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November 1, 2019

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: DISTRIBUTION SYSTEM – HOSTING CAPACITY ANALYSIS REPORT
DOCKET NO. E002/M-19-___

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits our Hosting Capacity Analysis (HCA) Report in compliance with Minn. Stat. § 216B.2425, subd. 8, and the Commission's August 15, 2019 Order in Docket No. E002/M-18-684.

The tabular spreadsheet results of our 2019 HCA (Attachment B to this filing) do not publicly provide the peak substation transformer load or peak feeder load data. We have marked this information as non-public, protected data and provide a detailed explanation for this treatment in our Compliance Filing, Section D, Customer Privacy and System Security Considerations.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on all parties on the attached service lists. Please contact me at bria.e.shea@xcelenergy.com or 612-330-6064 if you have any questions regarding this filing.

Sincerely,

/s/
BRIA E. SHEA
DIRECTOR, REGULATORY & STRATEGIC ANALYSIS

Enclosures
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Dan Lipschultz	Commissioner
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE XCEL ENERGY 2019 HOSTING CAPACITY REPORT UNDER MINN. STAT. § 216B.2425, SUBD. 8

DOCKET NO. E002/M-19-___

COMPLIANCE FILING – HOSTING CAPACITY ANALYSIS REPORT

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy (the Company), submits the attached Hosting Capacity Analysis (HCA) Report in compliance with Minn. Stat. § 216B.2425 subd. 8 and the Minnesota Public Utilities Commission's (the Commission) August 15, 2019 Order in Docket No. E002/M-18-684 (August 2019 Order).[1]

Today, we are also filing in a separate docket our Integrated Distribution Plan (IDP) for 2020-2029, which presents a detailed view of our distribution system, outlines how we plan the system to meet our customers' current and future needs, and proposes tools to significantly advance our distribution grid and planning capabilities. Together, these two filings represent significant progress and improvement in the distribution system planning and integration of distributed energy resources (DER) to the Company's system.

Our 2019 HCA Report describes in detail how we have enhanced both the HCA methodology and the presentation of the results. We have made significant efforts to improve the value of the HCA so that it is a useful tool to identify areas of constraints for DER interconnection in our distribution system. We have added actual values for several data components, included more information in the presentation of the results, and conducted new analyses – based on the Commission's August 2019 Order, stakeholder feedback, and guidance from the current industry practice. Our

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[1] Docket No. E002/M-18-684, *In the Matter of Xcel Energy's 2018 Hosting Capacity Study*, ORDER ACCEPTING STUDY AND SETTING FURTHER REQUIREMENTS, August 15, 2019.

2019 HCA Report is the culmination of lessons learned thus far and provides improved methodology, analyses, and presentation.

For this year's filing, we have prepared a separate HCA Report, which discusses in detail the methodology, analyses, and results of the 2019 HCA. This report is included as **Attachment A** to this filing. Additionally, we have included as **Attachment B** the HCA results in a tabular spreadsheet format and as **Attachment C** a compliance matrix that identifies where each compliance requirement established in the Commission's prior Orders is addressed in this filing.

In this compliance filing document, we provide the following general information on the 2019 HCA:

- Summary of the methodology, analyses, and results;
- Explanation of major changes and improvements in the methodology and in the presentation of results;
- Discussion on how we engaged stakeholders for feedback on the HCA; and
- Examination of customer data privacy and system security restrictions for providing certain data in the public heat map and tabular spreadsheet.

We have included the following attachments with the filing:

- Attachment A: 2019 HCA Report
- Attachment B: 2019 HCA Results Spreadsheet
- Attachment C: Compliance Matrix
- Attachment D: Stakeholder Workshop Presentation
- Attachment E: Stakeholder Survey Questionnaire
- Attachment F: Joint Petition to the California Public Utilities Commission.

A. 2019 HCA Methodology and Results

The Company filed its first HCA Report in December 2016, and has filed subsequent HCA Reports annually on November 1. For each HCA, we have used the DRIVE tool, developed by the Electric Power Research Institute (EPRI). Our methodology, data collection, presentation of results, and the DRIVE tool have evolved each year, improving the quality and usefulness of the HCA Report.

1. Background

Minn. Stat. § 216B.2425, subd. 8 requires that a utility operating under an approved multiyear rate plan:

> *Shall conduct a distribution study to identify interconnection points on its distribution system for small-scale distributed generation resources and shall identify necessary distribution upgrades to support the continued development of distributed generation resources, and shall include the study in its report required under subdivision 2.*

In its June 28, 2016 Order, the Commission clarified that for the purposes of the hosting capacity study, small-scale distributed generation resources are defined as resources that are 1 MW or less.[2] For reference, our Community Solar Garden program applications are similarly limited to 1 MW or less in size. Our continued use of the DRIVE tool's Large Centralized allocation method is supported by the amount of large-scale community solar gardens in service, exceeding 625 MW of installed capacity today in Minnesota. The Small Distributed method would be appropriate for a distribution system that has predominantly smaller-scale DER installations, such as rooftop solar and small wind. However, adoption of smaller-scale DER is relatively insignificant compared to community solar gardens – the total installed capacity is approximately 100 MW on our distribution system.

EPRI defines hosting capacity as the amount of DER that can be accommodated on the existing utility system without adversely affecting power quality or reliability under existing configurations and without requiring infrastructure upgrades. The two primary statutory objectives for the HCA are: 1) identifying available locations for DER interconnection on the distribution system, and 2) identifying upgrades necessary to support continued development of distributed generation.

Our objective for the HCA is aligned with Minn. Stat. § 216B.2425, subd. 8 and the Commission's Order that the HCA serves as a "starting point" for interconnection applications.[3] In our view, the current HCA plays an important role in streamlining the interconnection process by assisting Developers in choosing sites that potentially require only screening or a less involved study for interconnection, as we believe was intended by the statute.

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[2] Docket No. E002/M-15-962, *In the Matter of Xcel Energy's 2015 Biennial Distribution-Grid-Modernization Report*, ORDER CERTIFYING ADVANCED DISTRIBUTION-MANAGEMENT SYSTEM (ADMS) PROJECT UNDER MINN. STAT. § 216B.2425 AND REQUIRING DISTRIBUTION STUDY, June 28, 2016, Order Point 3.a.

[3] Docket No. E002/M-15-962, *In the Matter of Xcel Energy's 2015 Biennial Distribution-Grid-Modernization Report*, ORDER SETTING ADDITIONAL REQUIREMENTS FOR XCEL'S 2017 HOSTING CAPACITY REPORT, August 1, 2017, Order Point 1.

2. *Methodology*

The Company partnered with EPRI in 2015 to assist in the development of the DRIVE tool, has regularly participated in the DRIVE User Group, and has been actively involved in further improving and modifying DRIVE. We believe that DRIVE continues to be the best tool to conduct our HCA. DRIVE is currently used by more than 25 utilities and has several benefits, including speed of processing, accuracy of results, and multiple-use cases. Another advantage is our history of past DRIVE use and ability to participate in further tool development and modification. A good example of this advantage is that we are the first utility to use a new EPRI mitigation assessment tool, which was used in the 2019 HCA to assess mitigation options and costs to increase hosting capacity on those 95 feeders that showed zero hosting capacity in the 2018 HCA.

EPRI has conducted several evaluations on hosting capacity methods, which all reached parallel conclusions. EPRI recognized that hosting capacity methods are continuously evolving and found that different hosting capacity methods can provide similar, accurate results. EPRI concluded, however, that a hybrid method – such as DRIVE – is the most likely and successful path going forward.[4]

For the hosting capacity analyses, the DRIVE tool incorporates data and assumptions about the utility's distribution system, such as 1) characteristics of each substation and feeder, 2) characteristics of load, and, 3) characteristics of existing interconnected DER. As the first step of the 2019 HCA, we created 1,050 feeder models in Synergi Electric, which is our distribution load-flow program. Primarily, the information for these feeder models came from our Geographic Information System (GIS). We supplemented the GIS asset information with data from our 2019 load forecast and historic actual customer demand and energy data. After we extracted asset data from GIS to Synergi, we performed a series of clean-up scripts to address any errors, including specifying the head-end voltage, burial depths of underground cable, height of overhead conductor, and equipment settings for capacitors, reclosers, and regulators.

Once we had addressed all errors in a particular feeder model, we allocated the load to the feeder based on demand and customer energy usage data. At this point, we ran a load-flow and performed a final check for any abnormalities on the feeder. Finally,

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[4] *Impact Factors, Methods, and Considerations for Calculating and Applying Hosting Capacity*. January 31, 2018, pages xi-xii, 5-2. https://www.epri.com/#/pages/product/3002011009/?lang=en-US.

after the feeder models were finalized, we used DRIVE to perform the hosting capacity technical analysis.

Unless otherwise noted in our 2019 HCA Report (Attachment A), we have used the same overall methodology, DRIVE tool features, and data components as in our 2018 HCA. However, we have also made several improvements to our 2019 HCA, and some of the main changes are:

- *Use of Actual Daytime Minimum Load (DML) Data*: We determined actual DML data for every feeder with large amounts of existing DER and as a result, used actual DML values for approximately 25 percent of feeders in the DRIVE analysis. We continued to establish actual DML values during the rest of the HCA process, and 100 percent of feeders in the heat map and tabular results spreadsheet have actual DML data.
- *Use of Actual Power Factors*: The majority of feeders in the HCA have actual power factor values; in the previous HCA Reports we used an assumed power factor of 99% lagging.
- *Feeder Model Building*: We rebuilt (i.e., extracted GIS asset data for) approximately one-third of the 1,050 feeders, focusing on those feeders that had experienced large configuration, load, or generation changes. Building the feeder models is one of the most resource-intensive parts of the HCA, and we decided not to rebuild those feeders that did not have any significant changes.
- *Additional Data in Results Presentation*: The heat map and tabular spreadsheet display the following data: feeder name, substation name, DML for feeder, DML for substation, existing DER on substation, existing DER on feeder, queued DER on substation, queued DER on feeder, available hosting capacity, and limiting factors. The heat map also displays feeder voltage level, line phasing (single/three-phase line), line type (overhead/underground), field voltage regulator location, and substation location.
- *Heat Map*: When clicking a location on the heat map, a pop-up screen displays the additional system data described above.
- *New Analyses*: As directed by the Commission, we examined the 95 feeders that had no capacity in the 2018 HCA to explore mitigation options to increase available hosting capacity; conducted a case study on a feeder varying locations and levels of generation and load (WTN062 Case Study); and, evaluated the accuracy of HCA results, comparing 2018 DRIVE results to Synergi results and comparing 2018 DRIVE results to actual interconnection studies performed for community solar gardens on 15 feeders.

Our modeling considered only DER that acts as a generation source to the distribution system. DER that behaves primarily as an energy source (e.g., solar, wind, biomass) tends to only reduce hosting capacity. In contrast, battery storage has the potential to act as a load to reduce thermal and voltage impacts, effectively increasing hosting capacity, if sited and coordinated properly with DER output. Due to low penetration of energy storage in Minnesota generally and on our distribution system specifically, we excluded battery storage load characteristics from our 2019 HCA.

The DRIVE tool has the capability to analyze also the load characteristics of the newer forms of DER, including battery storage and electric vehicles (EVs). These load hosting capacity results could be used to identify areas with greater potential for siting EV charging stations or other loads associated with beneficial electrification, but we consider this type of analysis as part of traditional distribution planning rather than part of HCA. Our Integrated Distribution Plan for 2020-2029 discusses in detail how the Company is making investments to increase access to EVs and proposing a range of innovative programs that support the growth of EVs in Minnesota.

3. How to Read the Results

We provide the results of our 2019 HCA in a tabular spreadsheet (Attachment B) and as an interactive visual representation, or heat map. The results are a snapshot in time as of August 2019, based on the characteristics and topology of the Company's distribution system at that time. The hosting capacity for a feeder is a range of values that depends on several variables, including DER location, DER technology, load characteristics, feeder design, and feeder operation. Any addition of new generation on a feeder will reduce the available hosting capacity by an unknown value, impacted predominantly by the nameplate capacity and location of new DER.

The heat map is available on our website at: https://www.xcelenergy.com/working_with_us/how_to_interconnect/hosting_capacity_map_disclaimer. Figure 1A below is an example of the visual hosting capacity results on the heat map and Figure 1B displays a heat map pop-up screen.

Figure 1A: Example of Heat Map Results

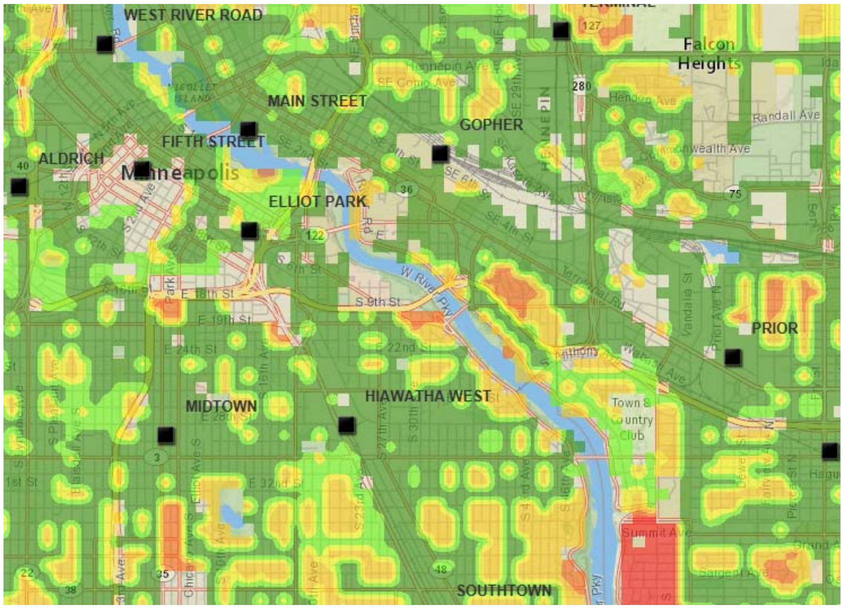
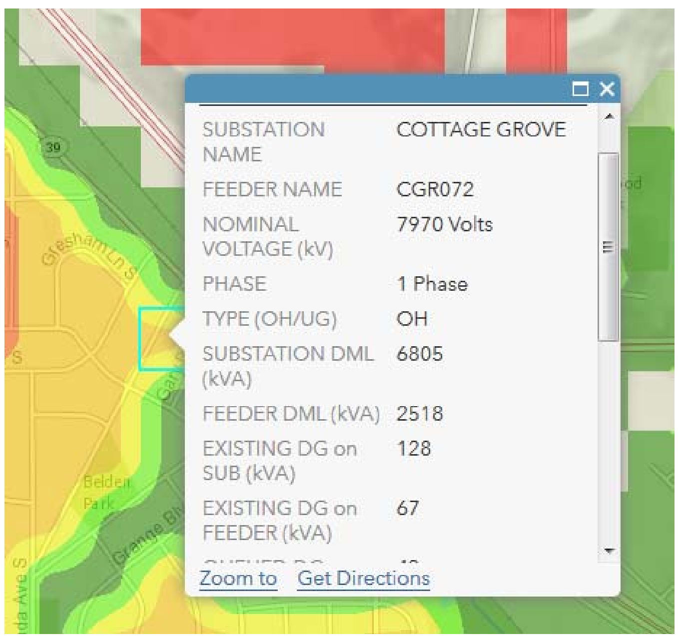


Figure 1B: Example of Heat Map Pop-Up Screen



We remind readers that the 2019 HCA presents the discrete hosting capacity of individual feeders without analysis of the cumulative effects of DER additions to substations or the transmission system. As DER penetration increases, system constraints are likely to limit hosting capacity in various geographical areas. For instance, a substation may have three feeders with 3 MW of available capacity on each

– but the substation or transmission systems may not have 9 MW of available capacity. As a result, the HCA is not a holistic system view, but rather a snapshot of the capabilities of individual feeders as they are positioned today.

The 2019 HCA results show that 129 feeders have zero maximum hosting capacity. Most of these feeders (101) have significant amounts of existing DER on them, and 97 feeders have at least 1 MW or more. These existing DER installations have essentially exhausted the hosting capacity. However, it is also important to note that DRIVE considers potential DER in increments of 100 kW on three-phase sections during the HCA process. This means that even if a particular feeder shows zero hosting capacity, there may actually be available hosting capacity for small secondary-connected DER, such as rooftop solar.

Additionally, the heat map and tabular spreadsheet provide the amount of hosting capacity available without conducting any mitigations. Therefore, even if a feeder may show low hosting capacity, it is possible that mitigations could allow higher levels of DER to be interconnected. However, an engineering study would need to be completed to determine whether mitigation would increase available capacity.

After consulting the heat map or tabular spreadsheet, we recommend Developers use progressively more detailed tools to assess the viability of the potential DER site. More informative and site-specific information on hosting capacity is offered in the following order:

1. The HCA does not reflect projects that are in the interconnection queue, because we lack certainty on whether the projects will be completed. However, we provide information on the queued DER projects by feeder and substation on the heat map and tabular spreadsheet as of August 2019. Developers may also use the public interconnection queue, which is updated monthly, in conjunction with the HCA results. The public interconnection queue is available online under the Public DER Queue prompt on https://www.xcelenergy.com/working_with_us/how_to_interconnect.
2. Developers may make a pre-application report request for a preliminary screen for a specific location. The current fee for a pre-application report is $300.00. More information is available under the Pre-Application Report prompt on https://www.xcelenergy.com/working_with_us/how_to_interconnect.
3. Developers may submit a formal request for interconnection at a specific site. For more information on submitting a formal request for interconnection see https://www.xcelenergy.com/working_with_us/how_to_interconnect. A completed interconnection application is the mechanism for how a project enters into the DER queue and begins the process for reserving hosting

capacity. The outcome of Screening or Studies will identify allowable interconnection capacity and any mitigation costs.

4. After the Section 10 Interconnection Agreement is signed and funded (or for newer MN DIP applications after the results of the System Impact Study), if system modifications are required, the Company will perform a detailed engineering design cost study with a more specific estimate of the Company's costs to build out the system to accommodate the interconnection.

4. 2019 HCA Costs

As directed by the Commission's August 2019 Order, we estimated the costs for preparing the 2019 HCA and Report. Overall, we estimate that the total cost for the 2019 HCA was over $300,000. This includes engineering staff time from June 2019 through October 2019 (approximately 1,600 hours), but excludes time spent prior to June 2019 for such tasks as stakeholder engagement; preparation for the analysis; hiring and training of multiple interns; and various other activities surrounding the DRIVE tool and collaboration with EPRI. This estimate also excludes the effort of other departments outside of Engineering, such as Regulatory and Legal. We have incurred additional costs to conduct the separate EPRI analysis of 95 feeders with no hosting capacity ($50,000), to acquire the DRIVE tool in 2016 ($250,000) and to participate in the DRIVE User Group ($30,000).

If we were required to update the HCA more frequently, we believe each round of updates would cost slightly less than $300,000, but still be substantial. While we would not need to prepare a separate HCA report, we would still need to rebuild feeder models and update system data for each update.

B. New Analyses: Accuracy, Mitigation, and WTN062 Case Study

The Commission's August 2019 Order directed us to provide additional analyses and discussion on the accuracy of our 2018 HCA results and mitigation upgrades, and to include an example of a feeder's hosting capacity with different locations and levels of generation and load. We provide summaries of these analyses here; a more detailed discussion is included in Attachment A.

1. Accuracy

We conducted two different analyses to assess the accuracy of our 2018 HCA results as directed by the Commission. First, we compared DRIVE results to Synergi results on 15 feeders, and second, we compared DRIVE results to actual interconnection studies on the same 15 feeders. We determined the 15 feeders by selecting all interconnection studies performed for community solar gardens during a six-month period from September 2018 to February 2019.

The first analysis focused on comparing the minimum hosting capacity value and the criteria threshold violated. The analysis found that the results between DRIVE and Synergi were consistent: the average difference in the minimum hosting capacity value between the two models was 81 kW.

The interconnection studies conducted for community solar gardens identify the capacity available without any distribution system upgrades. In the second analysis, we compared this value to the range of minimum and maximum hosting capacity produced in DRIVE. The results between DRIVE and actual interconnection studies were less consistent: we determined that seven feeders had results that correlated, while eight feeders had discrepancies where the interconnection study value fell outside the range of DRIVE hosting capacity. There were various reasons for the inconsistent results, such as different power factor values for the new and existing generation on the feeder and feeder upgrades that were not reflected in the HCA data.

This comparison highlighted the fundamental differences between the HCA and an interconnection study – a large-scale analysis of over 1,000 feeders cannot achieve the same level of detail and data integrity as an interconnection study that focuses on a specific location on one feeder. We believe the DRIVE tool produces accurate results for its purpose as the first step in the interconnection process.

2. *Mitigation*

Overall, mitigation upgrades vary by complexity, cost, and effectiveness, based on the type of constraint that is mitigated. There are some general principles, however:

- Feeder characteristics, distribution of DER, and size of DER can all create significant variability in mitigation costs,
- Voltage constraints are in general less expensive to mitigate (by adjusting inverter settings),
- Thermal overloads are in general more expensive to mitigate, and
- Upgrade costs can be minimized if the DER is placed at a better location on the same feeder.

For the 2019 HCA Report, we analyzed in more detail those 95 feeders[5] that in the 2018 HCA showed zero hosting capacity, as directed by the Commission. We are the first utility to use a new mitigation assessment tool developed by EPRI, allowing a streamlined analysis of a large number of feeders. This tool attempts to automate the mitigation comparison process by using predetermined mitigation settings and suggesting potential solutions based on those settings. Even then, it took EPRI 400 hours to complete the analysis for those 77 feeders that could be mitigated.

Our mitigation analysis focused on improving the hosting capacity on the feeder at the midpoint between the substation and the end of the line. We also focused on mitigations that would improve the hosting capacity by at least 1 MW at the midpoint. If several mitigation options were able to achieve 1 MW increase in capacity, we selected the least cost option.

We summarize the main findings below, but caution the readers that the mitigation analysis is a theoretical study of mitigation options and does not represent mitigation options that could be transferred as such to the Company's current interconnection process or practice. For example, the Company's regular interconnection process does not use regulators or smart inverters as a solution for mitigating violations. We refer the readers to review the complete mitigation analysis methodology, disclosures, and Company practice discussed in the 2019 HCA Report, Attachment A.

Multiple Violations: many feeders had several violations, including overvoltage (87 feeders), unintentional islanding (82 feeders), reverse power flow (81 feeders), breaker fault current (73), and feeder fault current (67 feeders). These were also the most common violations.

No Solution: 17 feeders required extensive mitigation and violations could not be solved with the mitigation options available. These feeders were removed from further analysis, which then focused on the remaining 77 feeders.

Overvoltage and Thermal Violations – Tier 1 (Under $5,000): 28 feeders gained at least 1 MW additional capacity with power factor adjustments to the existing and/or new generations, which is a no-cost solution. Another 5 feeders reached 1 MW by volt-var advanced inverter function, with no additional cost. Another 3 feeders reached 1 MW by using the volt-watt-inverter function, which costs under $5,000. On average, the hosting capacity for these 36 feeders increased by 1.9 MW per feeder.

[5] One feeder had been incorrectly assigned excess generation in the 2018 HCA and in fact did have available capacity. It was removed from the analysis, which then contained 94 feeders.

Overvoltage and Thermal Violations – Tier 2 ($75,000): Another 14 feeders achieved increased capacity with a new regulator (assumed cost $75,000 per installation). Although every feeder did not gain 1 MW, the average gain was 2 MW per feeder.

Overvoltage and Thermal Violations – Tier 3 ($500,000 and up): for the remaining feeders, the mitigation required extensive reconductoring and costs ranged from $500,000 to over $3 million per feeder.

Besides the overvoltage and thermal violations, most of the feeders had also other violations, such as reverse power flow and unintentional islanding, which also had to be mitigated. When these mitigation costs were added to the costs listed above, the average mitigation cost was approximately $170,000 per feeder for Tier 1 violations, $200,000 per feeder for Tier 2 violations, and $1.7 million per feeder for Tier 3 violations. However, the majority of feeders (53) could be successfully mitigated with comprehensive solutions that cost under $300,000.

3. WTN062 Case Study

The Commission directed us to provide at least one DRIVE case example of a feeder's hosting capacity with different locations and levels of generation and load. We conducted this case study on Watertown substation feeder WTN062. We selected WTN062 due to its primarily rural construction with small areas of town/urban loading. This topology is typical of feeders that experience interconnection requests for a large number of community solar gardens and some rooftop installations.

We ran 20 different scenarios for the WTN062 study. WTN062 was analyzed under low 20% load, 50% load, peak load, and 150% load circumstances. Additionally, 0.5 MW and 0.25 MW of DER was added to the feeder at close (0.26 miles) and far distances (5.15 miles) from the substation. Table 1 supplies the maximum and minimum hosting capacity results for each loading and generation scenario.

Table 1: WTN062 Case Study – Hosting Capacity Results

	Min HC (MW)	Min Limiting Factor	Max HC (MW)	Max Limiting Factor
20% Load No Gen	0.03	Unintentional Islanding	0.17	Reverse Power Flow
20% Load 0.5MW Near	0	Reverse Power Flow	0	Reverse Power Flow
20% Load 0.5MW Far	0	Primary Over-Voltage	0	Primary Over-Voltage
20% Load 0.25MW Near	0	Reverse Power Flow	0	Reverse Power Flow
20% Load 0.25MW Far	0	Primary Over-Voltage	0	Primary Over-Voltage
50% Load No Gen	0.07	Unintentional Islanding	0.45	Reverse Power Flow
50% Load 0.5MW Near	0	Reverse Power Flow	0	Reverse Power Flow
50% Load 0.5MW Far	0	Primary Over-Voltage	0	Primary Over-Voltage
50% Load 0.25MW Near	0.07	Unintentional Islanding	0.2	Reverse Power Flow
50% Load 0.25MW Far	0	Primary Over-Voltage	0	Primary Over-Voltage
Peak Load No Gen	0.16	Unintentional Islanding	0.92	Reverse Power Flow
Peak Load 0.5MW Near	0.16	Unintentional Islanding	0.42	Reverse Power Flow
Peak Load 0.5MW Far	0	Primary Over-Voltage	0	Primary Over-Voltage
Peak Load 0.25MW Near	0.16	Unintentional Islanding	0.67	Reverse Power Flow
Peak Load 0.25MW Far	0	Unintentional Islanding	0.67	Reverse Power Flow
150% Load No Gen	0.21	Unintentional Islanding	1.39	Reverse Power Flow
150% Load 0.5MW Far	0	Unintentional Islanding	0	Primary Over-Voltage
150% Load 0.5MW Near	0.2	Primary Over-Voltage	0.89	Reverse Power Flow
150% Load 0.25MW Far	0	Unintentional Islanding	1.14	Reverse Power Flow
150% Load 0.25MW Near	0.2	Primary Over-Voltage	1.14	Reverse Power Flow

Overall, the findings of this case study highlight the impact of feeder loading and DER location on hosting capacity. In all loading cases except the 20%, DER was able to be interconnected without consuming capacity for the entire feeder. In general, the results show that more hosting capacity is realizable if DER is interconnected closer to the substation and as more load is added.

C. Stakeholder Engagement

1. *Additional Stakeholder Input Requested by the Commission*

Several stakeholders submitted comments to the Commission on our 2018 Hosting Capacity Report, indicating a need to improve both the analysis and the presentation of results in order to provide more comprehensive and meaningful information. The Commission's August 2019 Order acknowledged the importance of stakeholder opinion and involvement, requesting that we work with stakeholders to:

- Improve the value of Xcel's hosting capacity analysis, including but not limited to the provision of more detailed substation, feeder, and other equipment data in its public-facing hosting capacity map,
- Collaborate with stakeholders in evaluating the costs and benefits associated with a hosting capacity analysis, with respect to the following objectives:
    - HCA remains an early indicator of possible locations for interconnection;
    - HCA replaces or augments initial review screens and/or supplemental review in the interconnection process; and
    - HCA automates interconnection studies.

We engaged our stakeholders to provide feedback on these topics in two ways: 1) we organized an HCA stakeholder workshop on September 6, 2019 and 2) conducted an online survey after the workshop later in September 2019. A presentation for the workshop is included as **Attachment D** and the survey questionnaire is included as **Attachment E**.

We emailed invitations to the Hosting Capacity Workshop (Workshop) and Survey to approximately 300 individuals on our internal Solar*Rewards and Solar*Rewards Community program list. The invite was also forwarded by the Minnesota Solar Energy Industries Association (MnSEIA) to its members. Approximately 15 stakeholders – most of them representing solar developers – participated in the Workshop or responded to the Survey. While the feedback from these participating stakeholders is informative, we note that they represent only a small portion of the total public or parties who are interested or involved in developing DER.

2. Workshop Discussion and Survey Results

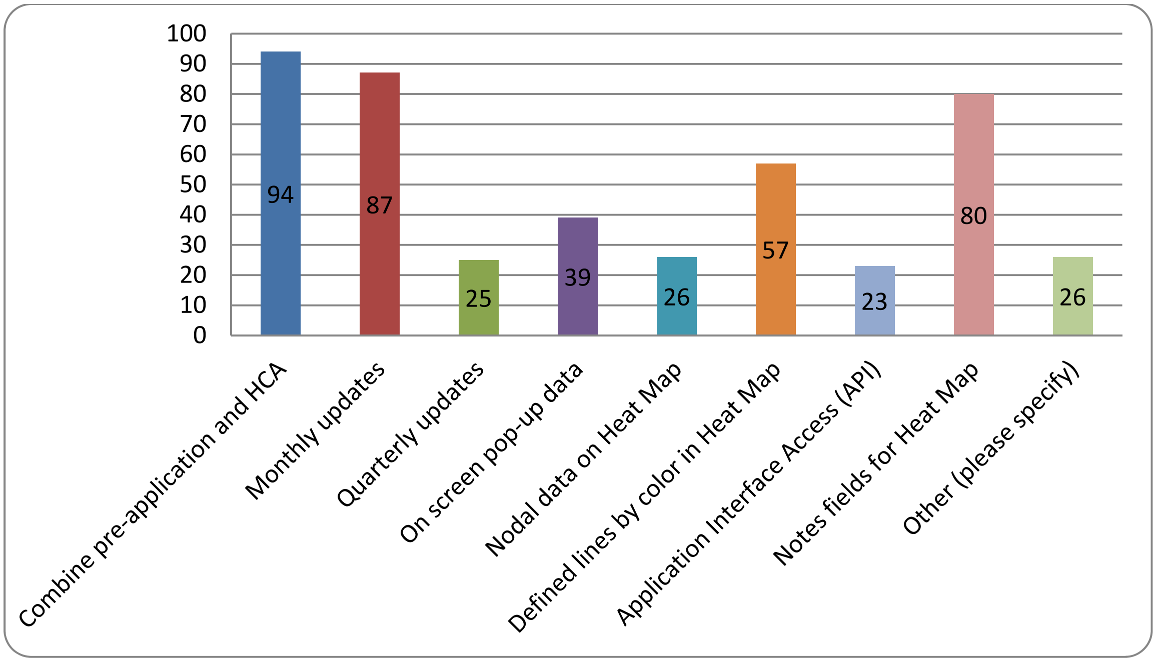
The key takeaway from the Workshop and Survey is that the stakeholders believe that the current HCA (as it was conducted in 2018) is not useful unless the presentation of results contains more detailed information. Participants stated that they use the HCA to identify viable potential locations for interconnections and to determine whether to request a more detailed pre-application report for a particular site. The participants stated that ideally the HCA would be integrated with the pre-application report. They also requested that the heat map and tabular spreadsheet include more detailed data for each substation and feeder.

The Workshop identified the following additional information as urgent: substation name, location, and transformer capacity; feeder name, voltage, and location; line characteristics (phase, overhead/underground); queued distributed generation (DER) capacity; daytime minimum load; and voltage regulation. The Workshop thought it was less urgent to include the number of feeders and transformers at substation, load profile, daytime maximum load, and service territory lines. The Survey results were less consistent, but indicated that several points of data are needed, including queued DER capacity and feeder details. Peak load for substation transformer or feeder were not mentioned as necessary data by the Workshop or Survey participants.

Based on this stakeholder feedback, we decided to include additional data in the heat map and tabular spreadsheet, as discussed above under the HCA methodology section. The stakeholders indicated that the main benefit from this additional data is that resources and time would no longer be spent on reviewing sites that are unsuitable because of capacity constraints or high distribution system upgrade costs. Several Survey respondents said that they spend a considerable amount of money developing a site before they know whether the site will accommodate additional DER. One developer indicated that typically 1 out of 4 projects submitted for interconnection will turn out to be unviable for a number of reasons, such as permitting, zoning or other land use restrictions, or prohibitively high interconnection cost. While the participants stated that a more detailed presentation of HCA results would generate savings, they said it was difficult to give specific estimates of these savings.

We also asked Workshop and Survey participants what additional functionality or features would be useful in the future. The stakeholders listed the following features: combining pre-application and hosting capacity information; providing a link to pre-application data; updating the HCA/heat map more frequently; adding on-screen display of key data points and a notes field; showing defined lines by color instead of blurred presentation; and including more granular locational data (node data). Figure 2 below shows the Survey results for ranking the five most important functionality changes for the HCA and heat map.

Figure 2: Rank the FIVE Most Important Functionality Changes for the HCA (Reported by Rank Score)



Based on this stakeholder feedback, we have added on screen pop-up functionality in the heat map, displaying additional data.

The stakeholders suggested combining pre-application and HCA data instead of maintaining two separate, but duplicative data sets. All respondents to the survey indicated that they would pay for a more detailed HCA combined with pre-application information, but most respondents were not willing to pay more than $300 per query. As noted previously, we have made enhancements to our heat map and added data into pop-ups. Over half of the items included in the pre-application report can now be taken directly or derived from the map. The remaining items are either difficult to provide on a case-by-case basis or present security and privacy concerns.

Despite some obvious benefits, there are some major barriers for fully integrating the pre-application data request with the HCA. As the 2019 HCA Report discusses in more detail, the collection to compile the pre-application data is extensive and would involve creating new types of query programs for GIS and Salesforce data. There are currently no existing programs that could integrate these queries with the web-based hosting capacity map, which would need to be outfitted with entirely new coding functions. In addition, currently this data is collected manually, which enables the engineers to scrub and correct the data for any obvious mistakes, which would not be possible with an automated web-based data collection.

It would take extra time, resources, and funding to integrate the pre-application data request with the hosting capacity map. It is also likely that the integrated tool would have a fee for use, similar to the current pre-application data request. We are concerned that the hosting capacity map was originally intended for public use free of charge, but the integrated tool would no longer serve this important public purpose.

Since the pre-application report is the most common and simple request that the Developers use in assessing DER, it logically follows that the Company would first focus on integrating this process with the hosting capacity map, before considering more complex screens and engineering studies. But even this less complicated integration is challenging and requires additional programming, coding, and resources.

D. Customer Privacy and System Security Considerations

The Commission's August 2019 Order acknowledged the tension between the need to provide information to support the continued development of DER, and the need to protect customer privacy and system security. This Order required the Company to provide publicly some additional data, but also qualified the Company's duty to protect that data when providing the information publicly would violate a specific data privacy requirement or pose a significant security risk to the Company's system or customers. In this event, the Order required the Company to provide a full description and specific basis for withholding that information, including any claim that the information is Trade Secret. (August 2019 Order, pp. 11 and 14).

As noted above, we have added information to the presentation of the 2019 HCA results, based on the Commission's Order and stakeholder feedback that this information is important to them. The new data includes the following: feeder name, substation name, daytime minimum feeder load, daytime minimum substation load, existing DER on substation, existing DER on feeder, queued DER on substation, queued DER on feeder, available hosting capacity, limiting threshold, feeder voltage level, line phasing (single/three), line type (overhead/underground), field voltage regulator location, and substation location. All of this data has been treated as public in this filing, the heat map, and tabular spreadsheet of HCA results. Providing public access to this information demonstrates our commitment to increase the value of our HCA.

We have continued to not to disclose publicly certain data, and provide support for our non-public treatment of the following information:

1.) Certain feeders are not shown on the heat map in an effort to not publicly display information that we believe is protected by the Company's 15/15 data aggregation standard[6] to preserve the anonymity of customer usage information or aligns with protecting Critical Infrastructure Sectors (CIS) as identified by the U.S. Department of Homeland Security (DHS). Showing this information on the heat map would make it easier to identify actual customer connections and create further customer privacy and CIS concerns. However, we provide data for all feeders publicly on the tabular spreadsheet. This spreadsheet does not identify which feeders fall under the 15/15 standard or CIS categories, consistent with our goal to not make it easy to identify which feeders have sensitive privacy or security concerns. Again, we have determined this approach – not to specifically mark feeders with privacy or CIS concerns on the spreadsheet – so that it would not be apparent for a bad actor to target sensitive feeders.

2.) The tabular spreadsheet does not publicly provide the peak substation transformer load or peak feeder load data, and this data is also excluded from the public heat map. Although the Commission specified peak feeder load information be provided with our 2019 HCA results, the developers who attended our Workshop or participated in the post-workshop Survey did not state that peak load was a necessary or useful piece of information, even when prompted. We have traditionally protected peak load information as not public for both customer privacy and grid and customer security reasons. While we can mitigate customer privacy concerns by applying the 15/15 standard, grid security concerns remain. Publicly publishing peak load or maximum capacity information for our system components would allow bad actors to target an attack for maximum impact and disruption. For these reasons, we provide this information required by the Commission's Order in a non-public version of the tabular spreadsheet.

We have marked information as protected data consistent with the application of the 15/15 standard as discussed in *In the Matter of a Commission Inquiry into Privacy Policies of Rate-Regulated Energy Utilities* (Docket No. E,G999/CI-12-1344. The 15/15 standard imposes two restrictions to protect customers' privacy: (1) An aggregation must contain at least 15 customers or premises per customer class; and (2) A single customer or premise cannot account for 15 percent or more of data of the aggregated group. Consistent with the Commission's January 19, 2017 Order in that docket, the Company filed its aggregation and release policies on February 10, 2017 and further explained the 15/15 standard in that filing. The information marked as protected data is not public and is accessible to individual subject of those data. Pursuant to Minn. Stat. § 13.37, subd. 1(b)., the information is Trade Secret as the specific customer

[6] This 15/15 data aggregation standard applied to the HCA identifies feeders that serve less than 15 premises and feeders where the load of one customer is 15 percent or more of the feeder's load. This standard is described in more detail later below.

information derives independent economic value, actual or potential, to Xcel Energy, its customers, suppliers, and competitors, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use. Disclosure of the trade secret provisions would have a detrimental effect by providing valuable information not otherwise readily ascertainable and from which could be obtained economic value.

Under typical circumstances, we would make the peak load data available to parties upon request and under protection of a non-disclosure agreement (NDA). However, this would require that we still mark data on those feeders that fall under the 15/15 standard as non-public in order to protect third-party private information. As explained above, this marking in itself would identify the feeders that fall under the 15/15 standard, disclosing that these feeders contain sensitive private information and defeating the purpose of protecting that information. We have not been able to find a solution to this "Catch-22" dilemma, and therefore have determined that we cannot provide the peak load information to parties even under an NDA. We are looking forward to further discussions with other parties on this issue.

We continue to be concerned with the risks of providing more detailed information on our distribution system publicly in the hosting capacity heat map or tabular spreadsheet. Current technological capabilities of combining information from various sources make protection of customer privacy and system security a complex issue. Publicly disclosing information that at first hand seems low-risk may in fact have unintended and irreversible consequences. Once information has been made public, it cannot be retrieved. Understanding and treatment of customer privacy and system security information continues to evolve across the utility industry.

An example of the continued learning in the industry is the attached joint petition filed at the Public Utilities Commission of the State of California on December 10, 2018[7] (included as **Attachment F**). The petition points out the serious risks of making certain hosting capacity information public and seeks to further restrict the types of hosting capacity information that should be publicly available. As of October 28, 2019, the California Commission has not ruled on that petition, but the petition shows how knowledge about the risks of making certain hosting capacity information public continues to evolve.

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[7] Joint Petition of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company for Modification of D.10-12-048 and Resolution E-4414 to Protect the Physical Security and Cybersecurity of Electric Distribution and Transmission Facilities, *Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program*, Rulemaking 08-08-009.

Further, through creation of a new arm of DHS, the Cybersecurity and Infrastructure Security Agency (CISA) has identified 16 critical infrastructure sectors whose assets, systems, and networks are considered so vital to the United States that their incapacitation or destruction would have a debilitating effect on security, national economic security, national public health or safety, or any combination thereof (see, https://www.cisa.gov/critical-infrastructure-sectors).[8] These sectors are: Chemical, Commercial Facilities, Communications, Critical Manufacturing, Dams, Defense Industrial Base, Emergency Services, Energy, Financial Services, Food and Agriculture, Government Facilities, Healthcare and Public Health, Information Technology, Nuclear Reactors Materials and Waste, Transportation Systems, and Water and Wastewater Systems. As explained below, we have correlated certain of these categories with our decision to remove from the heat map those feeders that serve these critical infrastructure sectors.

As we have stated previously in the hosting capacity context, at the state level, the Commission has examined customer privacy and confidentiality in terms of Customer Energy Usage Data (CEUD) and customer Personally Identifiable Information (PII).[9] At a national level, we have looked for guidance from the National Institute of Standards and Technology (NIST), North American Electric Reliability Corporation (NERC), Federal Energy Regulatory Commission (FERC) and DHS. We found that existing regulatory, legal, and industry frameworks provide little specific guidance with respect to data security protections and customer privacy and confidentiality considerations as it relates to distribution grid data. We are hopeful however, with CISA now in place and having authority over all energy infrastructure, we can engage in a new industry dialogue about the distribution grid's role as part of the nation's critical infrastructure.

We have considered existing national and state sources as advisory – also now factoring in the DHS CIS – and developed criteria to apply to the visual hosting capacity results that would protect what we believe is sensitive and therefore non-public grid and customer information. We did this while also balancing public policy

[8] CISA is a new federal agency, created to protect the nation's critical infrastructure. It was created through the Cybersecurity and Infrastructure Security Agency Act of 2018, which was signed into law on November 16, 2018. CISA is responsible for protecting the nation's critical infrastructure from physical and cyber threats. Its mission is to "build the national capacity to defend against cyber attacks" and to work "with the federal government to provide cybersecurity tools, incident response services and assessment capabilities to safeguard the .gov networks that support the essential operations of partner departments and agencies."

[9] Docket No. E,G999/CI-12-1344, *In the Matter of a Commission Inquiry into Privacy Policies of Rate-Regulated Energy Utilities.*

considerations that some may believe should result in full disclosure. In terms of customer privacy and confidentiality, we considered the Commission's decisions on customer PII and CEUD. While grid and customer connection details were not directly implicated in that proceeding, the Commission directed utilities to look to NIST principles for guidance with regard to collection and protection of customer PII – and required utilities to refrain from disclosing CEUD without the customer's consent unless the utility has adequately protected the customer's anonymity. In looking to NIST and other national standards that are generally applicable to the transmission grid, we found that they are broad and largely rely on utilities' judgement to apply them to their infrastructure.

We therefore have continued to apply our judgement within the broad guidance provided by these sources to develop more specific criteria that we believe balance public policy objectives with the public interest, in terms of energy security and national security as well as our customers' interests, in terms of their privacy and confidentiality.

Specifically, as in the 2018 HCA Report, we worked with our customer account management group to identify the customers and their associated feeder(s) that would fall into the following categories:

- Critical Energy Infrastructure (similar to DHS Energy sector) on distribution feeder,
- Critical Hospital - Level 1 or 2 Trauma Center (similar to DHS Healthcare and Public Health sector) on distribution feeder,
- Critical Data Center (similar to DHS Communications and Information Technology sectors) on distribution feeder, and
- Critical Public Gathering Center (similar to DHS Commercial Facilities sector) on distribution feeder.

This listing is not as robust as the 16 categories developed by the DHS, but it is consistent with what has already been publicly released. As we noted previously, feeders that met the security criteria listed above are excluded from the heat map but included on the tabular spreadsheet.

Again, as in the 2018 HCA Report, we then identified feeders serving less than 15 premises, which is the same threshold we apply to requests for aggregated CEUD – feeders with such low density may provide insights into those customer locations that could compromise customer confidentiality and/or customer energy security. We also identified feeders where the load of one customer was 15 percent or more, again, with the rationale that publicly disclosing these feeders could compromise customer privacy. Feeders that fell under this 15/15 standard were excluded from the heat map but included on the tabular spreadsheet.

We note that the Minnesota Government Data Practices Act (Minn. Stat. § 13.01 et seq.) addressing nonpublic data (Minn. Stat. § 13.02, subd. 9), private data on individuals (Minn. Stat. § 13.02, subd. 12), security information (Minn. Stat. § 13.37, subd. 1(a)), and trade secret information (Minn. Stat. § 13.37, subd. 1(b)), is not directly applicable to the Hosting Capacity heat map. The Minnesota Government Data Practices Act only addresses information held by state government. Here, the Hosting Capacity heat map developed by the Company has been publicly filed, and there is no trade secret or nonpublic version of the heat map on file with state government. Instead, in preparing the heat map, the Company has been sensitive to what could be considered to be nonpublic under this Act, and prepared the heat map to reflect these concerns.

In summary, we excluded from the public heat map 115 feeders out of a total of 1,050 feeders used for the 2019 HCA, applying the security and privacy criteria outlined above. We have also continued to blur the lines in the heat map presentation. On the tabular spreadsheet (Attachment B), we have marked as non-public the peak load data for substation transformers and feeders.

CONCLUSION

Our 2019 HCA and Report together with the IDP for 2020-2029 represent significant progress in the distribution system planning and integration of DER to the Company's system. The IDP provides comprehensive information on our distribution system and proposes tools to advance our grid and planning capabilities. The HCA provides detailed information to assist in identifying available locations and constraints for DER interconnection as well as for identifying necessary upgrades to support continued DER development. We have improved the 2019 HCA in many ways, such as by conducting new analyses, using actual values for several data components, and including more information in the presentation of results. The 2019 HCA is the culmination of lessons learned – from out past analyses, stakeholder feedback, and current industry practice.

Dated: November 1, 2019

Northern States Power Company

2019 Hosting Capacity Analysis Report

Xcel Energy
November 1, 2019

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Hosting Capacity Analysis Report

INTRODUCTION

Xcel Energy (the Company) filed its first Hosting Capacity Analysis (HCA) Report in December 2016, and has filed subsequent HCA Reports annually on November 1. For each HCA, we have used the DRIVE tool, developed by the Electric Power Research Institute (EPRI). Our methodology, data collection, presentation of results, and the DRIVE tool have evolved each year, improving the quality and usefulness of the HCA Report. Our 2019 HCA Report is the culmination of lessons learned thus far and provides enhanced methodology, analyses, and presentation.

Our objective for the HCA is aligned with Minn. Stat. § 216B.2425, subd. 8, which defines two primary statutory objectives for the HCA: 1) identifying available locations for DER interconnection on the distribution system, and 2) identifying upgrades necessary to support continued development of distributed generation. In our view, the HCA plays an important role in streamlining the interconnection process by assisting Developers in choosing sites that potentially require only technical screening or a less involved study for interconnection, as we believe was intended by the statute.

Unless otherwise noted, we have used in the 2019 HCA the same DRIVE tool features, overall methodology, and data components as in our 2018 HCA. However, we have also made several improvements and changes to our 2019 HCA, which are listed below:

- *Use of Actual Daytime Minimum Loads:* We prioritized finding the actual Daytime Minimum Load (DML) values for every feeder that had large amounts of existing interconnected DER and as a result, used actual DML data for approximately 25 percent of the feeders in the DRIVE analysis. We continued to establish actual DML values during the rest of the HCA process, and 100 percent of feeders in the heat map and tabular results spreadsheet have actual DML data.
- *Use of Actual Power Factors:* For the first time in the 2019 HCA, we used actual feeder power factor values where possible. The vast majority of the feeders in the analysis have actual power factor values; in the previous HCA Reports we used an assumed power factor of 99% lagging.
- *Use of Unintentional Islanding Threshold:* We utilized the "Unintentional Islanding" threshold that has been modified within DRIVE. This threshold no longer evaluates violations on every point of a feeder. Instead, unintentional islanding is examined only at major protective devices, such as breakers or reclosers,

based on those specific locations.

- *Additional Data in Results Presentation:* The heat map and tabular spreadsheet display significantly more data than in prior HCAs, such as minimum load and generation information. The heat map has also new functionality, a pop-up screen that shows the additional data.
- *Feeder Model Building:* We rebuilt (i.e., extracted GIS asset data for) approximately one-third of the feeders in the analysis, focusing on those feeders that had experienced large configuration, load, or generation changes. Building the feeder models is one of the most resource-intensive parts of the HCA, and we decided not to rebuild those feeders that did not have any significant changes.
- *Max Tap Regulator Setting:* We utilized the DRIVE tool's "Maximum Tap Regulators in Over/Under-Voltage Analysis" setting. This setting adjusts the voltage within the regulation zones to the bandwidth of the regulator for consideration in the Over-Voltage threshold. This could result in slightly less hosting capacity for instances where regulators are installed.

I. DRIVE TOOL

A. DRIVE Features and Evolving Capabilities

As a means to automate and streamline hosting capacity analyses, EPRI introduced the DRIVE (Distribution Resource Integration and Value Estimation) tool in 2016. The DRIVE tool is based on EPRI's streamlined hosting capacity method, which incorporates years of knowledge from detailed hosting capacity analyses conducted by EPRI in order to screen for voltage, thermal, and protection impacts from DER.

Due to EPRI's work in the field and our recognition of the value that a hosting capacity tool would bring, we sought out a partnership with EPRI in 2015 to assist in the development of the DRIVE tool. We believe that DRIVE, which has expanded its reach in the industry since we started using it, continues to be the best tool to conduct our HCA. DRIVE is currently used by more than 25 utilities, including the Joint Utilities of New York,[1] Salt River Project, Tennessee Valley Authority, and Southern Company. As DRIVE has expanded its reach, industry and stakeholder collaboration has been beneficial in creating consistency with the DRIVE application and methodologies.

[1] Con Edison, National Grid, Central Hudson, Orange and Rockland, NYSEG/RGE.

As part of that collaboration, EPRI has published a Technical Report on Hosting Capacity,[2] which provides an overview of the current state of industry methods and compares the benefits and disadvantages of various approaches to evaluate hosting capacity.

Similar to prior years, we have expanded and improved our 2019 HCA based on lessons-learned from our ongoing use of DRIVE and updates EPRI has made to DRIVE. This past experience of DRIVE use and improvements made to DRIVE continue to confirm our confidence in the tool.

EPRI has made several enhancements to the DRIVE tool since our 2018 HCA was completed. We used many, but not all of the new DRIVE features in our 2019 HCA. The following lists the DRIVE enhancements and indicates if we used them in the HCA:

- Evaluation of substation impacts, including backfeed, ground fault overvoltage protection (3V0).
- Better aggregation of results for mapping and tabular display (utilized).
- Error handling information when the model is failing or the program crashes (utilized).
- Consolidation of outputs such as new nodal output summary (utilized).
- Information on existing hosting capacity violations such as pre-existing overvoltage.
- Display equipment on DRIVE map (utilized).
- Reconfiguration assessment, which allows for an analysis with predefined switching for different feeder configurations.
- Centralized DER hosting capacity conducted on single and two-phase nodes (utilized).

EPRI has also already announced that it plans to make further changes to the DRIVE tool that will be available for our 2020 HCA. These changes are listed below, with a note whether we are considering to use these new features for the 2020 HCA:

- Translation of hosting capacity results for other DER types.
- Steady-state overvoltage, which allows controls to move after the addition of

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[2] *Impact Factors, Methods, and Considerations for Calculating and Applying Hosting Capacity*. January 31, 2018. https://www.epri.com/#/pages/product/3002011009/?lang=en-US.

DER (considering for next year).

- Analysis with combined Distributed DER and Centralized DER (considering for next year).
- Distributed load and DER growth.
- Parallel processing to increase solution speed (will utilize next year).
- Flicker calculation (considering for next year).
- Show or report on violated elements/locations.
- Improved report formatting (will utilize next year).
- Feeder Summary Report showing results only for metrics selected (will utilize next year).
- Pointing to minimum load allocations or minimum load multipliers for each feeder (considering for next year).

For purposes of the 2019 HCA, our definition of DER is aligned with IEEE 1547-2018 and the Minnesota Distributed Energy Resources DER Interconnection Process (MN DIP).[3] DER is defined as:

> *Sources and groups of sources of electric power that are not directly connected to a bulk electric system. DER includes both generators and energy storage technologies capable of exporting active power to an electric power system (EPS). An interconnection system or a supplemental DER device that is necessary for compliance with this standard is part of a DER.*

Our modeling considered only DER that acts as a generation source to the distribution system. DER that behaves primarily as an energy source (i.e., solar, wind, biomass) tends to only reduce hosting capacity. In contrast, battery storage has the potential to act as a load to reduce thermal and voltage impacts, effectively increasing hosting capacity, if sited and coordinated properly with DER output. It is possible for large amounts of energy storage acting as a load on a feeder to cause system constraints that appear like typical system loading limits managed by utilities for many years; this can occur at times of no DER generation or when the storage load greatly exceeds the DER generation. Our 2019 HCA did not take into consideration the load characteristics of battery storage, because we do not believe the penetration of energy storage on our distribution system (approximately 35 projects) has yet reached a level

[3] The MN DIP definition has an additional sentence related to the process, but not necessary for hosting capacity: "For the purpose of the MN DIP and MN DIA, the DER includes the Customer's Interconnection Facilities but shall not include the Area EPS Operator's Interconnection Facilities."

where the benefits of such additional analysis would justify the required resources.

The DRIVE tool has the capability to analyze also the load characteristics of the newer forms of DER, including battery storage and electric vehicles (EVs). These load hosting capacity results could be used to identify areas with greater potential for siting EV charging stations or other loads associated with beneficial electrification, but we consider this type of analysis as part of traditional distribution planning rather than part of HCA. Our Integrated Distribution Plan for 2020-2029 discusses in detail how the Company is making investments to increase access to EVs and proposing a range of innovative programs that support the growth of EVs in Minnesota.

B. DRIVE Comparison – Other Tools and Other Utilities

The following discussion on industry practices relies heavily on the 2018 EPRI Technical Report on Hosting Capacity referenced above. There are currently four main ways to analyze hosting capacity in the industry today: the Stochastic, Streamlined, Iterative and Hybrid methods. Exelon Corporation companies, such as Potomac Electric Power Company (Pepco)s and Commonwealth Edison (ComEd), have used the stochastic method while the California utilities have used both the Iterative and Streamlined Integrated Capacity Analysis (ICA) methods. Table 1 below summarizes the four methods.

Table 1: Four Main Methods to Analyze Hosting Capacity

Method	Industry Adoption	Recommended Use Case
Stochastic	Pepco, ComEd	+Enabling Planning +Informing the public
Iterative	SCE, SDG&E	+Assisting with Interconnection +Informing the public
Streamlined	PG&E	+Enabling Planning +Informing the public
Hybrid – DRIVE	>27 utilities worldwide (including Xcel, NY)	+Enabling Planning +Assisting with Interconnection +Informing the public

We continue to believe DRIVE is the right tool to conduct our HCA to help inform where our system has availability to interconnect DER. As a hybrid method, DRIVE has several benefits, including speed of processing, accuracy of results, and multiple-use cases. Another advantage is our history of past DRIVE use and ability to participate in further tool development and modification. DRIVE's continued growth in popularity has enhanced consistency across the industry in analyzing hosting capacity.

EPRI has conducted several evaluations on hosting capacity methods, which all reached parallel conclusions. EPRI recognized that hosting capacity methods are continuously evolving and found that different hosting capacity methods can provide similar, accurate results. EPRI concluded, however, that a hybrid method – such as DRIVE – is the most likely and successful path going forward.[4]

We include as **Appendix A** a summary that discusses in more detail the features, benefits, and disadvantages of different hosting capacity methods, based on the 2018 EPRI Technical Report on Hosting Capacity.

II. 2019 HCA METHODOLOGY

A. Overview

For the 2019 HCA, we created 1,050 feeder models in Synergi Electric, which is the Company's distribution load-flow program. The information for these models primarily came from our Geographic Information System (GIS). We supplemented the GIS information with data from our 2019 load forecast (prepared in 2018) and historic actual customer demand and energy data. To build the feeder models, we first extracted asset data from GIS to Synergi, and then ran a series of "clean-up" scripts to provide model assumptions and to address any common issues that may be present in the data. Unlike for the 2018 HCA, for this analysis we only extracted about one-third of the feeders from GIS to Synergi in an effort to reduce building time for feeders that did not have any significant changes to them. We focused on feeders that had experienced large configuration, load or generation changes.

The feeder model clean-up includes several tasks, such as specifying the head-end voltage, burial depths on underground cable, height of overhead conductor above the ground, and equipment settings for capacitors, reclosers, and regulators. If errors persisted in any of the feeder models, we worked to find the source(s) of the issues, including consulting other maps, performing visual inspections in the field, and calling Synergi for assistance with unique errors.

Once we had addressed all identified errors in a particular feeder model, we allocated the load to the feeder based on demand data and customer energy usage data. At this point, we ran a load-flow and performed a final check for any abnormalities on the

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[4] *Impact Factors, Methods, and Considerations for Calculating and Applying Hosting Capacity*. January 31, 2018, pages xi-xii, 5-2. https://www.epri.com/#/pages/product/3002011009/?lang=en-US.

feeder. After creating all of the feeder models, we analyzed them using DRIVE, which performed the hosting capacity technical analysis.

Our analysis is relevant for DER that acts as an energy source on the distribution system. We did not take the *load characteristics* of DER devices such as energy storage into consideration in our analysis. Therefore, inclusion of an under-voltage threshold was not necessary. DER sources that create reverse power flow may cause high voltage conditions. A DER device such as a battery storage device acting as a large load could potentially create low voltage conditions. Future analysis aimed at understanding the impacts of storage device load characteristic on the distribution system would need to include both load and generation characteristics of DER. Due to low penetration of energy storage in Minnesota generally and on our distribution system specifically, we excluded energy storage load characteristics from our analysis. However, we continue to monitor the energy storage market and incorporate energy storage into the analysis in the future as necessary.

Table 2 below shows interconnected DER by type on our distribution system as of July 2019. Our system has predominantly large-scale DER, nearly 700 MW of community solar gardens and grid-scale solar. In contrast, small-scale solar and wind totaled only about 100 MW. As discussed in more detail in our Integrated Resource Plan for 2020-2029, we expect this gap to widen in the next 5-10 years when our Community Solar Garden program continues to grow and add large-scale distributed solar on our system.

Table 2: Interconnected DER in the Company's Minnesota Distribution System (July 2019)

	Completed Projects		Queued Projects	
	MW/DC	# of Projects	MW/DC	# of Projects
Small-Scale Solar PV				
Rooftop Solar	67	4,391	61	1,101
RDF Projects	19	25	1	2
Wind	16	61	<1	8
Storage/Batteries[5]	N/A	35	N/A	20

	Completed Projects		Queued Projects	
	MW/AC	# of Projects	MW/AC	# of Projects
Large-Scale Solar PV				
Community Solar	585	208	313	286
Grid Scale (Aurora)	100	16	0	0

In addition, all utilities provide detailed information on the types of DER currently on their system in an annual March 1 filing in Docket No. E999/PR-[YEAR]-10. The link to the Company's March 2019 Distributed Generation Interconnection Report is: Live Public File.

B. Large Centralized Is the Appropriate DER Allocation Method

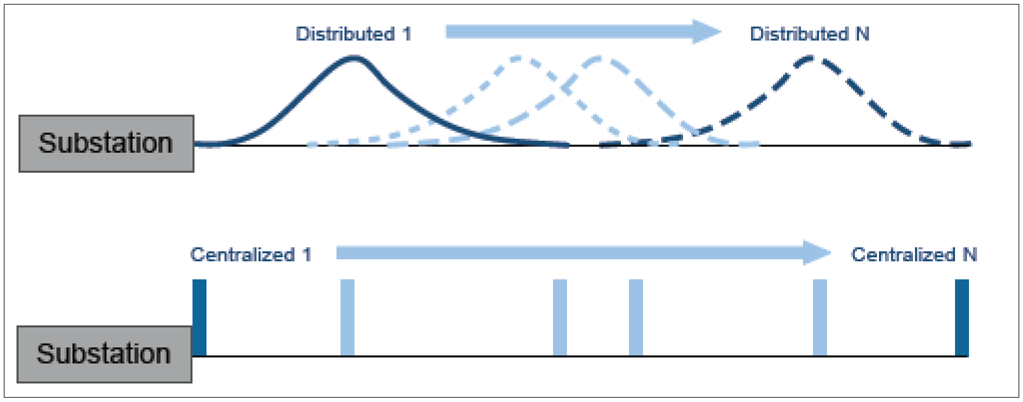
The DRIVE tool uses three different methods for allocating DER across a feeder. Each method is intended to cover a different DER deployment scenario:

1. *Large Centralized:* Considers large DER at a single location and does not consider DER at any other location on the feeder.
2. *Large Distributed:* Considers distribution of large DER at different feeder locations.
3. *Small Distributed:* Considers distribution of small DER at different feeder locations.

Figure 1 below demonstrates the difference between the distributed and centralized methods.

[5] All current battery projects are associated with other generation projects, such as solar. Therefore, any battery generation is accounted for in other DER categories and not listed duplicative here.

Figure 1: Difference Between the Distributed and Centralized DER Scenarios



Consistent with our 2018 HCA Report, we used the Large Centralized allocation method for this analysis. Our continued use of the Large Centralized method is supported by the amount of large-scale community solar gardens in service, already exceeding 625 MW of installed capacity in Minnesota as of October 2019. The Small Distributed method would be appropriate for a distribution system that has predominantly small-scale DER installations, such as rooftop solar and small wind. However, as Table 2 above shows, adoption of small-scale DER is relatively insignificant compared to community solar gardens – the total installed capacity is approximately 100 MW on our distribution system.

Use of the Large Centralized method affects the hosting capacity results by generally showing a larger maximum hosting capacity and smaller minimum hosting capacity. The Large Centralized method only focuses on installations on three-phase lines, which generally have more capacity and better align with the types of DER installations we experience on our system. The smaller minimum hosting capacity that results from this method is due to the concentration at specific locations, which has the tendency to affect the overvoltage and thermal violation thresholds a little more than distributing the load across the feeder. Consequently, that concentration also unmasks the potential to add more generation at ideal locations on the feeder (maximum hosting capacity).

1. *Secondary Voltage Level Equipment Data*

The Commission has requested that we consider the feasibility and practicality of including the results of both the Small Distributed method and the Large Centralized method in our hosting capacity analyses.

Our understanding of the main purpose of the HCA is that it provides realistic hosting capacity results at the primary voltage level for installations up to 1 MW, rather than informs small rooftop-style installations of available hosting capacity at the secondary voltage level. If there is available hosting capacity on a particular feeder, it is not necessarily indicative of whether upgrades are required for small secondary-connected DER. Likewise, if a particular feeder does not have hosting capacity available on a feeder, it does not necessarily mean that a small secondary-connected installation will be prohibited from interconnecting.

The accuracy of the results using the Small Distributed method are dependent on the inclusion of secondary voltage equipment data in the modeling, because most violations for small-scale installations occur on the secondary voltage level from the service transformer to the customer's meter. Since the Company does not maintain detailed secondary information beyond the transformer in its systems, using the Small Distributed method would have limited usefulness.

Data collection and modeling for the typical utility have focused on the transmission, substation and primary voltage systems – driven by the need to repair and modify our system as well as the evaluations necessary for planning and operations. Knowledge of the precise attributes of secondary systems has been less important, because utilities – including the Company – have been able to provide high quality service based on consistent standards and processes without the cost of collecting and maintaining detailed secondary system records.

Our knowledge of the secondary-system for transformer size and connectivity (i.e., which customers are connected to each transformer) is quite good. We know less about the secondary conductors. But over time, our processes have evolved and we now collect more detailed secondary information. For instance, we now record such attributes as type of installation, configuration, and installed length. However, gathering complete data on all necessary secondary components accurately would require additional field collection.

Collecting and validating field data is a costly, manual process. With over 1.3 million Minnesota electric customers, significant time and effort would be needed to visit each site with a secondary service. Collection would entail validation of the conductors – material, size and distance – of each common secondary line (serves multiple customers and branches into individual services) and each service line (serves an individual customer). The validation for overhead conductors may require aerial work and the validation of underground conductors requires qualified operators to open and locate equipment to identify the path of underground cables to quantify conductor length.

The validation of field data would take considerable time and effort, and additional resources would be necessary to update the GIS system with the findings. The costs of the whole effort would have a magnitude in the hundreds of millions of dollars.

The primary goals of using secondary data in a hosting capacity analysis are to prevent transformer overload, conductor overload, and over/under voltage. Today, the analysis capabilities are hampered more by the lack of interval data than by the gaps in secondary attribute data. Even with very specific secondary data, load and DER coincidence must be estimated, which understandably results in a lack of precision. With interval data, however, we will be able to calculate the DER impact based on coincident levels. We will also know the actual coincident loading and max/min voltage levels. These data will be sufficient, in nearly all cases, to properly determine DER impacts.

Rather than investing in costly field collection, the Company plans to leverage Advanced Metering Infrastructure (AMI) in the near future to gain information on its secondary system. AMI will assist in collecting transformer loading data, which will help us plan for increases in load or DER. AMI will also help us identify locations where customers are experiencing high or low voltages. We also anticipate mining and analyzing AMI data further for additional value and opportunities.

Analyzing hosting capacity is complex – and preparing two separate sets of results for very small and larger DER installations would complicate and increase the work involved. We do not believe there are benefits that would merit this extra work, particularly because the results for small secondary-connected installations would have questionable accuracy and value. While it is feasible to run the DRIVE analysis with both the Large Centralized and Small Distributed Methods, we do not believe it is currently beneficial.

However, we recognize the interest in providing hosting capacity evaluation for small, secondary-connected installations and have collaborated with EPRI to provide a solution that would not involve two separate sets of analyses. We see potential value in combining both the Large Centralized and Small Distributed methods, and have worked with EPRI to develop a new method that can accomplish this. The enhanced method will be available in the next version of the DRIVE tool and we will evaluate further whether to use it in our 2020 HCA.

C. Assumptions

The assumptions we applied to the 2019 HCA are consistent with the assumptions that we made for the 2018 HCA, except for the loading levels and feeder power factors. This year, we used the actual daytime minimum load values in the DRIVE analysis for those feeders that have significant amounts of DER on them (approximately 25 percent of feeders). We also used the actual power factors for most feeders instead of the assumed 99% lagging that was used in prior HCAs.

We applied the following assumptions to the 2019 HCA:

Data – We assumed the feeder-specific data from GIS was correct. In some instances, however, we made modifications to the data after verification. The primary validation of data took place when we created the feeder models within Synergi, our distribution load flow tool, as discussed above. When we manually allocated load to the feeder and run a load flow process, exceptions sometimes occurred. As a result, areas of the feeder were then highlighted due to overloading, high or low voltage, connectivity issues, and so on. The engineer would then further investigate the feeder model for any obvious issues, such as field equipment turned off or a lack of connectivity. If that did not resolve the issue, the engineer would then consult GIS or feeder maps that may have information different from what is in the model, or take other actions to verify or resolve the potential issues. When data modifications were necessary, they typically included conductor changes or various equipment updates.

Secondary Conductors – Secondary conductors connect from service transformers to the customer service entrance. The characteristics of secondary conductors combined with a high level of DER can lead to high voltage conditions on the customer premise. This has the potential to trigger conductor upgrades for interconnection of small residential or commercial DER systems. Since detailed secondary or low-voltage conductor information is not recorded in GIS, we were unable to account for the impacts beyond the medium-voltage (i.e., primary) distribution system. However, we have traditionally assumed a three Volt drop across the secondary conductors and transformers to ensure compliance with ANSI C84.1.[6] This means that when we model voltages on the primary system, we subtract three additional Volts to better quantify the actual voltage at the customer level.

Conductor Spacing – Conductor spacing, or the distance between lines, impacts the electrical characteristics of distribution lines. In the Synergi impedance model, we assumed that the conductor spacing was the same for each voltage class. While we know this is not the case, the majority of our system is at 13.8 kV, and we used that standard as the default. While there are other configurations on our system, most of those were constructed more than 30 years ago, and we do not have good historical information regarding their conductor spacing.

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[6]See discussion in our May 5, 2017 Reply Comments in Docket No. E002/M-15-962, *In the Matter of Xcel Energy's 2015 Biennial Distribution Grid Modernization Report.*

Capacitors – For modeling purposes, it is important to know the state of every capacitor bank. However, at any point in time this is not known for the entire system, because the on/off status of each capacitor bank is not recorded along with load. Consequently, we assumed that each capacitor bank was switched on at peak, unless known to be offline or high voltage issues existed. The state of the capacitor banks is driven by voltage and not by the peak hour. Even though our base assumption was that all capacitor banks were on at peak, if an overvoltage condition was witnessed, the capacitor would automatically switch off in the analysis just like it would do in the field. Therefore, the hour of the peak condition is irrelevant with regard to the capacitor status. For off-peak load analysis, we used a feature inside the DRIVE tool to switch off the capacitor banks where possible to more closely mimic that particular condition.

Feeder Topology – We regularly reconfigure feeders as a normal course of business. For purposes of this analysis, however, we assumed the configuration of the system is correct and static. Therefore, this analysis is a point-in-time snapshot of hosting capacity as of the date of our analysis – which is a reality of any analysis of the distribution system. However, we included future distribution capacity projects that are scheduled to be completed by June 2020 into the feeder models. While the feeder topology is generally a snapshot from the summer of 2019, we have included all known large capacity additions (such as conductor upgrades or new feeders) into the analysis to more accurately reflect future conditions.

Head-end Voltage – We set the voltage at the head-end of a feeder to 125 Volts on a 120 Volt base. This corresponds to 104 percent of whatever the nominal voltage is of a particular feeder. While the actual head-end voltage at different substations varies slightly, the 104 percent is intended to provide a realistic worst-case scenario in order to catch potential overvoltage impacts.

Distributed Generation Output – We assumed 100 percent of the allowed distributed generation output was flowing on the associated distribution feeders during the boundary conditions of peak load and daytime minimum loading.

Loading Levels – We populated each feeder model with non-coincident peak load and corresponding power factor information that was scaled down to 20 percent by the DRIVE tool for feeders that did not have significant amounts of DER on them to represent the Daytime Minimum Loading (DML). We prioritized finding the actual DML values for every feeder that had large amounts of existing interconnected DER and as a result, used actual DML data for approximately 25 percent of the feeders in the DRIVE analysis. We continued to establish actual DML values during the rest of the HCA process, and 100 percent of feeders in the heat map and tabular results spreadsheet have actual DML data. These feeder peak loads could be for any time of the day and are not in relation to any type of load curve. The source of the peak load data was our SCADA system. If SCADA data was not available, we obtained the peak load from our manual monthly peak substation read process. Similar to our approach in the interconnection study process, we use 20 percent of peak demand for calculating DML for feeders that do not have SCADA enabled, or other methods of determining the actual daytime minimum load. We initially relied on this value as a result of a National Renewable Energy Laboratory (NREL) paper.[7] Since that time, we have compared this value to nearly 150 feeders where we have SCADA data on our system and where interconnection requests have been submitted, concluding that it is representative of our system.

Load Allocation – We allocated loads for the feeder models on a section-by-section basis, which were based on the combination of appropriate load curves by customer type and customer energy usage. These are the only load curves used in our process. When available, we also used demand data from primary-metered customers. These factors are inputs to the Customer Management Module used within Synergi to allocate the peak load. Our load allocation methodology has evolved to this process from a prior process that only considered service transformer sizes. There is potential to further improve our load allocation method with the capabilities of the Advanced Metering Infrastructure.

Excluded Feeders – We excluded from the study 49 feeders serving low voltage networks located in the downtown Minneapolis and St. Paul areas. These feeders are not detailed in the GIS system and have not previously been modeled.[8] We also did not analyze a handful of other feeders that we serve, because we do not own them.

D. Limiting Criteria and Violation Thresholds

DRIVE provides thirteen limiting criteria with violation thresholds to determine hosting capacity on a given piece of equipment. We used eight of those criteria in the 2019 HCA; the remaining five are either limited in their calculation capabilities or are not applicable to DER. We used the same seven criteria as in the 2018 HCA, but were also able to use DRIVE's modified Unintentional Islanding threshold to identify

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[7] "Updating Interconnection Screens for PV System Integration." The file can be found online by navigating to: https://www.nrel.gov/docs/fy12osti/54063.pdf

[8] The special operating characteristics of secondary networks and processes to interconnect distributed generation is documented in "NSPM Network Connected PV Recommended Practice Based on Evaluation of Industry Practices, Standards and Experience" revision 2, dated June 17, 2014. System Planning and Strategy (NSPM) and Electric Distribution System Performance (EDSP) https://www.xcelenergy.com/staticfiles/xe/Corporate/Corporate%20PDFs/NSPM_PVNetwork_06_17_2014_Final_R2.pdf

islanding potential at protective devices such as reclosers and breakers.

We also utilized the "Maximum Tap Regulators in Over/Under-Voltage Analysis" advanced setting. This setting adjusts the voltage within the regulation zones to the bandwidth of the regulator for consideration in the Over-Voltage threshold. This could result in slightly less hosting capacity for instances where regulators are installed.

Table 3 below describes the limiting criteria and violation thresholds in more detail.

Table 3: Limiting Criteria and Violation Thresholds

Criteria	Description	Threshold	Basis
Primary Over-Voltage	High voltage exceeds nominal voltage by threshold	105%	ANSI C84.1 Range A – maintain quality of service to customers
Primary Voltage Deviation	Change in Voltage from no DER to full DER in aggregate	5%	MN Tariff Section 10, Sheet No. 146 – maintain power quality for customers
Regulator Voltage Deviation	Change in bandwidth from no DER output to full DER output at a regulated node	50%	Prevent reliability and power quality issues by avoiding excessive regulator operations
Thermal for Discharging DER	Element rating	100%	Continue reliable customer service by staying within the normal ratings of existing elements
Additional Element Fault Current	Deviation in feeder fault currents	10%	Based on worst case scenarios from internal studies – maintain customer reliability
Breaker Relay Reduction of Reach	Deviation in breaker fault current	10%	Based on worst case scenarios from internal studies – maintain customer reliability
Reverse Power Flow	Element minimum loading	100%	Potential protection and thermal issues can occur with reverse power flow in to the substation
Unintentional Islanding	Element minimum loading	100%	Criteria is now applied on all large three phase protective devices where islanding can occur
Sympathetic Breaker Tripping	*Breaker zero sequence current due to an upstream fault*	*Not used*	*For the analysis method used (Large Centralized) the criteria does not affect the hosting capacity*
Primary Under-Voltage	*Low voltage below nominal voltage threshold*	*Not used*	*Not a condition typically created by DER, unless considering the load aspects of energy storage*
Thermal for Charging DER	*Remaining element capacity at Peak Loading*	*Not used*	*Not a condition typically created by DER, unless considering the load aspects of energy storage*
Operational Flexibility	*Maintain ability to reconfigure feeders*	*Not used*	*Criteria not used in interconnection process*
Ground Fault Overvoltage (3V0)	*Power flow through substation not to be reduced by more than a percentage of minimum load power flow*	*Not used*	*Criteria not used in interconnection process*

III. ACCURACY

In this section, we first discuss industry efforts to compare the accuracy of different hosting capacity methods. We then describe our approach of assessing the accuracy of the HCA results.

A. Industry Assessment of the Accuracy of Hosting Capacity Methods

As we described above, there are four main methods to conduct hosting capacity analyses, and the utility industry has been assessing their value and accuracy. For example, San Diego Gas and Electric (SDG&E) undertook a study to compare the hybrid method employed by the DRIVE tool with the Iterative Integrated Capacity Analysis (ICA) method that was used by SDG&E to meet the California Hosting Capacity requirements.[9] The study found little difference between the results of the two methods, as indicated in Figure 2 below.

Figure 2: Hybrid/DRIVE Results Compared to Iterative ICA[10]

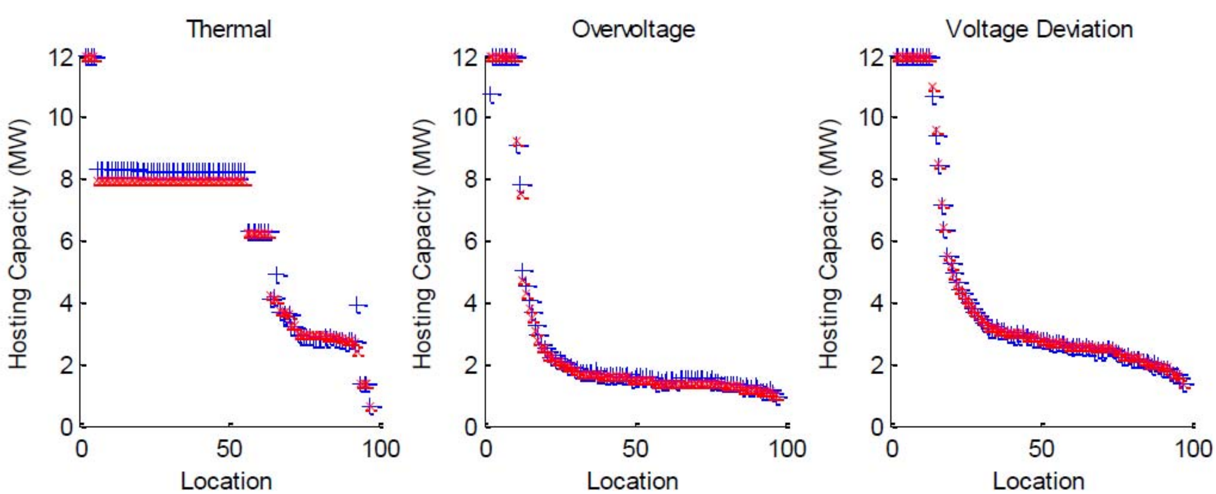

Figure 1. Comparative Results for One Feeder (Blue +: Iterative Analysis, Red x: DRIVE Analysis)

Key findings of the evaluation were that different hosting capacity methods can provide similar results; similar hosting capacity results can be derived more efficiently; and, hosting capacity methods will continue to evolve and improve. These findings demonstrate that the DRIVE hybrid method produces comparable results to one of

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9 San Diego Gas and Electric's EPIC Final Report (December 31, 2017) https://www.sdge.com/sites/default/files/EPIC-1%20Project%204_Module%203_Final%20Report_0.pdf

10 Source: San Diego Gas and Electric's EPIC Final Report, page iv.

the early leading industry approaches to hosting capacity that is significantly more labor intense to produce. We are confident that as DRIVE continues to be refined through further improvements and modifications, the accuracy of the hybrid method will correspondingly also improve.

As noted earlier, EPRI has recognized that hosting capacity methods are continuously evolving and concluded that a hybrid method – such as DRIVE – is the most likely and successful path going forward.

B. Company Assessment of the Accuracy of HCA Results

We conducted two different analyses to assess the accuracy of our 2018 HCA results, as directed in the August 2019 Commission Order.[11] While we recognize there are methodological differences between the 2018 HCA and the 2019 HCA, due to time constraints we were unable to use the 2019 HCA results for these evaluations.

First, we compared DRIVE results to Synergi results on 15 feeders, and second, we compared DRIVE results to actual interconnection studies conducted for community solar gardens on the same 15 feeders. We determined the 15 feeders by selecting all interconnection studies that were performed during a six-month period from September 2018 to February 2019. This time frame matches the time when the 2018 HCA was conducted and released (filed on November 1, 2018). During the six-month period, we had completed 23 interconnection studies for community solar gardens for 15 different feeders, which were then selected for the evaluation. We removed multiple studies from the assessment; for instance, four studies were performed for feeder SCL322, but we only included the results from the first study that was performed.

1. DRIVE Compared to Synergi

When running the analysis in Synergi, we made the same assumptions as we did for DRIVE, where possible. This included making the minimum loads 20% of the peak load, using 1.05 PU as the overvoltage violation threshold, and using 100% as the thermal violation threshold. However, the Synergi analysis had only four criteria thresholds available for selection, compared to the eight thresholds used in the DRIVE analysis.

We focused our comparison on the minimum hosting capacity values and the criteria

[11] Order Point 5B: Xcel Energy shall provide a comparison of other methodologies and interconnection study results on a selection of representative feeders…

thresholds violated. We chose not to report the maximum hosting capacity values because this comparison is not meaningful: the majority of Synergi's maximum hosting capacity values were limited due to a threshold for "reverse limit." Reverse limit is an arbitrary value set at 50% of the feeder limit and has no real bearing on hosting capacity at all, which would make any comparison irrelevant. In contrast, DRIVE uses a criterion called "reverse power flow," which limits the hosting capacity based on load. When we compared the minimum hosting capacity values, however, these criteria differences were not an issue. Table 4 below summarizes the comparison between DRIVE and Synergi results.

Table 4: DRIVE Results Compared to Synergi Results

Feeder	DRIVE Min Hosting Capacity (MW)	DRIVE Min Threshold Violated	Synergi Min Hosting Capacity (MW)	Synergi Min Threshold Violated	Difference in Min Values (MW)
MGN211	0	Primary Over-Voltage	0.09	voltage limit	0.09
ALB021	0.3	Primary Over-Voltage	0.38	voltage limit	0.08
RRK064	0.7	Primary Over-Voltage	0.72	voltage limit	0.02
SCL322	0	Primary Over-Voltage	0.00	voltage limit	0
LSP022	0.2	Primary Over-Voltage	0.05	voltage limit	0.15
WOB021	0	Primary Over-Voltage	0.06	voltage limit	0.06
BRO021	0	Primary Over-Voltage	0.04	voltage limit	0.04
PAT313	0	Primary Over-Voltage	0.07	voltage limit	0.07
PAT312	0	Primary Over-Voltage	0.00	voltage limit	0
CLC221	0.2	Primary Over-Voltage	0.01	voltage limit	0.19
WAT081	0.6	Primary Over-Voltage	0.00	voltage limit	0.6
CHI311	0.2	Primary Over-Voltage	0.00	thermal loading	0.2
DND062	0.28	Thermal for gen	0.45	thermal loading	0.17
NOF061	0	Primary Over-Voltage	0.00	voltage limit	0
ALT021	0	Primary Over-Voltage	0.07	voltage limit	0.07

Table 4 shows that the results between DRIVE and Synergi regarding the available minimum hosting capacity are consistent. The largest discrepancy came at feeder WAT081 and was due to a pocket of low-voltage, which caused Synergi to produce a value of zero. We did not use a similar threshold for low voltage in DRIVE because it is not relevant for generation, but rather for load. When that one feeder is disregarded, the average difference in the minimum hosting capacity values between the two models was 81 kW. The values between DRIVE and Synergi are remarkably similar and corroborate the comparisons performed by SDG&E and EPRI, discussed above. Overall, our assessment adds validity to both methods and should provide further confidence in the HCA results.

2. DRIVE Compared to Interconnection Studies

The interconnection studies conducted for community solar gardens identify the capacity available without any distribution system upgrades. We compared this value to the range of minimum and maximum hosting capacity value produced in DRIVE. The results between DRIVE and actual interconnection studies are less consistent, but the reasons for this variation are well understood. Hosting capacity results can vary for a number of reasons and we observed differences due to variations in load, connected DER power factors, and configuration changes. Table 5 below summarizes the comparison between DRIVE and interconnection study results.

Table 5: DRIVE Results Compared to Interconnection Study Results

Feeder	DRIVE Min Hosting Capacity (MW)	DRIVE Min Hosting Capacity Threshold	DRIVE Max Hosting Capacity (MW)	DRIVE Max Hosting Capacity Threshold	HC from Study (MW)	Reason for Difference
MGN211	0	Primary Over-Voltage	0	Primary Over-Voltage	.065	NA
ALB021	.3	Primary Over-Voltage	1.35	Reverse Power Flow	1	NA
RRK064	.7	Primary Over-Voltage	2.67	Reverse Power Flow	1	NA
SCL322	0	Primary Over-Voltage	0	Primary Over-Voltage	1	Minimum Load
LSP022	.2	Primary Over-Voltage	.59	Reverse Power Flow	.427	NA
WOB021	0	Primary Over-Voltage	0	Primary Over-Voltage	.6	Existing Gen Power Factor
BRO021	0	Primary Over-Voltage	0	Primary Over-Voltage	.775	Extension
PAT313	0	Primary Over-Voltage	0	Primary Over-Voltage	1	Minimum Load
PAT312	0	Primary Over-Voltage	0	Primary Over-Voltage	1	Minimum Load
CLC221	.2	Primary Over-Voltage	.85	Primary Over-Voltage	1	New GenPower Factor
WAT081	.6	Primary Over-Voltage	.6	Reduction of Reach	1	New GenPower Factor
CHI311	.2	Primary Over-Voltage	1.24	Reduction of Reach	1	NA
DND062	.28	Thermal for gen	.98	Reverse Power Flow	1	NA
NOF061	0	Primary Over-Voltage	0	Primary Over-Voltage	.1	NA
ALT021	0	Primary Over-Voltage	0	Primary Over-Voltage	.5	New GenPower Factor

Overall, seven of the 15 feeders had interconnection study results that were either between the minimum and maximum DRIVE hosting capacities or were within 100kW, which we consider to be a positive correlation. This means that eight feeders had interconnection study results that fell outside of the minimum and maximum DRIVE hosting capacities, and we discuss those eight feeders in further detail below.

In three of the eight feeders, discrepancies were due to minimum load values that had a difference of more than 1 MW. In the 2018 DRIVE analysis, we approximated the minimum loads to be 20% of peak, while the interconnection studies used actual minimum loads when available. Our 2019 DRIVE analysis uses actual minimum loads for a number of locations, so we anticipate this will be less of a concern going forward.

Another three of the eight feeders had a differing power factor value for the new DER generation that was being added. We assumed the new power factors to be at 98% leading in our 2018 HCA, while the actual studies identified that they all needed to be at 95% leading to accommodate the added generation without upgrades, which will lead to changes in hosting capacity. This will continue to be an issue, as we have to assume a DER power factor value in the HCA and this value could be different than what is studied and approved in the interconnection study. We will re-evaluate what the DER power factor assumption should be in future HCAs.

One of the eight feeders also had a different value for the power factor of the existing generation on the feeder. The study reflected 4 MW of existing generation at 98% leading power factor, while the HCA had a 100% power factor. This difference was the result of incorrect data received through our internal power factor tracking sheets. We have improved the tracking in 2019 to provide a better snapshot of what is occurring on a feeder-by-feeder-basis regarding power factor.

The final feeder with a discrepancy truly reflects the difficulty in comparing hosting capacity results to interconnection study results. While our hosting capacity analysis indicated a hosting capacity of zero for feeder BRO021, the interconnection study indicated 775 kW was available. Upon further review, we learned that nearly a mile of single-phase line was upgraded to three-phase and extended to the solar garden site. This represented a configuration change to the feeder that would have been impossible to determine prior to conducting the HCA. Extending a line to a new generation site can add substantial length and additional impedance to a feeder and this was not captured in our data for the HCA.

Beyond the challenges of comparing HCA results to interconnection study results listed above, it is important to understand that data integrity also plays a role. While we only discovered one instance where the data was clearly inaccurate, this is an issue that is hard to rectify for a large scale analysis with over 1,000 feeders, such as the HCA. The volume of work and inputs is substantial, but only a small amount of time can be devoted to each feeder. In contrast, our interconnection studies take weeks to complete and benefit from our ability to fine-tune the models and fix any issues that are observed during the process. Even then, sometimes errors in the modeling are only detected during detailed design if we observe that field conditions (such as type of feeder) are different than what was modeled.

Perhaps the key takeaway is that this comparison highlights the differences between an HCA and interconnection studies and helps to understand why an HCA cannot reach the same level of accuracy and detail as interconnection studies. We believe that the DRIVE tool produces accurate results for its purpose as a first step in the interconnection process. We continue to improve our HCA process and method as appropriate, but note that data integrity remains an issue in this kind of large-scale modeling effort.

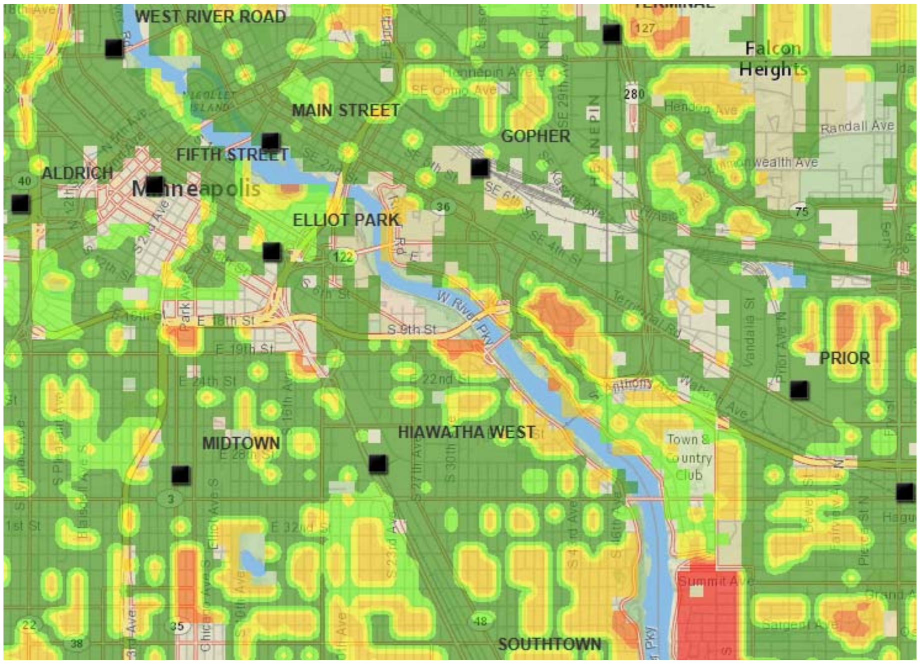
IV. 2019 HCA RESULTS

A. Heat Map and Tabular Spreadsheet

We provide the results of our 2019 HCA in a tabular spreadsheet and as an interactive visual representation, or heat map. The results are a snapshot in time as of August 2019, based on the characteristics and topology of the Company's distribution system at that time. The hosting capacity for a feeder is a range of values that depends on several variables, including DER location, DER technology, load characteristics, feeder design, and feeder operation. Any addition of new generation on a feeder will reduce the available hosting capacity by an unknown value, impacted predominantly by the location of new DER.

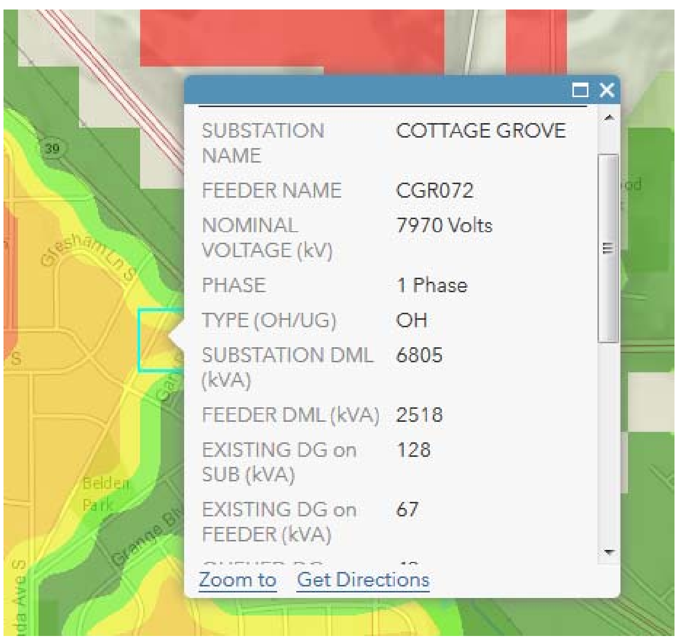
The tabular spreadsheet is provided as Attachment B to our 2019 HCA compliance filing. Figure 3A below is an example of the visual hosting capacity results that are available on our website at: https://www.xcelenergy.com/working_with_us/how_to_interconnect/hosting_capacity_map_disclaimer. The legend for the heat map is color-coded to indicate varying levels of available hosting capacity.

Figure 3A: Example of Heat Map Results



Users are able to zoom in and zoom out and also have the option for a full-screen view. For a feeder that is in close proximity to another feeder (and do not show separately on the map), the map indicates the higher capacity of the two feeders.

Figure 3B: Example of Heat Map Pop-Up Screen



We have improved the presentation in the heat map and tabular spreadsheet based on stakeholder feedback. A new feature this year is a pop-up screen on the heat map that displays additional information. Users can click on a feeder location and a pop-up screen will appear, displaying additional data. Figure 3B above displays the heat-map pop-up screen. We added the following new data on the pop-up tool and tabular spreadsheet, based on stakeholder input:

- Feeder name,
- Substation name,
- Daytime minimum feeder load,
- Daytime minimum substation load,
- Existing DER on substation,
- Existing DER on feeder,
- Queued DER on substation,
- Queued DER on feeder,
- Available hosting capacity,
- Limiting hosting capacity criteria threshold,
- Feeder voltage level (heat map only),
- Line phasing (single or three-phase line) (heat map only), and
- Line type (overhead or underground line) (heat map only).

We have also included in the heat map the location of field voltage regulators and substations on our distribution system. These elements were requested by stakeholders and should help increase the value of the hosting capacity map along with the new content contained in the pop-ups.

Our 2019 HCA results show that 129 feeders have zero maximum hosting capacity. DRIVE considers potential DER in increments of 100 kW on three-phase sections, which means that even if a feeder shows zero hosting capacity, the actual available capacity may be something between zero and 100kW. So, additional small-scale DER may not be prohibitive.

In addition, 101 of these feeders have significant amounts of existing DER on them (97 of which have 1 MW or more). These existing DER installations have essentially exhausted the hosting capacity. In some cases, mitigations on these feeders added just enough capacity to accommodate a specific DER resource.

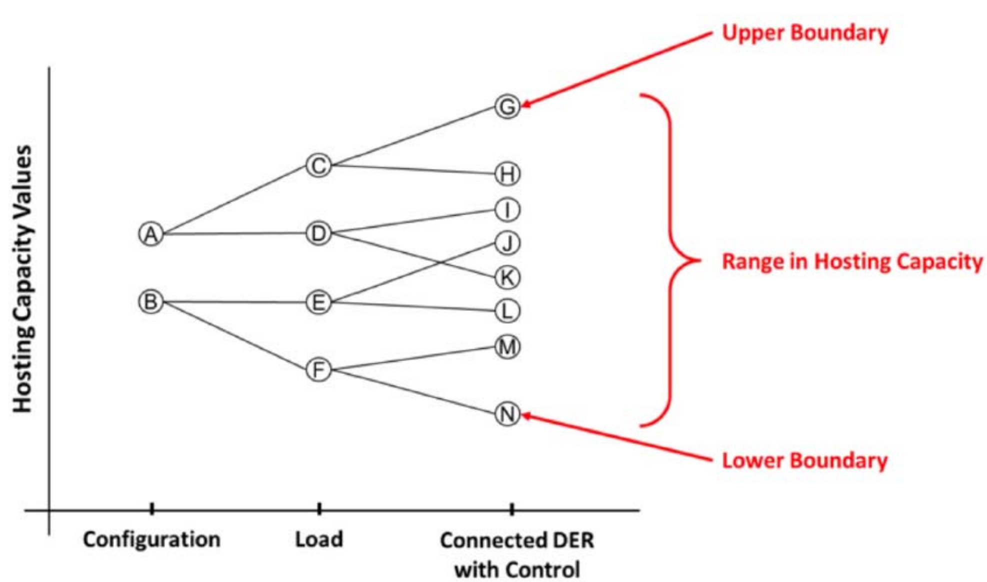
Later on in this report we discuss an analysis EPRI conducted for us on 94 feeders that had zero hosting capacity in our 2018 HCA. With the help of a newly developed tool it took EPRI 400 hours to complete that analysis for 77 of those feeders, with the remaining 17 needing more analysis than what could be completed with the automated tool at this time. It is still very complex and time consuming to determine how to increase hosting capacity on multiple feeders in an efficient manner.

The 2019 HCA results will differ from the 2018 HCA results for a number of reasons, including the following:

- Distribution system changes, such as changes to the configuration or capacity of a feeder,
- Feeder forecast changes (variations in load),
- New community solar gardens and other DER interconnected to the system, and
- Methodological changes, such as using actual daytime minimum load data and using DRIVE's Unintentional Islanding threshold.

Figure 4 outlines in general terms how different impact factors – feeder configuration, load characteristics, and existing connected DER – should be incorporated into a HCA analysis and how they affect the range of available hosting capacity.

Figure 4: Incorporating Impact Factors into HCA[12]



[12] Source: *Impact Factors and Recommendations on How to Incorporate Them When Calculating Hosting Capacity*. EPRI. September 13, 2018. https://www.epri.com/#/pages/product/3002013381/.

B. How to Read the HCA Results

We remind readers that the 2019 HCA presents the discrete hosting capacity of individual feeders without analysis of the cumulative effects of DER additions to substations or the transmission system. As DER penetration increases, system constraints are likely to limit hosting capacity in various geographical areas. For instance, a substation may have three feeders with 3 MW of available capacity on each – but the substation or transmission systems may not have 9 MW of available capacity. As a result, the HCA is not a holistic system view, but rather a snapshot of the capabilities of individual feeders as they are positioned today.

It is also important to note that DRIVE considers potential DER in increments of 100 kW on three-phase sections during the HCA process. This means that if a feeder shows zero hosting capacity, there may actually be available hosting capacity of less than 100 kW. However, because the intent of the Large Centralized methodology is to examine locations for large DER installations, we did not take a more granular approach to ascertain specific values below the 100 kW threshold.

Additionally, the heat map and tabular spreadsheet provide the amount of hosting capacity available without considering any mitigations. Therefore, even if a feeder may show low hosting capacity, it is possible that mitigations could allow higher levels of DER to be interconnected. However, an interconnection engineering study would need to be completed to determine whether mitigation would increase available capacity.

We further note that the HCA results are not intended to be used in lieu of engineering studies or for approving interconnection requests. Rather, they are intended to be an initial indication as to how much additional DER could be interconnected on a given feeder. After consulting the HCA heat map or tabular spreadsheet, we recommend Developers use progressively more detailed tools to assess the viability of the potential DER site. More informative and site-specific information on hosting capacity is offered in the following order:

1. Review the Company's publicly-available DER interconnection queue.[13] The queue is updated monthly, and therefore includes any additional generation that was proposed after the HCA data was drawn as a snapshot in time.
2. Request pre-application data for the interconnection location of interest in order to further identify characteristics of the circuit that may impact hosting

[13] Note that prior to June 2019, the public queue included only interconnection applications for the Solar*Rewards Community program.

capacity.

3. Submit an interconnection application for the DER project to initiate the Screening and/or Study process. A completed interconnection application is the mechanism how a project enters into the queue and begins the process for reserving hosting capacity. The outcome of Screening or Studies will identify allowable interconnection capacity and any mitigation costs.

C. Treatment of System Security and Customer Privacy Information

Our 2019 HCA compliance filing provides a more detailed discussion on the protection of information based on specific customer data privacy requirements or significant security risks to the Company's system or customers. That discussion also provides a full description and specific basis for withholding any information, as required by the Commission's August 2019 Order.

As noted above, we have added the following new information to the presentation of the 2019 HCA results: feeder name, substation name, daytime minimum feeder load, daytime minimum substation load, existing DER on substation, existing DER on feeder, queued DER on substation, queued DER on feeder, available hosting capacity, limiting threshold, feeder voltage level, line phasing (single/three), line type (overhead /underground), field voltage regulator location, and substation location. All of this data has been treated as public in the heat map and tabular spreadsheet. Providing public access to this information demonstrates our commitment to increase the value of our HCA Report.

As in the 2018 HCA Report, we have also continued to not to disclose publicly certain data, because this would compromise system security or customer privacy. First, we worked with our customer account management group to identify the customers and their associated feeder(s) that would fall into the following critical infrastructure categories:

- Critical Energy Infrastructure on distribution feeder,
- Critical Hospital - Level 1 or 2 Trauma Center on distribution feeder,
- Critical Data Center on distribution feeder, and
- Critical Public Gathering Center on distribution feeder.

Feeders that fell under the protection of these critical infrastructure assets were excluded from the heat map but included on the tabular spreadsheet.

Second, we then identified feeders serving less than 15 premises, which is the same threshold we apply to requests for aggregated customer energy usage data (CEUD) – feeders with such low density may provide insights into those customer locations that could compromise customer confidentiality and/or customer energy security. We also identified feeders where the load of one customer was 15 percent or more, again, with the rationale that publicly disclosing these feeders could compromise customer privacy. Feeders that fell under this 15/15 aggregation standard were excluded from the heat map but included on the tabular spreadsheet.

The tabular spreadsheet does not identify which feeders fall under the 15/15 standard or critical infrastructure categories, consistent with our goal to not make it easy to identify which feeders have sensitive privacy or security concerns. Again, we have determined this approach – not to specifically mark feeders with privacy or critical infrastructure concerns on the spreadsheet – so that it would not be apparent for a bad actor to target sensitive feeders.

Under typical circumstances, we would make the peak load data available to parties upon request and under protection of a non-disclosure agreement (NDA). However, this would require that we still mark data on those feeders that fall under the 15/15 standard as non-public in order to protect third-party private information. As explained above, this marking in itself would identify the feeders that fall under the 15/15 standard, disclosing that these feeders contain sensitive private information and defeating the purpose of protecting that information. We have not been able to find a solution to this "Catch-22" dilemma, and therefore have determined that we cannot provide the peak load information to parties even under an NDA. We are looking forward to further discussions with other parties on this issue.

In summary, we excluded from the public heat map 115 feeders out of a total of 1,050 feeders included in the 2019 HCA, applying the security and privacy criteria outlined above. We have also continued to blur the lines in the heat map presentation. On the tabular spreadsheet, we have marked as non-public the peak load data for substation transformers and feeders.

V. MITIGATION

A. Overview

In this section, we discuss the more common potential distribution upgrades that may be necessary to interconnect DER into our system. The most efficient and effective mitigation is dependent on the type(s) of constraints on each individual feeder in relation to a particular DER. Therefore, we generally discuss various constraint conditions and the type of mitigations that might be necessary to alleviate them.

To the extent a feeder has constraints, we identify the *primary* constraint in the tabular spreadsheet provided as Attachment B.[14] Similarly, the pop-up screen in the heat map identifies the primary limiting factor. Table 6 below shows the impacts we analyzed and the potential mitigations that could be implemented to increase hosting capacity. The specifics of each feeder and DER interconnection proposal are instrumental in determining the most appropriate and lowest cost mitigation for that specific situation. The mitigations can vary in degree from fairly straightforward to relatively complex. Therefore, a detailed engineering study is needed to determine the optimal solution for each DER interconnection.

Table 6: Potential Mitigations for the Most Common Constraints

Category	Impacts	Mitigation
Voltage	Overvoltage	Adjust DER power factor setting, reconductor
	Voltage Deviation	Adjust DER power factor setting, reconductor
	Equipment Voltage Deviation	Adjust DER power factor setting, adjust voltage regulation equipment settings (if applicable), or reconductor
Loading	Thermal Limits	Reconductor, replace equipment
Protection	Additional Element Fault Current	Adjust relay settings, replace relays, replace protective equipment
	Breaker Relay Reduction of Reach	Adjust relay settings, replace relays, move or replace protective equipment
	Sympathetic Breaker Relay Tripping	Adjust relay settings, replace relays, move or replace protective equipment
	Unintentional Islanding	Installation of Voltage Supervisory Reclosing

In terms of mitigating constraints, our standard approach is to first study interconnection using low-cost options, such as adjusting the DER power factor, before considering higher-cost options, such as reconductoring. However, specific characteristics of the feeder determine the effectiveness of certain mitigations (such as using a non-unity fixed power factor for the DER) and those mitigations may differ depending upon the location of the installation. Accordingly, attempting to pre-identify absolute mitigations that would increase the hosting capacity of each feeder will not always efficiently match the specific needs of a particular DER installation.

The National Renewable Energy Laboratory (NREL) has prepared a technical report[15]

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[14] Some feeders may have additional constraints.

[15] See *The Cost of Distribution System Upgrades to Accommodate Increasing Penetrations of Distributed Photovoltaic Systems on Real Feeders in the United States*. NREL. April 2018. https://www.nrel.gov/docs/fy18osti/70710.pdf

that further outlines costs and methods to increase hosting capacity on feeders in the United States. Some of the key takeaways from that report include:

- Feeder characteristics, distribution of DER, and size of DER can all create significant variability in hosting capacity and distribution upgrade costs.
- In general, voltage constraints are less expensive to mitigate due to the ability to adjust inverter settings.
- Thermal overloads are generally more expensive to mitigate.
- Upgrade costs can be minimized by guiding DER to better locations.

These findings align with our potential mitigation strategies and further reiterate the fact that a detailed interconnection study is needed to provide more specific mitigation alternatives for a proposed DER project on a specific feeder.

B. Study of 95 Feeders with No Hosting Capacity

In the 2018 HCA, the results showed 95 feeders with zero hosting capacity. In an effort to better understand how hosting capacity could be increased on those feeders, as directed by the Commission's August 2019 Order,[16] we worked with EPRI to complete additional analyses for these 95 feeders. We are the first utility to use a new mitigation assessment tool developed by EPRI, allowing a streamlined analysis of a large number of feeders. This mitigation tool is a first of its kind and attempts to automate the mitigation comparison process by using predetermined mitigation settings and suggesting potential solutions based on those settings.

At this time, we do not recommend this mitigation tool replace or even augment the regular interconnection study process. However, we do believe the tool is a big step forward in providing better insight on mitigation options for a large-scale analysis of

[16] Order Point 3: Regarding the 95 feeders that Xcel Energy identifies as having no hosting capacity, Xcel Energy shall
A. Complete an individual analysis of the feeders and available options for increasing their hosting capacity.
B. Provide the following information for each feeder:
1) The frequency at which the constraints to individual feeders occur.
2) The full range of mitigation options for an individual feeder, including DER capabilities, a range of potential costs for each of the mitigation options available, and a range of total costs.
3) The amount of additional hosting capacity that could be obtained by implementing the identified mitigation options on a technical and economic basis (that is, the technical potential of the mitigation options and the economic potential of the mitigation options).
4) Cost-effective mitigation options that might improve the economic viability of DERs, and the size of the financial benefit these options might provide.

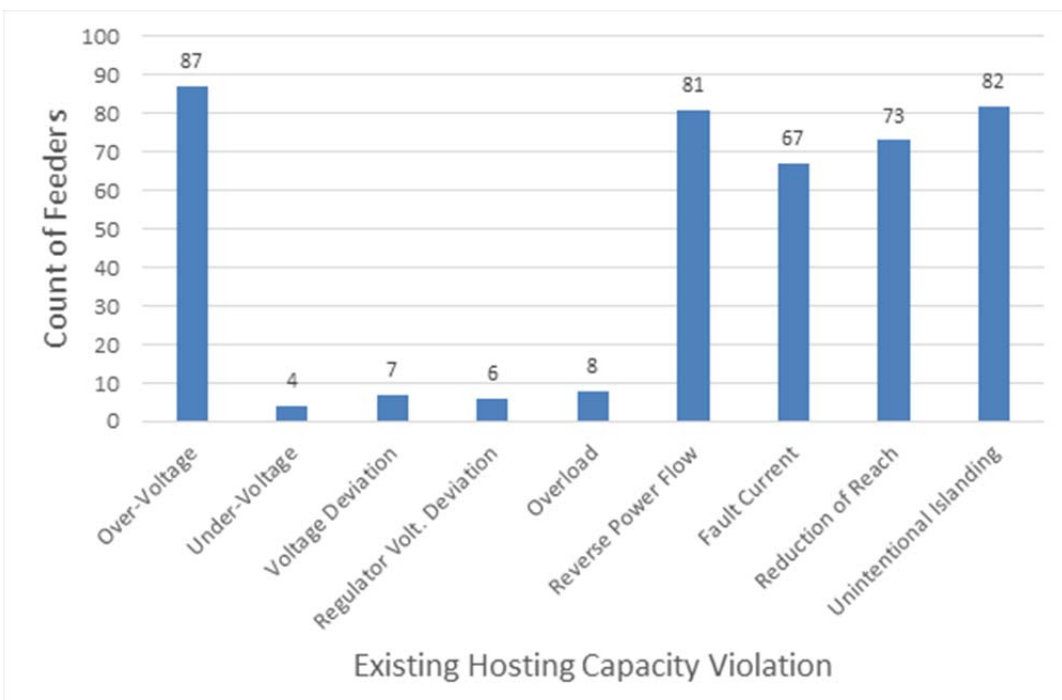
feeders.

1. *Violation Types and Mitigation Options*

We first verified the 2018 HCA results, and through this process discovered that we had incorrectly assigned excess generation to one of the 95 feeders, and it in fact had available hosting capacity. This feeder was removed from the mitigation analysis. We then examined the limiting criteria that were violated, and as Figure 5 below shows, most of the remaining 94 feeders had multiple violations. This meant that a solution that focused on one issue might not solve the other issues on that particular feeder. The most common violations were overvoltage (87 feeders), unintentional islanding (82 feeders), reverse power flow (81 feeders), breaker fault current (73 feeders), and feeder fault current (67 feeders).

For practical reasons, we did not attempt to quantify how many times per year an individual feeder would show no hosting capacity. This type of analysis would have required 8,760 hours of forecasted load data for each of the 94 feeders, which we do not have. We currently complete the HCA for two hours (peak and minimum load). Also, the DRIVE tool would need additional functionality to complete such an analysis and even then the process would be extremely slow.

Figure 5: Number and Type of Violations



The mitigation analysis first focused on mitigating overvoltage and thermal violations, which were some of the most typical violations and can also be mitigated with several no-cost options. We considered the following seven mitigation options for overvoltage and thermal violations:

- Adjusting the fixed Power Factor of existing generation – no cost
- Adjusting the fixed Power Factor of future generation – no cost
- Using Smart Inverters with volt-var function on future generation – no cost
- Using Smart Inverters with volt-watt function on future generation – $10 per kW curtailed
- Adjusting the settings of existing regulators – $5,000
- Adding a new regulator – $75,000
- Reconductoring – $250,000 per mile

After overvoltage and thermal violations were mitigated, most of the 94 feeders had also other secondary violations that had to be addressed next. Additional mitigation options for the remaining issues include:

- Updated Protection settings – $7,500
- New Recloser mid-feeder – $50,000
- Voltage Supervisory Reclosing at the feeder breaker – $120,000

The costs listed above are general estimates for the purposes of this mitigation analysis. They do not represent the indicative cost estimate obtained through an interconnection engineering study or the cost estimate developed in detailed design of the interconnection process.

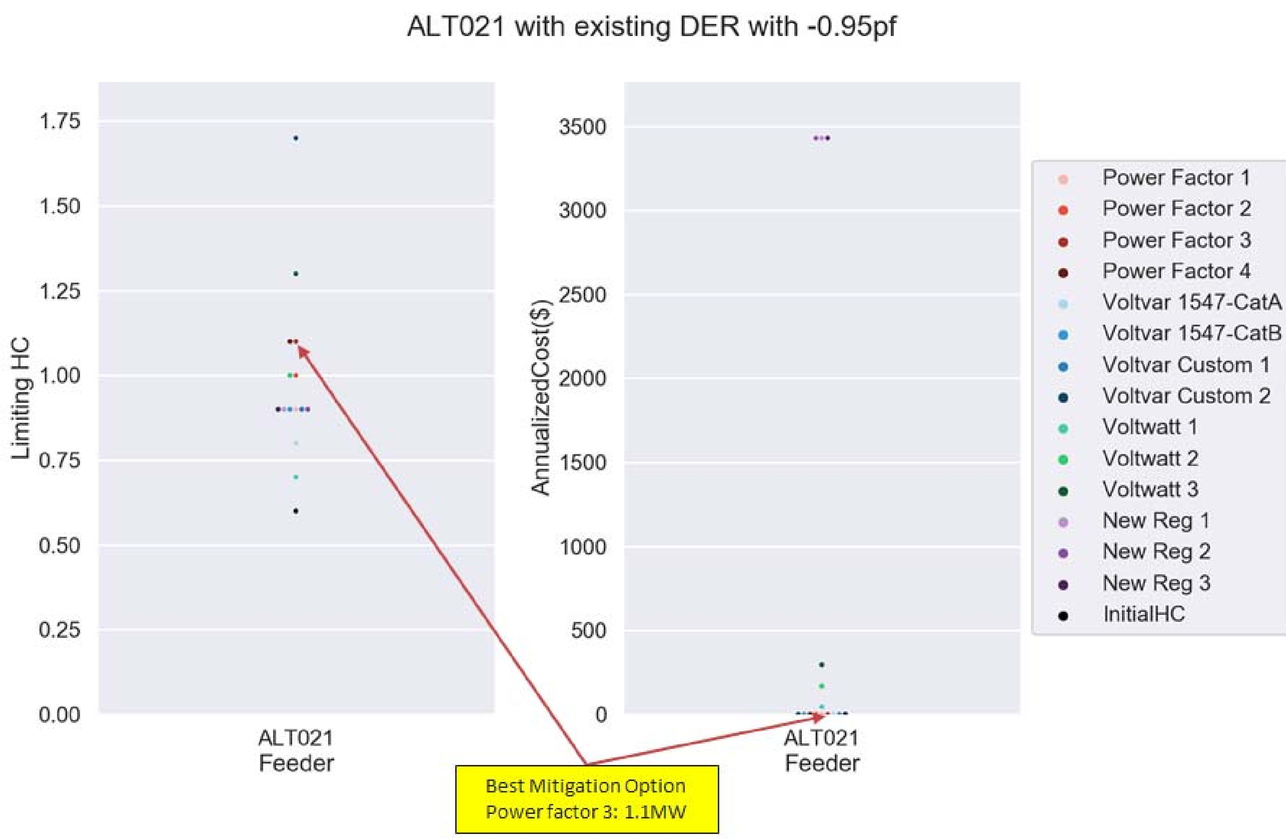
We also note that the mitigation analysis is a theoretical study of mitigation options and does not represent mitigation options that could be transferred as such to the Company's current interconnection process or practice. For example, the Company's regular interconnection process does not use regulators or smart inverters as a solution for mitigating violations. The use of regulators can result in excessive operations on the equipment, which may lead to premature failure. The use of regulators can also lead to low-voltage situations during periods of low or no DER output. Additionally, the Company is not currently leveraging smart inverter functions, but continues to assess their use as the industry standards on smart inverters continue to evolve.

Our mitigation analysis focused on improving the hosting capacity on the feeder at the midpoint between the substation and the end of the line. This was a practical decision, since it would be unfeasible to compare thousands of feeder points and their mitigation options. We also focused on mitigations that would improve the hosting capacity by at least 1 MW at the midpoint. This generally means that the hosting capacity between the midpoint and the substation is going to be greater than 1 MW and the hosting capacity between the midpoint and the end of the feeder will be below 1 MW.

In order to determine the best solution for each feeder, the mitigation analysis followed the criteria listed below. We did not try to convey this data for each feeder individually, as the volume was too large to interpret in a meaningful way. Conversely, the analysis focused on the best solution based on the criteria below and then compared that solution to the results of the other feeders.

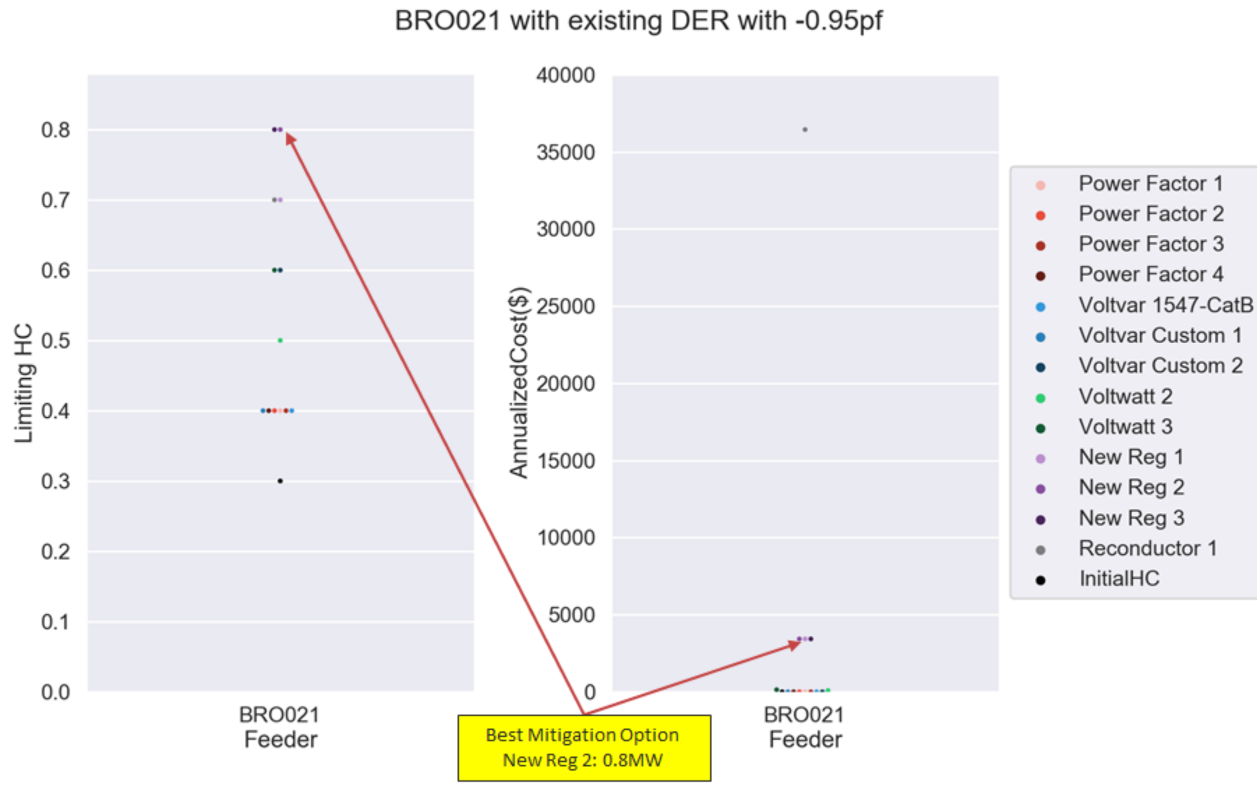
1) If several of the mitigation options increased the hosting capacity above 1MW, the least costly of them was selected (even if a more expensive option could get more hosting capacity). This is described in Figure 6 below.

Figure 6: Least-Cost Option Selected



2) If no mitigation could increase the hosting capacity beyond 1 MW, the one which offered the largest amount of additional hosting capacity was selected, regardless of cost. This is described in Figure 7 below.

Figure 7: Largest Amount of Capacity Option Selected

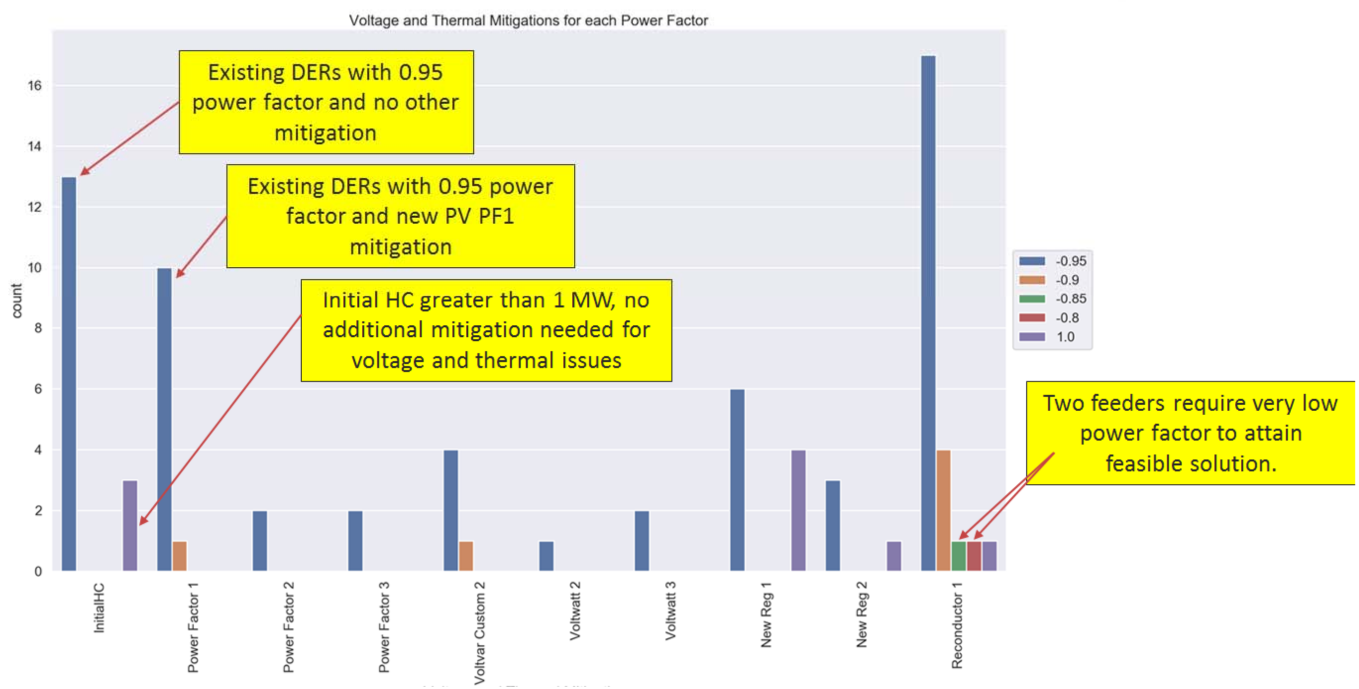


After applying these criteria to all 94 feeders, 17 feeders still required extensive mitigation and the violations could not be solved with the mitigation options that were available on an individual basis. These feeders were removed from further analysis, which then focused on the remaining 77 feeders.

2. *Mitigation for Overvoltage and Thermal Violations*

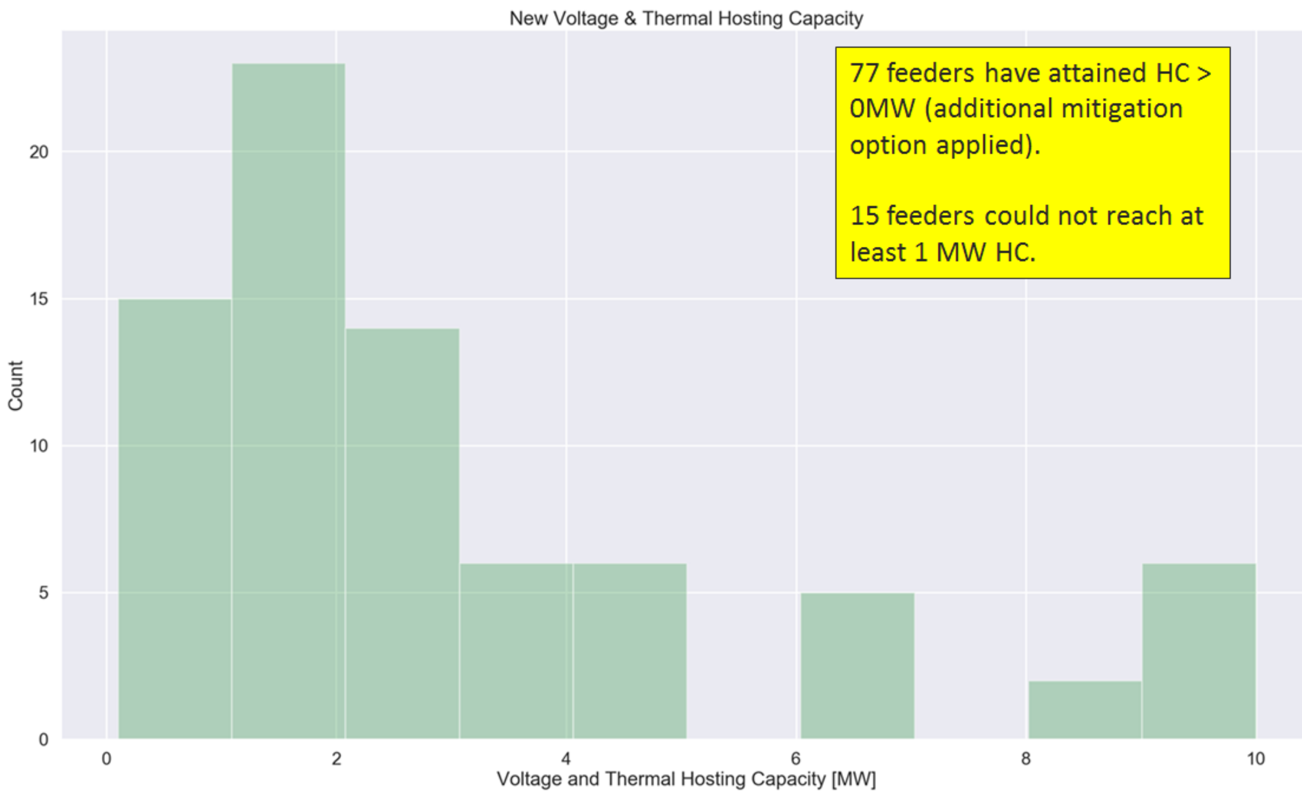
We considered the seven mitigation options discussed above to mitigate overvoltage and thermal violations. Of the remaining 77 feeders, 28 could gain at least 1 MW of hosting capacity with power factor adjustments to the existing and/or new generation. As Figure 8 below shows, 13 feeders were mitigated by simply adjusting the power factor of existing DER to 0.95. As the end of the figure shows, an additional 17 feeders were mitigated when power factors for existing DER were changed to 0.95 and reconductoring occurs. Some feeders even required more extreme power factors, like 0.8 or 0.85 plus the reconductoring. However, we have not considered power factors this low as valid solutions in our normal course of business due to the amount of reactive support required and the limited usefulness.

Figure 8: Mitigation for Overvoltage and Thermal Violations



As we applied these mitigations to overvoltage and thermal violations, the amount of hosting capacity gained per feeder varied. Figure 9 below shows that it was possible to increase hosting capacity on all 77 feeders. We were not able to achieve more than 1 MW of additional capacity on 15 feeders, but some feeders gained up to 10 MW of capacity.

Figure 9: Increased Capacity from Overvoltage and Thermal Mitigation



Tier 1: As mentioned earlier, 28 feeders gained at least 1 MW of hosting capacity with power factor adjustments to the existing and/or new generation, which is a no-cost solution. Another 5 feeders reached 1 MW by the volt-var advanced inverter function, also at no cost. Beyond that, 3 more feeders reached 1 MW by using the volt-watt inverter function, which costs under $5,000. These solutions were the most cost effective and resulted in an average hosting capacity increase of 1.9 MW per feeder for the 36 feeders.

Tier 2: Regulator additions were the next least-cost option. At an assumed cost of $75,000 per installation, 14 feeders achieved increased capacity by adding a new regulator. Although every feeder was not able to gain 1 MW, the average gain was 2 MW per feeder.

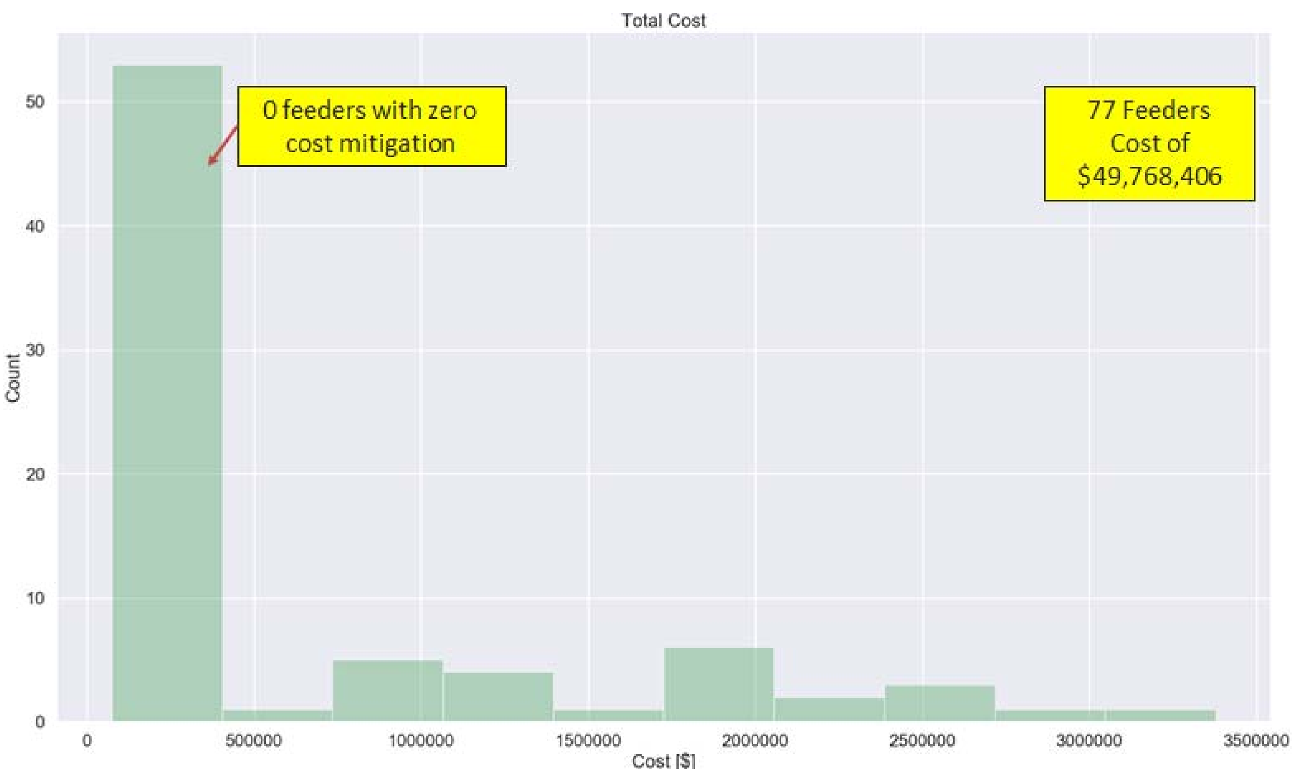
Tier 3: For the remaining feeders, the mitigation required extensive reconductoring, the cost of which ranged from approximately $500,000 to over $3 million per feeder. The reconductoring changed existing lines to a lower impedance and higher ampacity conductor. Similar to the regulator installation solution, every feeder was not able to gain 1 MW, but the average gain was 2.5 MW per feeder.

3. *Mitigation to Resolve Remaining Other Violations*

In order to fully attain the hosting capacity values in Figure 9 above, the mitigation analysis still needed to address the mitigation of other remaining violations, such as reverse power flow, unintentional islanding, and fault current issues. The costs for this second set of mitigation solutions were generally small.

As Figures 10 and 11 below show, the total cost for mitigating all violations on a feeder ranged from $75,000 to over $3.3 million per feeder and totaled nearly $50 million for all 77 feeders. However, the majority of feeders (53) could be successfully mitigated with comprehensive solutions that cost under $300,000.

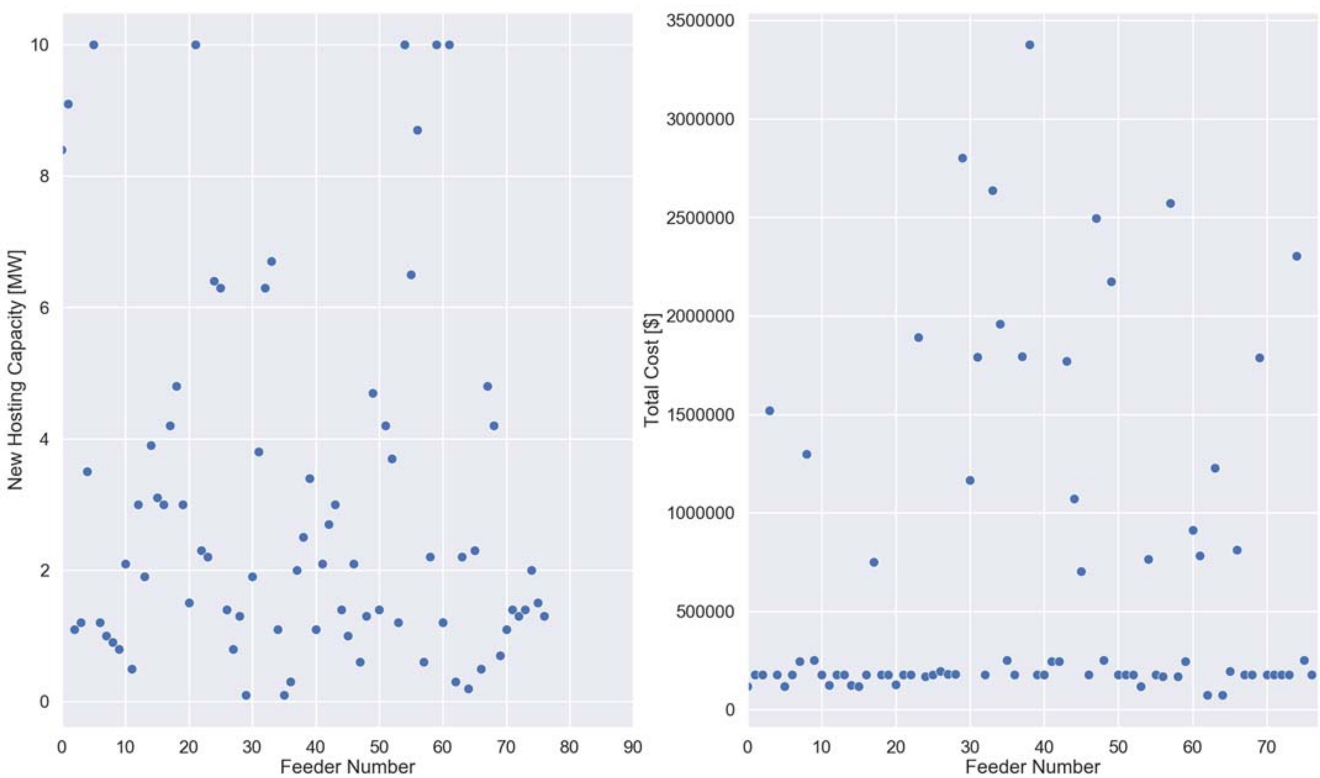
Figure 10: Total Cost of Mitigation per Feeder



We can also break down the costs by the three cost tiers referenced above, by combining the second set of mitigation costs with the overvoltage/thermal violation cost tier. For Tier 1 (power factor corrections), the average combined cost was about $170,000 per feeder. For Tier 2 (regulator additions), the combined cost averaged about $200,000 per feeder. For Tier 3 (reconductoring), the average combined cost was about $1.7 million per feeder.

For the most part, these mitigation solutions align with the Company's practice in how we conduct interconnection studies. We search for the least cost option, which usually involves power factor correction and sometimes reduction down to 0.95. If issues still exist, we move on to more expensive solutions, such as reconductoring. We note that the smart inverter functions – which we currently do not employ – showed additional benefit in a small number of cases and we may be able to use these functions in the future. The option to add a regulator also showed some potential in some cases, but we do not plan to utilize this option in the future because regulator installation has some other adverse impacts.

Figure 11: Hosting Capacity Gain and Cost per Feeder



VI. OTHER COMPLIANCE ITEMS

We completed a sensitivity analysis in the 2018 HCA that looked at varying the bus voltage and DER power factor on multiple feeders, as directed by a prior Commission Order. The adjustment of these factors primarily affects the overvoltage threshold. Since there has not been changes to the way that threshold is calculated and the results were for knowledge gain, we did not repeat this exercise in the 2019 HCA as the results would have been redundant and would not have yielded any additional conclusions.

A. Case Study WTN062

The Commission's August 2019 Order directed us to provide at least one DRIVE case example of a feeder's hosting capacity with different locations and levels of generation and load.[17] We conducted this case study on Watertown substation feeder WTN062. We selected WTN062 due to its primarily rural construction with small areas of town/urban loading. This topology is typical for feeders that experience interconnection requests for a large number of community solar gardens and some rooftop solar installations.

We ran 20 different scenarios for the WTN062 study. WTN062 was analyzed under low 20% load, 50% load, peak load, and 150% load circumstances. Additionally, 0.5 MW and 0.25 MW of DER was added to the feeder at close and far distances from the substation. DER modeled near the substation was connected at a site approximately 0.26 miles away from the substation near 212 Newton Ave NE, Watertown MN. DER located far from the substation was connected at 8975 County Rd. 6, Maple Plain MN, which is approximately 5.15 miles from the substation. Table 7 below provides a summary of each of the 20 scenarios run in the study.

[17] Order Point 4: Xcel Energy shall provide at least one example, using the DRIVE tool to the extent practicable, exploring a feeder's hosting capacity with different locations and levels of generation and load.

Table 7: WTN062 Case Study Scenarios – Loading and Generation Conditions

Load Scenario:	MW of Gen:	Distance from Gen to Sub:
20% Load	0	-
	0.5	0.26 mi.
	0.5	5.15 mi.
	0.25	0.26 mi.
	0.25	5.15 mi.
50% Load	0	-
	0.5	0.26 mi.
	0.5	5.15 mi.
	0.25	0.26 mi.
	0.25	5.15 mi.
Peak Load	0	-
	0.5	0.26 mi.
	0.5	5.15 mi.
	0.25	0.26 mi.
	0.25	5.15 mi.
150% Load	0	-
	0.5	0.26 mi.
	0.5	5.15 mi.
	0.25	0.26 mi.
	0.25	5.15 mi.

Under each scenario, a Synergi model was populated with the loading information outlined in Table 7 as well as any generation that was being considered. The model was then analyzed by the DRIVE software to receive hosting capacity results. DRIVE uses the following limiting factor criteria in the analysis: primary overvoltage, primary voltage deviation, regulator voltage deviation, thermal for generation, reverse power flow, additional element fault current, breaker relay reduction of reach, and unintentional islanding. Table 8 supplies the maximum and minimum hosting capacity results for each loading and generation scenario.

Table 8: WTN062 Case Study – Hosting Capacity Results

	Min HC (MW)	Min Limiting Factor	Max HC (MW)	Max Limiting Factor
20% Load No Gen	0.03	Unintentional Islanding	0.17	Reverse Power Flow
20% Load 0.5MW Near	0	Reverse Power Flow	0	Reverse Power Flow
20% Load 0.5MW Far	0	Primary Over-Voltage	0	Primary Over-Voltage
20% Load 0.25MW Near	0	Reverse Power Flow	0	Reverse Power Flow
20% Load 0.25MW Far	0	Primary Over-Voltage	0	Primary Over-Voltage
50% Load No Gen	0.07	Unintentional Islanding	0.45	Reverse Power Flow
50% Load 0.5MW Near	0	Reverse Power Flow	0	Reverse Power Flow
50% Load 0.5MW Far	0	Primary Over-Voltage	0	Primary Over-Voltage
50% Load 0.25MW Near	0.07	Unintentional Islanding	0.2	Reverse Power Flow
50% Load 0.25MW Far	0	Primary Over-Voltage	0	Primary Over-Voltage
Peak Load No Gen	0.16	Unintentional Islanding	0.92	Reverse Power Flow
Peak Load 0.5MW Near	0.16	Unintentional Islanding	0.42	Reverse Power Flow
Peak Load 0.5MW Far	0	Primary Over-Voltage	0	Primary Over-Voltage
Peak Load 0.25MW Near	0.16	Unintentional Islanding	0.67	Reverse Power Flow
Peak Load 0.25MW Far	0	Unintentional Islanding	0.67	Reverse Power Flow
150% Load No Gen	0.21	Unintentional Islanding	1.39	Reverse Power Flow
150% Load 0.5MW Far	0	Unintentional Islanding	0	Primary Over-Voltage
150% Load 0.5MW Near	0.2	Primary Over-Voltage	0.89	Reverse Power Flow
150% Load 0.25MW Far	0	Unintentional Islanding	1.14	Reverse Power Flow
150% Load 0.25MW Near	0.2	Primary Over-Voltage	1.14	Reverse Power Flow

The findings of this case study highlight the impact of feeder loading and DER location on hosting capacity. In all loading cases except the 20%, DER was able to be interconnected without consuming capacity for the entire feeder. In general, the results show that more hosting capacity is realizable if DER is connected closer to the substation and as more load is added.

B. 2019 HCA Costs

As directed by the Commission's August 2019 Order,[18] we estimated the costs for preparing the 2019 HCA and Report. Our engineering staff time from June 2019 through October 2019 has been approximately 1,600 hours. At an hourly cost of roughly $100/hour, this amounts to $160,000. However, this time does not include

[18] Order Point 7.B: Xcel Energy shall include all costs related to the hosting capacity exercise, including the time of Xcel Energy's engineering staff and any efforts Xcel Energy is making to reduce the costs over time.

time spent prior to June 2019 for such tasks as stakeholder engagement; preparation for the analysis; hiring and training of multiple interns; and various other activities surrounding the DRIVE tool and collaboration with EPRI. Additionally, this estimate excludes the effort of other departments outside of Engineering, such as Regulatory and Legal.

In addition, the cost to conduct the separate EPRI analysis of the 95 feeders without hosting capacity in the 2018 HCA was $50,000. We have incurred additional costs to acquire the DRIVE tool in 2016 ($250,000) and to participate in the DRIVE User Group ($30,000). The DRIVE User Group is expected to run for three years from June 1, 2017 to May 30, 2020, after which we anticipate that the User Group continues to operate for a similar cost.

Overall, we estimate that the total cost for the 2019 HCA and Report was over $300,000. If we are required to update the HCA more frequently, we believe each round of updates would cost slightly less than this, but still be substantial. While we would not need to file a separate report, we would still need to rebuild feeder models and update system data for each update.

C. Pre-Application Data Requests

The Commission has also requested that we provide information on the number and amount of fees collected for pre-application capacity screens.[19] In 2018, we received 288 pre-application data requests under our Section 9 Community Solar Garden tariff for applications not subject to the MN DIP. Each request cost $250, which means that we collected a total of $72,000 in fees for 2018. We note that these Section 9 pre-application data requests were called "capacity screens," but our Section 10 MN DIP pre-application report applies to new pre-application requests. The MN DIP pre-application report costs $300. The change in name also reflects more accurately the fact that these are not screens but rather requests for distribution system data at a specific location.

D. Costs for Integrating Pre-Application Data Requests with the Hosting Capacity Map

In order to comply with the Commission's August 2019 Order,[20] Xcel Energy has

[19] August 2019 Order, Order Point 7.C: Xcel Energy shall include information on the number of pre-application capacity screens conducted in the previous year, the amount collected for each, and the total amount collected to conduct the pre-application screens, in the previous year.

[20] Order Point 6: Xcel Shall collaborate with stakeholders in evaluating the costs and benefits associated with

engaged with stakeholders in a collaborative workshop to discuss positive changes that can be made to the current hosting capacity mapping tool. One of the most common requests expressed by stakeholders was the integration of the pre-application data report process with the HCA. As stated previously, pre-application reports and hosting capacity provide the most baseline determination of whether DER interconnection is viable in a location. Despite its clear benefits, integration of pre-application data with the hosting capacity map includes some significant costs and barriers that must be addressed. This section describes some of the obstacles and benefits of integrating the pre-application report and hosting capacity map.

Table 9 below lists the information supplied in the current iteration of pre-application reports. For each type of information, the table also highlights methods of obtaining the information, challenges, and technological requirements needed to provide that information within the hosting capacity map.

a hosting capacity analysis able to achieve the following objectives:
A. remaining an early indicator of possible locations for interconnection;
B. replacing or augmenting initial review screens and/or supplemental review in the interconnection process; and/or
C. automating interconnection studies.

Table 9: Assessment of Pre-Application Data

Type of Information	How Information Would Be Obtained	Effort Required to Obtain Information	Security/Privacy Concerns	Technological Requirements for Implementation	Frequency of Information Refresh
Substation Name	Engineering Data Sheet/GIS	Low	Low	Data Table	Yearly
Transformer Name	Engineering Data Sheet/GIS	Low	Low	Data Table	Yearly
Transformer Rating	Engineering Data Sheet	Low	Moderate	Data Table	Yearly
Transformer Peak	Engineering Data Sheet	Low	High	Data Table	Yearly
Transformer DML	Engineering Data Sheet	Moderate	Low	Data Table	Yearly
Transformer Absolute Min	Engineering Data Sheet	Moderate	Low	Data Table	Yearly
LTC or Regulator	Engineering Data Sheet	Low	Low	Data Table	Yearly
TR Existing Gen	Salesforce and data sheet	Moderate	Low	Query Salesforce and add non PV from data sheet	Daily
TR Queued Gen	Salesforce	Moderate	Low	Query Salesforce	Daily
TR Gen Capacity	Equation	Low	Low	Equation program within Map/Reporting	Per request
Distance from PCC to sub	GIS Query	High	Low	Query GIS system and report length	Per request
Feeder Name	Engineering Data Sheet/GIS	Low	Low	Data Table	Yearly
Feeder Rating	Engineering Data Sheet	Low	Moderate	Data Table	Yearly
Feeder Peak	Engineering Data Sheet	Low	High	Data Table	Yearly
Feeder DML	Engineering Data Sheet	Moderate	None	Data Table	Yearly
Feeder Absolute Min	Engineering Data Sheet	Moderate	None	Data Table	Yearly

Table 9: Assessment of Pre-Application Data (Continued)

Type of Information	How Information Would Be Obtained	Effort Required to Obtain Information	Security/Privacy Concerns	Technological Requirements for Implementation	Frequency of Information Refresh
Feeder Voltage	Engineering Data Sheet/GIS	Low	None	Data Table	Yearly
Feeder Existing Gen	Salesforce and data sheet	Moderate	None	Query Salesforce and add non PV from data sheet	Daily
Feeder Queued Gen	Salesforce	Moderate	None	Query Salesforce	Daily
Feeder Gen Capacity	Equation	Low	Low	Equation program within Map/Report	Per request
Nominal Voltage at PCC	GIS Query	Moderate	Low	Query GIS system	Per request
Network or Radial	Engineering Data Sheet	Low	Low	Data Table	Yearly
# of Phases	GIS Query	Moderate	Low	Query GIS system	Per request
Distance to 3 phase circuit	GIS Query	High	Low	Query GIS and determine when system returns to 3 phase	Per request
Devices in line between site and sub	GIS Query	High	Moderate	Query GIS and return devices and ratings	Per request
Conductor between site and sub	GIS Query	High	Moderate	Query GIS system and report length, type and reference data table for rating	Per request

As Table 9 shows, a large amount of information must be collected from a variety of sources in order to compile the pre-application information. Stakeholders described their vision of a pre-application report integration. The first major step in the process would be the website integration of the actual pre-application report. Whether this would be a link to another webpage or simply a pop-up within the map would need to be determined, but regardless, the current map would need to be outfitted with additional functions. As mentioned above, some security and privacy risks would need to be considered to apply the 15/15 aggregation standard to feeders, which also leads to a "Catch-22" that would even potentially prevent us from providing this information (even under an NDA) if this information is desired to be used in conjunction with the integrated hosting map tool.

The next area that should be analyzed is how the required data is collected, including an engineering data sheet and queries to GIS and Salesforce. The engineering data sheet provides the easiest access, and would take the form of a spreadsheet that is re-uploaded to the map/database whenever updates are made. The primary drawback of this is the engineering time necessary to implement and upkeep the large amount of data requested from all Company systems.

Also, query programs for GIS and Salesforce would need to be implemented and these pose the largest challenges to integration of pre-application data. No current web-query program exists for these services and new coding functions would need to be created to access the data. Another issue is that under the current process, engineers manually collect the data from GIS queries and are therefore able to scrub for any errors. Further, even if the data were in sync with that used for pre-application reports, there are still inherent limitations on this data as discussed at the Distributed Generation Workgroup meeting on April 7, 2017. For example, the data in a pre-Application report "... is existing, readily available data that a utility has access to. The workgroup clarified that 'access to data' means desktop data, not going into the field on each project. Pre-application report data is informational only and does not guarantee anything to the applicant."[21]

Since the pre-application report is the most common and simple request that the Developers use in assessing DER, it logically follows that the Company would first focus on integrating this process with the hosting capacity map, before considering more complex screens and engineering studies. But even this less complicated integration of the two processes would take significant funding and time, likely requiring a fee or subscription service for access in order to cover the cost. In addition, the hosting capacity map was originally intended to be a free tool, open to the public with an easy access. If these additional fees were implemented with the potential of also requiring an NDA for use, the combined map and report tool would no longer serve this important public purpose, and instead be locked behind a paywall.

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[21] See, Distributed Generation Workgroup Meeting Summary of April 7, 2017, filed in Docket No. 16-521, at page 4. This is available at this link: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={2002CF5E-0000-CA13-83BB-1A7F9608A630}&documentTitle=20179-135929-01.

CONCLUSION

We have significantly improved the 2019 HCA and worked hard to meet all of the requirements established by the Commission for the HCA – we believe we have meaningfully addressed and acted on each compliance item. We have enhanced the HCA methodology, used some new DRIVE features, conducted new analyses, and included more detailed information in the presentation of results. We believe the 2019 HCA is a meaningful tool to assist in identifying available locations and constraints for DER interconnection as well as for identifying necessary upgrades to support continued DER development.

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Excerpts from the 2018 EPRI Technical Hosting Capacity Report[1] – Comparison of Hosting Capacity Methods

Stochastic

The first hosting capacity method developed and used in the industry that captured many of the grid-related impact factors previously mentioned was referred to as a stochastic-based approach. The stochastic-based approach essentially starts by performing a baseline power flow analysis and increases DER penetration throughout the feeder using various sizes and locations to simulate 1000's of scenarios and extract the range of impacts conceivable for future DER deployments. Larger, three-phase systems can be analyzed as well as behind-the-meter DER systems.

The premise is that each DER system is modeled explicitly and detailed power flow and fault flow simulations are executed within the distribution modeling software to examine impacts. This is performed each time the DER penetration and/or location is changed. These power flow and fault flow solutions are simultaneously compared to baseline and user defined thresholds on each iteration. Hosting capacity is determined when DER impacts exceed the user defined thresholds.

Requirement	
Input Data	• Feeder circuit models
	• Two load levels
	• One DER type
	• 1000 load-based DER scenarios
Data Storage	• ~ 1.0 GB/feeder (varies based upon feeder and implementation)
Computational Times	• ~ 20 hours (varies based upon feeder and implementation)

Advantages

• *Educating the industry.* This method is easily understandable and valuable in educating the industry on the impacts of DER as it relates to size and location.
• *Effectively identifies "range" of impacts at future penetration levels.* From a research standpoint, this method is valuable in calculating the range of possible impacts due to DER locations and sizes that could exist at future penetration levels.

[1] Impact Factors, Methods, and Considerations for Calculating and Applying Hosting Capacity. January 31, 2018. https://www.epri.com/#/pages/product/3002011009/?lang=en-US.

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Disadvantages

• *Time and data intensive.* This approach is extremely time-consuming as well as data and computationally intensive.
• *Not effective at capturing full range of distributed DER impacts (locations).* Even with the large number of DER scenarios considered, EPRI found that it doesn't capture the full range of DER location-based scenarios. More cases could be considered such as locations and sizes of individual DERs, but at the expense of significant increases in data and time.
• *Applicable to specific impact factors only.* Sensitivity cases are executed based on the impact factors, however, each one of these scenario cases doubled the work effort and are used in select conditions/studies only.
• *Difficult to consider range of possible DER and grid scenarios.* The random nature of the deployments, including all locations (three-phase and single-phase), feeder reconfigurations, and DER types, etc., is extremely difficult to capture.

Streamlined Integrated Capacity Analysis (ICA)

In response to the California Legislature Assembly Bill 327, PUC Section 769, PG&E submitted their Distribution Resource Plan (DRP) that encompasses, among other items, an Integration Capacity Analysis (ICA) to determine hosting capacity. PG&E's approach was a streamlined ICA method that calculates hosting capacity across a distribution system, capturing the grid and DER specific impact factors. The streamlined method was developed recognizing that direct modeling of all the DER scenarios would require extensive resources and simulation time.

The method applies a set of equations and algorithms to evaluate power system criteria at each node on the distribution system. This method performs analysis in an efficient streamlined approach that does not require directly modeling DER in a power system tool to observe impact. By not relying on direct modeling and simulation of DER, system wide scenario analysis can be conducted with much less processing requirements. Details regarding the equations used within this streamlined method are described fully in PG&E's DEMO A/B report.

Requirement	
Input Data	• Feeder circuit models
	• 576 load levels derived from Smart Meter data
Data Storage	• ~ 15 MB/feeder (varies based upon feeder and implementation)
Computational Times	• SCE: 2 minutes/feeder
	• PGE: <10 minutes/feeder
	• SDG&E: 30 minutes/feeder

Advantages

• *Computational efficiency.* The ability to utilize equations and algorithms within a database enables faster computation of large datasets.
• *Time-based hosting capacity*. Provides insight to how hosting capacity changes over time and the ability to derive a hosting capacity portfolio based on DER profiles.

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• *Potential for scenario analysis.* Due to the computation efficiency, "what-if" scenarios such as DER forecasts, reconfiguration, smart inverter settings, DER mitigation strategies, etc. can easily be considered.
• *Solution convergence.* If the baseline power flows solve correctly, the method does not have non-convergence issues.

Disadvantages

• *Not well understood by all stakeholders.* The approach used is a new technique and not easily understood by all stakeholders.
• *Accuracy.* Methods utilized in the streamlined approach may not capture some of the dynamic effects on more complex circuits
• *Single site DER only.* This analysis considers single site DER and does not currently consider the aggregate impacts of distributed DER (e.g., rooftop PV) needed when planning for future DER scenarios.

Iterative ICA

Similar to PG&E, SCE and SDG&E responded to AB 327 with their own hosting capacity approach, the iterative Integration Capacity Analysis (ICA) method. In contrast to the streamlined ICA method, the iterative ICA approach leverages distribution planning tools such as CYME and Synergi to perform the voltage and thermal impact assessments rather than utilizing a calculation-based approach. This is a technique somewhat similar to the stochastic method listed previously. However, the difference in this method is that single locations are considered one at a time with DER modeled, while the DER capacity is increased until issues occur on the system. This method is also somewhat similar to the streamlined ICA method in that the analysis iterates through 576 load conditions with layered abstraction of agnostic hosting capacity results and assumed DER profiles for post-analysis.

The iterative method essentially increases the DER at each node until a violation occurs. Locations are analyzed independently with power flow simulations performed to determine the maximum level of DER that can interconnect at these locations without exceeding thermal and voltage limits.
In addition to the power flow simulations, which are used primarily to evaluate thermal and steady state voltage conditions, a protection analysis is also performed to evaluate the protection criteria and to determine the DER level that can be interconnected to each node without hindering the protection devices' ability to detect fault conditions.

Due to the more significant demand on the distribution software tool, the iterative analysis can result in long processing times, especially when expanded to large numbers of distribution feeders or when the feeders themselves are more complex. However, the iterative method attempts to parallel the California IOUs' interconnection studies that are performed as part of a detailed interconnection study process.

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Requirement	
Input Data	• Feeder circuit models
	• 576 hourly load profiles derived from Smart Meter data
Data Storage	• ~ 15 MB/feeder
Computational Times	• SCE: 0.5 hours/feeder
	• PGE: 1 hour/feeder
	• SDG&E: 27 hours/feeder

Advantages

• *Similar in concept to interconnection studies.* This method is similar in concept to what is performed when executing an interconnection study where the distribution planning software is leveraged to determine DER impact.
• *Uses readily available planning tools*. This approach does not require new algorithms to calculate hosting capacity, since the results are based on the standard load flow and fault flow engines.
• *Multiple platforms.* Methods have been implemented within both CYME and Synergi platforms.
• *Multi-feeder analysis.* The method can analyze all feeders into a substation simultaneously with the intent of capturing the aggregate impact to parallel feeders.
•*Effective for single DER location analysis.* This approach can be rather effective when analyzing single locations of DER.
• *Time-based hosting capacity*. Provides insight to how hosting capacity changes over time and the ability to derive a hosting capacity portfolio.

Disadvantages

• *False sense of accuracy*. While this method is similar in concept to what is performed in an interconnection study, it is not as accurate as a detailed study. In an interconnection study the analysis focuses on the specifics of the application at hand thus allowing the engineer to consider a range of other impact factors that affect hosting capacity at that location. This is in stark contrast to hosting capacity methods that analyze the "breadth" of distribution systems (1000's of feeders), wherein assumptions are made that do not capture the DER application specific impacts factors that are considered in detailed interconnection studies.
• *Time and data intensive.* Similar to the stochastic-based approach, this effort requires significant time, data, and computational cycles to complete.
• *Uses non-standard distribution modeling data.* This approach requires smart meter data and other sources to derive granular time-series load and DER forecast data at the node/section level for each distribution feeder (576 hour profiles).
• *Single site DER only.* This analysis considers single site DER and does not currently consider the aggregate impacts of distributed DER (e.g., rooftop PV) needed when planning for future DER scenarios. This will likely change as the method further evolves.
• *DER agnostic hosting capacity.* The iterative power flow solution's hosting capacity is derived irrespective of DER technology but depending upon how a specific type of DER interacts with the grid (solar, wind, storage, CHP, etc.) the hosting capacity can change. In some cases, this may require additional iterations and solutions to be performed.

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• *Limited scenario analysis capability.* Due to the computation burden to analyze systems as is, actual "what-if" scenarios such as DER forecasts, reconfiguration, smart inverter settings, DER mitigation strategies, etc. is limited.
• *Solution issues when analyzing additional time periods.* It is not uncommon to encounter bad data when attempting to create models for different time periods. EPRI has found, through extensive DER modeling, missing or "bad data" can cause simulations to provide undesirable outcomes.

DRIVE (Hybrid) Method

The Distribution Resource Integration and Value Estimation (DRIVE) hosting capacity method is the successor to the stochastic and detailed methods previously developed by EPRI. DRIVE was developed to overcome the computation burden but still capture critical grid responses for determining location-based hosting capacity.

Initially developed as a PV hosting capacity method, this method was further refined and updated as a DER technology neutral approach thus allowing other distributed technologies to be considered based on resource characteristics such as fault current contribution and active/reactive output variability. The specific DER technology determines how the analysis is setup to properly quantify the unique impacts of the particular resource. The DRIVE method does not provide an agnostic hosting capacity, but rather a hosting capacity for the resource characteristics being considered.

Working with a number of utilities throughout the world, further enhancements and refinements have been made to the initial approach to add new capabilities, improve overall accuracy, and increase efficiency.

The original method behind the DRIVE tool was similar in concept to the streamlined method developed by PG&E where a select number of power flow cases are used to characterize the feeder response, then calculations are performed to determine DER scenario impacts and hosting capacities. However, the current underlying approach and equations are different. DRIVE is also similar to the iterative ICA method in that the tool has employed ways to make the analysis more efficient, i.e., protection analysis. The DRIVE analysis has also evolved through extensive detailed studies and continues to evolve in the same manner. In practice, the DRIVE approach has been shown to take a streamlined approach, while still achieving results similar to a detailed analysis.

Requirement	
Input Data	• Feeder circuit models
	• Minimum of 2 loadflow cases
Data Storage	• ~ 1 MB per feeder
Computational Times	• ~ 5 minutes per feeder

Advantages

• *Hybrid Approach.* Built of learnings from all methods with roots in stochastic analysis, it now takes a streamlined approach while achieving an iterative result.

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• *Multiple software platforms.* Currently compatible with CYME, Synergi, Milsoft, Powerfactory, OpenDSS, Gridlab-D, DEW, and PVL platforms.
• *Consistency.* Due to compatibility with the range of distribution planning platforms, a consistent approach can be applied across service territories where different planning tools are used.
• *Single-site and multi-site DER.* The method considers various DER scenarios that combine iterative (single-site DER) and stochastic (multiple-site DER) analyses.
• *Computational efficiency.* Hosting capacity for all scenarios calculated within minutes per feeder.
• *Potential for scenario analysis.* Due to the computation efficiency, "what-if" scenarios such as DER forecasts, reconfiguration, smart inverter settings, DER mitigation strategies, etc. can easily be considered.
• *Solution convergence.* If the baseline power flow solves correctly, the method does not have non-convergence issues.
• *Industry collaboration.* Developed with broad industry input over the course of 5 years including over 50 utilities, Department of Energy, California Public Utilities Commission, and New York State Energy Research & Development Authority. Through the international DRIVE User Group, industry-wide collaboration will further provide guidance on future revisions/updates.
• *Time-based hosting capacity*. Easily applicable to observe how hosting capacity changes over time and derive a hosting capacity portfolio.

Disadvantages

• *Not well understood by all stakeholders.* The approach used in this analysis is a new technique developed for distribution analysis and not easily understood by all stakeholders.
Because of this, EPRI has published dozens of papers and participated/presented in multiple industry conferences and stakeholder processes to ensure transparency.
• *Different technique from interconnection studies.* The method used is different than that traditionally used for detailed interconnection studies. While this is the case, the results are still useful in informing interconnection processes.
• *DER Portfolios.* The present version does not enable consideration for portfolios of DER.
The hosting capacity calculations are calculated based on specific DER characteristics.
• *Single-feeder analysis only.* The current method analyzes one feeder at a time. Aggregate impacts of parallel feeder DER are captured through aggregation techniques. Substation impacts are not yet considered.

PROTECTED DATA SHADED

Substation	Feeder	Minimum Hosting Capacity (MW)	Min Limiting Factor	Maximum Hosting Capacity (MW)	Max Limiting Factor	Substation Transformer Forecasted Peak Load (kVA)	Substation Transformer Minimum Load (kVA)	Feeder 2020 Peak Load (kVA)	Feeder Daytime Minimum Load (kVA)	Substation Transformer Installed DG (kVA)	Substation Transformer Queued DG (kVA)	Feeder Installed DG (kVA)	Feeder Queued DG (kVA)
Afton	AFT314	0.3	Thermal for Gen - min	2.79	Breaker Relay Reduction of Reach - max		16,691		9,040	524	277	256	127
Afton	AFT315	0.2	Thermal for Gen - min	1.54	Breaker Relay Reduction of Reach - max		16,691		7,900	524	277	267	150
Afton	AFT321	0	Additional Element Fault Current - min	0.03	Breaker Relay Reduction of Reach - max		12,745		9,173	452	1157	380	1119
Afton	AFT322	0	Thermal for Gen - min	2.86	Reverse Power Flow - max		12,745		3,799	452	1157	72	38
Arden Hills	AHI021	0.3	Primary Over-Voltage - min	0.3	Primary Over-Voltage - max		5,580		2,047	194	215	72	53
Arden Hills	AHI022	0.11	Unintentional Islanding - min	0.3	Primary Over-Voltage - max		5,580		1,392	194	215	65	114
Arden Hills	AHI024	0.3	Primary Over-Voltage - min	0.3	Primary Over-Voltage - max		5,580		2,907	194	215	58	0
Arden Hills	AHI025	0.3	Primary Over-Voltage - min	0.3	Primary Over-Voltage - max		5,580		2,489	194	215	0	48
Arden Hills	AHI063	0.04	Unintentional Islanding - min	3.03	Reverse Power Flow - max		3,121		3,121	77	26	77	26
Airport	AIR060	0.3	Thermal for Gen - min	1.52	Reverse Power Flow - max		9,358		1,096	0	0	0	0
Airport	AIR061	0.9	Reverse Power Flow - min	0.9	Reverse Power Flow - max		9,358		1,807	0	0	0	0
Airport	AIR069	0.9	Primary Over-Voltage - min	1.01	Reverse Power Flow - max		9,358		1,245	0	0	0	0
Airport	AIR072	1.29	Reverse Power Flow - min	1.29	Reverse Power Flow - max		10,131		1,601	0	0	0	0
Airport	AIR073	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		10,131		1,116	0	0	0	0
Airport	AIR074	1.36	Reverse Power Flow - min	1.36	Reverse Power Flow - max		10,131		5,272	0	0	0	0
Airport	AIR077	1.4	Primary Over-Voltage - min	1.7	Reverse Power Flow - max		10,131		2,557	0	0	0	0
Airport	AIR078	0.21	Reverse Power Flow - min	0.21	Reverse Power Flow - max		10,131		922	0	0	0	0
Airport	AIR079	1.34	Reverse Power Flow - min	1.34	Reverse Power Flow - max		10,131		100	0	0	0	0
Airport	AIR62X	1.1	Thermal for Gen - min	1.49	Reverse Power Flow - max		9,358		1,012	0	0	0	0
Airport	AIR62Y	0	Reverse Power Flow - min	0	Reverse Power Flow - max		9,358		1,012	0	0	0	0
Albany	ALB021	0.05	Unintentional Islanding - min	1.26	Reverse Power Flow - max		2,582		2,107	10134	4035	42	3016
Albany	ALB022	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		2,582		1,342	10134	4035	92	1019
Albany	ALB023	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		2,582		303	10134	4035	10000	0
Aldrich	ALD072	0.5	Thermal for Gen - min	1.5	Reverse Power Flow - max		7,889		2,363	302	89	68	16
Aldrich	ALD073	0.15	Reverse Power Flow - min	0.15	Reverse Power Flow - max		7,889		3,178	302	89	111	17
Aldrich	ALD075	1.15	Reverse Power Flow - min	1.15	Reverse Power Flow - max		7,889		351	302	89	0	0
Aldrich	ALD076	0.2	Thermal for Gen - min	1.25	Breaker Relay Reduction of Reach - max		7,889		2,571	302	89	115	56
Aldrich	ALD081	0.62	Reverse Power Flow - min	0.62	Reverse Power Flow - max		18,182		671	395	490	0	0
Aldrich	ALD082	0.9	Thermal for Gen - min	1.32	Reverse Power Flow - max		18,182		2,121	395	490	57	254
Aldrich	ALD083	0.1	Thermal for Gen - min	0.91	Breaker Relay Reduction of Reach - max		18,182		1,663	395	490	6	3
Aldrich	ALD084	0.9	Thermal for Gen - min	1.17	Reverse Power Flow - max		18,182		2,162	395	490	74	93
Aldrich	ALD085	0.09	Unintentional Islanding - min	1.71	Reverse Power Flow - max		18,182		2,844	395	490	102	95
Aldrich	ALD086	0.5	Primary Over-Voltage - min	1.8	Reverse Power Flow - max		18,182		806	395	490	0	18
Aldrich	ALD087	0.81	Reverse Power Flow - min	0.81	Reverse Power Flow - max		18,182		2,203	395	490	0	0
Aldrich	ALD088	0.12	Unintentional Islanding - min	1.7	Reverse Power Flow - max		18,182		1,663	395	490	157	28
Aldrich	ALD091	0.71	Reverse Power Flow - min	0.71	Reverse Power Flow - max		18,828		1,218	174	1414	34	0
Aldrich	ALD092	0.9	Thermal for Gen - min	2.62	Reverse Power Flow - max		18,828		5,332	174	1414	42	0
Aldrich	ALD093	0.43	Reverse Power Flow - min	0.43	Reverse Power Flow - max		18,828		561	174	1414	4	10
Aldrich	ALD094	0.9	Thermal for Gen - min	1.14	Reverse Power Flow - max		18,828		1,814	174	1414	0	960
Aldrich	ALD095	0.9	Thermal for Gen - min	1.53	Reverse Power Flow - max		18,828		2,777	174	1414	32	13
Aldrich	ALD096	0.5	Thermal for Gen - min	1.37	Reverse Power Flow - max		18,828		1,218	174	1414	0	240
Aldrich	ALD097	0.9	Thermal for Gen - min	1.4	Reverse Power Flow - max		18,828		2,404	174	1414	63	191
Aldrich	ALD098	0.5	Thermal for Gen - min	0.99	Reverse Power Flow - max		18,828		561	174	1414	0	0

PROTECTED DATA SHADED

Substation	Feeder	Minimum Hosting Capacity (MW)	Min Limiting Factor	Maximum Hosting Capacity (MW)	Max Limiting Factor	Substation Transformer Forecasted Peak Load (kVA)	Substation Transformer Minimum Load (kVA)	Feeder 2020 Peak Load (kVA)	Feeder Daytime Minimum Load (kVA)	Substation Transformer Installed DG (kVA)	Substation Transformer Queued DG (kVA)	Feeder Installed DG (kVA)	Feeder Queued DG (kVA)
Air Lake	ALK063	0.9	Thermal for Gen - min	2.14	Reverse Power Flow - max		9,024		2,784	255	8	21	8
Air Lake	ALK064	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		9,024		1,328	255	8	8	0
Air Lake	ALK067	1.1	Thermal for Gen - min	1.51	Reverse Power Flow - max		9,024		1,456	255	8	226	0
Air Lake	ALK072	0.7	Primary Over-Voltage - min	2.22	Reverse Power Flow - max		5,635		2,068	191	31	191	31
Air Lake	ALK073	1.1	Thermal for Gen - min	1.71	Reverse Power Flow - max		5,635		1,854	191	31	0	0
Altura	ALT021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,081		1,081	2004	5056	2004	5056
Annandale	ANN021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		2,119		2,119	6152	1018	6152	1018
Apache	APA061	0.9	Thermal for Gen - min	1.47	Reverse Power Flow - max		10,500		2,668	229	109	27	20
Apache	APA064	1	Thermal for Gen - min	1.06	Reverse Power Flow - max		10,500		1,285	229	109	74	40
Apache	APA065	0.9	Thermal for Gen - min	1.17	Reverse Power Flow - max		10,500		2,234	229	109	8	0
Apache	APA067	0.5	Thermal for Gen - min	1.53	Reverse Power Flow - max		10,500		1,934	229	109	78	11
Apache	APA068	0.6	Thermal for Gen - min	1.23	Reverse Power Flow - max		10,500		1,416	229	109	25	36
Apache	APA069	0.59	Reverse Power Flow - min	0.59	Reverse Power Flow - max		10,500		848	229	109	17	3
Apache	APA071	0.16	Unintentional Islanding - min	1.34	Reverse Power Flow - max		17,922		2,309	564	249	72	24
Apache	APA072	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		17,922		2,062	564	249	83	20
Apache	APA073	0.9	Thermal for Gen - min	1.29	Reverse Power Flow - max		17,922		1,645	564	249	11	13
Apache	APA074	0.9	Thermal for Gen - min	1.68	Reverse Power Flow - max		17,922		2,913	564	249	3	0
Apache	APA075	0.9	Thermal for Gen - min	1.72	Reverse Power Flow - max		17,922		2,247	564	249	164	47
Apache	APA076	0.31	Unintentional Islanding - min	1.23	Reverse Power Flow - max		17,922		1,946	564	249	47	67
Apache	APA077	1.23	Reverse Power Flow - min	1.23	Reverse Power Flow - max		17,922		2,012	564	249	171	77
Apache	APA078	0.9	Thermal for Gen - min	0.99	Reverse Power Flow - max		17,922		1,942	564	249	13	0
Atwater	ATW061	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,930		547	4001	6411	4000	1000
Atwater	ATW062	0.1	Primary Over-Voltage - min	1.42	Reverse Power Flow - max		1,930		1,597	4001	6411	1	5411
Avon	AVN021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,789		1,789	3028	2008	3028	2008
Averill	AVR081	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,248		1,248	1500	5000	1500	5000
Birch	BCH311	0.9	Primary Over-Voltage - min	1.3	Primary Over-Voltage - max		1,204		1,204	75	18	75	18
Battle Creek	BCK061	10	Primary Over-Voltage - min	10	Primary Over-Voltage - max		11,653		9,849	0	0	0	0
Battle Creek	BCK062	1.35	Reverse Power Flow - min	1.35	Reverse Power Flow - max		11,653		1,432	0	0	0	0
Battle Creek	BCK071	0	Reverse Power Flow - min	0	Reverse Power Flow - max		1,465		0	0	0	0	0
Battle Creek	BCK072	0.61	Reverse Power Flow - min	0.61	Reverse Power Flow - max		1,465		213	0	0	0	0
Battle Creek	BCK073	1.2	Primary Over-Voltage - min	1.34	Reverse Power Flow - max		1,465		1,393	0	0	0	0
Battle Creek	BCK074	1.04	Reverse Power Flow - min	1.04	Reverse Power Flow - max		1,465		541	0	0	0	0
Bassett Creek	BCR061	0.9	Thermal for Gen - min	2.32	Reverse Power Flow - max		10,220		2,530	58	275	0	0
Bassett Creek	BCR062	1	Thermal for Gen - min	3.36	Reverse Power Flow - max		10,220		3,660	58	275	19	258
Bassett Creek	BCR063	0.9	Thermal for Gen - min	2.3	Reverse Power Flow - max		10,220		2,460	58	275	39	18
Bassett Creek	BCR081	0.99	Reverse Power Flow - min	0.99	Reverse Power Flow - max		4,060		1,120	30	0	8	0
Bassett Creek	BCR082	0.29	Unintentional Islanding - min	1.59	Reverse Power Flow - max		4,060		1,870	30	0	15	0
Bassett Creek	BCR083	0.9	Thermal for Gen - min	1.68	Reverse Power Flow - max		4,060		1,900	30	0	8	0
Belgrade	BEG001	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		483		483	720	1000	720	1000
Becker	BEK021	0.1	Primary Over-Voltage - min	0.1	Primary Over-Voltage - max		316		316	126	0	126	0
Becker	BEK311	0.01	Reverse Power Flow - min	0.01	Reverse Power Flow - max		10		10	44	0	44	0
Belle Plain	BEL061	0.1	Primary Over-Voltage - min	0.1	Primary Over-Voltage - max		3,044		1,997	4996	4016	22	1008
Belle Plain	BEL062	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		3,044		1,385	4996	4016	4974	3008

PROTECTED DATA SHADED

Substation	Feeder	Minimum Hosting Capacity (MW)	Min Limiting Factor	Maximum Hosting Capacity (MW)	Max Limiting Factor	Substation Transformer Forecasted Peak Load (kVA)	Substation Transformer Minimum Load (kVA)	Feeder 2020 Peak Load (kVA)	Feeder Daytime Minimum Load (kVA)	Substation Transformer Installed DG (kVA)	Substation Transformer Queued DG (kVA)	Feeder Installed DG (kVA)	Feeder Queued DG (kVA)
Buffalo Lake	BFL021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		525		525	1000	1000	1000	1000
Bird Island	BIS001	0.1	Primary Over-Voltage - min	0.3	Reverse Power Flow - max		505		505	30	11	30	11
Bluff Creek	BLC061	1.2	Primary Over-Voltage - min	1.23	Reverse Power Flow - max		13,483		1,626	41	53	0	0
Bluff Creek	BLC062	0.9	Thermal for Gen - min	2.18	Reverse Power Flow - max		13,483		3,108	41	53	36	34
Bluff Creek	BLC063	1	Primary Over-Voltage - min	1.9	Reverse Power Flow - max		13,483		2,762	41	53	5	18
Bluff Creek	BLC071	1.1	Thermal for Gen - min	1.96	Reverse Power Flow - max		13,483		2,915	41	53	0	0
Bluff Creek	BLC072	0.7	Primary Over-Voltage - min	1.27	Reverse Power Flow - max		13,483		2,338	41	53	0	0
Blue Herron	BLH061	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,911		1,560	3022	0	3015	0
Blue Herron	BLH062	0.2	Thermal for Gen - min	0.42	Reverse Power Flow - max		1,911		517	3022	0	7	0
Blue Lake	BLL062	0.5	Primary Over-Voltage - min	0.94	Reverse Power Flow - max		6,438		1,127	0	0	0	0
Blue Lake	BLL063	0.3	Thermal for Gen - min	1.53	Reverse Power Flow - max		6,438		3,232	0	0	0	0
Blue Lake	BLL064	0.44	Reverse Power Flow - min	0.44	Reverse Power Flow - max		6,438		59	0	0	0	0
Blue Lake	BLL071	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		4,004		1,404	3000	0	3000	0
Blue Lake	BLL072	0.9	Thermal for Gen - min	3.26	Reverse Power Flow - max		4,004		3,516	3000	0	0	0
Brooten	BRO021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,199		1,199	2060	6010	2060	6010
Brooklyn Park	BRP061	0.56	Reverse Power Flow - min	0.56	Reverse Power Flow - max		4,130		810	100	1092	0	0
Brooklyn Park	BRP062	0.9	Thermal for Gen - min	1.33	Reverse Power Flow - max		4,130		1,600	100	1092	100	1092
Brooklyn Park	BRP063	0.9	Thermal for Gen - min	1.01	Reverse Power Flow - max		4,130		1,100	100	1092	0	0
Brooklyn Park	BRP071	0.8	Primary Over-Voltage - min	1.31	Reverse Power Flow - max		5,350		1,610	39	324	23	14
Brooklyn Park	BRP072	0.9	Thermal for Gen - min	1.25	Reverse Power Flow - max		5,350		1,730	39	324	16	147
Brooklyn Park	BRP073	0.23	Unintentional Islanding - min	1.25	Reverse Power Flow - max		5,350		1,530	39	324	0	163
Brownton	BRW001	0.1	Reverse Power Flow - min	0.1	Reverse Power Flow - max		86		86	0	0	0	0
Butterfield	BTF001	0	Thermal for Gen - min	0.15	Reverse Power Flow - max		429		429	275	0	275	0
Burnside	BUR022	0.13	Unintentional Islanding - min	0.29	Reverse Power Flow - max		3,700		1,750	88	0	88	0
Burnside	BUR023	0.56	Unintentional Islanding - min	2.13	Reverse Power Flow - max		3,700		1,890	88	0	0	0
Burnside	BUR032	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,906		1,906	5028	4413	5028	4413
Baytown	BYT061	0.13	Unintentional Islanding - min	1.52	Reverse Power Flow - max		2,886		2,886	74	35	74	35
Baytown	BYT071	0.77	Unintentional Islanding - min	1.66	Reverse Power Flow - max		4,922		1,751	93	67	48	44
Baytown	BYT072	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		4,922		3,029	93	67	45	23
Cannon Falls	CAF021	0.57	Reverse Power Flow - min	0.57	Reverse Power Flow - max		1,204		611	0	1004	0	0
Cannon Falls	CAF022	0.3	Thermal for Gen - min	0.55	Reverse Power Flow - max		1,204		643	0	1004	0	1004
Cedarvale	CDV061	0.4	Reverse Power Flow - min	0.4	Reverse Power Flow - max		3,358		866	16	0	0	0
Cedarvale	CDV062	0.92	Reverse Power Flow - min	0.92	Reverse Power Flow - max		3,358		908	16	0	0	0
Cedarvale	CDV063	0.13	Unintentional Islanding - min	0.84	Reverse Power Flow - max		3,358		842	16	0	16	0
Cedarvale	CDV071	0.41	Additional Element Fault Current - min	1.2	Reverse Power Flow - max		7,857		1,800	929	20	750	0
Cedarvale	CDV072	0.5	Thermal for Gen - min	1.66	Reverse Power Flow - max		7,857		1,918	929	20	179	20
Cedar Lake	CEL061	0.8	Primary Over-Voltage - min	1.15	Reverse Power Flow - max		9,199		2,025	109	21	0	0
Cedar Lake	CEL062	0.9	Thermal for Gen - min	1.27	Reverse Power Flow - max		9,199		2,089	109	21	17	0
Cedar Lake	CEL063	0.88	Reverse Power Flow - min	0.88	Reverse Power Flow - max		9,199		765	109	21	0	0
Cedar Lake	CEL064	0.9	Thermal for Gen - min	1.6	Reverse Power Flow - max		9,199		2,041	109	21	60	17
Cedar Lake	CEL066	0.04	Unintentional Islanding - min	0.93	Reverse Power Flow - max		9,199		1,392	109	21	32	4

PROTECTED DATA SHADED

Substation	Feeder	Minimum Hosting Capacity (MW)	Min Limiting Factor	Maximum Hosting Capacity (MW)	Max Limiting Factor	Substation Transformer Forecasted Peak Load (kVA)	Substation Transformer Minimum Load (kVA)	Feeder 2020 Peak Load (kVA)	Feeder Daytime Minimum Load (kVA)	Substation Transformer Installed DG (kVA)	Substation Transformer Queued DG (kVA)	Feeder Installed DG (kVA)	Feeder Queued DG (kVA)
Cedar Lake	CEL071	1.2	Thermal for Gen - min	1.72	Reverse Power Flow - max		5,072		2,647	119	0	16	0
Cedar Lake	CEL072	0.9	Thermal for Gen - min	0.92	Reverse Power Flow - max		5,072		1,499	119	0	68	0
Cedar Lake	CEL075	0.87	Reverse Power Flow - min	0.87	Reverse Power Flow - max		5,072		1,087	119	0	34	0
Cottage Grove	CGR061	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		10,983		2,386	15165	1089	1066	37
Cottage Grove	CGR062	0.9	Thermal for Gen - min	3.09	Reverse Power Flow - max		10,983		4,809	15165	1089	20	0
Cottage Grove	CGR063	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		10,983		194	15165	1089	14067	1040
Cottage Grove	CGR064	0.9	Thermal for Gen - min	1.9	Reverse Power Flow - max		10,983		2,470	15165	1089	13	12
Cottage Grove	CGR071	0.6	Reverse Power Flow - min	0.6	Reverse Power Flow - max		6,805		906	128	43	25	18
Cottage Grove	CGR072	0.9	Thermal for Gen - min	2.31	Reverse Power Flow - max		6,805		2,518	128	43	67	20
Cottage Grove	CGR073	2.24	Reverse Power Flow - min	2.24	Reverse Power Flow - max		6,805		3,202	128	43	0	0
Cottage Grove	CGR074	0.9	Primary Over-Voltage - min	1.41	Reverse Power Flow - max		6,805		1,628	128	43	36	5
Chemolite	CHE063	0.3	Primary Over-Voltage - min	1.96	Reverse Power Flow - max		6,952		2,220	798	9	780	5
Chemolite	CHE064	0.5	Thermal for Gen - min	1.3	Reverse Power Flow - max		6,952		1,924	798	9	18	4
Chemolite	CHE075	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		6,822		3,712	4964	1032	4938	1011
Chemolite	CHE076	0.9	Thermal for Gen - min	1.76	Reverse Power Flow - max		6,822		2,159	4964	1032	27	21
Chisago County	CHI311	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		2,190		2,190	22728	19175	22728	19175
Clarks Grove	CKG041	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		421		421	289	2000	289	2000
Clara City	CLC022	0	Reverse Power Flow - min	0	Reverse Power Flow - max		633		633	1000	0	1000	0
Clara City	CLC221	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,324		1,324	2072	4036	2072	4036
Coon Creek	CNC061	1.91	Reverse Power Flow - min	1.91	Reverse Power Flow - max		6,327		3,035	42	0	0	0
Coon Creek	CNC062	1.1	Thermal for Gen - min	1.58	Reverse Power Flow - max		6,327		1,857	42	0	36	0
Coon Creek	CNC063	0.9	Thermal for Gen - min	1.09	Reverse Power Flow - max		6,327		2,909	42	0	6	0
Coon Creek	CNC071	0.9	Thermal for Gen - min	1.03	Reverse Power Flow - max		8,440		2,968	83	10	35	0
Coon Creek	CNC072	1.1	Thermal for Gen - min	1.75	Reverse Power Flow - max		8,440		3,522	83	10	4	10
Coon Creek	CNC073	0.9	Thermal for Gen - min	2.36	Reverse Power Flow - max		8,440		1,573	83	10	44	0
Cokato	COK061	0	Additional Element Fault Current - min	0.16	Breaker Relay Reduction of Reach - max		1,306		1,306	1007	5000	1007	5000
Crystal Foods	CRF061	0.51	Reverse Power Flow - min	0.51	Reverse Power Flow - max		1,750		522	0	0	0	0
Crystal Foods	CRF062	0.2	Thermal for Gen - min	1.25	Reverse Power Flow - max		1,750		1,260	0	0	0	0
Crooked Lake	CRL027	0.06	Unintentional Islanding - min	2.98	Reverse Power Flow - max		12,404		3,314	30	0	16	0
Crooked Lake	CRL031	0.14	Unintentional Islanding - min	1.19	Reverse Power Flow - max		4,838		1,315	6	11	0	11
Crooked Lake	CRL033	0.32	Unintentional Islanding - min	1.81	Reverse Power Flow - max		4,838		1,931	6	11	6	0
Crooked Lake	CRL065	1.07	Reverse Power Flow - min	1.07	Reverse Power Flow - max		12,404		1,204	30	0	15	0
Castle Rock	CSR001	0.1	Reverse Power Flow - min	0.1	Reverse Power Flow - max		100		100	5	0	5	0
Cannon Falls Transmission	CTF021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		3,915		991	12552	1025	10020	1025
Cannon Falls Transmission	CTF022	0.12	Unintentional Islanding - min	0.94	Reverse Power Flow - max		3,915		2,271	12552	1025	2532	0
Credit River	CTR021	0.17	Unintentional Islanding - min	1.09	Reverse Power Flow - max		2,558		1,811	50	0	45	0
Credit River	CTR022	0.67	Reverse Power Flow - min	0.67	Reverse Power Flow - max		2,558		1,000	50	0	5	0
Credit River	CTR031	0.55	Unintentional Islanding - min	2.11	Reverse Power Flow - max		3,229		3,229	19	85	19	85
Danube	DAN021	0.1	Primary Over-Voltage - min	0.47	Reverse Power Flow - max		224		224	0	1000	0	1000
Dassel	DAS061	0.1	Primary Over-Voltage - min	0.6	Reverse Power Flow - max		753		753	10	2048	10	2048
Dayton's Bluff	DBL060	0.3	Thermal for Gen - min	1.55	Breaker Relay Reduction of Reach - max		14,115		2,214	809	109	82	0
Dayton's Bluff	DBL061	0.5	Thermal for Gen - min	2.52	Reverse Power Flow - max		14,115		2,608	809	109	0	0
Dayton's Bluff	DBL062	0.79	Reverse Power Flow - min	0.79	Reverse Power Flow - max		14,115		806	809	109	0	0

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Dayton's Bluff	DBL063	0.29	Unintentional Islanding - min	1.69	Reverse Power Flow - max		14,115		1,844	809	109	28	24
Dayton's Bluff	DBL064	0.31	Reverse Power Flow - min	0.31	Reverse Power Flow - max		14,115		292	809	109	540	0
Dayton's Bluff	DBL065	0.9	Thermal for Gen - min	2.04	Reverse Power Flow - max		14,115		2,256	809	109	35	18
Dayton's Bluff	DBL066	0.1	Thermal for Gen - min	0.57	Reverse Power Flow - max		14,115		707	809	109	44	0
Dayton's Bluff	DBL067	0.07	Unintentional Islanding - min	2.22	Reverse Power Flow - max		14,115		2,707	809	109	23	6
Dayton's Bluff	DBL068	0.25	Unintentional Islanding - min	1.96	Reverse Power Flow - max		14,115		2,335	809	109	56	21
Dayton's Bluff	DBL069	0.6	Thermal for Gen - min	2.9	Reverse Power Flow - max		14,115		3,306	809	109	0	40
Dayton's Bluff	DBL072	0.78	Reverse Power Flow - min	0.78	Reverse Power Flow - max		13,825		143	51	110	0	0
Dayton's Bluff	DBL073	0.5	Thermal for Gen - min	1.32	Reverse Power Flow - max		13,825		1,942	51	110	51	22
Dayton's Bluff	DBL074	0.9	Thermal for Gen - min	1.13	Reverse Power Flow - max		13,825		2,044	51	110	0	88
Dayton's Bluff	DBL081	0.9	Thermal for Gen - min	0.97	Reverse Power Flow - max		13,188		1,676	0	0	0	0
Dayton's Bluff	DBL082	0.33	Reverse Power Flow - min	0.33	Reverse Power Flow - max		13,188		483	0	0	0	0
Douglas County	DGC061	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,082		1,082	5000	3012	5000	3012
Dahlgren	DHL061	0.3	Thermal for Gen - min	1.22	Reverse Power Flow - max		1,404		1,404	22	0	22	0
Delano	DLO021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		60		60	56	0	56	0
Dundas	DND061	0.5	Thermal for Gen - min	1.25	Reverse Power Flow - max		4,143		1,581	70	677	52	14
Dundas	DND062	0.2	Thermal for Gen - min	1.03	Reverse Power Flow - max		4,143		1,099	70	677	18	663
Dundas	DND071	0.2	Thermal for Gen - min	2.03	Reverse Power Flow - max		4,847		2,419	5090	7018	90	5018
Dundas	DND072	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		4,847		1,620	5090	7018	5000	2000
Dodge Center	DOC021	0.3	Thermal for Gen - min	1.96	Reverse Power Flow - max		2,125		2,125	10	30	10	30
Dodge Center	DOC031	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,508		1,508	13143	27	13143	27
Dodge Center	DOC211	0.1	Primary Over-Voltage - min	1.64	Breaker Relay Reduction of Reach - max		2,154		2,154	64	8260	64	8260
Deephaven	DPN061	0.6	Reverse Power Flow - min	0.6	Reverse Power Flow - max		7,012		845	62	760	8	0
Deephaven	DPN062	0.9	Thermal for Gen - min	1.48	Reverse Power Flow - max		7,012		1,625	62	760	38	750
Deephaven	DPN063	0.9	Thermal for Gen - min	2.12	Reverse Power Flow - max		7,012		2,204	62	760	17	10
Deephaven	DPN071	0.9	Thermal for Gen - min	1.37	Reverse Power Flow - max		6,749		1,451	143	50	15	20
Deephaven	DPN072	0.06	Unintentional Islanding - min	0.84	Reverse Power Flow - max		6,749		958	143	50	103	13
Deephaven	DPN073	0.9	Thermal for Gen - min	2.48	Reverse Power Flow - max		6,749		2,622	143	50	25	18
East Bloomington	EBL062	1.58	Reverse Power Flow - min	1.58	Reverse Power Flow - max		10,171		5,008	0	0	0	0
East Bloomington	EBL063	0.39	Reverse Power Flow - min	0.39	Reverse Power Flow - max		10,171		0	0	0	0	0
East Bloomington	EBL064	1.1	Thermal for Gen - min	1.56	Reverse Power Flow - max		10,171		540	0	0	0	0
East Bloomington	EBL065	1.01	Reverse Power Flow - min	1.01	Reverse Power Flow - max		10,171		1,600	0	0	0	0
East Bloomington	EBL066	0.86	Reverse Power Flow - min	0.86	Reverse Power Flow - max		10,171		721	0	0	0	0
East Bloomington	EBL067	1.07	Reverse Power Flow - min	1.07	Reverse Power Flow - max		10,171		1,204	0	0	0	0
East Bloomington	EBL071	0.2	Thermal for Gen - min	1.17	Reverse Power Flow - max		14,159		2,010	0	107	0	0
East Bloomington	EBL072	1.1	Thermal for Gen - min	1.57	Reverse Power Flow - max		14,159		1,581	0	107	0	107
East Bloomington	EBL073	0.35	Reverse Power Flow - min	0.35	Reverse Power Flow - max		14,159		1,204	0	107	0	0
East Bloomington	EBL074	1.31	Reverse Power Flow - min	1.31	Reverse Power Flow - max		14,159		3,454	0	107	0	0
East Bloomington	EBL075	1.33	Reverse Power Flow - min	1.33	Reverse Power Flow - max		14,159		1,581	0	107	0	0
East Bloomington	EBL076	0.69	Reverse Power Flow - min	0.69	Reverse Power Flow - max		14,159		609	0	107	0	0
East Bloomington	EBL077	1.19	Reverse Power Flow - min	1.19	Reverse Power Flow - max		14,159		2,022	0	107	0	0
East Bloomington	EBL081	1.06	Reverse Power Flow - min	1.06	Reverse Power Flow - max		11,227		1,649	70	77	0	0
East Bloomington	EBL082	0.5	Primary Over-Voltage - min	0.86	Reverse Power Flow - max		11,227		1,603	70	77	0	50
East Bloomington	EBL083	0.54	Reverse Power Flow - min	0.54	Reverse Power Flow - max		11,227		1,300	70	77	0	0
East Bloomington	EBL084	0.1	Unintentional Islanding - min	1.13	Reverse Power Flow - max		11,227		1,803	70	77	70	22
East Bloomington	EBL085	1	Reverse Power Flow - min	1	Reverse Power Flow - max		11,227		2,002	70	77	0	0
East Bloomington	EBL087	0.82	Reverse Power Flow - min	0.82	Reverse Power Flow - max		11,227		1,523	70	77	0	0
Elm Creek	ECK061	1.1	Thermal for Gen - min	1.71	Reverse Power Flow - max		7,411		1,903	106	83	22	3
Elm Creek	ECK062	0.5	Primary Over-Voltage - min	1.62	Reverse Power Flow - max		7,411		1,910	106	83	20	25
Elm Creek	ECK063	1.1	Thermal for Gen - min	3.03	Reverse Power Flow - max		7,411		3,214	106	83	64	55

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Elm Creek	ECK081	0.94	Reverse Power Flow - min	0.94	Reverse Power Flow - max		2,729		985	109	39	35	0
Elm Creek	ECK082	0.6	Primary Over-Voltage - min	1.07	Reverse Power Flow - max		2,729		1,304	109	39	74	39
Elm Creek	ECK321	0.8	Primary Over-Voltage - min	4.47	Reverse Power Flow - max		11,527		3,490	294	1603	139	86
Elm Creek	ECK322	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		11,527		2,814	294	1603	155	1517
Edina	EDA061	0.8	Primary Over-Voltage - min	0.92	Reverse Power Flow - max		18,371		1,414	415	44	113	5
Edina	EDA062	1.5	Primary Over-Voltage - min	2.06	Reverse Power Flow - max		18,371		3,306	415	44	0	0
Edina	EDA065	1.46	Reverse Power Flow - min	1.46	Reverse Power Flow - max		18,371		2,789	415	44	16	10
Edina	EDA066	1.2	Primary Over-Voltage - min	1.23	Reverse Power Flow - max		18,371		2,102	415	44	0	0
Edina	EDA067	0.1	Thermal for Gen - min	0.85	Breaker Relay Reduction of Reach - max		18,371		3,027	415	44	53	29
Edina	EDA068	0.9	Thermal for Gen - min	1.27	Reverse Power Flow - max		18,371		1,838	415	44	234	0
Edina	EDA069	0.78	Reverse Power Flow - min	0.78	Reverse Power Flow - max		18,371		1,140	415	44	0	0
Edina	EDA071	0.9	Thermal for Gen - min	1.17	Reverse Power Flow - max		17,944		1,304	119	122	0	18
Edina	EDA072	1.5	Thermal for Gen - min	1.81	Reverse Power Flow - max		17,944		2,377	119	122	16	6
Edina	EDA073	0.07	Unintentional Islanding - min	1.94	Reverse Power Flow - max		17,944		1,924	119	122	42	21
Edina	EDA074	0.9	Thermal for Gen - min	1.27	Reverse Power Flow - max		17,944		1,860	119	122	10	0
Edina	EDA075	1	Primary Over-Voltage - min	1.74	Reverse Power Flow - max		17,944		2,502	119	122	10	19
Edina	EDA076	0.62	Reverse Power Flow - min	0.62	Reverse Power Flow - max		17,944		510	119	122	0	0
Edina	EDA077	0.96	Reverse Power Flow - min	0.96	Reverse Power Flow - max		17,944		1,204	119	122	0	0
Edina	EDA078	0.69	Reverse Power Flow - min	0.69	Reverse Power Flow - max		17,944		1,551	119	122	40	30
Edina	EDA079	1.29	Reverse Power Flow - min	1.29	Reverse Power Flow - max		17,944		2,532	119	122	0	29
Edina	EDA081	0.5	Thermal for Gen - min	0.87	Reverse Power Flow - max		12,101		2,002	654	10	0	0
Edina	EDA082	1.1	Thermal for Gen - min	1.26	Reverse Power Flow - max		12,101		1,712	654	10	80	0
Edina	EDA083	1.32	Reverse Power Flow - min	1.32	Reverse Power Flow - max		12,101		1,360	654	10	0	0
Edina	EDA084	1	Thermal for Gen - min	1.5	Reverse Power Flow - max		12,101		1,775	654	10	33	0
Edina	EDA085	0	Reverse Power Flow - min	0	Reverse Power Flow - max		12,101		510	654	10	527	0
Edina	EDA087	0.29	Unintentional Islanding - min	1.56	Reverse Power Flow - max		12,101		1,726	654	10	9	10
Edina	EDA088	1.16	Reverse Power Flow - min	1.16	Reverse Power Flow - max		12,101		1,304	654	10	0	0
Edina	EDA089	0.7	Primary Over-Voltage - min	1.15	Reverse Power Flow - max		12,101		1,745	654	10	5	0
Eden Prarie	EDP062	1	Primary Over-Voltage - min	1.77	Reverse Power Flow - max		10,604		2,790	103	0	0	0
Eden Prarie	EDP063	1.3	Reverse Power Flow - min	1.3	Reverse Power Flow - max		10,604		1,400	103	0	0	0
Eden Prarie	EDP071	0.6	Primary Over-Voltage - min	1.06	Reverse Power Flow - max		10,604		1,000	103	0	0	0
Eden Prarie	EDP072	0.62	Reverse Power Flow - min	0.62	Reverse Power Flow - max		10,604		920	103	0	20	0
Eden Prarie	EDP073	1.3	Primary Over-Voltage - min	1.74	Reverse Power Flow - max		10,604		2,750	103	0	83	0
Eden Prarie	EDP081	0.14	Reverse Power Flow - min	0.14	Reverse Power Flow - max		6,591		167	152	106	0	0
Eden Prarie	EDP082	1	Primary Over-Voltage - min	1.14	Reverse Power Flow - max		6,591		1,517	152	106	36	106
Eden Prarie	EDP083	1.23	Reverse Power Flow - min	1.23	Reverse Power Flow - max		6,591		1,992	152	106	116	0
Eden Prarie	EDP084	0.47	Reverse Power Flow - min	0.47	Reverse Power Flow - max		6,591		590	152	106	0	0
Eden Prarie	EDP085	1.03	Reverse Power Flow - min	1.03	Reverse Power Flow - max		6,591		1,803	152	106	0	0
Eden Prarie	EDP091	0.5	Primary Over-Voltage - min	0.91	Reverse Power Flow - max		10,604		1,100	45	0	0	0
Eden Prarie	EDP092	1.2	Primary Over-Voltage - min	1.21	Reverse Power Flow - max		10,604		1,749	45	0	29	0
Eden Prarie	EDP093	1.4	Primary Over-Voltage - min	1.59	Reverse Power Flow - max		10,604		2,247	45	0	0	0
Eden Prarie	EDP094	1.1	Primary Over-Voltage - min	1.46	Reverse Power Flow - max		10,604		1,503	45	0	0	0
Eden Prarie	EDP095	1.29	Reverse Power Flow - min	1.29	Reverse Power Flow - max		10,604		1,503	45	0	16	0

PROTECTED DATA SHADED

Substation	Feeder	Minimum Hosting Capacity (MW)	Min Limiting Factor	Maximum Hosting Capacity (MW)	Max Limiting Factor	Substation Transformer Forecasted Peak Load (kVA)	Substation Transformer Minimum Load (kVA)	Feeder 2020 Peak Load (kVA)	Feeder Daytime Minimum Load (kVA)	Substation Transformer Installed DG (kVA)	Substation Transformer Queued DG (kVA)	Feeder Installed DG (kVA)	Feeder Queued DG (kVA)
Eagle Lake	EGL021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,122		641	5268	1406	5262	1406
Eagle Lake	EGL022	0.3	Thermal for Gen - min	0.54	Reverse Power Flow - max		1,122		592	5268	1406	6	0
Elko	EKO021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,039		1,039	884	56	884	56
Elliott Park	ELP061	1.44	Reverse Power Flow - min	1.44	Reverse Power Flow - max		14,560		2,742	55	0	0	0
Elliott Park	ELP062	0.5	Thermal for Gen - min	1.62	Reverse Power Flow - max		14,560		3,725	55	0	55	0
Elliott Park	ELP063	0.9	Thermal for Gen - min	1.44	Reverse Power Flow - max		14,560		2,984	55	0	0	0
Elliott Park	ELP064	0.61	Reverse Power Flow - min	0.61	Reverse Power Flow - max		14,560		2,207	55	0	0	0
Elliott Park	ELP071	0.75	Reverse Power Flow - min	0.75	Reverse Power Flow - max		14,285		1,943	50	0	50	0
Elliott Park	ELP072	0.68	Reverse Power Flow - min	0.68	Reverse Power Flow - max		14,285		1,372	50	0	0	0
Elliott Park	ELP073	0.87	Reverse Power Flow - min	0.87	Reverse Power Flow - max		14,285		660	50	0	0	0
Elliott Park	ELP074	1.21	Reverse Power Flow - min	1.21	Reverse Power Flow - max		14,285		1,649	50	0	0	0
Elliott Park	ELP075	0.9	Thermal for Gen - min	0.9	Reverse Power Flow - max		14,285		741	50	0	0	0
Elliott Park	ELP081	0.26	Reverse Power Flow - min	0.26	Reverse Power Flow - max		14,444		2,851	9040	0	0	0
Elliott Park	ELP082	0.5	Thermal for Gen - min	0.85	Reverse Power Flow - max		14,444		3,503	9040	0	40	0
Elliott Park	ELP083	0.62	Reverse Power Flow - min	0.62	Reverse Power Flow - max		14,444		659	9040	0	0	0
Elliott Park	ELP084	0.9	Thermal for Gen - min	1.29	Reverse Power Flow - max		14,444		4,915	9040	0	0	0
Elliott Park	ELP085	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		14,444		0	9040	0	9000	0
Elliott Park	ELP086X	0.67	Reverse Power Flow - min	0.67	Reverse Power Flow - max		14,444		2,626	9040	0	0	0
Elliott Park	ELP086Y	0.67	Reverse Power Flow - min	0.67	Reverse Power Flow - max		14,444		2,387	9040	0	0	0
Essig	ESG001	0.04	Reverse Power Flow - min	0.04	Reverse Power Flow - max		54		54	0	0	0	0
Eastwood	ESW061	0.3	Thermal for Gen - min	3.08	Reverse Power Flow - max		8,579		3,239	160	20	45	20
Eastwood	ESW062	0.33	Unintentional Islanding - min	3.87	Reverse Power Flow - max		8,579		4,219	160	20	115	0
Eastwood	ESW063	1.02	Reverse Power Flow - min	1.02	Reverse Power Flow - max		8,579		1,036	160	20	0	0
Eastwood	ESW071	0.9	Thermal for Gen - min	1.35	Reverse Power Flow - max		3,907		1,646	5539	0	0	0
Eastwood	ESW072	0.2	Thermal for Gen - min	1.85	Reverse Power Flow - max		3,907		1,825	5539	0	0	0
Eastwood	ESW073	0	Unintentional Islanding - min	0.71	Reverse Power Flow - max		3,907		804	5539	0	5539	0
Eastwood	ESW081	1	Primary Over-Voltage - min	1.64	Reverse Power Flow - max		5,109		1,500	112	5	30	5
Eastwood	ESW082	0.9	Primary Over-Voltage - min	2.25	Reverse Power Flow - max		5,109		2,927	112	5	82	0
East Winona	EWI022	0.4	Thermal for Gen - min	1.88	Reverse Power Flow - max		1,879		1,879	0	5	0	5
Excelsior	EXC061	0.9	Thermal for Gen - min	1.13	Reverse Power Flow - max		2,555		1,143	114	42	5	25
Excelsior	EXC062	0.5	Thermal for Gen - min	1.39	Reverse Power Flow - max		2,555		1,432	114	42	109	17
Faribault	FAB061	0.5	Thermal for Gen - min	1.19	Reverse Power Flow - max		4,800		1,879	57	2987	0	8
Faribault	FAB063	0.2	Primary Over-Voltage - min	0.99	Breaker Relay Reduction of Reach - max		4,800		2,864	57	2987	57	2979
Faribault	FAB071	0.2	Thermal for Gen - min	1.69	Reverse Power Flow - max		3,646		2,062	33	18	33	0
Faribault	FAB073	0.2	Thermal for Gen - min	0.85	Reverse Power Flow - max		3,646		1,584	33	18	0	18
Fair Park	FAP061	0	Unintentional Islanding - min	2	Breaker Relay Reduction of Reach - max		2,663		2,663	5568	52	5568	52
Fair Park	FAP071	0.6	Thermal for Gen - min	2.07	Reverse Power Flow - max		2,843		2,843	14	25	14	25
Fiesta City	FIC021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,837		1,258	4036	3097	4000	97
Fiesta City	FIC022	0.6	Thermal for Gen - min	0.75	Reverse Power Flow - max		1,837		1,300	4036	3097	36	3000
Fiesta City	FIC031	0.1	Primary Over-Voltage - min	0.99	Reverse Power Flow - max		1,100		1,100	0	0	0	0
Franklin	FRA001	0.1	Primary Over-Voltage - min	0.16	Reverse Power Flow - max		248		248	0	0	0	0
Franklin	FRA211	0.31	Reverse Power Flow - min	0.31	Reverse Power Flow - max		347		347	0	0	0	0
Farmington	FRM061	0.61	Reverse Power Flow - min	0.61	Reverse Power Flow - max		1,084		640	10753	0	734	0
Farmington	FRM062	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,084		447	10753	0	10019	0
Farmington	FRM071	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,360		1,360	6149	9	6149	9
Frontenac	FRO021	0	Unintentional Islanding - min	0.45	Reverse Power Flow - max		563		563	5031	0	5031	0

PROTECTED DATA SHADED

Substation	Feeder	Minimum Hosting Capacity (MW)	Min Limiting Factor	Maximum Hosting Capacity (MW)	Max Limiting Factor	Substation Transformer Forecasted Peak Load (kVA)	Substation Transformer Minimum Load (kVA)	Feeder 2020 Peak Load (kVA)	Feeder Daytime Minimum Load (kVA)	Substation Transformer Installed DG (kVA)	Substation Transformer Queued DG (kVA)	Feeder Installed DG (kVA)	Feeder Queued DG (kVA)
First Lake	FSL311	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		13,320		6,003	11119	51	11050	20
First Lake	FSL312	0.2	Thermal for Gen - min	1.36	Breaker Relay Reduction of Reach - max		13,320		7,747	11119	51	69	31
Fifth Street	FST067	1.06	Reverse Power Flow - min	1.06	Reverse Power Flow - max		11,171		720	35	0	35	0
Fifth Street	FST068	1.1	Reverse Power Flow - min	1.1	Reverse Power Flow - max		11,171		1,228	35	0	0	0
Fifth Street	FST077	0.82	Reverse Power Flow - min	0.82	Reverse Power Flow - max		11,626		525	32	0	0	0
Fifth Street	FST078	1.03	Reverse Power Flow - min	1.03	Reverse Power Flow - max		11,626		1,726	32	0	32	0
Fifth Street	FST085	0.45	Reverse Power Flow - min	0.45	Reverse Power Flow - max		11,910		445	0	0	0	0
Fifth Street	FST086	0.62	Reverse Power Flow - min	0.62	Reverse Power Flow - max		11,910		768	0	0	0	0
Fifth Street	FST087	0.87	Reverse Power Flow - min	0.87	Reverse Power Flow - max		11,526		561	0	0	0	0
Fifth Street	FST088	0.89	Reverse Power Flow - min	0.89	Reverse Power Flow - max		11,526		333	0	0	0	0
Gaylord	GAY001	0.1	Primary Over-Voltage - min	0.22	Reverse Power Flow - max		749		291	14	1000	8	0
Gaylord	GAY002	0.1	Primary Over-Voltage - min	0.41	Reverse Power Flow - max		749		507	14	1000	6	1000
Gaylord	GAY003	0.1	Primary Over-Voltage - min	0.27	Reverse Power Flow - max		749		373	14	1000	0	0
Greenfield	GFD021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,280		772	10147	0	10031	0
Greenfield	GFD022	0.2	Primary Over-Voltage - min	0.54	Reverse Power Flow - max		1,280		604	10147	0	116	0
Gibbon	GIB021	0.1	Unintentional Islanding - min	0.41	Reverse Power Flow - max		439		439	3370	0	3370	0
Glenwood	GLD021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		2,800		2,800	11101	3040	11101	3040
Glenwood	GLD031	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,204		1,204	2	0	2	0
Goose Lake	GLK061	0.01	Unintentional Islanding - min	2.32	Reverse Power Flow - max		11,624		2,830	118	172	37	45
Goose Lake	GLK062	0.25	Unintentional Islanding - min	1.99	Reverse Power Flow - max		11,624		2,968	118	172	11	40
Goose Lake	GLK063	0.14	Unintentional Islanding - min	1.39	Reverse Power Flow - max		11,624		1,868	118	172	0	26
Goose Lake	GLK064	0.09	Unintentional Islanding - min	1.82	Reverse Power Flow - max		11,624		2,040	118	172	40	54
Goose Lake	GLK065	0.22	Unintentional Islanding - min	1.12	Reverse Power Flow - max		11,624		1,237	118	172	30	8
Goose Lake	GLK071	0.23	Unintentional Islanding - min	2.18	Reverse Power Flow - max		10,307		2,751	199	255	33	67
Goose Lake	GLK072	0.9	Thermal for Gen - min	1.78	Reverse Power Flow - max		10,307		3,239	199	255	55	56
Goose Lake	GLK073	0.6	Thermal for Gen - min	1.77	Reverse Power Flow - max		10,307		2,062	199	255	48	45
Goose Lake	GLK074	0.1	Primary Over-Voltage - min	1.59	Breaker Relay Reduction of Reach - max		10,307		2,410	199	255	63	87
Glen Lake	GNL061	0.92	Reverse Power Flow - min	0.92	Reverse Power Flow - max		5,314		1,086	73	170	10	0
Glen Lake	GNL062	0.8	Primary Over-Voltage - min	1.36	Reverse Power Flow - max		5,314		1,861	73	170	25	157
Glen Lake	GNL063	0.9	Primary Over-Voltage - min	1.24	Reverse Power Flow - max		5,314		1,642	73	170	39	13
Glen Lake	GNL071	0.5	Thermal for Gen - min	1.21	Reverse Power Flow - max		4,916		1,728	102	251	19	29
Glen Lake	GNL072	0.8	Primary Over-Voltage - min	1.59	Reverse Power Flow - max		4,916		2,536	102	251	63	17
Glen Lake	GNL073	0.99	Reverse Power Flow - min	0.99	Reverse Power Flow - max		4,916		1,637	102	251	20	205
Gopher	GPH061	0.9	Thermal for Gen - min	1.32	Reverse Power Flow - max		6,946		4,380	57	16	28	12
Gopher	GPH062	0.9	Thermal for Gen - min	1.99	Reverse Power Flow - max		6,946		4,454	57	16	29	4
Gopher	GPH068	2.62	Reverse Power Flow - min	2.62	Reverse Power Flow - max		6,946		1,034	57	16	0	0
Gopher	GPH069	1.36	Reverse Power Flow - min	1.36	Reverse Power Flow - max		6,946		3,333	57	16	0	0
Gopher	GPH073	0.9	Thermal for Gen - min	1.03	Reverse Power Flow - max		3,333		1,355	36	0	36	0
Gopher	GPH074	1.35	Reverse Power Flow - min	1.35	Reverse Power Flow - max		3,333		0	36	0	0	0
Gopher	GPH075	1.66	Reverse Power Flow - min	1.66	Reverse Power Flow - max		3,333		0	36	0	0	0
Gopher	GPH079	1	Reverse Power Flow - min	1	Reverse Power Flow - max		3,333		0	36	0	0	0

PROTECTED DATA SHADED

Substation	Feeder	Minimum Hosting Capacity (MW)	Min Limiting Factor	Maximum Hosting Capacity (MW)	Max Limiting Factor	Substation Transformer Forecasted Peak Load (kVA)	Substation Transformer Minimum Load (kVA)	Feeder 2020 Peak Load (kVA)	Feeder Daytime Minimum Load (kVA)	Substation Transformer Installed DG (kVA)	Substation Transformer Queued DG (kVA)	Feeder Installed DG (kVA)	Feeder Queued DG (kVA)
Granite City	GRC062	0.69	Unintentional Islanding - min	1.71	Reverse Power Flow - max		5,783		2,816	325	391	179	333
Granite City	GRC063	0.15	Unintentional Islanding - min	2.46	Reverse Power Flow - max		5,783		2,746	325	391	147	58
Granite City	GRC073	0.2	Primary Over-Voltage - min	1.5	Reverse Power Flow - max		2,596		2,596	43	0	43	0
Granite City	GRC311	0	Reverse Power Flow - min	0	Reverse Power Flow - max		6,526		2,886	9094	58	5065	0
Granite City	GRC312	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		6,526		6,361	9094	58	4030	25
Granite City	GRC313	0.4	Primary Over-Voltage - min	1.35	Reverse Power Flow - max		6,526		1,304	9094	58	0	33
Green Isle	GRI001	0.1	Primary Over-Voltage - min	0.21	Reverse Power Flow - max		228		228	0	1035	0	1035
Gleason Lake	GSL061	0.69	Reverse Power Flow - min	0.69	Reverse Power Flow - max		5,148		1,020	58	48	12	8
Gleason Lake	GSL064	0.5	Thermal for Gen - min	1.84	Reverse Power Flow - max		5,148		2,110	58	48	15	40
Gleason Lake	GSL065	0.5	Thermal for Gen - min	1.58	Reverse Power Flow - max		5,148		1,924	58	48	30	0
Gleason Lake	GSL074	0.24	Unintentional Islanding - min	1.97	Reverse Power Flow - max		5,743		2,193	95	91	44	57
Gleason Lake	GSL075	0.9	Thermal for Gen - min	2.27	Reverse Power Flow - max		5,743		2,511	95	91	9	0
Gleason Lake	GSL076	1.1	Thermal for Gen - min	1.69	Reverse Power Flow - max		5,743		1,803	95	91	24	17
Gleason Lake	GSL079	0.9	Thermal for Gen - min	1.07	Reverse Power Flow - max		5,743		1,334	95	91	18	17
Gleason Lake	GSL341	0.2	Thermal for Gen - min	1.73	Breaker Relay Reduction of Reach - max		12,170		6,414	166	47	36	47
Gleason Lake	GSL342	1.5	Thermal for Gen - min	6.06	Reverse Power Flow - max		12,170		7,607	166	47	130	0
Goodview	GVW021	0.1	Thermal for Gen - min	1.53	Reverse Power Flow - max		6,589		1,604	212	1557	46	46
Goodview	GVW022	0.2	Thermal for Gen - min	1.93	Reverse Power Flow - max		6,589		1,933	212	1557	46	8
Goodview	GVW023	0.2	Thermal for Gen - min	2.09	Reverse Power Flow - max		6,589		1,854	212	1557	121	1504
Goodview	GVW031	0.2	Thermal for Gen - min	1.84	Reverse Power Flow - max		5,382		1,766	385	5084	320	5084
Goodview	GVW032	0.11	Unintentional Islanding - min	1.84	Reverse Power Flow - max		5,382		1,980	385	5084	66	0
Hadley	HAD021	0.15	Unintentional Islanding - min	0.17	Reverse Power Flow - max		337		180	1011	0	3	0
Hadley	HAD022	0	Reverse Power Flow - min	0	Reverse Power Flow - max		337		157	1011	0	1008	0
Hastings	HAS021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		3,552		129	4673	7	4637	7
Hastings	HAS022	0.3	Thermal for Gen - min	2.01	Reverse Power Flow - max		3,552		2,408	4673	7	36	0
Hastings	HAS023	0.8	Thermal for Gen - min	1.44	Reverse Power Flow - max		3,552		1,000	4673	7	0	0
Hastings	HAS031	0.6	Reverse Power Flow - min	0.6	Reverse Power Flow - max		2,667		1,204	23	7	23	0
Hastings	HAS032	0.04	Unintentional Islanding - min	0.78	Reverse Power Flow - max		2,667		762	23	7	0	7
Hastings	HAS033	0.72	Reverse Power Flow - min	0.72	Reverse Power Flow - max		2,667		701	23	7	0	0
Hector	HEC001	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		594		594	3000	0	3000	0
Henderson	HEN021	0.2	Primary Over-Voltage - min	0.3	Reverse Power Flow - max		342		342	0	0	0	0
Hollydale	HOL061	0.7	Primary Over-Voltage - min	1.47	Reverse Power Flow - max		4,597		2,010	74	41	21	26
Hollydale	HOL062	0.9	Thermal for Gen - min	1.97	Reverse Power Flow - max		4,597		2,561	74	41	53	15
Howard Lake	HOW061	0.06	Unintentional Islanding - min	1.32	Reverse Power Flow - max		1,416		1,416	106	118	106	118
Hassan	HSN311	0.24	Unintentional Islanding - min	3.08	Reverse Power Flow - max		11,841		5,219	465	1045	357	39
Hassan	HSN312	0	Unintentional Islanding - min	3.25	Breaker Relay Reduction of Reach - max		11,841		6,775	465	1045	108	1006
Hassan	HSN321	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		16,669		5,827	5130	30	5099	19
Hassan	HSN322	1.4	Thermal for Gen - min	4.54	Reverse Power Flow - max		16,669		8,222	5130	30	31	11
Hugo	HUG311	0.2	Primary Over-Voltage - min	0.85	Breaker Relay Reduction of Reach - max		7,240		4,649	179	176	59	73
Hugo	HUG312	0.1	Primary Over-Voltage - min	3.91	Breaker Relay Reduction of Reach - max		7,240		4,364	179	176	120	102

PROTECTED DATA SHADED

Substation	Feeder	Minimum Hosting Capacity (MW)	Min Limiting Factor	Maximum Hosting Capacity (MW)	Max Limiting Factor	Substation Transformer Forecasted Peak Load (kVA)	Substation Transformer Minimum Load (kVA)	Feeder 2020 Peak Load (kVA)	Feeder Daytime Minimum Load (kVA)	Substation Transformer Installed DG (kVA)	Substation Transformer Queued DG (kVA)	Feeder Installed DG (kVA)	Feeder Queued DG (kVA)
Hugo	HUG321	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		4,412		2,804	11755	2190	11733	2190
Hugo	HUG322	2.24	Reverse Power Flow - min	2.24	Reverse Power Flow - max		4,412		3,431	11755	2190	22	0
Hiawatha West	HWW061	0.06	Unintentional Islanding - min	1.65	Breaker Relay Reduction of Reach - max		18,116		914	1719	174	729	5
Hiawatha West	HWW062	0.9	Thermal for Gen - min	1.97	Reverse Power Flow - max		18,116		2,184	1719	174	113	75
Hiawatha West	HWW071	0.06	Unintentional Islanding - min	1.43	Reverse Power Flow - max		18,116		3,520	1719	174	24	8
Hiawatha West	HWW072	0.9	Thermal for Gen - min	1.07	Reverse Power Flow - max		18,116		2,087	1719	174	130	8
Hiawatha West	HWW073	0.16	Unintentional Islanding - min	1.49	Reverse Power Flow - max		18,116		1,684	1719	174	264	36
Hiawatha West	HWW074	0.9	Thermal for Gen - min	1.24	Reverse Power Flow - max		18,116		2,165	1719	174	161	43
Hiawatha West	HWW075	0.9	Thermal for Gen - min	2.76	Reverse Power Flow - max		18,116		3,040	1719	174	298	0
Hyland Lake	HYL061	1.3	Primary Over-Voltage - min	1.74	Reverse Power Flow - max		15,804		1,529	206	185	16	180
Hyland Lake	HYL062	1	Thermal for Gen - min	1.49	Reverse Power Flow - max		15,804		2,121	206	185	19	0
Hyland Lake	HYL063	0.6	Primary Over-Voltage - min	1.64	Reverse Power Flow - max		15,804		1,304	206	185	30	0
Hyland Lake	HYL064	0.8	Primary Over-Voltage - min	2.73	Reverse Power Flow - max		15,804		1,628	206	185	16	5
Hyland Lake	HYL065	1.4	Primary Over-Voltage - min	2.11	Reverse Power Flow - max		15,804		4,604	206	185	125	0
Hyland Lake	HYL071	0.11	Reverse Power Flow - min	0.11	Reverse Power Flow - max		6,356		200	116	71	0	0
Hyland Lake	HYL072	0.9	Primary Over-Voltage - min	1.23	Reverse Power Flow - max		6,356		1,616	116	71	40	0
Hyland Lake	HYL073	0.41	Unintentional Islanding - min	1.73	Reverse Power Flow - max		6,356		1,838	116	71	41	37
Hyland Lake	HYL074	0.6	Thermal for Gen - min	1.4	Reverse Power Flow - max		6,356		1,910	116	71	8	15
Hyland Lake	HYL075	0.8	Primary Over-Voltage - min	1.23	Reverse Power Flow - max		6,356		1,404	116	71	27	19
Indiana	IDA061	0.74	Reverse Power Flow - min	0.74	Reverse Power Flow - max		4,493		545	113	15	0	0
Indiana	IDA062	0.19	Unintentional Islanding - min	1.11	Reverse Power Flow - max		4,493		1,400	113	15	38	15
Indiana	IDA063	1.1	Thermal for Gen - min	1.47	Reverse Power Flow - max		4,493		2,435	113	15	5	0
Indiana	IDA064	0.9	Thermal for Gen - min	1.29	Reverse Power Flow - max		4,493		2,046	113	15	71	0
Indiana	IDA071	0.81	Reverse Power Flow - min	0.81	Reverse Power Flow - max		7,508		1,310	261	28	0	0
Indiana	IDA072	0.9	Thermal for Gen - min	1.25	Reverse Power Flow - max		7,508		1,968	261	28	11	0
Indiana	IDA073	0.9	Thermal for Gen - min	1.71	Reverse Power Flow - max		7,508		2,002	261	28	232	19
Indiana	IDA074	0.8	Thermal for Gen - min	1.47	Reverse Power Flow - max		7,508		2,698	261	28	18	9
Jordan	JOR021	0.08	Unintentional Islanding - min	0.84	Reverse Power Flow - max		1,979		944	9021	1400	718	400
Jordan	JOR022	0	Unintentional Islanding - min	1.03	Reverse Power Flow - max		1,979		1,207	9021	1400	8303	1000
Kasson	KAN022	0	Unintentional Islanding - min	1.19	Reverse Power Flow - max		1,244		1,244	5034	2000	5034	2000
Kasson	KAN031	0	Unintentional Islanding - min	2.18	Reverse Power Flow - max		2,456		2,456	5181	4000	5181	4000
Kenyon	KEN021	0.2	Primary Over-Voltage - min	0.21	Reverse Power Flow - max		283		219	2844	0	8	0
Kenyon	KEN022	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		283		134	2844	0	2836	0
Kimball	KIM021	0.48	Reverse Power Flow - min	0.48	Reverse Power Flow - max		522		522	0	1041	0	1041
Kegan Lake	KLK061	0.5	Thermal for Gen - min	1.22	Reverse Power Flow - max		2,121		2,121	17	14	17	14
Kohlman Lake	KOL061	0.5	Thermal for Gen - min	1.24	Reverse Power Flow - max		8,040		1,877	81	110	0	0
Kohlman Lake	KOL062	1.4	Thermal for Gen - min	1.65	Reverse Power Flow - max		8,040		2,138	81	110	35	0
Kohlman Lake	KOL063	0.74	Reverse Power Flow - min	0.74	Reverse Power Flow - max		8,040		1,119	81	110	0	0
Kohlman Lake	KOL064	1.3	Thermal for Gen - min	1.35	Reverse Power Flow - max		8,040		1,318	81	110	40	0
Kohlman Lake	KOL065	1.5	Thermal for Gen - min	2.08	Reverse Power Flow - max		8,040		2,725	81	110	6	110
Kohlman Lake	KOL071	0.9	Primary Over-Voltage - min	0.99	Reverse Power Flow - max		4,317		1,612	111	76	18	51
Kohlman Lake	KOL073	0.5	Primary Over-Voltage - min	0.7	Primary Over-Voltage - max		4,317		1,711	111	76	93	25

PROTECTED DATA SHADED

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Kohlman Lake	KOL074	0.9	Thermal for Gen - min	1.38	Reverse Power Flow - max		4,317		1,970	111	76	0	0
Lake Bavaria	LAB311	0.4	Primary Over-Voltage - min	1.84	Reverse Power Flow - max		6,736		2,408	29	36	0	0
Lake Bavaria	LAB312	0.3	Thermal for Gen - min	2.58	Breaker Relay Reduction of Reach - max		6,736		3,041	29	36	29	36
La Crescant	LAC062	0.1	Thermal for Gen - min	1.49	Reverse Power Flow - max		2,389		1,610	534	4155	384	4047
La Crescant	LAC063	0.08	Unintentional Islanding - min	0.87	Reverse Power Flow - max		2,389		878	534	4155	150	108
Lake Emily	LAE061	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		705		705	8505	1000	8505	1000
Lafayette	LAF001	0.1	Primary Over-Voltage - min	0.19	Reverse Power Flow - max		247		247	0	1000	0	1000
Lake City	LAK032	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		399		399	76	71	76	71
Lake Pulaski	LAP311	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		5,135		5,135	26657	2049	26657	2049
Lake Yankton	LAY061	0.08	Unintentional Islanding - min	0.37	Reverse Power Flow - max		794		794	0	0	0	0
Lawrence Creek	LCR311	0	Reverse Power Flow - min	0	Reverse Power Flow - max		2,110		2,110	27692	1069	27692	1069
Lexington	LEX061	0.6	Primary Over-Voltage - min	1.54	Reverse Power Flow - max		7,704		2,766	95	540	11	522
Lexington	LEX062	0.85	Reverse Power Flow - min	0.85	Reverse Power Flow - max		7,704		1,581	95	540	0	0
Lexington	LEX063	1.1	Thermal for Gen - min	1.65	Reverse Power Flow - max		7,704		2,202	95	540	44	18
Lexington	LEX064	0.23	Unintentional Islanding - min	1.49	Reverse Power Flow - max		7,704		1,878	95	540	40	0
Lexington	LEX065	0.03	Unintentional Islanding - min	1.07	Reverse Power Flow - max		7,704		1,100	95	540	0	0
Lexington	LEX071	0.01	Unintentional Islanding - min	1.81	Reverse Power Flow - max		7,049		2,299	106	35	18	19
Lexington	LEX072	0.36	Reverse Power Flow - min	0.36	Reverse Power Flow - max		7,049		671	106	35	0	0
Lexington	LEX073	0.4	Thermal for Gen - min	0.63	Reverse Power Flow - max		7,049		1,020	106	35	8	0
Lexington	LEX074	0.01	Unintentional Islanding - min	1.46	Reverse Power Flow - max		7,049		6,540	106	35	36	4
Lexington	LEX075	0.9	Thermal for Gen - min	1.63	Reverse Power Flow - max		7,049		1,838	106	35	43	13
Lexington	LEX331	0.9	Thermal for Gen - min	2.67	Reverse Power Flow - max		14,277		3,911	376	981	8	0
Lexington	LEX332	1.1	Unintentional Islanding - min	6.33	Reverse Power Flow - max		14,277		6,485	376	981	106	975
Lexington	LEX333	0.09	Unintentional Islanding - min	2.73	Breaker Relay Reduction of Reach - max		14,277		6,194	376	981	262	7
Lake Lillian	LIL021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		562		562	2008	1000	2008	1000
Lindstrom	LIN022	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,542		1,542	3148	18	3148	18
Lindstrom	LIN031	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		4,080		4,080	374	5085	374	5085
Long Lake	LLK061	0.9	Thermal for Gen - min	1.43	Reverse Power Flow - max		4,001		1,825	31	23	31	23
Long Lake	LLK063	0.9	Thermal for Gen - min	1.41	Reverse Power Flow - max		4,001		1,903	31	23	0	0
Long Lake	LLK071	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		6,280		2,596	123	43	106	27
Long Lake	LLK072	1.1	Primary Over-Voltage - min	1.76	Reverse Power Flow - max		6,280		2,508	123	43	17	15
Linn Street	LNS021	0.7	Primary Over-Voltage - min	0.76	Reverse Power Flow - max		812		812	4	0	4	0
Linn Street	LNS022	0.01	Reverse Power Flow - min	0.01	Reverse Power Flow - max		759		32	4	0	0	0
Linn Street	LNS032	0.57	Reverse Power Flow - min	0.57	Reverse Power Flow - max		1,253		685	8	8	0	0
Linn Street	LNS033	0.4	Primary Over-Voltage - min	0.67	Reverse Power Flow - max		1,253		789	8	8	8	8
Lone Oak	LOK061	1.2	Thermal for Gen - min	1.39	Reverse Power Flow - max		7,400		2,332	66	30	29	7
Lone Oak	LOK062	0.5	Thermal for Gen - min	2.35	Reverse Power Flow - max		7,400		3,590	66	30	38	23
Lone Oak	LOK063	1.19	Reverse Power Flow - min	1.19	Reverse Power Flow - max		7,400		1,281	66	30	0	0
Lone Oak	LOK081	0.7	Unintentional Islanding - min	1.77	Reverse Power Flow - max		17,170		4,031	288	225	75	0

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Lone Oak	LOK082	0.9	Thermal for Gen - min	0.99	Reverse Power Flow - max		17,170		1,838	288	225	0	0
Lone Oak	LOK083	1	Primary Over-Voltage - min	2.14	Reverse Power Flow - max		17,170		2,110	288	225	174	0
Lone Oak	LOK091	0.8	Primary Over-Voltage - min	1.52	Reverse Power Flow - max		17,170		2,040	288	225	0	0
Lone Oak	LOK092	1.1	Primary Over-Voltage - min	1.48	Reverse Power Flow - max		17,170		3,324	288	225	36	180
Lone Oak	LOK093	0.4	Thermal for Gen - min	1.22	Reverse Power Flow - max		17,170		2,837	288	225	2	45
Lowry	LOW021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		879		879	5034	5012	5034	5012
Lester Prarie	LSP021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,722		1,355	6082	3433	6066	2000
Lester Prarie	LSP022	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,722		609	6082	3433	16	1433
Maple Lake	MAP061	0.1	Primary Over-Voltage - min	1.08	Reverse Power Flow - max		1,205		1,205	45	25	45	25
Mazeppa	MAZ021	0.05	Unintentional Islanding - min	0.3	Primary Over-Voltage - max		477		477	27	2063	27	2063
Medford Junction	MDF021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		996		996	2035	2000	2035	2000
Midtown	MDT061	0.8	Thermal for Gen - min	1.25	Reverse Power Flow - max		12,130		2,257	349	58	47	0
Midtown	MDT062	0.9	Thermal for Gen - min	1.86	Reverse Power Flow - max		12,130		532	349	58	71	18
Midtown	MDT067	0.9	Thermal for Gen - min	1.76	Reverse Power Flow - max		12,130		3,329	349	58	33	16
Midtown	MDT071	0.3	Thermal for Gen - min	2.27	Reverse Power Flow - max		12,130		778	349	58	84	0
Midtown	MDT073	0.96	Reverse Power Flow - min	0.96	Reverse Power Flow - max		12,130		1,706	349	58	30	0
Midtown	MDT074	1	Thermal for Gen - min	1.81	Reverse Power Flow - max		12,130		2,123	349	58	68	20
Midtown	MDT077	0.1	Unintentional Islanding - min	1.24	Reverse Power Flow - max		12,130		2,149	349	58	16	4
Meire Grove	MEI021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		388		388	324	2000	324	2000
Meeker	MEK021	0.09	Reverse Power Flow - min	0.09	Reverse Power Flow - max		96		96	34	0	34	0
Medicine Lake	MEL061	0.89	Reverse Power Flow - min	0.89	Reverse Power Flow - max		13,084		1,193	753	190	354	43
Medicine Lake	MEL062	0.9	Thermal for Gen - min	1.16	Reverse Power Flow - max		13,084		1,684	753	190	68	27
Medicine Lake	MEL063	0.26	Reverse Power Flow - min	0.26	Reverse Power Flow - max		13,084		285	753	190	148	0
Medicine Lake	MEL064	0.8	Thermal for Gen - min	1.58	Reverse Power Flow - max		13,084		2,053	753	190	118	0
Medicine Lake	MEL065	0.86	Reverse Power Flow - min	0.86	Reverse Power Flow - max		13,084		473	753	190	12	6
Medicine Lake	MEL066	0.51	Reverse Power Flow - min	0.51	Reverse Power Flow - max		13,084		576	753	190	0	0
Medicine Lake	MEL067	0.9	Thermal for Gen - min	1.34	Reverse Power Flow - max		13,084		1,791	753	190	3	33
Medicine Lake	MEL068	0.9	Thermal for Gen - min	1.52	Reverse Power Flow - max		13,084		1,771	753	190	33	77
Medicine Lake	MEL069	0.06	Unintentional Islanding - min	0.56	Reverse Power Flow - max		13,084		2,630	753	190	17	5
Medicine Lake	MEL071	0.75	Unintentional Islanding - min	1.02	Reverse Power Flow - max		19,104		1,516	256	369	10	8
Medicine Lake	MEL072	0.04	Unintentional Islanding - min	1.23	Reverse Power Flow - max		19,104		2,436	256	369	8	8
Medicine Lake	MEL073	0.9	Thermal for Gen - min	1.44	Reverse Power Flow - max		19,104		2,623	256	369	33	243
Medicine Lake	MEL074	0.9	Thermal for Gen - min	1.54	Reverse Power Flow - max		19,104		2,604	256	369	108	80
Medicine Lake	MEL075	0.9	Thermal for Gen - min	2.08	Reverse Power Flow - max		19,104		2,469	256	369	0	0
Medicine Lake	MEL076	1	Reverse Power Flow - min	1	Reverse Power Flow - max		19,104		1,887	256	369	0	0
Medicine Lake	MEL077	0.9	Thermal for Gen - min	1.46	Reverse Power Flow - max		19,104		1,831	256	369	50	5
Medicine Lake	MEL078	0.9	Thermal for Gen - min	1.04	Reverse Power Flow - max		19,104		1,864	256	369	48	19
Medicine Lake	MEL079	0.83	Reverse Power Flow - min	0.83	Reverse Power Flow - max		19,104		1,357	256	369	0	7
Medicine Lake	MEL081	0.9	Thermal for Gen - min	1.26	Reverse Power Flow - max		11,720		1,657	97	298	13	22
Medicine Lake	MEL082	0.9	Thermal for Gen - min	1.2	Reverse Power Flow - max		11,720		1,585	97	298	48	0
Medicine Lake	MEL083	0.8	Primary Over-Voltage - min	1.28	Reverse Power Flow - max		11,720		2,267	97	298	0	0
Medicine Lake	MEL087	0.74	Reverse Power Flow - min	0.74	Reverse Power Flow - max		11,720		514	97	298	4	276
Medicine Lake	MEL088	1.1	Primary Over-Voltage - min	1.28	Reverse Power Flow - max		11,720		1,347	97	298	27	0
Medicine Lake	MEL089	1.5	Thermal for Gen - min	1.59	Reverse Power Flow - max		11,720		2,309	97	298	6	0
Morgan	MGN211	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,455		1,455	3151	4860	3151	4860

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Mayhew Lake	MHW311	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		10,194		5,055	27021	7044	11061	7044
Mayhew Lake	MHW312	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		10,194		2,306	27021	7044	15960	0
Mound	MND061	0.5	Thermal for Gen - min	0.9	Reverse Power Flow - max		6,738		1,369	115	118	3	8
Mound	MND062	0.24	Unintentional Islanding - min	2.16	Reverse Power Flow - max		6,738		3,162	115	118	49	44
Mound	MND063	0.1	Primary Over-Voltage - min	1.91	Reverse Power Flow - max		6,738		2,222	115	118	63	66
Mound	MND071	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		4,850		1,875	33	25	0	13
Mound	MND072	0.3	Thermal for Gen - min	1.74	Reverse Power Flow - max		4,850		3,013	33	25	33	11
Minnesota Lake	MNL001	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		336		336	1840	0	1840	0
Minnesota Valley	MNV211	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		800		800	3000	0	3000	0
Moore Lake	MOL061	0.5	Thermal for Gen - min	1.7	Reverse Power Flow - max		18,956		1,924	379	34	26	0
Moore Lake	MOL062	1.5	Thermal for Gen - min	2.48	Reverse Power Flow - max		18,956		2,474	379	34	40	0
Moore Lake	MOL063	0.5	Thermal for Gen - min	1.84	Reverse Power Flow - max		18,956		3,142	379	34	8	0
Moore Lake	MOL064	0.9	Thermal for Gen - min	1.55	Reverse Power Flow - max		18,956		1,828	379	34	109	0
Moore Lake	MOL065	0.9	Thermal for Gen - min	1.5	Reverse Power Flow - max		18,956		1,485	379	34	39	0
Moore Lake	MOL066	0.36	Unintentional Islanding - min	1.82	Reverse Power Flow - max		18,956		2,535	379	34	31	6
Moore Lake	MOL067	0.6	Thermal for Gen - min	1.19	Reverse Power Flow - max		18,956		1,321	379	34	8	4
Moore Lake	MOL068	0.1	Primary Over-Voltage - min	1.85	Reverse Power Flow - max		18,956		2,163	379	34	113	24
Moore Lake	MOL069	0.53	Reverse Power Flow - min	0.53	Reverse Power Flow - max		18,956		342	379	34	6	0
Moore Lake	MOL071	0.9	Thermal for Gen - min	1.36	Reverse Power Flow - max		15,814		1,855	283	783	0	10
Moore Lake	MOL072	0.25	Unintentional Islanding - min	1.38	Reverse Power Flow - max		15,814		2,307	283	783	84	8
Moore Lake	MOL073	0.9	Thermal for Gen - min	2.01	Reverse Power Flow - max		15,814		2,138	283	783	92	740
Moore Lake	MOL074	0.24	Unintentional Islanding - min	0.87	Reverse Power Flow - max		15,814		1,571	283	783	0	0
Moore Lake	MOL076	0.9	Thermal for Gen - min	1.69	Reverse Power Flow - max		15,814		2,732	283	783	0	0
Moore Lake	MOL077	0.89	Reverse Power Flow - min	0.89	Reverse Power Flow - max		15,814		1,272	283	783	0	0
Moore Lake	MOL078	0.9	Thermal for Gen - min	1.76	Reverse Power Flow - max		15,814		2,159	283	783	83	25
Moore Lake	MOL079	0.9	Primary Over-Voltage - min	1.08	Reverse Power Flow - max		15,814		1,888	283	783	24	0
Merriam Park	MPK061	2.65	Reverse Power Flow - min	2.65	Reverse Power Flow - max		11,554		3,158	7350	192	0	0
Merriam Park	MPK062	0.9	Thermal for Gen - min	1.2	Reverse Power Flow - max		11,554		1,304	7350	192	40	0
Merriam Park	MPK063	0.5	Thermal for Gen - min	3.19	Reverse Power Flow - max		11,554		3,245	7350	192	83	64
Merriam Park	MPK064	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		11,554		1,503	7350	192	7033	55
Merriam Park	MPK065	0.6	Thermal for Gen - min	2.01	Reverse Power Flow - max		11,554		2,193	7350	192	34	21
Merriam Park	MPK066	1.07	Reverse Power Flow - min	1.07	Reverse Power Flow - max		11,554		1,105	7350	192	0	0
Merriam Park	MPK067	0.9	Thermal for Gen - min	2.02	Reverse Power Flow - max		11,554		2,102	7350	192	35	0
Merriam Park	MPK068	0.4	Primary Over-Voltage - min	2.65	Reverse Power Flow - max		11,554		2,927	7350	192	126	52
Merriam Park	MPK071	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		11,089		1,679	7831	100	7049	53
Merriam Park	MPK072	2.27	Reverse Power Flow - min	2.27	Reverse Power Flow - max		11,089		2,763	7831	100	0	0
Merriam Park	MPK073	0.81	Reverse Power Flow - min	0.81	Reverse Power Flow - max		11,089		1,053	7831	100	11	3
Merriam Park	MPK074	1.1	Thermal for Gen - min	2.85	Reverse Power Flow - max		11,089		3,306	7831	100	195	34
Merriam Park	MPK075	0.9	Thermal for Gen - min	1.86	Reverse Power Flow - max		11,089		1,903	7831	100	447	0
Merriam Park	MPK076	1.5	Thermal for Gen - min	1.5	Reverse Power Flow - max		11,089		1,581	7831	100	43	4
Merriam Park	MPK077	1.5	Thermal for Gen - min	3.06	Reverse Power Flow - max		11,089		3,158	7831	100	38	0
Merriam Park	MPK078	0.1	Primary Over-Voltage - min	1.21	Breaker Relay Reduction of Reach - max		11,089		2,864	7831	100	47	6
Merriam Park	MPK081	2.32	Reverse Power Flow - min	2.32	Reverse Power Flow - max		13,314		2,766	671	348	0	0
Merriam Park	MPK082	0.5	Primary Over-Voltage - min	2.07	Reverse Power Flow - max		13,314		2,247	671	348	124	41

PROTECTED DATA SHADED

Substation	Feeder	Minimum Hosting Capacity (MW)	Min Limiting Factor	Maximum Hosting Capacity (MW)	Max Limiting Factor	Substation Transformer Forecasted Peak Load (kVA)	Substation Transformer Minimum Load (kVA)	Feeder 2020 Peak Load (kVA)	Feeder Daytime Minimum Load (kVA)	Substation Transformer Installed DG (kVA)	Substation Transformer Queued DG (kVA)	Feeder Installed DG (kVA)	Feeder Queued DG (kVA)
Merriam Park	MPK083	0.5	Primary Over-Voltage - min	2.01	Reverse Power Flow - max		13,314		2,550	671	348	133	17
Merriam Park	MPK084	0.3	Thermal for Gen - min	1.6	Breaker Relay Reduction of Reach - max		13,314		1,970	671	348	45	39
Merriam Park	MPK085	0.9	Thermal for Gen - min	1.53	Reverse Power Flow - max		13,314		1,868	671	348	154	85
Merriam Park	MPK086	0.82	Reverse Power Flow - min	0.82	Reverse Power Flow - max		13,314		922	671	348	89	113
Merriam Park	MPK087	0.9	Thermal for Gen - min	2.43	Reverse Power Flow - max		13,314		2,550	671	348	127	53
Mapleton	MPN081	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		982		982	6587	1000	6587	1000
Meridian	MRN021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		464		464	3465	0	3465	0
Main Street	MST063	1.87	Reverse Power Flow - min	1.87	Reverse Power Flow - max		7,310		0	330	216	0	0
Main Street	MST064	0.37	Reverse Power Flow - min	0.37	Reverse Power Flow - max		7,310		623	330	216	0	0
Main Street	MST066	0.9	Thermal for Gen - min	1.17	Reverse Power Flow - max		7,310		1,847	330	216	81	4
Main Street	MST068	0.9	Thermal for Gen - min	1.25	Reverse Power Flow - max		7,310		1,953	330	216	35	212
Main Street	MST069	0.9	Thermal for Gen - min	1.09	Reverse Power Flow - max		7,310		1,405	330	216	62	0
Main Street	MST070	0.9	Thermal for Gen - min	1.66	Reverse Power Flow - max		13,328		2,499	304	66	22	30
Main Street	MST071	0.9	Thermal for Gen - min	1.64	Reverse Power Flow - max		13,328		3,053	304	66	187	36
Main Street	MST074	0.9	Thermal for Gen - min	1.03	Reverse Power Flow - max		13,328		211	304	66	0	0
Main Street	MST075	0.9	Thermal for Gen - min	1.83	Reverse Power Flow - max		13,328		3,564	304	66	0	0
Main Street	MST076	0.4	Thermal for Gen - min	0.8	Reverse Power Flow - max		13,328		1,041	304	66	95	0
Main Street	MST080	0.1	Thermal for Gen - min	0.81	Breaker Relay Reduction of Reach - max		7,310		1,633	330	216	152	0
Main Street	MST082						13,328		0	304	66	0	0
Montrose	MTR021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,531		1,531	8548	5	8548	5
Montevideo	MTV001	0.2	Primary Over-Voltage - min	0.23	Reverse Power Flow - max		1,012		315	36	0	30	0
Montevideo	MTV002	0.29	Reverse Power Flow - min	0.29	Reverse Power Flow - max		1,012		345	36	0	6	0
Montevideo	MTV003	0.4	Thermal for Gen - min	0.43	Reverse Power Flow - max		1,012		465	36	0	0	0
Montevideo	MTV021	0.01	Unintentional Islanding - min	0.52	Reverse Power Flow - max		1,279		734	5082	2035	42	1035
Montevideo	MTV022	0.06	Unintentional Islanding - min	0.6	Reverse Power Flow - max		1,279		687	5082	2035	5040	1000
Morristown	MTW021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		554		554	1095	5018	1095	5018
Maynard	MYN021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		482		482	2000	0	2000	0
Nerstrand	NER021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		341		341	3081	16	3081	16
Nine Mile Creek	NMC063	1.52	Reverse Power Flow - min	1.52	Reverse Power Flow - max		10,765		5,358	0	0	0	0
Nine Mile Creek	NMC064	1.59	Reverse Power Flow - min	1.59	Reverse Power Flow - max		10,765		5,309	0	0	0	0
Nine Mile Creek	NMC082	0.11	Unintentional Islanding - min	1.72	Reverse Power Flow - max		12,246		3,429	103	10	14	10
Nine Mile Creek	NMC083	0.9	Thermal for Gen - min	1.77	Reverse Power Flow - max		12,246		2,670	103	10	29	0
Nine Mile Creek	NMC092	0.9	Thermal for Gen - min	1.88	Reverse Power Flow - max		12,246		2,207	103	10	54	0
Nine Mile Creek	NMC093	0.9	Thermal for Gen - min	1.84	Reverse Power Flow - max		12,246		2,598	103	10	6	0
Northfield	NOF061	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		4,724		1,696	15591	2057	15591	2057
Northfield	NOF062	0.7	Thermal for Gen - min	2.03	Reverse Power Flow - max		4,724		1,502	15591	2057	0	0
Northfield	NOF071	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		4,371		1,696	6930	3019	6820	2019
Northfield	NOF072	0.2	Thermal for Gen - min	1.77	Reverse Power Flow - max		4,371		2,489	6930	3019	80	1000
Northfield	NOF073	1.15	Reverse Power Flow - min	1.15	Reverse Power Flow - max		4,371		699	6930	3019	30	0
Oakdale	OAD061	0.9	Thermal for Gen - min	1.7	Reverse Power Flow - max		8,481		2,138	331	22	19	4
Oakdale	OAD062	0.74	Reverse Power Flow - min	0.74	Reverse Power Flow - max		8,481		1,020	331	22	7	5
Oakdale	OAD063	0.9	Thermal for Gen - min	1.6	Reverse Power Flow - max		8,481		2,435	331	22	24	8
Oakdale	OAD064	0.69	Reverse Power Flow - min	0.69	Reverse Power Flow - max		8,481		2,309	331	22	4	5
Oakdale	OAD065	0.25	Unintentional Islanding - min	1.3	Reverse Power Flow - max		8,481		2,121	331	22	277	0
Oakdale	OAD071	0.5	Thermal for Gen - min	1.49	Reverse Power Flow - max		7,266		2,220	333	91	22	9
Oakdale	OAD072	0.7	Thermal for Gen - min	2.16	Reverse Power Flow - max		7,266		2,354	333	91	39	20

PROTECTED DATA SHADED

Substation	Feeder	Minimum Hosting Capacity (MW)	Min Limiting Factor	Maximum Hosting Capacity (MW)	Max Limiting Factor	Substation Transformer Forecasted Peak Load (kVA)	Substation Transformer Minimum Load (kVA)	Feeder 2020 Peak Load (kVA)	Feeder Daytime Minimum Load (kVA)	Substation Transformer Installed DG (kVA)	Substation Transformer Queued DG (kVA)	Feeder Installed DG (kVA)	Feeder Queued DG (kVA)
Oakdale	OAD073	0.9	Thermal for Gen - min	1.52	Reverse Power Flow - max		7,266		1,649	333	91	10	41
Oakdale	OAD074	0.9	Thermal for Gen - min	1.36	Reverse Power Flow - max		7,266		1,746	333	91	201	10
Oakdale	OAD075	0.83	Unintentional Islanding - min	3.41	Reverse Power Flow - max		7,266		3,443	333	91	61	12
Oak Park	OPK065	0.4	Primary Over-Voltage - min	1.52	Reverse Power Flow - max		6,763		1,872	31	37	23	37
Oak Park	OPK066	0.52	Reverse Power Flow - min	0.52	Reverse Power Flow - max		6,763		881	31	37	0	0
Oak Park	OPK067	0	Unintentional Islanding - min	1.44	Reverse Power Flow - max		6,763		1,534	31	37	8	0
Oak Park	OPK071	0.63	Reverse Power Flow - min	0.63	Reverse Power Flow - max		7,251		870	358	4013	50	3
Oak Park	OPK072	0.9	Thermal for Gen - min	1.03	Reverse Power Flow - max		7,251		1,288	358	4013	3	0
Oak Park	OPK073	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		7,251		2,020	358	4013	169	65
Oak Park	OPK074	1.56	Reverse Power Flow - min	1.56	Reverse Power Flow - max		7,251		1,976	358	4013	0	0
Oak Park	OPK075	1	Reverse Power Flow - min	1	Reverse Power Flow - max		7,251		1,019	358	4013	0	0
Oak Park	OPK077	0.31	Unintentional Islanding - min	2.02	Reverse Power Flow - max		7,251		3,321	358	4013	136	3945
Orono	ORO061	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		5,192		2,040	66	602	19	226
Orono	ORO062	0.9	Thermal for Gen - min	2.96	Reverse Power Flow - max		5,192		3,354	66	602	48	375
Osseo	OSS061	0.9	Thermal for Gen - min	1.94	Reverse Power Flow - max		14,186		2,154	275	8	54	0
Osseo	OSS062	0.9	Thermal for Gen - min	2.78	Reverse Power Flow - max		14,186		3,027	275	8	43	8
Osseo	OSS063	0.6	Primary Over-Voltage - min	0.76	Reverse Power Flow - max		14,186		1,005	275	8	57	0
Osseo	OSS064	0.5	Thermal for Gen - min	1.48	Reverse Power Flow - max		14,186		1,924	275	8	44	0
Osseo	OSS065	0.9	Thermal for Gen - min	1.6	Reverse Power Flow - max		14,186		2,983	275	8	43	0
Osseo	OSS066	1.5	Thermal for Gen - min	1.52	Reverse Power Flow - max		14,186		2,022	275	8	35	0
Osseo	OSS071	0.9	Thermal for Gen - min	1.89	Reverse Power Flow - max		11,369		1,879	178	389	76	178
Osseo	OSS072	0.37	Reverse Power Flow - min	0.37	Reverse Power Flow - max		11,369		447	178	389	36	120
Osseo	OSS073	0.8	Primary Over-Voltage - min	1.59	Reverse Power Flow - max		11,369		1,844	178	389	25	46
Osseo	OSS074	0.66	Reverse Power Flow - min	0.66	Reverse Power Flow - max		11,369		721	178	389	0	0
Osseo	OSS075	1.4	Thermal for Gen - min	1.45	Reverse Power Flow - max		11,369		1,942	178	389	36	40
Osseo	OSS076	1.1	Thermal for Gen - min	1.26	Reverse Power Flow - max		11,369		1,414	178	389	5	0
Osseo	OSS077	0.9	Thermal for Gen - min	1.66	Reverse Power Flow - max		11,369		2,040	178	389	0	5
Paynesville Transmission	PAT312	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		5,428		5,428	2085	3000	2085	3000
Paynesville Transmission	PAT313	0	Reverse Power Flow - min	0	Reverse Power Flow - max		4,830		4,170	16041	2018	16041	2018
Paynesville Transmission	PAT314	0.4	Primary Over-Voltage - min	0.48	Reverse Power Flow - max		4,830		701	16041	2018	0	0
Pine Bend	PBE061	0.5	Thermal for Gen - min	0.91	Reverse Power Flow - max		1,084		1,084	5	990	5	990
Pine Island	PIL021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		940		940	8175	643	8101	632
Pine Island	PIL022	0.01	Unintentional Islanding - min	1.09	Reverse Power Flow - max		1,392		1,392	8175	643	74	11
Pipestone	PIP061	0.6	Thermal for Gen - min	1.94	Reverse Power Flow - max		3,746		2,121	116	1000	8	0
Pipestone	PIP062	0.5	Thermal for Gen - min	1.06	Reverse Power Flow - max		3,746		1,140	116	1000	109	1000
Pipestone	PIP090	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		601		601	6298	1059	6298	1059
Parkers Lake	PKL061	1.1	Thermal for Gen - min	2.77	Reverse Power Flow - max		11,916		2,902	1034	39	0	0
Parkers Lake	PKL062	1.1	Thermal for Gen - min	1.14	Reverse Power Flow - max		11,916		1,237	1034	39	121	0
Parkers Lake	PKL063	0.7	Primary Over-Voltage - min	0.84	Reverse Power Flow - max		11,916		922	1034	39	5	0
Parkers Lake	PKL064	1.1	Thermal for Gen - min	1.62	Reverse Power Flow - max		11,916		1,803	1034	39	0	33
Parkers Lake	PKL065	1.2	Thermal for Gen - min	1.42	Reverse Power Flow - max		11,916		1,612	1034	39	888	0
Parkers Lake	PKL066	0.6	Reverse Power Flow - min	0.6	Reverse Power Flow - max		11,916		806	1034	39	20	6
Parkers Lake	PKL071	0.9	Thermal for Gen - min	2.29	Reverse Power Flow - max		12,462		2,402	139	129	54	120
Parkers Lake	PKL072	0.9	Thermal for Gen - min	1.19	Reverse Power Flow - max		12,462		1,265	139	129	60	0
Parkers Lake	PKL073	0.72	Reverse Power Flow - min	0.72	Reverse Power Flow - max		12,462		854	139	129	0	0
Parkers Lake	PKL074	0.7	Primary Over-Voltage - min	1.94	Reverse Power Flow - max		12,462		2,231	139	129	0	4

PROTECTED DATA SHADED

Substation	Feeder	Minimum Hosting Capacity (MW)	Min Limiting Factor	Maximum Hosting Capacity (MW)	Max Limiting Factor	Substation Transformer Forecasted Peak Load (kVA)	Substation Transformer Minimum Load (kVA)	Feeder 2020 Peak Load (kVA)	Feeder Daytime Minimum Load (kVA)	Substation Transformer Installed DG (kVA)	Substation Transformer Queued DG (kVA)	Feeder Installed DG (kVA)	Feeder Queued DG (kVA)
Parkers Lake	PKL075	0.7	Primary Over-Voltage - min	1.69	Reverse Power Flow - max		12,462		2,002	139	129	25	6
Parkers Lake	PKL081	0.9	Primary Over-Voltage - min	1.01	Reverse Power Flow - max		10,539		1,414	180	56	5	0
Parkers Lake	PKL082	0.2	Thermal for Gen - min	1.3	Reverse Power Flow - max		10,539		1,432	180	56	6	0
Parkers Lake	PKL083	1.5	Thermal for Gen - min	1.85	Reverse Power Flow - max		10,539		1,965	180	56	7	11
Parkers Lake	PKL084	1.1	Thermal for Gen - min	2.52	Reverse Power Flow - max		10,539		2,657	180	56	78	0
Parkers Lake	PKL085	1	Primary Over-Voltage - min	1.48	Reverse Power Flow - max		10,539		1,800	180	56	84	45
Plato	PLA022	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		2,693		510	58	6000	58	6000
Plato	PLA023	2.07	Unintentional Islanding - min	2.08	Reverse Power Flow - max		2,693		1,712	58	6000	0	0
Prior	PRR061	0.3	Thermal for Gen - min	1.82	Reverse Power Flow - max		4,563		2,135	417	52	271	29
Prior	PRR062	1.1	Thermal for Gen - min	1.11	Reverse Power Flow - max		4,563		811	417	52	63	0
Prior	PRR063	0.9	Thermal for Gen - min	1.03	Reverse Power Flow - max		4,563		1,261	417	52	83	22
Ramsey	RAM061	1	Thermal for Gen - min	1.13	Reverse Power Flow - max		4,046		1,540	198	55	17	27
Ramsey	RAM062	0.14	Unintentional Islanding - min	1.26	Reverse Power Flow - max		4,046		1,414	198	55	59	18
Ramsey	RAM063	0.21	Unintentional Islanding - min	1.42	Reverse Power Flow - max		4,046		2,012	198	55	10	6
Ramsey	RAM064	0.9	Thermal for Gen - min	1.72	Reverse Power Flow - max		4,046		2,354	198	55	111	5
Ramsey	RAM071	1.1	Thermal for Gen - min	1.94	Reverse Power Flow - max		10,073		2,879	405	335	76	65
Ramsey	RAM072	0.24	Unintentional Islanding - min	1.19	Reverse Power Flow - max		10,073		1,712	405	335	88	20
Ramsey	RAM073	0.74	Additional Element Fault Current - min	1.04	Reverse Power Flow - max		10,073		2,408	405	335	204	199
Ramsey	RAM077	0.14	Unintentional Islanding - min	2.44	Reverse Power Flow - max		10,073		2,693	405	335	37	51
Rapidan	RAP081	0.04	Unintentional Islanding - min	0.29	Breaker Relay Reduction of Reach - max		474		474	5	1244	5	1244
Richmond	RCH061	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		775		775	5005	6	5005	6
Red River	RED091	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max				5,338	0	0	0	0
Red Wing	REW021	0.18	Unintentional Islanding - min	1.11	Reverse Power Flow - max		4,103		632	4995	65	31	10
Red Wing	REW022	0.8	Thermal for Gen - min	1.25	Reverse Power Flow - max		4,103		1,100	4995	65	30	43
Red Wing	REW023	0	Unintentional Islanding - min	1.45	Reverse Power Flow - max		4,103		1,687	4995	65	4934	11
Red Wing	REW031	0.1	Primary Over-Voltage - min	1.12	Reverse Power Flow - max		4,855		2,102	177	29	86	0
Red Wing	REW032	0.65	Reverse Power Flow - min	0.65	Reverse Power Flow - max		4,855		900	177	29	20	4
Red Wing	REW033	0.4	Primary Over-Voltage - min	0.65	Reverse Power Flow - max		4,855		1,044	177	29	71	25
Riverside	RIV061	0.9	Thermal for Gen - min	1.24	Reverse Power Flow - max		7,367		1,704	976	1022	283	25
Riverside	RIV062	0.9	Thermal for Gen - min	1.76	Reverse Power Flow - max		7,367		1,887	976	1022	15	2
Riverside	RIV063	0.57	Unintentional Islanding - min	1.28	Reverse Power Flow - max		7,367		2,797	976	1022	597	995
Riverside	RIV064	0.8	Thermal for Gen - min	1.31	Reverse Power Flow - max		7,367		1,341	976	1022	80	0
Riverside	RIV065	0.82	Reverse Power Flow - min	0.82	Reverse Power Flow - max		7,367		537	976	1022	0	0
Riverside	RIV066	0.74	Reverse Power Flow - min	0.74	Reverse Power Flow - max		7,367		747	976	1022	0	0
Riverside	RIV071	1.04	Reverse Power Flow - min	1.04	Reverse Power Flow - max		7,424		741	617	9	0	0
Riverside	RIV072	1.09	Reverse Power Flow - min	1.09	Reverse Power Flow - max		7,424		186	617	9	0	0
Riverside	RIV073	0.9	Thermal for Gen - min	1.1	Reverse Power Flow - max		7,424		1,470	617	9	599	3
Riverside	RIV074	0.32	Reverse Power Flow - min	0.32	Reverse Power Flow - max		7,424		123	617	9	0	0
Riverside	RIV075	0.79	Reverse Power Flow - min	0.79	Reverse Power Flow - max		7,424		824	617	9	0	6
Riverside	RIV076	0.9	Thermal for Gen - min	1.35	Reverse Power Flow - max		7,424		2,139	617	9	19	0
Rogers Lake	RLK064	0.6	Primary Over-Voltage - min	1.37	Reverse Power Flow - max		11,235		1,703	365	532	70	18
Rogers Lake	RLK065	0.9	Thermal for Gen - min	1.48	Reverse Power Flow - max		11,235		2,209	365	532	79	395
Rogers Lake	RLK066	0.9	Thermal for Gen - min	1.58	Reverse Power Flow - max		11,235		900	365	532	71	51

PROTECTED DATA SHADED

Substation	Feeder	Minimum Hosting Capacity (MW)	Min Limiting Factor	Maximum Hosting Capacity (MW)	Max Limiting Factor	Substation Transformer Forecasted Peak Load (kVA)	Substation Transformer Minimum Load (kVA)	Feeder 2020 Peak Load (kVA)	Feeder Daytime Minimum Load (kVA)	Substation Transformer Installed DG (kVA)	Substation Transformer Queued DG (kVA)	Feeder Installed DG (kVA)	Feeder Queued DG (kVA)
Rogers Lake	RLK068	1.1	Thermal for Gen - min	1.1	Reverse Power Flow - max		11,235		2,864	365	532	0	0
Rogers Lake	RLK069	0.2	Thermal for Gen - min	1.72	Reverse Power Flow - max		11,235		2,309	365	532	144	68
Rogers Lake	RLK071	0.02	Unintentional Islanding - min	2.65	Reverse Power Flow - max		8,732		2,730	203	191	36	163
Rogers Lake	RLK072	0.9	Thermal for Gen - min	0.98	Reverse Power Flow - max		8,732		1,432	203	191	55	5
Rogers Lake	RLK073	0.9	Thermal for Gen - min	1.49	Reverse Power Flow - max		8,732		2,126	203	191	27	23
Rogers Lake	RLK079	0.6	Thermal for Gen - min	1.63	Reverse Power Flow - max		8,732		2,596	203	191	85	0
Rosemount	RMT311	0	Reverse Power Flow - min	0	Reverse Power Flow - max		3,726		782	10277	2017	10000	1000
Rosemount	RMT312	0	Additional Element Fault Current - min	0.01	Breaker Relay Reduction of Reach - max		5,515		4,688	10277	2017	277	1017
Renville	RNV021	0.4	Primary Over-Voltage - min	0.5	Reverse Power Flow - max		603		603	1093	2028	1093	2028
Rock River	ROC090	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		754		72	6710	0	4710	0
Rock River	ROC091	0	Reverse Power Flow - min	0	Reverse Power Flow - max		754		682	6710	0	2000	0
Rose Place	RPL061	0.9	Thermal for Gen - min	1.57	Reverse Power Flow - max		8,848		2,463	343	829	186	0
Rose Place	RPL062	1.04	Reverse Power Flow - min	1.04	Reverse Power Flow - max		8,848		1,094	343	829	0	0
Rose Place	RPL063	1	Thermal for Gen - min	2.96	Reverse Power Flow - max		8,848		2,988	343	829	84	41
Rose Place	RPL064	0.9	Thermal for Gen - min	2.82	Reverse Power Flow - max		8,848		2,849	343	829	73	788
Rose Place	RPL071	0.9	Thermal for Gen - min	2.09	Reverse Power Flow - max		10,288		2,684	94	50	35	0
Rose Place	RPL072	0.19	Unintentional Islanding - min	1.13	Reverse Power Flow - max		10,288		1,500	94	50	0	0
Rose Place	RPL073	0.9	Thermal for Gen - min	1.13	Reverse Power Flow - max		10,288		2,113	94	50	0	0
Rose Place	RPL074	0.9	Thermal for Gen - min	1.61	Reverse Power Flow - max		10,288		2,893	94	50	5	50
Rose Place	RPL075	0.9	Thermal for Gen - min	0.98	Reverse Power Flow - max		10,288		497	94	50	54	0
Red Rock	RRK061	1.5	Thermal for Gen - min	1.75	Reverse Power Flow - max		13,124		1,099	91	3085	0	0
Red Rock	RRK062	1.5	Thermal for Gen - min	1.78	Reverse Power Flow - max		13,124		5,412	91	3085	0	0
Red Rock	RRK063	0.9	Thermal for Gen - min	1.57	Reverse Power Flow - max		13,124		3,081	91	3085	7	0
Red Rock	RRK064	0.9	Thermal for Gen - min	2.73	Reverse Power Flow - max		13,124		2,302	91	3085	84	3085
Red Rock	RRK071	1.5	Thermal for Gen - min	2.63	Reverse Power Flow - max		8,805		6,628	0	0	0	0
Red Rock	RRK072	1.3	Thermal for Gen - min	1.4	Reverse Power Flow - max		8,805		1,221	0	0	0	0
Red Rock	RRK081	2.2	Reverse Power Flow - min	2.2	Reverse Power Flow - max		9,177		5,567	123	17	0	0
Red Rock	RRK082	0.1	Primary Over-Voltage - min	0.77	Reverse Power Flow - max		9,177		1,063	123	17	123	17
Red Rock	RRK083	0.2	Thermal for Gen - min	2.04	Reverse Power Flow - max		9,177		2,485	123	17	0	0
Rich Spring	RSP061	0.91	Unintentional Islanding - min	0.93	Reverse Power Flow - max		1,179		1,179	0	986	0	986
Rich Valley	RVA061	0.5	Primary Over-Voltage - min	2.6	Reverse Power Flow - max		7,695		2,696	122	29	62	29
Rich Valley	RVA062	0.2	Primary Over-Voltage - min	1.27	Breaker Relay Reduction of Reach - max		7,695		2,228	122	29	60	0
Rich Valley	RVA063	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		7,695		0	122	29	0	0
Riverwood	RWD061	0.5	Thermal for Gen - min	0.94	Reverse Power Flow - max		5,708		1,533	215	1795	0	8
Riverwood	RWD062	0.9	Thermal for Gen - min	1.79	Reverse Power Flow - max		5,708		2,035	215	1795	93	20
Riverwood	RWD063	1.3	Primary Over-Voltage - min	1.38	Reverse Power Flow - max		5,708		2,013	215	1795	122	1768
Riverwood	RWD081	0.08	Unintentional Islanding - min	0.84	Reverse Power Flow - max		3,276		1,591	207	49	91	16
Riverwood	RWD082	0.5	Thermal for Gen - min	1.13	Reverse Power Flow - max		3,276		1,790	207	49	117	33
Sauk River	SAK311	0	Unintentional Islanding - min	0.8	Breaker Relay Reduction of Reach - max		5,240		3,497	9171	5917	98	5917
Sauk River	SAK312	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		5,240		3,878	9171	5917	9073	0
Sauk River	SAK321	0.74	Unintentional Islanding - min	2.68	Reverse Power Flow - max		2,707		2,707	19	0	19	0
Savage	SAV063	0.31	Unintentional Islanding - min	2.1	Reverse Power Flow - max		4,027		2,164	68	43	21	16
Savage	SAV067	0.5	Primary Over-Voltage - min	2.06	Reverse Power Flow - max		4,027		3,507	68	43	0	0
Savage	SAV069	0	Unintentional Islanding - min	1.34	Reverse Power Flow - max		1,167		280	68	43	47	27

PROTECTED DATA SHADED

Substation	Feeder	Minimum Hosting Capacity (MW)	Min Limiting Factor	Maximum Hosting Capacity (MW)	Max Limiting Factor	Substation Transformer Forecasted Peak Load (kVA)	Substation Transformer Minimum Load (kVA)	Feeder 2020 Peak Load (kVA)	Feeder Daytime Minimum Load (kVA)	Substation Transformer Installed DG (kVA)	Substation Transformer Queued DG (kVA)	Feeder Installed DG (kVA)	Feeder Queued DG (kVA)
Savage	SAV071	0.9	Thermal for Gen - min	1.94	Reverse Power Flow - max		2,850		1,781	60	37	0	11
Savage	SAV072	0.49	Reverse Power Flow - min	0.49	Reverse Power Flow - max		2,850		1,016	60	37	0	0
Savage	SAV073	0.85	Reverse Power Flow - min	0.85	Reverse Power Flow - max		2,850		1,144	60	37	60	26
Scandia	SCA021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		2,259		2,259	14247	1071	14247	1071
Sacred Heart	SCH001	0.1	Primary Over-Voltage - min	0.16	Reverse Power Flow - max		634		199	1042	2000	0	0
Sacred Heart	SCH211	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		634		434	1042	2000	1042	2000
Saint Cloud	SCL311	0.9	Primary Over-Voltage - min	1.91	Reverse Power Flow - max		16,286		3,569	328	703	9	0
Saint Cloud	SCL312	0.1	Thermal for Gen - min	0.88	Breaker Relay Reduction of Reach - max		16,286		6,687	328	703	63	433
Saint Cloud	SCL313	0	Unintentional Islanding - min	1.61	Breaker Relay Reduction of Reach - max		16,286		8,219	328	703	257	270
Saint Cloud	SCL322	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		6,789		4,456	29192	7925	29192	7925
Saint Cloud	SCL323	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		6,789		2,116	29192	7925	0	0
Salida Crossing	SDX061	2.9	Reverse Power Flow - min	2.9	Reverse Power Flow - max		1,265		1,265	0	0	0	0
Salida Crossing	SDX311	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		4,689		1,322	8050	3000	8050	3000
Salida Crossing	SDX312	0.66	Reverse Power Flow - min	0.66	Reverse Power Flow - max		4,689		1,461	8050	3000	0	0
Salida Crossing	SDX313	2.47	Reverse Power Flow - min	2.47	Reverse Power Flow - max		4,689		2,485	8050	3000	0	0
Sedan	SED061	0.04	Reverse Power Flow - min	0.04	Reverse Power Flow - max		70		70	0	14	0	14
Shepard	SHP061	0.89	Reverse Power Flow - min	0.89	Reverse Power Flow - max		3,354		1,334	100	82	48	37
Shepard	SHP062	0.5	Thermal for Gen - min	1.87	Reverse Power Flow - max		3,354		2,844	100	82	52	45
Shepard	SHP063	0.7	Reverse Power Flow - min	0.7	Reverse Power Flow - max		3,354		1,221	100	82	0	0
Shepard	SHP071	0.9	Thermal for Gen - min	1.47	Reverse Power Flow - max		3,354		2,040	51	40	4	6
Shepard	SHP072	0.3	Thermal for Gen - min	0.96	Reverse Power Flow - max		3,354		1,105	51	40	46	34
Sibley Park	SIP061	0	Unintentional Islanding - min	0.45	Reverse Power Flow - max		11,075		2,528	53	11	47	11
Sibley Park	SIP062	1.98	Reverse Power Flow - min	1.98	Reverse Power Flow - max		11,075		2,024	53	11	0	0
Sibley Park	SIP063	0.6	Thermal for Gen - min	1.43	Reverse Power Flow - max		11,075		1,283	53	11	5	0
Sibley Park	SIP071	0.19	Unintentional Islanding - min	1.57	Reverse Power Flow - max		7274		2,637	98	20	27	4
Sibley Park	SIP072	0.5	Primary Over-Voltage - min	1.36	Reverse Power Flow - max		7274		2,215	98	20	24	10
Sibley Park	SIP073	0.11	Unintentional Islanding - min	1.29	Reverse Power Flow - max		7274		1,874	98	20	47	7
Saint John's	SJO001	0.47	Reverse Power Flow - min	0.47	Reverse Power Flow - max		505		505	0	0	0	0
Saint Louis Park	SLP071	0.5	Thermal for Gen - min	1.56	Reverse Power Flow - max		18,761		2,171	304	81	3	10
Saint Louis Park	SLP072	0.21	Unintentional Islanding - min	1.85	Reverse Power Flow - max		18,761		2,489	304	81	17	36
Saint Louis Park	SLP073	0.16	Unintentional Islanding - min	1.95	Reverse Power Flow - max		18,761		2,391	304	81	38	3
Saint Louis Park	SLP074	0.4	Thermal for Gen - min	1.83	Breaker Relay Reduction of Reach - max		18,761		2,869	304	81	174	7
Saint Louis Park	SLP075	0.5	Thermal for Gen - min	1.51	Reverse Power Flow - max		18,761		2,231	304	81	58	4
Saint Louis Park	SLP076	0.9	Thermal for Gen - min	1.82	Reverse Power Flow - max		18,761		2,499	304	81	14	20
Saint Louis Park	SLP077	0.9	Thermal for Gen - min	1.28	Reverse Power Flow - max		18,761		1,947	304	81	0	3
Saint Louis Park	SLP081	0.9	Thermal for Gen - min	1.4	Reverse Power Flow - max		15,620		2,058	592	164	15	35
Saint Louis Park	SLP082	0.9	Thermal for Gen - min	2.05	Reverse Power Flow - max		15,620		3,047	592	164	188	38
Saint Louis Park	SLP083	0.9	Thermal for Gen - min	1.54	Reverse Power Flow - max		15,620		2,210	592	164	109	6
Saint Louis Park	SLP084	0.9	Thermal for Gen - min	1.48	Reverse Power Flow - max		15,620		2,034	592	164	170	41
Saint Louis Park	SLP085	0.9	Thermal for Gen - min	1.52	Reverse Power Flow - max		15,620		2,021	592	164	52	28
Saint Louis Park	SLP086	0.9	Thermal for Gen - min	1.42	Reverse Power Flow - max		15,620		2,758	592	164	44	6
Saint Louis Park	SLP087	0.9	Thermal for Gen - min	0.92	Reverse Power Flow - max		15,620		1,494	592	164	14	10
Saint Louis Park	SLP091	0.9	Thermal for Gen - min	0.94	Reverse Power Flow - max		14,536		1,343	783	248	0	0
Saint Louis Park	SLP092	0.9	Thermal for Gen - min	1.65	Reverse Power Flow - max		14,536		2,177	783	248	526	28
Saint Louis Park	SLP093	0.8	Primary Over-Voltage - min	1.61	Reverse Power Flow - max		14,536		3,199	783	248	73	0

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Saint Louis Park	SLP094	0.9	Thermal for Gen - min	1.24	Reverse Power Flow - max		14,536		2,031	783	248	67	44
Saint Louis Park	SLP095	0.41	Unintentional Islanding - min	0.98	Reverse Power Flow - max		14,536		1,743	783	248	4	6
Saint Louis Park	SLP096	0.9	Thermal for Gen - min	1.86	Reverse Power Flow - max		14,536		2,618	783	248	75	158
Saint Louis Park	SLP097	0.9	Thermal for Gen - min	1.21	Reverse Power Flow - max		14,536		1,934	783	248	39	12
Saint Louis Park	SLP321	0.7	Thermal for Gen - min	2.51	Reverse Power Flow - max		11,613		4,367	76	48	68	48
Saint Louis Park	SLP322	0.4	Thermal for Gen - min	3	Breaker Relay Reduction of Reach - max		11,613		6,217	76	48	8	0
Slayton West	SLW061	0	Thermal for Gen - min	0	Reverse Power Flow - max		1,140		265	1044	0	1020	0
Slayton West	SLW062	0.76	Reverse Power Flow - min	0.76	Reverse Power Flow - max		1,140		927	1044	0	24	0
Summit Ave	SMT061	0.7	Thermal for Gen - min	1.08	Reverse Power Flow - max		11,602		2,637	8112	1031	2	0
Summit Ave	SMT062	0.04	Unintentional Islanding - min	0.52	Breaker Relay Reduction of Reach - max		11,602		2,469	8112	1031	0	31
Summit Ave	SMT063	0.35	Unintentional Islanding - min	1.19	Reverse Power Flow - max		11,602		1,157	8112	1031	20	0
Summit Ave	SMT071	1.5	Thermal for Gen - min	2.2	Reverse Power Flow - max		11,602		1,079	8112	1031	18	0
Summit Ave	SMT072	0	Unintentional Islanding - min	0.76	Breaker Relay Reduction of Reach - max		11,602		2,640	8112	1031	8072	1000
Summit Ave	SMT081	0.9	Thermal for Gen - min	2.81	Reverse Power Flow - max		7,798		3,020	1260	15	0	0
Summit Ave	SMT082	0.1	Primary Over-Voltage - min	0.7	Breaker Relay Reduction of Reach - max		7,798		1,107	1260	15	61	8
Summit Ave	SMT091	0.4	Thermal for Gen - min	2.55	Reverse Power Flow - max		7,798		2,576	1260	15	158	0
Summit Ave	SMT092	0.4	Thermal for Gen - min	0.4	Reverse Power Flow - max		7,798		483	1260	15	1040	7
South Haven	SOH001	0.1	Primary Over-Voltage - min	0.1	Reverse Power Flow - max		112		112	0	0	0	0
Southtown	SOU061	0.4	Thermal for Gen - min	1.46	Reverse Power Flow - max		12,369		1,851	708	246	30	39
Southtown	SOU063	1	Thermal for Gen - min	1.74	Reverse Power Flow - max		12,369		2,544	708	246	223	66
Southtown	SOU064	0.2	Thermal for Gen - min	2.25	Reverse Power Flow - max		12,369		2,635	708	246	117	75
Southtown	SOU065	1.2	Primary Over-Voltage - min	1.4	Reverse Power Flow - max		12,369		2,862	708	246	179	27
Southtown	SOU066	0.97	Reverse Power Flow - min	0.97	Reverse Power Flow - max		12,369		1,089	708	246	98	14
Southtown	SOU069	0.29	Unintentional Islanding - min	1.1	Reverse Power Flow - max		12,369		1,260	708	246	62	26
Southtown	SOU072	0.9	Thermal for Gen - min	1.94	Reverse Power Flow - max		12,680		2,586	676	281	70	82
Southtown	SOU073	0.85	Reverse Power Flow - min	0.85	Reverse Power Flow - max		12,680		1,036	676	281	76	16
Southtown	SOU075	0.4	Thermal for Gen - min	1.88	Reverse Power Flow - max		12,680		2,391	676	281	125	69
Southtown	SOU076	0.4	Thermal for Gen - min	1	Reverse Power Flow - max		12,680		1,099	676	281	79	3
Southtown	SOU077	0.9	Thermal for Gen - min	2.05	Reverse Power Flow - max		12,680		2,179	676	281	165	36
Southtown	SOU078	0.2	Thermal for Gen - min	1.55	Reverse Power Flow - max		12,680		1,175	676	281	0	6
Southtown	SOU079	0.4	Thermal for Gen - min	1.53	Reverse Power Flow - max		12,680		1,900	676	281	159	70
Southtown	SOU081	0.9	Thermal for Gen - min	0.9	Reverse Power Flow - max		15,704		1,216	768	261	69	34
Southtown	SOU082	0.4	Thermal for Gen - min	1.94	Reverse Power Flow - max		15,704		2,854	768	261	127	75
Southtown	SOU083	0.4	Thermal for Gen - min	1.69	Reverse Power Flow - max		15,704		1,427	768	261	147	48
Southtown	SOU084	0.27	Reverse Power Flow - min	0.27	Reverse Power Flow - max		15,704		783	768	261	38	7
Southtown	SOU085	0.9	Thermal for Gen - min	1.62	Reverse Power Flow - max		15,704		3,248	768	261	0	0
Southtown	SOU086	0.4	Thermal for Gen - min	1.73	Reverse Power Flow - max		15,704		1,432	768	261	103	59
Southtown	SOU087	0.4	Thermal for Gen - min	1.18	Reverse Power Flow - max		15,704		1,204	768	261	269	38
Southtown	SOU088	0.2	Thermal for Gen - min	1.29	Reverse Power Flow - max		15,704		847	768	261	14	0
South Ridge	SRD211	0.2	Thermal for Gen - min	1.29	Reverse Power Flow - max		1,016		1,016	0	0	0	0
Saint Joseph	STO001	0.64	Reverse Power Flow - min	0.64	Reverse Power Flow - max		1,238		663	0	32	0	0
Saint Joseph	STO002	0.1	Primary Over-Voltage - min	0.57	Reverse Power Flow - max		1,238		640	0	32	0	32
Stewart	STW021	0.1	Primary Over-Voltage - min	0.42	Reverse Power Flow - max		358		358	0	3000	0	3000
Stockyards	STY061	0.7	Primary Over-Voltage - min	2.33	Reverse Power Flow - max		10,914		2,900	166	1187	29	9
Stockyards	STY062	0.8	Primary Over-Voltage - min	1.62	Reverse Power Flow - max		10,914		2,309	166	1187	18	0
Stockyards	STY063	0.5	Primary Over-Voltage - min	0.8	Primary Over-Voltage - max		10,914		2,550	166	1187	78	1003
Stockyards	STY065	0.6	Thermal for Gen - min	1.45	Reverse Power Flow - max		10,914		1,599	166	1187	42	175
Stockyards	STY071	0.9	Thermal for Gen - min	2.42	Reverse Power Flow - max		10,906		5,122	132	40	13	15

PROTECTED DATA SHADED

Substation	Feeder	Minimum Hosting Capacity (MW)	Min Limiting Factor	Maximum Hosting Capacity (MW)	Max Limiting Factor	Substation Transformer Forecasted Peak Load (kVA)	Substation Transformer Minimum Load (kVA)	Feeder 2020 Peak Load (kVA)	Feeder Daytime Minimum Load (kVA)	Substation Transformer Installed DG (kVA)	Substation Transformer Queued DG (kVA)	Feeder Installed DG (kVA)	Feeder Queued DG (kVA)
Stockyards	STY072	0.13	Unintentional Islanding - min	1.38	Reverse Power Flow - max		10,906		1,924	132	40	14	5
Stockyards	STY073	0.09	Unintentional Islanding - min	1.48	Reverse Power Flow - max		10,906		2,040	132	40	15	15
Stockyards	STY075	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		10,906		1,603	132	40	90	4
Swan Lake	SWN021	0.3	Primary Over-Voltage - min	0.4	Reverse Power Flow - max		1,042		429	6070	7008	56	0
Swan Lake	SWN022	0.01	Unintentional Islanding - min	0.49	Reverse Power Flow - max		1,042		710	6070	7008	6014	7008
Terminal	TER061	0.9	Thermal for Gen - min	1.52	Reverse Power Flow - max		17,255		2,388	547	87	350	24
Terminal	TER062	0.9	Thermal for Gen - min	1.3	Reverse Power Flow - max		17,255		2,631	547	87	135	39
Terminal	TER063	0.8	Thermal for Gen - min	1.39	Reverse Power Flow - max		17,255		2,765	547	87	53	24
Terminal	TER064	0.9	Thermal for Gen - min	1.34	Reverse Power Flow - max		17,255		1,276	547	87	0	0
Terminal	TER065	0.4	Thermal for Gen - min	1.43	Reverse Power Flow - max		17,255		4,521	547	87	10	0
Terminal	TER066	1.1	Thermal for Gen - min	1.5	Reverse Power Flow - max		17,255		2,670	547	87	0	0
Terminal	TER071	0.9	Thermal for Gen - min	1.73	Reverse Power Flow - max		7,609		2,134	134	1979	87	20
Terminal	TER072	1.2	Reverse Power Flow - min	1.2	Reverse Power Flow - max		7,609		838	134	1979	0	0
Terminal	TER073	0.1	Thermal for Gen - min	0.88	Breaker Relay Reduction of Reach - max		7,609		1,204	134	1979	0	125
Terminal	TER074	0.42	Reverse Power Flow - min	0.42	Reverse Power Flow - max		7,609		169	134	1979	0	0
Terminal	TER075	0.5	Reverse Power Flow - min	0.5	Reverse Power Flow - max		7,609		1,724	134	1979	47	1834
Terminal	TER076	0.69	Reverse Power Flow - min	0.69	Reverse Power Flow - max		7,609		510	134	1979	0	0
Terminal	TER081	0.2	Thermal for Gen - min	1.87	Reverse Power Flow - max		10,380		2,481	114	514	29	514
Terminal	TER082	0.9	Thermal for Gen - min	1.5	Reverse Power Flow - max		10,380		2,230	114	514	45	0
Terminal	TER083	0.5	Thermal for Gen - min	1.29	Reverse Power Flow - max		10,380		947	114	514	41	0
Terminal	TER084	1.35	Reverse Power Flow - min	1.35	Reverse Power Flow - max		10,380		121	114	514	0	0
Terminal	TER085	0.9	Thermal for Gen - min	0.96	Reverse Power Flow - max		10,380		1,358	114	514	0	0
Terminal	TER086	1.03	Reverse Power Flow - min	1.03	Reverse Power Flow - max		10,380		2,017	114	514	0	0
Tanner's Lake	TLK023	2.08	Reverse Power Flow - min	2.08	Reverse Power Flow - max		16,651		2,155	277	48	0	0
Tanner's Lake	TLK032	1.04	Reverse Power Flow - min	1.04	Reverse Power Flow - max		15,221		1,168	166	11	0	0
Tanner's Lake	TLK034	0.73	Reverse Power Flow - min	0.73	Reverse Power Flow - max		15,221		932	166	11	0	0
Tanner's Lake	TLK061	0.9	Thermal for Gen - min	1.91	Reverse Power Flow - max		16,651		2,548	277	48	11	30
Tanner's Lake	TLK062	0.9	Thermal for Gen - min	1.46	Reverse Power Flow - max		16,651		2,345	277	48	181	3
Tanner's Lake	TLK064	0.9	Thermal for Gen - min	1.12	Reverse Power Flow - max		16,651		2,077	277	48	39	10
Tanner's Lake	TLK065	0.62	Reverse Power Flow - min	0.62	Reverse Power Flow - max		16,651		730	277	48	0	0
Tanner's Lake	TLK066	0.6	Thermal for Gen - min	1.55	Reverse Power Flow - max		16,651		2,571	277	48	0	0
Tanner's Lake	TLK067	0.5	Thermal for Gen - min	1.48	Reverse Power Flow - max		16,651		2,398	277	48	46	6
Tanner's Lake	TLK071	0.94	Reverse Power Flow - min	0.94	Reverse Power Flow - max		15,221		1,411	166	11	35	0
Tanner's Lake	TLK073	1	Thermal for Gen - min	1.04	Reverse Power Flow - max		15,221		1,321	166	11	56	0
Tanner's Lake	TLK075	0.9	Thermal for Gen - min	1.3	Reverse Power Flow - max		15,221		2,029	166	11	10	3
Tanner's Lake	TLK076	0.94	Reverse Power Flow - min	0.94	Reverse Power Flow - max		15,221		726	166	11	0	0
Tanner's Lake	TLK077	0.75	Unintentional Islanding - min	2.08	Reverse Power Flow - max		15,221		4,421	166	11	65	8
Tracy	TRA001	0.23	Reverse Power Flow - min	0.23	Reverse Power Flow - max		547		307	8	11	0	0
Tracy	TRA002	0.1	Primary Over-Voltage - min	0.23	Reverse Power Flow - max		547		240	8	11	8	11
Tracy Switching Station	TSS061	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		680		680	4197	1059	4197	1059
Twin Lake	TWL061	1.1	Thermal for Gen - min	2	Reverse Power Flow - max		18,643		2,022	297	81	0	0
Twin Lake	TWL062	0.7	Primary Over-Voltage - min	1.21	Reverse Power Flow - max		18,643		1,703	297	81	47	0
Twin Lake	TWL063	1.2	Primary Over-Voltage - min	1.29	Reverse Power Flow - max		18,643		1,844	297	81	42	16
Twin Lake	TWL064	0.4	Primary Over-Voltage - min	1.37	Reverse Power Flow - max		18,643		1,746	297	81	14	0
Twin Lake	TWL065	0.9	Thermal for Gen - min	2.41	Reverse Power Flow - max		18,643		2,802	297	81	20	44
Twin Lake	TWL066	0.51	Unintentional Islanding - min	1.41	Reverse Power Flow - max		18,643		1,552	297	81	53	4
Twin Lake	TWL067	0.9	Thermal for Gen - min	1.21	Reverse Power Flow - max		18,643		1,503	297	81	5	4
Twin Lake	TWL068	0.5	Thermal for Gen - min	1.74	Reverse Power Flow - max		18,643		2,121	297	81	46	13
Twin Lake	TWL069	0.9	Thermal for Gen - min	1.7	Reverse Power Flow - max		18,643		1,811	297	81	71	0

PROTECTED DATA SHADED

Substation	Feeder	Minimum Hosting Capacity (MW)	Min Limiting Factor	Maximum Hosting Capacity (MW)	Max Limiting Factor	Substation Transformer Forecasted Peak Load (kVA)	Substation Transformer Minimum Load (kVA)	Feeder 2020 Peak Load (kVA)	Feeder Daytime Minimum Load (kVA)	Substation Transformer Installed DG (kVA)	Substation Transformer Queued DG (kVA)	Feeder Installed DG (kVA)	Feeder Queued DG (kVA)
Twin Lake	TWL071	0.8	Primary Over-Voltage - min	1.43	Reverse Power Flow - max		19,105		1,502	272	371	9	23
Twin Lake	TWL072	0.9	Thermal for Gen - min	2.76	Reverse Power Flow - max		19,105		2,915	272	371	72	0
Twin Lake	TWL073	0.43	Reverse Power Flow - min	0.43	Reverse Power Flow - max		19,105		707	272	371	0	191
Twin Lake	TWL074	0.9	Thermal for Gen - min	1.47	Reverse Power Flow - max		19,105		1,726	272	371	131	95
Twin Lake	TWL075	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		19,105		1,020	272	371	30	4
Twin Lake	TWL076	0.9	Thermal for Gen - min	1.93	Reverse Power Flow - max		19,105		2,121	272	371	14	58
Twin Lake	TWL077	0.9	Thermal for Gen - min	0.99	Reverse Power Flow - max		19,105		1,077	272	371	0	0
Twin Lake	TWL078	0.5	Thermal for Gen - min	1.6	Reverse Power Flow - max		19,105		1,712	272	371	8	0
Twin Lake	TWL079	0.12	Unintentional Islanding - min	3.38	Reverse Power Flow - max		19,105		3,513	272	371	7	0
Twin Lake	TWL081	0.8	Primary Over-Voltage - min	2.38	Reverse Power Flow - max		8,628		2,530	113	852	0	327
Twin Lake	TWL082	0.5	Thermal for Gen - min	1.9	Reverse Power Flow - max		8,628		1,924	113	852	36	480
Twin Lake	TWL083	0.9	Thermal for Gen - min	1.68	Reverse Power Flow - max		8,628		1,825	113	852	77	5
Twin Lake	TWL089	0.9	Thermal for Gen - min	1.96	Reverse Power Flow - max		8,628		2,121	113	852	0	40
Upper Levee	UPP061	0.9	Thermal for Gen - min	1.54	Reverse Power Flow - max		20,580		2,025	115	2018	0	2000
Upper Levee	UPP062	0.9	Thermal for Gen - min	2.02	Reverse Power Flow - max		20,580		3,096	115	2018	0	2
Upper Levee	UPP063	0.9	Thermal for Gen - min	1.75	Reverse Power Flow - max		20,580		2,929	115	2018	66	8
Upper Levee	UPP064	0.9	Thermal for Gen - min	2.04	Reverse Power Flow - max		20,580		2,340	115	2018	0	0
Upper Levee	UPP065	1.1	Thermal for Gen - min	1.23	Reverse Power Flow - max		20,580		1,502	115	2018	0	0
Upper Levee	UPP066	0.3	Thermal for Gen - min	1.47	Reverse Power Flow - max		20,580		1,965	115	2018	14	0
Upper Levee	UPP067	0.72	Reverse Power Flow - min	0.72	Reverse Power Flow - max		20,580		539	115	2018	0	0
Upper Levee	UPP068	0.9	Thermal for Gen - min	1.35	Reverse Power Flow - max		20,580		1,460	115	2018	36	9
Upper Levee	UPP069	0.66	Reverse Power Flow - min	0.66	Reverse Power Flow - max		20,580		502	115	2018	0	0
Upper Levee	UPP081	0.9	Thermal for Gen - min	2.03	Reverse Power Flow - max		19,791		1,596	303	243	0	8
Upper Levee	UPP082	0.5	Thermal for Gen - min	1.67	Reverse Power Flow - max		19,791		2,416	303	243	113	49
Upper Levee	UPP083	1.03	Reverse Power Flow - min	1.03	Reverse Power Flow - max		19,791		869	303	243	0	0
Upper Levee	UPP084	0.1	Unintentional Islanding - min	1.94	Reverse Power Flow - max		19,791		3,093	303	243	77	59
Upper Levee	UPP085	0.9	Thermal for Gen - min	1.35	Reverse Power Flow - max		19,791		2,510	303	243	62	95
Upper Levee	UPP086	0.9	Thermal for Gen - min	1.73	Reverse Power Flow - max		19,791		1,883	303	243	28	32
Upper Levee	UPP088	1.99	Reverse Power Flow - min	1.99	Reverse Power Flow - max		19,791		3,752	303	243	0	0
Upper Levee	UPP089	0.9	Thermal for Gen - min	1.36	Reverse Power Flow - max		19,791		2,518	303	243	23	0
Vesili	VES021	0	Unintentional Islanding - min	0.54	Reverse Power Flow - max		731		731	7998	2043	7998	2043
Villard	VIL021	0.18	Reverse Power Flow - min	0.18	Reverse Power Flow - max		315		315	0	1000	0	1000
Viking	VKG061	1.35	Reverse Power Flow - min	1.35	Reverse Power Flow - max		8,538		1,547	902	24	21	5
Viking	VKG065	0.9	Thermal for Gen - min	1.48	Reverse Power Flow - max		8,538		2,509	902	24	28	0
Viking	VKG071	0.98	Reverse Power Flow - min	0.98	Reverse Power Flow - max		8,538		1,444	902	24	0	0
Viking	VKG072	0.9	Primary Over-Voltage - min	1.65	Reverse Power Flow - max		8,538		2,721	902	24	854	19
Vermillion	VMR061	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		3,545		570	5087	2031	5015	2006
Vermillion	VMR062	0.9	Thermal for Gen - min	1.44	Reverse Power Flow - max		3,545		1,692	5087	2031	26	26
Vermillion	VMR063	0.31	Reverse Power Flow - min	0.31	Reverse Power Flow - max		3,545		1,282	5087	2031	45	0
Wabasha	WAB021	0.11	Unintentional Islanding - min	0.77	Reverse Power Flow - max		909		909	301	7	301	7
Wabasha	WAB031	0	Unintentional Islanding - min	1.15	Breaker Relay Reduction of Reach - max		1,914		1,914	3534	4194	3534	4194
Wakefield	WAK321	1.97	Reverse Power Flow - min	1.97	Reverse Power Flow - max		2,907		2,907	5036	11	5036	11
Waseca	WAS081	0	Unintentional Islanding - min	0.09	Reverse Power Flow - max		0		0	10000	0	10000	0
Waseca	WAS091	1.2	Thermal for Gen - min	6.96	Reverse Power Flow - max		12,807		7,403	8286	9137	0	3000
Waseca	WAS092	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		12,807		3,767	8286	9137	8286	6137
Waseca	WAS231	2.6	Reverse Power Flow - min	2.6	Reverse Power Flow - max		0		0	0	0	0	0
Waterville	WAT021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		775		775	3036	33	3036	33
Waterville	WAT081	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,758		1,758	6160	6032	6160	6032

PROTECTED DATA SHADED

Substation	Feeder	Minimum Hosting Capacity (MW)	Min Limiting Factor	Maximum Hosting Capacity (MW)	Max Limiting Factor	Substation Transformer Forecasted Peak Load (kVA)	Substation Transformer Minimum Load (kVA)	Feeder 2020 Peak Load (kVA)	Feeder Daytime Minimum Load (kVA)	Substation Transformer Installed DG (kVA)	Substation Transformer Queued DG (kVA)	Feeder Installed DG (kVA)	Feeder Queued DG (kVA)
Waterville	WAT221	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		680		680	5000	0	5000	0
Waverly	WAV021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		782		782	5033	21	5033	21
Williams Brothers Propane	WBP061	0.9	Primary Over-Voltage - min	1.23	Reverse Power Flow - max		5,970		4,748	30	0	30	0
Williams Brothers Propane	WBP062	1.2	Primary Over-Voltage - min	1.27	Reverse Power Flow - max		5,970		1,280	30	0	0	0
West Coon Rapids	WCR061	0.9	Primary Over-Voltage - min	1.08	Reverse Power Flow - max		6,125		1,716	77	40	30	5
West Coon Rapids	WCR062	0.7	Primary Over-Voltage - min	1.61	Reverse Power Flow - max		6,125		2,232	77	40	22	25
West Coon Rapids	WCR063	0.7	Primary Over-Voltage - min	1.9	Primary Over-Voltage - max		6,125		2,408	77	40	25	9
West Coon Rapids	WCR311	0.2	Thermal for Gen - min	3.44	Reverse Power Flow - max		9,135		5,930	140	99	63	59
West Coon Rapids	WCR321	0.1	Thermal for Gen - min	1.04	Breaker Relay Reduction of Reach - max		15,073		7,607	423	1162	267	21
West Coon Rapids	WCR322	0.7	Primary Over-Voltage - min	6.3	Reverse Power Flow - max		15,073		9,099	423	1162	156	1141
Waconia	WCS062	0.71	Reverse Power Flow - min	0.71	Reverse Power Flow - max		2,341		1,020	9088	16	16	0
Waconia	WCS064	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		2,341		1,602	9088	16	9072	16
Waconia	WCS071	0.9	Thermal for Gen - min	1.78	Reverse Power Flow - max		3,566		2,085	2115	6	18	0
Waconia	WCS072	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		3,566		1,108	2115	6	2098	6
Woodbury	WDY311	0.2	Thermal for Gen - min	1.72	Breaker Relay Reduction of Reach - max		13,959		3,384	232	58	84	39
Woodbury	WDY312	1.5	Thermal for Gen - min	8.9	Reverse Power Flow - max		13,959		9,737	232	58	148	19
Woodbury	WDY321	0.9	Thermal for Gen - min	2.7	Reverse Power Flow - max		10,993		4,214	243	566	41	0
Woodbury	WDY322	3.8	Thermal for Gen - min	6	Reverse Power Flow - max		10,993		7,151	243	566	202	566
West Byron	WEB021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		2,586		2,586	5215	6000	5215	6000
West Faribault	WEF061	0.2	Thermal for Gen - min	1.31	Reverse Power Flow - max		1,923		1,923	18	37	18	37
West Faribault	WEF071	0.46	Unintentional Islanding - min	2.37	Reverse Power Flow - max		2,532		2,532	364	9025	364	9025
West Hastings	WEH021	0.4	Primary Over-Voltage - min	1.32	Reverse Power Flow - max		4,278		2,000	18	0	18	0
West Hastings	WEH022	0.8	Thermal for Gen - min	1.36	Reverse Power Flow - max		4,278		2,103	18	0	0	0
Wells Creek	WEL021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		520		520	1047	3013	1047	3013
Western	WES061	0.6	Thermal for Gen - min	1.57	Reverse Power Flow - max		13,771		2,720	365	921	45	0
Western	WES062	0.8	Thermal for Gen - min	1.34	Reverse Power Flow - max		13,771		2,025	365	921	213	85
Western	WES063	0.3	Primary Over-Voltage - min	0.98	Reverse Power Flow - max		13,771		1,947	365	921	82	0
Western	WES064	0.9	Thermal for Gen - min	1.86	Reverse Power Flow - max		13,771		2,976	365	921	7	173
Western	WES065	0.2	Primary Over-Voltage - min	1.55	Reverse Power Flow - max		13,771		2,891	365	921	18	663
Western	WES071	0.9	Thermal for Gen - min	1.42	Reverse Power Flow - max		15,536		2,010	297	207	9	8
Western	WES072	0.9	Thermal for Gen - min	2.67	Reverse Power Flow - max		15,536		2,864	297	207	51	70
Western	WES073	0.3	Primary Over-Voltage - min	1.76	Reverse Power Flow - max		15,536		2,010	297	207	52	62
Western	WES074	0.5	Thermal for Gen - min	2.35	Reverse Power Flow - max		15,536		2,746	297	207	111	34
Western	WES075	0.9	Thermal for Gen - min	1.51	Reverse Power Flow - max		15,536		2,532	297	207	23	4
Western	WES076	0.5	Thermal for Gen - min	1.6	Reverse Power Flow - max		15,536		2,040	297	207	52	29
Wilson	WIL071	0.9	Thermal for Gen - min	1.62	Reverse Power Flow - max		19,573		1,649	342	325	21	101
Wilson	WIL072	0.7	Thermal for Gen - min	1.53	Reverse Power Flow - max		19,573		2,760	342	325	0	40
Wilson	WIL073	0.9	Thermal for Gen - min	1.78	Reverse Power Flow - max		19,573		1,513	342	325	78	88
Wilson	WIL074	0.9	Thermal for Gen - min	1.29	Reverse Power Flow - max		19,573		1,930	342	325	65	0
Wilson	WIL075	0.9	Thermal for Gen - min	0.95	Reverse Power Flow - max		19,573		1,628	342	325	60	0
Wilson	WIL076	0.18	Unintentional Islanding - min	1.48	Reverse Power Flow - max		19,573		2,102	342	325	23	33

PROTECTED DATA SHADED

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Wilson	WIL077	0	Unintentional Islanding - min	1.24	Reverse Power Flow - max		19,573		1,628	342	325	76	33
Wilson	WIL078	0.9	Thermal for Gen - min	1.2	Reverse Power Flow - max		19,573		1,875	342	325	8	10
Wilson	WIL079	1.4	Primary Over-Voltage - min	1.7	Reverse Power Flow - max		19,573		2,121	342	325	12	19
Wilson	WIL081	1	Thermal for Gen - min	1.69	Reverse Power Flow - max		18,861		2,138	304	167	94	0
Wilson	WIL082	0.7	Thermal for Gen - min	1.42	Reverse Power Flow - max		18,861		1,616	304	167	53	52
Wilson	WIL083	0.6	Thermal for Gen - min	0.82	Reverse Power Flow - max		18,861		1,513	304	167	8	0
Wilson	WIL084	0.6	Thermal for Gen - min	1.67	Reverse Power Flow - max		18,861		1,899	304	167	0	0
Wilson	WIL085	0.14	Unintentional Islanding - min	1.97	Reverse Power Flow - max		18,861		3,324	304	167	63	50
Wilson	WIL086	0.05	Unintentional Islanding - min	1.64	Reverse Power Flow - max		18,861		2,869	304	167	48	43
Wilson	WIL087	0.9	Thermal for Gen - min	1.91	Reverse Power Flow - max		18,861		3,152	304	167	30	0
Wilson	WIL088	0.5	Thermal for Gen - min	0.64	Reverse Power Flow - max		18,861		626	304	167	0	0
Wilson	WIL089	0.9	Thermal for Gen - min	1.89	Reverse Power Flow - max		18,861		3,147	304	167	8	23
Wilson	WIL091	0.9	Thermal for Gen - min	1.24	Reverse Power Flow - max		18,781		1,810	362	694	57	0
Wilson	WIL092	0.9	Thermal for Gen - min	1.44	Reverse Power Flow - max		18,781		1,894	362	694	134	0
Wilson	WIL093	0.9	Thermal for Gen - min	1.33	Reverse Power Flow - max		18,781		1,787	362	694	20	0
Wilson	WIL094	1.44	Reverse Power Flow - min	1.44	Reverse Power Flow - max		18,781		1,582	362	694	0	0
Wilson	WIL095	0.9	Thermal for Gen - min	1.6	Reverse Power Flow - max		18,781		2,977	362	694	0	0
Wilson	WIL096	0.9	Thermal for Gen - min	1.4	Reverse Power Flow - max		18,781		2,470	362	694	35	660
Wilson	WIL097	0.5	Thermal for Gen - min	1.61	Reverse Power Flow - max		18,781		2,105	362	694	81	8
Wilson	WIL098	0.6	Thermal for Gen - min	1.66	Reverse Power Flow - max		18,781		2,480	362	694	35	26
Winona	WIN021	0.1	Primary Over-Voltage - min	0.13	Reverse Power Flow - max		4,342		700	60	10	6	0
Winona	WIN022	0.1	Primary Over-Voltage - min	1.24	Reverse Power Flow - max		4,342		1,709	60	10	12	0
Winona	WIN023	0.1	Thermal for Gen - min	1.17	Reverse Power Flow - max		4,342		1,860	60	10	43	10
Winona	WIN032	0.2	Thermal for Gen - min	1.27	Reverse Power Flow - max		6,637		3,401	69	6	10	0
Winona	WIN033	0.8	Thermal for Gen - min	1.81	Reverse Power Flow - max		6,637		2,720	69	6	59	0
Winona	WIN034	0.1	Thermal for Gen - min	1.74	Reverse Power Flow - max		6,637		2,662	69	6	0	6
Winona	WIN041	0.6	Thermal for Gen - min	1.19	Reverse Power Flow - max		5,523		224	225	22	0	0
Winona	WIN042	0.22	Reverse Power Flow - min	0.22	Reverse Power Flow - max		5,523		2,039	225	22	21	11
Winona	WIN043	0.1	Thermal for Gen - min	1.52	Reverse Power Flow - max		5,523		2,309	225	22	205	11
Watkins	WKN001	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		392		392	801	0	801	0
Wobegon Trail	WOB021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		806		224	4005	1998	4005	1998
Wobegon Trail	WOB022	0.1	Thermal for Gen - min	0.45	Reverse Power Flow - max		806		300	4005	1998	0	0
West River Road	WRR061	1	Thermal for Gen - min	1.38	Reverse Power Flow - max		8,601		1,761	200	75	45	0
West River Road	WRR064	0.9	Thermal for Gen - min	2.41	Reverse Power Flow - max		8,601		2,729	200	75	155	75
West River Road	WRR065	1.1	Thermal for Gen - min	1.85	Reverse Power Flow - max		8,601		0	200	75	0	0
West River Road	WRR074	0.9	Thermal for Gen - min	1.77	Reverse Power Flow - max		10,807		2,721	264	148	0	0
West River Road	WRR075	1.5	Thermal for Gen - min	1.5	Reverse Power Flow - max		10,807		2,579	264	148	264	148
West River Road	WRR081	0.9	Thermal for Gen - min	1.67	Reverse Power Flow - max		8,583		2,225	120	118	0	29
West River Road	WRR084	0.06	Unintentional Islanding - min	0.77	Reverse Power Flow - max		8,583		2,316	120	118	0	66
West River Road	WRR085	0.06	Unintentional Islanding - max	0.77	Reverse Power Flow - max		8,583		1,008	120	118	120	23
Winsted	WSD061	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,300		1,300	7012	0	7012	0
Westgate	WSG061	1.5	Thermal for Gen - min	1.85	Reverse Power Flow - max		11,116		1,649	468	165	31	17
Westgate	WSG062	0.01	Unintentional Islanding - min	1.11	Reverse Power Flow - max		11,116		1,700	468	165	40	100
Westgate	WSG063	1	Primary Over-Voltage - min	1.62	Reverse Power Flow - max		11,116		1,503	468	165	127	31
Westgate	WSG064	0.9	Primary Over-Voltage - min	1.54	Reverse Power Flow - max		11,116		2,400	468	165	27	0
Westgate	WSG065	0.7	Primary Over-Voltage - min	1.45	Reverse Power Flow - max		11,116		2,010	468	165	206	18

PROTECTED DATA SHADED

Substation	Feeder	Minimum Hosting Capacity (MW)	Min Limiting Factor	Maximum Hosting Capacity (MW)	Max Limiting Factor	Substation Transformer Forecasted Peak Load (kVA)	Substation Transformer Minimum Load (kVA)	Feeder 2020 Peak Load (kVA)	Feeder Daytime Minimum Load (kVA)	Substation Transformer Installed DG (kVA)	Substation Transformer Queued DG (kVA)	Feeder Installed DG (kVA)	Feeder Queued DG (kVA)
Westgate	WSG066	0.8	Primary Over-Voltage - min	1.94	Reverse Power Flow - max		11,116		1,513	468	165	37	0
Westgate	WSG071	1	Primary Over-Voltage - min	1.78	Reverse Power Flow - max		9,362		2,138	234	682	121	16
Westgate	WSG072	0.45	Reverse Power Flow - min	0.45	Reverse Power Flow - max		9,362		608	234	682	0	0
Westgate	WSG073	0.52	Reverse Power Flow - min	0.52	Reverse Power Flow - max		9,362		530	234	682	0	0
Westgate	WSG074	0.9	Primary Over-Voltage - min	1.9	Reverse Power Flow - max		9,362		3,415	234	682	50	0
Westgate	WSG075	1.2	Thermal for Gen - min	1.5	Reverse Power Flow - max		9,362		2,202	234	682	13	627
Westgate	WSG076	0.1	Thermal for Gen - min	1.2	Reverse Power Flow - max		9,362		1,334	234	682	50	40
Westgate	WSG351	0.5	Thermal for Gen - min	1.25	Reverse Power Flow - max		4,832		409	187	70	11	0
Westgate	WSG352	0.7	Thermal for Gen - min	2.74	Reverse Power Flow - max		4,832		3,714	187	70	177	70
Westgate	WSG361	0.3	Thermal for Gen - min	2.86	Breaker Relay Reduction of Reach - max		10,072		1,807	123	135	79	128
Westgate	WSG362	0.9	Primary Over-Voltage - min	3.52	Reverse Power Flow - max		10,072		5,295	123	135	44	8
Westport	WSP021	0.06	Reverse Power Flow - min	0.06	Reverse Power Flow - max		73		73	0	0	0	0
West Union	WSU021	0.03	Reverse Power Flow - min	0.03	Reverse Power Flow - max		29		29	0	0	0	0
Watab River	WTB021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		424		424	6081	0	6081	0
Watertown	WTN061	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,525		653	5104	11	5078	11
Watertown	WTN062	0.16	Unintentional Islanding - min	0.92	Reverse Power Flow - max		1,525		1,004	5104	11	26	0
West Waconia	WWK311	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		5,197		5,197	15949	1027	15949	1027
West Waconia	WWK321	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,826		1,826	6044	1049	6044	1049
Wyoming	WYO021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		4,938		2,815	5028	23	20	15
Wyoming	WYO022	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		4,938		2,556	5028	23	5008	8
Wyoming	WYO031	0.8	Thermal for Gen - min	2.27	Reverse Power Flow - max		7,423		2,500	50	25	39	8
Wyoming	WYO032	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		7,423		2,042	50	25	6	8
Wyoming	WYO033	0.33	Unintentional Islanding - min	2.12	Reverse Power Flow - max		7,423		2,476	50	25	4	10
Crossroads	XRD061	0.82	Reverse Power Flow - min	0.82	Reverse Power Flow - max		6,835		2,163	9	553	0	33
Crossroads	XRD062	1	Thermal for Gen - min	1.43	Reverse Power Flow - max		6,835		2,088	9	553	9	11
Crossroads	XRD063	0.9	Thermal for Gen - min	1.63	Reverse Power Flow - max		6,835		2,319	9	553	0	509
Crossroads	XRD075	0.9	Thermal for Gen - min	1.2	Reverse Power Flow - max		6,629		860	181	5	69	0
Crossroads	XRD076	0.05	Unintentional Islanding - min	1.22	Breaker Relay Reduction of Reach - max		6,629		2,602	181	5	78	5
Crossroads	XRD077	0.9	Thermal for Gen - min	1.33	Reverse Power Flow - max		6,629		2,280	181	5	34	0
Young America	YAM021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,163		1,163	4887	18	4887	18
Young America	YAM031	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		1,168		1,168	110	7	110	7
Yellow Medicine	YLM211	0.1	Primary Over-Voltage - min	0.66	Breaker Relay Reduction of Reach - max		1,686		1,185	54	6	36	0
Yellow Medicine	YLM212	0.14	Unintentional Islanding - min	0.46	Reverse Power Flow - max		1,686		589	54	6	18	6
Zumbro Falls	ZUF021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		745		745	4948	1212	4948	1212
Zumbrota	ZUM021	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		2,762		1,176	4145	11246	2041	0
Zumbrota	ZUM022	0	Primary Over-Voltage - min	0	Primary Over-Voltage - max		2,762		1,962	4145	11246	2104	11246

Source	Requirement	Location Requirement Is Addressed
Docket 18-684 8/15/2019 Order		
Order Point 2	2. Regarding data acquisition and display,	
	a. Xcel shall Work with stakeholders to improve the value of Xcel's hosting capacity analysis, including but not limited to the provision of more detailed substation, feeder, and other equipment data in its public-facing hosting capacity map.	Compliance Filing – Section C, Stakeholder Engagement
	b. In spreadsheet format, provide hosting capacity data by substation and feeder, with appropriate disclaimers about the data's accuracy, precision, and timeliness. The data shall include, when available, peak load, daytime minimum load, installed generation capacity, and queued generation capacity.	Attachment B: 2019 HCA Results Attachment A: 2019 HCA Report
	c. Xcel shall provide the same information in its public-facing hosting capacity map, except to the extent that publicly disclosing this data would violate specific data privacy requirements or pose a significant security risk to Xcel's system or its customers. If Xcel withholds any information on this basis, Xcel shall provide the Commission with a full description and specific basis for withholding the information, including any Trade Secret claims.	Compliance Filing – Section D, Customer Privacy and System Security Considerations
	d. Xcel shall make the tracking and updating of actual feeder daytime minimum load a priority in 2019, and include those values in its 2019 hosting capacity analysis.	Attachment A: 2019 HCA Report – Section II, 2019 HCA Methodology, C Assumptions
Order Point 3	3. Regarding the 95 feeders that Xcel identified as having no hosting capacity, Xcel shall:	
	a. Complete an individual analysis of the feeders and available options for increasing their hosting capacity.	Attachment A: 2019 HCA Report – Section V Mitigation, B Study of 95 Feeders with No Hosting Capacity
	b.Provide the following information for each feeder: 1. The frequency at which the constraints to individual feeders occur. 2. The full range of mitigation options for an individual feeder, including DER capabilities, a range of potential costs for each of the mitigation options available, and a range of total costs. 3. The amount of additional hosting capacity that could be obtained by implementing the identified mitigation options on a technical and economic basis (that is, the technical potential of the mitigation options and the economic potential of the mitigation options). 4. Cost-effective mitigation options that might improve the economic viability of DERs, and the size of the financial benefit these options might provide.	Attachment A: 2019 HCA Report – Section V Mitigation, B Study of 95 Feeders with No Hosting Capacity
Order Point 4	4. Xcel shall provide at least one example, using the DRIVE tool to the extent practicable, exploring a feeder's hosting capacity with different locations and levels of generation and load.	Attachment A: 2019 HCA Report – Section VI Other Compliance Items, A Case Study WTN062
Order Point 5	5. Xcel shall provide a complete analysis of the DRIVE tool, including the following:	
	a. Report on the evolving capabilities of the DRIVE tool and whether it is capable of incorporating the technologies included in the broadened definition of DERs, including a discussion of how Xcel's hosting capacity analysis can be used to assist state energy policy goals related to beneficial electrification.	Attachment A: 2019 HCA Report – Section I DRIVE Tool, A DRIVE Features and Evolving Capabilities
	b. A comparison of other methodologies and interconnection study results on a selection of representative feeders, including a discussion of the tools and analyses used by other utilities in other jurisdictions— in particular, Pepco Holdings and other Exelon Corporation utilities.	Attachment A: 2019 HCA Report – Section I DRIVE Tool, B DRIVE Comparison - Other Tools and Other Utilities; Appendix A Summary of Different Hosting Capacity Methods

Source	Requirement	Location Requirement Is Addressed
Order Point 6	6. Xcel shall collaborate with stakeholders in evaluating the costs and benefits associated with a hosting capacity analysis able to achieve the following objectives:	Compliance Filing – Section C Stakeholder Engagement Attachment A: 2019 HCA Report – Section VI Other Compliance Items, D Costs for Integrating Pre-Application Data Requests with the Hosting Capacity Map
	a. Remaining an early indicator of possible locations for interconnection;	See above
	b. Replacing or augmenting initial review screens and/or supplemental review in the interconnection process; and/or	See above
	c. Automating interconnection studies.	See above
Order Point 7	7. In its 2019 Report, Xcel shall include—in addition to the requirements set forth above—the following:	
	a. Updates on the appropriateness of the methodological choice of the hosting capacity analysis, a discussion of Xcel's ability to obtain more detailed secondary voltage equipment data, and the types of DERs being interconnected in future reports.	Attachment A: 2019 HCA Report – Section II 2019 HCA Methodology, A Overview, B Large Centralized Is the Appropriate DER Allocation Method, 1 Secondary Voltage Level Equipment Data
	b. All costs related to the hosting capacity exercise, including the time of Xcel's engineering staff and any efforts Xcel is making to reduce the costs over time.	Attachment A: 2019 HCA Report – Section VI Other Compliance Items, B 2019 HCA Costs
	c. Information on the number of pre-application capacity screens conducted in the previous year, the amount collected for each, and the total amount collected to conduct the pre-application screens, in the previous year.	Attachment A: 2019 HCA Report – Section VI Other Compliance Items, C Pre-Application Data Requests
Order Point 8	8. In future hosting capacity reports, Xcel shall do the following:	
	a. Re-evaluate Xcel's choice to focus its hosting capacity analysis on large centralized DERs rather than smaller ones.	Attachment A: 2019 HCA Report – Section II 2019 HCA Methodology, B Large Centralized Is the Appropriate DER Allocation Method
	b. Discuss Xcel's ability to obtain more detailed data on secondary voltage equipment, and the types of DERs being interconnected to Xcel's system.	Attachment A: 2019 HCA Report – Section II 2019 HCA Methodology, A Overview, B Large Centralized Is the Appropriate DER Allocation Method, 1 Secondary Voltage Level Equipment Data
	c. Continue to consider and address relevant requests from parties.	Compliance Filing – Section C Stakeholder Engagement
	d. Continue to consider and address the requirements from the 2017 Order, 2018 Order, and the current Order.	Compliance Filing Attachment A: 2019 HCA Report
	Requirements from the 2018 Order (Docket 17-777) :	
	2. Xcel's 2018 Hosting Capacity Report must be detailed enough to provide developers with a reliable estimate of the available level of hosting capacity per feeder at the time of submittal of the report to the extent practicable. The information should be sufficient to provide developers with a starting point for interconnection applications.	Attachment B: 2019 HCA Results Attachment A: 2019 HCA Report
	3. Xcel's 2018 Hosting Capacity Report must be detailed enough to inform future distribution system planning efforts and upgrades necessary to facilitate the continued efficient integration of distributed generation.	Attachment A: 2019 HCA Report

Source	Requirement	Location Requirement Is Addressed
	4. Xcel must file a color-coded, map-based representation of the available Hosting Capacity down to the feeder level. This information should be provided to the extent it is consistent with what Xcel believes are legitimate security concerns. If security concerns arise, Xcel must explain in detail the basis for those concerns.	2019 HCA results are presented on a heat map, available publicly online. Compliance Filing – Section D Customer Privacy and System Security Considerations
	5. Xcel must provide the Hosting Capacity results in downloadable, MS-Excel or other spreadsheet file formats.	Attachment B: 2019 HCA Results
	6. Xcel must provide information on the accuracy of the Hosting Capacity Report information; both estimates on the accuracy of the 2018 report and an analysis of the 2017 results compared to actual hosting capacity determined through any interconnection studies or other reasonable metric.	Attachment A: 2019 HCA Report – Section III Accuracy
	7. The Commission hereby requests that Xcel Energy address stakeholder recommendations in the Company's 2018 Hosting Capacity Report filing, including:	
	a. consider the methodological options to both improve and measure accuracy of the hosting capacity analysis, including identification and analysis of industry best practices and an explanation of the Company's methodological choice;	Attachment A: 2019 HCA Report – Section I DRIVE Tool; Section II 2019 HCA Methodology
	b. consider the feasibility and practicality of including the results of both the Small Distributed methodology and the Large Centralized methodology in future hosting capacity analyses;	Attachment A: 2019 HCA Report – Section II 2019 HCA Methodology, B Large Centralized Is the Appropriate DER Allocation Method
	c. conduct a sensitivity analysis;	Attachment A: 2019 HCA Report – Section VI Other Compliance Items
	d. explore a range of options for better presenting the public-facing results of the Hosting Capacity Analysis after consideration of, but not limited to, any security and privacy issues that may be implicated in providing more detailed information and what information might be useful to developers and stakeholders;	Compliance Filing – Section C Stakeholder Engagement; Section D Customer Privacy and System Security Considerations
	e. provide an update in each report on the evolving capability of the EPRI DRIVE tool and whether it is capable of incorporating the technologies included in the broadened definition of DERs;	Attachment A: 2019 HCA Report – Section I DRIVE Tool
	f. file more detailed data on load profile assumptions used in the analysis, including peak load (kW) by substation and feeder; and	Attachment B: 2019 HCA Results Attachment A: 2019 HCA Report – Section II 2019 HCA Methodology, C Assumptions
	g. file supplemental information that would result in a broader understanding of how to guide distribution upgrades for additional hosting capacity.	Attachment A: 2019 HCA Report – Section V Mitigation
	Requirements from the 2017 Order (Docket 15-962):	
	1. The 2017 Hosting Capacity Report must be detailed enough to provide developers with a reliable estimate of the available level of hosting capacity per feeder at the time of submittal of the report to the extent practicable. The information should be sufficient to provide developers with a starting point for interconnection applications.	Attachment A: 2019 HCA Report Attachment B: 2019 HCA Results
	2. The 2017 Hosting Capacity Report must be detailed enough to inform future distribution system planning efforts and upgrades necessary to facilitate the continued efficient integration of distributed generation.	Attachment A: 2019 HCA Report Attachment B: 2019 HCA Results
	3. Xcel shall provide a color-coded, map-based representation of the available Hosting Capacity down to the feeder level. This information should be provided to the extent it is consistent with what Xcel believes are legitimate security concerns. If security concerns arise, Xcel must explain in detail the basis for those concerns.	2019 HCA results are presented on a heat map, available publicly online. Compliance Filing – Section D Customer Privacy and System Security Considerations
	4. Xcel shall provide the Hosting Capacity results in downloadable, MS-Excel or other spreadsheet file formats.	Attachment B: 2019 HCA Results

Source	Requirement	Location Requirement Is Addressed
	5. Xcel shall provide (at minimum) in its next Hosting Capacity Report the information requested by Commission staff and parties in response to the 2016 Report (through comments or information requests) regarding data used in the modeling, including model assumptions and methodology, reasons for the model assumptions and methodological choices, additional detail on the model used and its inherent assumptions.	Attachment A: 2019 HCA Report
	6. Xcel shall provide information on the accuracy of the Hosting Capacity Report information; both estimates on the accuracy of the 2017 report and an analysis of the 2016 results compared to actual hosting capacity determined through any interconnection studies or other reasonable metric.	Attachment A: 2019 HCA Report – Section III Accuracy
	7. Xcel shall file a Hosting Capacity report on an annual basis, by November 1 of each year.	

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Hosting Capacity Analysis Stakeholder Workshop

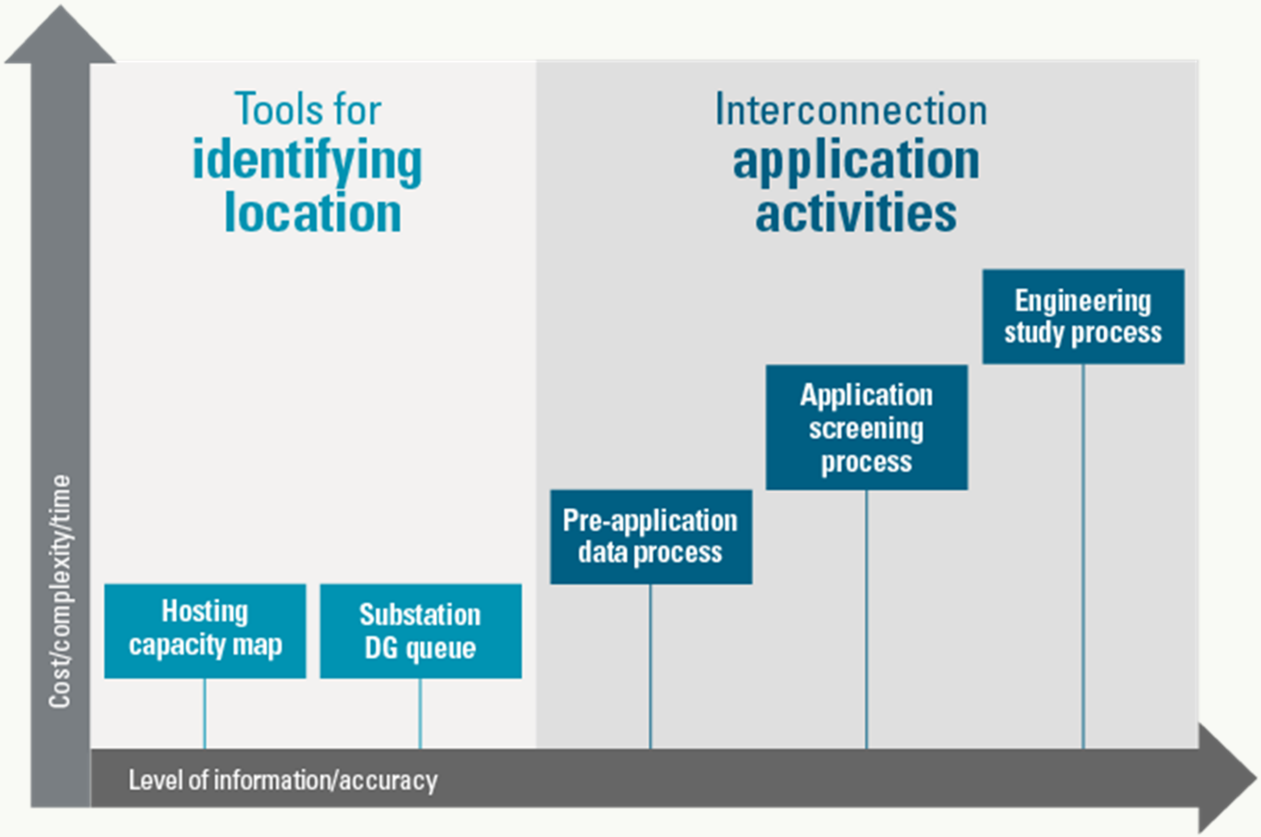
September 6, 2019

Background

- Hosting Capacity is the amount of distributed energy resources (DER) that can be accommodated on the existing system without adversely affecting power quality or reliability under existing control configurations and without requiring infrastructure upgrades. (EPRI)
- A Hosting Capacity Analysis (HCA) evaluates a utility's distribution system to identify locations where DER may be able to interconnect.
- Minn. Stat. § 216B.2425, subd. 8 requires Xcel Energy:

  …to conduct a distribution study to identify interconnection points on its …system for small-scale distributed generation and shall identify necessary distribution upgrades to support the continued development of distributed generation resources…

Current Interconnection Tools – for Reference



Workshop Objectives

- **Discuss Use Cases – Assess Costs and Benefits**
  - Remain an early indicator of possible locations for interconnection
    - *How can we improve the value of the Hosting Capacity Analysis through provision of additional information?*
  - Replace or augment initial review screens and/or supplemental review in the interconnection process
  - Automate interconnection studies

Note: Discussion is intended to be conceptual and exploratory. There may be technical feasibility, economic, and/or customer privacy and/or customer and grid security implications or issues associated with proposed changes to the current hosting capacity analysis

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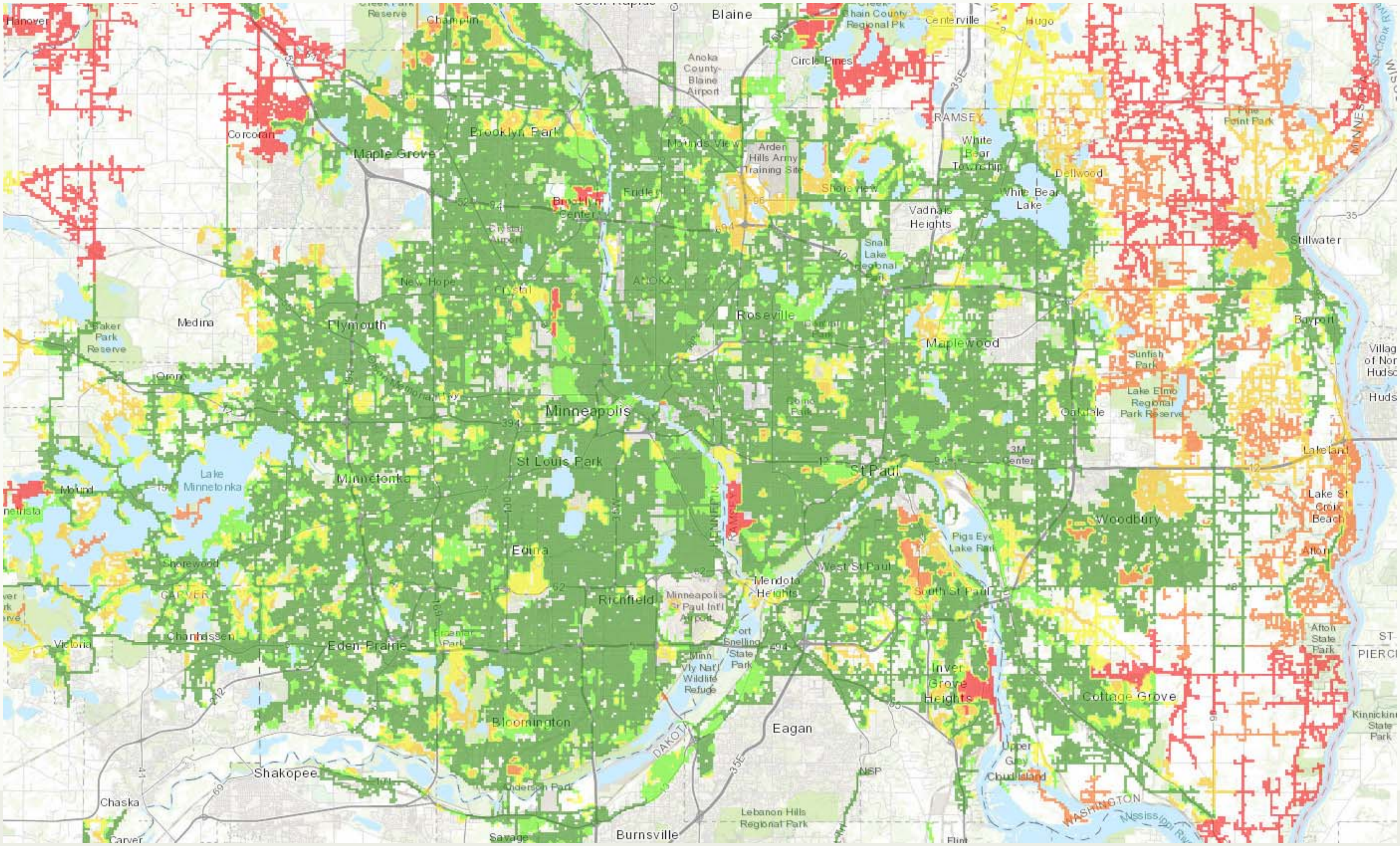
Current State – Hosting Capacity Heat Map



If we started from scratch…

Goal: Identify potential interconnection points on our system for small-scale distributed generation

- **Describe your ideal tool or set of information**
  - What data/information
    - Why/how would you use it?
  - How would it be presented?
  - How would you access it?
  - When/at what point in your process would it be ideal? Absolutely necessary?

Use Case Considerations

Assess Costs and Benefits

Order Requirement: Discuss Use Cases and Assess Costs and Benefits

1- Remain an early indicator of possible locations for interconnection

Specific question: *Of the information we have discussed adding or replacing the current heat map, what is most important/highest priority to you for this purpose?*

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Order Requirement: Discuss Use Cases and Assess Costs and Benefits

2 – Replace or augment initial review screens and/or supplemental review in the interconnection process

Specific question: *Can the map provide results that match the interconnection screens and include the information currently provided by Xcel's pre-application report?*

Specific question: *What is your preference:*

1- provide more pre-application data upfront, or

2- keep the HCA map, but have it also include the pre-application data?

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Order Requirement: Discuss Use Cases and Assess Costs and Benefits

3 – Automate interconnection studies

Specific question: *Can the HCA replace the interconnection screens and streamline Xcel's interconnection?*

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Assess Value of Additional Information

Specific Suggestions

Additional Information to Improve Value – Heat Map Suggestions from Comments

- Substation location
- Additional substation information: Total MVA, existing DG on substation, DG in queue.
- Substation transformer capacity would be more valuable to a developer then the feeder capacity. The value of the map would be enhanced if it showed:
  - Transformer capacity
  - Minimum daytime load
  - DG installed
  - DG in queue
- Include solar gardens that are underway but not yet in-service. If a project has a signed Interconnection Agreement, the hosting capacity has been claimed by that project and its standing in the queue.

Additional Information to Improve Value – Heat Map Suggestions from Comments (cont'd)

- More detailed feeder data
  - The specific capacity available per feeder
- Map the location/area served of that feeder in a distinguishable way
- If upgrades <$100k where included to show as having capacity
- More detailed other equipment data
- The map would be more useful if it were in a .KMZ format
  - So that it could be integrated into other software to include parcel data, wetlands, etc.
  - Also, the different colors on the map are difficult for color blind people distinguish.
  - If the map were in .KMZ format we could filter the layers by capacity.

Additional Information – General Suggestions

- More frequent updates
  - Physical equipment (transformer/conductors/etc.) updated more often
  - Update capacity annually based on changes in load and whenever a new proposed project is added to that feeder.
- Peak load data by substation and feeder in spreadsheet format with the tabular results.
- Constraint information
  - Range of potential costs for each of the mitigation options available for an individual feeder and
  - A range of total costs of all mitigations on an individual feeder
  - How much additional hosting capacity could be obtained by implementing the identified mitigation options

How Important?

- To have load DER (storage, EVs) factored into the analysis results
- The availability of actual daytime minimum load information
- Include advanced inverter functionality in the model results
- Include the secondary portions of the system in the analysis (for potential rooftop installations)

Xcel Energy conducts an annual hosting capacity analysis that provides a high level estimate of the available hosting capacity for adding distribution generation. The intent for this analysis is that it serves as a starting point for interconnections. We want to hear from you how we may be able to provide additional value to our interconnection customers through further hosting capacity functionalities. Your feedback as to how you would use potential additional hosting capacity information and the value it provides to you and your customers is essential to our examination of this interconnection tool.

What are your primary considerations in choosing where to site distributed generation?

Which interconnection types does your company work on? Select all that apply.

- ☐ Community Solar Gardens
- ☐ Rooftop Solar
- ☐ Wind
- ☐ Batteries
- ☐ Other (please specify)

Have you viewed or used Xcel Energy's Hosting Capacity heat map?

- ○ Yes
- ○ No

Have you viewed or used Xcel Energy's Hosting Capacity tabular report?

- ○ Yes
- ○ No

Is it important to you to add the pre-application data to the yearly analysis of hosting capacity?

- ○ Yes
- ○ No

During our September 6, 2019 Workshop regarding Hosting Capacity, the Company received feedback to include the following additional capabilities as part of the Hosting Capacity website. Please select the most important capability in siting your DER interconnection:

- Voltage regulation - location & number of
- Service territory lines (Overlay)
- Existing constraints
- Feeder details (name, location, available capacity)
- Line Build - overhead & underground
- Conductors
- Point of interconnection details (voltage at PCC, line phasing)
- Protective devices and regulators between site and substation
- Substation detail (name, location, ratings, available transformer capacity)
- DER currently in queue (nameplate capacity)
- List of feeders at/near capacity
- Loading characteristics (minimum and maximum load)
- DER installed (online and active)
- Other (please specify)

If you were installing a rural community solar garden versus a rooftop solar (garden or small scale), would you answer these rankings differently? How?

During our September 6, 2019 Workshop, the Company received feedback to change the functionality of the Hosting Capacity process. Please rank the FIVE most important of these changes in siting your DER interconnections.

- On screen display of key data points
- More frequent Heat Map updates (monthly)
- More frequent Heat Map updates (quarterly)
- Notes fields (e.g., Feeder is near capacity, Limiting Factor such as Voltage Fluctuation)
- Nodal data (Note: approx. 4,000 nodes per Feeder)
- Provide more defined lines by color rather than a Heat Map
- Application Interface Access (API) capabilities

- [ ] Combine pre-application and hosting capacity information
- [ ] Other (please specify) ____________

If you were installing a rural community solar garden versus a rooftop solar (garden or small scale) would you answer these rankings differently? How?

If these details were implemented, how would it help your company? Select all that apply

- [ ] Remove the need for a pre-application report
- [ ] Reduce the interconnection application cost
- [ ] Reduced interconnection study costs
- [ ] Reduced time committed to review unsuited sites (e.g., no capacity or high interconnection cost potential)
- [ ] Reduced standard cost as a result of the interconnection application process
- [ ] Other (please specify) ____________

If you could get pre-application report information by clicking on the Hosting Capacity map, would you be willing to pay for this capability?

- ○ Yes
- ○ No

Would these additional capabilities reduce your cost to interconnect to Xcel Energy's system?

- ○ Yes
- ○ No

Are you willing to provide further context or information regarding your thoughts on hosting capacity? If so, please provide your name and contact information.

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 08-08-009 (Filed August 21, 2008))

JOINT PETITION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E), AND SOUTHERN CALIFORNIA EDISON COMPANY (U 338 E) FOR MODIFICATION OF D.10-12-048 AND RESOLUTION E-4414 TO PROTECT THE PHYSICAL SECURITY AND CYBERSECURITY OF ELECTRIC DISTRIBUTION AND TRANSMISSION FACILITIES

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December 10, 2018

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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JOINT PETITION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E), AND SOUTHERN CALIFORNIA EDISON COMPANY (U 338 E) FOR MODIFICATION OF D.10-12-048 AND RESOLUTION E-4414 TO PROTECT THE PHYSICAL SECURITY AND CYBERSECURITY OF ELECTRIC DISTRIBUTION AND TRANSMISSION FACILITIES

Pursuant to Rule 16.4 of the Rules of Practice and Procedure of the California Public Utilities Commission ("CPUC" or "Commission"), Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company (collectively, "Joint IOUs") hereby respectfully submit this Petition for Modification ("Petition") of Decision ("D.") 10-12-048 and Resolution E-4414.[1] This Petition is submitted in compliance with the Commission's legal authority and responsibility to regulate and supervise the safety, reliability, physical security and cybersecurity of public utility electricity service pursuant to Sections 451, 364 and 761 of the Public Utilities Code.[2] This Petition also is submitted in compliance with the findings and guidance provided by the July 24 and October 9, 2018, Administrative Law Judge's ("ALJ") Rulings in R.14-08-013, *et al*.[3] The facts stated in this Petition are supported by the

[1] Counsel for SCE and SDG&E have authorized PG&E to file this Petition for Modification on their behalf. This Petition for Modification is being served in the above-captioned proceedings, as well as the related proceedings R.14-08-013, *et al*. and R.15-06-009.

[2] Pursuant to Rule 16.4, this Petition could not have been filed within a year of the decision and resolution sought to be modified, because cybersecurity and physical security threats that this Petition seeks to mitigate did not exist at that time at the level of severity and danger that exist today, including as identified in Commission proceedings such as R.15-06-009.

[3] *Administrative Law Judge's Ruling Addressing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company's Claims for Confidential Treatment and Redaction of Distribution System Planning Data Ordered by Decisions 17-09-026 and 18-02-004* ("July 24 ALJ Ruling"),R.14-08-013, *et al*., July 24, 2018; *Administrative Law Judge's Ruling Regarding Photo Voltaic Renewable Auction Mechanism Maps* ("October 9 ALJ Ruling"), R.14-08-013, et al., October 9, 2018.

attached sworn declarations of Bernard A. Cowens and William C. Sauntry, based on their expertise, experience and knowledge of the potential cyber- and physical-security threats to the safety and reliability of the Joint IOUs' electric distribution and transmission facilities.

I. INTRODUCTION

For the reasons discussed below, in order to protect the Joint IOUs' electric distribution and transmission facilities from potential physical security and cybersecurity attacks, D.10-12-048 and Resolution E-4414 should be modified to authorize the Joint IOUs to require that access to their Photo Voltaic Renewable Auction Mechanism Maps ("PV RAM Maps") be limited to entities and individuals which demonstrate a (1) "need to know" the data contained on the maps (2) demonstrate an adequate level of ability to protect the data using proposed standards approved by the Commission and (3) which execute and agree to an appropriate Non-Disclosure Agreement ("NDA").[4] The dissemination of this data to the public as currently required by D.10-12-048 and Resolution E-4414 presents a serious risk to public safety and security.

In addition, unrestricted access to this data conflicts with the physical and cyber security findings in the July 24, 2018, ALJ Ruling on Critical Energy Infrastructure Information ("CEII") data redaction criteria in the Commission's Distributed Resources Plan (DRP) rulemaking, R.14-08-013, as well as the California Legislature's direction to the Commission in Public Utilities Code Section 364 to consider adopting standards to protect the physical security of the electric utility distribution systems.[5]

II. BACKGROUND

The following background is taken primarily from the findings and legal conclusions of the July 24 and October 9, 2018, ALJ Rulings in the data redaction phase of the Commission's

[4] These modifications are consistent with the standards and protocols proposed by the Joint IOUs for the same physical security and cybersecurity sensitive data required to be made available through the Data Access Portals ordered in the Distribution Resources Plan (DRP) proceeding, R.14-08-013.

[5] July 24 ALJ Ruling, pp. 13- 21; Public Utilities Code Section 364(a).

Distribution Resources Plan ("DRP") proceeding, R.14-08-013, and the Commission's Physical Security Rulemaking proceeding, R.15-06-009.[6].

In 2010 and 2011, nearly eight years ago, the Commission issued D.10-12-048 (*Decision Adopting the Renewable Auction Mechanism)* and Resolution E-4414, implementing the Renewable Auction Mechanism ("RAM") for procurement of renewable energy resources by the Joint IOUs. One element of the RAM addressed by the Commission in D.10-12-048 was the availability to distributed generators of PV RAM maps which displayed the Joint IOUs' physical electric distribution and transmission facilities. D.10-12-048 "anticipate[d] that each IOU will, over time, provide system-wide information," and instructed that "IOUs should eventually provide reasonable data on all areas, and let developers, along with IOUs and other stakeholders, decide if it makes sense to interconnect at various locations."[7] D.10-12-048 determined that the PV RAM Maps must provide data at the substation or circuit level. (Conclusions of Law 44 and 46; and Appendix A: Summary of Adopted Program at 5.) However, D.10-12-048 did not require that the PV RAM maps be made available to the public.

In August 2011, the Commission issued Resolution E-4414, implementing D.10-12-048. The Resolution rejected the IOUs' security concerns about publication of the PV RAM maps, and instead ordered as follows that the PV RAM maps be made public without any restrictions and without the need for execution of an NDA by third parties or the public accessing the maps:

> *25. The Investor-owned utilities shall post publicly by March 31, 2012 updated maps that cover their service territory, including both the distribution and transmission system.*
>
> *26. The investor-owned utilities may require developers to register in order to access the interconnection maps as an alternative to signing a non-disclosure agreement. The investor-owned utilities shall not require signing a non-disclosure agreement to access the interconnection maps.*[8]

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[6] These proceedings were initiated by the Commission several years after D.10-12-048 and Resolution E-4414.

[7] D.10-12-048, pp. 71- 72.

[8] Resolution E-4414, Ordering Paragraphs 25 and 26, p. 47.

In June 2015, nearly four years after issuance of Resolution E-4414, the Commission approved Order Instituting Rulemaking (R.) 15-06-009 to establish policies, procedures, and rules for the regulation of physical security risks to the electric distribution facilities of electrical corporations. The Commission opened R.15-06-009 in compliance with Pub. Util. Code § 364(a) which states:

> *The commission shall adopt inspection, maintenance, repair, and replacement standards, and shall, in a new proceeding, or new phase of an existing proceeding, to commence on or before July 1, 2015, consider adopting rules to address the physical security risks to the distribution systems of electrical corporations. The standards or rules, which shall be prescriptive or performance based, or both, and may be based on risk management, as appropriate, for each substantial type of distribution equipment or facility, shall provide for high-quality, safe, and reliable service.*[9]

R.15-06-009 also reflects the Commission's high priority need to protect critical energy infrastructure information ("CEII") from physical and/or cyber security attack or infiltration.[10] The *Assigned Commissioner's Phase I Scoping Memo and Ruling* in R.15-06-009 dated March 10, 2017, identified several issues for resolution, including:

> *What new rules or standards or modifications to existing policies should the Commission consider to allow for adequate disclosure of information to the public without disclosing sensitive information that could pose a physical security risk or threat if disclosed?*[11]

To date, the Commission has not adopted a decision in R.15-06-009 that addresses the physical security issues required to be addressed by Public Utilities Code Section 364, but recently issued a proposed decision which would adopt the same categories of CEII as identified by the July 24 ALJ Ruling in this proceeding, and would require that information regarding the utilities' physical-security-sensitive electric distribution facilities be kept confidential until the utilities' physical security plans are finalized and the Commission adopts new confidentiality criteria.[12]

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[9] July 24 ALJ Ruling, p. 17, citing Pub. Util. Code § 364(a).

[10] *Id*., pp. 16- 17.

[11] *Id*, p. 17, citing *Assigned Commissioner's Phase I Scoping Memo and Ruling,* R.15-06-009, March 10, 2017.

[12] *Phase I Decision on Order Instituting Rulemaking Regarding the Physical Security of Electrical Corporations*, R.15-06-009, November 9, 2018, pp. 24, 36- 37, 39.

In parallel with R.15-06-009, the Commission's DRP proceeding, R.14-0-013, has evaluated the new tools, data and on-line maps for distributed energy resources ("DERs") and the IOUs to optimize the integration of DERs onto the IOUs' electric distribution grids. D.17-09-026 in the DRP proceeding requires the IOUs to implement an approved Integrated Capacity Analysis ("ICA") methodology, and Locational Net Benefit Analysis ("LNBA") methodology on a system-wide basis that replace the PV RAM maps by making certain data available to the public via an online map and/or data portal.[13] D.18-02-004 recognized the need to protect the physical and cyber security of the new DRP maps and data, and ordered the IOUs to file Tier 2 advice letters that proposed DRP data redaction criteria that ensure the physical and cyber security of the electric system and reflect the customer privacy provisions established by the Commission previously in Decision (D.) 14-05-016.[14]

In June 2018, the IOUs filed their separate proposals to redact security- and privacy-sensitive data from their ICA/LNBA maps and associated DRP data portals. The IOUs proposed to redact, among other things, (1) individual customer energy usage; (2) Facility Identification (Facility ID); (3) Critical Energy Infrastructure Information ("CEII"); and (4) market sensitive information. On July 24, 2018, the ALJ in the DRP proceeding issued his ruling on the IOUs' data redaction proposals, largely approving the IOUs' customer privacy redaction criteria, but adopting separate criteria for protecting CEII. In his ruling on CEII, the ALJ summarized national and California priorities for protecting CEII and preventing physical and cyber attacks on the IOUs' electric infrastructure:

> *[I]t is necessary that I discuss and acknowledge the importance that both the Federal Government and this Commission have placed on the need to ensure safeguards are in place to protect CEII data categories and data subcategories against physical and/or cyber security attacks. This background information will also help ensure that no aspect of this Ruling conflicts with the laws already promulgated to protect CEII. Following the domestic terrorist attack on September 11, 2001, the Federal Energy Regulatory Commission (FERC) began to take steps to protect information that was considered CEII. On February 21,*

[13] July 24 ALJ Ruling, p. 3, citing D.17-09-026.

[14] July 24 ALJ Ruling, pp. 3- 4, citing D.18-02-004; see also, D.18-02-004, pp. 40- 41, 61; p. 84, Ordering Paragraph 2.g.

2003, FERC issued a final rule amending its regulations to establish procedures for protecting and accessing CEII, which it defined as information that:
Relates details about the production, generation, transportation, transmission, or distribution of energy;
Could be useful to a person in planning an attack on critical infrastructure;
Is exempt from mandatory disclosure under the Federal Freedom of Information Act (5 U.S.C. § 552); and
Does not simply give the general location of the critical infrastructure.

On December 4, 2015, President Obama signed the Fixing America's Surface Transportation (FAST) Act into law. Although the FAST Act is a federal transit spending law, it also added section 215A to the Federal Power Act (FPA) to improve the security and resilience of energy infrastructure in the face of emergencies.

On November 17, 2016, FERC issued Order No. 833, which amended its CEII Regulations to implement the provisions of the FAST Act that pertain to the designation, protection, and sharing of CEII. FPA, Section 215(d)(2), required FERC to promulgate regulations necessary to establish criteria and procedures to designate information as CEII.26 FPA, Section 215A(a)(3), defined CEII as follows:

"Information related to critical electric infrastructure, or proposed critical electrical infrastructure, generated by or provided to the Commission or other Federal agency other than classified national security information, that is designated as critical electric infrastructure information by the Commission or the Secretary of the Department of Energy pursuant to subsection (d). Such term includes information that qualifies as critical energy infrastructure information under the Commission's regulations."

Other amendments of note that are relevant to this proceeding is that the new CEII regulations:

Provide a process for requesting CEII treatment of information;
Provide an administrative appeals process to challenge CEII designations or disclosures; and
Provide a process for the public to request access to CEII by submitting a detailed statement of need and executing a NDA.

But FERC is not the only federal agency tasked with protecting CEII. Homeland Security Presidential Directive 7 (December 17, 2003) established a national policy for federal departments and agencies to identify and prioritize United States critical infrastructure and key resources, and to protect them from terrorist attacks. Critical infrastructure was defined as follows:

"The term 'critical infrastructure' has the meaning provided in section 1016(e) of the USA Patriot Act of 2001 (42 U.S.C. § 5195c(e)), namely systems and assets, whether physical or virtual, so vital to the United States that the incapacity or destruction of such systems and assets would have a debilitating impact on security, national economic security, national public health or safety, or any combination of those matters."

The Department of Homeland Security (DHS) is the agency responsible for coordinating the overall national effort. Presidential Policy Directive 21

> *(February 12, 2013) superseded Homeland Security Presidential Directive 7 and identified 16 critical infrastructure sectors (one of which includes energy) "whose assets, systems, and networks, whether physical or virtual, are considered so vital to the United States that their incapacitation or destruction would have a debilitating effect on security, national economic security, national public health or safety, or any combination thereof."*
>
> *I highlight these regulations and directives from FERC and DHS as they underscore the United States' strong public policy to protect CEII against physical and/or cyber security attacks, and any ruling from this Commission must be cognizant of that policy. The regulations and directives from FERC and DHS also aid our understanding of the scope of CEII, and provide guidance to the Commission in developing a ruling that adopts consistent criteria for determining CEII, safeguarding information from physical and/or cyber security attacks, and providing a process for stakeholders to request access to redacted CEII.*[15]

Based on "the overriding objective to any CEII redaction to prevent the public dissemination of information that could constitute a physical and/or cyber security risk,"[16] the ALJ then authorized the IOUs to apply the following data redaction criteria to protect CEII from unauthorized disclosure in their DRP maps and data portals, including maps and data related to their ICA, LNBA, Grid Needs Assessments, and Distribution Deferral Opportunity Reports:

> *[E]ach IOU that wishes to redact CEII from the public version of the DRP maps [must] demonstrate that the redacted information fits within one or more of the following examples:*
>
> *(1) Distribution Facility necessary for crank path, black start, or capability essential to the restoration of regional electricity service that are not subject to the California Independent System Operator's operational control and/or subject to North American Electric Reliability Corporation Reliability Standard CIP-014-2 or its successors;*
>
> *(2) Distribution Facility that is the primary source of electrical service to a military installation essential to national security and/or emergency response services (may include certain air fields, command centers, weapons stations, emergency supply depots);*
>
> *(3) Distribution Facility that serves installations necessary for the provision of regional drinking water supplies and wastewater services (may include certain aqueducts, well fields, groundwater pumps, and treatment plants);*
>
> *(4) Distribution Facility that serves a regional public safety establishment (may include County Emergency Operations Centers; county sheriff's department and major city police department headquarters; major state and county fire service headquarters; county jails and state and federal prisons; and 911 dispatch centers);*

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[15] July 24 ALJ Ruling, pp.13- 16.

[16] *Id.*, p.20.

> *(5) Distribution Facility that serves a major transportation facility (may include International Airport, Mega Seaport, other air traffic control center, and international border crossing);*
>
> *(6) Distribution Facility that serves as a Level 1 Trauma Center as designated by the Office of Statewide Health Planning and Development; and*
>
> *(7) Distribution Facility that serves over 60,000 meters.*[17]

The ALJ Ruling also required that third-parties requesting access to the CEII data file a formal motion with the Commission "demonstrating the specific information needed, why that information cannot be obtained from another source, and how the information will be used."[18] If the motion is approved, the third party must execute and agree to an NDA such as the Model NDA expressly approved by the Commission to protect customer privacy in D.14-05-016.[19]

Subsequent to the July 24, 2014, ALJ Ruling, PG&E and SCE sought clarification of how the CEII data redaction criteria should be implemented, including preventing disclosure of partially redacted maps and data that would, by omission of the CEII, indirectly disclose the physical location-specific CEII to the public and unauthorized "bad actors."[20] The Joint IOUs also were granted an extension to December 31, 2018 to implement the new DRP datasets and Data Access Portal in compliance with the data redaction criteria.[21]

Because the existing PV RAM maps and data sets disclosed to the public without restriction the same physical location-specific data about the Joint IOUs' electric distribution and transmission facilities that the July 24, 2018, ALJ Ruling authorized to be redacted, the Joint

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[17] *Id.*, pp.20- 21.

[18] *Id.*, p. 21.

[19] *Id.*

[20] *Joint Motion of Pacific Gas and Electric Company (U 39 E) and Southern California Edison Company (U 338 E) for Public Workshop and Opportunity for Stakeholder Comments Prior to Implementation of Administrative Law Judge's July 24, 2018, Ruling Adopting Data Redaction Criteria*, R.14-08-013 et.al, August 24, 2018.

[21] Alice Stebbins, Executive Director, letter to Laura Genao, Southern California Edison, August 31, 2018.

IOUs also immediately restricted access to the PV RAM maps and datasets, based on the assumption that the ALJ Ruling applied to the PV RAM maps and dataset that were in any event required to be integrated with the DRP datasets and Data Access Portal. However, on October 9, 2018, the ALJ in the DRP proceeding issued a second ruling, finding that the IOUs lacked legal authority to protect the CEII in the existing PV RAM maps from unauthorized disclosure, because the data in the PV RAM maps was authorized to be disclosed to the public without restriction in the Commission's 2010 and 2011 PV RAM decision and resolution.[22] The October 9, 2018, ALJ Ruling reasoned as follows:

> *The IOUs should not have taken the PV RAM Maps down from public view and then shifted them to a confidential portal, as my July 24, 2018 Ruling did not give the IOUs the authority to countermand a prior Commission decision that the PV RAM Maps be made public. Since the requirement to make the PV RAM Maps publicly available was done through a Commission decision, the IOUs must continue to comply with same and pursue alternative remedies, such as a petition for modification pursuant to Rule 16.4 of the Commission's Rules of Practice and Procedure, to be relieved from this requirement.*
>
> *The parameters surrounding requirement that PV MAP Maps be publicly available were also addressed in Resolution E-4414. Issued on August 22, 2011, Resolution E-4414, at 47, contained the following three Ordering Paragraphs relevant to this issue:*
>
> *"24. In its renewable auction mechanism map, Southern California Edison Company shall provide the available capacity at the substation or circuit level for its preferred locations within 30 days of this resolution."*
>
> *"25. The Investor-owned utilities shall post publicly by March 31, 2012 updated maps that cover their service territory, including both the distribution and transmission system."*
>
> *"26. The investor-owned utilities may require developers to register in order to access the interconnection maps as an alternative to signing a non-disclosure agreement. The investor-owned utilities shall not require signing a non-disclosure agreement to access the interconnection maps."*
>
> *My July 24, 2018 Ruling did not address, nor could it reverse, a resolution that the Commissioners adopted.*[23]

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[22] October 9 ALJ Ruling, Ordering Paragraphs 1 and 2.

[23] *Id.*, pp. 3- 4.

Based on this background and in particular the guidance provided by the ALJ in his July 24 and October 9, 2018, Rulings in the DRP proceeding, the Joint IOUs file this Petition in order to apply CEII and security-sensitive data redaction criteria consistently to their Data Access Portals, containing both DRP and PV RAM data sets, in order to protect the Joint IOUs' electric distribution and transmission facilities from physical and cyber attacks.

III. PUBLIC RELEASE OF THE PV RAM MAPS PRESENTS AN UNJUSTIFIABLE AND SERIOUS RISK TO PUBLIC SAFETY AND SECURITY. D.10-12-048 AND RESOLUTION E-4414 SHOULD BE MODIFIED TO PROTECT PHYSICAL SECURITY AND CYBERSECURITY CONSISTENT WITH THE FINDINGS AND REQUIREMENTS APPLICABLE TO CRITICAL ENERGY INFRASTRUCTURE INFORMATION IN THIS PROCEEDING.

As demonstrated in the attached declarations of Bernard A. Cowens and William C. Sauntry, the physical location, attributes and configuration of the Joint IOUs' electric distribution substations, circuits and feeders, as well as those of related transmission facilities currently disclosed on the IOUs' PV RAM maps, can be used by a "bad actor" to commit a physical or cyber attack on utility facilities. Such an attack could lead to outages to tens of thousands of utility customers and critical energy facilities and infrastructure, catastrophic and costly damage to the Joint IOUs' ability to provide electricity service, theft and misuse of critical energy infrastructure information, and damage to the national security of the United States. The information on the PV RAM maps includes the same information determined by the July 24, 2018, ALJ Ruling in the DRP proceeding to be Critical Energy Infrastructure Information (CEII) that needs protection against public and unauthorized disclosure.

Although the increased risk or scale of potential disruption due to public and unauthorized access to the PV RAM maps is not quantifiable, evidence of suspicious and unknown actors accessing the maps indicates a level of risk that needs to be mitigated, to reduce the risk of even a "low probability, high magnitude" cyber or physical attack. The national security policies and standards described in the July 24, 2018, ALJ Ruling, as well as the clear direction provided to the Commission by the California Legislature in Public Utilities Code Section 364, emphasize the extreme importance of protecting the Joint IOUs' electric distribution and transmission facilities against the unauthorized disclosure of CEII that could lead to a catastrophic physical or cyber attack.

The PV RAM maps clearly lay out the electrical connectivity configuration of both the electric distribution and electric transmission grids. This information could allow a "bad actor" to identify which lines extend to specific substations and/or critical customer facilities. Knowing these routes and potential backup power supply routes can help "bad actors" coordinate specific targeted attacks for increased impact.

A commonly invoked justification for making Joint IOUs' information public is that "this information is already available on Google Maps," or similar third-party mapping software. Not so: while certain specific distribution and transmission assets may be identifiable through physical views and public non-utility on-line maps, it is difficult if not infeasible to piece together from these sources a digital connectivity map in one full map such as the ones proposed to be made public. In addition, the PV RAM data sets provide the locations of underground electric infrastructure which are not visible on non-utility public maps.

The unrestricted dissemination of information providing the location of a utility's major loads, substations, and distribution and transmission facilities serving those loads renders the grid unnecessarily vulnerable. If one or more substations serving major loads or large geographical areas were attacked, it could result in a wide scale outage for a prolonged period. Massive power outages caused by an attack on significant substations or other distribution facilities could disrupt the economy and countless industries, halt transportation, impede emergency services and responders, cause shortages of food, water and other essential supplies, distract from and hinder the ability to respond to a simultaneous attack elsewhere.

Events that have occurred and policies that have been adopted in the eight years since D.10-12-048 and Resolution E-4414 make clear that unrestricted public access to the PV RAM maps is in dangerous conflict with California's and the nation's priorities for protecting the electric grid from attacks, both physical and cyber.[24] For these reasons, D.10-12-048 and Resolution E-4414 must be modified to apply consistent protection of the CEII disclosed in the PV RAM maps from unauthorized disclosure. The findings and rulings on CEII in the DRP proceeding provide the "roadmap" for bringing the PV RAM maps and data sets up to the same standards applicable to the DRP maps and data portals which will replace the PV RAM maps.

IV. CONSISTENT WITH THE DATA REDACTION CRITERIA APPROVED FOR THE DRP MAPS THAT WILL REPLACE THE PV RAM MAPS PURSUANT TO D.17-09-026, ACCESS TO THE PV RAM MAPS CAN BE PROVIDED TO DISTRIBUTED ENERGY RESOURCE PROVIDERS AND OTHER PARTIES ON A "NEED TO KNOW" BASIS WITH A REASONABLE NON-DISCLOSURE AGREEMENT.

The CEII data redaction criteria adopted by the ALJ in the DRP proceeding provides DERs and other stakeholders with access to CEII data through a two-step process common to third-party access to confidential data in CPUC proceedings and other "security-sensitive" venues. First, the stakeholder seeking access must identify themselves and demonstrate a "need to know" the CEII to accomplish a particular objective, such as optimizing the location of their DER projects as provided in the CPUC's DRP proceeding. Second, once the stakeholder demonstrates their "need to know," they execute a reasonable NDA to contractually commit to protect the confidentiality and security of the CEII they are accessing for the limited purpose they have identified.

Some stakeholders may protest that this two-step process is "burdensome" or "inconvenient," or that an NDA is unnecessary, but the process is not new. It is routinely utilized for interested parties to access confidential or sensitive information in CPUC proceedings, and it is the Commission-approved process for stakeholders to access private, customer-specific information under the Commission's customer privacy rules.[25] The California

[24] See *Phase I Decision on Order Instituting Rulemaking Regarding the Physical Security of Electrical Corporations*, R.15-06-009, November 9, 2018, pp. 3- 10.

[25] CPUC Rule 11.4, *Motion for Leave to File Under Seal*; D.14-05-016, Attachment B, Model Non-Disclosure Agreement.

Independent System Operator correctly treats distribution and transmission planning data as CEII, places it behind a secured web portal, and requires parties who have a business reason to access such information to execute an NDA.[26] In the Commission's own DRP proceeding, it is the process by which interested parties may participate in the Distribution Planning Advisory Group (DPAG), members of which access confidential information included in the IOUs' distribution planning processes.

The Joint IOUs support the ALJ Ruling's two-step process to provide stakeholder access to the CEII and security-sensitive data on the PV RAM and successor DRP maps and underlying data. However, the Joint IOUs also appreciate that DERs and other stakeholders want the most convenient, streamlined process for accessing the CEII and security-sensitive data where they have demonstrated a "need to know" and agree to sign an appropriate NDA. To that end, the Joint IOUs propose the following registration and access process for expedited two-step access to the CEII information:

1. Each stakeholder would request access to the Data Access Portal by providing information sufficient to validate the identity of the requestor, along with the reason for requesting access and intended use of the CEII and security-sensitive data and map.

2. If (i) the identity of the stakeholder can be validated, and (ii) that stakeholder has demonstrated sufficient ability to protect the data using standards that Joint IOUs propose be developed and approved by the Commission and (iii) their reason for requesting access meets the objective "need to know" criteria approved in advance by the Commission, then the utility would provide the stakeholder with an NDA. Once the NDA is executed, the stakeholder would be authorized to access the CEII and security-sensitive data using an appropriate authentication,

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[26] See CAISO Non-Disclosure and Use of Information Agreement for Transmission Planning Data, available at https://www.caiso.com/Documents/RegionalTransmissionNon_DisclosureAgreement.pdf

such as user name and password.

The July 24, 2018, ALJ Ruling in the DRP proceeding recommended that the form of NDA used for access to the DRP maps and CEII data be comparable to the Model NDA approved by the Commission in D.14-05-014. The Joint IOUs also support this recommendation but suggest using the DRP DPAG NDA as the model for the NDA for CEII and security-sensitive data access, with the cybersecurity and physical security terms added from the D.14-05-014 Model NDA. A copy of the Joint IOUs' recommended NDA for this purpose is provided as Attachment B to this Petition. The Joint IOUs' recommended NDA and "two-step" process for access to confidential distribution planning data pursuant to D.17-09-026 and D.18-02-004 are the same as proposed in this Petition, because the PV RAM maps and data will be replaced by the D.17-09-026 and D.18-02-004 Data Access Portals and data upon full implementation of those decisions.[27]

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[27] See Joint IOUs' Periodic Status Report, R.14-08-013, *et al.*, November 16, 2018.

V. CONCLUSION

For the reasons discussed above, the Joint IOUs respectfully request that the Commission modify D.10-12-048 and Resolution E-4414, as set forth above and in Attachment A.

Respectfully submitted,

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Dated: December 10, 2018

Attachment A – Proposed Modifications to D.10-12-048 and Resolution E-4414

D.10-12-048:

Conclusion of Law 44:

44. IOUs should provide the "available capacity" at the substation and circuit level, updated on a monthly basis, which is defined as the total capacity minus the allocated and queued capacity***, provided that such detail does not compromise safety and security, and provided that such detail complies with the data redaction criteria adopted in the July 24, 2018, Administrative Law Judge's Ruling in R.14-08-013***. The IOUs should provide this information in map format, ***until replaced by the Distribution Resources Plan Data Access Portal required by D. 17-09-026 and D.18-02-004***.

Conclusion of Law 46:

46. The IOUs should work with parties and Commission staff through the Renewable Distributed Energy Collaborative (Re-DEC) or other forums in order to improve the data, usefulness of the maps, and to discuss other issues related to the interconnection of distributed resources ***provided that such maps and data do not compromise safety and security, and provided that such maps and data comply with the data redaction criteria adopted in the July 24, 2018, Administrative Law Judge's Ruling in R.14-08-013***.

Appendix A: Summary of Adopted Program, p.5:

6. Market Elements
a. **Preferred Locations**: The IOUs must provide the "available capacity" at the substation and circuit level, defined as the total capacity minus the allocated and queued capacity***, provided that such detail does not compromise safety and security, and provided that such detail complies with the data redaction criteria adopted in the July 24, 2018, Administrative Law Judge's Ruling in R.14-08-013***. The IOUs should provide this information in map format ***until replaced by the Distribution Resources Plan Data Access Portal required by D. 17-09-026 and D.18-02-004***. If unable to initially provide this level of detail, each IOU must provide the data at the most detailed level feasible, and work to increase the precision of the information over time. This information is to be available in the advice letter implementing RAM and updated on a monthly basis.

Resolution E-4414

Ordering Paragraphs 24, 25 and 26:

24. In its renewable auction mechanism map, Southern California Edison Company shall provide the available capacity at the substation or circuit level for its preferred locations within 30 days of this resolution***, provided that the detail does not compromise safety and security, and provided that the detail complies with the data redaction criteria adopted in the July 24, 2018, Administrative Law Judge's Ruling in R.14-08-013***.

25. The investor-owned utilities shall post publicly by March 31, 2012 updated maps that cover their service territory, including both the distribution and transmission system***, provided that the maps and data do not compromise safety and security, and provided that the maps and data comply with the data redaction criteria adopted in the July 24, 2018, Administrative Law Judge's Ruling in R.14-08-013 until replaced by the Distribution Resources Plan Data Access Portal required by D. 17-09-026 and D.18-02-004***.

26. The investor-owned utilities may require developers to register in order to access the interconnection maps ~~***as an alternative to signing a non-disclosure agreement***~~. The investor-owned utilities shall ~~***not***~~ require signing a nondisclosure agreement to access the ***Data Access Portals in a form comparable to the Model NDA approved by the Commission in D.14-05-014.***

Attachment B – Recommended Model NDA

**MODEL NONDISCLOSURE AGREEMENT
REGARDING ACCESS TO PV RAM MAP DATA**

1. Scope.

A. Pursuant to Decision ("D.") __-__-___, of the California Public Utilities Commission issued on ________, 201_, and consistent with the July 24, 2018 Administrative Law Judge's Ruling on confidential treatment and redaction of distribution system planning data in California Public Utilities Commission Rulemaking 14-08-013, *et al*., [NAME OF UTILITY] ("Disclosing Party") is providing access to confidential information ("Confidential Information") on its Photovoltaic Renewable Auction Mechanism (PV RAM) maps and related Distributed Energy Resource data ("PV RAM Confidential Data") subject to this agreement with the third-party ("Recipient") granted access to such information.

B. This Nondisclosure Agreement does not apply to employees of the California Public Utilities Commission acting in their official capacities ("Commission Staff") to view the Confidential Information

C. This Nondisclosure Agreement shall govern access to and the use of Confidential Information, produced by, or on behalf of, the Disclosing Party in connection with access to the Disclosing Party's Data Access Portal Confidential Data.

D. Confidential Information is the safety and security-sensitive data of Disclosing Party's electric distribution and transmission facilities contained in Disclosing Party's Data Access Portal Confidential Data.

E. The term "redacted" refers to situations in which Confidential Information in a document, whether the document is in paper or electronic form, have been covered, blocked out, or removed.

F. The "Disclosing Party" is ____________ [insert utility name].

G. The "Recipient" is _________________ [Insert entity name].

H. The term "Nondisclosure Certificate" refers to the Nondisclosure Certificate attached as Appendix A.

2. Access to Confidential Information. Subject to the terms of this Nondisclosure Agreement, Recipient shall be entitled to access to the Confidential Information. Recipients may make notes of Confidential Information, which shall be treated as Confidential Information if such notes disclose any Confidential Information.

3. Maintaining Confidentiality of Confidential Information. Each Recipient shall treat Confidential Information as confidential in accordance with this Nondisclosure Agreement and the Nondisclosure Certificate. Confidential Information shall not be disclosed in any manner to any person except a Recipient's employees and administrative personnel, such as clerks, secretaries, and word processors, to the extent necessary to assist the Recipient, provided that they shall first ensure that such personnel are familiar with the terms of this Nondisclosure Agreement and have signed a Nondisclosure Certificate. Recipients shall adopt suitable measures to maintain the confidentiality and security of Confidential Information they have obtained pursuant to this Nondisclosure Agreement and shall treat such Confidential Information in the same manner as they treat their own most highly confidential information. At no time shall a Recipient give Confidential Information to anyone who is not a Recipient.

The Recipient shall take "Security Measures" with the handling of Confidential Information to ensure that the Confidential Information will not be compromised and shall be kept secure. Security Measures shall mean administrative, technical, and physical safeguards to protect Confidential Information, at a level and degree deemed appropriate by the Disclosing

Party to the Confidential Information's sensitivity, from unauthorized access, destruction, use, modification or disclosure, including but not limited to:

a. written policies regarding information security, disaster recovery, third-party assurance auditing, and penetration testing;

b. password protected workstations at Recipient's premises, any premises where work or services are being performed, and any premises of any person who has access to such Confidential Information;

c. encryption of the Confidential Information at rest and in motion;

d. measures to safeguard against the unauthorized access, destruction, use, alteration or disclosure of any such Confidential Information including, but not limited to, restriction of physical access to such data and information, implementation of logical access controls, sanitization or destruction of media, including hard drives, and establishment of an information security program that at all times is in compliance with any security requirements as agreed to between Recipient and Disclosing Party.

e. Measures to respond to an unauthorized, or suspected unauthorized, disclosure of Confidential Information.

4. <u>Liability for Unauthorized Disclosure by Recipient</u>. Recipient shall be liable for any unauthorized disclosure or use by themselves and/or their employees, paralegal, or administrative staff. In the event any Recipient is requested or required by applicable laws or regulations, or in the course of administrative or judicial proceedings (in response to oral questions, interrogatories, requests for information or documents, subpoena, civil investigative demand or similar process) to disclose any of Confidential Information, the Recipient shall

immediately inform the Disclosing Party of the request, and the Disclosing Party may, at its sole discretion and cost, direct any challenge or defense against the disclosure requirement, and the Recipient shall cooperate in good faith with such Disclosing Party upon request by such Disclosing Party either to oppose the disclosure of the Confidential Information consistent with applicable law, or to obtain confidential treatment of the Confidential Information by the person or entity who wishes to receive them prior to any such disclosure. If there are multiple requests for substantially similar Confidential Information in the same case or proceeding where a Recipient has been ordered to produce certain specific Confidential Information, the Recipient may, upon request for substantially similar materials by another person or entity, respond in a manner consistent with that order to those substantially similar requests.

5. Notification of Unauthorized Disclosure. Recipient shall notify Disclosing Party of any confirmed, or reasonably suspected, unauthorized disclosure of Disclosing Party's Confidential Information. Recipient shall notify Disclosing Party within 72 hours of confirming, or reasonably suspected unauthorized disclosure.

6. Return or Destruction of Confidential Information. Confidential Information shall remain available to Recipient for a predefined period. If requested to do so in writing at any time, the Recipient shall, within fifteen days after such request, return the Confidential Information to the Disclosing Party that produced such Confidential Information, or shall destroy the materials, Within such time period each Recipient, if requested to do so, shall also submit to the Disclosing Party an affidavit stating that, to the best of its knowledge, all Confidential Information have been returned or have been destroyed. To the extent Confidential Information are not returned or destroyed, such Confidential Information shall remain subject to this Nondisclosure Agreement.

7. Dispute Resolution. All disputes that arise under this Nondisclosure Agreement, including but not limited to alleged violations of this Nondisclosure Agreement and disputes concerning whether materials were properly designated as Confidential Information, shall first be addressed by the Parties through a meet and confer process in an attempt to resolve such disputes. If the meet and confer process is unsuccessful, either Party may present the dispute for resolution by the Commission, subject to the rights of parties to seek judicial review of any such Commission decision.

8. Other Objections to Use or Disclosure. Nothing in this Nondisclosure Agreement shall be construed as limiting the right of a Party to object to the use or disclosure of Confidential Information on any legal ground, including relevance or privilege.

9. Remedies. Any violation of this Nondisclosure Agreement shall constitute a violation of an order of the Commission. Notwithstanding the foregoing, the Parties reserve their rights to pursue any legal or equitable remedies that may be available in the event of an actual or anticipated disclosure of Confidential Information.

10. Withdrawal of Designation. A Disclosing Party may agree at any time to remove the “Confidential Information” designation from any Confidential Information of such Disclosing Party if, in its opinion, confidentiality protection is no longer required. In such a case, the Disclosing Party will notify all Recipients that the Disclosing Party has agreed to withdraw its designation of Confidential Information for specific documents or material.

11. Modification. This Nondisclosure Agreement shall remain in effect unless and until it is modified or terminated by written agreement of the parties. The Parties agree that modifications to this Nondisclosure Agreement may become necessary, and they further agree to work cooperatively to devise and implement such modifications in as timely a manner as

possible. Each Party governed by this Nondisclosure Agreement has the right to seek modifications in it as appropriate from the Commission.

12. Interpretation. Headings are for convenience only and may not be used to restrict the scope of this Nondisclosure Agreement.

RECIPIENT	**DISCLOSING PARTY**
By: ______________________________	By: ______________________________
Title: ___________________________ _	Title: ___________________________ _
Representing: ______________________	Representing: ______________________
Date: ___________________________ _	Date: ___________________________ _

APPENDIX A TO NONDISCLOSURE AGREEMENT

NONDISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Confidential Information is provided to me pursuant to the terms and restrictions of the Nondisclosure Agreement between [NAME OF RECIPIENT] and [NAME OF UTILITY], that I have been given a copy of and have read the Nondisclosure Agreement, and that I agree to be bound by it. I understand that the contents of the Confidential Information, including any notes or other memoranda, or any other form of information that copies or discloses Confidential Information shall not be disclosed to anyone other than in accordance with that Nondisclosure Agreement. I acknowledge that a violation of this certificate constitutes a violation of an order of California Public Utilities Commission and that my access to Confidential Information can be terminated at any time by the Commission.

Signed: ________________________

Name: _________________________

Title: __________________________

Organization: __________________

Dated: _________________________

Declaration of Bernard A. Cowens
Vice President and Chief Security Officer
Pacific Gas and Electric Company

I am Vice President and Chief Security Officer of Pacific Gas and Electric Company

In this position, I am responsible for leading company-wide efforts to identify and manage physical and cyber security risks to protect PG&E's people, critical infrastructure, and information assets.

Prior to joining PG&E, I was Chief Information Security Officer for First American, where I oversaw all aspects of information security for the company and its global business units. I have held senior security executive positions at PricewaterhouseCoopers, Experian and the Automobile Club of Southern California. I previously served as the vice president and Chief Information Officer for SafeNet, a global encryption technology manufacturing company.

A former military officer and Special Agent, I have extensive international counterintelligence, counter-terrorism and physical security experience. I completed my military service as the Chief Technology Officer and Chief Security Officer for the Defense Intelligence Agency in Los Angeles. I have more than 30 years of security and technology leadership experience, and hold the CISSP and CISA designations.

In my opinion, unrestricted public access to the Photo Voltaic Renewable Auction Mechanism (PV RAM) maps and other maps and data that disclose the geo-spatial attributes of PG&E's electric grid represents a serious and significant threat to the physical security of PG&E's electric distribution and transmission facilities and to PG&E's electric customers, for the following reasons:

The physical location, attributes and configuration of PG&E's electric distribution and substations, circuits and feeders, as well as those of related transmission facilities currently disclosed on the IOUs' PV RAM maps, can be used by a "bad actor" to commit a physical or cyber attack on utility facilities. Such an attack could lead to outages to tens of thousands of utility customers and critical energy facilities and infrastructure, catastrophic and costly damage to the Joint IOUs' ability to provide electricity service, theft and misuse of critical energy infrastructure information, and damage to the national security of the United States. Although the increased risk or scale of potential disruption due to public and unauthorized access to the PV

RAM maps is not quantifiable, evidence of suspicious and unknown actors accessing the maps indicates a level of risk that needs to be mitigated, to reduce the risk of even a "low probability, high magnitude" cyber or physical attack.

The PV RAM maps and related maps clearly lay out the electrical connectivity configuration of both the electric distribution and electric transmission grids. This information could allow a "bad actor" to identify which lines extend to specific substations and/or critical customer facilities. Knowing these routes and potential backup power supply routes can help "bad actors" coordinate specific targeted attacks for increased impact.

A commonly invoked justification for making PG&E's electric distribution and transmission maps public is that "this information is already available on Google Maps," or similar third party mapping software. Not so: while certain specific distribution and transmission assets may be identifiable through physical views and public non-utility on-line maps, it is difficult if not infeasible to piece together from these sources a digital connectivity map in one full map such as the ones proposed to be made public. In addition, the PV RAM data sets provide the locations of underground electric infrastructure which are not visible on non-utility public maps.

The unrestricted dissemination of information providing the location of a utility's major loads, substations, and distribution and transmission facilities serving those loads renders the grid unnecessarily vulnerable. If one or more substations serving major loads or large geographical areas were attacked, it could result in a wide scale outage for a prolonged period. Massive power outages caused by an attack on significant substations or other distribution facilities could disrupt the economy and countless industries, halt transportation, impede emergency services and responders, cause shortages of food, water and other essential supplies, distract from and hinder the ability to respond to a simultaneous attack elsewhere. Furthermore, while there may be some "basic" information available regarding electric distribution and transmission assets, there is not the technical information which identifies our most critical assets or their function and value in maintaining the reliability of the grid. PG&E seeks to ensure that the confidentiality of this information is protected and maintained. Exposing this information allows adversaries to pinpoint significant or critical assets or locations that can have a significant impact on grid reliability. Our federal regulators (FERC and NERC) expect us to keep this information confidential, and we do so, even within PG&E.

PG&E, like other utilities and organizations, faces the increasing risk of cyber and physical security threats. These threats are further magnified by factors such as the sophistication of active adversaries and the growing dependence on technology in the utility industry. PG&E must work diligently to anticipate and effectively combat these threats. Active adversaries, including nation states, criminals, and potential insiders, are constantly innovating, with threats evolving in complexity and sophistication. The energy sector is among the top three most attacked critical infrastructure sectors in the United States (U.S.).[1] In 2017, power grid attacks were identified in the U.S. and Europe. Additionally, technology innovations in critical infrastructure have become an important element in achieving PG&E's business objectives for safe and reliable service to our customers. As a consequence, security programs must evolve to defend against challenges presented by modern technologies and new and complex threats.

PG&E takes security very seriously and has been positioning the company to effectively address evolving security threats, both cyber and physical, and security challenges presented by innovative technologies. The increased threat of physical or cyber attacks on PG&E's electric distribution and transmission facilities should be mitigated by reducing the unrestricted access to security-sensitive maps of PG&E's electric grid and facilities, and limiting the access to third-parties who have a legitimate "need to know" and adhere to standard security protocols to protect the maps from being used by "bad actors" to attack or disrupt PG&E's utility services to its millions of customers.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Executed on December 10, 2018, at San Francisco, California.

Name: Bernard A. Cowens

Vice President and Chief Security Officer
Pacific Gas and Electric Company

[1] Power Engineering International, "Cybersecurity: How Utilities Can Prepare the Next Generation of Smart Grid," February 12, 2018, by Scott Foster, Chief Executive of Delta Energy and Communications.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of the California Renewables Portfolio Standard Program.	Rulemaking 08-08-009 (Filed August 21, 2008)

DECLARATION OF WILLIAM C. SAUNTRY ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) IN SUPPORT OF JOINT PETITION FOR MODIFICATION

I, William C. Sauntry, do hereby declare:

1. I am the Risk and Compliance Manager within Corporate Security for Sempra Energy, of which San Diego Gas & Electric Company ("SDG&E") is a subsidiary. I make this Declaration on behalf of SDG&E in support of the Joint Petition for Modification submitted on behalf of Pacific Gas and Electric Company, Southern California Edison Company, and SDG&E. I have personal knowledge of the matters referred to herein and, if called upon to testify, I could and would competently testify thereto.

2. In my current role, I am responsible for the implementation of a risk management and intelligence program to prioritize and mitigate threats, vulnerabilities, and consequences to the company and its infrastructure. Before this role, I was the supervisor for the Critical Infrastructure Protection, Cyber Intelligence, and the Geospatial Intelligence Units within the San Diego Law Enforcement Coordination Center, a Department of Homeland Security ("DHS") fusion center, which is part of the California State Threat Assessment System. In that role, I performed vulnerability assessments for the California Office of Emergency Services and the

County of San Diego to evaluate the security of critical infrastructure. I have also worked for DHS performing vulnerability assessments on infrastructure throughout the nation. The first step in each of these assessments was to review online material for sensitive information, which may be used to plan attacks against infrastructure. In addition, I understand the breadth of information included within Geographic Information System ("GIS") data and how important it can be to assist with pre-operational planning of attacks on critical infrastructure.

3. SDG&E takes protective measures to minimize the potential of critical information being used to attack and disrupt California's electric system. This information may be used in preoperational planning of attacks by malicious actors, allowing them to plan an attack remotely, without having seen or been present at any of the facilities.

4. SDG&E treats its GIS data with special care because it recognizes that precise critical infrastructure information that is made publicly available—for instance, through publication of otherwise non-public GIS data—may be misused. For example, the public availability of this information may limit or eliminate the need for a malicious actor to perform onsite reconnaissance or surveillance to assist with target selection. This enhances preoperational planning of an attack because it reduces the chances that a malicious actor will be detected and/or apprehended in the early stages of an attack. Stopping an attack during preoperational planning is preferred to responding to an attack while in progress. Identifying potential indicators of an attack, such as onsite reconnaissance or surveillance, is such an important component of preventing terrorism, DHS has created a national

campaign called "If you see something, say something,"[1] to recognize and report suspicious activity. This campaign is part of the National Suspicious Activity Reporting ("SAR") Initiative ("NSI"). Recent research on the Nationwide SAR Initiative, an effort to establish reporting standards with respect to SARS, has validated that there is good alignment between pre-incident activities of previous terrorist attacks and the indicators identified as important by the NSI.

5. Furthermore, this research has found that some of these indicators were observable by the public prior to an attack.[2] Additionally, the RAND Homeland Security and Defense Center report titled, "Terrorist Plots Against the United State, what We Have Really Faced, and How We Might Best Defense Against It" (September 2015), states between 1995 to 2012, SARs constituted the third largest source of initial clues leading to foiling plots. A wide variation of types of suspicious activity reported, including potential target site surveillance.[3]

6. Electric transmission and distribution system facility information, such as location and configuration (*e.g.*, identification, routing, ratings, loading, status), are especially sensitive because this information provides a holistic system overview as well as detailed information that may assist with the identification of a single point of failure, choke points, or nodes servicing critical infrastructure. Maps and configuration of the electric system may allow a malicious actor to more easily

[1] Department of Homeland Security, "If You See Something, Say Something," *available at* https://www.dhs.gov/see-something-say-something.
[2] University of Maryland, Study of Terrorism and Responses to Terrorism, "Research Brief: Validation of the Nationwide Suspicious Activity Reporting (SAR) Initiative" (2015), *available at* https://www.start.umd.edu/pubs/STARTResearchBrief_NationalSARInitiative_March2015.pdf.
[3] RAND Homeland Security and Defense Center, "Terrorist Plots Against the United State, What We Have Really Faced, and How We Might Best Defense Against It" (September 2015) at 11, *available at* https://www.rand.org/content/dam/rand/pubs/working_papers/WR1100/WR1113/RAND_WR1113.pdf.

identify the location of infrastructure necessary to disrupt electric service to life/safety, national defense, communications, or other critical infrastructure.

7. Remote planners can use detailed information and locations to evaluate the electric system and security locations and vulnerabilities at point along electric system; this of course can be accomplished from afar without any risk of detection by law enforcement or company personnel.

8. Even assuming that a bad actor could theoretically obtain the similar information that is in the online access portal from other means, such as onsite reconnaissance (which they cannot), or data sources the increased availability (e.g., more sources) and granularity of publicly accessible safety- and security-sensitive data would accelerate target selection and maximize the consequences of an attack. Having ready and on-going access to increased amounts of this type of data allows the malicious actor to complete the targeting phase of the attack remotely and more expeditiously because the detailed and time-intensive planning steps discussed above would be unnecessary.

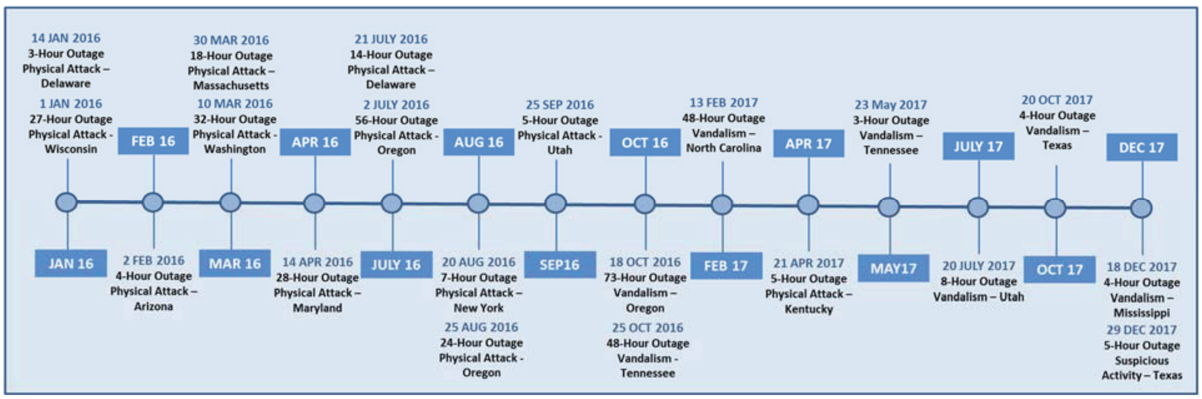
9. Therefore, although the Commission has ordered public access to some maps and information of the electric system in the past, SDG&E has an even better understanding of the threats against electric infrastructure through the hiring of risk and intelligence analysts to provide threat analysis. If this data were misused and electric infrastructure were disrupted or attacked, critical infrastructure within San Diego region may be affected, with a real risk of harm to life and property.

10. The risk of third-party action, whether acts of terrorism, theft, or vandalism, is not speculative. Utilities are mandated by the Department of Energy, Office of

Electricity Delivery and Energy Reliability ("OE") to report the causes of major interruptions or outages through the Electric Emergency Incident and Disturbance Report (OE-417). The following table provides OE-417 statistics of incidents caused by actual or suspected physical attacks, sabotage, and vandalism:

	2014	2015	2016	2017
Total Reports	73	42	44	44
WECC Region	31	23	26	23

The following illustration lists the incidents with restoration greater than three hours between January 2016 and December 2017.



11. Several other incidents have highlighted malicious intent against the electric system including:

- In April 2013, the Metcalf transmission substation in San Jose, California, was attacked by gunfire resulting in damaging of 17 transformers, 6 circuit breakers, and release of 52,000 gallons of oil. As part of the attack, AT&T and Level 3 fiber optic communication cables were severed.[4]
- In September 2016, Stephen McRae reportedly shot at a Garkane Energy

[4] California Public Utilities Commission, "PG&E Metcalf Incident and Substation Security," *available at* http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Safety/Presentations_for_Commission_Meeting/SafteySlidesfromPowerPointforthe22714Meeting3331.pdf.

Cooperative substation, damaging a transformer and causing a power outage of around 13,000 people in Kane and Garfield counties. This is an open case with pending charges of 'Destruction of an Energy Facility,' 'Unlawful Possession of a Firearm,' and 'Possession of Marijuana.'[5]

- In December 2014, a pilot and owner of a flight school reportedly threw objects on Hydro Quebec's high voltage power lines affecting over 188,000 households in Quebec, Canada. This is currently an open case and involves a $28.6M lawsuit.[6]
- Three separate incidents occurred in Arkansas from August 2013 until October 2013. Investigators successfully linked these incidents and arrested one individual, Jason Woodring, on charges of destruction of an energy facility:[7]
    - In October 2013, Woodring cut two power poles, used a tractor to pull down one of the poles, which severed a 115KV power transmission line resulting in loss of power to approximately 10,000 customers.
    - In September 2013, Woodring set fire to an electrical switching station resulting in substantial damages.

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[5] Lake Powell Life News, "Charges Brought Against Shooter of Garkane Energy Substation" (February 17, 2017), *available at* https://www.lakepowelllife.com/charges-brought-against-shooter-of-garkane-energy-substation.

[6] Le Journal de Montreal, "Hydro wants a secret trial for the "star pilot" (January 9, 2017), *available at* http://www.journaldemontreal.com/2017/01/09/hydro-veut-un-proces-secret-pour-le-pilote-des-stars. *See also* Montreal Gazette, "Pilot's attack on 'spinal column' of Hydro-Québec is unprecedented: lawyer" (October 31, 2018*), available at* https://montrealgazette.com/news/local-news/pilots-attack-on-spinal-column-of-hydro-quebec-is-unprecedented-lawyer.

[7] FBI News, "Attack on Arkansas Power Grid" (August 10, 2015), *available at* https://www.fbi.gov/news/stories/attacks-on-arkansas-power-grid/attacks-on-arkansas-power-grid.

- August 2013, 500KV power lines fell on a nearby active rail line after being deliberately cut with over 100 support bolts removed from the 100 ft support tower where it was attached. The power lines were eventually struck by a train which led to a power outage affecting a substantial number of customers.

- In February 2014, three militia extremists in Georgia attempted to obtain pipe bombs and other explosives which they planned to use in guerilla warfare-style attacks. According to the criminal complaint, "'the group' was planning to 'start the fight' with the government by strategically planning to sabotage power grids, transfer stations, and water treatment facilities . . . this action would cause mass hysteria and if enough sabotage was successful, then martial law would be declared, therefore triggering other militias to join the fight."[8]

12. On October 24, 2017, two individuals were arrested for breaking into a Kinder Morgan Trans Mountain Pipeline facility in the State of Washington in an attempt to shut the valve on the oil pipeline.[9] One of the individuals involved posted a live feed of the attack on his Facebook page. The live feed was accompanied by a comment stating, "In honor of the one year anniversary of the Valve Turner's actions, I ask that you join me in continuing their work."[10] Posted comments also

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[8] *United States v. Peace*, 4:14-cr-00011-HLM-WEJ (N.D. Ga. Crim. 2014) (*see* Criminal Complaint, dated February 18, 2014 at 6).

[9] Goskagit.com, "Two arrested after apparent break-in at Kinder Morgan facility" (October 24, 2017), *available at* https://www.goskagit.com/news/local_news/two-arrested-after-apparent-break-in-at-kinder-morgan-facility/article_ab690b5c-1f7a-5402-a20b-4b1f56265cc2.html.

[10] https://www.facebook.com/donaldz/videos/10155315875063409/. "Valve Turners" refers to a group of climate change activists.

included coordinates of valve stations in North Dakota, Michigan, Minnesota, and Florida urging others to commit similar attacks.[11]

13. These recent posts highlight the need to keep the locations and configurations of critical infrastructure (electric or otherwise) offline because the Internet allows such information to be transmitted and shared instantaneously, anonymously, and to untold numbers of people.

14. Domestic and international intelligence communities have also reported on the use of the Internet for terrorist pre-operational planning. In 2012, the United Nations Office on Drugs and Crimes published a report entitled "The use of the Internet for terrorist purposes," stating:

> *Some sensitive information that may be used by terrorists for illicit purposes is also made available through Internet search engines, which may catalogue and retrieve inadequately protected information from millions of websites. Further, online access to detailed logistical information, such as real-time closed-circuit television footage, and applications such as Google Earth, which is intended for and primarily used by individuals for legitimate ends, may be misused by those intent on benefiting from the free access to high-resolution satellite imagery, maps and information on terrain and buildings for the reconnaissance of potential targets from a remote computer terminal.*[12]

15. Aside from government entities, activists have themselves admitted that publicly available data can be used for pre-operational planning of an attack on a pipeline. In 2014, activist Tom Steyer commissioned a three-month study, conducted by former Navy SEAL David M. Cooper, which concluded:

> *Keystone XL was an especially attractive target for terrorists . . . Cooper said he conducted the study by using publicly available information that anyone planning a terrorist attack could find, relying on such sources to determine Keystone XL's path and the thickness of*

[11] *Id*.
[12] United Nations Office on Drugs and Crime, "The use of the Internet for terrorist purposes" at 10-11, *available at* https://www.unodc.org/documents/frontpage/Use_of_Internet_for_Terrorist_Purposes.pdf.

the pipe.[13]

16. Given the potential consequences of an attack on the electric system, SDG&E considers electric system location and configuration data, such as information contained within the PV RAM maps and DRP access portal (as those acronyms are defined in the Joint Petition for Modification), to be safety- and security-sensitive information that should not be made publicly available.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed: December 7, 2018

William C. Sauntry

[13] Portland Press Herald, "Study: Keystone XL pipeline would be juicy terrorist target" (June 5, 2014), *available at* http://www.pressherald.com/2014/06/05/study-keystone-xl-pipeline-would-be-juicy-terrorist-target/.

CERTIFICATE OF SERVICE

I, Jim Erickson, hereby certify that I have this day served copies of the foregoing document on the attached lists of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket No. **E002/M-18-684**
XCEL ENERGY'S MISCELLANEOUS ELECTRIC SERVICE LIST

Dated this 1st day of November 2019

/s/
____
Jim Erickson
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
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