EXPLORING THE FUTURE OF HOSTING CAPACITY ANALYSIS AT XCEL ENERGY

2020 HCA Workshop 6

Use Cases 2, 3, 4 – Integrate the HCA with various interconnection steps

September 15, 2020
Workshop Goals

• Get your feedback, input, and perspective
• Work toward increasing the efficiency and value of the HCA tools
• Shape the HCA roadmap for further integration with the Minnesota DER Interconnection Process (MN DIP)
• Get your feedback, input, and perspective!
AGENDA

Introductions

Recap Workshops to-date

Discuss current state and future features for remaining potential integration improvements:

• Use Case 2) Integrate with MN DIP – Pre-Application Data Report

• Use Case 3) Integrate with MN DIP – Replace or Augment Initial or Supplemental Screens

• Use Case 4) Integrate with MN DIP – Automate Interconnection Process
Introductions
Quick roundup of participants

Name
Organization
Role & priorities regarding these tools
2020 HCA Workshop Recap

June 2 – Synergi & DRIVE capabilities, demonstration and Xcel Energy HCA analysis process

June 16 – HCA Criteria, Inputs and Thresholds

June 30 – HCA Criteria, Inputs and Thresholds

September 2 – Series start for potential future HCA uses

September 10 – Examine Use Case 1: HCA remaining an early indicator for the interconnection process

September 15 – Examine Use Cases 2-4: Integration of the HCA with various MN DIP steps and processes
POLL – SERIES 1

1) What is your interest in the HCA/interconnection integration topic?
   - Solar developer – engineer
   - Solar developer – business operations
   - Solar developer – owner
   - Interested party – environmental advocate
   - Interested party – solar industry
   - Interested party – academic
   - Interested party – regulatory oversight
   - Other

2) What is your main reason for attending today?
   - Listen
   - Learn
   - Generate ideas
   - Provide feedback on existing processes
PRE-APPLICATION REPORTS
HCA in Relation to MN DIP

Tools for identifying location:
- Hosting capacity map
- Substation DG queue

Interconnection application activities:
- Pre-application data process
- Application screening process
- Engineering study process

Cost/complexity/time
Level of information/accuracy
Simplified View of MN DIP Process

* Inverter-based projects less than 20 kW will follow the MN DIP Simplified process, the first step of which is also an Initial Screen.
Current State – Pre-Application Report Example

Xcel Energy has identified the substation/area bus, bank or circuit likely to serve the proposed Point of Common Coupling (PCC). This selection by Xcel Energy does not necessarily indicate, after application of the screens and/or study, that this would be the circuit the project ultimately connects to.

Pre-Application Reports will only include pre-existing data and do not obligate Xcel Energy to conduct a study or other analysis of the proposed DER in the event that data is not available. If Xcel Energy cannot complete all or some of a Pre-Application Report due to lack of available data, Xcel Energy will provide the Interconnection Customer with a Pre-Application Report that includes the data that is available.

The provision of information on “Available Capacity” does not imply that an interconnection up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process. The distribution system is dynamic and subject to change and data provided in the Pre-Application Report may become outdated at the time of submission of the complete Interconnection Application. Xcel Energy will, in good faith, include data in the Pre-Application Report that represents the best available information at the time of reporting.
**Current State – Pre-Application Report Process**

**MNDIP**
- Online Application portal
- $300 e-pay
- 15 business days
- Non-Disclosure Agreement
- Based on address or GPS, plus photo or map

Requests for an Interconnection Pre-Application Report shall include the information identified in Sections 1.4.1.1 through 1.4.1.8 of the Minnesota Distributed Energy Resource Interconnection Process (MN DIP) (and as provided in the fields below) to clearly and sufficiently identify the location of the proposed Point of Common Coupling and relevant project details.

Additionally, a non-refundable processing fee of $300 is required as specified in Section 1.4.1 of the MN DIP.

Upon receipt of a complete Request Form (including site map) and processing fee, the Area EPS Operator shall provide a report containing as much of the data described in Section 1.4.2 as is pre-existing and available within 15 business days. A Pre-Application Report request does not obligate the Area EPS Operator to conduct a study or other analysis of the proposed project if data is not available.

Click "NEXT" to start the Pre-Application Report Request Form.
Current State – Pre-Application Report Process (Continued)

Application Submitted → Site Map → Payment → Signed Agmt

Report Prepared → Compile Data → Review Data → Finalize Report

Send → Email → Portal upload
DISCLAIMERS – Pre-Application Report

MN DIP

1) the existence of “Available Capacity” in no way implies that an interconnection up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process,

2) the distribution system is dynamic and subject to change and

3) data provided in the Pre-Application Report may become outdated and not useful at the time of submission of the complete Interconnection Request.
POL\texttext{L} – SERIES 2

1) How do you use Pre-application Reports today?
- CSG high frequency (>25 per year)
- CSG moderate frequency (10-25 per year)
- CSG low frequency (<10 per year)
- CSG but never use
- On-site high frequency
- On-site moderate frequency
- On-site low frequency
- On-site but never use
- Not a potential user of these reports

2) How do you anticipate your Pre-application Report use changing in the next 1-3 years?
- More than double
- Double
- Stay about the same
- Drop by half
- Drop by more than half
- No longer be used
- Not a potential user of these reports

3) What is your top priority for Pre-Application Reports?
- Cost
- Fast turn-around
- Security
- Quick & easy to request
- Accuracy
Discussion: Use Cases

How do you use Pre-Application Reports?
Discussion: Use Cases

What value do Pre-Application Reports add beyond hosting capacity data?
Discussion: Use Cases

Real-life success stories about Pre-Application Reports?
What worked well to enable this?
Any stories about frustrations or concerns that might be resolved through HCA integration?
Live Ideation

Potential features & process improvements enabled by HCA integration
MN DIP – INITIAL REVIEW

Current State, Use Case, Feedback, Features Brainstorm, Prioritization
Simplified View of MN DIP Process

Fast Track Process*

Initial Review Screen → Supplemental Screen

Study Process

* Inverter-based projects less than 20 kW will follow the MN DIP Simplified process, the first step of which is also an Initial Screen.
MN DIP Tracks At-A-Glance

<table>
<thead>
<tr>
<th>Simplified Initial Screen</th>
<th>Fast – Initial Engineering Screens</th>
<th>Fast – Supplemental Review</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt;= 20 kW</td>
<td>Up to 5 MW, or based on voltage</td>
<td>Up to 5 MW, or based on voltage</td>
</tr>
</tbody>
</table>

Initial review screen looks at capacity, feeder & sub parameters, plus protection information to yield a pass/fail result.

Pass no upgrades: IA
Pass with upgrades: Facilities Study
Fail: to Supplemental Review

Initial review screen looks at capacity, feeder & sub parameters, plus protection information to yield a pass/fail result.

Pass no upgrades: IA
Pass with upgrades: Facilities Study
Fail: Supplemental Review

Looks at high-level modeling using feeder, sub and system inputs; more actual conductor information, distance. Used when initial screens raise red flags.

Pass no upgrades: IA
Pass with upgrades: Facilities Study
Fail: System Impact Study

Part of engineering process fee
Part of engineering process fee
Additional cost

<table>
<thead>
<tr>
<th>Fast Track Eligibility for Distributed Energy Resources</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Line Voltage</strong></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>&lt;= 5 kV</td>
</tr>
<tr>
<td>≥ 5 kV and &lt; 15 kV</td>
</tr>
<tr>
<td>≥ 15 kV and &lt; 30 kV</td>
</tr>
<tr>
<td>≥ 30 kV and ≤ 69 kV</td>
</tr>
</tbody>
</table>

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POLL – SERIES 3

1) What is your role and application volume?
   - CSG high frequency (>25 per year)
   - CSG moderate frequency (10-25 per year)
   - CSG low frequency (<10 per year)
   - CSG but never use
   - On-site high frequency
   - On-site moderate frequency
   - On-site low frequency
   - On-site but never use
   - Non-applicable (different role)

2) What volume change do you expect to see annually in the next 2-3 years
   - More than double
   - About double
   - Slight increase
   - About the same
   - Slight decrease
   - About half of current
   - Decrease by more than half
   - Not applicable (different role)

2) What is your top priority for screening/study results?
   - Cost
   - Fast turn-around
   - Security
   - Quick & easy to request
   - Accuracy
Initial Review

Within 15 Business Days after the Area EPS Operator notifies the Interconnection Customer, it has received a complete Interconnection Application, the Area EPS Operator shall perform an initial review using the screens set forth below, identify the Interconnection Customer of the results, including copies of the analysis and data underlying the Area EPS Operator’s determinations under the screens. The technical screens listed in this section shall not preclude the Area EPS Operator from seeking approval of tools that perform screening functions using different methodology given that the analysis is aimed at preventing the same voltage, thermal and protection limitations as the initial and supplemental review screens described below.

3.2.1 Initial Review Screens

3.2.1.1 The proposed DER’s Point of Common Coupling must be on a portion of the Area EPS Operator’s Distribution System.

3.2.1.2 For interconnection of a proposed DER to a radial distribution circuit, the aggregated generation, including the proposed DER, or on the circuit shall not exceed 17% of the line section peak loading as most recently measured. A last section is that portion of an Area EPS Operator’s electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. The Area EPS Operator may consider 100% of applicable loading (e.g. daytime minimum load for solar), if available, instead of 17% of line section peak load.

3.2.1.3 For interconnection of a proposed DER to the load side of network protection, the proposed DER must utilize an inverter-based equipment package and, together with the aggregated inverter-based DERs, shall not exceed the smaller of 5% of a network’s minimum load or 50 kVAr.

3.2.1.4 The proposed DER, in aggregate with other DERs on the distribution circuit, shall not contribute more than 10% to the distribution circuit’s maximum fault current as the point on the high voltage (primary) level nearest the proposed Point of Common Coupling.

3.2.1.5 The proposed DER in aggregate with other Distributed Energy Resources on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substations breakers, fuse cutouts, and line enclosures), or interconnection Customer equipment on the system to exceed 17.5% of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 17.5% of the short circuit interrupting capability.

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 provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the Area EPS Operator’s electric power system due to a loss of ground during the operating time of any anti-islanding function.

<table>
<thead>
<tr>
<th>Primary Distribution Line Type</th>
<th>Type of Interconnection to Primary Distribution Line</th>
<th>Results/Criteria</th>
</tr>
</thead>
<tbody>
<tr>
<td>Three-phase, three wire</td>
<td>3-phase or single phase, phase-to-phase</td>
<td>Pass screen</td>
</tr>
<tr>
<td>Three-phase, four wire</td>
<td>Effectively-grounded 3 phase or</td>
<td>Pass screen</td>
</tr>
<tr>
<td></td>
<td>Single-phase, line-to-neutral</td>
<td></td>
</tr>
</tbody>
</table>

3.2.1.7 If the proposed DER is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed DER, shall not exceed 20 kW or 65% of the transformer nameplate rating.

3.2.1.8 If the proposed DER 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.

3.2.1.9 If the proposed DER is single-phase and is to be interconnected to a three-phase service, its Nameplate Rating shall not exceed 10% of the service transformer nameplate rating.

3.2.1.10 If the DER’s Point of Common Coupling is behind a line voltage regulator, the DER’s Nameplate Rating shall be less than 250 kW.

3.2.2 If the proposed interconnection passes the screens, or of the proposed interconnection fails the screens, but the Area EPS Operator determines that the DER may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the Interconnection Application shall proceed as follows:

3.2.2.1 If the proposed interconnection requires no construction of facilities by the Area EPS Operator on its own system, the Area EPS Operator shall provide the Interconnection Customer an executed Interconnection Agreement within five (5) Business Days after the determination.

3.2.2.2 If the proposed interconnection requires construction of any facilities, the Area EPS Operator shall notify the Interconnection Customer of such requirement when it provides the Initial Review results and copies of the analysis and data underlying the Area EPS Operator’s determinations under the screens and either: 1) provide a good faith cost estimate; or 2) require a facilities study pursuant to 4.4.1. Within five (5) Business Days, the Interconnection Customer shall inform the Area EPS Operator if the Interconnection Customer elects to proceed with the proposed interconnection. If the Interconnection Customer makes such an election, the Area EPS Operator shall either provide: i) an Interconnection Agreement, along with a non-binding good faith cost estimate and construction schedule for such upgrades, within twenty (20) Business Days after the Area EPS Operator receives such an election or ii) a facilities study agreement pursuant to section 4.4.

See for more information: https://mn.gov/puc/energy/distributed-energy/interconnection/
Current State – *Initial Review Example*

### Initial Review Results

<table>
<thead>
<tr>
<th>MIN DIP</th>
<th>Initial Review Results</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Container:</strong> John Smith</td>
<td><strong>Case #:</strong> 124567</td>
</tr>
<tr>
<td><strong>Address:</strong> 123 4th Ave NW</td>
<td><strong>KA:</strong> 10,000</td>
</tr>
<tr>
<td><strong>DER Application Size:</strong> 11.49 kW</td>
<td><strong>DER Active on Feeder:</strong> 0.00 kW</td>
</tr>
<tr>
<td><strong>DER In Queue on Feeder:</strong> 0.00 kW</td>
<td><strong>DER In Queue on Substation:</strong> 0.00 kW</td>
</tr>
</tbody>
</table>

**Summary of Results:**

- This project has failed the Initial Review Screens, the details of which are provided below. A supplemental review will be required to determine if the DER may be interconnected consistently with safety, reliability, and power quality standards. The interconnection customer has the option to attend a customer options meeting. This meeting must be accepted or declined prior to the initiation of the Supplemental Review.

- Ground referencing adequacy: This project is not responsible for installing ground referencing equipment as it is less than 100 kW.

#### Initial Review Screens

<table>
<thead>
<tr>
<th>MIN DIP Section</th>
<th>Screen</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>12.1:</strong></td>
<td>The proposed DER’s Point of Common Coupling must be on a portion of Excel Energy’s Distribution System</td>
</tr>
</tbody>
</table>

**Screen:** Yes

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### 12.2: Interconnection to a radial distribution circuit

For interconnection of a proposed DER to a radial distribution circuit, the aggregated generation shall not exceed 33% of the line section annual peak load as measured recently. A line section is that portion of an area EPS Customer’s electric system connected to a customer located by automatic sectionalizing devices or the end of the distribution line. Excel Energy may consider 100% of applicable load (i.e., daytime minimum load) for Solar, if available, instead of 33% of line section peak load.

**Screen:** Yes

<table>
<thead>
<tr>
<th>MIN DIP Section</th>
<th>Screen</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>12.2.1:</strong></td>
<td>The proposed DER in aggregate with other Distributed Energy Resources on the distribution circuit shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse, outlets, and line reclosers) to operate, or interconnection Customer equipment on the system to exceed 97.5% of the short circuit interrupting capability. No der (interconnection) be proposed for a circuit that already exceeds 97.5% of the short circuit interrupting capability.</td>
</tr>
</tbody>
</table>

**Screen:** Yes

### 12.3: Interconnection to a network

For interconnection of a proposed DER to the load side of network protectors, the proposed DER must utilize an intertie-based equipment package and, together with the aggregated other intertie-based DERs, shall not exceed the smaller of 9% of a network’s maximum load or 99 kW.

**Screen:** Yes

<table>
<thead>
<tr>
<th>MIN DIP Section</th>
<th>Screen</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>12.3.1:</strong></td>
<td>Interconnection on a network as defined by Section 12.3.1.</td>
</tr>
<tr>
<td><strong>12.3.2:</strong></td>
<td>DER Inverter Based?</td>
</tr>
<tr>
<td><strong>12.3.3:</strong></td>
<td>Net load maximum load</td>
</tr>
<tr>
<td><strong>12.3.4:</strong></td>
<td>Aggregate DER, including other DERs</td>
</tr>
<tr>
<td><strong>12.3.5:</strong></td>
<td>Aggregate DER at 9% of Network Maximum Load</td>
</tr>
<tr>
<td><strong>12.3.6:</strong></td>
<td>Passes Screen</td>
</tr>
</tbody>
</table>

**Screen:** Yes

### 12.4: Distribution Circuit Maximum Fault Current near the PCC

The proposed DER, in aggregate with other DERs on the distribution circuit, shall not contribute more than 9% of the distribution circuit’s maximum fault current at the point on the high voltage (primary) level near the proposed Point of Common Coupling.

**Screen:** Yes

<table>
<thead>
<tr>
<th>MIN DIP Section</th>
<th>Screen</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>12.4.1:</strong></td>
<td>Distribution Circuit Maximum Fault Current near the PCC</td>
</tr>
<tr>
<td><strong>12.4.2:</strong></td>
<td>Aggregate DER, including proposed DER, on feeder</td>
</tr>
<tr>
<td><strong>12.4.3:</strong></td>
<td>Aggregate DER Fault current contribution</td>
</tr>
<tr>
<td><strong>12.4.4:</strong></td>
<td>Aggregate DER Fault current contribution as % of Distribution Circuit Max Fault Current</td>
</tr>
<tr>
<td><strong>12.4.5:</strong></td>
<td>Passes Screen</td>
</tr>
</tbody>
</table>

**Screen:** Yes

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### Current State – Initial Review Example (Continued)

#### Ground Referencing

Inverters, based systems greater than 100 kW require ground referencing. The adequacy of the provided ground referencing specifications are evaluated below.

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Requirement Met?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Requirement 1: ( X_{\text{DG}} ) as specified</td>
<td>( 2 ) p.u.</td>
</tr>
<tr>
<td>Requirement 2: ( X_{\text{DG}} R_{\text{DER}} ) as specified</td>
<td>( 4 ) p.u.</td>
</tr>
<tr>
<td>Requirement 3: Neut. Current Rating for ( V_e = 4% )</td>
<td>( 0 ) amperes</td>
</tr>
<tr>
<td>Requirement 4: Min. required fault current withstand rating</td>
<td>( 0 ) amperes</td>
</tr>
</tbody>
</table>

#### Other Construction of Facilities

Construction of other facilities may be required to interconnect the DER. They are listed below:

- Are construction of other facilities required? No

#### Transformer Nameplate Ratings

<table>
<thead>
<tr>
<th>DER Size</th>
<th>Transformer Nameplate Rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

#### Transformer Nameplate Ratings

<table>
<thead>
<tr>
<th>DER Size as a % of Transformer Nameplate Rating</th>
<th>N/A</th>
</tr>
</thead>
<tbody>
<tr>
<td>Passes Screen</td>
<td>N/A</td>
</tr>
</tbody>
</table>

#### Transformer Nameplate Ratings

<table>
<thead>
<tr>
<th>DER Size</th>
<th>Transformer Nameplate Rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>11.40</td>
<td>15.25%</td>
</tr>
</tbody>
</table>

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Discussion: Use Cases

How do you use Initial Review reports?
Discussion: Use Cases

How could they be improved through HCA integration?
Discussion: Use Cases

Real-life success stories?
Discussion: Use Cases

Real-life frustrations you're hoping to resolve?
Live Ideation
Potential features & process improvements enabled by HCA integration
MN DIP – SUPPLEMENTAL SCREENS

Current State, Use Case, Feedback, Features Brainstorm, Prioritization
3.4.3 Safety and Reliability Screen: The location of the proposed DER and the aggregate generation capacity on the line sections do not create impacts to safety or reliability that cannot be adequately addressed without application of the Study Process. The Area EPS Operator shall give due consideration to the following and other factors in determining potential impacts to safety and reliability as applying this screen.

3.4.3.3 Whether the line section has significant minimum loading levels dominated by a small number of customers (e.g., several large commercial customers).

3.4.3.4 Whether the loading along the line section is uniform or even.

3.4.3.5 Whether the proposed DER is located in close proximity to the substation (i.e., less than 2.5 electrical circuit miles), and whether the line section from the substation to the Point of Common Coupling is a Main line rated for normal and emergency ampacity.

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

3.4.3.7 Whether operational flexibility is reduced by the proposed DER, such that transfer of the DER to neighboring distribution circuit-substation may trigger overloads or voltage issues.

3.4.3.8 Whether the proposed DER employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, inrush, reverse power flow, or voltage quality.

3.4.5 If the proposed interconnection passes the supplemental screens in sections 3.4.4.3, 3.4.4.4, and 3.4.4.5 above, or if the proposed interconnection fails the screens, but the Area EPS Operator determines that the DER may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the interconnection shall proceed as follows:

3.4.5.1 If the proposed interconnection passes the supplemental screens in sections 3.4.4.1, 3.4.4.2, and 3.4.4.3 above and does not require construction of facilities by the Area EPS Operator on its own system, the Area EPS Operator shall provide the Interconnection Customer an executable Interconnection Agreement within five (5) Business Days.

3.4.5.2 If the proposed interconnection requires construction of any facilities, the Area EPS Operator shall notify the Interconnection Customer of such requirement, and when it provides the supplemental review results and either: 1) provide a good faith cost estimate; or 2) require a facilities study pursuant to 4.4.1. Within five (5) Business Days, the Interconnection Customer shall inform the Area EPS Operator if the Interconnection Customer elects to proceed with the proposed interconnection. If the Interconnection Customer makes such an election, the Area EPS Operator shall either provide: 1) an Interconnection Agreement, along with a non-binding good faith cost estimate and construction schedule for such upgrades, within twenty (20) Business Days after the Area EPS Operator receives such an election or a) a facilities study agreement pursuant to 4.4.

3.4.6 If the proposed interconnection fails the screens, and the Area EPS Operator does not or cannot determine that the DER may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer is willing to consider minor modifications or further study, the Area EPS Operator shall provide the Interconnection Customer the option of commencing the Section 4 Study Process. If the Interconnection Customer wishes to proceed it shall notify the Area EPS Operator within fifteen (15) Business Days to retain its queue position.

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Supplemental Review Sample

Minnesota Distributed Energy Resources Interconnection Process (MN DIP)

Supplemental Review Results

Customer: John Smith
Address: 123 4th Ave NW
DER Application Size: 11.40 kVA

Interconnection Feeder: Substation:
DER Active on Feeder: KW DER Active on Substation:
DER in Queue on Feeder: KW DER in Queue on Substation:

Safety and Reliability:
Conductor Loading:
The line section from the substation to the Point of Common Coupling is rated for the current produced by the DER.
Approximate maximum conductor loading as a percentage of rating or capacity:
When DER is on: Passes Screen?

Substation Transformer Loading:
Substation Transformer Rating: kVA
Aggregate DER on Substation: kVA
Peak Load (Native): kW Substation Transformer Rating Exceeded by Screen Passes?

Direct Transfer Trip:
Is there existing rotating machine DER on the Substation Transformer?
Is there existing rotating machine on the Feeder?
Is a System Impact Study required to determine if Direct Transfer Trip is required?
Passes Screen?

Transmission Impacts:
Is a study required to verify Transmission System impacts?
Passes Screen?

Protection Coordination:
Is a study required to verify Protection Coordination?
Passes Screen?

Service Conductor Upgrades:
Service Conductor Upgrades may be required due to loading, voltage fluctuation violations, or steady state voltage violations.
Is service conductor upgrade required?
Approximate footage of extension:

Voltage Supervisory Reclosing (VSR):
If the load to DER ratio is 1.25, VSR is required on reclosing devices. If this DER project causes the threshold to be exceeded, it will be responsible for installing VSR.

Peak Load (Native): 365 kVA
Aggregate DER on Feeder: 555 kVA
Load to Generation Ratio: 0.95
New DER causes VSR threshold to be exceeded?: No
Is VSR required to be installed to allow this project to interconnect?: No

Reverse Power Flow Controls:
If the feeder experiences reverse power flow, regulating devices may need to be upgraded or replaced. If this DER project is the cause of the reverse power flow, it will be responsible for these upgrades/

Reverse Power Flow on Feeder:
New DER causes reverse power flow?: No
Is this project responsible for upgrading regulation devices that need to be capable of reverse flow?: No

Primary Conductor Construction:
Construction of Primary Conductor may be required to convert a single-phase line to a three-phase line to the PCC.

Is a three phase primary conductor extension required?
Approximate footage of extension:

Other Construction of Facilities

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Supplemental Review Sample (Continued)

Construction of other facilities may be required to interconnect the DER. They are listed below.

Are construction of other facilities required? [No]

Description of facilities:

Ground Referencing
Inverter-Based Systems greater than 100 kW require ground referencing. The adequacy of the provided ground referencing specifications are evaluated below.

Requirement 1:
As Specified: \( X_{0,\text{DER}} = \) p.u.
Requirement Met?: N/A

Requirement 2:
As Specified: \( X_{0,\text{DER}/R_{0,\text{DER}}} = \) p.u.
Requirement Met?: N/A

Requirement 3:
Neutral Current Rating for \( V_s = 480 \) V
Neutral Current Rating, as specified: 0 amps
Neutral Current Rating, as specified: 0 amps
Requirement Met?: N/A

Requirement 4:
Required fault current withstand rating: 0 amps
As Specified: 0 amps
Requirement Met?: N/A
Discussion: Use Cases

Any differences in how you use supplemental review reports?
Discussion: Use Cases

Any incremental ways they might be improved through HCA integration?
Discussion: Use Cases

Real-life success stories?
Discussion: Use Cases

Real-life frustrations you're hoping to resolve?
Live Ideation

Potential features & process improvements enabled by HCA integration
AUTOMATE INTERCONNECTION PROCESS

Feedback, Features Brainstorm, Prioritization
Discussion: Use Cases

What opportunities do you see for improvement through HCA integration beyond these areas?
Discussion: Use Cases

Real-life success stories for how HCA integration has helped with overall interconnection?

Real-life frustrations you're hoping to resolve?
Live Ideation

Potential features & process improvements enabled by HCA integration
What’s Next?

HCA filing November 2, 2020

Will include –

- HCA Results in Tabular Report and Heat Map formats
- Summaries of our 2020 Workshops
- Our analysis of the Potential Future HCA Use Cases
THANK YOU FOR YOUR FEEDBACK

If you have additional feedback to share, please send to:

Paget.J.Pengelly@xcelenergy.com
<table>
<thead>
<tr>
<th>Pre-Application Report Data Type</th>
<th>Data Exists in Current HCA Map?</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation Name</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>Transformer Name</td>
<td>N</td>
<td>Adding in 2020 Analysis</td>
</tr>
<tr>
<td>Transformer Rating</td>
<td>N</td>
<td></td>
</tr>
<tr>
<td>Transformer Peak</td>
<td>N</td>
<td></td>
</tr>
<tr>
<td>Transformer DML</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>Transformer Absolute Min</td>
<td>N</td>
<td>Adding in 2020 Analysis</td>
</tr>
<tr>
<td>LTC or Regulator</td>
<td>N</td>
<td>Adding in 2020 Analysis</td>
</tr>
<tr>
<td>TR Existing Gen</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>TR Queued Gen</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>TR Gen Capacity</td>
<td>N</td>
<td></td>
</tr>
<tr>
<td>Distance from PCC to sub</td>
<td>N</td>
<td></td>
</tr>
<tr>
<td>Feeder Name</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>Feeder Rating</td>
<td>N</td>
<td></td>
</tr>
<tr>
<td>Feeder Peak</td>
<td>N</td>
<td></td>
</tr>
<tr>
<td>Feeder DML</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>Feeder Absolute Min</td>
<td>N</td>
<td>Adding in 2020 Analysis</td>
</tr>
<tr>
<td>Feeder Voltage</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>Feeder Existing Gen</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>Feeder Queued Gen</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>Feeder Gen Capacity</td>
<td>N</td>
<td></td>
</tr>
<tr>
<td>Nominal Voltage at PCC</td>
<td>Y</td>
<td></td>
</tr>
<tr>
<td>Network or Radial</td>
<td>N</td>
<td>Adding in 2020 Analysis</td>
</tr>
<tr>
<td># of Phases</td>
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<td></td>
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<tr>
<td>Distance to 3 phase circuit</td>
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<tr>
<td>Protective devices in line</td>
<td>N</td>
<td></td>
</tr>
<tr>
<td>between site and sub</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Conductor between site and sub</td>
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</tbody>
</table>
## Pre-Application Report Features

<table>
<thead>
<tr>
<th>Feature Description</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total capacity</strong> (in megawatts (MW)) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Common Coupling.</td>
<td></td>
</tr>
<tr>
<td><strong>Substation nominal distribution voltage and/or transmission nominal voltage if applicable</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Whether the Point of Common Coupling is located behind a line voltage regulator.</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Whether the Point of Common Coupling is located on a spot network, grid network, or radial supply.</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Common Coupling.</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Nominal distribution circuit voltage at the proposed Point of Common Coupling.</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Number and rating of protective devices and number and type (standard, bidirectional) of voltage regulating devices between the proposed Point of Common Coupling and the substation/area. Identify whether the substation has a load tap changer.</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Based on the proposed Point of Common Coupling, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of generation in the queue) likely to serve the proposed Point of Common Coupling.</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Approximate circuit distance between the proposed Point of Common Coupling and the substation.</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Number and rating of protective devices and number and type (standard, bidirectional) of voltage regulating devices between the proposed Point of Common Coupling and the substation/area. Identify whether the substation has a load tap changer.</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Available capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed Point of Common Coupling (i.e., total capacity less the sum of existing aggregate generation capacity and aggregate queued generation capacity).</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load as described in section 3.4.4.1 below and absolute minimum load, when available.</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Limiting conductor ratings from the proposed Point of Common Coupling to the distribution substation.</strong></td>
<td></td>
</tr>
</tbody>
</table>