Xcel Energy™

Statement of Work Requested

Date: September 18, 2015

Work Requested By: SUNSHARE

Work Location: 0

Address: [redacted]

Project/Site Name: LAKE NOKOMIS 8-12

Account # | Premise #

CONSISTING OF:

$22,000.00 fee to perform Engineering Scoping Studies for [redacted] under the Solar Rewards Community program for the Community Solar Garden Site as proposed by SUNSHARE to be located at [redacted]

The Engineering Scoping Study will identify potential Distribution, Substation, and Transmission system and operational issues and limitations associated with the proposed installation and operation of up to 5 [redacted] Systems to be connected to the [redacted] kV feeder line approximately [redacted] miles from [redacted] Substation.

The number of MW of distributed generation ahead of Customer's project in the Study Queue: [redacted] MW

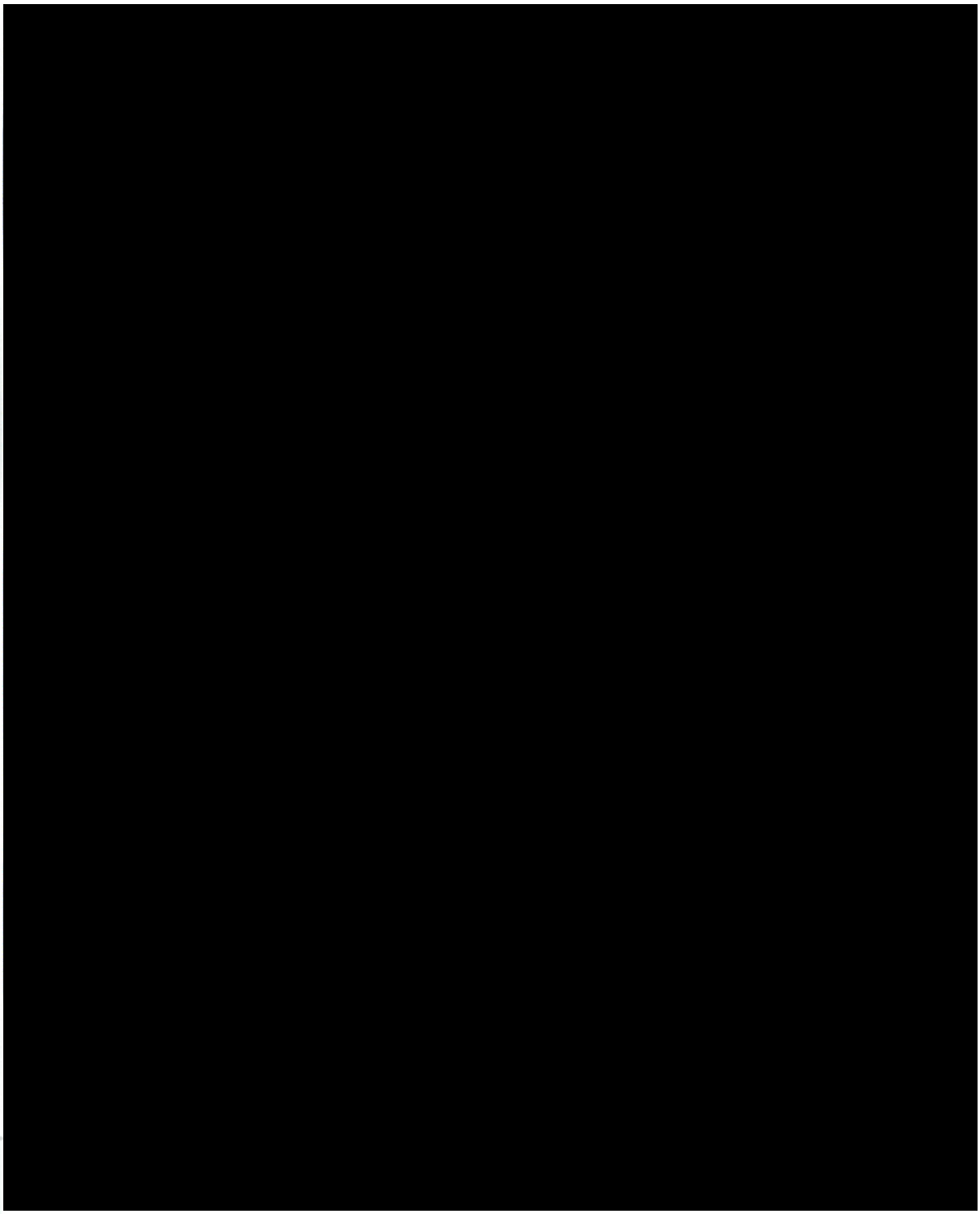
The Engineering Scoping Study includes: prepare steady-state model for minimum and maximum loads, develop accurate power flow models, develop model impedances and loads from generation site to the transmission system, identify substation and feeder loading and voltage profile issues, identify system deficiencies and required mitigations, review grounding system calculations, and evaluate Substation impact, metering, protection, telemetry, communication, and breaker short circuit limits.

An indicative cost estimate per Steps 3-4 of the Section 10 Interconnection tariff will be performed. The number of MW of distributed generation ahead of Customer's project in the Study Queue will also be provided. Other terms and conditions associated with the Engineering Scoping Study are set forth in and are contingent upon the Commission approval of Company proposed tariff provisions submitted to the Commission for review on September 14, 2015, in Commission Docket No. E002/M-13-867

Xcel Energy, by providing this Statement of Work, or by performing the Engineering Scoping Study, is not waiving its position, where applicable, that the Community Solar Garden Size exceeds the Co-Location Limits

Please returned signed copy of this Statement of Work (SOW), Completed Appendix C, and full payment directly to:

Xcel Energy, attention: Bode Falade 5309 W 70th St, Edina MN 55435



TRADE SECRET – MAY ALSO CONTAIN SENSITIVE INFRASTRUCTURE INFORMATION

EXHIBIT B

February 19, 2016 Linden Study Report

414 Nicollet Mall
Minneapolis, MN 55401

1-800-895-4999
xcelenergy.com

Xcel Energy®
RESPONSIBLE BY NATURE®

February 19, 2016

Solar*Rewards Community Study Results

Developer/Customer Name: Sunshare
Contact Name: [redacted]
Site Name: Sunshare "Linden"
Site Address: [redacted]
Project Description [redacted]

Xcel Energy is pleased to deliver the engineering indicative cost estimate for the Solar*Rewards Community solar garden application(s) for the above-referenced site:

Site	Legal Name
1	Lake Nokomis 08, LLC
2	Lake Nokomis 09, LLC
3	Lake Nokomis 10, LLC
4	Lake Nokomis 11, LLC
5	Lake Nokomis 12, LLC

[redacted]

We note that you have requested us to perform an engineering indicative cost estimate for your Co-Located 5 MW project which was submitted as part of our Solar*Rewards Community program. Under the MPUC's December 15, 2015 Order, we have revised our tariff to allow up to 5 MW of Co-Located Community Solar Garden sites for a certain period of time. We are therefore delivering our indicative cost estimate for the largest installation associated with your applications for the above site that would be compliant with the MPUC's Order and our revised tariff sheets.

The engineering indicative cost estimate has identified that of the amount of MW in the above application(s), [redacted] is the maximum generation allowed at this location.

Greater than [redacted] of PV cannot be accommodated due to extensive rebuilding/reconductoring that would be required to support that amount of generation. The existing infrastructure could support a maximum of [redacted] of PV at the garden site. Supporting greater than [redacted] would require completely reconductoring 19,000 feet of existing overhead line which cost estimates indicate the total cost of all distribution work would exceed the $1,000,000 threshold. We show below itemized cost inputs including unit costs applicable to providing service greater than [redacted] Providing service for greater than 1000 kW would entail a "material upgrade" exceeding the $ 1 million limitation applicable to (1) three-phase line extension on existing feeders and (2) reconductor /build line.

Item	#	Unit Cost	Total Cost
OH - Total ft. of new 336 Al for tap to interconnection points	200	50/ft	$10,000.00
OH - Total ft. of rebuild to 336 Al	19000	55/ft	$1,045,000.00
OH - Total ft. of new tap level OH from tap to individual meter poles	750	30/ft	$22,500.00
Recloser installation	1	40000/ea	$40,000.00
Install Primary Pole	4	5000/ea	$20,000.00
		Total	$1,137,500.00

Our indicative estimated cost for proceeding with [redacted] for the above site is $113,000.

There are no projects ahead of the above in the applicable Study Queue.

You have the option of further proceeding with this project at this [redacted] level based on the indicative estimate if you pay to us either the full amount or one-third of this amount within 30 days along with a Letter of Credit. You agree to pay the actual costs consistent with the Section 10 Interconnection Agreement and comply with all provisions of the Section 10 Tariff. Pursuant to Minn. R. 7835.4750, please note that the Commission's interconnection standards are set forth in our Section 10 Tariff which as of the date of this letter is available at this link: http://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/Me_Section_10.pdf

Please note that you need to provide certain contact information or signatures on the following:

1.) Provide contact information on Sheet 124 of the Interconnection Agreement,
2.) Sign the Interconnection Agreement on Sheet 127,
3.) Sign the attached Statement of Work associated with Exhibit B to the Interconnection Agreement,
4.) Provide the 24/7 contact information on Exhibit D, par. 9.3 to the Interconnection Agreement,
5.) Sign Exhibits D and E to the Interconnection Agreement.

Exhibit B contains cost for the garden. A separate Statement of Work (SOW) will be issued for the Community Solar Garden, and this also needs to be signed and returned.

Study Results and Construction Estimates:

This letter is to provide system requirements and cost estimates of system modifications necessary for interconnection of the project identified above. The requested project proposes interconnecting [redacted] with Xcel Energy's distribution system at a voltage of [redacted]. The requirements for this project have been broken into two sections: operational requirements and system modifications. Operational requirements include generator facility size, settings, or procedures necessary to interconnect the proposed system. System modifications are physical equipment modifications that Xcel Energy will need to make to distribution and substation facilities for the interconnection to be feasible.

A model of the feeder, [redacted], on which the solar garden would interconnect, was created for the purpose of studying the feasibility of the proposed interconnection. A study analyzed flicker, grounding issues, metering/monitoring, and short circuit protection to determine impacts on the Xcel Energy distribution system.

In addition, an engineering indicative cost estimate has been prepared for the Distribution and Substation costs required to accommodate this project. It is produced before any detailed engineering design has begun to provide an indicative estimate that incorporates as many project-specific factors as possible. However, the engineering indicative cost estimate is generally based on typical conditions encountered on past construction projects, which may or may not be directly comparable. The engineering indicative cost estimate will only give a broad-based estimate of the possible costs that may be incurred during a potential construction project.

Below is a list of operational requirements uncovered during the study that will need to be addressed as well as a list of system modifications that will be necessary for the interconnection to take place. The system modifications and associated costs are as follows:

- **Operational**
  - List the various limitations and options identified in the Study here:
    - The study indicated that there were violations of both the steady state voltage and voltage flicker requirements that require curtailment to [redacted] and power factor control of 0.95 leading power factor with the existing infrastructure;
    - Greater than [redacted] at .95 PF can be accommodated if the 19,000' of #2AL and 1/0 AL conductor is replaced with 336 AL. However this would exceed the $1 million limit imposed by the tariff.
    - Replacing an existing recloser with a VSR enabled recloser to prevent anti-islanding
  - The Substation Transformer is rated 14 MVA and the Substation minimum load is 3.02 MVA.
  - The Short Circuit Analysis did not identify any issues.
    - Additional fault current information may be found in the *Xcel Energy Standard for Electric Service* and Use book. Secondary services refer to Tables found in Section 5
    - The model calculated short circuit values at the point of interconnection was for three phase momentary short circuit current to 7341 Amps and the single line to ground short circuit current to 7392 Amps.

- **Ground Referencing:**
  - The study found that the entirety of the range of impedance values for the grounding transformer provided in the submitted design **does** meet Xcel Energy's effective grounding requirement.
    - If the requirements are not met updated calculations are required for review and approval.
    - Please refer to the "PV and Inverter-based DER Ground Referencing Requirements and Sample Calculations" document for additional information. Please provide detailed calculations and any other

information demonstrating compliance for review and approval by Xcel Energy.

- Please include details within the Protection coordination study to demonstrate the PV system will cease operations for loss of ground reference. This study will be reviewed and approved by Xcel Energy prior to system energization.

- **System Modifications**
  - Substation - $43,500:
    - Installation of remote monitoring (telemetry) and satellite communication system. $43,500.
      - This solution also requires an ongoing charge of $200/month for operation and maintenance.
    - Upgrade regulator or LTC controls for reverse power flow operation
    - For photovoltaic (PV) inverter base systems, when minimum *daytime* load is less than 125% of aggregate generation AC nameplate rating, Voltage Supervisory Reclosing shall be installed. Installation of Voltage
    - Add Reverse Power Flow Protection to the feeder [redacted]
  - Metering - $13,500:
    - For installation of Main Service and Production primary metering equipment for 1 separate sites. $13,500 each.
    - An ION meter and associated CT's and PT's is proposed for the Production Meter and has Ethernet capability that can be utilized for Telemetry.
    - A standard A3 meter and associated CT's and PT's is proposed for the main service meter.
    - Communication provisions for meter billing data:
      - The preferred method of gathering billing data from both Main Service and Production meters would be over a customer supplied internet connection. Each meter has a single Ethernet port and a local IP address that once connected to the network can be contacted externally by Xcel Energy's billing system. It is the customer's responsibility to provide the Conduit, associated cabling/Ethernet switches, aux power requirements, and to maintain an active internet connection to enable remote meter reading. Customer would be responsible to provide fiber conversion as required for communications between devices.
      - The routing rules would involve IP forwarding from a range of IP addresses and ports which would then be forwarded from the on-site routing device to each meter. Routing rules would need to be setup on the customer owned device to allow for the meters to be accessed from an external network.
  - Distribution - $56,000:
    - Extend primary distribution facilities approximately 200' from the Point of Common Coupling to the first Point of Interconnection. $11,000
    - Install 1 primary meter pole (for primary services) $5,000 each
    - Replace line recloser with electronic VSR enabled recloser. $40,000

- All new services shall be approved by local inspector prior to Xcel Energy scheduling energization.
  - Refer to the Xcel Energy Standard for Electric Installation and Use.
- Easements are required by Xcel Energy to install any facilities on private property. The Customer/Developer is responsible to provide the easement descriptions as well as any costs to obtain the easements. All easements shall utilize Xcel Energy documents and be drafted and recorded by Xcel Energy. Provide 30' private easements for facilities not located along roadways, and 15' if adjacent to road right of way.
- Xcel Energy requires provisions for 24/7, unescorted, keyless access to all metering locations.

- MISO/Transmission Assessment
  - A transmission system assessment was not required.

- *Preliminary schedule*: Design, Engineering, and Construction resources, material, and outage availabilities may impact project lead times.
  - Xcel Energy Substation Project Lead Time: 6-9 Months
  - Xcel Energy Distribution and Metering Project Lead Time: 6-9 Months
  - Customer's proposed completion date earlier than these may not be feasible. Additional schedule details can be developed during detailed Engineering and Design. For example, testing may be accommodated prior to allowing the system to operate at full output.

- Distribution Facility Credit or Distributed Generation distribution constrained credits:
  - There are no Distribution Facility Credits available at this location.
  - There are no Distributed Generation distribution constrained credits available at this location.

The total cost for this interconnection is estimated to be **$113,000**. Labor costs associated with the final review, meeting attendance, and the final acceptance testing is integrated into the total project costs. Please keep in mind that the figures above are based on historical costs from similar Xcel Energy projects. The above figures can vary significantly and the customer will be responsible for the actual costs of the project.

Insurance requirements can be found in Section XI, Sheet 122 of the Interconnection Agreement. Please submit this information to the Solar Rewards Community project office, if not already provided and approved.

Each Interconnection Agreement packet is comprised of the following for the individual garden project(s). If there are Co-Located projects it is assumed that all such projects are constructed, tested, and energized simultaneously and in such order to realize the economics of Co-Location for the Distribution System extension and service to each individual Community Solar Garden project. Additional costs may result if this is not coordinated sufficiently.

- Appendix E, Interconnection Agreement
- Exhibit A: Description (Appendix B Application Form) and Single Line Diagram

- Exhibit B: Estimated costs payable by customer and associated Statement of Work (SOW)
- Exhibit C: Engineering Data Submittal Form (Appendix C).
- Exhibit D: Operating Agreement
- Exhibit E: Maintenance Agreement
- Form of Letter of Credit

The detailed design and material procurement will begin once the signed documents described above are returned with the requested information and the payment. You have the option of paying now the total estimated costs, or paying 1/3 of this amount now and providing a Letter of Credit in an approved form for the remainder of the estimated costs. An acceptable form of Letter of Credit is attached.

This cost is valid for **30 days** from the date of this letter.

Return all completed and signed agreements, exhibits, supporting documentation, etc. referenced to:

Xcel Energy
Solar*Rewards Community
825 Rice Street
St. Paul, MN 55117

Please contact me at garrett.heidorn-anderson@xcelenergy.com if you have any questions regarding this information.

Thank you again; we look forward to working with you to bring more solar choices to our customers.

Garrett Heidorn-Anderson
Xcel Energy | Responsible By Nature
Engineer
825 Rice St, 1st Floor, St. Paul, MN 55117

STATEMENT OF WORK REQUESTED

DATE: 19-Feb ,2016
WORK REQUESTED BY: SunShare LLC
WORK LOCATION:
ADDRESS: [redacted]

CONSISTING OF:
See reverse side for additional details. If this SOW is for Co-Located Community Solar Gardens, and the customer chooses to go forward with less than all of the sites set forth in Exhibit B, indicate here the total number of sites you choose to go forward with: _____ Community Solar Gardens.

Return all required documentation and payments to:
Xcel Energy Solar*Rewards Community
825 Rice Street
Saint Paul, MN 55117
srcmn@xcelenergy.com

The facilities installed or removed by Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company") shall be the property of the Company and any payment by customer shall not entitle customer to any ownership interest or right therein. Customer's and Company's rights and obligations with respect to the facilities and services provided through the facilities are subject to additional terms and conditions as provided in the General Rules and Regulations and/or in the Rate Schedules of Xcel Energy's Electric Rate Book for customer's specific service, as they now exist or may hereafter be changed, on file with the state regulatory commission in the state where service is provided.

The undersigned hereby requests and authorizes Northern States Power Company, a Minnesota corporation ("Xcel Energy") to do the work described above, and in consideration thereof, agrees to pay ($ 113000.00 in accordance with the following terms:
Payment required to move forward with design and construction for Solar Garden

Receipt of the above amount hereby acknowledged on behalf of the Company by SRCMN

Northern States Power Company, a Minnesota corporation ("Xcel Energy")	Customer
Print Full Name and Title	Print Full Name and Title (if applicable)
Signature	Signature

FOR XCEL ENERGY USE
Xcel Energy Representative _____ Xcel Energy Work Order # _____

Construction$ 113000.00 Removal $ _____ Total $ 113000.00

Form 17-7012

Xcel Energy℠

Statement of Work Requested

Date: February 19, 2016

Work Requested By: SunShare LLC

Work Location: [redacted]
Address:
Project/Site Name:
SRC #'s:

CONSISTING OF:

$113,000 for the required substation, distribution, and metering work required to accommodate this project.
See Exhibit B for breakdown of the costs by site. One-third of the estimated cost is to be paid within 30 days and a Letter of Credit issued to cover the remaining estimated payment consistent with the Section 10 Interconnection Agreement. Above-named entity agrees to comply with all provisions of the Section 10 tariff. Where work is for one or more Co-Located Community Solar Gardens, the Co-Located Community Solar Gardens are jointly and severally liable for all due amounts. Separate SOWs will be issued for each Co-Located Community Solar Garden, each needs to be signed and returned, but the amount reflected in this SOW is the total among all of the Co-Located Community Solar Gardens. If customer chooses to go forward with some, but not all, of the Community Solar Gardens, it must go forward in the sequence of the garden site numbers as set forth in Exhibit B. In such a situation the total estimated cost is the sum of the applicable amounts for these chosen garden sites, and the required payment at this time is one-third of this estimated amount plus the appropriate Letter of Credit to cover the remaining estimated payment for the garden sites selected. If customer chooses to go forward with less than all of the sites set forth in Exhibit B, indicate on the front side of this SOW the total number of sites you choose to go forward with.

These cost estimates are based on historical costs from similar Xcel Energy projects. Actual costs can vary significantly and the customer will be responsible for the actuals costs of the project. This statement of work is valid for 30 days from the date of this notice. If either the signed agreement or initial one-third payment is received after this date, the SOW will not be in countersigned by Xcel Energy, and the project is subject to rejection, loss of queue position, and will require a new application to be submitted to be considered.

Installing telemetry equipment, metering equipment, approximately 200' extension of new overhead lines to the Solar Garden point of interconnection, with protective device.

See attached documentation for details and requirements identified by the engineering studies.

Please returned signed copy of this Statement of Work (SOW), IA, and supporting documentation, along with full payment directly to:
Xcel Energy Solar*Rewards Community; 825 Rice Street, Saint Paul, MN 55117; SRCMN@xcelenergy.com

IE Dispute
Project Timeline
Attachment D: 1 of 1

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

Attachment D to this response is marked as "Non-Public" pursuant to Minn. Stat. §13.37, subd. 1(b). This information is subject to efforts to maintain its secrecy. This information derives independent economic value, actual or potential, claimed by the customers, 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.

Attachments D is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Attachment D includes specific conversations and details regarding the Linden project site.
2. **Authors:** The timeline was prepared by Xcel Energy based on information exchanged with, or provided by, SunShare.
3. **Importance:** Specific project details require non-public treatment.
4. **Date the Information was Prepared:** Attachment D was prepared on June 28, 2018 for Xcel Energy's Initial Response.

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

IE Dispute
One Line Diagram
Attachment E: 1 of 1

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

Attachment E to this response is marked as "Non-Public" pursuant to Minn. Stat. §13.37, subd. 1(b). This information is subject to efforts to maintain its secrecy. This information derives independent economic value, actual or potential, claimed by the customers, 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.

Attachment E is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Attachments E is a one-line diagram for SunShare's Linden project.
2. **Authors:** The one line diagram was prepared by SunShare.
3. **Importance:** Specific project details require non-public treatment.
4. **Date the Information was Prepared:** Attachment E was prepared on April 28, 2015 by SunShare.

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

IE Dispute
IA Packet ver_2.19.16
Attachment F: 1 of 1

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

Attachment F to this response is marked as "Non-Public" pursuant to Minn. Stat. §13.37, subd. 1(b). This information is subject to efforts to maintain its secrecy. This information derives independent economic value, actual or potential, claimed by the customers, 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.

Attachment F is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Attachments F is the Interconnection Agreement for the Linden project.
2. **Authors:** Prepared by Xcel Energy based on information provided by SunShare.
3. **Importance:** Specific project details require non-public treatment.
4. **Date the Information was Prepared:** Attachment F was prepared on February 19, 2016.

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

Attachment G to this response is marked as "Non-Public" pursuant to Minn. Stat. §13.37, subd. 1(b). This information is subject to efforts to maintain its secrecy. This information derives independent economic value, actual or potential, claimed by the customers, 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.

Attachment G is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Attachment G is the study performed for SunShare's Linden project.
2. **Authors:** Prepared by Xcel Energy hired consultant.
3. **Importance:** Study analysis is proprietary and requires non-public treatment.
4. **Date the Information was Prepared:** Attachment G was prepared on May 6, 2016.

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

IE Dispute
IA Packet ver_5.18.16 & IA Packet ver_6.22.16
Attachment H & I: 1 of 1

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

Attachments H - I to this response is marked as "Non-Public" pursuant to Minn. Stat. §13.37, subd. 1(b). This information is subject to efforts to maintain its secrecy. This information derives independent economic value, actual or potential, claimed by the customers, 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.

Attachments H-I is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Attachments H and I are Interconnection Agreements for the Linden project.
2. **Authors:** Prepared by Xcel Energy based on information provided by SunShare.
3. **Importance:** Specific project details require non-public treatment.
4. **Date the Information was Prepared:** Attachment H was prepared on May 18, 2016 and Attachment I was prepared on June 22, 2016.

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

IE Dispute
Interconnection Study ver_4.14.17
Redacted
Attachment J: 1 of 1

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

Attachment J to this response is marked as "Non-Public" pursuant to Minn. Stat. §13.37, subd. 1(b). This information is subject to efforts to maintain its secrecy. This information derives independent economic value, actual or potential, claimed by the customers, 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.

Attachment J is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Attachment J is the study performed for SunShare's Linden project.
2. **Authors:** Prepared by Xcel Energy hired consultant.
3. **Importance:** Study analysis is proprietary requires non-public treatment.
4. **Date the Information was Prepared:** Attachment J was prepared on April 14, 2017.

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

IE Dispute
IA Packet ver_7.14.17
Attachment K: 1 of 1

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

Attachment K to this response is marked as "Non-Public" pursuant to Minn. Stat. §13.37, subd. 1(b). This information is subject to efforts to maintain its secrecy. This information derives independent economic value, actual or potential, claimed by the customers, 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.

Attachment K is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Attachment K is the Interconnection Agreement for the Linden project.
2. **Authors:** Prepared by Xcel Energy based on information provided by SunShare.
3. **Importance:** Specific project details require non-public treatment.
4. **Date the Information was Prepared:** Attachment K was prepared on July 14, 2017.

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

IE Dispute
Interconnection Study ver_6.27.17
Redacted
Attachment L: 1 of 1

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

Attachment L to this response is marked as "Non-Public" pursuant to Minn. Stat. §13.37, subd. 1(b). This information is subject to efforts to maintain its secrecy. This information derives independent economic value, actual or potential, claimed by the customers, 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.

Attachment L is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Attachment L is the study performed for SunShare's Linden project.
2. **Authors:** Prepared by Xcel Energy hired consultant.
3. **Importance:** Study analysis is proprietary and requires non-public treatment.
4. **Date the Information was Prepared:** Attachment L was prepared on June 27, 2017.

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

IE Dispute
Email Correspondence
Attachment M: 1 of 1

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

Attachment M to this response is marked as "Non-Public" pursuant to Minn. Stat. §13.37, subd. 1(b). This information is subject to efforts to maintain its secrecy. This information derives independent economic value, actual or potential, claimed by the customers, 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.

Attachment M is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Attachment M is email correspondence between Xcel Energy and SunShare.
2. **Authors:** Prepared by Xcel Energy and SunShare.
3. **Importance:** Project details require non-public treatment.
4. **Date the Information was Prepared:** Attachment M includes emails sent between December 13, 2016 and March 15, 2018.

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

IE Dispute
Example Signed IA
Attachment N: 1 of 1

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

Attachment N to this response is marked as "Non-Public" pursuant to Minn. Stat. §13.37, subd. 1(b). This information is subject to efforts to maintain its secrecy. This information derives independent economic value, actual or potential, claimed by the customers, 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.

Attachment N is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Attachment N is an additional Interconnection Agreement for SunShare.
2. **Authors:** Prepared by Xcel Energy based on information provided by SunShare.
3. **Importance:** Specific project details require non-public treatment.
4. **Date the Information was Prepared:** Attachment N was prepared on February 23, 2016.

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

IE Dispute
SunShare NDA
Attachment O: 1 of 1

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

Attachment O to this response is marked as "Non-Public" pursuant to Minn. Stat. §13.37, subd. 1(b). This information is subject to efforts to maintain its secrecy. This information derives independent economic value, actual or potential, claimed by the customers, 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.

Attachment O is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Attachment O is the NDA agreement between Xcel Energy and SunShare.
2. **Authors:** Prepared by Xcel Energy.
3. **Importance:** Specific project details require non-public treatment.
4. **Date the Information was Prepared:** Attachment O was prepared on January 31, 2018.

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

From: sam wheeler [redacted]
Sent: Tuesday, July 24, 2018 5:05 PM
To: David [redacted] dan ryan SS; Peterson, Jessica K; Denniston, James R
Cc: susan.peirce@state.mn.us
Subject: MNDOC RULING

Parties,

I have just been informed that the MNDOC has ruled that SunShare's specific Request for Relief on the Linden Dispute - that the IE rule that Xcel allow SunShare to proceed with construction of it 3 MW Solar Garden and that Xcel sign the IA and accept SunShare's 350k+ check for the IA - is beyond the jurisdiction of the IE.

MNDOC notes SunShare, at its own discretion take this specific Request for Relief item to the PMNPUC for resolution.

All other SunShare Requests for Relief are still in play within the existing Linden Dispute.

Thank you

Sam

Sam Wheeler
Energy Consultant
[redacted]

Solar*Rewards Community
Intake Form for Independent Engineer Review

This Intake Form should be used by an applicant to request an Independent Engineer (IE) Review under the Northern States Power Company Minnesota Tariff Section 9 Solar*Rewards Community Program, and to introduce into the IE Review any additional issues raised by the applicant during the review to be considered as part of the IE Review for the same SRC numbers at issue in the applicant's initial request. To initiate an IE Review, this form should be sent via email to the Minnesota Department of Commerce with a cc sent to SRCMN@xcelenergy.com

Please succinctly identify the engineering issues that you want the IE to resolve. Number each issue, and provide the SRC number and name of the applicant's legal entity associated with each SRC number. Describe the specific action requested from the IE and provide support for your position. Please duplicate the table below for any additional issues you would like to have resolved in this IE Review, and change the Issue Number in the top line of each copy of the table so that the issues are numbered consecutively.

This Intake Form was submitted on 8/14/2018, by:
Dan Ryan, SunShare, LLC and Lake Nokomis 8-12 LLC's,PROTECTED DATA BEGINS HERE [redacted] PROTECTED DATA ENDS HERE

Issue Number 1	
Succinct description of engineering issue.	As previously described in other Intake Forms, the Linden project has been materially impacted both in interconnection costs and limitations on the project's allowed interconnection capacity. A primary reason for these impacts are the assumptions and methods utilized by Xcel to mitigate Flicker. As currently modeled, we believe that Xcel is not incorporating the capabilities of Advanced Functionality Inverters (AFIs) as a way to mitigate flicker. AFIs have the capability to correct flicker and use of this functionality should be allowed and incorporated into the analyses. In previous disputes on the Glazier project (2015), Xcel argued that AFIs were not yet tested or certified by a Nationally Recognized Testing Laboratory (NRTL), such as Underwriters Laboratory (UL). In the dispute findings, the IE determined that the Glazier project would not be allowed to utilize the AFIs to perform voltage mitigation, until such time as the IEEE Standard 1547 or UL 1741 are updated or revised, and the AFIs functions are tested and certified by such. Since 2015, the testing and functionality of AFIs have improved drastically and the proposed inverters at the project include advanced functionality that can support voltage control that could be used to correct flicker.

SRC number(s) and Solar Garden name(s)to which this issue applies. Also include the name of the applicant's legal entity for each SRC number.	PROTECTED DATA BEGINS HERE PROTECTED DATA ENDS HERE
Specific action requested from the Independent Engineer.	We respectfully request the IE rule that the inverter functionality be incorporated into the interconnection study process and be allowed to help mitigate any flicker issues. The industry and inverter functionality have improved since the previous IE ruling and this functionality should be allowed to be utilized.
Explanation of and support for the position (include additional sheets if needed).	RESOLUTION OF THE SUNSHARE DISPUTE AT THE FOXTROT/BLUE HERON/COLD SPRING/GLAZIER INTERCONNECTION SITE

Utility Garden Name	Utility Award Level	Utility SRC
Linden01	Lake Nokomis 08 LLC	[redacted]
Linden02	Lake Nokomis 09 LLC	
Linden03	Lake Nokomis 10 LLC	
Linden04	Lake Nokomis 11 LLC	
Linden05	Lake Nokomis 12 LLC	

Issue Number 2	
Succinct description of engineering issue.	Tariff Section 10 states that the maximum value of allowable Flicker is 4%, which was written in the mid-2000's prior to the mass entrance of AFIs into the renewable energy market. In a previous dispute at the Glazier project, the IE determined that it is reasonable that Xcel use a value of 2.0% for Flicker in both "aggregate" and "individual" PV systems for interconnection modeling. However, following this IE ruling on the Glazier/Foxtrot/Blue Heron/Cold Spring site, the PUC required that Xcel provide an assessment of the impacts from voltage fluctuation and flicker, if any, on its system within three months of the operation (and annually thereafter_ of the Glazier project, which was designed and interconnected using a 2.0% assumption in models. This was done to provide more insight on the practical impacts to the PUC for future consideration. In the compliance report, both the short-term and long-term flicker severity calculated from measured data was approximately half of the planning levels from the relevant Standard. Therefore, we believe that the 2% assumption is too conservative given the actual performance data tracked at the direction of the PUC, since the measured data at a project designed with the 2% assumption experienced flicker much lower than allowable limits. Per the Glazier Compliance Report: *"Figure 8 depicts the short term flicker severity cumulative distribution for Pst which shows Pst-99% = 0.47 and Pst-95% = 0.41. These values are below the Pst planning level of 0.9, which indicates no violation in short term flicker severity is observed." "Figure 9 depicts the long term flicker severity cumulative distribution for Pst which shows Pst-99% = 0.35 and Pst-95% = 0.31. These values are below the Pst planning level of 0.7, which indicates no violation was observed."*

Figure 8 – Pst Statistical Summary

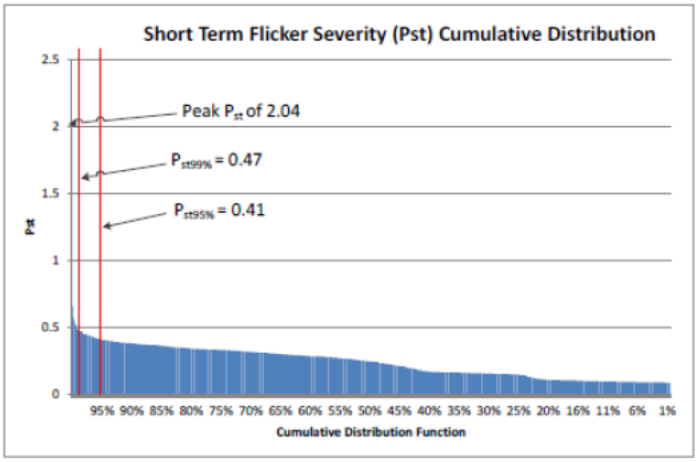
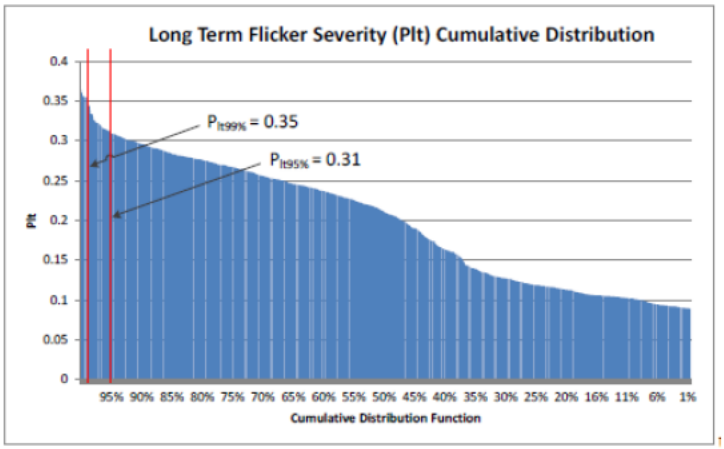


Figure 9 – Plt Statistical Summary



SRC number(s) and Solar Garden name(s)to which this issue applies. Also include the name of the applicant's legal entity for each SRC number.

Utility Garden Name	Utility Award Level	Utility SRC
Linden01	Lake Nokomis 08 LLC	[redacted]
Linden02	Lake Nokomis 09 LLC	
Linden03	Lake Nokomis 10 LLC	
Linden04	Lake Nokomis 11 LLC	
Linden05	Lake Nokomis 12 LLC	

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Specific action requested from the Independent Engineer.

We respectfully request the IE rule that the allowable flicker be increased from 2% to 4% and to recommend to the PUC that Xcel be required to track voltage at the Linden/Kane site again within the first 3 months and annually thereafter to report back to the PUC, since the measurements from an operational project designed with the 2.0% limitation had significantly less measured flicker than allowed.

Explanation of and support for the position (include additional sheets if needed).

1) RESOLUTION OF THE SUNSHARE DISPUTE AT THE FOXTROT/BLUE HERON/COLD SPRING/GLAZIER INTERCONNECTION SITE
2) Compliance Report – Voltage Fluctuation Glazier Site

From: Peirce, Susan (COMM) [mailto:susan.peirce@state.mn.us]
Sent: Tuesday, September 04, 2018 2:19 PM
To: Peterson, Jessica K; David Amster-Olszewski [redacted]
Cc: [redacted]
Subject: SunShare IE dispute

David, Jessica and Sam,

My understanding was that Xcel and SunShare were trying to reach a settlement on the Linden dispute, but that is no longer the case. Consequently, Sam should work on determining his finding on this dispute. I am including the additional intake form submitted by SunShare with this email. With respect to the request that smart inverters be considered in resolving this dispute, smart inverters have not yet been required by the Minnesota Commission and remain under consideration by the technical workgroup convened to develop technical standards for Minnesota interconnections, consequently, they cannot be required of Xcel at this time. Further consideration of the use of smart inverters will need to be taken up with the Commission if either party has a dispute. Sue

Sue Peirce
Rate Analyst Coordinator
Minnesota Department of Commerce
85 7th Place East, Suite 500, Saint Paul, MN 55101
P: 651-539-1832

In the Matter of an Independent Engineer Review as Authorized by the Minnesota Public Utilities Commission in Docket No. E002/M-13-867

Independent Engineer Review requested by SunShare LLC and Lake Nokomis LLC for the following SRC# listed:

Linden [PROTECTED DATA BEGINS ([redacted]; [redacted]) PROTECTED DATA ENDS]

Xcel Energy's Response to Intake Form Dated 8/14/2018

September 21, 2018

RESPONSE

Northern States Power Company (Company or Xcel Energy) provides this response to the Independent Engineer (IE) regarding the Linden project dispute identified above. SunShare has submitted an additional Intake Form dated August 14, 2018, which listed two new issues and requested the following action from the IE:

1. Incorporate capability of Advanced Functionality Inverters (AFIs) into the interconnection study process as a way to mitigate flicker, and
2. Use a 4 percent flicker standard for the Linden project study instead of the simplified IEEE 1453 voltage fluctuation approach adopted by Xcel Energy in April 2017.

The Department of Commerce determined on September 4, 2018 that the IE cannot require Xcel Energy to use smart inverter (AFI) capability, because this remains under consideration by the technical workgroup convened to develop technical standards for Minnesota interconnections and has not been required by the Minnesota Public Utilities Commission (Commission) to date.[1] Therefore we are not responding to issue No. 1 above.

With respect to what voltage fluctuation criteria should be used to study the Linden project, we have provided a comprehensive overview and explanation in our Initial Response dated June 28, 2018 (June Response) and in our response to IE's

[1] Email from Susan Peirce dated September 4, 2018.

Information Request (IR) No. 4 dated July 19, 2018. The January 2017 Settlement Agreement executed between SunShare and Xcel Energy regarding the Linden project **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]**. This Settlement Agreement is binding on SunShare and does not include an option to study the project with a 4 percent flicker standard, which has never been applied to any other Solar*Rewards Community project.

As we explained in our June Response, Xcel Energy has applied the simplified IEEE 1453-based approach consistently to all Solar*Rewards Community projects beginning April 1, 2017. This methodology was thoroughly developed and vetted in a transparent process; including extensive research on industry standards, peer utility reviews, stakeholder input through a Technical Stakeholder Group, and public filing with the Commission without objection. It would be discriminatory against all other developers to favor SunShare by applying a 4 percent flicker standard to the Linden project.

SunShare's Intake Form references results from a voltage fluctuation assessment – an April 2017 compliance report to the Commission that is specific to the Glazier project – as a justification for a higher 4 percent flicker standard. The Commission ordered the Company to use 2 percent full on/full off individual and aggregate flicker standard (based on IEEE 141 flicker curve) for the Glazier project in its November 1, 2016 Order. The Commission also required the Company to provide a compliance report for the Glazier project, with an assessment of impacts from voltage fluctuation and flicker on Xcel Energy's distribution system.[2] Based on this Glazier report, SunShare is now requesting that for the Linden project "allowable flicker be increased from 2% to 4%." We assume that this means a request to re-study the Linden project with a 4 percent full on/full off individual and aggregate flicker standard.

[2] The Glazier Compliance Report was filed on April 28, 2017 in Docket No. E002/M-13-867, see https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={9E04B71D-EB41-4059-9DD2-95AA4631975A}&documentTitle=20174-131402-01

The compliance report referenced by SunShare is specific to the Glazier project site characteristics and the analysis should not be used to draw any general conclusions about the appropriate voltage fluctuation standard that should be applied to all Solar*Rewards Community project sites. The Glazier analysis uses IEEE 1453-2015 evaluation procedures for data monitoring and assessment. SunShare is misinterpreting the concepts used in the IEEE 1453 standard and Glazier report as well as their application. For example, Sunshare misses the important distinction between flicker and rapid voltage change, which is essential in applying the voltage fluctuation limits. Further, SunShare indicates that the entire planning limit for flicker should be allocated to a single customer, which is in direct conflict with the IEEE 1453 evaluation standard that states "individual customer emission limits are developed using a procedure that allots each customer some portion of a planning limit after allowing for flicker that propagates from other network voltage levels (or locations)." Due to these fundamental misunderstandings, the IE should disregard SunShare's claim that the flicker standard can be doubled because the measured Glazier data was about half of the planning levels – a conclusion that has no firm footing in technical standards or good utility practice.

Furthermore, the IE should not consider a new 4 percent voltage fluctuation approach based on a moot IEE 141 flicker standard, when Xcel Energy has moved forward to implement a more robust IEEE 1453-based approach – a transition that was widely requested and supported by the solar developer industry.

SunShare's February 21, 2017 email (included as Attachment E to Xcel Energy's Response to IR No. 4) confirmed SunShare's understanding that the Linden project was going to be studied under IEEE 1453-based standard after it was finalized in Xcel Energy's IEEE 1453 work group. This IEEE 1453 methodology was then used in the most recent Linden project study dated June 27, 2017.

If SunShare's position is that the simplified IEEE 1453-based approach adopted by Xcel Energy in April 2017 is not the true IEEE 1453 standard **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]**, as was stated in SunShare's July 12, 2018 email to Sam Wheeler, then the only available option **[PROTECTED DATA BEGINS** [redacted]

[redacted] **PROTECTED DATA ENDS]** is that the Linden project will be studied with the 2 percent full on/full off flicker standard.

Respectfully submitted,

Xcel Energy
Date: September 21, 2018

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

Attachment J to our Appeal is marked as "Non-Public" pursuant to Minn. Stat. §13.37, subd. 1(b). This information derives independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from its use and is marked as "Not Public" in its entirety. This information is also classified as security information under Minn. Stat. §13.37, subd. 1(a) as the disclosure of this information would be likely to substantially jeopardize the security of information or property against tampering, improper use, illegal disclosure, trespass or physical injury. Further, consistent with Minn. Stat. §13.02, subd 9, and §13.03, subd 1, this information is "nonpublic data" as federal law treats it as "trade secret" under 18 USC §1839, because it reflects business, scientific, technical, economic, or engineering information, including patterns, plans, compilations, formulas, designs, methods, techniques, processes, programs, or codes, where reasonable measures have been taken to keep such information secret and it derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable through proper means by, another person who can obtain economic

Attachment J is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Overhead and Underground Distribution Manual, Standards for Engineering and Design of Distribution Substations, Guidelines for System Protection Relaying Philosophy, Standards for Distribution System Integrated Design Phase I, and Standards for Substation Integration Design Phase II.2.
2. **Authors:** The data was prepared by several Company employees.
3. **Importance:** This document contains trade secret information, security information, and nonpublic data.
4. **Date the Information was Prepared:** The information was prepared over the period of many years.

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

☒ **Not Public Document – Not For Public Disclosure**
☐ **Public Document – Not Public Data Has Been Excised**
☐ **Public Document**

Xcel Energy
Docket No.: E002/13-867 IRSX Linden
Response To: Sam Wheeler Information Request No. 4

Requestor: Sam Wheeler
Date Received: July 13, 2018

Question:

Provide the written, policy/procedure/methodology, that is currently in place at Xcel for what Xcel calls its IEEE 1453 "Simplified" Flicker Standard noted as by Xcel in its counter-arguments, and a complete, written, explanation of specific, actual IEEE 1453 series Standards, sections, methods it is based on.

Response:

The Minnesota Public Utilities Commission's November 1, 2016 Order directed Xcel Energy to "work with other interested parties to develop a plan for transition to incorporating the standards of IEEE 1453 into its modeling of voltage fluctuations and flicker for solar PV. The plan shall be filed within six months of this order." (Order Point 2). The Commission Order is included as **Attachment A**.

Accordingly to this Order, Xcel Energy initiated analysis, peer-review and a stakeholder process to develop an IEEE 1453-based voltage fluctuation methodology for analyzing impacts of solar PV generation. On April 26, 2017, Xcel Energy filed a compliance filing with the Commission regarding transition to incorporating the standards of IEEE 1453, including a Compliance Report, White Paper detailing the simplified IEEE 1453 methodology, and minutes from three IEEE 1453 Technical Stakeholder Group meetings along with the Group Charter. This filing in its entirety is included as **Attachment B** (a link to the filing was provided in our June 28, 2018 Response on pages 17 and 19). The White Paper dated March 31, 2017 (included in **Attachment B**, as Attachment A to the April 26 filing) constitutes Xcel Energy's written IEEE 1453-based methodology which is currently in place. The Commission issued a separate Notice of Receipt for the compliance filing on June 2, 2017, see **Attachment C**.

The IEEE 1453-based methodology was introduced and discussed in a S*RC Implementation Workgroup meeting on March 15, 2017. Minutes and presentations from this meeting were filed with the Commission on May 12, 2107 and are included as **Attachment D** (see Attachment A to the filing, pages 6, 22-23).

Xcel Energy has consistently called the current adaptation of IEEE 1453-based methodology a simplified approach because implementation of the full IEEE 1453 standard would require additional time-series data and more powerful software tools. For example, the full time-series analysis would require that generation and load data is collected at one-second time interval with specialized equipment. As our April 26, 2017 Compliance Report explained, the time-series data, and software to run dynamic power flow analysis simulations are not currently available to Xcel Energy (see Attachment B, pages 6-8 for more discussion on challenges regarding full implementation of IEEE 1453).

Application of the IEEE 1453 standard to the Linden site, as worded in the Settlement Agreement, is qualified by stating that the **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]** The only way in which the IEEE 1453 standard has been implemented by Xcel Energy for purposes of design study is by the simplified approach as described in the White Paper set forth in **Attachment B**. Xcel Energy has consistently applied the IEEE 1453 analysis method to all solar garden applications since April 1, 2017.

We also include as **Attachment E** an email from SunShare's Director of Construction and Program Execution dated February 21, 2017 – after entering into the Settlement Agreement – that SunShare would like to restudy the Linden project **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]**

The interconnection standard IEEE 1547-2018 was published in April 2018 and includes a simplified adoption of IEEE 1453 concepts in Section 7.2 (*Limitation of voltage fluctuations induced by DER)*. The Company has an ongoing effort to assure interconnection practices are harmonized with the newly revised standard. While the review of voltage fluctuation has yet to be completed, the Company views the fact that IEEE 1547-2018 also used a simplified approach to IEEE 1453 as indication that the Company's current voltage fluctuation approach is reasonable.

Because of licensing and copyright regulation, Xcel Energy cannot provide a copy of the IEEE 1453-2015 Standard to the IE. The Standard is available for purchase from multiple sources, for example:

- https://standards.ieee.org/findstds/standard/1453-2015.html

- https://webstore.ansi.org/RecordDetail.aspx?sku=IEEE%201453-2015&msclkid=4fecc06f7f1c12f5ec289b21792db808&utm_source=bing&utm_medium=cpc&utm_campaign=Campaign%20%231&utm_term=IEEE%201453&utm_content=IEEE

- https://www.techstreet.com/searches/20420976?searchText=%22IEEE+1453%22&sid=msn&utm_medium=cpc&utm_source=bing

This response has marked certain data as being protected data as this information is treated as confidential under the Settlement Agreement and is classified as trade secret pursuant to Minn. Stat. §13.37, subd. 1(b).

Preparer:	Jessie Peterson/ Patrick Dalton
Title:	Sr. Regulatory Analyst / Sr. Engineer
Department:	Customer Solutions / Distribution Engineering
Telephone:	612.330.6850 / 612.229.5591
Date:	July 19, 2018

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
John A. Tuma	Commissioner

In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program

In the Matter of a Formal Complaint and Petition by SunShare, LLC for Relief Under Minn. Stat. § 216B.1641 and Sections 9 and 10 of Xcel Energy's Tariff Book

ISSUE DATE: November 1, 2016

DOCKET NO. E-002/M-13-867

DOCKET NO. E-002/M-15-786

ORDER RESOLVING INDEPENDENT-ENGINEER APPEALS AND ESTABLISHING PROCEDURES FOR FUTURE DISPUTES

PROCEDURAL HISTORY

On August 6, 2015, the Commission issued an order establishing a process for developers in Xcel Energy's solar-garden program to submit interconnection disputes to an independent engineer.[1] The order provided that parties could seek Commission review of an independent engineer's decision by filing an appeal in Docket No. E-002/M-13-867 within five business days of delivery of the engineer's written report.

Between April 7 and August 5, 2016, the Commission received appeals of seven independent-engineer decisions, as well as responses to those appeals.

On April 20, 2016, the Commission issued a notice soliciting comments on certain issues raised by the appeals. On May 20 and June 1, the following parties filed comments and/or reply comments in response to the Commission's notice:

- GreenMark Solar LLC
- Minnesota Department of Commerce (Department)
- Minnesota Solar Energy Industry Association (MnSEIA)
- Novel Energy Solutions
- Sunrise Energy Ventures, LLC
- SunShare, LLC
- Xcel Energy

[1] Docket No. E-002/M-13-867, Order Adopting Partial Settlement as Modified ("August 2015 order").

On September 20, 2016, the Commission met to consider the appeals.

FINDINGS AND CONCLUSIONS

I. Summary of Commission Action

In this order, the Commission resolves the seven appeals before the Commission and establishes new procedures for future interconnection disputes. The Commission will require Xcel to submit, within 30 days of the date of this order, any compliance filings necessary to reflect the Commission's decisions.

II. Background

A. Community Solar Gardens

Under Xcel's community-solar-garden program, its customers may subscribe to solar photovoltaic generating facilities (known as "community solar gardens," or simply "solar gardens") and receive bill credits for a portion of the energy generated by the solar garden.[2]

A solar garden may be owned by Xcel or by a private company that contracts to sell the output to the utility. To date, all solar gardens in Xcel's program have been developed by private companies. These developers must obtain Xcel's approval to connect to its electric system through a process known as "interconnection."

B. Solar-Garden Interconnection

Solar-garden interconnection is governed by two sections of the Xcel's tariff. Section 10 sets forth the process for interconnecting any distributed-generation facility with a capacity of ten megawatts (MW) or less.[3] Section 9 contains Xcel's solar-garden program rules, which modify the Section 10 process in several respects.[4]

The Section 10 process begins with the developer submitting an interconnection application (Step 1). This is followed by a preliminary review in which Xcel determines whether an engineering study needs to be done (Step 2). The purpose of an engineering study is to determine whether modifications to the interconnecting facility or upgrades to Xcel's system will be necessary to maintain safe and reliable service.

If an engineering study is needed, the applicant must decide whether to proceed and pay for the study or exit the interconnection queue (Step 3). If the applicant elects to go forward, Xcel completes the engineering study in a specified timeframe that ranges from 20 to 90 working days depending on the size of the project (Step 4).

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[2] *See* Minn. Stat. § 216B.1641.

[3] *See* Minnesota Electric Rate Book section 10, sheets 73–162.

[4] *See* Minnesota Electric Rate Book section 9, sheets 64–68.16.

Once the study is done, Xcel provides the applicant with an interconnection agreement and an estimate of the costs for Xcel's work, including any system upgrades necessary to accommodate the new facility (Step 5). If the applicant wants to continue with the interconnection, it must make any required up-front payments, sign the interconnection agreement, and provide Xcel with a final, detailed design of the facility (Step 6).

Xcel then does a final design review, and the parties order equipment and complete construction of the facility and any system upgrades (Steps 7–8). After final testing, Xcel gives its written approval for the facility to operate, and the applicant provides Xcel with updated engineering drawings (Steps 9–11).

Section 9 modifies the Section 10 interconnection process in at least two ways that are relevant to the appeals under review. First, it excuses Xcel from making "material" upgrades to its distribution system to accommodate co-located solar-garden projects.[5] Second, Section 9 allows a solar-garden developer to obtain an interconnection agreement on an expedited basis if its project meets certain criteria. These modifications will be discussed in greater detail in the sections that follow.

C. Interconnection Disputes

As required by the Commission's August 2015 order, Section 9 provides a process for solar-garden developers to submit interconnection disputes to an independent engineer selected by the Department. The tariff includes a nonexclusive list of topics that may be submitted to an independent engineer: Xcel's determination that a developer's application is incomplete, the timeliness of application and study processing, and the cost and necessity of required study costs and distribution-system upgrades.[6]

Either the developer or Xcel may appeal an independent engineer's decision to the Commission by making a filing in Docket No. E-002/M-13-867 within five business days of delivery of the engineer's written report.

III. SunShare's Becker, Glazier, Bartlett, and Murphy Sites

A. Introduction

On August 28, 2015, SunShare filed a complaint in Docket No. E-002/M-15-786 alleging that Xcel had violated its Section 9 and 10 tariffs in processing the developer's requests to interconnect solar gardens to Xcel's system.[7]

The Commission referred SunShare's complaint to the Department for review by an independent engineer under the process set forth in Section 9.[8]

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[5] A "co-located" solar-garden project is a group of solar gardens that display characteristics of a single development. Section 9, sheet 68.

[6] Section 9, sheet 68.11.

[7] The original complaint encompassed more than 100 solar gardens located at 15 separate sites. However, only 4 of those sites are involved in these appeals.

[8] Docket No. E-002/M-15-786, Order Finding Jurisdiction and Referring Complaint to Independent Engineer (December 1, 2015).

The Department appointed an engineer to hear the case. The parties submitted written arguments to the engineer, executed nondisclosure agreements, and responded to numerous information requests.

In early 2016, the independent engineer issued reports setting forth his recommended resolution of the parties' disputes for four of SunShare's solar-garden sites. In many cases, SunShare alleged the same tariff violation at multiple sites; the engineer treated these global issues consistently among the affected sites.

Xcel and SunShare both appealed aspects of the engineer's first report, which concerned SunShare's Becker site. Xcel also appealed the reports for the other three sites.

By the time the matter came before the Commission, the parties had significantly reduced the number of live issues. At the Commission hearing, the major points of contention concerned

- Xcel's decision to limit the allowed generation capacity and/or require costly upgrades at two sites due to concerns about system impacts from voltage fluctuation and its refusal to permit SunShare to use advanced-functionality inverters to mitigate these impacts; and
- Variations between Xcel's preliminary, or "indicative," interconnection-cost estimates and updated estimates that it provided at later stages of the interconnection process.

In the following sections, the Commission addresses these topics and related issues raised by the parties' appeals.

B. Voltage Fluctuation

1. Introduction

Voltage fluctuation, also called "flicker," refers to repeated changes in voltage magnitude within a utility's distribution system that may cause customers' lights to visibly flicker or sensitive electronic equipment to malfunction.

Flicker can occur when a generator comes online or goes offline. More relevant to this case, it can also occur if clouds passing over the solar arrays cause large, rapid changes in electricity production.

Xcel's Section 10 tariff requires that a distributed generator must not produce "excessive flicker" to adjacent customers.[9] The tariff specifies that the maximum acceptable amount of flicker is 4% when the load is added to or removed from Xcel's system.[10] But it states that most utilities use a 2% "design criteria."[11]

[9] Section 10, sheet 146.

[10] *Id.*

[11] *Id.*

In its engineering studies of SunShare's solar gardens, Xcel limited the permissible level of flicker to 1.5%.[12] At the Becker site, where SunShare had planned to locate 5 MW of solar gardens, this restriction reduced the allowable capacity to 3.5 MW. At the Glazier site, it created a need for extra infrastructure upgrades to accommodate the planned gardens.

The independent engineer concluded that Xcel's flicker-related interconnection practices were not in compliance with current engineering standards. More specifically, he concluded that the IEEE[13] 1547 standard and related GE Flicker Chart, which Xcel relies on in its modeling, had been superseded by IEEE 1453 and other standards.

The engineer recommended that Xcel use a 2.0% flicker threshold in modeling both the individual and the aggregate impact of the Becker and Glazier gardens. Longer term, he recommended that the Commission provide a deadline for Xcel to come into compliance with the latest IEEE standards and suggested that one year would be a reasonable period.

SunShare also requested that it be allowed to use advanced-functionality inverters (also known as smart inverters) to mitigate potential flicker.[14] Xcel had granted SunShare permission to install smart inverters but not to activate their advanced functions.

Xcel's tariff requires that, prior to installation, an inverter "shall be Type-Certified for interconnection to the electrical power system."[15] "Type-certified" means that the inverter "is listed by an OSHA listed national testing laboratory as having met the applicable type testing requirement of UL 1741."[16]

The independent engineer found that no manufacturer's advanced inverter functions had yet been approved by IEEE or tested and certified by UL. He concluded that Xcel was justified in forbidding the use of smart inverters' voltage-control functions until such time as the relevant IEEE standards and UL 1741 are jointly updated and revised and the functions are tested and certified by UL.

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[12] Xcel's internal distributed-generation-study requirements specified a 1.5% flicker limit for individual systems and a 2% limit for the aggregate solar PV on a distribution feeder. *See* Docket No. E-999/CI-15-755, Response to MPUC Information Requests 1–5, Attachment C.1 "Distributed Generation Engineering Study Requirements," at 2 (February 5, 2016).

[13] Institute of Electrical and Electronics Engineers

[14] An inverter is a component of a solar PV system that converts the direct current (DC) electricity produced by solar panels into grid-compatible alternating current (AC) electricity. An advanced-functionality inverter or smart inverter has voltage-control functions that enable it to fully or partially mitigate flicker.

[15] Section 10, sheet 143.

[16] Section 10, sheet 138. UL, formerly Underwriters Laboratories, develops product-safety standards and tests products for compliance with those standards.

2. Positions of the Parties

a. Xcel

Xcel disagreed with the engineer's conclusion that the voltage-fluctuation standards on which it relies have been superseded by IEEE 1453. According to Xcel, IEEE 1453 merely offers an alternative approach to measuring and evaluating voltage fluctuation that relies on data-driven modeling to account for the particular attributes of the site in question. But Xcel stated that it was not opposed to further studying IEEE 1453 and refining its voltage-fluctuation study practices over the coming year.

Xcel argued that its specific flicker limits, while conservative, are reasonable and in line with industry practice. The Company nevertheless acknowledged that the independent engineer's recommended limit of 2% individual/aggregate for the Becker and Glazier sites was within a range of reasonable flicker values. And at the September 2016 hearing in this matter, Xcel stated that it currently applies a 2% individual/aggregate flicker limit to new solar-garden applications.[17]

Finally, Xcel agreed with the independent engineer's conclusion that the Company had properly declined to allow SunShare to use advanced inverter functions, arguing that these functions had not been certified under national standards, did not comply with the relevant IEEE standards, and posed unjustified risks to system reliability and safety.

b. SunShare

SunShare asked that Xcel be required to restudy its Becker and Glazier projects using a 2% individual/aggregate flicker threshold, consistent with the independent engineer's recommendation. And it supported the engineer's recommendation that Xcel be given a year to comply with the latest IEEE standards pertaining to flicker.

SunShare appealed the engineer's determination that Xcel properly denied its request to use advanced smart-inverter functions. It argued that permitting the use of advanced inverter functions would allow more megawatts of solar gardens to interconnect, reduce interconnection costs, and increase project certainty.

SunShare stated that, although IEEE has not yet updated its standards for advanced functionality inverters, the State of California has developed its own standard, known as Rule 21, and UL has provided a supplement to UL 1741 (UL 1741 "SA") that allows inverters to be type-certified to the Rule 21 standard. SunShare asked that the Commission require Xcel to make a compliance filing indicating how it will use Rule 21 and UL 1741 SA type-certified smart inverters as a flicker mitigation strategy for solar gardens greater than 1 MW in size.

[17] Xcel apparently changed the limit in or around August 2016; on August 23, it filed with the Commission a "voltage fluctuation settlement offer" offering developers without signed interconnection agreements the option to have their previously studied projects restudied using a 2% limit, subject to certain conditions.

c. Voltage Flicker Task Force

Finally, a group of solar-garden developers filing jointly as the Voltage Flicker Task Force proposed additional modifications to Xcel's flicker modeling assumptions.[18] The modeling assumptions suggested by this taskforce were intended to better approximate the effect of clouds passing over solar gardens, and included

- A maximum change of 70% nameplate capacity in PV plant output due to transient cloud cover (as opposed to the "full-on full-off" assumption used in Xcel's current modeling);
- A minimum of 1.5 seconds ramp time (up and down) due to fast-moving clouds; and
- A maximum of 10 to 25 voltage changes within any 60-minute period.

3. Commission Action

The Commission will require Xcel to use a 2.0% flicker threshold (full-on full-off), for both individual and aggregate PV systems, in its engineering studies for SunShare's projects at the Becker and Glazier sites. This resolution conforms to Xcel's current practice of using a 2% threshold and addresses the specific complaints raised by SunShare. In particular, as Xcel confirmed at hearing, using a 2% flicker threshold will allow the full 5 MW to be interconnected at the Becker site and will reduce the reconductoring required at the Glazier site from 6,400 feet to only 2,400 feet.

More generally, the Commission finds that Xcel's flicker-related interconnection practices comply with IEEE 1547, a current engineering standard. However, IEEE 1453—which is also a current engineering standard—provides a data-driven method for modeling voltage fluctuations from solar PV. This method holds promise for better reflecting real-world conditions, once the necessary input data are available. Accordingly, the Commission will require Xcel to work with other interested parties to develop and file a plan for transition to incorporating the standards of IEEE 1453 into its modeling of voltage fluctuations and flicker for solar PV.

Additionally, the Commission will require Xcel to file a compliance report, within three months of the date the Becker and Glazier projects begin operating, providing an assessment of impacts from voltage fluctuation and flicker, if any, on Xcel's system—and to file a similar assessment annually for the solar-garden program as a whole. This will allow the Commission and other stakeholders to assess the extent of voltage fluctuations from solar gardens and how they are affecting Xcel's system.

Finally, the Commission agrees with the independent engineer that SunShare should not be permitted to activate noncertified functions of advanced-functionality inverters to perform flicker mitigation without Xcel's explicit permission until such time as the inverter functions have been tested and certified under UL standards, or until further order of the Commission. Xcel's tariff requires that inverters be type-certified using UL 1741. UL 1741 is specifically intended to be used with IEEE 1547, which does not yet include standards for advanced smart inverter functions.

[18] The members of the taskforce who joined in this recommendation were GreenMark Solar, Novel Energy Solutions, Innovative Power Systems, Sunrise Energy Ventures, Minnesota Solar Connection, Ameresco, and SunShare.

C. Indicative Cost Estimates

1. Introduction

As mentioned earlier, Xcel's Section 9 tariff provides a process for solar-garden developers to obtain an interconnection agreement on an expedited basis. Once a developer has shown that its garden project is "expedited ready," Xcel has 50 business days to study the project and to provide an interconnection agreement.[19]

In addition to shortening the deadline for Xcel to deliver an interconnection agreement, Section 9 makes several changes to the Section 10 engineering-study process. Instead of completing a detailed engineering study, Xcel undertakes a more abbreviated "engineering scoping study" that results in an "indicative cost estimate."[20]

The developer must pay one-third of the indicative cost estimate and provide a letter of credit for the remaining portion before Xcel will countersign the interconnection agreement.[21] Detailed engineering studies are not done until after the parties sign the interconnection agreement.[22]

In August 2015, Xcel provided SunShare with indicative cost estimates for the Becker, Glazier, and Bartlett sites. It provided updated indicative cost estimates in October. In December, Xcel began a design-refinement process to produce more detailed cost estimates for these garden sites. As part of this process, Xcel performed "site due diligence" by visiting the sites and confirming the details of its infrastructure adjoining the sites.

In January 2016, Xcel provided SunShare with refined cost estimates. Certain components of these refined estimates showed substantial variation from the earlier, indicative estimates. For example, at the Becker site, Xcel had initially projected substation upgrades costing $339,000; in the January 2016 estimate, the number was $181,000, a 47% decrease. For distribution upgrades, the Company had initially projected costs of $233,250; in the January estimate, the number was $486,000, a 108% increase.

The independent engineer concluded that it would be reasonable for Xcel to undertake infrastructure due diligence before performing the engineering scoping study and delivering an indicative cost estimate. He also concluded that it would be reasonable for Xcel to provide indicative cost estimates with +/-20% accuracy and recommended that the Commission excuse SunShare from paying actual costs above a +20% threshold. Finally, he concluded that it would be

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[19] *See* Section 9, sheets 68 (establishing 50-day "Interconnection Agreement Time Line") and 68.5 (providing that "once a Community Solar Garden is Expedited Ready, the Company will have the time in the Interconnection Agreement Time Line . . . to provide an Interconnection Agreement for signature"). A developer must meet a number of requirements to achieve "expedited ready" status, but these requirements are not material to the dispute at hand.

[20] Section 9, sheet 68.

[21] Section 9, sheet 68.8.

[22] *See* Section 9, sheet 68.5 (providing that "[n]o detailed estimates per Step 5 of the Section 10 tariff will be performed" before an applicant is provided with an interconnection agreement).

unreasonable for Xcel to charge SunShare for redoing any studies, models, or cost estimates based on incorrect flicker values, equipment ratings, or other errors.

2. Positions of the Parties

a. Xcel

Xcel appealed the independent engineer's indicative-cost-estimate findings. It argued that under the expedited Section 9 process, no detailed cost estimates are performed before an interconnection agreement is signed, and that requiring the Company to perform cost estimates to a +/-20% certainty could require changes to the tariff.

Xcel argued that it cannot complete the diligence contemplated by the independent-engineer reports in 50 business days. According to Xcel, assuring a +/-20% level of accuracy would require several visits to the project site to inspect surrounding poles, wires, trees, and the relevant substation, as well as coordination between the Company's distributed-generation engineers, local-area engineers, substation engineers, project designers, the developer, and internal or external construction resources.

Moreover, Xcel argued that the engineer's recommendation that Xcel not be allowed to charge SunShare for costs above a +20% threshold both conflicts with the tariff and fails to account for the complexities involved in designing and constructing interconnection projects. The tariff requires developers to pay the actual costs of interconnection even if those costs exceed what is initially estimated.[23] And Xcel argued that requiring the Company or its ratepayers to absorb costs above the initial estimate would unreasonably insulate developers from the risk of costs changing due to unforeseen circumstances such as weather, permitting requirements, equipment availability, or the actions of other developers in the interconnection queue.

b. SunShare

SunShare asked the Commission to require Xcel to (1) perform its detailed infrastructure due diligence prior to delivering an indicative cost estimate and (2) calculate cost estimates within a +/-20% certainty based on site-verified Xcel infrastructure data.

SunShare argued that Xcel should be required to provide developers with an accurate estimate before they are required to put down a deposit, stating that widely varying cost estimates make gardens difficult to finance. It argued that there is nothing in the tariff to prevent Xcel from undertaking site due diligence before calculating an indicative cost estimate, and it found Xcel's claim that it cannot deliver detailed estimates within 50 days unpersuasive.

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[23] See Section 10, sheet 116, which states,

> The Interconnection Customer is responsible for the actual costs to interconnect the Generation System with Xcel Energy, including, but not limited to any Dedicated Facilities attributable to the addition of the Generation System, Xcel Energy labor for installation coordination, installation testing and engineering review of the Generation System and interconnection design. . . . While estimates, for budgeting purposes, have been provided . . . the actual costs are still the responsibility of the Interconnection Customer, even if they exceed the estimated amount(s).

SunShare maintained that Xcel should be held to its initial estimate by being forced to bear costs above 120% of the estimate. However, if the Commission chooses not to implement this cost-allocation recommendation, SunShare recommended that the Commission implement some other mechanism to ensure that Xcel is making its best efforts to deliver accurate, financeable cost estimates.

c. Department

The Department recommended that Xcel be required to stand behind its cost estimates by keeping the costs within a +/-20% variance from the original estimate. It argued that developers need some assurance of the accuracy of interconnection cost estimates to successfully finance and construct solar gardens.

3. Commission Action

The Commission finds that Xcel's cost-estimate process, which provides an indicative cost estimate prior to execution of the interconnection agreement and a refined estimate later, is consistent with the Section 9 process outlined earlier. The Commission therefore declines to adopt the independent engineer's recommendation to require Xcel to undertake infrastructure due diligence before calculating an indicative cost estimate or to hold the Company to a +/-20% accuracy range for the estimate.[24]

SunShare argues that widely varying estimates make gardens difficult to finance. Yet Xcel reports that hundreds of megawatts of solar gardens are currently in the detailed design and construction phase of development, a fact which the Company suggests undercuts SunShare's claim that the process is hindering garden financing. Without knowing the level of cost variance experienced by developers other than SunShare, however, it is difficult to evaluate either party's argument.

To gain a better understanding of cost-estimate variance across Xcel's solar-garden program, the Commission will require the Company to report variances between the indicative cost estimate and actual project costs—both the total cost and the substation and distribution components. For each of these costs that falls outside a +/-20% range, Xcel will be required to provide a detailed explanation for the variance. The Company will report this information within 30 days of the actual cost being provided to the developer, in its monthly solar-garden program update.

Finally, the independent engineer recommended that Xcel not be allowed to charge SunShare for redoing any studies, models, or cost estimates based on incorrect flicker values, equipment ratings, or other errors by the Company. At hearing, Xcel stated that when it makes a mistake in its modeling, its practice is to correct the error at its own expense. The Commission agrees that Xcel's current practice is appropriate and will require the Company to perform all engineering rework necessary to correct its input errors at no additional charge to SunShare.

[24] As of April 2016, none of the four SunShare projects had experienced cost increases of more than 16% on a total-project basis.

D. Information Exchange

In the proceedings before the independent engineer, Xcel and SunShare executed a nondisclosure agreement (NDA) establishing the conditions under which the parties would share sensitive information with each other and the engineer. Through the NDA, SunShare was able to gain access to the computer models Xcel used in conducting its engineering studies, as well as other trade-secret information.

The independent engineer determined that it was reasonable that a single NDA be sufficient for all future requests to obtain, view, or review information related to SunShare's four projects for the duration of the interconnection process.

Xcel maintained that the NDA does not apply beyond the context of the independent engineer's review of the parties' disputes. The Company noted that the express purpose of the NDA is to allow the engineer to prepare a written report. It argued that since the engineer has already issued his reports, SunShare can no longer access confidential or trade secret material under the NDA.

Xcel also noted that the NDA provides that Xcel's confidential information is shareable with SunShare only if the engineer expects to rely on the information as a basis for his decision or wants SunShare to respond to the information. Xcel argued that this provision further suggests that the NDA is limited to facilitating the independent engineer's review and does not continue in perpetuity.

The Commission concurs with Xcel that, by its terms, the nondisclosure agreement signed as part of SunShare's independent-engineer review process does not apply beyond the context of that process, and is limited in scope to facilitating the engineer's review.[25]

IV. Novel's Raser Project

A. Introduction

As mentioned earlier, Xcel's Section 9 tariff excuses the Company from making material upgrades to its distribution system to accommodate co-located solar-garden projects.

Material upgrades fall into two categories. Certain upgrades, such as installing or upgrading a substation transformer, are "per se" material and will never be performed for co-located solar gardens. A second category of upgrades, generally those that entail extending or rebuilding power lines, will be considered material only if, based on Xcel's indicative cost estimate, the aggregate cost of those upgrades will exceed $1 million.[26] If Xcel determines that a project will require this second type of material upgrade, it must provide the developer with an itemized list of the cost inputs, including unit costs and any underlying data and documentation related to those unit costs.

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[25] The independent engineer's reports also dealt with information that Xcel had withheld on the basis that it was critical infrastructure information as defined in Federal Energy Regulatory Commission (FERC) rules. However, at this time there are no outstanding disputes on the issue of critical infrastructure information, and the independent engineer's statements on this issue are not findings that require the Commission to take action.

[26] Section 9, sheets 68.4–.5.

Xcel's indicative cost estimate for Novel's Raser site was $1,079,500, which exceeded the material-upgrade limit.

Novel requested an independent-engineer review, arguing that its project should be allowed to proceed since indicative cost estimates have a low degree of accuracy, and Xcel's estimate for this project was within a reasonable range of the material-upgrade threshold.

Xcel responded that it uses least-cost assumptions in calculating the indicative cost estimate, an approach that favors developers by subjecting fewer projects to the material-upgrade limit. Moreover, if the estimate later rises above the limit, a project will still be allowed to proceed.

The independent engineer concluded that Xcel's application of the material-upgrade limit was consistent with the tariff. The engineer also found that the Company's use of an indicative cost estimate is consistent with interconnection practices in other states—where initial cost estimates take the form of either "good faith" estimates without an accuracy requirement or nonbinding ranges.

B. Positions of the Parties

1. Novel

Novel recommended that Xcel be required to calculate indicative cost estimates with a greater degree of accuracy, or alternatively, to mitigate the impact of the current indicative cost estimate through one or more of the following approaches:

- Permit developers to move a project to a new site within three miles of the original site if it results in interconnection costs below the material-upgrade limit;
- Let developers hire a third-party cost estimator to determine if the material-upgrade limit is exceeded; or
- Allow developers to pay Xcel a reasonable fee for an estimate with +/-20% accuracy to determine if the limit is exceeded.

2. Xcel

Xcel argued that it had complied with Section 9 by applying the material-upgrade limit to its indicative cost estimate for the Raser project, and that this estimate was reasonable and based on least-cost assumptions. It stated that Novel had not raised any objection to the particulars of how the estimate was calculated.

The Company argued that the tariff is clear that no detailed cost estimate will be performed until after the interconnection agreement is signed. It argued that it could not continue relying on least-cost assumptions if the Commission requires a greater degree of accuracy for indicative cost estimates, and instead would have to either study the projects in depth or use greatest-cost assumptions when calculating the indicative cost estimate.

Xcel stated that, at Novel's request, it had conducted a high-level review of alternative interconnection sites. Xcel found that moving the project to one of these sites would not lower the indicative cost estimate below $1 million. Moreover, Xcel stated that, based on the cost of several recently completed interconnections, the unit costs it used in Novel's indicative cost estimate likely underestimate the actual cost of interconnection.

C. Commission Action

The Commission accepts the independent engineer's finding upholding Xcel's application of the material-upgrade limit to Novel's Raser site. Xcel applied the material-upgrade limit to the indicative cost estimate, as required by Section 9. And its approach to calculating the indicative cost estimate was fair to Novel in that it used least-cost assumptions for the unit costs that were part of the estimate.

Novel listed several alternative requests for relief. However, the relief it seeks is extremely unlikely to bring its project below the material-upgrade limit, since Xcel's existing estimate already relies on least-cost assumptions. Moreover, the requested relief would require significant changes to Xcel's tariff. While it may make sense to consider tariff changes once Xcel has gained more experience with the program, the Commission does not find it reasonable to make broad program changes at this time.

V. Minnesota Solar's Projects at the Lake Pulaski, Lester Prairie, Montrose, and Waverly Substations

A. The Issue

Minnesota Solar has proposed to develop community solar gardens at eight sites associated with four Xcel substations: Lake Pulaski, Lester Prairie, Montrose, and Waverly. Xcel rejected 37 of the proposed gardens after finding that the substations would not be able to accommodate them without material upgrades.

Minnesota Solar sought an independent-engineer review of Xcel's determination that the substations lacked sufficient capacity to accommodate the gardens. During this review, Xcel reevaluated its prior analysis and determined that hosting capacity totaling 2.1 megavolt-amperes (MVA) was in fact available at the Lester Prairie substation.

The independent engineer confirmed Xcel's analysis, finding that, with the exception of the 2.1 MVA at Lester Prairie, each of the substations had reached its maximum capacity for hosting distributed generation.

Minnesota Solar appealed the engineer's determination, arguing that the engineer's report did not include a sufficiently detailed review of the facts and disputes. It requested that the Commission serve the independent engineer with information requests to establish that the engineer independently verified Xcel's substation-capacity calculations.

Xcel responded that the independent engineer had properly addressed the issues and reviewed the technical assumptions Xcel used in its calculation of substation hosting capacity. The Company argued that it acted properly in rejecting applications that exceeded the available capacity, since increasing the hosting capacity would have required a material upgrade.

B. Commission Action

The Commission will accept the independent engineer's finding that the only available project capacity that could potentially move forward at the four substations in dispute is 2.1 MVA at the Lester Prairie substation. The engineer's report outlines the parties' dispute and sets forth the facts supporting its capacity finding for each substation. Minnesota Solar's request that the independent engineer be served with information requests is unsupported and beyond of the scope of this review process.

VI. Minnesota Solar's Klingelhutz and Rice Brunansky Sites

A. The Issue

Minnesota Solar also sought independent-engineer review of Xcel's determination that the material-upgrade limit had been exceeded at its Klingelhutz and Rice Brunansky solar-garden sites. It challenged Xcel's cost calculations and sought clarification of why the utility did not consider connecting the Klingelhutz gardens to a substation closer to the site to reduce the costs.

The independent engineer found Xcel's cost calculations accurate. The engineer found that the Company does not allow developers in its solar-garden program to choose where their projects will connect to the distribution system. But the engineer suggested that this practice "may be viewed as discriminatory" in light of Xcel's offer, in 1996, to run a dedicated feeder line to a large industrial customer's plant from a nearby substation.

Xcel objected to the engineer's suggestion that the Company's conduct was discriminatory. Xcel stated that it assigned the Klingelhutz gardens to the nearest existing feeder line, as it has done for other solar gardens. According to Xcel, a retail customer does not generally have the right to choose the feeder that serves it; the Company distinguished the 1996 example based on several factors—the customer was one of Xcel's largest, the substation was only 800 feet away and was already assigned to the customer's service address, and the new feeder line was expected to enhance system reliability.

B. Commission Action

The Commission will accept the independent engineer's finding that Xcel's calculation of the amount of reconductoring for these sites is accurate, that the cost per foot is within a reasonable range, and that the overall indicative cost estimates are reasonable. However, the Commission does not accept the engineer's finding that Xcel's conduct may be discriminatory in light of the 1996 case; that case is distinguishable on its facts.

VII. Procedures for Future Interconnection Disputes

The Commission's August 2015 order outlined basic procedures for independent-engineer review of solar-garden interconnection disputes. Having gained experience with the existing process, the Commission will establish the following additional procedures to further standardize the process and promote the efficient resolution of disputes:

- Once a dispute is submitted to the Department and an independent engineer selected, Xcel will file a notice in Docket No. E-002/M-13-867 that includes (1) the filing and date, (2) the developer, (3) the engineer assigned, and (4) a brief summary of the disputed issues. Once an engineer report is issued, Xcel will file it within ten business days.
- If an appeal is filed, notice shall be given to the E-002/M-13-867 service list and the Commission will open a new docket.
- The independent engineer should address only those issues necessary to resolve the dispute between the parties.
- The independent engineer's report must include the engineer's credentials and licensing.
- When a party appeals an independent-engineer report, each party must identify the documents submitted to the engineer that are necessary for the Commission's record.
- Xcel will be required to revise its Section 9 tariff at sheet 68.13, paragraph 9.h, to allow a party to file an appeal within ten business days of the delivery of the engineer's report, rather than five business days, as currently set forth in the tariff.
- The independent engineer may request additional information from parties necessary to resolve the dispute before the engineer.
- Xcel will be required to work with the Department and developers to develop a standardized format for independent engineer reports.

ORDER

SunShare's Becker, Glazier, Bartlett, and Murphy Sites

1. Xcel shall use a 2.0% flicker threshold (full-on full-off) for both individual and aggregate PV systems in the Section 10, Step 3 and 4 feasibility study computer models for the SunShare projects at the Becker and Glazier interconnection sites.

2. Xcel shall work with other interested parties to develop a plan for transition to incorporating the standards of IEEE 1453 into its modeling of voltage fluctuations and flicker for solar PV. The plan shall be filed within six months of this order.

3. Xcel shall file as a compliance report, within three months of the operational date of the Becker and Glazier projects, an assessment of impacts from voltage fluctuation and flicker, if any, on its system, and shall do so annually for the solar-garden program as a whole.

4. Xcel shall perform all engineering rework (computer models, studies, or cost estimates) necessary to correct Xcel's input errors at no additional charge to SunShare.

5. Xcel shall report cost variances between the indicative cost estimate and the actual costs for the total project, the substation costs, and the distribution costs. For each of these costs that fall outside a +/-20% range, Xcel shall provide a detailed explanation for the variance. Xcel shall report this information to the Commission within 30 days of the actual cost being provided to the developer in its next monthly community-solar-garden update report.

6. SunShare will not be permitted to activate noncertified functions of advanced-functionality inverters to perform flicker mitigation without Xcel's explicit permission until such time as the inverter functions have been tested and certified under UL standards or until further order of the Commission.

7. The nondisclosure agreement signed as part of the SunShare independent-engineer review process does not apply beyond the context of that review process, and is limited in scope to facilitating the independent engineer's review.

Novel's Raser Project

8. The Commission accepts the independent engineer's finding in the report for Novel's Raser project upholding Xcel's application of the material-upgrade limit to that project.

Minnesota Solar's Projects Interconnecting at the Lake Pulaski, Lester Prairie, Montrose, and Waverly Substations

9. The Commission accepts the independent engineer's finding in the Lake Pulaski, Lester Prairie, Montrose, and Waverly report that the only available project capacity that could potentially move forward at the four substations in dispute is 2.1 MVA at Lester Prairie.

Minnesota Solar's Klingelhutz and Rice Brunansky Sites

10. The Commission accepts the independent engineer's finding in the Klingelhutz and Rice Brunansky report that Xcel's unit cost for distribution upgrades is within a reasonable range, its indicative cost estimate is reasonable, and its reconductoring footage is accurate.

Procedures for Future Interconnection Disputes

11. The Commission sets the following parameters for the independent-engineer review process:

    a. Once a dispute is submitted and an engineer selected, Xcel shall file a notice in Docket No. E-002/M-13-867 that includes (1) the filing and date, (2) the developer, (3) the engineer assigned, and (4) a brief summary of the disputed issues. Once an engineer report is issued, Xcel shall file it with the Commission within ten business days.

    b. If an appeal is filed, notice shall be given to those on the E-002/M-13-867 service list, and the Commission will open a new docket.

    c. The independent engineer should address only those issues necessary to resolve the dispute between the parties.

    d. An independent engineer's report must include the engineer's credentials and licensing.

e. When a party appeals an independent engineer's report, each party must identify the documents submitted to the engineer in the record necessary for the Commission's record.

f. Xcel shall revise its Section 9 tariff at sheet 68.13, paragraph 9.h, to allow a party to file an appeal within ten business days of the delivery of the engineer's report rather than five business days as currently set forth in the tariff.

g. The independent engineer may request additional information from parties necessary to resolve the dispute before the engineer.

h. Xcel shall work with the Department and developers to develop a standardized format for independent-engineer reports.

12. Within 30 days of this order, Xcel shall make any compliance filings necessary to reflect the Commission's decisions.

13. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf

Daniel P. Wolf
Executive Secretary

This document can be made available in alternative formats (e.g., large print or audio) by calling 651.296.0406 (voice). Persons with hearing loss or speech disabilities may call us through their preferred Telecommunications Relay Service.

Linden Distribution Dispute
Information Request #004
Attachment D: 1 of 39

Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

May 12, 2017

—Via Electronic Filing—

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

RE: STAKEHOLDER MINUTES
COMMUNITY SOLAR GARDENS
DOCKET NO. E002/M-13-867

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits the attached Compliance information in response to the Commission's February 13, 2015 Order (Order Point 3) submitted in the above-noted docket.

Per Commission Order, all agendas, approved minutes and attachments from the Solar*Rewards Community (S*RC) Implementation Workgroup will be filed in eDockets. Attachment A includes the agenda, meeting minutes and attachments for our March 15, 2017, meeting.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact Jessica Peterson at Jessica.K.Peterson@xcelenergy.com or 612-330-6850 if you have any questions regarding this filing.

Sincerely,
/s/

SHAWN WHITE
MANAGER, DSM & RENEWABLE REGULATORY STRATEGY AND PLANNING

Enclosure
c: Service List

Linden Distribution Dispute
Information Request #004
Attachment D: 2 of 39

Docket No. E002/M-13-867
Stakeholder Meeting Minutes
Attachment A: 1 of 30

Meeting Agenda: S*RC Implementation Working Group

Date: March 15, 2017	
Start Time: 1:00 pm Central	**Location:** 401 Nicollet Mall, Bay 6
End Time: 4:00 pm Central	**Phone:** 612-330-5656 or 1-866-672-3839 Code: 4423764 **Web**: https://webconference.xcelenergy.com/invite/126976/3972425/en/avaya

TIME	TOPIC	LEADER	DESIRED OUTCOME
1:00	**Welcome and approval of minutes**	Shaffer	Approval
Review of Agenda Approval of 1.12.17 Minutes and Documents			
1:10	**Program Details Discussion**	Klemm	Update & Discussion
1. Program Status 2. Projects on Hold/Challenges created 3. Subscribers 4. Operational Gardens – public information discussion 5. Annual Reports by Developers – we are missing documents 6. Training Suggestions for 2017 7. Mechanical Completion Details			
2:00	**Regulatory Update**	Peterson	Update
1. IEEE Discussions 2. IE Report Template and Commission Filings 3. Voting*			
2:45	**Construction Update**	McDermott	Update & Discussion
1. Update 2. In-service dates 3. Updated one-line drawings – metering and site plans 4. State electrical inspections (deleted the word of) 5. Access road to our facilities 6. Reminder for the design time for a project 7. Easements on the property vs ownership of the property			
	Open Discussion	Shaffer	Discussion

Given the lack of response to the online survey – a vote will be taken during the workgroup.

Linden Distribution Dispute
Information Request #004
Attachment D: 3 of 39

Docket No. E002/M-13-867
Stakeholder Meeting Minutes
Attachment A: 2 of 30

Meeting Minutes

S*RC Implementation Workgroup

Meeting Minutes
March 15, 2017

OPENING

The S*RC Implementation Workgroup was called to order at 1:00 p.m. on March 15, 2017 via webconferance by David Shafer, MNSEIA.

PRESENT

Companies Present - Companies		
Phone Attendee	*Attendee*	*Attendee*
• Duane Hebert, Novel Energy • Sue Pierce, Department of Commerce • Bill Smeaton, Ecoplexus • Bricky Davis, NRG	• David Shaffer, MNSEIA • Ben Adamoioh, Geronimo • Lee Gabler, Xcel Energy • Daniel Enelesten, A-Sharp Energy • Brenda McDermott, Xcel Energy • John Harlander, Xcel Energy • Jamie Borell, IPS • Tom Santori, Xcel Energy	• Joe Tierney, SunRise Energy • Joe Devito, SolarStone • Joseph Hamel, NextEra Energy • Alan Urban, Xcel Energy • Ross Abbey, MN Solar Connection • Andy Melka, MN Solar Connection • Jessie Peterson, Xcel Energy • Kerry Klemm, Xcel Energy

APPROVAL OF MINUTES

The workgroup attendees approved the meeting minutes from January 12, 2017 with a minor spelling change. Moved by IPS and seconded by MN Solar Connection.

DISCUSSION/RESULTS

Topic 1: Program Details Discussion

Please see Document A containing the presentation used during the workgroup meeting.

1. *Program Status*

Xcel Energy provided a status update including completed projects (19 sites and 72 MW) and new applications received in 2017 (zero). The majority of projects to-date are in Design Development, however several one megawatt projects should receive study results over the next two months.

2. *Projects on Hold/Challenges*

Xcel Energy forewarned developers that if they had projects on hold their 24-months timeframe does not stop nor does the need to spend money on their project if there is an impacted project

behind them. Developers are responsible for all costs as part of the Interconnection Agreement, so even if a project is cancelled, Xcel Energy will still need to bring their system back to steady state, which could entail additional project costs.

Xcel Energy noted that developer provided in-service dates continued to be a challenge and again requested that if there is a change in project dates to please let them know as soon as possible so that construction details could be rescheduled. Xcel Energy is building according to schedules requested, which means that in some cases we are done by the requested date and continue to see empty fields next to our facilities.

3. Public Information (Operation Gardens)

Once a site is operational, the Section 9 Tariff allows for Xcel Energy to make certain site details public including location, operator name, nameplate capacity & generation data. This information will be available as part of the 2016 Solar*Rewards Community Annual Report (March 31).

4. Annual Reports by Developers

The Section 9 Tariff requires that Garden Operators provide Xcel Energy with annual financial reports, with the first one due within one year after the project is completed. Reports need to go to both Xcel Energy and subscribers. If these reports are not sent Xcel Energy can shut down the system itself. Xcel Energy does not currently intend to publish these reports; developers can publish them if they wish. If reporting requirements are not met, Xcel Energy will provide a 30-day notice and cure period prior to cancelling the garden application.

5. 2017 Training Options

Xcel Energy requested whether or not developers have what they need or if they could suggest additional training models needed. Developers suggested the following:

- Technical review guidance for applications will be very helpful moving forward
    a) Xcel Energy now offers a technical document found under Engineering Documents on xcelenergy.com.
    b) Grounding calculations are required and are defined in the review guidance document

- Additional Training Topics
    a) Witness Testing and final steps before receiving permission to operate including one-line documents and insurance requirements (lessons learned); and
    b) Metering and data feeds available for real-time production.

Xcel Energy noted that the commercial operations document is pretty true to form when it comes to timeframes. This document can give developers a good timeframe for operation/energization. As favorable building conditions present themselves, keeping true to provided in-service dates will be important for developers. There will only be so many time slots available throughout the summer.

Material and crew procurement is also important to keep in mind – it can affect development schedule.

Next Steps/Resolution: Xcel Energy will email the Commercial Operations document as part of the Workgroup follow up. In addition, Xcel Energy will take the additional training topics back to determine next steps.

6. Subscribers

Garden Operators are responsible for managing their subscriber portfolio. The Garden Operator is also responsible for making sure that subscribers are receiving the appropriate bill credits. Xcel Energy can help, but ultimately the Garden Operator needs to set-up subscribers and details within the Salesforce system correctly.

Xcel Energy warned Garden Operators to not wait until the last minute to add subscribers. If there are errors, premises incorrect, data incorrect, etc., let Xcel Energy know so that they can address within the system prior to the date in which bill credits begin to accrue.

Subscriber agency agreements need to be valid. As gardens are sold, these documents have become an issue since they are required to be updated including these key fields:

- Community Solar Garden Operator = Legal Entity (these have to match)
- Community Solar Garden Address
- Telephone Number – must correspond with primary application manager
- Email Address– must correspond with primary application manager

If these fields do not match with the garden, the subscriber details could be invalidated and therefore bill credits will not be paid. The 120 percent rule is also reviewed to determine if the subscription is valid – as invalid subscriptions cause issues for subscribers.

If a developer is selling ownership of a garden from one company to another without changing the LLC listed as the Garden Operator, this is not an issue – however, if they are assigning the SRC Garden Operator entity (which is named on the contracts) to another company the Subscriber Agency Agreements forms will need to be re-issued and freshly signed by each Subscriber.

A developer asked whether the 120 percent review is performed by an automated system? Xcel Energy clarified that, yes, it is automated. However, Xcel Energy will need to review it manually in certain cases such as less than four months data, etc. The 120 percent rule includes any Distributed Generation on the system including rooftop solar.

7. Mechanical Completion

Mechanical completion references Section 10. However, there has been confusion regarding these details.

Xcel Energy views mechanical completion to meet the following requirements:

1. Submission to Xcel Energy of appropriate proof of insurance as required by the Interconnection Agreement;
2. Submission to Xcel Energy of approved testing procedures; and
3. Submission to Xcel Energy of the State of Minnesota electrical inspection sign-off.

Garden Operators continue to ask "24-months from what?" Upon review by Xcel Energy, it was determined that Jan. 5, 2016, would be the earliest possible start of every project's Expedited Ready date. The earliest date for required completion is then Jan. 5, 2018. In addition, there are projects that have day-to-day extensions, if a developer feels one needs should be granted please let SRCMN know so that we can review and update the 24-month date in SalesForce as appropriate.

Question: If the facility is completed and the electrical inspection is not completed, would Xcel Energy not interconnect? **Answer:** According to the Section 9 Tariff Xcel Energy can cancel the project in this situation if it goes beyond the 24-month timeline from being Expedited Ready.

Xcel Energy does not want to cancel projects that are making good progress and close to completion; however, there have been in situations where the interconnection has been delayed repeatedly by the developer. Perhaps a late fee should be created for a non-timely interconnection instead of cancellation.

Some developers would prefer it to be a penalty rather than a cancellation of the project/interconnection. The majority of developers agree.

A late fee of –perhaps $200 per day per MW was discussed. Xcel Energy does have a late fee in CO for these types of situations as well, but this is more than $200. The late fee needs to be significant enough to be a true penalty for those who continue to delay, as there are impacts to subscribers and some developers are working aggressively (and incurring costs by doing so) to meet that deadline.

Developers: Day-to-Day extensions are reasonable. This year will have several problems as there will be many projects – labor will be an issue, timing will be an issue, etc. This will be a problem so having a penalty in place will help set the stage for accurate in-service dates moving forward.

It was again noted that there are only so many electricians and laborers available in the state of MN. Everyone should be planning ahead to meet deadlines.

Electricians do not like solar – word on the street – so timely connections have been an issue. Be sure to schedule a minimum of several weeks in advance, and if you miss your date, don't expect that they'll be there the next day.

Can Xcel Energy complete a contract amendment for this? Xcel Energy was going to review and follow-up with an email communication regarding the potential change.

A developer suggested that a single point of field contact will continue to be helpful for the developers as well – this is not always the case during construction.

Xcel Energy asked whether a construction checklist be helpful for developers moving forward? Additional training, checklists are great, but a single point of contact would be very helpful as well.

Xcel Energy noted that it would be helpful to have a single point of contact on the developer side as well – the EPC filed crews are not always on the same page as the project manager we work

with. The developers concurred that this also is the case. The take away is that more communication, though it takes time, leads to better results.

Next Steps/Resolution: Xcel Energy will review the possibility for a contract amendment to the 24-month requirement and follow-up with an email to the SRC Implementation Workgroup.

Topic 2: Regulatory Update

1. ***IEEE 1453 Stakeholder Discussion – Update***

   Xcel Energy provided an update to the IEEE 1453 Stakeholder process. To-date, three meetings were held with 13 different companies/groups involved.
   The Stakeholder group's charter is to review the simplified 1453 approach Xcel Energy is proposing to move forward with and then discuss the transition to the full standard upon developing additional data points and options for the time-series data required for the full standard.

   Xcel Energy recommends a simplified approach based on the IEEE 1453 Standard and known factors in the field:
   - Single Facility Trip Limit – 3% at any point on the MV system
   - All Facility Trip Limit – 5% at any point on the MVsystem
   - Compatibility Limit (System Limit) – 2% full on/full off

   Xcel Energy has basically moved from a one-approach-fits-all to a three layered approach based on the IEEE 1453 Standard. With a recent adjustment from 3 to 5% for the all facility trip limit, Xcel energy feels as though this is the farthest they are willing to study interconnection without further analysis and data. Xcel Energy discussed with the SRC Workgroup next steps in this process, the dissent currently at the Stakeholder discussions, and how Xcel Energy could move forward.

   Garden Operators had several questions such as how long a full transition may take (it may depend on the General Interconnection Standards discussion – we want to be consistent for all interconnections – likely in 2018), who has access to the data Xcel Energy is collecting now (Xcel Energy will be required to report on the data being analyzed today) and why is the equipment requirement there (it is a mass tripping event requirement on equipment).

   The SRC Workgroup also suggested other mitigation theories such as more robust regulators (from a technical perspective there are not more "robust" regulators that control more than the ones out there today) and the addition of batteries.

   The next steps to meet one last time for the Stakeholder Workgroup – we hope to have enough support to begin implementing the simplified version for Solar*Rewards Community projects in the study pipeline.

2. ***IE Report Template and Commission Filings*** *(See Document B)*

The Commission's 11/1/16 Order, Ordering Point 11.h., states "Xcel shall work with the department and developers to develop a standardized format for independent-engineer reports."

Xcel Energy and the Department worked on a template and this is Document B. This was sent to the workgroup via email prior to the meeting. The workgroup discussed the template.

The SRC Implementation Workgroup had no concerns with the template or format.

3. ***FAQ & Updated Workgroup Charter*** *(See Document C)*

The updates to the Solar*Rewards Community FAQ's and Workgroup Charter we sent to voting participants on February 10th, but no quorum was reached.
During the meeting, the Workgroup still did not have quorum in order to take a vote. Therefore, several process adjustments were discussed as alternatives.

Solar Stone recommended that the voting quorum change from half to eight. IPS requested this be adjusted to seven. Solar Stone motioned the change and IPS seconded.

An online vote will be sent again in March. Seven people will need to vote for these changes to move them forward.

Next Steps/Resolution: Xcel Energy requests that parties vote for the changes in order to make needed adjustments.

Topic 3: Construction Update

1. Update

Xcel Energy provided an update on projects in the construction phase including:

a. 120 projects in Design and Construction
b. 25 in Construction
c. 21 sites now energize – 70+ MW (busy month in March)
d. 3 new projects on hold (9 to 12)
e. 60 projects scheduled to come on line in 3rd quarter – this will be an issue especially since Xcel Energy is still missing several one-line documents; 30 projects are currently scheduled in 4th quarter.

2. In-Service Dates

Xcel Energy again noted that in-service dates are vital to project completion. If an in-service date changes, please let Xcel Energy know immediately. Again the in-service date is the date a developer anticipates the switch to be flipped.

Xcel Energy schedules our resources around in-service dates. If a developer has a June in-service date Xcel Energy begins construction in March and equipment is ordered far in advance of that. This is how the company schedules all resources from design time to metering to engineers. If a developer does not have a good in-service date, Xcel Energy cannot spend a lot of time on it.

In Xcel Energy's experience, they have seen that a 5 MW project takes about six months for the developer to build; if a project has not yet started construction it is unlikely to be ready for a June in-service date. As a reminder, we are spending money on these projects based on the expected in-service date that the developer provides.

3. One-Lines

Xcel Energy requested that one lines be updated ***as soon as possible***. Missing documentation will hold projects up – Xcel Energy will not commission a project if the one-lines do not match the constructed system.

Metering timeframes continue to take approximately 15 weeks (includes ordering the correct equipment, which cannot be done until final drawings are received). Distribution equipment (pad mounted) can take up to 6 months + to get in and some cities/counties are requiring them.

4. Electrical Inspections

Xcel Energy will require an electrical inspection 2-3 days prior to energization and energization will be cancelled if this documentation has not been received. As we get closer to summer, this could cause a project to go to the back of the line – likely waiting for another 2-3 weeks.

Please note that some county inspectors are already 2-3 outs so schedule your inspection as soon as you can.

5. Access Roads

Access Roads are required prior to energization! Xcel Energy has run into times where there's no access road and could construct when the ground was frozen, but when it's thawed the facilities have not been accessible by our trucks. They will not energize if there is not a sufficient access road. Often the times when we need to access our facilities there has been inclement weather. This is a safety and reliability issue.

6. Design Time

Xcel Energy explained that design time takes about 16 weeks. Resources are based on in-service dates. Xcel Energy also noted that projects on hold do not stop the 24-month clock. There may be projects behind projects on hold that Xcel Energy is working on and developers will be required to pay the costs associated with those moving forward.

7. Easements on property vs ownership of the property

If you are the owner of the garden and you own the property – Xcel Energy does not require easements but if the two names are not the same entity an easement will be required.

8. Others

Weather does affect projects; keep this in mind. Storms or weather situations will take priority over solar project installations. These escalated situations last 2-3 days if not more.
In 2016, Xcel Energy had about 12 of these situations.

Do not shoot for the last days of your 24-month period. If you are due in Jan – try for November in order to provide greater certainty.

Topic 5: Wrap-Up

The next meeting of the Implementation Workgroup will take place via teleconference on ***May 10, 2017, 1:00 – 3:00. No meeting will be held in April.***

Minutes submitted by: Jessie Peterson, Xcel Energy

Approved by: SRC Workgroup on May 10, 2017

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Stakeholder Workgroup

Solar*Rewards Community

March 15, 2107

Linden Distribution Dispute
Information Request #004
Attachment D: 12 of 39

Docket No. E002/M-13-867
Stakeholder Meeting Minutes
Attachment A: 11 of 30

Agenda

TIME	TOPIC	LEADER	DESIRED OUTCOME
1:00	Welcome and approval of minutes	Shaffer	Approval
Review of Agenda Approval of 1.12.17 Minutes and Documents			
1:10	Program Details Discussion	Klemm	Update & Discussion
1. Program Status 2. Projects on Hold/Challenges created 3. Subscribers 4. Operational Gardens – public information discussion 5. Annual Reports by Developers – we are missing documents 6. Training Suggestions for 2017 7. Mechanical Completion Details			
2:00	Regulatory Update	Peterson	Update
1. IEEE Discussions 2. IE Report Template and Commission Filings 3. Voting*			
2:45	Construction Update	McDermott	Update & Discussion
1. Update 2. In-service dates 3. Updated one-line drawings – metering and site plans 4. State electrical inspections (deleted the word of) 5. Access road to our facilities 6. Reminder for the design time for a project 7. Easements on the property vs ownership of the property			
	Open Discussion	Shaffer	Discussion

Approval of Minutes

Program Details Discussion

Program Status

PROJECT STATUS

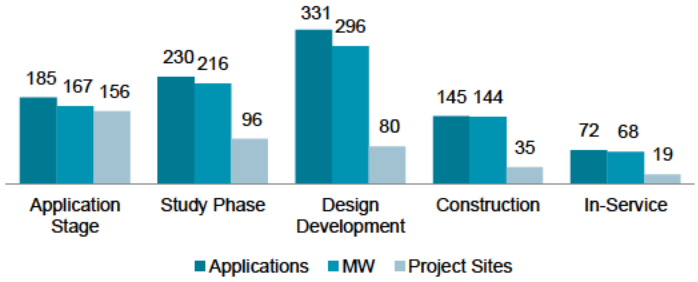
- New Applications (2017) = 0
- 369 active projects
- 19 projects in-service to date for 68 MW

As of March 2, 2017	Apps	MW	Project Sites
Active Applications	891	823	369
In Service	72	68	19
Withdrawn	1,415	1,353	315
↓ PROGRESS SUMMARY ↓			
Application Stage	**185**	**167**	**156**
Initial application	4	1	4
Applications in review	181	166	152
Study	**230**	**216**	**96**
Waiting for Study Proposal	11	10	7
SOW Waiting for Developer	28	28	24
In progress	47	46	37
Interconnection Application issued – waiting for developer	115	114	28
No Interconnection Application issued	29	18	N/A*
Design and Construction	**476**	**440**	**115**

* Projects sites can be in multiple categories based on study results per MW

APPLICATION DISTRIBUTION

- 19% of projects are in the early application stages
- 24% of projects remain in the Study phase
- 34% of projects are in Design
- 15% of projects are in Construction
- 7% have reached the Commercial Operation



PROGRAM UPDATE

- No new applications have been received to-date in 2017.
- 260 new applications submitted in Q4 2016 are eligible for the ARR bill credit rate if deemed complete by 4/15/17.

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Program Updates

Projects on Hold/Challenges

- Xcel Energy is proceeding with work on our end and spending money to complete necessary work to meet all in-service date requests
- Challenges: Communication, In-Service Dates, Queue Position
- Garden Developer is responsible for all costs incurred in their IA, even if they aren't actively proceeding

Public Information (Operational Gardens)

- MN Solar Gardens in Progress table
- Section 9 tariff (Sheet 78): Disclosure of Community Solar Garden Information including Location, Operator Name, Nameplate Capacity, & Generation data
- Operator Discretion: Subscription status & Contact Information

Program Updates

Annual Reports by Developers

- Section 9 tariff (Sheet 77) – provide Xcel Energy and each subscriber public annual reports
- Amendment to Standard S*RC Contract – Annual Reporting
  - Combine into a single report
- Notice of Need to Remedy will be sent for applications out of compliance

Training Suggestions for 2017

- Group discussion

Subscribers

- Garden Operators are responsible for managing their subscriber portfolio
- Subscriber Agency Agreement/Data Release – only applies to the garden operator listed on the SAA and the Interconnection Agreement
- If Garden Operator changes – previously signed SAA will become invalid and validation required for new subscriber entry

Attachment "A"

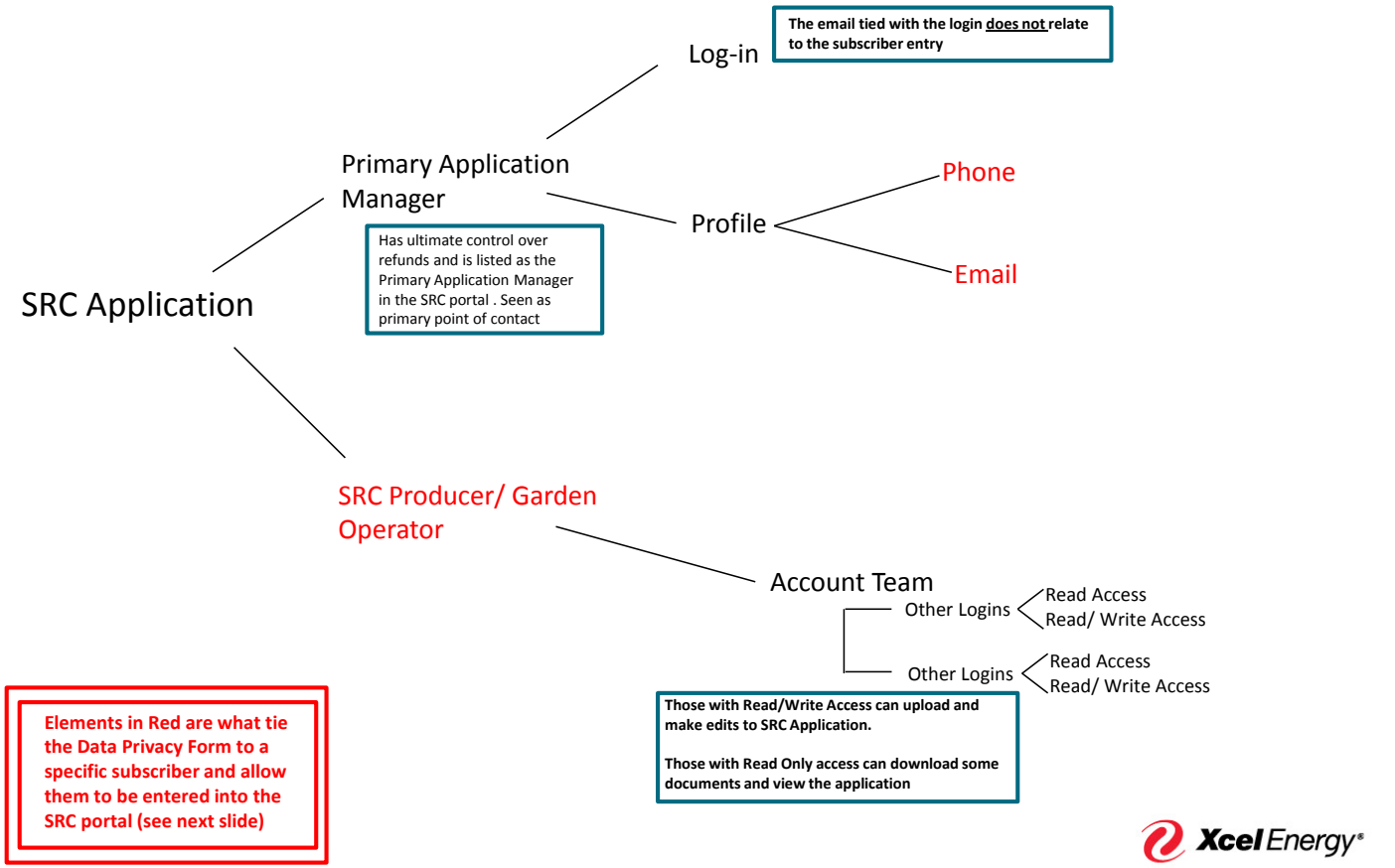
Solar*Rewards Community
Subscriber Agency Agreement and Consent Form

The undersigned ("Subscriber") has a Subscription to the following Community Solar Garden:

Community Solar Garden Name: _____	**Community Solar Garden Address:** _____ _____
Community Solar Garden Operator: _____	**Community Solar Garden contact information for Subscriber questions and complaints:** **Address (if different from above);** _____ _____ **Telephone number:** _____ **Email address:** _____ **Web Site URL:** _____

Subscriber Name:	**Subscriber Service Address where receiving electrical service from Northern**

How Subscribers tie with SRC Applications



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Mechanical Completion

- Defined in the Section 9 tariff Sheet 68:
  - "Mechanical Completion" means completion by the Applicant of each of the nine items the Applicant's personnel is required to complete in Step 8 of Section 10 (at Sheet No. 98).

- Section 10 Sheet No. 98 defines Step 8 as:

By the Applicant's personnel:

1) Ordering of Generation System equipment.
2) Installing Generation System.
3) Submit approval drawings for interconnection equipment and protection systems, as required by Xcel Energy.
4) Provide final relay settings provided to Xcel Energy.
5) Submit Completed and signed Engineering Data Submittal form.
6) Submit proof of insurance, as required by Xcel Energy tariff(s) or interconnection agreements.
7) Submit required State of Minnesota electrical inspection forms ("blue Copy) filed with Xcel Energy.
8) Inspecting and functional testing Generation System components.
9) Work with Xcel Energy personnel and equipment vendor(s) to finalize the installation testing procedure.

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Mechanical Completion

- Step 8 requirements need to be met prior to the 24 month application required completion date
- Some of these requirements are sequential and compliance with the final step in a specific sequence would show compliance with the pre-requisite steps
- The three main cumulative requirements from this list are:
  1. submission to Xcel Energy of appropriate proof of insurance as required by the Interconnection Agreement
  2. submission to Xcel Energy of approved testing procedures
  3. submission to Xcel Energy of the State of Minnesota electrical inspection sign off.

- If those three items as well as the other applicant's responsibilities are met, then the application will have achieved "Mechanical Completion" and will be ready for the final steps of energization and witness testing

Regulatory Update

IEEE 1453

- Stakeholder group of 13
- Three meetings to-date (one follow-up in April)
- Xcel Energy proposal
  - Simplified Approach to IEEE 1453 (Interim Step)
  - Ongoing analysis for full implementation

Summary of Recommendations

- RVC Single Facility Trip Limit Recommendation:

  ***3%** at any point on the MV system*

- RVC All Facility Trip Limit Recommendation:

  ***5%** at any point on the MV system*

- MV Equipment Compatibility Limit Recommendation:

  ***Passing Cloud ΔV of ≤ 1.5%** at the MV upstream regulation device (2% full on/ full off)*

SRC Workgroup Review

IE Report and Template

- The Commission's 11/1/16 order, ordering point 11.h., states: "Xcel shall work with the Department and developers to develop a standardized format for independent-engineer reports." Accordingly, we would need to tee this up for a workgroup discussion.
- Review and discussion during meeting

FAQ & Charter Vote

- Voting note was sent to parties on February 10th for the FAQ documents and Charter Update – No Quorum Reached
- Changes to Process needed
- Voting during meeting

Construction Update

Design and Construction

1. Update
2. In-service dates
   - Why they are important
   - When they change, let us know
3. Updated one-line drawings – metering and site plans
   - Why they are important
   - Lead time to order material
4. State electrical inspections
   - Needed 2-3 days prior to energization
5. Access road to our facilities
   - Needed prior to us building on private property
6. Reminder for the design time for a project
   - ~16 weeks
   - Resources
7. Easements on the property vs ownership of the property
   - Same Entity

Wrap Up

- Next Meetings:
  - Update Meeting Held in May (over the phone)
  - In-person meeting in June
  - NO meeting in April

- Topics for next discussion?
  - Annual Report

Solar*Rewards Community
Intake Form for Independent Engineer Review

This Intake Form should be used by an applicant to request an Independent Engineer (IE) Review under the Northern States Power Company Minnesota Tariff Section 9 Solar*Rewards Community Program, and to introduce into the IE Review any additional issues raised by the applicant during the review to be considered as part of the IE Review for the same SRC numbers at issue in the applicant's initial request. To initiate an IE Review, this form should be sent via email to the Minnesota Department of Commerce with a cc sent to SRCMN@xcelenergy.com

Please succinctly identify the engineering issues that you want the IE to resolve. Number each issue, and provide the SRC number and name of the applicant's legal entity associated with each SRC number. Describe the specific action requested from the IE and provide support for your position. Please duplicate the table below for any additional issues you would like to have resolved in this IE Review, and change the Issue Number in the top line of each copy of the table so that the issues are numbered consecutively.

This Intake Form was submitted on _[insert date]_____, by:
[provide personal name, company name, address, email address and telephone number]

Issue Number 1	
Succinct description of engineering issue.	
SRC number(s) and Solar Garden name(s)to which this issue applies. Also include the name of the applicant's legal entity for each SRC number.	
Specific action requested from the Independent Engineer.	
Explanation of and support for the position (include additional sheets if needed).	

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Stakeholder Meeting Minutes
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Solar*Rewards Community
Standard Format for Independent Engineer Report

This **Standard Format for Independent Engineer (IE) Report** MUST be used by the IE for purposes of organizing the IE Report. The material highlighted below must be included in the report. The material that is not in bold helps explain the needed content of the IE Report.

The IE should address only those issues raised in the Intake Form(s) as completed by the applicant and necessary to resolve the dispute between the parties. If, after the initial filing for this IE Review, the applicant requests to raise one or more additional issues to be considered as part of the current IE Review, the applicant needs to complete one sheet of the Intake Form for each such additional issue. The IE must address the applicant's issues as set forth in Intake Forms, with facts or support that the applicant adds during the IE Review as allowed by the IE, and Xcel Energy's responses to those issues. For each issue, the IE will have to decide whether the issue is within his or her authority and necessary to resolve the dispute between the parties. If the applicant did not use an Intake Form to initiate the IE Review, the IE shall direct the applicant to complete the Intake Form for each issue presented and provide that to the IE and Xcel Energy.

The top of the report should contain a caption in the following format:

INDEPENDENT ENGINEER REPORT

IN RE DISPUTE RE:
CSG NAMES AND SRN NUMBERS

DEVELOPER NAME:

NAME OF IE:

DATE OF LAST SIGNATURE ON CONTRACT FOR IE REVIEW:

DATE IE DECISION ISSUED:

The IE Report should be structured with the following sections:

A. <u>Summary of Issues</u>. Provide a brief summary of the issues between by the parties. Refer to the completed Intake Forms to make sure that all issues raised by the applicant are addressed. For example:

Issue 1: What is appropriate standard to be used to determine flicker at SRC number _____.
Issue 2: Reasonableness of indicative cost estimate for SRC number ___.

IE should state what, if any, issues have been resolved by the parties during the dispute resolution process and, therefore, will not be addressed by the IE the report. It should also include any issues that will not be addressed by the IE because they exceed the IE's authority or are not necessary to resolve the dispute between the parties.

B. <u>Analysis of Outstanding Issues</u>. For each of the outstanding issues address each of the following areas. For example, in discussion Issue 1 identified above, the following four headings should be used. Then the IE Report would address Issue 2, and also include these same headings.

Linden Distribution Dispute
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I. Description of the issue. Describe this issue in detail, including, but not limited to, which solar gardens (identified by name and SRC number) the issue is relevant to. For additional clarity, the Intake Form for a given issue can be attached to the IE Report and referenced here.

II. Summary of party positions and pertinent facts. First, provide a summary of each party's position and the pertinent facts on the issue.

III. List relevant authority. Provide a list of the relevant authority for this issue that the IE relies upon in the IE Report on this issue. Relevant authority may include Minnesota Statutes, Minnesota Rules, MPUC Orders, Tariffs of Northern States Power Company, and engineering standards.

IV. Analysis and conclusions on issue. Explain how the relevant authority applies to the relevant facts and supports the conclusion of the IE on the issue. Explain how this compares to the relief requested by the applicant on this issue. Be clear on what exactly is the conclusion and recommended relief of the IE on this issue.

C. Summary of Findings. Provide a summary of the findings for each issue that was addressed. For example:

I. The appropriate standard for flicker at SRC number is ____.
II. The reasonable indicative cost estimate for SRC number is ___.

D. Independent Engineer Credentials and Licensing. Provide an attachment describing the education, credentials, licenses and significant publications of the IE. This requirement for IE Reports was established by Commission order.

Linden Distribution Dispute
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CERTIFICATE OF SERVICE

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

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

xx by electronic filing.

Docket Nos.: E002/M-13-867

Dated this 12th day of May.

/s/

_____

Jim Erickson
Regulatory Administrator

Linden Distribution Dispute
Information Request #004
Attachment B: 1 of 45

414 Nicollet Mall
Minneapolis, MN 55401

April 26, 2017

—Via Electronic Filing—

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

RE: COMPLIANCE – TRANSITION TO INCORPORATING THE STANDADARDS OF IEEE 1453
COMMUNITY SOLAR GARDENS PROGRAM
DOCKET NO. E002/M-13-867

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits the attached Compliance information in response to the Commission's November 1, 2016 Order (Order Point 2) submitted in the above-noted docket.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact Jessica Peterson at Jessica.K.Peterson@xcelenergy.com or 612-330-6850 if you have any questions regarding this filing.

Sincerely,

/s/

SHAWN M. WHITE
MANAGER, DSM &RENEWABLE REGULATORY STRATEGY AND PLANNING

Enclosures
c: Service List

Linden Distribution Dispute
Information Request #004
Attachment B: 2 of 45

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF ITS PROPOSED COMMUNITY SOLAR GARDENS PROGRAM	DOCKET NO. E002/M-13-867 **COMPLIANCE – TRANSITION TO INCORPORATING THE STANDARDS OF IEEE 1453**

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy (Xcel Energy or the Company), files this compliance Report in response to the Commission's November 1, 2016 Order (Order Point 2). The Order states, "Xcel shall work with other interested parties to develop a plan for transition to incorporating the standards of IEEE 1453 into its modeling of voltage fluctuations and flicker for solar PV. The plan shall be filed within six months of the order."

The Company has conducted an extensive review of industry research surrounding the IEEE 1453 methodology as well as domestic and international utility adoptions of the underlying IEC 61000-4-15 2010 and IEC 61000-3-7 2008 standards from which the IEEE 1453 method is derived. Using this review along with first-hand experience with interconnecting Distributed Energy Resources (DER) across our eight state service territory, we created a white paper identifying a simplified approach to adopting IEEE 1453. The white paper entitled, "Applying IEEE 1453-2015 for Determining the Voltage Deviation Limits for Medium Voltage Distribution Connected Photovoltaics for Step-Changes in Voltage and Ongoing Voltage Deviations due to the Passing of Clouds," is attached to this report as Attachment A.

The white paper provides background regarding voltage fluctuation limits in the review and design of interconnection in order to identify and prevent power quality issues. In addition, it sets forth the Company's plan to begin adopting a simplified IEEE 1453 methodology within our design review for proposed DER projects including community solar gardens. The white paper was reviewed with peer utility

groups within and outside Minnesota. We also reviewed the paper with a stakeholder group convened between January and March 2017. The Company's plan incorporates feedback from these important reviews. The Company began adopting the practice outlined in Attachment A beginning on April 1, 2017.

The balance of this Report provides several additional details. First, we provide background regarding voltage fluctuation limits for DER interconnections, including the Solar*Rewards Community program. We then discuss the complexities of adopting the entire methodology presented by IEEE 1453, specifically without the benefit of additional clarity in the recommended practice document for studying DER or a consistent industry approach to implementation. Third, we provide a summary of stakeholder engagement before summarizing our simplified approach to adopting the IEEE 1453 methodology and our adoption of the new simplified methodology. Finally, we foreshadow future adoption of the full methodology as the tools required to analyze time-series data become cost-effective and reasonably available.

COMPLIANCE REPORT

I. BACKGROUND

Verifying that new practices comply with the Company's safety, reliability and quality of service standards for our customers is the Company's first priority when adopting new practices and standards. We know customers want renewable energy options; as a result, we are among national leaders in providing renewable energy, both in terms of portfolio mix and installed capacity. The Company's support for and expansion of renewable energy options needs to ensure system reliability and power quality; therefore, our practices and standards must be research-based, field-tested and proven to work.

Power quality, including voltage fluctuation and flicker, affects customers' and utilities' equipment ability to function properly – poor power quality can cause electrical equipment to malfunction or fail prematurely. In addition, voltage fluctuation and flicker also have potential to cause visual change in lighting, which can be an irritant to customers. The 5 MW size of co-located projects grandfathered into Solar*Rewards Community could have significant effects on voltage fluctuation experienced by our customers. The Company's impact review methodology can result in curtailment to a lower capacity or indicate an equipment upgrades is necessary (reconductoring, for example) prior to interconnecting to our system.

The appropriate voltage fluctuation limit to be used in the design for interconnection has been at issue between the Company and some Garden Operators, resulting in the

majority of Independent Engineering (IE) disputes escalated to the Commission. The Company has historically used the GE "flicker curve" approach based on the IEEE 141-1993 Section 3.9.2 and Figure 3-8 (flicker chart). Initially we applied a standard that allowed for 1.5 percent fluctuation on an individual system basis and 2.0 percent fluctuation on an aggregate system basis (full-on/full-off). The "full on/full off" designation refers to a study practice that begins with the generator outputting full rated power before turning the generation completely off. Voltage values are calculated for each the "full on" and "full off" states in order to determine the degree of voltage fluctuation. The flicker curve based on the IEEE 141 approach remains a valid, widely-used industry approach and is the most widely accepted practice for determining study thresholds.

Some developers participating in our program requested the Company apply higher thresholds, and the Company proposed to use the 2.0 percent individual and aggregate threshold, as well as application of IEEE 141-1993 as a valid standard, at the Commission's September 20, 2016 hearing. The Company further acknowledged that IEEE 1453 offers an alternative approach to measuring and evaluating voltage fluctuation but does not supersede the IEEE 141 Standard; to our knowledge very few U.S.-based utilities use this standard in a dynamic model based simulation for design purposes.[1]

II. IEEE 1453 STANDARD

Prior to the technical disputes associated with Solar*Rewards Community, the Company had adopted the full IEEE 1453 time-series analysis when monitoring power quality for complete and operational facilities. The industry standards, research, and tools are available to support this practice. However, the IEEE 1453 methodology does not represent a widely used industry practice for studying DER impacts specific to design criteria. Therefore, the implementation of the methodology can vary widely. These two specific issues (not an industry-wide practice and non-standard implementation) can cause complexities when adopting the IEEE 1453 approach for use in the interconnection design reviews, including those associated with Solar*Rewards Community.

There is no agreement across the industry on the method for how to apply IEEE 1453 for DER interconnection design purposes. One utility, PacifiCorp, uses a simplified version of the IEEE 1453 approach without using the actual, time-series PV output data. As was necessary with the Company's adoption of a simplified IEEE

[1] We understand that National Grid is pioneering the use of IEEE 1453 for design purposes in the United States. Further, PacifiCorp appears to use a simplified approach based on IEEE 1453.

1453 approach, the PacifiCorp approach extends the methods in the standard to cover a gap[2]. Yet, PacifiCorp and the Company extended the standard method in different ways. The Company is aware of one utility, National Grid, which uses a time-series IEEE 1453 approach for DER interconnection design. This full time series approach is largely dependent on the availability of high-resolution data and powerful software modeling tools.

While IEEE 1453-2015 has defined "fluctuating installations" to include both load and generation, it is clear from the content of the document that it is mainly written to cover loads[3] and that no standard methodology exists for applying it to generation. In fact, the first sentence of the Scope section of IEEE 1453-2015 reads as follows: "This recommended practice provides background on light flicker caused by fluctuations in power demands of variable loads."

It is possible to apply the IEEE 1453 approach to generation in a number of ways, as illustrated by the multiple approaches suggested by independent engineers as part of IE disputes regarding Solar*Rewards Community projects. This is consistent with the IEEE 1453.1 guide document that recognizes implementation will require flexibility and engineering judgment:

> *Since the guidelines outlined in this report are necessarily based on certain simplifying assumptions, there is no guarantee that this approach will always provide the optimum solution for all flicker situations.* ***The recommended approach should be used with flexibility and engineering judgment as far as engineering is concerned, when applying the given assessment procedures in full or in part.***
>
> ***The system operator or owner is responsible for specifying requirements for the connection of fluctuating installations to the system.*** *The fluctuating installation is to be understood as the customer's complete installation (i.e. including fluctuating and non-fluctuating parts).* [**emphasis added**]

III. STAKEHOLDER ENGAGEMENT

The Company has performed a significant analysis and review of the IEEE 1453 methodology. As a result of several utility conversations, our knowledge as part of the

[2] The PacifiCorp method points out the absence of a magnitude-duration component to Rapid Voltage Changes and defines a 3% limit when the voltage deviation is not characterized by the voltage level recovering to pre-disturbance level in less than 10 seconds.
[3] Generation is only mentioned in the definitions section and a section talking about transfer coefficient of large synchronous machines.

standards workgroup, and our experience both in Minnesota and Colorado, we developed a whitepaper detailing our simplified approach towards the adoption of IEEE 1453. This considerable effort included a peer review by a number of utilities in Minnesota and across the country. The Company continues to share and seek feedback from other companies experienced with operating electric distribution systems. The paper was updated based on several conversations with a peer utility in California.

In addition, the Company held a series of three IEEE 1453 Stakeholder engagement discussions regarding the simplified 1453 methodology and next steps in the transition. The intent of the stakeholder group was to:

1. Gather feedback from interested parties regarding Xcel Energy's proposed adoption of a simplified IEEE 1453 standard approach for voltage fluctuation for PV distributed generation system impact studies, and
2. Discuss the future approach and steps needed to plan for transition to the IEEE 1453 methodology that uses time series data into the Xcel Energy's modeling of voltage fluctuation and flicker.

The Stakeholder group included a handful of developers, other Minnesota utilities, the Department of Commerce and Commission Staff (as observers). We have attached our workgroup charter and the summaries of the meetings held on January 30, February 24, and March 15, 2017, as Attachment B to this filing.

The Stakeholder process generated feedback leading to a plan modification whereby the Company supports an aggregate limitation moving from four percent to five percent with the use of inverter ramp rate limiting functions. In addition, stakeholders provided wide-ranging input on other issues relying on engineering judgment, and forward-looking technical opportunities. The white paper was updated based on these discussions and finalized in March 2017.

IV. XCEL ENERGY'S SIMPLIFIED IEEE 1453 APPROACH

Our simplified IEEE 1453 approach uses engineering judgment and the practical use of known data – as required by the guide document stating, "The recommended approach should be used with flexibility and engineering judgment as far as engineering is concerned, when applying the given assessment procedures in full or in part."

The Company officially adopted the methodology in the white paper for all projects starting the study process on or after April 1, 2017; this was done in order to improve

the viability of several projects in the pipeline. We summarize the changes to our voltage fluctuation limits below.

The Company recommends the following voltage deviation limitations when studying DER impacts:

- All feeder DG facilities tripping - ≤ 5 percent at any point on the medium voltage system including all existing, reviewed, and approved DG prior to the next-in-queue review. Additional study may be required when exceeding the 4 percent level in order to determine appropriate ramp rate limiting, random delays, or other inverter functions to mitigate the risks associated with exceeding service voltage limits.
- Single facility DG tripping - ≤ 3 percent at any point in the medium voltage system
- Passing cloud fluctuation due to voltage regulation limit - ≤1.5 percent[4] at the regulator. A single PV trip ≤ 75 percent cloud caused power drop and no perception based flicker limit will be imposed.

Each facility will be evaluated under group RVC, single RVC and equipment compatibility criteria (passing clouds). The most limiting criterion must be met along with steady state voltage limitations.

V. FUTURE TRANSITION

The simplified IEEE 1453 approach identified above is one step towards adoption of the methodology. As described above, implementation of the IEEE 1453 time-series approach is highly dependent on available data and software tools– including high-resolution solar irradiance or PV output data and load data necessary to complete the analysis contemplated by IEEE 1453. Many solutions are not readily available and are both time intensive and cost prohibitive as industry software continues to evolve.

Additional research and analysis will be needed before we are able to implement a more detailed analysis for voltage fluctuation using the IEEE 1453 methodology. Scandia National Labs[5] has stated that the data to implement the IEEE 1453 time-series methodology needs to be captured at one-second time interval resolution. In order to obtain the capabilities to use full time-series analysis captured in one-second intervals, we will need further development in two specific areas: data and tools.

[4] The 1.5% with 75% output drop for passing cloud cover equates to 2% using the full-on to full-off method.
[5] Sandia National Labs, Time Series Power Flow Analysis for Distribution Connected PV Generation, Pg. 18 http://prod.sandia.gov/techlib/access-control.cgi/2013/130537.pdf

A. Data

Collecting one-second data for generation and load for every circuit on the distribution system is difficult. In fact, the monitoring equipment needed for this resolution of data is not a standard component for interconnections[6] or for monitoring load. Power quality meters with this level of capability are typically installed for a limited duration on an as-needed basis and we have a limited number of these devices. Furthermore, for a full detailed analysis, the IEEE 1453 methodology recommends power quality meters on the feeder itself prior to the fluctuating installations going into service in order to characterize background voltage fluctuation levels. IEEE 1453-2015 recommends a two-week period to characterize background flicker prior to start-up of the new facility[7].

The Company continues to discuss data collection practices with others in the industry. There are several ways to get to this data; however, to our knowledge only one company is using time series analysis today – National Grid – to determine voltage fluctuation impacts. We have also reviewed proposals for this type of work and the cost of performing impact studies could increase significantly if the analysis were to be performed with existing tools and data. The time required to perform this type of analysis would also lengthen the study performance timeframe, given the Company's current tools and data systems.

The Stakeholder group suggested that partnering with developers to collect one second data could be an option, and we agree that collaboration may be constructive. However, no developers in the stakeholder group were able or willing to provide the data at that time.

The Company has a limited quantity of monitoring equipment in the field today because the equipment is expensive, specialized, and we have not to date had a business need to acquire more of the equipment. The Company is collecting data now at one minute intervals from telemetry for sites larger than 250 kVA. For specific projects that we have been ordered to monitor or have decided to monitor for further information, higher resolution data is being collected in the field using specialized equipment.

[6] The Company's telemetry solution captures 1-minute time resolution data due to cellular data cost limitations.
[7] IEEE 1453-2015 suggests determining background flicker using a 2-week time period.

We will be analyzing data from two projects developed by SunShare. The first analysis will be released in late April 2017 and the other is expected to be released within three months from commercial operation. These two SunShare projects will not represent worst case conditions as other feeders have weaker system sources or higher penetrations of DER. We intend to review two to three additional higher risk sites as part of our efforts to collect additional data in the field to represent these poorer case scenarios.

We will continue to explore options for obtaining high resolution load and generation data to ultimately be used for time series analysis to determine voltage fluctuation impacts, including flicker, and equipment impacts when studying DER interconnection proposals.

B. Tools

The Company has begun to evaluating available tools capable of performing time series analysis. The more powerful tools are often considered to be more of research tools rather than commercial power flow analysis packages. OpenDSS and Matlab are two examples of this type of tool. These more complicated tools require more labor-intensive analysis and often require highly specialized employees or consultants. The Company's current power flow analysis package, Synergi, is capable of performing load flow analysis on a second-by-second basis, but it does not currently have the capability to perform an IEEE 1453 flicker analysis on the simulation voltage results.

The Company participates in Synergi's users group and will explore how the roadmap for future product development can enable time-series analysis of flicker and voltage fluctuation impacts. This interest is among others, such as integrating the EPRI hosting capacity analysis into commercial software.

CONCLUSION

Approaches used for flicker limit thresholds were historically based on the GE Flicker Curve. This was a "one size fits all approach" for which the IEEE 1453 methodology provides a more accurate representation of voltage fluctuation and flicker impacts when the proper resolution of data is used.

For a number of years, the Company has used the IEEE 1453 methodology for monitoring impacts of voltage fluctuation in existing and operational facilities installations because most commercially available power quality monitors contain this function. However adoption of the IEEE 1453 methodology for DER impact studies in design, in full, is complicated. The IEEE 1453 methodology is a recommended

practice that does not explicitly cover DER situations nor does it have fixed implementation requirements, so the implementation requires engineering judgment. In addition, full implementation requires time-series load and generation data with one-second intervals.

We have identified a simplified approach to adopting the IEEE 1453 methodology as the basis for design criteria associated with interconnection impact studies by identifying new thresholds that protect our customers and system from power quality impacts. We believe the assumptions and engineering judgment used to create this methodology are reasonable as identified in our white paper. That said, we intend to perform field verification of impacts from DER installed with the higher simplified IEEE 1453 thresholds. Future power quality monitoring data findings, industry research, or standards revisions may lead to addition adjustment to the methodology as the Company continues to work towards a full time-series analysis.

Full adoption of IEEE 1453 methodology for interconnection studies will require additional tools and resources for collecting time-series data and running dynamic power flow analysis simulations. In addition to increased costs and time constraints associated with the full adoption, a potentially more significant challenge is the development of the Company's power flow analysis tool's capabilities. We continue to explore these steps and see an opportunity through Docket No. E999/CI-16-521 technical working group for Minnesota to identify boundaries that define adequate adoption of IEEE 1453 and many other important standards.

We appreciate the opportunity to provide this information to the Commission regarding the transition towards the IEEE 1453 methodology.

Dated: April 26, 2017

Northern States Power Company

Linden Distribution Dispute
Information Request #004
Attachment B: 11 of 45

Docket No. E002/M-13-867
Transition to 1453
Attachment A: 1 of 15

Applying IEEE 1453-2015 for Determining the Voltage Deviation Limits for Medium Voltage Distribution Connected Photovoltaics for Step-Changes in Voltage and Ongoing Voltage Deviations Due to the Passage of Clouds

March 30, 2017

Executive Summary

Voltage fluctuation standards are evolving from the old "GE" flicker curves to the IEEE 1453-2015 Recommended Practice. Both were based on the visual perception of rectangular periodic voltage changes on the voltage supply to an incandescent bulb. The ongoing study of human visual perception has shown people are heavily influenced by waveshape, rate of voltage change, and periodic or aperiodic nature of the voltage variation. IEEE 1453 includes various adjustment factors to convert reference rectangular waveform reference curves to actual perception severity.

Large photovoltaic (PV) farms provide voltage fluctuation quantification challenges that are not directly addressed by standards. The sudden voltage change caused by a PV farm tripping can be quantified by the rapid voltage change standard limits of IEEE 1453. The occasional power output reduction and resulting voltage dips caused by passing clouds can be quantified through an extension of the IEEE 1453 perception modification adjustments. Large electric storage will introduce similar issues proposals for transmission frequency and reserve markets. The frequency of fluctuation occurrence due to market participation is not well understood today and could pose serious power quality challenges

The discussion shows that the passing cloud flicker is not a significant perception factor and perception limits do not need to be set. The passing cloud voltage variations can be a serious maintenance factor for medium-voltage voltage-regulation devices. Ongoing voltage variation limits do need to be set for equipment compatibility reasons such as this.

All PV on a feeder or all feeders on a substation can trip at the same time for various disturbances, which results in substantial impacts to service quality. The step-voltage limit of 5% voltage change is proposed for this highly coincident situation. The step voltage limit of 3% for a single large PV tripping is proposed. 3% preserves some system fluctuation tolerance for other sources and the medium and small Distributed Energy Resources (DER), greatly reduces the analysis burden for smaller DER facilities. Excess voltage regulation equipment operations are likely to occur for passing clouds if the voltage change is in excess of 1.5% at the regulating device. Due to spatial diversity, there is little coincidence between separate PV installations and evaluating the impact of a large installation will ensure an acceptable quantity of operations.

Background

This paper is focused on the rapid voltage change, equipment compatibility, and flicker limits appropriate for use at medium-voltage for large three-phase photovoltaic farms. The paper can

also be applied to rapid voltage change and equipment compatibility for large electric storage facilities.

Standards

IEEE 1453-2015[1] is based on the IEC 61000-4-15 2010 and IEC 61000-3-7 2008. IEEE 1453-2011[2] adopted the IEC 61000-4-15 flickermeter standard and IEEE 1453.1-2012[3] adopted IEC 61000-3-7. IEEE 1453-2015 incorporates the IEEE 1453-2011 and 1453.1-2012 into the one document and includes added information. The following discussion applies to use of IEEE 1453-2015. This whitepaper references IEC 61000-3-7 for additional details not included in IEEE 1453-2015. The following uses information from IEC 61000-3-7 (IEEE 1453.1).

IEEE 1453-2015 provides both simpler approaches to pre-determine the permissible fluctuation magnitude for a facility and more detailed study approaches that incudes pre-study characterization of the proposed location and more detailed information on the characteristics of existing sources of fluctuations. Developing this characterization requires unique resources, modeling tools, and additional time. This paper focuses on the simpler approach as it is faster, adequate in most situations, and requires more readily available information. The detailed study approach may become appropriate for interconnection studies at some time in the future.

Basics

The document is based upon the Flicker meter measurement methodology. The graph in IEEE 1453 Figure 5 is the reference graph used in the waveshape adjustment calculations. This graph provides the delta-voltage change (ΔV) in percent voltage change from a repeating rectangular wave versus changes/minute to produce a reading of unity for the short time reference number (P_{st}). The Flickermeter outputs a weighted average integrated over 10 minutes[4] with a reading of 1.0 being the average level of fluctuations that are perceived by people. The meter uses various filters and algorithms to approximate the non-linear perception of light intensity variation produced by a 60W incandescent light. Longer-term exposure to variation can lead to irritation in people. The 2 hour integrated rolling sum (12 P_{st} intervals) of the P_{st} produces a long time reference number (P_{lt}).

A repeated rectangular voltage fluctuation is the most perceptible fluctuation shape[5]. This rectangular waveshape was also used in the "GE" flicker curve. The non-linearity of human

[1] IEEE 1453-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems
[2] IEEE 1453-2011, IEEE Recommended Practice – Adoption of IEC 6100-4-12:2010, Electromagnetic compatibility (EMC – Testing and measurement techniques – Flickermeter – Functional and design specifications
[3] IEEE 1453.1-2012, IEEE Guide – Adoption of IEC/TR 61000-3-7:2008, Electromagnetic compatibility (EMC) – Limits – Assessment of emission limits for the connection of fluctuation installations to MV, HV and EHV power systems
[4] A 10-minute integration interval is the default interval. Other intervals may be used for specific reasons.
[5] Repeated rectangular fluctuations have two fluctuations for each complete cycle of fluctuation.

perception extends to variations in fluctuation waveshape, aperiodic timing, and step or pulse versus continuous waveshape. IEEE 1453 addresses these shape factors to modify the severity predictions of perception and thus get a more representative perceived severity impact. For rectangular fluctuations, human perception is usually more limiting than the equipment compatibility limits. For many of the modified waveshapes, equipment is more often limiting than perception. The IEEE 1453 fluctuation analysis applies equally whether caused by a load or generator. The various graphs apply equally if there is a rise or a dip.

The general summation equation for short-term flicker severity is Equation (22):

$$P_{st} = \sqrt[m]{\sum_i P_{sti}^m}$$

m	Voltage Fluctuations	Example
4	Rare coincidence	Single PV farm trip for local secondary fault
3	Small risk of coincidence	Cloud passing PV fluctuation
2	Likely coincidence	Secondary roof PV
1	Very high coincidence	All PV trips on feeder for lateral fault

Passing clouds will reduce the output of a PV farm but will rarely cover more than one farm fully. This would be an m of 3 or 4. Area cloud passing severity is low coincidence due to geographic diversity.

A group of residential rooftop PV on a shared secondary is likely to have locally highly coincident output variations. This would be an m of 1 or 2. Cloud passing effects are high for small, clustered PV due to minimal geographic diversity.

A feeder fault will likely trip all PV on the feeder and perhaps depress the substation bus voltage enough to trip the PV on adjacent feeders also. This would be an m of 1 as all would trip at essentially the same time.

These factors strongly influence the estimated global fluctuation severity for a feeder and thus the assumed post installation operational impact. Accurately pre-calculating the total P_{st} at a point of common coupling (PCC) would require calculating the transfer factor for each major source to the PCC before these are combined into a total P_{st}. This is usually not needed if the feeder model includes all major fluctuation sources.[6] Solving the model provides an approximation of the total impact.

[6] There are a number of sources of fluctuations that most feeder models do not capture and must be accounted for separately. Sources like capacitor bank switching, faults on adjacent feeders, faults on the transmission system, fault on the feeder interrupted by a branch or downstream protective device, load switching, etc.

Ongoing PV Fluctuations

The ongoing PV output variations create voltage fluctuations that are more extended and with much longer repetition times than the information provided in IEEE-1453. The graphs can be extended or extrapolated in a conservative manner to get an estimated ΔV permissible fluctuation limit. For medium-voltage connected facilities, the fluctuations from passing clouds will have a low coincidence factor.

Very large PV farms can trip for system upsets causing a voltage step-change that trigger the inverter anti-islanding protection. The same result can occur with all PV on a feeder tripping. Occasionally the mass PV tripping can be for all feeders on one substation bus. Rarely, the mass trip can be for a geographic area when the disturbance originates on the transmission system. These events are considered to have a high coincidence factor.

The default inverter restart time is 5 minutes. This can lead to a swift, near simultaneous rise in output that is nearly as severe as a group trip. This second step-change can be greatly reduced on a perceptional and voltage swing severity basis by limiting the ramp-up rate of the inverters. The resulting change is a more perception-friendly shape and less likely to upset the operation of some equipment.

Typical Thresholds

There are two limit levels for P_{st} and two limit levels for P_{lt}, one is the compatibility level and the other is a planning level. The planning level purposely leaves some margin since the calculation methods are approximate. Since there are existing sources of voltage variations, the ability of the system is already partly used and an allocation less than the planning level is often assigned to the next customer when dealing with larger sources of fluctuation[7]. The customer allocation depends on the facility fluctuation impact relative to the system strength and on the degree of coincidence with other sources. The default levels are given in the following table:

Limits	Compatibility	Planning	Allocation
P_{st}	1.0	0.9	≤ 0.8[8]
P_{lt}	0.8	0.7	≤ 0.6

The step-voltage change, whether from cap bank switching, a large motor starting, or a large PV tripping, is a rapid voltage change (RVC)[9]. RVCs are changes in fundamental-frequency rms

[7] The allocation can be determined if the background level is known by: $P_{st\_customer} = \sqrt[3]{(P_{st\_actual}^3 - P_{st\_background}^3)}$. P_{st_actual} is the target Pst level after connection.
[8] 0.8 was derived from IEEE 1453.1, Equation (2) using a coincidence factor of 3 with indicative P_{st} = 0.9 with a background of all other ongoing sources of 0.6. The measured MV background level from a number of PQ measurements done for other reasons yielded a P_{st} between 0.2 and 0.6 with occasional readings well over 1.

voltages over several cycles. This is illustrated in IEEE 1453 Figure 13 with a motor starting example. The indicative planning levels are given in Table 3 in IEEE 1453-2015, see table for medium voltage (MV) values below.[10]

Number of changes, N[11]	MV $\Delta V/V_r$ (%)
N ≤ 4 per day	5 – 6
N ≤ 2 per hour and > 4 per day	4
2 < N ≤ 10 per hour	3

Recommendations

Step-Change Limit

A step-change will occur either for a single facility tripping due to internal problems or for part or all of the DER facilities on the feeder[12] due to system problems. A second step change will occur when DER automatically resumes operation. The resumption step change may be mitigated through ramp rate limiting or partially through staggered restart times.[13] The resumption of operations poses several challenges. When a PV trips, the voltage drops. With higher penetrations, controlling voltage rise to maintain service within ANSI C84.1 Range A is a challenge.[14] After the PV trip, the voltage regulation devices return the voltage to a normal range. When a large PV facility automatically restarts, the voltage is pushed above the ANSI A limit and voltage regulation equipment does not respond for 30-60 seconds. The regulation equipment includes substation transformer LTCs, line regulators, and switched capacitor banks. The larger the RVC step that is allowed with PV, the greater the overvoltage, which can become excessive.[15] If PV ramp-up rates are limited so a full-power restore requires well over the regulation control delay time, this will mostly mitigate the overvoltage risk.

Large electric storage, such as batteries, presents a new source of RVC and may also present flicker issues. Storage is capable of rapid up and down ramp operation as well as swift power

[9] The term RVC is used in 1453 and a number of standards worldwide. It is not a well-defined term that can be reliably measured and applied. "Rapid Voltage Changes - Definitions and Minimum Requirements", CIGRE, Paper 0789, CIRED-2009.
[10] For this table, a capacitor bank switching on is one change (N = 1) and off is another change. A motor start initial voltage drop is one change but the gradual decreasing tail is not counted as a change. A ramped return to normal voltage of one-second duration or more imparts minimal perception impact.
[11] The number of changes in a time period will need to consider all other larger RVC sources on the feeder, such as other large PVs. When this table is used with an industrial customer with multiple large motors, multiple large motors starting for the day in sequence will result in a high equivalent N for a fraction of the day.
[12] Some faults on a feeder or the transmission system can result in all DER on a substation transformer simultaneously tripping. The degree of voltage change this causes can require additional analysis of voltage change limits for group trips.
[13] If there are multiple large PV facitlies that restart, staggered restart times may create enough closely associated events so as to create a perception of flicker. If this occurs, a lower ΔV limit for restart will need to be imposed.
[14] IEEE 1453.1 RVC section states that system operators or owners have to maintain the voltage magnitude within narrow limits and individual customers should not produce significant voltage variations even if they are tolerable from the flicker point of view.
[15] IEEE P1547 indicates that "further technologies and concepts to integrate DER into existing EPS continue to be further developed to fully realize benefits and to avoid negative impacts on system reliability and safety." This supports a more conservative approach to the degree of overvoltages that are to be allowed at the design stage.

direction changes. When operating in parallel with the system, they are subject to being part of a group trip similar to PV. Large storage must be part of the RVC analysis. Some operating modes must be restricted to the same level or lower as individual large PV. Upcoming markets for storage participation in transmission reserves and frequency response can call for frequent, major output shifts without ramp rate limiting. Aggregation of smaller storage units for participation may occur and may create concentrations operating simultaneously that will need to be treated as one large storage unit. This participation can drive the daily/hourly N event numbers quite high for RVC analysis. The frequency of fluctuation occurrence due to market participation is not well understood today and the treatment of storage will need to evolve. Large electric storage market participants may also require analysis under the flicker requirements of IEEE 1453.

RVC caused by transformer inrush or motor starting drops the voltage and it quickly returns to near pre-event levels. The duration is too short for the voltage regulation control delay. Normal practice is to operate the feeder within the +5% part of the ±5% ANSI A range. This allows greater tolerance for RVC dips than for rises. This allows for a 5% RVC for very rare events that have brief *dip* durations[16]. Large electric storage under some modes of operation can seriously degrade power quality with frequent excursions outside of the ANSI A limits. If major excursions are more than rare, the electric storage design will need to comply with the MV equipment compatibility fluctuation limits recommended below.

Three approaches can be used for determining the appropriate RVC limits when including large PV.[17] One is to provide an allocation factor that takes into account the impact from other PV facilities on the line, the variations passed down from higher voltage system levels, and the composite frequency of all significant step changes. The second is to determine the fraction of the feeder capacity that is to be devoted to that facility and use it to allocate a fraction of the total variation absorption ability. The third is to estimate the significant step-voltage variation frequency and use the default allocation factor. Each has merit and is discussed in the IEEE 1453 text. The following provides examples of each approach. The full time series study approach, not discussed here, can provide some additional accuracy for a specific case. The full study approach is time consuming and the simplified approach is usually adequate. Since the system is continually evolving, the relative accuracy at 5 years down the road of the simplified and full study approaches are likely to be similar.

The first method is to assume the events are relatively rare and allocate 60% of the higher limit to the facility. The allocation factor A includes the planning margin.

$$MV\,\frac{\Delta V}{Vr(\%)} = \Delta Vlimit\ x\ A = \ 5\%\ x\ 0.6\ =\ 3\%$$

[16] PacifiCorp publishes an adoption of IEEE 1453 and indicates the absence of magnitude-duration limits is a gap in the standard. The document states that for "fluctuations lasting ten seconds or longer at the customer site, the magnitude of fluctuation should be 3% or less, regardless of frequency". PacifiCorp Engineering Handbook, Volume 1 – General, Part C – Power Quality, Section 5.1

[17] The coincidence of occurrences due simultaneous tripping of PV and reconnection for system disturbance is very high requiring summation and allocation principles to be applied to RVC to quantify step change.

The second method is to allocate by customer power, ratioed to the feeder rated power and the planning level (P).

$$MV\frac{\Delta V}{Vr(\%)} = \frac{Sc}{Ssc} x\ 5\%\ x\ P$$

For a 2 MW PV on a 4 MW feeder and a planning level of 0.9, this would be:

$$\frac{2}{4}\ x\ 5\%\ x\ 0.9\ =\ 2.25\%$$

Another approach is to assume the events can be more frequent at times and use the Allocation default of 0.8 and 4% based on a system composite of 4 or more daily events. The frequency of events includes the activity of all PV and other non-DG sources like capacitor switching, motor starts, and faults[18].

$$MV\frac{\Delta V}{Vr(\%)} =\ 4\%\ x\ 0.8\ =\ 3.2\%$$

The use of the 0.8 allocation allowance could be considered to be double counting an allocation factor that is already built into the 4% RVC limit. If this approach is taken, the all-PV tripping RVC limit would be 4%. This means that an allocation factor must be separately applied to an individual large PV tripping. Reserving only 20% of the all-PV tripping limit for all other PV is below the likely need of the medium and small PV that may share the circuit[19]. The single PV trip RVC limit would be 3% under this approach.

RVC Single Facility Trip Limit Recommendation: ***3%*** *at any point on the MV system*

A Single Facility RVC of greater than 3% is not recommended due to likely conflicts with equipment compatibility limits[20].

RVC All Facility Trip Limit Recommendation: ***5%*** *at any point on the MV system*

For impacts exceeding 4%, additional study may be performed in order to determine appropriate ramp rate limiting, random delays, or other inverter functions to mitigate the risks associated with exceeding voltage limits[21] for an extended duration after a coincidental tripping event.

[18] The upcoming P1547 ride-through requirements will include fast resumption of production after a group cease-to-energize. This significantly increases the likelihood of flicker perception, due to the quick double change, and a need for imposition of a lower ΔV limit if a limit above 3% is used.
[19] The 3% single PV trip RVC would have about the same system allocation as the first method which allows a 40% allocation for all other PV and all other feeder activity that would apply to the composite limit allocation needs.
[20] If the first large PV interconnected causes a full 3% ΔV, the ongoing cloud driven fluctuations will exceed the equipment compatibility limit discussed in the Equipment Compatibility section. With two or more large PV, the amount of ΔV allocated to each facility will allow the equipment compatibility limit to be met.
[21] Voltage rise caused by reconnection of DER shall not result an abnormal voltage condition as defined by IEEE 1547 or in utility system operation above ANSI C.84.1 range B limits. RVC limits shall not preclude or supersede the need to meet power quality standards as defined by PUC or state rules.

Ongoing Cloud Caused Fluctuation Limit

The ongoing voltage fluctuation perception limit for clouds can be based on IEEE 1453.1 Figure E.2 Shape Factor curves for double ramp change shape, Figure E.4 Shape Factor for aperiodic changes, and a d_{max} of 2%[22] ($P_{st,2\%}$)[23]. These are combined with Equation (E.6):

$$Pst = F * \left(\frac{dmax}{d(st,1)}\right) * Pst,2\%$$

The double ramp factor F emulates the ramp down of PV output due to a passing cloud and the ramp up. The ramp is assumed to be a few seconds in duration. The total double ramp is assumed to be 1-2 minutes in duration. The aperiodic curve Figure E.4 uses a rectangular wave with t_1 and t_2 unequal parts to give the aperiodic severity conversion factor to a square wave. The cloud passage frequency is assumed the longer period t_1. T_2 is the 1-2 minute dip period. This is a very conservative estimate as longer ramps, longer dip times, and longer repeat intervals all increase the amount of $\Delta V/V_{r(\%)}$ voltage variation that can be allowed without exceeding a perceptional $P_{st} = 1$.

Double ramp

For a ramp duration of 1 second[24], F = 0.2 (Figure E.2), for a 1 minute cycle period, the rectangular wave curve (Figure A.1) gives 2.6% ΔV for N changes per minute = 2[25] for a $P_{st} = 1$ at 2 changes per minute. For a d_{max} = 2%, $Pst,1\%,(E.6)\ gives\ (0.2)(2\%/2.6\%) = 0.15$. For a 2 minute cloud duration, the perceived severity is 0.21 if the chart is extrapolated to a 3 second ramp, F ~ 0.1 for a one minute period. This assumes worst case where there is no ramp up rate limit.

Aperiodic

Figure E.4 has t_1 times up to 5 minutes and t_2 times up to 1.67 minutes. The curves are converging on a P_{st} equivalent of 0.75. Using Equation (E.6) given above using the double ramp F of 0.2 for a period of 1 minute, the aperiodic cycle time is 6 minutes for N = 2:

$P_{st,1}$ for a 1 change per 3 minutes, from A.1, is 4.5% ΔV

$$Pst = (0.2)\left(\frac{4.5}{2}\right)(0.75) = 0.34$$

[22] 2% is the reference ΔV used in the waveshape graph.
[23] All equation, table, and figure references are from 1453.1-2012 for this flicker recommendation section.
[24] 1 second is the longest ramp time given in E.2.
[25] The cycle time refers to the ramp up, hold time, and ramp down. Each ramp is one change giving two changes (N) for the cycle duration.

The worst possible voltage variation due to passing clouds would result in a perception P_{st} of a fraction of 1.0. If the figures are extended to longer repeat periods and slower ramps, the effect would be an even smaller actual P_{st}.[26]

A passing cloud will cause a less than a 100% array power dip. A reasonable conservative approximation is a 75% dip of the ΔV for an individual PV farm trip.

Flicker *Perception* Limit Recommendation: *do not impose a PV perception based flicker limit as the RVC limit is more restrictive.*

MV Equipment Compatibility Limits

The standards indicate that the equipment compatibility limit for low voltage (LV) customers is defined but no such limits exist for MV. LV equipment is compatible with a P_{st} of 1. Voltage fluctuations that exist on the MV level will appear with minimal attenuation at the LV level. The following focuses on voltage regulation equipment. Equipment compatibility goes beyond ongoing variations and incudes impacts due to high RVC events. Malfunctions of control systems acting on voltage angle, braking or accelerating moments from motors, or impairment of electronic equipment have been noted in literature.[27]

The medium-voltage system contains voltage regulation equipment. Compatibility with voltage regulation devices is the main challenge for equipment compatibility limits. Load tap changers (LTC) and line regulators usually have a regulation deadband of 2-3% with a time delay of 30-60 seconds. Equipment responds to the ΔV and the duration of the fluctuations. To minimize the impact to the voltage regulation equipment and maintenance, the ΔV at the regulating equipment from passing clouds must be less than the deadband and no more than half of the deadband has been recommended by several sources.[28] The limit would be 1-1.5%.

LTCs and regulators are likely to respond to these events at the 5% all trip rapid voltage change (RVC) limit. These events should be rare and should not increase maintenance excessively. If ongoing voltage fluctuations were allowed at the flicker perception limits as discussed in the previous section, substantial increases in operations and maintenance could occur with resulting degraded power quality and reliability.

If the single RVC limit is set at 3%, the shading effect of a cloud[29] will give a passing cloud's ΔV of up to 2.2%[30] at some point on the MV system but may be significantly less at the voltage

[26] The extension intervals go beyond what has been well documented. Some have questioned the accuracy for figures for the longer duration ramp rates and aperiodic repeat times. Since the results show a very low severity, even a significant change due to additional research will not push the severity to a level of concern.
[27] "Rapid Voltage Changes in Power System Networks and Their Effect on Flicker," IEEE TPWRD, Vol 31, No. 1, February 2016, pp. 262-270.
[28] The SunShot High Penetration PV Integration Handbook recommends in Appendix B that the voltage variation be limited to one half of the active regulation band width; 1% for a 2% bandwidth.
[29] Cloud shading of over 80% ΔV does occur. A ΔV of 75% is use as being a more typical worst case for review purposes.

regulator. A 1.5% ΔV at the regulator may result in a modest increase in operations. This increase is expected to be modest for several reasons. Smaller clouds will not fully cover a large PV farm. Most clouds will not pass directly over a larger PV and shade only part of the panels. There are relatively few large PVs on a feeder and only large clouds may intercept more than one large PV. Small PVs are too small to add significantly to the MV voltage deviations.

MV Equipment Compatibility Limit Recommendation: ***RVC single facility limit of ≤ 3%*** *and* ***Passing Cloud ΔV of ≤ 1.5%*** *at a MV regulation device.*[31,32]

Combined Limit Recommendation:

- Isolated, very rare voltage dips - 5% at any point on the MV system
- All feeder DG facilities tripping[33] – ≤ **5%** at any point on the MV system
  - Includes all existing DG and DG reviewed and approved prior to next in queue review.
  - Additional study may be required when exceeding the 4% level in order to determine appropriate ramp rate limiting, random delays, or other inverter functions to mitigate the risks associated with exceeding service voltage limits.
- Single facility DG tripping - ≤ **3%** at any point on the MV system
- Passing cloud fluctuation due to voltage regulation limit – ≤ **1.5%** *at the regulator*
  - Single PV trip * ≤75% cloud caused power drop[34]
  - No perception based flicker limit will be imposed[35]

Each facility must be evaluated under group RVC, single RVC, and equipment compatibility criteria. The most limiting criterion must be met. In some cases, this may result in significant reduction in the usable limit of one or more of the other criteria.

[30] The ΔV for one facility tripping may be as high as 3% and with the partial cloud shading, less than 75% of the trip ΔV may be seen on the MV system. If the regulating device is some distance up stream of the facility, the regulating equipment may see even less variation.
[31] "Analysis to Inform California Grid Integration Rules for Photovoltaics", EPRI, 3002008300, uses 3% and 1.5% as their criteria to avoid adverse distribution system impacts. 5% is used for the limit for secondary service.
[32] "Determining Practical Planning Limits for DG on Distribution Circuits" CIGRED2011, Paper 1277, states a drop from the DG tripping of 2-3% is appropriate and higher than that indicates inappropriate active or reactive power at the POC. A fluctuating change of over 1% requires further investigation. A 5% drop may be acceptable for constant output dispatchable generation.
[33] Some faults on a feeder or the transmission system can result in all DER on a substation transformer simultaneously tripping. The degree of voltage change this causes can require additional analysis of voltage change limits for group trips.
[34] For an all PV trip limit of 4%, a single PV trip will be less. The cloud passage at 75% shading will give under 3% ΔV on the MV system and likely less than this at the regulating device.
[35] This is consistent with the conclusions of "Survey of Harmonic and Flicker of PV Systems", EPRI, 3002005983.

Proposed PV Voltage Variation Analysis Process

This discussion is focused on the interconnection analysis of larger distributed energy resources (DER) interconnections, primarily for PV farms. The review is based on the use of a feeder model with loads and DER sources represented. Small PV is assumed to be connected with default settings and no mitigations and may be lumped. Larger PV sites should be represented individually with their required mitigations applied, such as fixed non-unity power-factor control. The study is conducted with all DER that have been approved prior to the DER that is under study represented in the model. *The model is run with the substation and line automatic voltage regulation set to off and set to the normal plus limit of deadband voltage. Any feeder switched capacitor banks should be in their nominal state and set on manual for the load and PV output conditions prior to the removal of the one large PV facility. This will also provide insight into possible voltage excursions prior to automatic regulating equipment action.*

The model will be run first with all PV at full output. The voltage at each bus on the MV system is noted. The model is run with all PV turned off. The voltage at each bus on the MV system is again noted. The ΔV is the difference at each bus on the MV system between the two runs. If the value is greater than 5% at any bus, then the all PV model is re-run with various mitigations to determine what is needed to comply with the 5% limit. For impacts exceeding 4%, additional analysis may be performed in order to determine appropriate ramp rate limiting, random delays, or other inverter functions to mitigate the risks associated with exceeding service voltage limits for an extended duration after a coincidental tripping event.

The model is run with all PV on and then again, with the applicant PV off. If the ΔV_{trip} value is greater than 3%, then the all-PV model is re-run with various mitigations to determine what is needed for the applicant to comply with the 3% limit.

The equipment limit of 1.5% is determined using the all-PV-on model at the upstream regulating device. The model is run with all PV on and then again, with the applicant PV off. The voltage change at the regulating device is noted. The ΔV_{trip} is the difference in the two voltages *at the upstream regulating device*. A passing cloud will cause a voltage change that is less than a full PV trip. An assumed output reduction due to the cloud of 75% is used. The expected ΔV_{cloud} at the regulator will be $0.75 \times \Delta Vtrip$. If the voltage change ΔV_{cloud} exceeds 1.5% at a regulating device, voltage change mitigations should be considered. 1.5% is about half of the typical voltage regulation dead-bandwidth.[36]

Repeated voltage changes above 1.5% at the regulating device will result in a rapidly escalating number of regulating equipment operations and maintenance.[37] The ≤ 1.5% recommendation will result in some increase in operation count due to the longer-term large cloud passage events, like a cloud front covering a broad area.

[36] Where the dead band is at 2%, an expansion to 3% may be appropriate.
[37] The voltage change must exceed the deadband for longer than the operation delay timer setting. Only then, will there be a corrective tap change operation. Most cloud passage situations will not meet both the magnitude and time constraints. Clouds must closely align with the array and be large enough to actually trigger an operation. Any detailed time series studies must take many factors such as mentioned into account for the modeling to yield usable detailed results and predictions of the number of actual operations.

The mitigations required to bring the new PV farm into compliance with the all-PV tripping step limit of 4% will proportionally reduce the single facility trip and the cloud passage caused voltage variations. If mitigations are needed for the equipment compatibility limit, the same approaches can be considered. Other approaches may be suitable for meeting the equipment compatibility limit.

Upon publication of the updated IEEE P1547, smart inverters that meet the IEEE 1547 criteria will become available. The smart inverters will have additional control abilities that affect how the analysis of new applications will be conducted. Various studies are underway to determine how best to apply these added abilities to better mitigate the adverse impacts of high penetrations that are encountered today.[38] Approaches such as volt-var and volt-watt are promising in areas with high PV penetration. Supplemental voltage regulation devices are becoming available that may allow revisiting the equipment compatibility limit. These changes should allow for greater penetrations and larger DER in the future while meeting the power quality limits.

Limitations of IEEE 1453-2015

The IEEE 1453 standard and the Flickermeter have higher accuracy than the predecessor approaches. While the primary non-linearities of human perception are approximated, the use of a single limit to represent a broad range of human perception sensitives does not ensure that compliance with the values will meet the needs of the populace as a whole.

People become sensitized to repeated flicker when it becomes perceptible, they are more likely to notice its occurrence, and become irritated sooner. This can become a major non-linear escalation of complaints. The P_{lt} monitoring does a partial job of capturing this effect.

The standard and meter are calibrated for use of a 60W incandescent light. Newer lighting technologies have different perception limits. The Electric Power Research Institute (EPRI)[39] testing indicates there are significant variations in perception thresholds depending on lighting equipment design. Depending on the device, the ΔV required for human perception range from similar to the severity level of a 60W incandescent to over twice the ΔV variation needed to be perceived. Most CFL and LED lights tend to have half the perception impact. Halogen lights can have 150% of the ΔV for the same perception level of an incandescent.

Interharmonic frequencies are increasing in magnitude due mainly to electronics. Interharmonics can produce significant flicker. The flicker meter responds to interharmonics

[38] IEEE 1547-2003 and the updated P1547 are based on the impact of individual DER. There are no aspects that focus on the aggregate impacts on the system nor if or how the settings and other functionality will interact with each other or the system controls and devices. The smart inverters have an increased ability to adversely interact with each other and the system controls and devices. Studies are showing that various combinations of settings and advanced functions can produce results with adverse performance and be less able than legacy DER to handle higher penetrations and smart-grid devices. For example, volt-var can produce better results but on average, suitable fixed, non-unit power factor can perform as well, is simple to apply, and naturally resilient to system changes.
[39] EPRI PQTN Brief No. 24, September 1995; and No. 37, August 1996

up to twice the fundamental frequency. This is a fair representation of the incandescent interaction. Electronic ballast lights will react differently and also to higher frequencies. The effect of higher frequency interharmonics have not been well quantified yet. As little as 0.2% of the fundamental ($V_{f,1}$) at or near 50 or 70 Hz can produce perceptible light flicker due to the beat frequencies generated.

The standard suggests using the ratio of load power to short circuit power (S_c/S_{sc}) to estimate a ΔV contribution. This requires that both factors have similar X/R ratios. While this is suitable for conventional motor starts and capacitor bank switching, it is not suitable for high power factor loads, variable frequency drive (VFD) motor starting, or for inverters. For these circumstances, mitigations like power factor control or dynamic regulation can further decrease the accuracy of this method.[40]

The standard includes application graphs and equations geared to traditional loads with their shorter repetition rates. Using these for longer period phenomena is not explained or documented. Longer period phenomena[41] do not accurately register on the flicker meter.

The standard uses rapid voltage change (RVC) for fast changes, like a step change. The characteristics of RVC are not defined well.[42] The ramp-rate, interval until another change, and short dip duration all impact perception and to some degree equipment compatibility.[43]

Methodology Assumptions

The text, equations, and figures in IEEE 1453-2015 and IEEE 1453.1-2012 do not cover the time frames and the waveshapes that are experienced due to voltage fluctuations cause by a series of small clouds passing over a PV array. The standards are focused on the much shorter time intervals of conventional fluctuation sources, from consumer to industrial scale sources of voltage fluctuation. The advent of high penetrations of variable sources like PV has introduced a need to better quantify the effects for the time scales associated with this source of disturbance.

By using the figures within the time and shape ranges available in the two standards, a worst-case approximation of a cloud-passing event can be constructed. The figures show trends for adjustment factors for longer duration waveshape factors such as for longer ramp rate times and longer repetition time intervals. These can be extrapolated to some extent. The perception severity reduction beyond the given time ranges is uncertain but the general trend direction can be assumed with fair certainty.

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[40] d ≈ ratio of customer S to short circuit S is valid for sources of a similar X/R ratio. It is not valid for inverters or other loads with a very different X/R ratio. For these use $d = \frac{(RL \times \Delta P)+(XL \times \Delta Q)}{Vr2}$

[41] Long term is any phenomenon that exceeds the P_{st} interval setting. The default setting is 10 minutes.

[42] The term RVC is used in 1453 and a number of standards worldwide. It is not a well-defined term that can be reliably measured and applied. "Rapid Voltage Changes - Definitions and Minimum Requirements", CIGRE, Paper 0789, CIRED-2009.

[43] "Quantifying Voltage Variations on a Time Scale Between 3 seconds and 10 Minutes", CIRED 2005, Session 2.

For example, a period between cloud passing events of 5 minutes has a slight lower $P_{st,1}$ factor than for 1 minute and the curve is nearly horizontal. This implies that the ~0.75 adjustment factor will not decrease appreciably with 10 minutes or longer events but may decrease some. Actual perception will be less severe than this estimate. The aperiodic figure goes out to 1.67 minutes for the dip, but due to the curve being nearly horizontal, it will not change appreciably for somewhat shorter or longer events.

The double ramp change in figure E.2 is similar in shape to the PV output power drop and later restoration of output. The longest ramp time shown on the adjustment graph is 1 second but the downward slope trend indicates the waveshape factor will continue to drop for longer ramp times. The curve shape indicates a gradual flattening of the curve is occurring with longer ramp times.

The aperiodic graph determines the conversation factor of an aperiodic rectangular wave to give the equivalent perception impact of a periodic rectangular wave. The result is a very conservative estimate of ongoing flicker perception severity. The ΔV needed to be perceptible would need to be in excess of the 3% step-voltage limit. Other factors are more limiting than the worst cloud passing change possible for an individual large PV farm.

Conclusion

The approaches used for flicker limit determinations historically were based on the curve in IEEE 141 (GE curve). There was a "one size fits all" approach for single step events, random events like an electric arc furnace, repeating events, and infrequent events. The research that culminated in IEEE 1453 demonstrates that such an approach is not an accurate representation of human perception and IEEE 1453 offers a more inclusive and accurate approach.

When setting limits for generation sources like PV, storage, and wind, the limits need to focus on equipment MV compatibility and rapid voltage changes, such as a PV farm tripping off-line. Historically, limits were set for individual facilities without adequate consideration for the other, existing fluctuation sources. The approach needs to shift to allocating the system's ability to absorb fluctuations among multiple fluctuation sources. This approach is illustrated in the IEEE 1453 standard.

The limits recommended in this paper reduce the review analysis to determining two variation factors by a method that is repeatable and aligned with the review processes for other factors such as line capacity.

Determining the background level of existing fluctuations so as to avoid over allocating the voltage variation allowance for a new customer requires pre-analysis monitoring with a Flickermeter. Similar monitoring with a power quality meter is needed to determine the background level of events related to RVC limits. The monitoring to enforce the variation limits per customer requires involved monitoring. While in many cases, suitable allocation factors can

be estimated adequately, situations involving large customers may need to be more involved. The procedure and training for this new approach will require time to establish.

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IEEE 1453
Technical Stakeholder Group

The technical stakeholder group for the transition to Institute of Electronic and Electrical Engineers (IEEE) Std 1453-2015 is a result of the Minnesota Public Utilities Commission Order from November 1, 2016, requiring Xcel Energy to review the adoption of IEEE 1453 with interested parties and file a transition plan by May 1, 2017.

Objective:
Xcel Energy is convening a technical stakeholder group to:

a) Gather feedback from interested parties regarding Xcel Energy's proposed step towards a transition to the methodology presented by the IEEE 1453 standard for voltage fluctuation for PV distributed generation system impact studies, and
b) Discuss the future approach and steps needed to plan for transition to the IEEE 1453 methodology that uses time series data into Xcel Energy's modeling of voltage fluctuation and flicker.

The technical stakeholder group is an advisory body with the task of making thoughtful collaborative recommendations to Xcel Energy to consider in both the short-term preliminary step and the long-term transition plan using time series data that the Company is compiling. These collaborative discussions may guide the Company in developing its plan.

The stakeholder group will consist of members with a technical background to not spend unnecessary time to achieve a common understanding on the basic engineering principles associated with the electric power discipline. An active Professional Engineer (PE) license in the state of Minnesota is not a requirement but is strongly preferred. Interested parties invited include other utilities, solar developers and environmental stakeholders.

Working Group Meetings: It is currently anticipated that the IEEE 1453 Technical Stakeholder will meet three times per the schedule below. Additional information may be provided via email. Due to the collaborative nature of the stakeholder, a call-in option will not be available.

1. January 30, 2017: Review of purpose of stakeholder, Proposal review, Discussion and feedback
2. February 15, 2017: Further discussion and Implementation of proposal discussion (*tentative*)
3. March 15, 2017: Final discussion and Feedback of proposal, Discussion of future full adoption)

Group Leadership: Xcel Energy will lead the Stakeholder group.

Location:
401 Nicollet Mall
Minneapolis MN 55401

Meeting 1: Monday, January 30, 2017

IEEE 1453 Stakeholder Discussion

Xcel Energy, 401 Nicollet Mall
Minneapolis, MN 55401

Stakeholder Objective

1. Gather feedback from interested parties regarding Xcel Energy's proposed step towards a transition to the methodology presented by the IEEE 1453 standard for voltage fluctuation for PV distributed generation system impact studies, and
2. Discuss the future approach and steps needed to plan for transition to the IEEE 1453 methodology that uses time series data into Xcel Energy's modeling of voltage fluctuation and flicker.

Discussion details, presentations and feedback will be part of the Companies filing with the Commission on May 1, 2017.

Today's Discussion

Today's discussion will review the purpose of this stakeholder group and review/discuss Xcel Energy's proposal to transition to the methodology presented by IEEE 1453 in the short-term.

We will discuss project impacts and future transitions to methodology using time-series data at future meetings.

Agenda

1:00	Introductions	Jessie Peterson, Xcel Energy
1:05	Background/Objectives	Jessie Peterson, Xcel Energy
1:20	Current Practices for Voltage Fluctuation	Patrick Dalton, Xcel Energy
1:30	IEEE 1453: Xcel Energy Proposal	Patrick Dalton, Xcel Energy
2:30	Break	
2:45	Group Discussion of Proposal – What are the benefits of the proposal and what may be the shortfalls of the proposal?	
3:45	Wrap-up, Next Steps	Jessie Peterson, Xcel Energy

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Transition to IEEE 1453 Standards for PV Distributed Generation
Stakeholder Meeting
January 30, 2017 – Summary

Attendees:

- Xcel Energy
- EVS
- Department of Commerce
- Otter Tail Power
- Fresh Energy
- SunRise Energy Ventures
- MN Power
- Exoplexus
- Dakota Electric
- Minnesota Solar/Potential Solar

Additional Members not in attendance:

- MPUC Staff - observers
- Ameresco
- SunShare

Summary

The Stakeholder group met on January 30, 2017, to discuss the transition to IEEE 1453 for PV Distributed Generation Resources, which details voltage fluctuation.

The group had a brief discussion on the objectives of the workgroup, including:

1. Gather feedback from interested parties regarding Xcel Energy's proposed step towards a transition to the methodology presented by the IEEE 1453 standard for voltage fluctuation for PV distributed generation system impact studies, and
2. Discuss the future approach and steps needed to plan for transition to the IEEE 1453 methodology that uses time series data into Xcel Energy's modeling of voltage fluctuation and flicker.

Patrick Dalton, Xcel Energy, then reviewed the background of what the application of voltage fluctuation looked like today before launching into Xcel Energy's proposal, as detailed in the Xcel Energy Whitepaper.

As Dalton explained, Xcel Energy's proposal is to move forward in two steps. First, to adjust Xcel Energy's current analysis of voltage fluctuation, as described in the Whitepaper. Since Xcel Energy will be one of the first to move in this direction, within the industry, they have had to move beyond just looking at the standard for guidance causing peer review by various utilities across the nation and now with local stakeholders. The second phase is to make alterations towards an analysis using time series data upon the completion and approval of IEEE 1453.2. The second phase will also require further analysis of current projects.

The first step, or simple analysis of IEEE 1453.1, will include PV review in two ways:

1. Voltage impacting visible perception (causing a "tripping" on the system) to be reviewed at 3% single and 4% aggregate levels –for the purposes of a allocation limit, and;
2. Medium Voltage Review (the cause of rapid voltage changes in the system impacting equipment limitations) at 1.5%–(2% equivalent assumes that cloud cover is at 75% at a single facility level limit)

Stakeholders had an opportunity to discuss many of the assumptions found within the analysis and provided further details on how these conclusions were reached. Xcel Energy noted that the planning and compatibility criteria came directly from the IEEEE standard while the allocation level was derived from both the standard and Xcel Energy's experience. Xcel Energy further explained that this proposal is less restrictive than the current 2% full on/full off methodology, but more precise.

In addition, stakeholders had several additional questions for discussion such as why Xcel Energy was using the current active Standards contained in MN Statewide Interconnection Rules (i.e. Section 10 tariff) (why not accept smart inverter technologies), how these changes may affect voltage regulator requirements and if batteries can be used to help mitigate these impacts further. A summary of some of these answers are below:

1. Why start with active Standards (i.e. IEEE 1547-2003 and IEEE 1547A-2014) when new technologies are available and used in other areas such as California?
    a. Xcel Energy needs to begin with the standards that are approved in Minnesota. To-date, smart inverters are not approved for certification within standards (IEEE 1547, IEEE 1547.1, & UL 1741) and therefore cannot be used in Minnesota. As these certifications change, rules will need to adapt.
    b. There are a set of Standards that are followed in Minnesota. Xcel Energy's proposal is already going above what is expected without a finalized IEEE 1547 Standard, but Xcel Energy needs to be as consistent as possible with state standards as well.
2. Will these changes change regulator requirements?
    a. Not necessarily
    b. Regulators will still need to be added depending upon the situation and location of the PV system.
3. What is the role of LVT?
    a. Xcel Energy is aware that this is changing in the IEEE 1547 revision process and that California uses a different threshold.
    b. Xcel Energy does not adopt standards until they are approved.
4. Can batteries be used to help mitigate further impacts of voltage regulation?
    a. Batteries can be used to mitigate this further
    b. Xcel Energy has not seen any developer choose to go this direction, but the stakeholder group presented some interesting options that perhaps could be piloted.

Stakeholders also suggested that the workgroup further discuss how Xcel Energy can collect data today in order to move to time series analysis 2-3 years in the future. This will be a major topic of conversation at our next workgroup meeting in February.

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Meeting 2: Friday, February 24, 2017 9:00 a.m. – 12:00 p.m.

IEEE 1453 Stakeholder Discussion

Xcel Energy, 401 Nicollet Mall
Minneapolis, MN 55401

Stakeholder Objective

1. Gather feedback from interested parties regarding Xcel Energy's proposed step towards a transition to the methodology presented by the IEEE 1453 standard for voltage fluctuation for PV distributed generation system impact studies, and
2. Discuss the future approach and steps needed to plan for transition to the IEEE 1453 methodology that uses time series data into Xcel Energy's modeling of voltage fluctuation and flicker.

Discussion details, presentations and feedback will be part of the Companies filing with the Commission on May 1, 2017.

Today's Discussion

Today's discussion will be a follow-up on Meeting #1 by discussing additional comments provided to Xcel Energy. We will also discuss adoption timeframe of the simplified approach before getting into further discussion on longer-term planning towards a time series approach.

Agenda

9:00	Introductions/Meeting Objectives	Jessie Peterson, Xcel Energy
9:05	Meeting #1 Follow-up/Additional Discussion	Patrick Dalton, Xcel Energy
10:15	Break	
10:30	Adoption timeframe for the simplified approach	Patrick Dalton, Xcel Energy
10:50	Time series approach	Patrick Dalton, Xcel Energy
11:50	Wrap-up, Next Steps	Jessie Peterson, Xcel Energy

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Attachment B: 6 of 12

Transition to IEEE 1453 Standards for PV Distributed Generation
Stakeholder Meeting
February 24, 2017

Attendees:

- Xcel Energy
- EVS
- Department of Commerce
- Otter Tail Power
- Fresh Energy
- SunRise Energy Ventures
- MN Power
- Ecoplexus
- Dakota Electric
- Minnesota Solar/Potential Solar
- MPUC Staff - observers

Additional Members not in attendance:

- Ameresco
- SunShare

Summary

The Stakeholder group met on February 24, 2017, to continue the discussion towards the transition to IEEE 1453 for PV Distributed Generation Resources, which details voltage fluctuation. The objectiveof this meeting was to discuss the comments provided by parties in relation to Xcel Energy's simplified transition proposal and further discussion on next steps.

Two parties provided comments prior to the meeting including SunRise Energy (with input from several other solar developers and MNSEIA) and Fresh Energy. The Comments are summarized below:

- Fresh Energy used the comments as an opportunity to clarify details of the whitepaper including the usage of voltage regulators and LTC controls and how the 1.5% with a 75% cloud reduction translates to full-on full-off.
- SunRise, et all, provided comments regarding the aggregate level within Xcel Energy's proposal (currently at 3%). Their proposal was to drop the 3% individual plan and 4% all-circuit limits (aggregate) while adding a 5-6% RVC limit for individual sites.

The Stakeholder group spent a considerable amount of time discussing the proposal presented by SunRise on behalf of several developers. One of the larger concerns was the reference to IEEE 1453 for 4%. Many developers felt that this was not based on the standard itself and was not justified as it assumes the potential for several mass tripping events per community solar garden. Xcel Energy noted that the table containing the Rapid Voltage Change limits was labeled as Indicative Planning Levels, which by definition are subject to input by those owning and operating the electric system in order to ensure quality and reliable service.

Xcel Energy noted that mass tripping does occur and has in California[1]. They also noted that PV tripping of individual units has already occurred once with one of the community solar garden projects currently in operation. More importantly, the 4% was based on the IEEE 1453[2] as well as operational knowledge across the country.

Other utilities acknowledged that conservative approaches are typically used to avoid end-customer impacts; however, for planning purposed the utility needs to assume worst-case scenarios. In situations where this would occur, customers (and potential subscribers) could be negatively impacted to the point of voltage caused equipment failure in manufacturing plants causes economic loses. The other utilities in attendance agreed that to remove the aggregate level, and essentially assume no mass tripping would ever occur, would be considerably more risky than the utilities in attendance would be willing to accept. They also indicated a tendency to start receiving customer complaints when voltage fluctuations reach around 3%.

In addition, another concern exists regarding moving too far ahead of the industry. If it is discovered that the solution is not working in the field, it can result in PV disconnections, additional reconductoring and potential increased costs to either the developer and/or ratepayers. That is a situation that has no benefit to any involved party and creates significant uncertainty for end customers, subscribers, garden owners and operators, the utility and rate payers.

The stakeholders continued to discuss the approach behind the white paper and again noted that this is a simplified approach as an interim before additional data is collected on current community solar gardens and other large-scale PV deployments. Phase 2 of our approach would be to take the data collected and adjust the approach moving closer to the IEEE 1453 time-series analysis practice.

SunRise suggested, in light of the utilities concerns, that one option would be to change the 4% aggregate level to 5-6% as suggested by IEEE 1453. Developers agreed this would be an option they could support in the simplified approach. Xcel Energy and the other utilities agreed with reviewing the potential of moving to a 5% level and maintaining the other criteria as proposed in the Xcel Energy whitepaper.

Continued discussion identified concern regarding actual data. Solar City agreed to see if there was any information available from their company to provide the utilities with interim data until actual data can be obtained from completed gardens in the Solar*Rewards Community program. Solar City also discussed the monitoring of PV systems, what they do today, what they can do and how, sharing processes with the group in practice today. Rapid voltage change was not something necessary monitored, but Solar City was not aware of series mass tripping events. Xcel Energy shared their current plan for collecting data for two projects required by Commission order and further analysis for a total of around 4-5 when including additional projects at feeders in rural areas once the projects are completed.

[1] The Company will provide the FERC Study referencing this event to stakeholder members
[2] Patrick Dalton, Xcel Energy, referenced the Planning Levels Definition in 1453.

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Solar City also suggested that Xcel Energy perhaps review the white paper and make clear that not all details determined are directly from the IEEE 1453 practice, but also includes operational considerations known today.

The stakeholder group decided to wrap-up the discussion early so that focus could be taken on first phase of this process prior to discussing phase two, which will review time series data.

Next Steps:

- Xcel Energy and other utilities will review the potential for moving from 4% to 5% in aggregate
- Solar City will determine if they have data that can be shared
- The next Stakeholder Meeting will be held on March 15 and include a discussion on how to move forward with a proposal and what the second phase of these changes may look like

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Meeting 3: Wednesday, March 15, 2017
9:00 a.m. – 12:00 p.m.

IEEE 1453 Stakeholder Discussion

Xcel Energy, 401 Nicollet Mall
Minneapolis, MN 55401

Stakeholder Objective

1. Gather feedback from interested parties regarding Xcel Energy's proposed step towards a ***transition to the methodology presented by the IEEE 1453*** standard for voltage fluctuation for PV distributed generation system impact studies, and
2. Discuss the future approach and steps needed to plan for transition to the IEEE 1453 methodology that uses time series data into Xcel Energy's modeling of voltage fluctuation and flicker.

Discussion details, presentations and feedback will be part of the Companies filing with the Commission on May 1, 2017.

Today's Discussion

Today's discussion will be a follow-up on Meeting #2 by discussing additional comments and alternatives. We will also discuss adoption timeframe of the simplified approach before getting into further discussion on longer-term planning towards a time series approach.

Agenda

9:00	Introductions/Meeting Objectives	Jessie Peterson, Xcel Energy
9:05	Meeting #2 Follow-up/Additional Discussion	Patrick Dalton, Xcel Energy
10:00	Adoption timeframe for the simplified approach	Patrick Dalton, Xcel Energy
10:30	Break	
10:45	Transition to full Standard – timeframe, time series, etc.	Patrick Dalton, Xcel Energy
11:50	Wrap-up, Next Steps	Jessie Peterson, Xcel Energy

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Transition to IEEE 1453 Standards for PV Distributed Generation
Stakeholder Meeting
March 15, 2017– Summary

Attendees:

- Xcel Energy
- Otter Tail Power
- Fresh Energy
- SunRise Energy Ventures
- MN Power
- Minnesota Solar/Potential Solar
- MNSEIA
- MPUC Staff - observers

Additional Members not in attendance:

- Ameresco
- SunShare
- Ecoplexus
- Dakota Electric
- Department of Commerce
- EVS

Summary

The Stakeholder group met on March 15, 2017, to continue the discussion towards the transition to IEEE 1453 for PV Distributed Generation Resources, which details voltage fluctuation. The objectives of this meeting were to discuss further Xcel Energy's proposal to implement a simplified version of IEEE 1453, and begin to further the discussion on a full transition to time-series analysis.

Xcel Energy began the conversation responding to the proposal to change the 4% aggregate level to 5% under the simplified version. The Company agreed on the merits of this change, with the ability to perform additional study on necessary ramp rate limiting when exceeding 4%, and determined it was a suggestion that could be incorporated as part of the overall proposal. The simplified version will be adjusted to increase the aggregate to 5%.

Two additional action items were discussed as well. SolarCity was unable to provide requested documentation for review supporting their comments (i.e. 5% individual and no aggregate limit) and Xcel Energy will provide written documentation regarding the comments submitted by SunRise by the end of the month. SolarCity apologized for not providing them sooner.

However, there continued to be dissent within the workgroup regarding the simplified approach to IEEE 1453 recommended practice. SunRise maintained that the Company has chosen a "best practice" approach, which does not necessarily following all the specifics of the current recommended practice. Xcel Energy noted that the recommended practice itself does not address several requirements of an engineering study for DER and therefore, it would not be in the interest of the utility or participants in the program to adopt aspects that do not consider the complete picture. Xcel Energy noted that this aligns with other utilities adoption of the simplified IEEE 1453 approach, such as PacifiCorp's published guidelines which were referenced in a previous Independent Engineer review on this topic.

Discussion continued regarding the merits of the simplified approach and the group revisited the charter stating that the simplified approach is the first step towards adopting the IEEE 1453 approach before

transitioning to the time series approach at a later date. Xcel Energy requested to understand how, as a group, we could move forward. The Stakeholder group seemed to be comfortable moving forward with the simplified approach in the interim for 1 MW projects in the pipeline. SunRise however, continued to have concern with the approaches use in their four pilot projects. Xcel Energy requested technical details on why the approach would be adequate for one set of projects but not another set of projects, but no technical response was provided.

MNSEIA mentioned that some of its members are also concerned with moving forward with an approach that is not 100% detailed in the standard itself. However, MNSEIA seemed comfortable moving forward with the simplified approach as long as the transition to the full standard – using time series data – continued over time. Xcel Energy again stated that there is no approach for studying DER using IEEE 1453 that is 100% detailed in the document.

The group discussed other options, such as a developer mitigating its own issues by monitoring etc., but Xcel Energy noted that once the problem occurs it is often quite complex to fix at a customer site. This can also cause legal disputes and after-the-fact mitigations. This is why the criteria is applied during the design of the interconnection. The other utilities at the table supported this discussion – some noting that they felt Xcel Energy's proposal may be going too far for them to adopt. Xcel Energy indicated a concern with moving beyond technical requirements that can be implemented on a statewide basis under the future interconnection requirements that will result from open docket 16-521.

The group agreed to meet in April to address the full implementation issues, but still engaged in discussion. The time series approach and further transition was the next topic of discussion. Xcel Energy noted that Scandia National Labs has stated that one-second data resolution will be needed to capture the impacts discussed in the IEEE 1453 standard. In order to obtain the capabilities for a full time-series analysis, Xcel Energy will need further development in two areas: Tools and Data.

The methodology for time-series data is defined by the standard itself. Xcel Energy is collecting data now at one minute intervals from telemetry for sites larger than 250 kVA. Higher resolution data is being collected for some of the projects in the field using specialized equipment. Due to the limited availability of the specialized equipment, most projects have not had the equipment installed to gather the data needed for future analysis.

OpenDSS was discussed as another tool that could be used to analyze grid impacts using time series load and generation data. SolarCity agreed that OpenDSS is a decent tool to use for this type of analysis. Xcel Energy indicated that this tool is useful for research or specific study purposes, but may not be ideal for bringing the time-series IEEE 1453 analysis into the production environment of impact studies.

One of the issues is collecting one-second data for generation and load – the monitoring equipment needed for this resolution of data is not a standard component for interconnections or for monitoring load. The power quality meters with this level of capability are typically installed for a limited duration on an as-needed basis. For a full detailed analysis, the IEEE 1453 Standard recommends power quality meters on the feeder itself prior to the fluctuating installation going into service in order to characterize background voltage fluctuation.

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Xcel Energy asked the Stakeholder group what they have seen done elsewhere. The Company is discussing with other utilities – and has already discovered there are a number of ways to get there. Solar City noted that they have seen studies with the time series data from the system and they have also used OpenDSS for solar on circuits.

National Grid is the only other company Xcel Energy has found that does a time series analysis today. Xcel Energy has also reviewed proposals for this type of work and concluded that the cost of performing impact studies could increase significantly if the analysis were to be performed with existing tools and data.

It was noted that developers may be collecting this data today, but perhaps not to the granularity needed (1 second data). Xcel Energy suggested that they could collaborate with developers to collect the data using a power quality meter at a sub cycle. Solar City was unable to provide any high-resolution data for PV plant output.

The Stakeholder group did not have further suggestions towards the transition. Many members felt getting through Phase 1 of this process was critical before they could focus on the next steps of gathering data. Xcel Energy felt that they could take conceptual ideas and start determining exactly what tools are needed and how to collect data moving forward. It is likely that this subject will be taken up in the General Interconnection Docket for Minnesota as well.

These decisions will also need to be made with other DER applications and not just solar gardens, which is further justification for moving the longer term objective of using time-series analysis into the General Interconnection Dockets.

Study analysis regarding the inverter discussion with time series (and overlapping functions). Phase II of interconnection docket is set to begin in December of 2017.

Next Steps:

- Xcel Energy will provide written comments to SunRise Energy Ventures original comments by month end
- Xcel Energy will discuss the simplified approach to IEEE 1453 with other developers not in attendance to this meeting and MNSEIA further regarding their concerns
- The Workgroup determined an optional follow-up call regarding next steps for full implementation would be the best next step for the team (to be held on April 12th)

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CERTIFICATE OF SERVICE

I, Jim Erickson, hereby certify that I have this day served copies of the foregoing document on the attached list 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-13-867

Dated this 26th day of April 2017

/s/

_____

Jim Erickson
Regulatory Administrator

Minnesota Public Utilities Commission

Daniel P. Wolf, Executive Secretary

NOTICE OF RECIEPT OF COMPLIANCE FILINGS

Issued: June 2, 2017

In the Matter of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program

PUC Docket Number: E-002/M-13-867

Case Background: On November 1, 2016, the Commission issued its *Order Resolving Independent Engineer Appeals and Establishing Procedures for Future Disputes,* in the above-cited docket. Order Point #2 required Xcel Energy (Xcel) to work with other interested parties to develop a plan for a transition to incorporating the standards of IEEE 1453 into its modeling of voltage fluctuations and flicker for solar photovoltaics. Order Point #3 required Xcel to file an assessment of the impacts from voltage fluctuation and flicker, if any, on its system, within three months of the operational date of the Becker and Glazier projects, and to file annual assessments for the solar-garden program as a whole.

PLEASE TAKE NOTICE that on April 26, 2017, Xcel submitted a compliance filing in response to Order Point #2. On April 28, 2017, Xcel submitted a compliance filing in response to Order Point #3.

In its April 26, 2017 compliance filing, Xcel provided background information on the review and design of voltage fluctuation limits for medium-sized photovoltaic interconnections. The filing also summarized its outreach efforts and established a plan for the adoption of a simplified IEEE 1453 methodology within its design review for proposed Distributed Energy Resources including community solar gardens.

In its April 28, 2017 compliance filing, Xcel provided a report on voltage fluctuation and flicker for the Glazier community solar garden site. Xcel indicated that a 2 percent voltage fluctuation threshold for the project was sufficient to prevent measurable adverse system or customer voltage impacts during the study period; but that the data is inconclusive in determining how other community solar gardens would perform or how the new criteria would impact observed voltage fluctuations.

If you have questions about this docket or the Commission's process and procedures, please direct them to Susan Mackenzie at 651-201-2241 or susan.mackenzie@state.mn.us.

Change your mailing preferences: Email docketing.puc@state.mn.us or call 651-201-2204.

To request this document in alternative formats, such as large print or audio, call 651-296-0406 (voice). Persons with a hearing or speech impairment may call us through their preferred Telecommunications Relay Service or email consumer.puc@state.mn.us for assistance.

Linden Distribution Dispute
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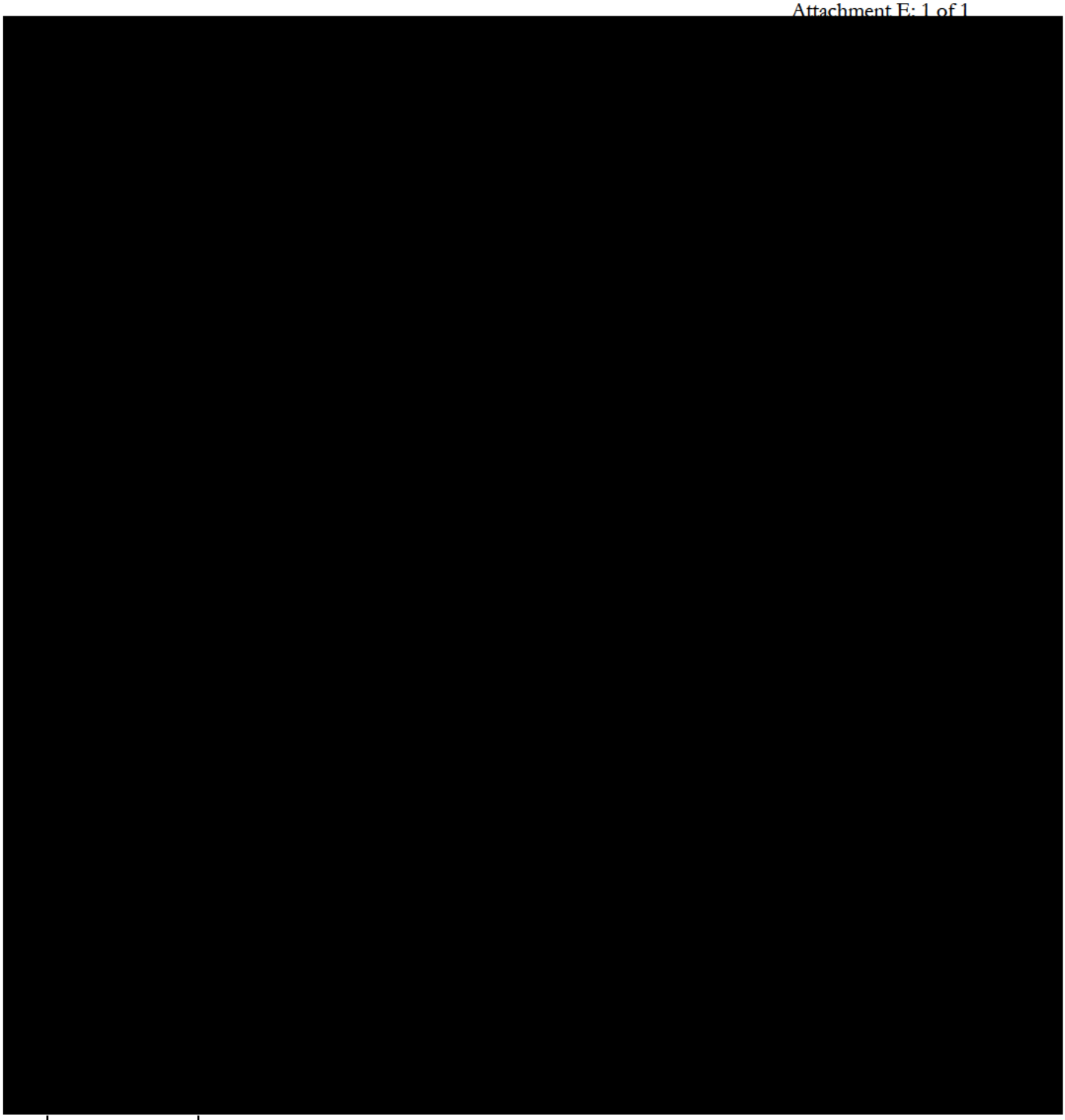

☒ **Not Public Document – Not For Public Disclosure**
☐ **Public Document – Not Public Data Has Been Excised**
☐ **Public Document**

Xcel Energy
Docket No.: E002/13-867 IRSX Linden
Response To: Sam Wheeler Information Request No. 9

Requestor: Sam Wheeler
Date Received: October 3, 2018

Question:

SunShare notes the PUC mandated Xcel Glazier Flicker Compliance Study in Issue Number 2 of their Second Intake Form (dated August 16, 2018). Xcel, the PUC order requires an annual update of this Study.

- Please provide the 2017 and 2018 editions of the Glazier Flicker Compliance Study. If the 2018 edition is not available, please explain in detail, why it is not available. Note specifically what equipment, by brand name and model number was used to perform the 2017 and 2018 studies in the field.

Response:

SunShare's Second Intake Form states under Issue Number 2:

"However, following this IE ruling on the Glazier/Foxtrot/Blue Heron/Cold Spring site, the PUC required that Xcel provide an assessment of the impacts from voltage fluctuation and flicker, if any, on its system within three months of the operation (and annually thereafter_ of the Glazier project, which was designed and interconnected using a 2.0% assumption in models."

However, this is a mischaracterization of the Minnesota Public Utilities Commission's November 1, 2016 Order which states at Order Point 3:

"Xcel shall file as a compliance report within three months of the operational date of the Becker and Glazier projects, an assessment of impacts from voltage fluctuation and flicker, if any, on its system, and shall do so ***annually for the solar-garden program as a whole***." Emphasis added.

The Company submitted its analysis on Glazier on April 28, 2017. We provided further analysis on a subset of community solar gardens on March 30, 2018. The analysis for Becker has not been conducted as the project is not yet completed. The trade secret document for Glazier is attached as Attachment A. We have also provided the public version of our 2017 annual report filed on March 30, 2018, as Attachment B. We further note that the public documents are available on the state's eDocket site at:

- Glazier: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={9E04B71D-EB41-4059-9DD2-95AA4631975A}&documentTitle=20174-131402-01
- 2017 Annual Report: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={30637862-0000-C020-8F04-D7024376CCB3}&documentTitle=20183-141570-02

Attachment F of the 2017 Annual Report provides an assessment of the program's impact on voltage fluctuation, based on monitoring two additional CSG sites on two different electric distribution feeders. For this analysis, sites were selected based on their likelihood to influence feeder voltage and these two sites with high relative CGS system strength were selected from all CSG sites greater than 1 MW and in service as of January 2018. These two sites entered into service in 2017 and were studied in 2015 with a 1.5 percent individual voltage fluctuation threshold, while the Glazier site was studied with a 2 percent threshold. We have provided the Public version of the 2017 Annual Report and cannot provide the Not Public version as the Not Public version contains third-party confidential information.

We note that the two garden sites reviewed do not represent worst case scenarios and sites likely to have more significant impacts are still in construction. In addition, neither of the sites were studied under the current voltage fluctuation criteria, adopted in April 2017. Therefore, this study is inconclusive as to how other CSGs will perform or how CSGs perform under the current voltage fluctuation criteria.

Preparer:	Jessica Peterson
Title:	Sr. Regulatory Analyst
Department:	Customer Solutions
Telephone:	612.330.6850
Date:	October 15, 2018

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

Attachment M to our Appeal is marked as "Non-Public" pursuant to Minn. Stat. §13.37, subd. 1(b). his information derives independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from its use and is marked as "Not Public." This information, including information as it relates to SunShare, is Trade Secret and is subject to efforts from SunShare and Xcel Energy to maintain its secrecy. This 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. The internal emails show company business methods, techniques, and processes. The engineering information contains information regarding the Company's feeders and other system components. This information is also classified as "security information" as defined by Minn. Stat. § 13.37, subd. 1(a). Xcel Energy believes the information could be manipulated to reveal the location and size of facilities serving our customers, which would substantially jeopardize the security of information or property against tampering, improper use, illegal disclosure, trespass or physical injury.

Further, consistent with Minn. Stat. §13.02, subd 9, and §13.03, subd 1, this information is "nonpublic data" as federal law treats it as "trade secret" under 18 USC §1839, because it reflects business, scientific, technical, economic, or engineering information, including patterns, plans, compilations, program devices, formulas, designs, methods, techniques, processes, programs, or codes, where reasonable measures have been taken to keep such information secret and it derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable through proper means by, another person who can obtain economic value from the disclosure or use of the information.

Attachment M is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: The attachment contains private customer and technical, engineering design information.

2. **Authors:** The data was prepared by Northern States Power Company and its contractors.
3. **Importance:** The attachment contains information describing technical, engineering aspects of Linden project's interconnection.
4. **Date the Information was Prepared**: 2016-2018.

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

LINDEN PROJECT TIMELINE SINCE 3/15/2018

3/15/2018 – SunShare initiates this IE dispute by an email to the Department.

3/16/2018 – SunShare submits an Intake Form.

4/ 17/2018 – SunShare submits a revised Intake Form.

6/13/2018 – SunShare, Mr. Wheeler, and Xcel Energy execute a Services Agreement and NDA, included as Attachments C and D to this Appeal.

6/28/2018 – Xcel Energy submits a response to issues identified in the revised Intake Form dated 4/17/18, included as Attachment E to this Appeal.

7/19/2018 – Xcel Energy responds to the IE's Information Requests No. 1-4.

7/24/2018 – The IE determines, based on guidance from the Department, that SunShare's request that the IE order Xcel Energy to begin immediate construction of 3 MW is outside the IE's jurisdiction. The IE's email is included as Attachment F to this Appeal.

8/7/2018 – the IE determines that the prior Settlement Agreement does not preclude the Linden dispute from moving forward. The IE's decision is included in the IE Report pp. 6-7, Attachment A to this Appeal.

08/14/2018 – SunShare submits a second Intake Form with two new issues, included as Attachment G to this Appeal.

8/21/2018 – Xcel Energy responds to the IE's Information Requests No. 5, 6, and 8.

9/4/2018 – Department determines that SunShare's request that the IE order Xcel Energy to incorporate smart inverter capability is outside the IE's jurisdiction. Department's email is included as Attachment H to this Appeal.

9/14/2018 – Xcel Energy responds to IR No. 7.

9/21/2018 – Xcel Energy submits a response to issues identified in the Intake Form dated 8/14/18, included as Attachment I to this Appeal.

10/15/2018 – Xcel Energy responds to the IE's Information Requests No. 9-10.

11/14/2018 – Xcel Energy responds to the IE's Information Request No. 11, marking information as "Attorney Eyes Only."

11/19/2018 – Department recommends that the IE complete his report, and if the report references any emails marked as "Attorney Eyes Only," Xcel Energy shall provide all parties with a standard confidential version of those emails.

12/18/2018 – the IE issues his written report, included as Attachment A to this Appeal.

Attachment O: Confidentiality Concerns

The IE report at pages 2-5, and 10-12, raises Confidentiality issues. At a high level, three issues are raised: 1.) the standards that should be used in determining the level of Confidentiality, including the role of the IE on this non-engineering issue; 2.) whether Xcel Energy should release to SunShare, or make public, the specific name, street address, and PV capacity of other community solar gardens that have either been proposed or are in commercial operation on the same feeder as SunShare's Linden project; and, 3.) whether employees of SunShare (other than its attorneys) should have access to inside company Xcel Energy emails that the IE has not relied upon for his IE report.

1.) Standards for Determining Level of Confidentiality

The standards that should be used for determining what information is Confidential are set forth on pages 1-3 of the Non-Disclosure Agreement (NDA) entered into by the parties in this matter. This Confidential information includes trade-secret and security information as set forth in Minnesota Statutes Chapter 13, Critical Energy Infrastructure Information as defined by the FERC, and any other information that is classified by statute, rule or regulation as private, confidential or non-public. This also includes information that is confidential to a third-party. There is a sub-category of Confidential information that is called "Attorney Eyes Only" information, and this defined in the NDA as including inside company emails.

The IE Report, however, does not refer to the NDA on this issue when he addressed the Confidentiality issue in the IE report. First, on pages 2 and 3, the IE Report states that the IE is "… chartered to determine what information is considered to be Confidential, Trade Secret or other classifications of sensitive material, and how to define and use such in this Dispute Case." This directly conflicts with the NDA that does not refer to any such "charter" and does not vest with IE as being the ultimate decision maker on what is Confidential, Trade Secret or other classification. Instead, this is the role of the Commission in case of disagreement. (See, NDA, Attachment D, p. 4, par. 14). Further, we do not know what "Charter" document the IE relied upon to reach this conclusion. The un-identified Charter cannot be used to define the scope of authority of the IE for this IE review.

2.*) Confidential Nature of Developers Name, Location and Capacity.*

The specific name, service address, and PV capacity of other community solar gardens on the same feeder that have either been proposed or are in commercial operation should not be released to SunShare. The IE Report references a study where this information is listed, and this information has been treated as being third-party confidential by Xcel Energy and therefore not shareable with the IE and SunShare. The IE Report, at pages 3-4, states that this should be public information, even though this issue was not raised by SunShare to the IE. If SunShare, following the issuance of the IE report, now wants its own project location and capacity publicly known, then it can make that decision for itself. But, neither the IE or SunShare can compel the release of another developer's confidential information.

Community solar gardens are customers of ours, and are to be accorded similar privacy protections as our other customers except where specifically noted. The type of data that the IE wants us to make public and share with SunShare includes customer account information and customer energy usage data (CEUD) that the Commission has determined is part of the private information of a customer. See, generally, *In the Matter of a Commission Inquiry into Privacy Policies of Rate-Regulated Energy Utilities*, Docket No. E,G999/CI-12-1344. Accordingly, it should not be publicly shared. Nor should it be shared with SunShare, a competitor, without the express written consent of the customer whose privacy is at issue.

The IE also relies upon, and misapplies, the provision from our Section 9 tariff, Sheet 78, that states: "*The Community Solar Garden Operator acknowledges and agrees that the Company may publicly disclose the Community Solar Garden Location, Community Solar Garden Operator, nameplate capacity and generation data of the Community Solar Garden.*" This is a quotation from part of the Standard Contract for Solar*Rewards Community, and therefore only applies once the garden is in commercial operation. It does not apply to studies performed while an application is pending, but prior to the date that this tariffed contract has been signed. Further, even when a garden is in commercial operation, this provision is only applied as worked-out at community solar garden workgroup meetings and filings in the Community Solar Garden docket (Docket No. 13-867).

Through the workgroup process, developers and the Company tried to even-handedly balance the interests of the developers with how to apply this tariff. The development of the policy on how to apply this tariff provision and protect the interests of all developers in an even-handed basis is highlighted by the following filings in the Community Solar Garden Docket:

1. April 16, 2015 filing of Minutes of Workgroup meeting of March 4, 2015.[1] At this meeting, attended by a large number of developers (and three representatives from SunShare), it was determined that Garden Operators would be added to a listing by County that includes email address once an interconnection agreement is signed. The current version of this is available at the following link https://www.xcelenergy.com/working_with_us/renewable_developer_resource_center/solar_rewards_community_developer_resources , under the sub-link for "Garden Application Status by County". We monthly update community solar garden application data, showing by county (not service address), the status of applications. This information is available at the above link,

2. July 20, 2015 letter from Xcel Energy detailing request from the Star Tribune for confidential information about the location of projects that have made applications under the Community Solar Garden program.[2] This letter noted that, consistent with the above April 16, 2015, filing, we only provide by county groupings of applicants under this program.

3. May 12, 2017 filing of Minutes of Workgroup meeting of March 15, 2017. The minutes note that the Section 9 tariff referenced above allows Xcel Energy to make certain site details public once a garden site is operational, including the location, operator name, nameplate capacity and generation data. The minutes reflect agreement that this information would be available as part of the Xcel Energy Solar*Rewards Community Annual Report. This information has been included as Attachment C to the 2017 Annual Report filed in 2018, and as Attachment B to the

[1] This filing is available at this link: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={2AF63D37-BDB4-4AFF-911E-8699ED2B1738}&documentTitle=20154-109347-01

[2] This filing is available at this link: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={5CB6D5AE-7BD2-4FB7-923E-9A62B101051E}&documentTitle=20157-112564-01

2016 Annual Report filed in 2017. The location in these reports was only at the city level, not street address.

The policy that the IE proposes in his report would require making public the exact street address and developer name and project capacity for any other proposed or completed project on the same feeder as SunShare. This would upset the current balanced release of information that so far has served the program well, and has been consistent with what has been worked out with developers at the workgroup sessions. Further, it would unnecessarily infringe on the privacy, and fair competition expectations, of other developers.

The conduct of SunShare in this IE review, prior to the issuance of the IE report, was consistent with the above understanding as to the private nature of community solar garden applicants. For example, in June 2018, as Xcel Energy was getting ready to file with the Commission a notice of the current IE dispute, it reached out to SunShare to inquire as to what information SunShare regarded as non-public. SunShare responded by requesting non-public treatment of the capacity of its applications at issue here, as well as the email address of its president. Accordingly, this information was redacted from the public notice filed by Xcel Energy in Docket 13-867 on June 13, 2018. Further, the NDA, page 2, par. 1, specifically states that the confidential information of SunShare is expected to include the locations and sizes of its applications submitted for IE review. Again, the conduct of SunShare at the time it signed the Service Agreement on June 12, 2018, was consistent with keeping such information non-public.

Xcel Energy has also properly treated the inside company emails that were the subject of discovery in this matter as being "Attorney Eyes Only". The NDA, on page 2, par. 2, specifically allows "inside company emails" to be designated as "Attorney Eyes Only" material, which is a subset of Confidential Information. The IE, at pages 5 and 10-12, takes issue with the fact that the inside company emails were marked by Xcel Energy as Attorney Eyes Only, but this is exactly what the NDA allows Xcel Energy to do. When Xcel Energy so marked these emails as Attorney Eyes Only, consistent with the NDA it provided copies of these to the IE and to the attorneys for SunShare. Once the IE indicated which specific emails from this set of emails he intended to rely on in his report, Xcel Energy and SunShare, consistent with the NDA then

determined what additional levels of protection would be required to allow which non-attorneys from SunShare, under what circumstances, to view the specific emails that the IE intended to rely upon. (NDA, pages 2-3, par. 2). But, the IE wanted Xcel Energy to ignore the protections in the NDA, and to provide all of the emails that it had produced in discovery to all SunShare employees (not just attorneys) who had signed the NDA. This proposal from the IE is not consistent with the requirements in the NDA, and should not be accepted by the Commission.

The IE Report seems to emphasize the November 5 telephone call as a basis for arguing that the Attorney Eyes documents that the IE did not rely upon in his IE Report should be provided to non-attorneys at SunShare. The summary of the November 5 telephone in the IE report at pages 5 and 10-11 is incomplete and misleading. The call included the following issues:

1.) Housekeeping. We asked for guidance on when the IE's written report would be issued. We were told that the goal was by the end of November.
2.) We explained that the NDA specifies that inside emails are to be considered Attorney Eyes Only documents. These emails show the Company process of how we convey information, who is communicating with whom and about what, with what level of detail. We do not share this material with others.
3.) We explained that none of the information in these inside company emails adds value to this engineering review. We pointed out that as the IE had mentioned on the prior call, there is "nothing earth shattering" in this information and that it is "innocuous." In our response to the various issues in this IE review in June 2018, we had provided a timeline of communications with SunShare and nothing in the inside company emails conflicts with this. Also, Xcel Energy and SunShare had previously provided to the IE all of the emails exchanged between they had in their possession relating to this project.
4.) Under the NDA (at pages 2-3) there is a process and conditions that must be met to allow further disclosure of these internal Xcel Energy emails to SunShare (beyond its attorneys). Under the NDA (pages 2-3, par.2), the IE must inform us that it intends to rely on the emails as part of the conclusions in the written report or have SunShare respond to the emails.

> We had mentioned during the November 5 call that this was discussed during our prior call, and this requirement still had not been met.

The IE report fails to mention most of the above issues that were discussed during that call, but instead focuses on the fact that the inside company emails included third-party confidential information of other developers that Xcel Energy had redacted. The IE wanted to have the full un-redacted version of these inside company emails provided to him and to SunShare. This information was properly redacted in the Attorney Eyes Only version of the documents. The IE refused this request to keep the redactions of the third-party confidential information in the copies of the inside company emails that were provided. Xcel Energy insisted on keeping the redactions it had made that were focused on preserving the third-party confidential nature of this information. The IE's review of this matter was not impaired by not having this third-party confidential information provided to him. The IE Report refers to additional redactions that we had requested, but these refer to contact information for our consultant who prepared the studies and this is not related to the redactions of the third-party confidential information of other developers.

Xcel Energy has followed the provisions in the NDA. Once the IE determined which specific inside company emails he would be relying on, consistent with the NDA Xcel Energy worked out additional protections with SunShare to specify who else, and under what conditions, the specific inside Company emails relied upon by the IE could be shared with.