aggregate DER capacity for further regulated zones (beyond any LVRs) is limited to that which does not cause backfeed of the line voltage regulator. |
| Exemption #3 | PPA with co-located load on secondary of transformer | Up to 1 MW | |
| Exemption #4 | PPA, stand-alone | Up to 250 kW | |

6 For the purposes of these requirements, utility-scale projects are defined as utility-scale/sell-all DER which do not meet the “exempt” definitions in Table 2.
7 For the purposes of this document, “nameplate capacity” refers to the “OA” or “ONAN” rating, typically the MVA rating upon which the transformer percent impedance is based.
8 If a single-phase DER facility > 20 kW causes unacceptable imbalance on any portion of the distribution circuit, the interconnection may be deemed infeasible for a single-phase interconnection and may be required to alter its design to three phase.
9 Note that for South Carolina, there are reserved circuit capacities for individual DER ≤ 20 kW, detailed in section 2.1 of the South Carolina Interconnection Standards (effective 4/26/2016). Such DER will be also deemed exempt from all considerations, including backfeed of an existing LVR, and the cost of any associated studies or upgrades for DER included as part of these reserved circuit capacities are the responsibility of DEC and DEP.
10 DEC and DEP will employ reasonable methods, as determined by internal engineering resources responsible for performing interconnection studies, and subject to change, to identify the high-level potential for backfeed at the time of the interconnection request under review. When such a potential is suspected, a Supplemental Review or System Impact Study shall be performed in order to determine if backfeed may occur under any circuit loading conditions.
11 When backfeed is identified in the Supplemental Review or System Impact Study, for exempt sites as identified in this table, DEC/DEP Distribution management and DET (Distributed Energy Technologies) management shall be made aware and shall confer and decide as to the proper disposition of the project(s) in question.
12 “PPA” facilities ≥ 250 kW are considered the low end of “utility-scale” facilities, and, for purposes of these guidelines, present the potential for significant impact on a distribution circuit.
13 IEEE 1547-2003, section 4.1.6, requires DER ≥ 250 kVA at a single PCC (Point of Common Coupling) to have monitoring provisions for its status, real and reactive power flow and voltage. Duke Energy requires such
2.2 Interconnection to a general distribution circuit: method “D”

This size of interconnection as indicated in Table 1 should generally be accommodated onto the general distribution system, at the most logical interconnection point consistent with optimizing the factors of reliability, operational ease and flexibility for the utility, and overall cost, and subject to other considerations in this document related to distribution interconnections.

2.2.1 Considerations & alternatives

2.2.1.1 System upgrades: Distribution and retail substation

The System Impact Study (SIS) shall identify and detail the electric system impacts that would result if the proposed generating facility were interconnected without project modifications or electric system modifications. The SIS shall evaluate the impact of the proposed interconnection on the reliability of the electric system, including the distribution and transmission systems, if required. The SIS shall include identification of system upgrades required to correct any system problems identified.

When performing a SIS for a method “D” interconnection, DEC or DEP, as applicable, will consider (among other mitigation options) necessary upgrades to existing retail substation facilities, upgraded to their maximum standard design criteria.

For method “D” interconnections, any extension of distribution facilities to connect DER facilities cannot be “dedicated” by their nature and must be constructed consistent with the DEC or DEP Line Extension Plan and with other practices consistent with DEC or DEP standard distribution system design. The interconnection recloser and meter must both be located at the POI (at the point of change in ownership of facilities).

Interconnection Customers can consider constructing their own lines; such lines would be completely owned, operated and maintained by the Interconnection Customer. The POI would remain at the point of change in ownership of facilities.

2.2.1.2 Alternatives when facilities cannot be further upgraded

If local distribution facilities and/or retail substation facilities cannot be sufficiently further upgraded in order to accommodate the proposed generating facility, then the remaining alternative for the Interconnection Customer is:

1. New retail substation (along with necessary transmission facilities to serve the substation) and general distribution facilities, constructed by Duke Energy, to serve the requested point of interconnection. This can only be considered if this would be consistent with area planning needs and any other specific constraints associated with local transmission and distribution infrastructure (which cannot be pre-determined). Distribution lines can also be designed and constructed by the Interconnection Customer, at their option.

monitoring per this capacity criteria, as this size of DER facility is consistent with more noticeable impacts to distribution planning and operations in both DEC and DEP.
2.3 Interconnection: direct connection to a retail substation: method “S”

2.3.1 Limiting impacts to the transmission system

It should be noted that DEC/DEP maintains the right to limit the total number of taps on a transmission line when DEC/DEP has determined they may grow to be too great in number for that transmission line. In such a case, DEC/DEP may propose alterations to the local area transmission infrastructure in order to get back to a higher reliability arrangement, whatever that may be. The options available for facilities within this size range will be highly impacted by the specific transmission & distribution facilities in the area.

These considerations are guidelines; DEC and DEP maintain full discretion as to the ultimate method of interconnection.

2.3.2 Considerations & alternatives

There are three primary methods for interconnections within this category: (1) connection to an existing nearby retail substation, (2) connection to an existing nearby retail substation along with an additional transformer installation, or (3) construction of a new general retail substation:

(1) Connection to an unregulated bus at an existing nearby retail substation, utilizing a DER-dedicated distribution circuit and associated dedicated circuit breaker. This would involve substation modifications, and may not always be available if (a) there are no available breaker positions, (b) if some breaker positions are in place for area load growth, or (c) where substation rebuild options do not include the establishment of an accessible unregulated bus. The assessment of the feasibility of this overall method and its options are at the discretion of transmission planning, substation engineering, and/or distribution planning. If this method is not deemed feasible, then the remaining two options below can be considered.

(2) Connection to a new unregulated bus established with an additional substation transformer at an existing substation, utilizing a DER-dedicated distribution circuit and associated dedicated circuit breaker. (Note: such an expansion shall be built to normal general retail substation standards, only where a second transformer and distribution voltage shall match that of the local operating voltage of the surrounding circuits so that the substation transformer could remain possibly available for general distribution load currently or in the future if the DER facility were to shut down. Essentially this should be treated like a normal substation expansion with an additional transformer, assuming such expansion can be feasibly done.)

(3) Connection to a new unregulated bus established at a new retail substation, utilizing a DER-dedicated distribution circuit and associated dedicated circuit breaker. (Note: such a substation shall be built to normal general retail substation standards, and distribution voltage shall match that of the local operating voltage of the surrounding circuits so that the substation transformer could remain possibly available for general distribution load currently or in the future if the DER facility were to shut down.) In such a situation, note that transmission system reliability considerations may require alterations or reconfigurations to the local transmission system infrastructure, at the generator’s cost, in order to maintain overall system reliability.
2.3.3 Special notes

(1) For method “S” interconnections, extension of distribution voltage class lines from the POI back to substation facilities shall be dedicated by nature, meaning that they are only in place to serve one or more DER interconnections. While Duke Energy can offer to construct such dedicated lines, the Interconnection Customer can also elect to construct a portion or all of the line required.

(2) Note that any DER-dedicated Duke-owned distribution circuit would be likely limited in capacity to no more than 600 amps, and possibly less, due to prevailing available construction methods on general distribution. This could limit 15 kV class interconnection capacity to ~13 MW or less, and could present unique challenges in connecting facilities in the approximate range of 13 MW to 20 MW when substation designs must utilize 15 kV class due to the prevailing distribution voltages in the area.

(3) DER-dedicated circuits constructed and owned by Duke Energy and installed for generation may be built to slightly different standards than conventional “greenfield new general distribution circuits,” if their design allows more capacity by slight changes such as increased pole height (with associated increased phase to neutral spacing) and/or reduced span lengths. In no case should the circuit design parameters exceed the ability for Duke Energy distribution field crews to maintain the line. This means that pole height, conductor size, etc., must be maintained within expected usual maximums for distribution field crews to be able to provide effective maintenance services.

(4) At the discretion of transmission and/or distribution planning, an interconnection directly to an unregulated bus can be required to be set at (a) fixed power factor, at unity or off of unity, or (b) active voltage regulation.
2.4 **Interconnection to the transmission system: method “T”**

Note: method “T” interconnections are specifically guided by DEC’s or DEP’s appropriate FCR (Facility Connection Requirements) documents, which are accessible at DEC’s and DEP’s OASIS sites ([oasis.oati.com/duk/](http://oasis.oati.com/duk/) and [oasis.oati.com/cpl/](http://oasis.oati.com/cpl/)).
3 Other interconnection project study and design guidelines

3.1 Applicability of double circuits for DER

In general, construction of full or partial “double circuits” (multiple three-phase circuits on one set of poles in a single right of way (ROW)) for line extension to a DER site is not considered Good Utility Practice, whether the consideration is the location of line voltage regulators (LVRs) or some other factor. The inherent ROW present for a second circuit in an existing single-circuit line is a key part of DEC’s and DEP’s area planning approach for the transmission & distribution system, as part of the Companies’ continuous obligation to serve current and future retail customers. Any double-circuiting of an existing single-circuit line must be installed only as part of a comprehensive long-term plan to serve area load. Such double-circuiting cannot be installed solely as a DER interconnection solution, as doing so would impair DEC’s and DEP’s area planning obligations.
3.2 Interconnection locations beyond line voltage regulators (LVRs)
DEC and DEP have identified that interconnection of uncontrolled\textsuperscript{14} utility-scale\textsuperscript{15} generation resources with no dependable capacity,\textsuperscript{16} at locations beyond LVRs and in high quantities across an entire system, is not consistent with Good Utility Practice. At high quantities across an entire system, facilities with the aforementioned attributes are more naturally adapted to the first zone of regulation outside the substation. Interconnection of such facilities beyond LVRs will likely require non-standard LVR settings, which can (1) limit the switching flexibility of the distribution system, (2) inhibit the effective management of circuits in certain operating areas if regulator control technologies for backfeed are not yet an accepted and tested practice, and/or (3) negatively impact the measured effectiveness of some volt/var control systems such as DEP’s DSDR\textsuperscript{17} system. Alternatively, interconnection of such facilities beyond LVRs will likely require operation of generating facilities in a reactive power absorption mode, which is not compatible with some volt/var optimization systems and would require further consideration for the impacts to the transmission system if done at wide scale. Therefore, DEC and DEP have established technical guidelines that restrict location of uncontrolled utility-scale generation with no dependable capacity, as referenced and defined above, to the first regulated zone of distribution circuits (substation bus regulation or circuit exit regulation).

3.2.1 DEC and DEP: “Planned” LVR locations previously identified
In some cases, a DEC or DEP Distribution Capacity Planning five-year load-growth study may have already been performed and completed (without having yet been field implemented) prior to the date the Interconnection Customer executes the SIS Agreement to initiate the SIS. In such cases, if such Capacity Planning study had identified changes in LVR placement on the circuit, the planned LVR placement(s) for the circuit (rather than what is currently installed) will be included as part of the SIS. Interconnection locations beyond such planned LVRs will be considered equivalent to interconnection locations beyond existing LVRs. Upon request, DEC or DEP will provide a load-growth study summary with the recommended planned LVR location to the DER interconnection customer.

If no such planning study recommendation pre-dates the initiation of the SIS, and there are no LVR placement changes identified as part of DSDR continuous system maintenance (DEP only, see below), the SIS will only consider the location of any existing LVRs as part of the project study.

\textsuperscript{14} “Uncontrolled” means that the facility output (MW) is not capable of being dispatched in a throttled manner by the grid operator.

\textsuperscript{15} For the purposes of this document, “utility-scale” generally refers to stand-alone generation facilities (not directly co-located with load) 250 kW or larger.

\textsuperscript{16} “No dependable capacity” means that the facility cannot be relied upon for production of a value of capacity (MW) for a specified period or when dispatched.

\textsuperscript{17} Distribution System Demand Response.
3.2.2 **DEP only: continuous system maintenance of DSDR circuit voltage criteria**

The DSDR system in DEP requires adherence to specific circuit voltage criteria in order to maintain system performance. The condition of the circuit and its ability to meet the needed voltage criteria is reviewed as part of the Companies’ distribution planning function, whether it is for a regular capacity planning study, for addition of a large “spot load” (commercial or industrial customer), or any other reason to study a circuit.

If during the SIS (the scope of which considers voltage levels on the entire circuit) there is a need identified for LVR placement changes in order to maintain DSDR system performance, the SIS shall include such LVR placement changes and associated cost responsibility in its scope. The cost of such LVR placement changes will only be cost assigned to the interconnection customer if the interconnection creates the need for the LVR placement changes.

Any LVR placement change(s) identified for the circuit (rather than what is currently installed) will be included as part of the assumed “current condition of the circuit” when the SIS if performed. Interconnection locations beyond the LVRs identified pursuant to this subsection will be considered equivalent to interconnection locations beyond existing LVRs, and the study will treat the identified LVR as an existing LVR under these guidelines. Upon request, DEP will provide a study summary with the required LVR placement changes to the DER interconnection customer.

3.2.3 **Smart Inverter functionality**

It is important to note that at this time DEC and DEP do not assume that generating facilities are capable of modification(s) to their operating characteristics (e.g., “smart inverter functions” such as volt-watt functions, voltage regulation functions, etc.). These modified operating characteristics are under consideration for future adoption by DEC and DEP, but are still considered technologies not yet fully embraced by industry standards and not yet as widely accepted Good Utility Practice. Moreover, use of these functions involves many other considerations, such as impacts to energy production (which in turn has contractual impacts), additional protection & control requirements, utility-to-customer control interface requirements, etc.

3.2.4 **Clarifications on “partial double circuits”**

When considering the restriction of connection of certain generating facilities below LVRs, it may appear that construction of a “partial double circuit” from the generation site back up to a location ahead of the LVR would facilitate the interconnection. However, as discussed above, the inherent ROW present for a second circuit in an existing single-circuit line is a key part of DEC’s and DEP’s area planning approach for their transmission & distribution systems, as part of the Companies’ continuous obligation to serve current and future retail customers. Any double-circuiting of such a line can only occur as part of a comprehensive plan to serve area load, and cannot be installed solely an incremental consideration for an interconnection project.
3.2.5 Certain DERs exempt

It is important to note that certain DER sites are exempt from restriction to the first regulated zone of distribution circuits, and are therefore allowed to locate beyond LVRs:

<table>
<thead>
<tr>
<th>Exemption #1</th>
<th>Tariff</th>
<th>Individual DER capacity</th>
<th>Aggregate DER capacity per circuit, segment or regulated zone</th>
</tr>
</thead>
<tbody>
<tr>
<td>Exemption #2</td>
<td>Sell Excess</td>
<td>Up to 1 MW</td>
<td>The aggregate DER capacity for the first regulated zone of the circuit (substation bus regulation or circuit exit regulation) is limited to the circuit planning capacity or other lesser value as determined in the Supplemental Review or System Impact Study.</td>
</tr>
<tr>
<td>Exemption #3</td>
<td>PPA with co-located load on secondary of transformer</td>
<td>Up to 1 MW</td>
<td>The aggregate DER capacity for further regulated zones (beyond any LVRs) is limited to that which does not cause backfeed of the line voltage regulator.</td>
</tr>
</tbody>
</table>

| Exemption #4 | PPA, stand-alone | Up to 250 kW | |

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18. If a single-phase DER facility > 20 kW causes unacceptable imbalance on any portion of the distribution circuit, the interconnection may be deemed infeasible for a single-phase interconnection and may be required to alter its design to three phase.

19. Note that for South Carolina, there are reserved circuit capacities for individual DER ≤ 20 kW, detailed in section 2.1 of the South Carolina Interconnection Standards (effective 4/26/2016). Such DER will be also deemed exempt from all considerations, including backfeed of an existing LVR, and the cost of any associated studies or upgrades for DER included as part of these reserved circuit capacities are the responsibility of DEC and DEP.

20. DEC and DEP will employ reasonable methods, as determined by internal engineering resources responsible for performing interconnection studies, and subject to change, to identify the high-level potential for backfeed at the time of the interconnection request under review. When such a potential is suspected, a Supplemental Review or System Impact Study shall be performed in order to determine if backfeed may occur under any circuit loading conditions.

21. When backfeed is identified in the Supplemental Review or System Impact Study, for exempt sites as identified in this table, DEC/DEP Distribution management and DET (Distributed Energy Technologies) management shall be made aware and shall confer and decide as to the proper disposition of the project(s) in question.

22. “PPA” facilities ≥ 250 kW are considered the low end of “utility-scale” facilities, and, for purposes of these guidelines, present the potential for significant impact on a distribution circuit.

23. IEEE 1547-2003, section 4.1.6, requires DER ≥ 250 kVA at a single PCC (Point of Common Coupling) to have monitoring provisions for its status, real and reactive power flow, and voltage. Duke Energy requires such monitoring per this capacity criteria, as this size of DER facility is consistent with more noticeable impacts to distribution planning and operations in both DEC and DEP.
3.3 Line extensions on new ROW
In situations where a line extension is necessary, such as when a DER is located beyond an existing LVR, or is simply located far from existing facilities, DEC or DEP will propose construction of a line extension to connect the site to the circuit at the most logical point on the circuit considering reliability, voltage, capacity, operational considerations, and cost, consistent with Good Utility Practice. DEC or DEP will be responsible for design and construction of the non-dedicated (method “D”) or DER-dedicated (method “S”) line. The POI will be at the point of change in facilities ownership (at the generator site). DEC or DEP must initially attempt acquisition of ROW. In the event DEC or DEP are unable to acquire ROW during the Facilities Study design process, DEC or DEP will advise the DER owner to assume the obligation for ROW acquisition. Any such ROW shall comply with applicable DEC and DEP ROW specifications.

3.3.1 Distribution line construction and ownership by private entities
If the DER owner requests to build, own, and maintain the line from the circuit tap (as decided by DEC or DEP) to the DER, DEC or DEP will allow the DER owner to pursue this option. In such a situation, the POI will be at the point of change in facilities ownership, at the circuit tap. The DER owner is required to always build all medium voltage (MV) facilities (> 600 volts AC) with DEC/DEP construction and ROW specifications used as the minimum design standard, and all DER owner-constructed-and-owned MV facilities will be inspected by DEC/DEP or its authorized inspection contractor.

24 If an LVR location is the consideration, the circuit “tap” will be ahead of the LVR location, along with all of the other considerations stated.
3.4 Circuit Stiffness Review (CSR) screen & evaluation

As part of the interconnection process, the SIS is designed to analyze the impact of interconnecting the proposed facility on electric system reliability and the potential for negative impacts to other customers on the system. Effective for all distribution system interconnection requests (except for those noted in the “exemptions” section), Duke Energy will identify (1) areas of high penetration/low grid stiffness through a stiffness factor evaluation, in order to assure that the location of future interconnections do not detrimentally impact power quality and grid operations.

The stiffness factor takes into account the actual equivalent system impedance at the point of interconnection and the relative size of the generation source. It is intended to be an indicator of the potential impacts an individual project may have on the system voltage variability, harmonics impacts, and other related items at its point of interconnection in light of the strength or weakness of the system at that point. A small ratio indicates that the project individually represents a relatively large share of the total short circuit capability at the project site and, by inference, may have an outsized influence at that location across a number of factors. A low stiffness factor will also accentuate local impacts and can cause inverters to be sensitive to normal distribution system operations, such as capacitor bank operations.

The stiffness factor criterion also helps to evaluate the potential for unknowns that may occur in “high penetration” scenarios of utility-scale facilities on the localized distribution system. As of mid-2016, industry technical standards have not yet been developed for high penetration of large distributed generators and North Carolina is seemingly unique in the level of large utility-scale interconnections (especially at 5 MW) interconnecting to the rural distribution system. Such facilities are not necessarily designed for high penetration/low stiffness interconnections, especially when such facilities cannot yet be expected to operate in a voltage regulating mode. At this time, failure of the CSR evaluation screen is simply designed to trigger a slightly more rigorous study into two types of harmonics: steady-state harmonics and the transient impacts of transformer energization (when the DER facility connects back to the circuit after any time it has been disconnected). This is known informally as “Advanced Study” and is part of the overall SIS (System Impact Study) process.

25 Stiffness factor, also known as “stiffness ratio,” is defined in IEEE Std 1547.2™-2008, IEEE Application Guide for IEEE Std 1547, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems: “The relative strength of the area EPS at the PCC compared with the DR, expressed in terms of the short-circuit kilovolt-amperes of the two systems. The general term “stiffness” refers to the ability of an area EPS to resist voltage deviations caused by DR or loading.”

26 Integrated volt/var control systems are not yet compatible with DER operation in a voltage regulating mode. Also, industry practices involving DER operation in a voltage regulating mode, on the distribution system, are clearly not mature at this time. The current IEEE 1547 standard generally prohibits such practice.
### 3.4.1 Exempted projects

In general, the following situations are to be exempted from the stiffness evaluation:

<table>
<thead>
<tr>
<th>Exemption #1</th>
<th>Exemption #2</th>
<th>Exemption #3</th>
<th>Exemption #4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Metered</td>
<td>Sell Excess</td>
<td>PPA with co-located load on secondary of transformer</td>
<td>PPA</td>
</tr>
<tr>
<td>Up to 1 MW</td>
<td>Up to 1 MW</td>
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### 3.4.2 Evaluation criteria & methodology

Proposed generator interconnection requests will be reviewed at the outset of the Section 4.3 SIS process to determine whether the project can (1) achieve a minimum POI “stiffness factor” of 25 (as further described below) and (2) achieve a minimum substation “stiffness factor” of 25 (as further described below), in order to pass this screen.

This stiffness evaluation will be performed at two locations – at the POI and at the substation.

#### 3.4.2.1 POI Stiffness Evaluation

At the POI, this evaluation will be performed. A POI Stiffness Factor of exactly 25 or greater (no rounding) for the individual site will be considered as a “pass” for this screen.

\[
SF_{POI} = \frac{\sqrt{3} \times 12.47 \times 6500}{1000} = 28.08
\]

EXAMPLE: A 5 MW DER requests to interconnect on a 12.47 kV feeder. The available fault current at the planned POI, at 12.47 kV, is 6,500 amps. The POI Stiffness Factor is:

\[
SF_{POI} = 28.08 > 25, \text{ so this would pass the “POI” portion of the CSR screen.}
\]

NOTE: POI Stiffness shall be calculated at the POI (high-voltage side of transformer) for utility-scale DER with a single transformer dedicated to the facility.

---

27 The impacts of switching large blocks of transformer capacity onto the utility system are more of an issue when interconnection reclosers are present, which is generally for DERs ≥ 1 MW. Since this is the primary issue of concern studied when the CSR evaluation indicates lower stiffness, CSR does not have to be evaluated for DERs < 1 MW.

28 The value of the DER capacity shall be the Requested Maximum Physical Export Capability at the POI.

29 Note that the exact nominal distribution voltage should be used in the calculation of utility short-circuit MVA.
3.4.2.2 Substation bus Stiffness Evaluation

In addition, a separate evaluation will be performed at the substation bus with respect to all utility-scale DER connected to the substation, including the proposed DER. A substation bus stiffness factor of exactly 25 or greater (no rounding) will be considered as a “pass” for this screen.

Substation Stiffness Factor = \( \frac{\text{Short circuit availability at substation bus (MVA) without any DER contribution}}{\text{Total facility maximum export, connected beyond substation (MW)}} \)

EXAMPLE: A 5 MW DER wants to interconnect on a 12.47 kV feeder. There is already 2 MW of utility-scale DER off of this substation. The available fault current at the substation bus, at 12.47 kV and without contribution from DER, is 8,000 amps. The Substation Stiffness Factor is:

\[
SF_{\text{Substation}} = \frac{\sqrt{3} \times 12.47 \times 8000}{7} = 24.68
\]

24.68 < 25, so this would not pass the “Substation” portion of the CSR screen.

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30 The value of the total DER capacity beyond the substation shall be the sum of the Requested Maximum Physical Export Capability for all non-exempt DER sites.
4 Glossary of terms

**Non-dedicated distribution line or circuit:** This is a distribution circuit which is designed to serve any common class of distribution customer: residential, commercial, industrial and DER. Such a circuit must be designed to +/- 5% voltage so as to assure that existing or future residential customers are assured of proper voltage levels.

**DER-dedicated distribution line/circuit:** In the context of this document, this refers to a distribution voltage class circuit that is built strictly for DER facilities; no other class of customer is to be located on this circuit. Such a circuit is allowed to be designed to +/- 10% voltage and can be used for DER interconnections only. Due to the unique nature of DER and the flows on this line, this line shall NOT be used for commercial or industrial customers (who normally might be tolerant of +/- 10% voltage).
## 5 Revision history

<table>
<thead>
<tr>
<th>Revision</th>
<th>Date</th>
<th>Comments</th>
</tr>
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<tbody>
<tr>
<td>1.0</td>
<td>9/11/2017</td>
<td>Initial release</td>
</tr>
</tbody>
</table>
| 1.1      | 9/20/2017  | (a) Clarified that “S” interconnection is inclusive of 20 MW; “T” interconnection is for > 20 MW.  
            |            | (b) Changed Table 4 to indicate that sites are exempt from CSR evaluation below 1 MW.                                                  |
|          |            | (c) Changed header title to read “DEC & DEP: Distributed Energy Resource (DER) Planning & Interconnection guidelines for DER no larger than 20 MW.” |
            |            | Also, “MVA” changed to “MW” in Table 1, as this is mostly a distribution system document, and this MW value is the value that corresponds to the Maximum Physical Export Capability Requested in the Interconnection Request. |
| 1.21     | 11/01/2017 | Clerical and grammatical errors addressed.                                                                                               |