MN SOLAR PATHWAYS
illuminating pathways to 10% solar

Assessing Opportunities and Challenges for Streamlining Interconnection Processes

FINAL REPORT
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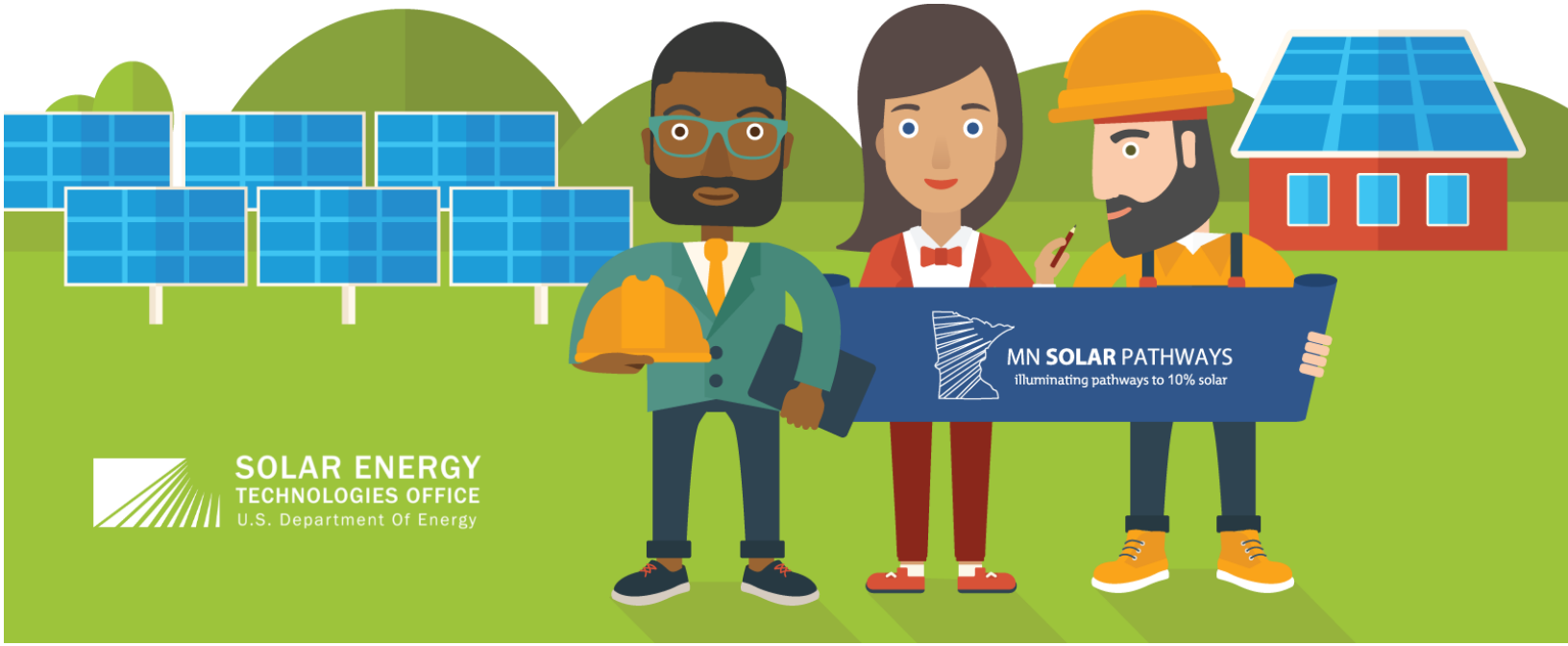

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Table of Contents

Executive Summary **4**
Summary of Findings 4
1 Introduction **7**
1.1 Balancing Trade-Offs in Interconnection Streamlining 11
1.2 Assessing Opportunities to Streamline Utility Interconnection Practices 12
1.3 Study Approach and Scope 13
2 Utility Summary and Context **19**
2.1 Characterizing the Project Utility Group 19
2.1.1 Regulatory and Legislative Influences 25
3 Current Utility Interconnection Procedures **27**
3.1 Documented Utility Practices: Commonalities and Differences 27
3.1.1 Website Functionality and Features 27
3.1.2 Pre-Application / Consultation 29
3.1.3 Application Submission 31
3.1.4 Customer Communication 33
3.1.5 Utility Staffing and Internal Communication Flows 34
3.1.6 Screening / Expedited Review Process 36
3.1.7 Detailed Study / Technical Review Process 37
3.1.8 Billing and Payment Procedures 40
3.1.9 Software / Hardware Tools and their Integration 42
3.1.10 Application Status and Queue Management 44
3.1.11 Customer Information: Privacy and Security 46
3.1.12 Electronic Mapping and GIS 46
3.1.13 Metering Procedures 49
3.1.14 Reporting 50
3.1.15 Process Automation and Online Portal 51
4 Utility Self-Assessments **54**
4.1 Arrowhead Electric Cooperative 54
4.2 Lake Region Electric Cooperative 57
4.3 Minnesota Power 59
4.4 Otter Tail Power 63
4.5 Rochester Public Utilities 65

4.6 Xcel Energy 67
5 Interconnection Process Streamlining Assessment 71
5.1 Optimization Indicators 72
5.1.1 Numerical Indicators 72
5.1.2 Process Indicators I – Application Management 74
5.1.3 Process Indicators II – Technical Review 75
5.1.4 Functional Elements 76
6 Potential Pathways Forward 79
6.1 Cost-Benefit Considerations 79
6.2 Opportunities for Streamlining and Optimization 81
6.2.1 Low-hanging Fruit Opportunities 82
6.2.2 Moderate Intensity Opportunities 86
6.2.3 Stretch Goals 88
6.2.4 Summary of Opportunities 92
Appendix A : References 94
Appendix B : In-Depth Interview (IDI) Transcripts 96

Executive Summary

Over the next two years, the Minnesota Solar Pathways project, sponsored by the Department of Energy's Solar Energy Technologies Office, is exploring various strategies for meeting the State of Minnesota's 10% by 2030 solar goal. A central objective of the Pathways research is to identify best practices for reducing PV grid integration costs while upholding grid reliability, power quality, safety, and security standards.

As part of the project, the Electric Power Research Institute (EPRI) has conducted an evaluation of existing utility solar photovoltaic (PV) system interconnection practices and assessed opportunities for streamlining them. Drawing from content gathered from in-depth interviews with utilities operating in Minnesota as well as secondary sources, this "interconnection streamlining assessment" activity characterizes existing interconnection approaches, successes, and challenges and highlights potential pathways for accelerating PV interconnections that can improve both utility and end-user economics (e.g. thru utility labor savings, accelerated application processing, etc.). It is intended to complement the Minnesota Public Utility Commission's current effort to update the state's 2004 interconnection standard.

This report summarizes findings uncovered in the assessment. It first provides an overarching rationale for pursuing streamlined interconnection processes and activities. Next, it offers context for analyzing utility interconnection procedures and protocols by comparing the PV interconnection experience, levels of demand, and customer make-ups of a range of electric utilities operating in Minnesota. A comparison of utility interconnection practices – spanning administrative processes and technical review approaches – is subsequently described. The baseline status of utility interconnection practices and the degree to which they are optimized according to numerical, process-oriented, and functional indicators is then assessed for streamlining opportunities. Finally, a concluding section recommends pathways forward for enhancing utility interconnection processes, categorized as easier, moderate, and stretch implementation opportunities.

Summary of Findings

Table ES-1 provides a summary overview of the streamlining/automation opportunities identified in this report. It offers a convenient way to compare across the opportunities and to evaluate their relative contributions to enhancing interconnection practices.
The recommendations are based on a combination of EPRI findings captured during utility interviews, observations from prior interconnection-related EPRI research efforts, as well as

ideas stemming from a number of external sources. They are divided amongst three organizing categories used to denote a generalized level of resources required to implement them:

- "Low-hanging fruit" – Opportunities requiring the least amount of resources either due to their relative simplicity or because they have already been partially put in place and thus only require small tweaks or upgrades to realize the benefit of full implementation.
- Moderate intensity – Opportunities requiring more pronounced resources dedicated to their implementation that can potentially be implemented in a medium-term timeframe.
- Stretch goals – High-intensity, longer-term opportunities that demand greater dedicated project resources and potentially external skillsets to implement.

Each identified opportunity is mapped to seven functional elements used to define a streamlined interconnection process. These include:

1. The ability to respond to interconnection applicants in a consistent and timely manner
2. Interconnection application process transparency
3. Support for application status tracking
4. Sharing of non-identifying information via a publicly maintained queue
5. The ability for utility customers to apply for interconnection online
6. Automated management of the application approval process
7. Identified opportunities for increasing automation of technical screens

The variety of suggested possibilities shown in Table ES-1 is intended to provide utility companies and state regulators with a range of options that might broadly achieve the core objectives of the Minnesota Solar Pathways project and like initiatives. That said, practices are currently evolving throughout the United States to accommodate both common and contextually-specific interconnection issues. For example, efforts are either planned or underway to determine optimal approaches for incorporating revisions to IEEE 1547. As such, the development of "leading practices" for DER interconnection and the assignment of their priority is a work in progress.

Moreover, there are a number of cost-benefit tradeoffs associated with different interconnection process reforms that require careful consideration. No formal quantification of the value of each opportunity described in this report has been conducted primarily because actual implementation costs and benefits will vary across utilities due to their respective circumstances.

Table ES-1. Summary Table of Streamlining Opportunities including the Functional Elements Addressed

Opportunity	FE# 1	FE# 2	FE# 3	FE# 4	FE# 5	FE# 6	FE# 7
"Low-hanging Fruit" Opportunity							
Informative and Easily Navigable DG Website	X	X					
Single Point-of-Contact for Applicants	X	X					
Customer Application Checklist		X					
Internal Application Review Checklist	X		X				
Standardized Template for Engineering Study Report	X						X
Pre-Application Consultation		X					
Pre-Application Report		X					
Commissioning/Meter Swap Checklist		X					
Restricted Internal Access to Customer Information			X				
Moderate Intensity Opportunity							
Mathematically-Defined Technical Pass/Fail Screening Requirements	X	X					X
Automated Email Response Confirming Application Submission	X	X	X			X	
Availability of Public Queue Position and Status		X		X			
Streamlined Flagging of Potential Interconnection Application Issues	X					X	
Online Payment					X	X	
Publicly-Available Educational/Training Classes		X					
Stretch Goals							
Online Application Portal	X	X	X	X	X	X	X
Automated Document Generation	X					X	
Automated Workflow Reminders and Application Status Updates	X	X	X			X	
Automated Preliminary Screens	X						X
Online Hosting Capacity Maps	X	X					X
Integrated Application Data with Mapping Tools						X	
Integrated Mapping Tools with Analysis Tools							X
Capability to Remotely Update Meter Settings	X						X

1 Introduction

The Minnesota Solar Pathways project, sponsored by the Department of Energy Solar Energy Technologies Office, is exploring least-risk, best-value strategies for meeting the State of Minnesota's goal to supply 10% of its electricity portfolio through solar power by 2030.[1] As part of this aim, the three-year project (2017-2019) is conducting technical analysis and modeling, assessing technology performance, and evaluating management approaches that can overcome grid integration challenges caused by increasing penetrations of grid-connected solar.

The component of the Pathways research in this report involves an evaluation of the current utility interconnection practices and procedures used to grid integrate distributed energy resources (DER) like solar photovoltaic (PV) systems, as well as an assessment of opportunities for streamlining them. Intended to complement the Minnesota Public Utility Commission's effort to update the state's 2004 interconnection standards, this report seeks to identify optimal approaches – some potentially through automation – for reducing the costs of PV interconnection and grid integration while upholding grid reliability, power quality, safety, and security aims.

The core objectives of the report reflect an increasing need for the utility industry to adapt to a changing energy landscape. The nationwide proliferation of DER, largely comprised of PV, is driving development of improved utility interconnection processes that aim to more fully leverage technology advances, enable procedural transparency, and adhere to evolving technical standards.

Driven by improving economics and expanding financing mechanisms, incentive supports, and technology advances, the total installed PV capacity in the United States has increased tenfold over the last decade—from 4.4 GW to 49.2 GW as of Q3 2017.[2] Over roughly the same time period, the number of deployed PV systems has exploded from roughly 50,000 to over 1.35 million.[3] Growth is occurring across the residential-, commercial-, and utility-scale market segments and is, moreover, projected to continue in the near-term.[4] In some geographic

[1] If achieved, the state's goal would increase Minnesota's installed PV capacity from roughly 250 MW as of the end of 2016 to 6 GW by 2030.
[2] *U.S. Solar Market Insight Q4 2017.* GTM Research, Boston, MA: 2017.
[3] Ibid.
[4] Industry consensus is that U.S. PV growth will temporarily slow in 2017-2018 given project delays caused by the extension of the 30% federal Investment Tax Credit (ITC). There is, however, potential for meaningful contraction in the short-term future if Section 201 trade tariffs are enacted.

locales, relatively new solar deployment models like community solar are helping to fuel this outlook.[5]

PV grid interconnections in Minnesota are a microcosm of broader market trends. As shown in Figure 1-1, the state's accelerating deployments have particularly taken off in the last 24 months.[6] As of November 2017, cumulative installs reached 661 MW, and they are forecast to reach roughly 700 MW by the end of the year. Meanwhile, an estimated 500 MW of future projects resides in the near-term pipeline—a plurality of which are composed of community solar projects.[7]

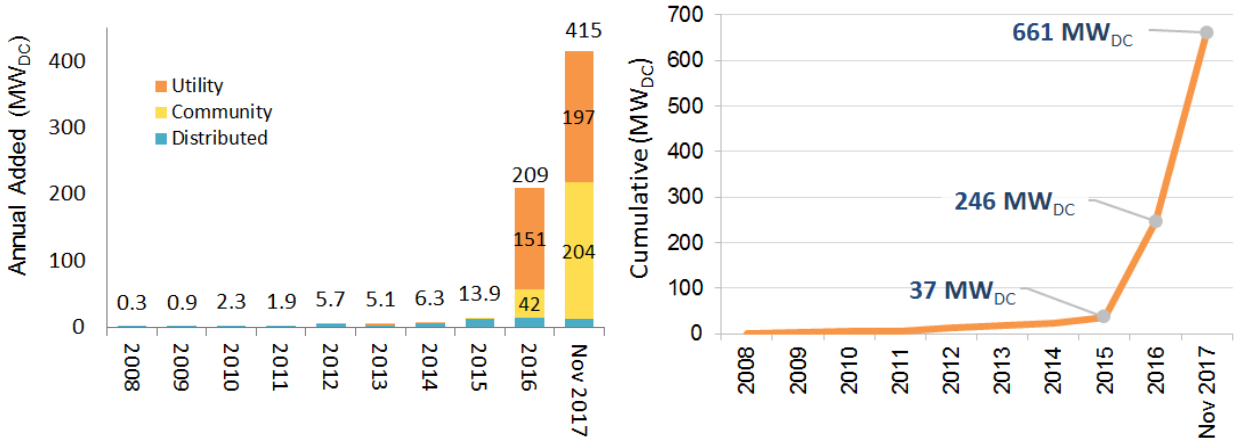

Figure 1-1. Annual (left) and Cumulative (right) Installed PV Capacity in Minnesota, 2008-Nov 2017
Source: MN Department of Commerce
Note: as of November 30, 2017

The sheer growth and dispersion of grid-connected PV systems, along with their associated operating characteristics, is impacting an increasing number of utility interconnection processes in both Minnesota and other jurisdictions. Among emerging challenges are growing connection queues as well as mounting pressure to improve procedural consistency, transparency, and automation in ways that better accommodate applicant (e.g. customers, asset owners, and developers) and regulator expectations. Technical considerations surrounding PV system integration are also being affected. For example, there are often inconsistencies across utilities

[5] Community solar essentially allows multiple energy consumers, or subscribers, to share the benefits of a single, typically mid-sized (0.5-5 MW) PV generating system by allocating the electricity and/or financial benefits of the system to offset individual consumers' electricity bills.
[6] As of November 2017, Minnesota's cumulative solar capacity was 661 MW, broken down as follows: 13 MW residential-scale, 41 MW commercial-scale, 248 MW community solar gardens, and 350 MW+ utility-scale. Cumulative installs are forecast to exceed 700 MW by year end 2017, and another 500 MW resides in the near-term pipeline.
[7] *U.S. Solar Market Insight Q2 2017*. GTM Research, Boston, MA: 2017.

about how and when technical screens are being applied to address reliability concerns caused by DER. Needed clarifications to the content and timing of technical review processes are increasingly being identified.

Additionally, evolving interconnection standards and technical requirements are impacting utility protocols. These reforms seek to account for technology changes (e.g. smart inverter functions that can provide grid support) and process-oriented bottlenecks that can enable utilities to better balance interconnection volumes with power system reliability and distribution safety requirements.[8] For instance, a 2014 amendment and ongoing revision efforts to the IEEE Standard 1547-2003, the primary model used to inform DER interconnection technical requirements in North America, are incrementally specifying the operational requirements of grid-connected DER devices.[9] Meanwhile, the Federal Energy Regulatory Commission's (FERC's) Small Generator Interconnection Procedure (SGIP), adapted from transmission-level interconnection approaches, has been continually modified to comport with individual state-level interconnection standard revision efforts.[10]

In response to rising DER activity, a number of states have either recently revised or are currently revising their interconnection standards (see Figure 1-2). These efforts, which often motivate updates to utility procedures and the manner in which they are carried out, seek to align equipment and installation requirements with other interconnection obligations like methods for communicating with and operating DER. They also frequently aim to streamline and/or automate administrative and technical processes. Key principles incorporated into rules and regulations include:

- Clearly identifying fees associated with the process,
- Specifying milestone timelines,
- Standardizing and simplifying forms, and
- Promoting information transparency and open communication.

[8] State-level standards and their implementation differ across states, and often incorporate elements of voluntary or non-binding directives put forth by independent entities like the Institute of Electrical and Electronics Engineers (IEEE), a respected technical professional organization.

[9] A latest proposed revision to IEEE 1547 has, as of this writing, recently been completed and the draft standard is progressing towards official publication potentially by Q1 2018. Revisions stipulate the performance of smart inverter functions, their default settings, level of interoperability, and range of adjustability.

[10] The SGIP was originally issued in 2005 and applies to DER projects that generate 20 MW or less. Through its Orders 792 and 792-A, FERC adopted revised SGIP standards in November 2013 and September 2014, respectively.

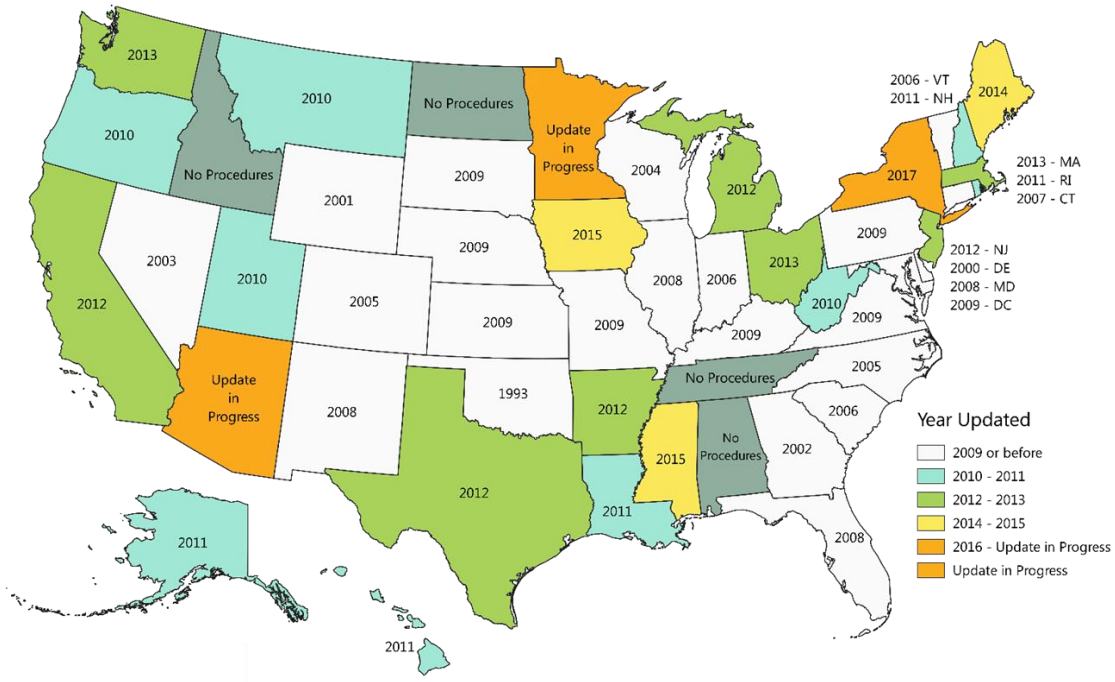

Figure 1-2. Recent Updates to State Interconnection Standards
Source: DSIRE (Hanna Terwilliger, MPUC), as of May 1, 2017

Notably, as part of the New York State Public Service Commission's Reforming the Energy Vision (REV) initiative,[11] the state's investor-owned utilities have been tasked with streamlining their interconnection application processes for distributed generation projects.[12] This multi-year effort is building on New York's existing Standardized Interconnection Requirements (NY SIR) to develop uniform distributed generation and energy storage contract terms and procedures, expedite interconnection application processing though the development of an online portal and web-based services, as well as convey greater procedural certainty.[13]

The REV's process revisions are, among other things, attempting to harmonize with innovative information technologies, electronic controls, and other digital economy advances that are demonstrating the potential to benefit electric distribution system operations and management. The core rationales guiding the initiative's interconnection streamlining effort,

[11] The REV is an initiative to reform energy networks initiated by New York Governor Andrew Cuomo in 2014. It seeks to develop a grid modernization strategy that moves away from the traditional utility model and instead creates a framework that encourages increased DER integration, allows customers to make educated decisions about their energy usage, supports environmental goals, and creates a more robust and resilient energy grid.
[12] See Case 14-M-0101, Order Adopting Regulatory Policy Framework and Implementation Plan (February 26, 2015).
[13] For more details, see *Interconnection of Distributed Generation in NY State: A Utility Readiness Assessment*. New York State Energy Research and Development Authority. Report Number 15-28, Albany, NY: September 2015.

including process standardization and automation, are angling to overcome inconsistent utility practices that are impeding timely and cost-effective DER adoption. Furthermore, they are informing other state-wide revision activities.

Minnesota is also in the process of updating its state interconnection standards. In January 2017, the Minnesota Public Utilities Commission (PUC) issued an order establishing a workgroup and a process to amend the state's standards. The PUC has since adopted a multi-phase process. Initial activities have focused on the non-technical aspects of interconnection, based on FERC's Small Generation Interconnection Procedures as a template. In 2018, the PUC will lead a stakeholder process to examine and update Minnesota's technical requirements for interconnection.[14]

Additionally, in May 2015 the Minnesota PUC initiated an inquiry into electric utility grid modernization with a focus on distribution planning. This process is currently underway and has thus far included information gathering workshops, with presentations by experts and public comments, to inform steps by the PUC to plan for an increasingly modern, clean, and efficient grid.

1.1 Balancing Trade-Offs in Interconnection Streamlining

Although streamlining utility interconnection practices can offer numerous advantages, the cost-benefit of implementing different enhancements is highly variable. It is often dependent upon the utility context, the level of interconnection activity in a service area, and statutory mandates, among other things. For a number of reasons, the scope, comprehensiveness, and degree of automation embedded in current utility interconnection procedures varies. As such, so too does the level of motivation to reform practices in ways that can introduce functional enhancements and responsibly accelerate interconnection processing.

Current and expected levels of interconnection activity will, for example, greatly influence the labor and avoided cost savings that can be achieved through investments in process enhancements. They will also affect the value and priority utilities assign to process improvements that can strengthen customer relations through reduced applications costs (i.e. soft cost reductions), time savings, and open communication. Likewise, cost-benefit tradeoffs exist regarding the potential introduction of automated processes that either partially or fully replace engineering judgment during technical screening reviews. Automating aspects of the

[14] PUC Docket Number: E-999/CI-16-521

screening process may also affect the level of risk attached to some reviews, particularly those that may require human judgment to assess assorted technical issues.

Moreover, the existence of synergies with other in-house or commercial solutions (e.g. utility software and/or hardware platforms), degree to which data is accessible, and the available mechanisms for funding capital improvements will color the urgency with which utilities undertake initiatives to streamline interconnection processes. Cultural considerations may also exist. For example, some utilities, particularly rural electric cooperatives, espouse a cultural ethos of person-to-person member interaction that process automation can undermine.

Amid this backdrop, this report comprehensively assesses the existing interconnection practices and capabilities of a representative group of Minnesota's utilities, and highlights potential pathways for supporting PV interconnection that can improve utility and end-user economics. In understanding existing procedures – as well as the context in which they operate – this document seeks to empower stakeholders to evaluate needs and prioritize process improvements that are of value to both utilities and their customers.

1.2 Assessing Opportunities to Streamline Utility Interconnection Practices

Among the aims of the MN Solar Pathways research effort is the development of streamlined utility interconnection processes that can integrate greater penetrations of PV safely, reliably, and more affordably. To this end, the Electric Power Research Institute (EPRI) was subcontracted to explore existing utility interconnection practices carried out in the state of Minnesota, and to identify the challenges and opportunities for further improving them.

Based on prior experience, EPRI defined process objectives to serve as the basis for assessing utility interconnection practices and protocols. These objectives were developed based on previous research contributions made by EPRI toward several state-level efforts to address a range of technical and administrative interconnection issues.

For this project, utility interconnection processes were evaluated to discern the degree to which they are streamlined through procedural consistency, automation, and a utility-customer engagement Web platform (i.e. an online application portal). Documented utility practices were then compared against seven functional elements to diagnose their general progress toward meeting the project's overarching goal. These functional elements include:

1. The ability to respond to interconnection applicants in a consistent and timely manner.

2. Interconnection application process transparency.
3. Support for application status tracking.
4. Sharing of non-identifying information via a regularly maintained public queue.
5. The ability for utility customers to apply for interconnection online.
6. Automated management of the application approval process.
7. Identified opportunities for increasing the automation of technical screens.

Drawing from content gathered during in-depth interviews with Minnesota utilities as well as secondary sources, this "interconnection streamlining assessment" compares utility interconnection practices – spanning administrative processes and technical review approaches. It also suggests pathways forward for streamlining and optimizing the utility interconnection process, categorized along easy, moderate, and stretch implementation opportunities and goals. Findings are ultimately intended to help industry stakeholders identify different value propositions, inform solar development strategies, and facilitate a range of solar deployment opportunities.

The objectives of EPRI's streamlining assessment include:

- Documenting each of six Minnesota utilities' existing interconnection capabilities, including approaches associated with their processing of interconnection applications;
- Determining the degree to which Minnesota utilities have optimized their interconnection practices to cost-effectively expedite process flows through automation, online portals, and tools integrated with utility functions.
- Recommending process improvement opportunities that can be considered according to a utility's orientation, the maturity of its process, and relative demand for change.

This report distills findings from EPRI's analysis, providing summary tables and charts along with accompanying narrative to objectively describe current utility interconnection practices, gaps in utility processes for achieving streamlined interconnection procedures, and future opportunities for process enhancements. The study is intended to support the further development of standardized and streamlined utility interconnection processes and, in turn, reduce the costs, uncertainties, and time requirements – for both applicants and utilities – of submitting and managing PV interconnection applications.

1.3 Study Approach and Scope

EPRI leveraged multiple sources and utilized a number of data gathering and packaging techniques to complete its assessment of utility interconnection practices in Minnesota. Most information was derived from detailed in-person interviews, conducted over a two-week

period, with six Minnesota-based utilities (see Table 1-1). The geographically-dispersed group of companies (see Figure 1-3) – which included three investor-owned utilities (IOUs), two cooperative utilities (co-ops), and one municipal utility – provided a diversity of perspectives useful to more comprehensively characterizing interconnection practices and aspirations across the state. Likewise, the range in size, service territory area, demographic customer profile, and other circumstances further influenced utility viewpoints.

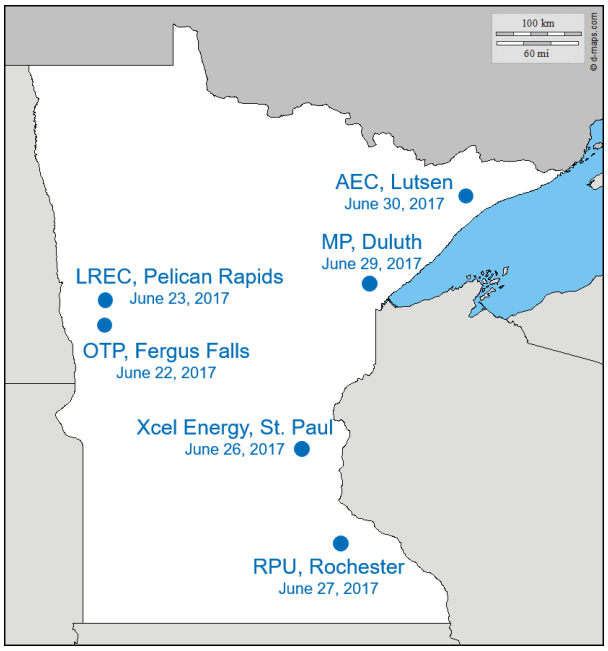

Figure 1-3. Mapped Locations and Dates of the In-Person Project Interviews
Source: Map outline from d-maps.com

Utility	Abbreviation Used in Report	Utility Type	In-Person Interview Details	
			Location	Date
Arrowhead Electric Cooperative	AEC	Cooperative	Lutsen, MN	June 30, 2017
Lake Region Electric Cooperative	LREC	Cooperative	Pelican Rapids, MN	June 23, 2017
Minnesota Power	MP	Investor-Owned	Duluth, MN	June 29, 2017
Otter Tail Power	OTP	Investor-Owned	Fergus Falls, MN	June 22, 2017
Rochester Public Utilities	RPU	Municipal	Rochester, MN	June 27, 2017
Northern States Power Company - Minnesota, dba Xcel Energy*	XE	Investor-Owned	St. Paul, MN	June 26, 2017

Table 1-1. Locations, Dates, and Details of the In-Person Project Interviews
*Note: *Unless noted or context indicates otherwise, the use of "XE" in this document refers to Northern States Power Company, and specifically, to Xcel Energy's Minnesota business.*

The day-long interview sessions involved intensive discussion with a range of utility personnel and aimed to cover many aspects of the interconnection process and adjacent topics of relevance. Subject matter included:

- Baseline utility interconnection application practices and management procedures (e.g. current processes, practices, and protocols for receiving and processing interconnection applications)
- Infrastructure and resource portfolio issues
- Planned application process improvements
- Opportunities for streamlining and/or automating interconnection procedures.

Extensive follow-up ensued between EPRI and the utilities to fill knowledge gaps and address outstanding questions. Figure 1-4 outlines the steps EPRI completed as part of the in-depth interview (IDI) process. Overall, the approach involved close collaboration with the utility project partners to enable rigorous data collection and cleansing. (Raw IDI transcripts are available in Appendix B.)

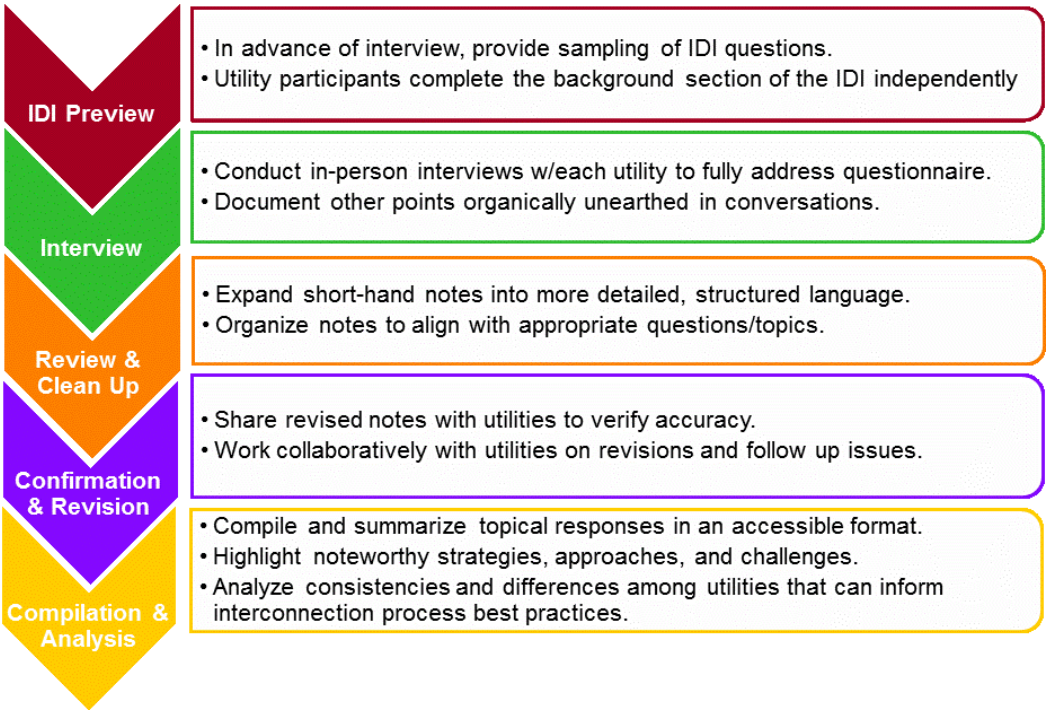

Figure 1-4. Interview Process Flowchart

To provide additional perspective, the utilities were asked to complete self-assessments of their respective interconnection processes. Written in the utilities' own words, these brief write-ups, which can be found in their entirety in Chapter 4, comprise high-level summaries of current interconnection procedures, future plans for process improvements, recognized challenges, and thoughts on future interconnection-related innovations. Specific topical areas that the utilities were asked to address include the following topical areas:

- *Utility context* – brief background on utility makeup, level of PV interconnections/applications and related trends (underlying drivers/obstacles).
- *Characterization of current interconnection process* – overarching utility objectives, work process flow, implemented streamlined/automation improvements.
- *Protocols and tools used to govern interconnections* – perceived merits and potential areas of improvement.
- *Notable challenges to the existing process* – perspective on existing needs and knowledge gaps.
- *Planned/proposed future enhancements* – overall opinion on the degree to which the current process is working, a near and long term vision, as well as the perceived applicability of developing an online portal.

Additional sources were referenced to incorporate ideas for streamlining the utility interconnection process. These sources, listed in Appendix A, convey interconnection "leading

practices" in other states, discuss areas of unresolved debate, and present an assortment of process improvement possibilities and challenges. Collectively, they buttress EPRI knowledge gleaned through primary sources with supplementary information for characterizing existing interconnection approaches, and spotlighting potential pathways for accelerating PV interconnections in the future.

The accumulated quantitative and qualitative data gathered for the project was combined and distilled to convey a baseline of each interviewed utility's business and technical review processes. These data serve as the basis for evaluating the degree to which current practices are optimized for efficiency and transparency, and present potential opportunities for improvement. The contents of the entire research effort are organized within the remaining chapters of this report as follows:

- *Chapter 2 – The Utility Landscape.* Characterizes the composition of the utilities participating in the project, the level of DER activity in their service areas, and the regulatory context informing interconnection practices.
- *Chapter 3 – Current Utility Interconnection Procedures.* Conveys a foundational understanding of each utility's present day interconnection operations to provide the necessary context and perspective for a subsequent streamlining assessment.
- *Chapter 4 – Utility Self-Assessments*. Presents individual utility assessments of their current interconnection procedures and resources, as well as planned or potential areas of improvement.
- *Chapter 5 – Interconnection Process Streamlining Assessment.* Considers the baseline status of interconnection processing for the participating utilities and evaluates the degree to which current interconnection practices are optimized according to numerical, process-oriented, and functional indicators.
- *Chapter 6 – Potential Pathways Forward*. Delineates potential opportunities for interconnection streamlining and optimization along low-hanging fruit, moderate, stretch goal dimensions. These recommendations are grouped based on a general interpretation of their resource intensity. No cost-benefit analysis has been performed to quantify the value of implementing each recommendation because actual implementation costs and benefits will vary on a utility-by-utility basis. In addition, no consideration has been given to determining who should pay for the costs associated with each proposed interconnection improvement opportunity.
- *Appendices*: Contain raw data and supporting study materials, including each of the in-depth interview (IDI) questionnaires that were completed by utilities.

Note: This report does not address PV interconnection at the transmission level; it exclusively focuses on distribution-level interconnection practices and processes. However, large-scale solar installations at the transmission level may be a key part to achieving Minnesota's 10% solar goal by 2030.

2 Utility Summary and Context

Minnesota utilities employ a diverse set of interconnection processes and protocols; they also assign varying levels of priority to streamline interconnection process improvements. The disparate utility interconnection practices and outlooks, described in Chapter 3, are an outgrowth of a number of influencing factors, including utility make-up, service territory size, demographic customer profile, level of DER development activity, and statutory directives. Recognizing these and other circumstances among this project's research sample of utilities – which represent a microcosm of Minnesota's overarching utility landscape[15] – is necessary for framing perspectives about interconnection best practices and relevant opportunities for enhancement.

Note: For brevity, the Minnesota utilities discussed throughout this report are consistently referred to in the following abbreviated manner:

- *Arrowhead Electric Cooperative = AEC*
- *Lake Region Electric Cooperative = LREC*
- *Minnesota Power = MP*
- *Otter Tail Power = OTP*
- *Rochester Public Utilities = RPU*
- *Xcel Energy = XE*

2.1 Characterizing the Project Utility Group

As shown in Table 2-1, the project utility group represents a range of characteristics and, consequently, perspectives about interconnection processes and their streamlining. Differences in service territory size, number of customers served, and customer densities inform utility viewpoints about future PV development and the ability to adequately support it while upholding grid reliability objectives.

[15] There are 125 municipal utilities, three electric IOUs, and ~45 rural electric co-ops currently operating in the State of Minnesota.

Utility	Total Service Territory (area mi²)	Total Miles of Distribution Line	Customers in MN	Mean Customer Density[1]	Mean Customer Line-Density[2]
AEC	3,340	607	3,530	1.3	5.8
LREC	3,200	5,600	26,730	8.4	4.8
MP	24,000	6,216	145,000	6.0	23.3
OTP	70,000	Not available	61,100	1.9[3]	Not available
RPU	65	Not available	54,000	819	Not available
XE	28,980	77,150	1,230,524	50[3]	18.9[3]

Table 2-1. Comparison of Utility Characteristics

Notes: Values are approximations. [1]Customers per square mile; [2]Customers per linear mile of line across entire service territory; [3]Figure represents the mean value calculated with total number of customers in the utility's service territory, not just those in Minnesota.

For example, XE has by far the greatest number of customers and distribution line miles in its territory, serving roughly half of the state's electricity customers. For a number of reasons – including the higher income level of a relatively larger number of the utility's customer population, as well as mandated utility rooftop and community solar incentive programs (discussed further below) – XE has received the vast majority of interconnection applications in the state, and expects considerably more in the future. Consequently, it has significantly invested in updating its interconnection procedures and service platforms, in part aided by state-required utility funding mechanisms. By contrast, RPU has the smallest service territory of the group with the greatest mean customer density (see Figure 2-1). Given RPU's circumscribed service area of just 65 square miles, utility staff do not expect significant utility-scale or community solar development. Distributed rooftop solar is more likely, and broad uptake is not immediately anticipated. As a result, the utility's interconnection process is comparatively less automated and is staffed at lower levels.

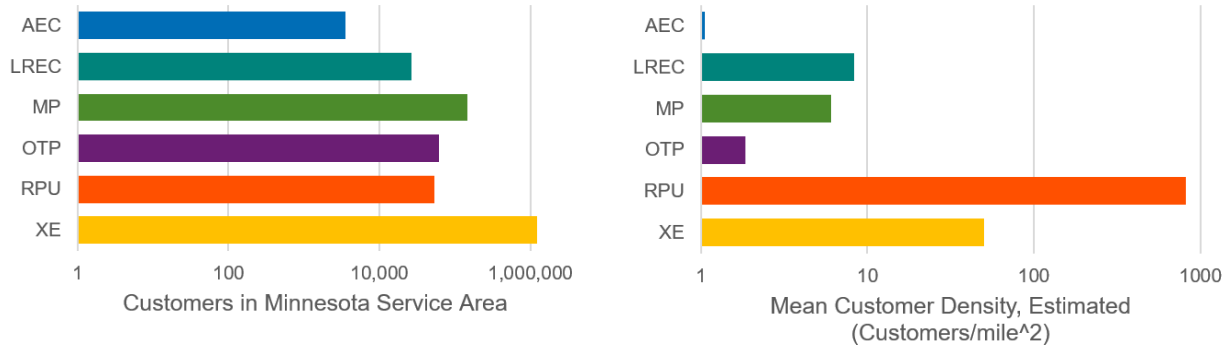

Figure 2-1. Utility Customers in Minnesota (left) and Estimated Mean Customer Density (right)

Note: Graphs depict logarithmic scale. As such, the units of the graphs are exponential powers of 10 to enable easier comparison of results across the utilities.

Meanwhile, although OTP has the largest service territory area of the utility group and ample space for solar deployments, its rural, predominately lower income customers are unlikely to substantially adopt solar PV in the near term. The average town within OTP's jurisdiction has 320 people and reflects lower housing values than the state average. Moreover, the utility's culture embraces nurturing customer relationships via community outreach and face-to-face interactions, impacting its motivation to transition its interconnection process online. Finally, Lake Region Electric Cooperative's rural orientation is similar to OTP's, but it serves a seasonal customer population subset with disposable income that is more likely to purchase solar PV. The utility's retail distribution cooperative structure obligates it to purchase all but 5% of its resource supply from Great River Energy, however, which influences its strategic thinking regarding DER deployment and interconnection initiatives.

The relative level of DER interconnection activity across utility service territories is also influencing utility practices. PV system deployments are occurring in fairly concentrated pockets of the state. As a partial result, local electric utilities are generally employing interconnection practices that are commensurate to the amount of DER application requests they are experiencing. Furthermore, historical and projected interconnections are often influencing the priority utilities are assigning to future interconnection process improvements. Figure 2-2 portrays the cumulative *number* of DG systems installed and interconnected in each of the six examined utility service areas, while Figure 2-3 conveys the associated amount of DG *capacity* installed. In each graph, the DG systems are color coded according to PV and non-PV technology type, and where possible, by system size. Community solar is also categorized, but not along size thresholds. XE's territory is clearly the territory where most DER interconnection activity has historically occurred. It has, to date, executed the most interconnections across all technology types and size categories and has a significant number of community solar gardens interconnections. Another IOU in the state, MP, has interconnected the second most PV systems, mostly under 10 kW. Conversely, LREC has experienced few DG interconnections, averaging about one new PV install per year.

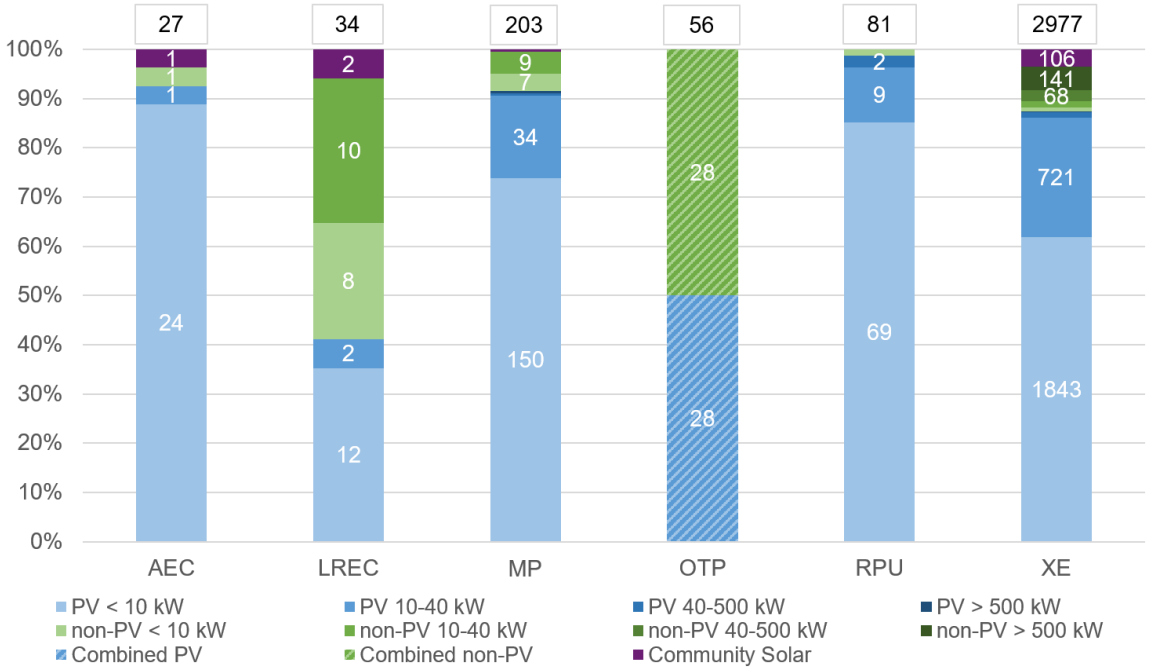

Figure 2-2. Cumulative DG Systems Interconnected across Utilities
Source: Utility interviews
Note: Numbers approximate, as of June 2017.

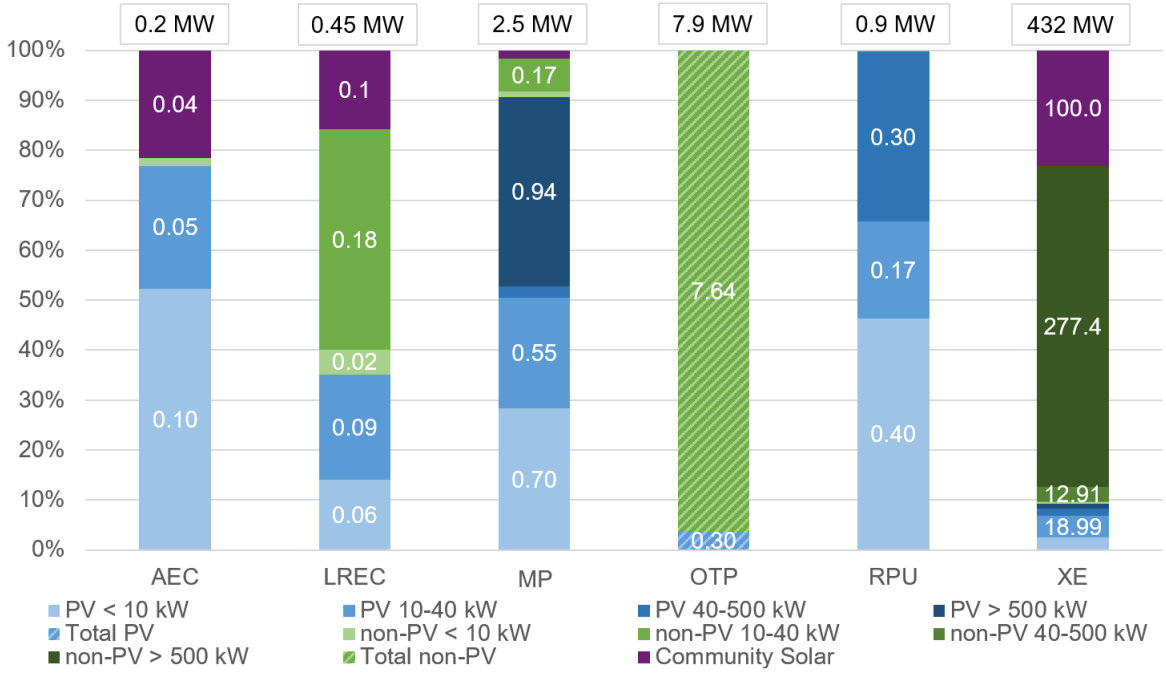

Figure 2-3. Cumulative DG Capacity (MW_{dc}) Installed across Utilities
Source: Utility interviews
Note: Numbers approximate, as of June 2017.

To date, XE also hosts the majority of DG capacity installed (432 MW) by several orders of magnitude. By contrast, LREC and AEC each have less than 500 kW of DG on their systems, and RPU has less than 1 MW.

Community solar garden development is a primary reason for the comparative disparity in installed PV capacity across the utility group. Figure 2-4 depicts community solar interconnection activity and accompanying capacities for each utility. The graphs relate current systems that have been interconnected, those that are in the queue, as well as others that have been canceled. With the exception of voluntary projects sited in the service areas of LREC, MP, and AEC, virtually all of the community solar activity has taken place in XE's state mandated Solar*Rewards Community program. Moreover, with the exception of one project in the queue at MP, all future garden development is currently slated to occur in XE's service area as well.

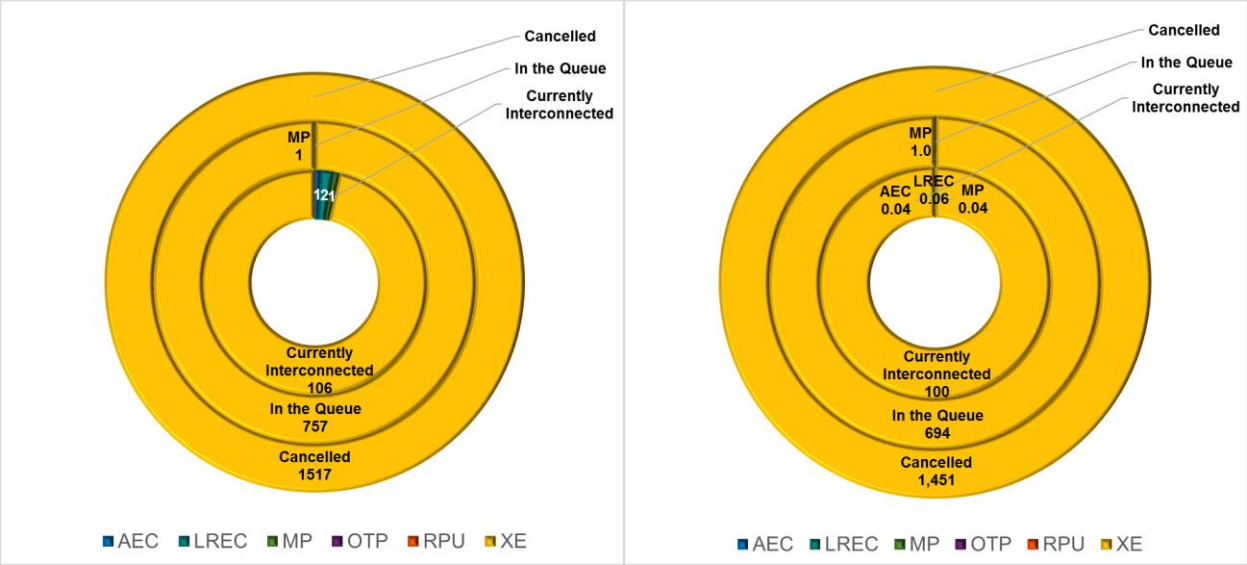

Figure 2-4. Community Solar Applications (left) and Installed Capacity (MW_{dc}) (right) across Utilities
Source: Utility interviews
Note: Numbers approximate, as of June 2017.

CSG Project Status	AEC	LREC	MP	OTP	RPU	XE	Total
Currently Interconnected	1 (0.04 MW)	1 (0.06 MW)	1 (0.04 MW)	0	0	106 (100 MW)	110 (100 MW)
In the Queue	0	0	1 (1.00 MW)	0	0	757 (694 MW)	758 (695 MW)
Cancelled	0	0	0	0	0	1517 (1451 MW)	1517 (1451 MW)

Table 2-2. Community Solar Applications and Corresponding Capacity that is Interconnected, in Queue, and Cancelled across Utilities
Source: Utility interviews
Note: Numbers approximate, as of June 2017.

Figure 2-5 isolates the number of PV applications that have been processed over the last 12 months (June 2016 to June 2017) across different system size categories. Although community solar is not included in the data, the graph helps to further frame the utility mindset regarding interconnection practices. Applications are concentrated primarily in one service area, and predominate for systems sized less than 40 kW in nameplate capacity. With the exception of XE's situation, they are not particularly pronounced when viewed over a 12-month period. The level of sophistication adopted by each utility's interconnection process largely correlates with DG activity.

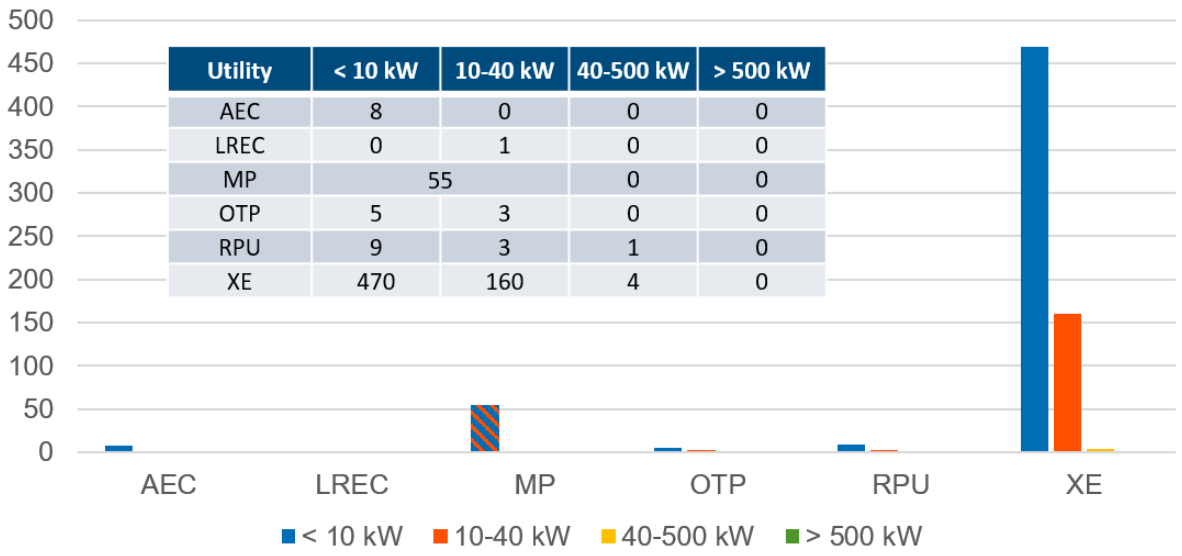

Figure 2-5. DG Applications Processed across Utilities by Size Category, June 2016-June 2017
Source: Utility interviews
Note: Numbers approximate, as of June 2017.

2.1.1 Regulatory and Legislative Influences

Recent regulatory and legislative actions are also contributing to the disparity in utility interconnection practices. Multiple factors, including utility-specific mandates set by the state legislature, Minnesota Public Utilities Commission, and the Department of Commerce (Commerce); approved and deferred utility filings; and ongoing proceedings to update the state's 2004 interconnection standards[16] have all impacted the degree to which local utilities are implementing interconnection process reforms. Many of these activities are, in particular, responsible for stimulating unique procedural improvements by XE to handle the utility's higher volume of interconnection requests.

Notably, legislative requirements that XE establish production-based incentive programs for grid-connected rooftop solar systems up to 20 kW and 40 kW[17] and for typically larger-scale community solar gardens, have triggered significant PV deployment in XE's service area. State-required utility funding for programs has, meanwhile, also supported reassessment and modifications to the utility's interconnection process.[18] Legislatively approved in 2013, the Made in Minnesota, Solar*Rewards, and Solar*Rewards Community programs,[19] have either directly or indirectly prompted XE to, for example, develop the capability to submit interconnection payments online[20] and to publish a public-facing interconnection queue for tracking community solar applications.[21] Meanwhile, as a result of a grid modernization statute passed by the state legislature in mid-2015, the PUC required XE to complete hosting capacity

[16] On January 24, 2017, the Minnesota Public Utilities Commission issued its Order Establishing a Workgroup and Process to Update and Improve the State Interconnection Standards in Docket No. E-999/CI-16-521.
[17] MN Statute 216C.417 established the Made in Minnesota Solar Incentive Program in 2013. It is a production-based incentive for PV systems using solar modules certified as manufactured in Minnesota. The program is administered by Commerce for the participating IOUs. The program was repealed in May 2017.
[18] For example, MN Statute 116c.7792 stipulates that the Solar*Rewards program shall be operated for 8 years starting in 2014, with $5M allocated to the program in 2014-2017, $15M in 2018, $10M in 2019-20, and $5M in 2021. Xcel Energy has used funding from the Solar*Rewards budget and the Conservation Improvement Program (CIP) to, among other things, set up an online application and process automation.
[19] The 2013 Solar Energy Jobs Act established the Solar*Rewards Community program and the production-based incentive version of the Solar*Rewards program. In both arrangements, XE offers a compensation for the renewable energy credits (RECs) associated with the electricity produced by participating systems for an established period of time (10 years for rooftop solar).
[20] Minnesota Department of Commerce, Analysis and Decision of the Minnesota Department of Commerce, Division of Energy Resources Regarding Xcel Energy's Request for Program Modification of its 2013-2015 Triennial and its Solar Energy Incentive Program Proposal in Compliance with Minnesota Statutes 116C.7792, Docket No. E002/M-13-1015 and E,G002/CIP-12-447, March 28, 2014.
[21] Minnesota Public Utilities Commission, *In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program*, Order Adopting Partial Settlement as Modified, Docket No. E-002/M-13-867, August 6, 2015.

studies of its distribution system,[22] which has aided in the development of the utility's public-facing hosting capacity maps, available online at: https://www.xcelenergy.com/working_with_us/how_to_interconnect/hosting_capacity_map_disclaimer.

A 2015 filing by XE to the Minnesota PUC has additionally allowed the utility to add a pre-application process and associated fee to its interconnection offering.[23] [24] These and other procedural enhancements are exclusive to XE; they do not apply to the other utilities in the state. Other Minnesota utilities largely adhere to the Minnesota PUC-approved DER interconnection guidance and documentation, established in 2004 under Statute 216B.1611.

Proceedings to update the state-wide standards based on FERC SGIP and independent third party proposals are likely to kindle future interconnection improvements across the state's electric utilities. Once codified, the new DG interconnection standards may result in a more universal procedure that further evolves and streamlines interconnection practices.

[22] The hosting capacity analysis was required by a June 28, 2016 order in the Grid Modernization proceeding: Minnesota Public Utilities Commission, *In the Matter of Xcel Energy's 2015 Biennial Distribution-Grid-Modernization Report*, Order Certifying Advanced Distribution-Management System (ADMS) Project Under Minn. Stat. § 216B.2425 and Requiring Distribution Study, Docket No. E-002/M-15-962, June 28, 2016.

[23] The pre-application and public-facing interconnection queue processes came out of a partial settlement with Xcel Energy that was adopted in the PUC's August 6, 2015 order in the Community Solar docket (Docket No. E-002/M-13-867). In response to the order, Xcel Energy filed a draft tariff: Xcel Energy, Draft Tariffs, Community Solar Gardens Program, Docket No. E-002/M-13-867, September 15, 2015.

[24] The pre-application report process is described under the section titled "Capacity Screen" in Xcel's Rate Book, Section 9, sheets 68.13-68.14.

3 Current Utility Interconnection Procedures

A range of utility interconnection practices, systems, and managing philosophies exists among the six power companies examined as part of this study. Some are shared across the utilities, while others are unique. This chapter explores the commonalities and differences identified among the utility group across 15 core subject matter areas listed in Table 3-1. Findings are intended to inform the study's interconnection streamlining assessment as well as potential pathways forward for pursuing procedural and technical improvement opportunities. Note: for the sake of comprehensiveness, some findings are reiterated throughout this chapter given their relevance to multiple subject matter areas.

1. Website Functionality and Features	9. Software / Hardware Tools and their Integration
2. Pre-Application / Consultation	10. Application Status and Queue Management
3. Application Submission	11. Customer Information: Privacy and Security
4. Customer Communication	12. Electronic Mapping and GIS
5. Utility Staffing and Internal Communication Flows	13. Metering Procedures
6. Screening / Expedited Review Process	14. Reporting
7. Detailed Study / Technical Review Process	15. Process Automation and Online Portal
8. Billing and Payment Procedures	

Table 3-1. Subject Matter Themes for Comparative Analysis

3.1 Documented Utility Practices: Commonalities and Differences

3.1.1 Website Functionality and Features

	Apply Online	Online App. Status	All Forms Avail Online	Process Description / Overview	Online DG Maps	Customer Checklist	Ref. Material Links	Training Materials Avail.
AEC	No	No	No, considering addition	No, considering addition	No	No	Yes	No
LREC	No	No	Yes	Yes	No	No	Yes	No
MP	No, considering web portal	No	Yes	Yes	No	No; instructions resemble checklist	Yes	No
OTP	No	No	Yes	Yes	No	No; simplified quick-start guide	Yes	No
RPU	No	No	Yes	Yes	No	No, under development	Yes	No
XE	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Table 3-2. Existing Utility Website Functionalities and Features
Source: In-depth utility interviews conducted by EPRI.

Distributed generation websites are available for each of the utilities. These contain

information and documentation relevant to the interconnection process, including application forms, instructions, links to reference materials, and other resources. Per Table 3-2, XE's website comprises a comparatively greater depth of information and functionality that is more outwardly transparent and supportive to applicant self-sufficiency. The disparity in website features largely reflects the relative amount of DER grid penetration and application demand experienced by the utilities as well as the perceived value associated with website development.

All the utilities make available a central point of contact to help shepherd applicants through the interconnection process. However, given low numbers of interconnection requests as well as management philosophies, some utilities prefer to speak with applicants directly to address their questions or concerns. Only XE currently allows applicants to both apply and actively track the status of their applications online. The utility has incorporated a front-end online portal into its website, developed by Salesforce, that coordinates interconnection applications, including initial application completion, electronic document/payment submittal, e-signature, regulatory reporting, and application tracking. (Application must be submitted online, though payment may be submitted by mail.) Meanwhile, the utility's portal allows applicants to track their applications through the primary steps of the process, such as confirmation of application receipt, engineering review, comments/approval, and meter orders.[25] (See Section 3.1.10 for more information.)

All of the utility websites except for AEC's provide information that conveys step-by-step interconnection process details and guidelines, as well as predominately static interconnection application materials for download and use. (XE operates a dynamic online portal, while MP supports fillable PDF forms.) For example, OTP offers a four-page quick-start guide, XE presents example drawings for applicants to emulate, and RPU publishes procedures surrounding interconnection at different sizes. However, only XE provides external checklists for reference on its website—a potential "low-hanging fruit" opportunity for supporting a more efficient application process.

All of the utility websites except for AEC's provide information that conveys step-by-step interconnection process details and guidelines, as well as predominately static interconnection application materials for download and use.

[25] Developers cannot see where they stand in the queue through Salesforce. They must instead check a monthly substation DG-CSG queue report that provides a snapshot of community solar garden project statuses. The three distinguishing statuses are 1) under study, 2) have executed an interconnection agreement, 3) are in detailed design phase.

Reference materials and links are another common feature across the utility websites, excluding AEC's. Links to the state's 2004 interconnection rules are typically available; FAQs, local incentive and program information, and a trade list that includes local installers are provided in some cases. Uniquely, in its online information portal, XE provides documents that were used in a 2016 developer training intended to familiarize contractors with the interconnection procedures governing community solar gardens. Although this feature is exclusive to XE's website, utilities generally report increasing developer awareness of interconnection processes, which they attribute to growing interpersonal relationships with a recurring group of installers.[26]

Although all of the utilities are, to varying degrees, mapping distributed generation installations into their geographic information systems (GIS), nearly all of these efforts convey information for internal use only. Only XE currently has customer-facing hosting capacity maps as referenced above. The maps seek to provide general education and help alleviate queue bottlenecks (see Section 3.1.12 for more details).

3.1.2 Pre-Application / Consultation

	Pre-Application Report	Consultation	Pre-Application Cost	NDA Required	Aerial Map Required	Pre-Application Reports / Consultations
AEC	No	Yes	N/A	No	No	N/A
LREC	No	Yes	N/A	No	No	N/A
MP	No	Yes	N/A	No	No	~50*
OTP	No	Yes	N/A	No	No	N/A
RPU	No	Yes	N/A	No	No	N/A
XE	Yes	Yes	$250 for capacity screen	Yes	No; Request Google Map w/system layout superimposed and/or coordinates	> 500**

Table 3-3. Utility Pre-Application/Consultation Services and Requirements
Source: In-depth utility interviews conducted by EPRI.
*Notes: *MP has completed a total of ~50 consultations.*
***Since late 2015, XE has received 500+ pre-applications in its Minnesota territory for its community solar gardens alone.*

As a courtesy, all of the interviewed utilities provide varying levels of consultation for customers interested in installing solar. Typically, these interactions offer an opportunity to set

[26] Excluding XE, between 2 and 6 installers are responsible for the majority of installations within each of the examined utility service territories.

customer expectations should they proceed through the interconnection process and, more broadly, improve the rapport between the utilities and their customers. For example, as part of its GoWest Solar offering, LREC conducts site visits and solar assessments; it will also author a solar feasibility report for prospective applicants. MP offers preliminary site visits through its Solar Energy Analysis (SEA) program, and in-person or phone consultations are also available to review customer usage patterns and solar economics, evaluate solar potential, and reference reputable installers. AEC provides an informational consultation that can include simple payback calculations as well as answers to equipment/interconnection questions. And XE program administrators are available to field specific questions via email about programmatic and procedural issues.

Of the utilities interviewed, only XE offers a pre-application data request process. As of this writing, the utility has received over 500 pre-applications, primarily for community solar projects.

Of the utilities interviewed, only XE offers a pre-application data request process. (The development of the utility's pre-application process is the result of an approved regulatory filing.) At a price of $250, a report details DG capacity screen results for a specified feeder location. These reports provide information for identifying optimal grid locations for project interconnection, offering some indication where grid upgrades or lengthy study are likely to be required. As of this writing, the utility has received over 500 pre-applications, primarily for community solar projects, and the number of pre-applications requested appears to be rising.[27] Per the utility's Section 9 tariff, XE will provide a pre-application report within 15 business days of receiving a request and payment.

A non-disclosure agreement (NDA) is also necessary for the utility to share distribution infrastructure and feeder load analysis, as well as results for previously studied projects, where available. Request for information in a pre-application report may include feeder-specific voltage, concurrent minimum and peak loading analysis, existing DG under operation, amount of DG in the interconnection queue, and terminated maximum distance to substation.

None of the utilities require an aerial map to consult with prospective applicants, or in XE's case, assemble a pre-application report; however, an address and/or confirmed GPS coordinates are necessary to indicate and verify the locations of intended projects. To this end, XE has written and posted a user guide on its interconnection portal to assist various parties in communicating consistent GPS coordinates.

[27] XE also offers pre-applications for non-community solar garden applications as well.

3.1.3 Application Submission

	Application Submission	Electronic Signature	Payment	Initial Application Reviewer	Confirm App. Receipt
AEC	In-person, mail, email	No	Cash, check, credit card	Member Services Manager	Yes, manually
LREC	Paper copy (in-person or mail)	No	Check, credit card	Engineer	No, unless something missing
MP	In-person, mail, email	No, but digital signature supported in fillable PDF	Cash, check	DG Program Lead	Yes, manually
OTP	In-person, mail, email	No	Check	Interconnection Coordinator	No, unless something missing
RPU	In-person, mail, email	No	Cash, check, credit card	Marketing Representative	Yes, manually
XE	Online only	Yes, required	Online payment or paper check	Marketing Rep, Interconnection Coordinator/Engineer (separate contacts for DG and community solar)	Automatic notification via Salesforce

Table 3-4. Interconnection Application Submission Processes and Options
Source: In-depth utility interviews conducted by EPRI.

Hard copy applications and supporting documents (or emailed versions of the same) are accepted by all utilities interviewed except XE, which requires that all materials be submitted electronically through its Salesforce web portal. Those that accept hard copy applications do not currently support electronic signature – although MP allows digital signature in its fillable PDF forms – while XE requires it as part of its online-only application. Currently, only XE offers an online payment option (payments for non-community solar gardens applications are tracked using unique identification numbers created in the utility's Salesforce portal)[28]; all other utilities require paper check, cash, or credit card payment. However, electronic payment systems to fulfill standard rate billing exist at all of the utilities, suggesting potential to integrate a mechanism for submitting interconnection payments online in the future.

Commonly, contractors may act on behalf of customers to fill out the necessary forms and submit payment on their behalf; however, a customer's signature is still required for the application to be considered complete. No formal training is provided to contractors by a

[28] Required program (not interconnection) deposits for community solar gardens applications can be made via online check/wire. Alternatively, US Bank can execute an escrow agreement to fund program deposits outside of directly paying XE.

majority of the utilities interviewed, though, XE has previously run training sessions for contractors to familiarize them with procedures associated with the utility's Solar*Rewards, Solar*Rewards Community, and Made in Minnesota programs. (As of this writing, future training sessions are not scheduled, though possible.) Moreover, the utility hosts quarterly cross-functional working group meetings with community solar developers to address contentious and generic issues, as well as share lessons learned. That said, the interviewed utilities generally report that because the same contractors are often selected to install multiple projects, and repeatedly work hand-in-hand with utility personnel, they have become progressively more proficient at completing the interconnection process.

Emailed application materials tend to go to either a designated DG interconnection inbox or directly to the DG Program lead's inbox. For XE, all application materials reside in its Salesforce portal, which serves as a central hub for document management that is accessible only to designated utility employees (account managers, engineers, and others).

The application screening process is largely a manual one, and utilities will usually review applications within 48 to 72 hours of receipt.

Once an application is submitted, a central point of utility contact will typically review submissions for completeness and communicate with applicants, as necessary, to collect missing information. This process is largely a manual one, and utilities will usually review applications within 48 to 72 hours of receipt. LREC and OTP will not contact applicants to confirm receipt unless there is a problem with the application. These utilities prefer to communicate a full response (i.e. approval or need for further study) within a 10-day timeframe. Meanwhile, AEC, MP, and RPU will confirm, either by email or phone, receipt and next steps. XE's online application system will send out an automatic reply indicating successful application submission.

Incomplete applications can cause delays in the application processing step as utilities must contact the applicant to request missing or rectify invalid information. LREC, OTP, and RPU report that the handful of applications they received in the past 12 months were all submitted complete. Meanwhile, AEC and MP assert that about 25% and 20% of their applications were, respectively, incomplete upon initial receipt. Of these all but two were pursued for interconnection. XE did not report this metric. As a partial indicator, about 85% of non-community solar DG applications it received in the past 12 months were approved, of which

over 90% were installed. Meanwhile, of the 2,380 community solar applications the utility has received in total to date, 1,517 (64%) have been withdrawn.

3.1.4 Customer Communication

The frequency and method of utility communications with interconnection applicants throughout the process varies considerably among the utilities. Often, the first instance of customer-utility interaction occurs with the submission of an application. This practice is common in part because customers will often first seek out contractors who will then submit interconnection applications on their behalf. Other times, customer contact may occur well in advance of submission via informal phone or email interactions and/or in-person meetings. For example, if requested, MP will conduct informal, preliminary site visits for free through its Solar Energy Analysis (SEA) program. Some utility customer reps may also informally discuss the interconnection process and answer questions at field events, such as utility-run educational classes. However, all the utilities provide some form of correspondence mechanism to address inquiries, including through template-based web email forms, "go to" DG email addresses, and customer call centers.

All six utilities designate a person or department to serve as the primary customer contact point throughout the interconnection process. This role is typically spearheaded by an interconnection coordinator, sometimes known as a DG program leader, who primarily handles many of the administrative and processing activities; in some cases, an engineer will coordinate and potentially complete both administrative and technical tasks.

All six utilities designate a person or department to serve as the primary customer contact point throughout the interconnection process.

Utilities make contact with customers at multiple points during the process. Initial communications typically confirm that an application has been received and/or convey when additional/verified information is needed. Confirmation of application receipt is typical but not universal. For example, XE responds immediately with an auto-generated email via its Salesforce portal, while LREC and OTP opt to contact applicants only if information is missing or once a decision to approve or seek additional study has been made. Most of the other utilities employ some form of immediate follow-up; these vary in levels of automation from purely manual to fully automated.

Utility-customer interactions later in the process include notifications of application approval, potential need for technical study, detailed study cost estimates (or re-approval if revised),

permission to schedule meter swap and/or commissioning, and others. For detailed studies, OTP and XE engineers sometimes contact customers directly to discuss technical matters, while keeping program managers or interconnection coordinators in the loop. XE's DER engineers hand off engineering "contact point" responsibilities to distribution area engineers once projects reach the procurement and construction phase. MP maintains the interconnection coordinator as sole contact point and has this person set up meetings between engineers and customers as needed.

3.1.5 Utility Staffing and Internal Communication Flows

	Primary Customer Contact	Staff for App. Admin./ Processing	Staff for Screening and Studies	Processing Hours per Application	Automated Tracking/ Internal Reminders	Internal App. Status Tracking/ Workflow Management Software
AEC	Member Services	2	1	4-5	No	Excel spreadsheet
LREC	Designated engineer/ interconnection coordinator	2	1; outsource detailed studies	15-20*	No	Excel spreadsheet
MP	DG Program lead/ Renewable Programs department	2	2, plus 1-2 meter techs for info gathering	4	No	Excel spreadsheet (ArcGIS in future)
OTP	Interconnection Coordinator	2-3	~5	15-20*	No	Excel spreadsheet; enterprise platform update planned
RPU	Marketing department rep	2	2	2-3	No	Excel spreadsheet
XE	Program office	~6 (covering comm. solar and DG programs)	~7-8, plus 5-6 external contractors**	Not Reported	Yes, some as part of Salesforce	Salesforce & SharePoint (for more granular tracking)

Table 3-5. Utility Employees Contributing to Application Processing and Workflow Features
Source: In-depth utility interviews conducted by EPRI.
*Notes: *Includes estimated time associated with time required for paperwork processing and recordkeeping as well as an initial screening. **Staff who contribute to XE's screening and study processes are not all full-time employees.*

Generally speaking, all the utilities have a designated person or department responsible for processing and handling the administration of interconnection applications. In many cases, these responsibilities have been appended to existing job positions since the volume of applicants does not justify new full-time employees. In this way, staff contribute labor time on an "as-needed" basis, and this often requires between 5-50% of their annual labor utilization. However, in some instances, dedicated positions have been created to manage customer relations and internal workflow. For example, XE employs more people to process the greater relative number of applications it receives and dedicates some employees almost exclusively to

the interconnection application process; others who work on interconnection spend a small fraction of their time on related activities. MP has likewise created a dedicated Renewable Programs group to supervise its interconnection process. Technical screenings and payment processing are, meanwhile, usually performed by existing internal departments already established for other utility services (e.g. area engineering, distribution planning, metering, customer billing, etc.).

As shown in Table 3-5, it typically takes an estimated 2-5 hours to process an interconnection application. (Note: the processing estimates for OTP and LREC include labor time associated with completing an initial engineering screening investigation as well as project administrative set-up activities.) Meanwhile, staff hours required to complete individual screens and detailed studies are highly variable, and depend on the unique circumstances for each project. The majority of utilities report that they either currently contract out most detailed power flow modeling studies to engineering consulting firms, or would do so if the need arose. Several utilities have yet to receive an application requiring a detailed engineering study. Quality assurance is subsequently performed by utility staff once outsourced study results are received.

A simple Excel spreadsheet […] is used to manually track application status for five of the six companies.

For many of the utilities, the process used to track and manage applications is often limited and informal. A simple Excel spreadsheet that typically resides in an internal network folder behind the utility firewall is used to manually track application status for five of the six companies. Permission to access the spreadsheet is frequently assigned, and application information is typed into the spreadsheet as process steps are completed. Few, if any, automated reminders are embedded in the Excel files; utility staff are instead responsible for monitoring progress and assuring that procedural deadlines are met.

In the future, MP intends to leverage a new ArcGIS tool and process to, among other things, track and log the status of applications in a way that can be visually illustrated (i.e. color coded) on mapping systems used by various personnel. The system is also intended to inform responsible staff of next steps via email distribution.[29] (See Section 3.1.12 for more details).

Separately, XE's Salesforce portal provides internal (and limited external) tracking with some automated reminders for administrative and technical reviews. Additionally, a SharePoint list is

[29] Initially, all data will be manually input into Minnesota Power's GIS. An aspirational goal is to engineer the GIS tool to auto populate with new application data (e.g. enter an account number to have forms self-populate in GIS).

used to internally track in-progress engineering studies with greater granularity than is presently available in Salesforce.

3.1.6 Screening / Expedited Review Process

Preliminary screens are applied to interconnection applications largely based on those listed in the state's 2001 statute (which resulted in the 2004 Commission order), as well as rules of thumb that each utility has developed from past experience. These screens are applied manually by all six utilities, typically to systems > 40 kW; nothing is outsourced.[30] Note: The screens are not required in the state's existing interconnection rules, and some utilities have defined their own set of screens. For example, XE has developed screens that are a combination of the Initial and Supplemental review screens in SGIP.

In general, the screens are intended to uphold safety and grid reliability standards by identifying conditions that require more in-depth engineering study. The screens typically include review of minimum daytime loading, backfeed issues, transformer kVA vs. solar size, among others things; also, utility-specific issues can be included, such as evaluating the length of a secondary run.

None of the utilities automatically accepts applications without some screening, but a number of them also do not employ a defined fast track process to accelerate the review and approval of applications. The majority of the utilities interviewed do not believe the current speed of interconnection processing to be a barrier to DER adoption for their customers. The consensus screening approach is to allow for defined screens aided by some engineering judgement to assure consistency of review. That said, although there is no kW rating threshold for automatic approval, systems < 10 kW usually receive some sort of expedited review. This typically involves assessment of system configuration, transformer sizing, system and metering inspection, and equipment certification.

Some utilities have developed rudimentary tools to help further accelerate the process. For example, XE and OTP have developed in-house spreadsheet-driven screening tools that run a series of calculations – such as minimum load for a feeder, fault current, or secondary voltage impacts – to determine outcomes. These tools essentially compare user inputs to established thresholds and return a pass/fail designation. Embedding the necessary software code into the

[30] The general consensus is that outsourcing screens to contractors would likely only be beneficial in situations when multiple analyses can be done on a given circuit or in a given area. Otherwise, contractors will have to spend significant amounts of time interacting with the utility to fill in and validate models before their results could be trusted.

preliminary screening spreadsheet to enable some form of automation would require the integration of more advanced software.

3.1.7 Detailed Study / Technical Review Process

	Detailed Study Completed?	Customer Point of Contact	Issues Assessed in Detailed Study	Study Completion Time*	Key Obstacle(s) to Timely Completion	Outsource Studies to 3rd Party?
AEC	No	To be defined	N/A	N/A; Goal: 7-14 days	N/A	N/A; Would consider existing distribution system contractor
LREC	No	To be defined	N/A	N/A; Goal: < 30 days	N/A	N/A; Would consider existing engineering contractor
MP	Yes	Interconnection coordinator	Dynamic impact study (with/wo adv. inverter functions), voltages, capacities, backfeed, cloud-induced flicker, inverter-distribution system interactions	< 90 days	Obtaining complete and finalized data/plans from customer; staff bandwidth	Rarely; Historically, outsourced ~1% of studies. Dependent upon complexity
OTP	Yes	Interconnection coordinator (engineers may directly interact w/specific questions)	Voltage violations, thermal fault current contribution, backfeed, system modification cost estimates	4-6 weeks; < 90 days for facilities study	Staff bandwidth	No
RPU	No	Yet to be defined	N/A	N/A	N/A	N/A; Would consider
XE	Yes	Area engineers via Program Office	Thermal, voltage, and protection violations; mitigation cost estimates	< 50 business days (solar gardens only), otherwise < 90 days	Staff bandwidth	Yes; Outsource ~90% of detailed studies; XE performs quality review

Table 3-6. Characteristics of the Detailed Technical Review Process, by Utility
Source: In-depth utility interviews conducted by EPRI.
Note: Based on statewide rules, timelines for completing interconnection studies have an upper limit of 90 days unless otherwise stipulated for specific PV systems (e.g., community solar gardens).

To date, only half of the interviewed utilities have performed a detailed technical study, and the majority of studies have been completed by XE—largely due to the popularity of its

Solar*Rewards Community program, which supports the development of larger-scale systems.[31]

There are a range of factors that trigger a technical study. Generally, though, the utilities follow guidelines in the state's 2004 state interconnection standards. Facilities studies and load flow analyses (i.e. 8760 steady state analysis) determine the need for more detailed review on a project-by-project basis. Typical triggers may include exceeded voltage or capacity thresholds, power quality issues, concerns about protection (for fault events), or expected back-feeding to transmission.

Applications that do not pass applied screens are assigned to an internal or outsourced contract engineer to perform technical review. This review can be subject to a requirement that the customer pre-pay estimated costs for the review. (In these cases, unused funds are returned to the customer.) Technical review involves using software to determine what upgrades are necessary to make the project feasible (i.e. creating a feeder model and running a power flow analysis to check for thermal, voltage, and protection violations, and identify mitigation solutions). Utility engineers reference feeder and substation maps to measure potential infrastructure upgrades or needed reconductoring and, in turn, develop cost estimates for system interconnection. For instances in which detailed studies are outsourced, utility engineering staff will verify contractor results to inform their estimation of mitigation/upgrade costs.

XE has created internal checklists for its area engineers to increase the efficiency and precision of its initial screen and detailed study processes. This development has reportedly helped better assure that all of the various cost categories associated with an application (e.g. labor, material, and equipment) are captured and input into a unit cost estimator spreadsheet to generate indicative costs for applicants. In addition, the utility has developed a cover letter template that guides engineering staff in developing a clear narrative of estimated costs for applicant review.

The engineer or utility interconnection coordinator who serves as the primary point of contact typically communicates findings to customers by written communication or phone, along with the indicative cost estimate of anticipated infrastructure upgrades. Work to modify system

[31] As of June 2017, XE has received close to 2,400 applications to its Solar*Rewards Community program, of which 106 have been approved and interconnected, 1,517 applications have been cancelled, and 757 applications are in the queue.

design and incorporate upgrades usually commences after a cost and timing study is completed and the initial upfront payment and any necessary paperwork are in place.[32]

Due mainly to resource constraints, nearly all of the interviewed utilities either are or would consider outsourcing most detailed technical study work to an outside firm. For instance, while all application completeness checks and screenings are handled internally at XE, the utility outsources roughly 90% of its detailed engineering studies to a third party and assigns engineering personnel to subsequently perform quality reviews of each completed study and develop indicative cost estimates. This approach is, in part, a result of the high number of studies the utility receives, tight compliance timelines for completing the studies, and labor resource constraints.

Due mainly to resource constraints, nearly all of the interviewed utilities either are or would consider outsourcing most detailed technical study work to an outside firm.

MP is, meanwhile, able to be more selective about the technical studies it outsources given the ratio of its engineering staffing level to the low volume of studies thus far fielded. It currently outsources ~1% of studies based upon their complexity, project size and location, and engineering staff availability; with application growth, the utility does, however, expect to increasingly outsource (5-10% of technical reviews). By contrast, OTP performs all technical studies in-house due mostly to the cost effectiveness of handling the small volume of studies it receives; OTP's ability to perform distribution studies and preliminary transmission studies are another contributing factor for its approach.

The range of software tools used when performing technical studies is unique to each utility. Essentially, each retrieves data from one or more internal customer databases, and feeds the data by differing means into its analysis software. That said, some utilities report that a significant amount of time to complete a technical study is spent gathering the required information to create an accurate model because the data resides in multiple databases and across different systems; in some cases, it must also be field verified. Additionally, it takes considerable time to develop the correct model and verify all of its parameters. OTP, for

[32] For example, for an application to proceed to design stage, a developer is required to pay the full indicative cost estimate, or pay one-third along with an approved Letter of Credit for the remaining balance. The PUC requires XE to annually report on the degree of variances (+/- 20%) that have occurred between its indicative cost estimates and actual costs for applications in the Solar*Rewards Community program.

example, must take GIS data and input it into middleware to pull a model that can then be used in Synergi power flow analysis.

Resource constraints and labor bandwidth is a common utility challenge for processing technical studies. To bolster staff efficiency, XE, for instance, has considered practices for resourcing its area engineers either by contractor or geography. Each approach has tradeoffs. The former builds relationships and familiarity, but also requires that the engineers become educated about the many distribution circuits a contractor may be building on. The latter faces the reverse compromise.

Processing can also be delayed by missing or incorrect customer application data and supporting documents, slow response time from developers when documents are requested, and intermittent spikes in application volumes that are often caused by approaching incentive deadlines. To address data needs, some utilities will utilize their meter technicians to gather missing study data and verify equipment in the field (e.g. transformer sizes, wire sizes and lengths, meter and sockets inspection, voltage checks, etc.).

3.1.8 Billing and Payment Procedures

	Application Fee Structure Follows 2004 MN Statute [a]	Accepted Means of Payment				Full Upgrade Cost Paid for by Developer (Regardless of Estimate Accuracy)
		Cash	Check	Credit Card (Offline)	Online	
AEC	No, flat $537 fee	Yes	Yes	Yes	No	Yes
LREC	Yes	No	Yes	Yes	No	No precedent
MP	Yes, but $0 for ≤40 kW	Yes	Yes	No	No [b]	Yes
OTP	Yes	No	Yes	No	No	Yes
RPU	No, $0 if ≤40 kW, $250 otherwise	Yes	Yes	Yes	No	Yes
XE	No [c]	No	Yes	No	Yes [d]	Yes

Table 3-7. Application Fee Structure and Means of Payment
Source: In-depth utility interviews conducted by EPRI.
Notes: [a] See
Table 3-8 for 2004 MN fee structure.
[b] Wire transfer is accepted for large engineering study costs.
[c] XE's interconnection fees are defined by its Section 9 and Section 10 tariffs.
[d] XE's Solar*Rewards Community program deposits can occur either via online check/wire or via US Bank escrow agreement.

The majority of the utilities default to using the application fee structure established by the 2004 Minnesota Interconnection Standards, and shown for reference in
Table 3-8; however, some diverge from the standards' guidance. For example, AEC charges an

application fee of $537 – down from an arbitrarily set flat fee of $1,000 – that covers the utility's estimated costs of completing the clerical work and processing, truck roll(s), anti-islanding testing, and system/site inspections associated with the interconnection process. XE, meanwhile, has specific fees for DG and community solar defined in its Section 9 and Section 10 tariffs. Solar*Rewards systems < 20 kW run $250 each, while Solar*Rewards Community aspirants must submit a $100 per kW fully refundable deposit with their online applications. Note: As a result of a rate case, the fees in the Xcel Energy Section 10 tariff (sheet 93) differ from those set forth below.

Interconnection Type	≤ 20kW	>20kW & ≤250kW	>250kW & ≤500kW	> 500 kW & ≤1000kW	>1000 kW
Open Transfer	$0	$0	$0	$100	$100
Quick Closed	$0	$100	$100	$250	$500
Soft Loading	$100	$250	$500	$500	$1000
Extended Parallel (Pre Certified System)	$0	$250	$1000	$1000	$1500
Other Extended Parallel Systems	$100	$500	$1500	$1500	$1500

Table 3-8. Generation Interconnection Application Fee Structure from 2004 Minnesota Interconnection Standards

A variety of payment methods are supported across the utility group, but only XE accepts online payments for smaller-scale DG interconnection applications. These payments are tracked using unique identification numbers created in the utility's Salesforce portal for each application. XE, meanwhile, accepts Solar*Rewards Community program deposits via online check/wire, and developers can alternatively access US Bank's escrow program in lieu of making a program deposit. (MP can also accept wire transfer for larger engineering studies.) While all of the interviewed utilities are equipped to accept electronic payment for monthly retail billing, only a few have extended this capability to interconnection payments citing cost-benefit considerations.

Thus far, necessary system upgrades are a rare occurrence for five of the six utilities interviewed. (Note: XE did not provide data about system upgrades, but noted that upgrades are not rare. The utility is reporting in its monthly reports the dollar amount of the upgrades after a Solar*Rewards Community system is in operation.) The statewide interconnection rules dictate that customers or developers are responsible for paying for any distribution system upgrade costs associated with their DER systems' interconnection. Multiple utilities provide good faith cost estimates on needed upgrades; Some also notify customers if costs approach the upgrade estimate and cost overages are anticipated.

No cost envelope or insurance is currently provided by any utility, though cost estimates are common. XE's initial indicative cost estimate methodology now incorporates unit cost estimates broken out into labor, material, and equipment. This increases both the transparency and comprehensiveness of the utility's estimates.[33] It charges an upfront fee of $22,500 per detailed engineering study of projects sized 1 MW and above with refunds sent for any unused portion. Study results are then used to inform the indicative cost estimate for interconnecting a project.

No cost envelope or insurance is currently provided by any utility, though cost estimates are common.

3.1.9 Software / Hardware Tools and their Integration

As illustrated in Table 3-9, the utilities use a wide range of software tools during the interconnection application process and there are varying degrees of integration among their application processing software tools. In general, facilitating connections between the different back office information sources and systems represents a primary area of potential process improvement, but may take considerable time, effort, and cost to develop.

With the exception of XE, data from customer interconnection applications must be manually entered. A number of utilities also maintain Excel spreadsheets to internally reference and track applications. For XE, all of the application data related to interconnection, including requested/allowed capacity and physical location, lives in its Salesforce portal; it is a central hub for internal document management that also provides internal and external tracking with some embedded automated reminders for administrative and technical reviews. Once entered, the information is permanent—it can be marked as cancelled, but cannot be deleted. SharePoint is also used by XE to track and help coordinate engineering reviews required for a subset of its DG applications.

[33] The PUC mandates that XE provide reporting on the degree of variances (+/- 20%) that have occurred between its estimates and actual upgrade costs.

Process	Activity	AEC	LREC	MP	OTP	RPU	XE
Application Management	App Submission	Email, hard copy	Email, hard copy	Email, hard copy	Email, hard copy	Email, hard copy	Salesforce portal
	App. Data Storage	NISC electronic records system (CIS), hard copy	Internal DB, Excel	Access DB, transitioning to Oracle billing system.	Electronic document mgmt./storage system, Internal DB, Excel	Digital folder repository, Excel	Salesforce portal
	App. Payment	Cash, check, credit card	Check, credit card	Cash, check*	Check	Cash, check, credit card	Salesforce portal, paper check**
	Internal App. Tracking	Excel	Excel	Excel, transitioning to GIS	Excel; enterprise platform update planned	Excel	Salesforce portal, SharePoint (for more granular tracking)
	DG Updates to utility mapping	ArcGIS	GIS	ArcGIS	ArcGIS	ArcGIS	Smallworld GIS
	Request for Meter Set	Email	Email	Email, transitioning to Oracle billing system	Phone / email	Email	CRS
Technical Review	Screening	Not specified	Not specified	Not specified	Power Profiler, ASPEN, Synergi (not typical), Excel	Not specified	Excel, Synergi, DEMS (EMS/SCADA data), SAP (load forecasting data)
	Detailed Technical Review	N/A	N/A	Voltage drop calculator, SINCAL, PSSE; currently migrating to WindMil	Excel, PSSE, ASPEN, Stoner/Synergi, Power Profiler	N/A	Synergi, SKM, PSSE, OpenDSS, Projectwise, Access, CAPE
	Initial Indicative Cost Estimate of Study Results	N/A	N/A	Not specified	Excel	N/A	Excel

Table 3-9. Representative Tools Used by Utilities during Interconnection Application Process

Source: EPRI utility IDI notes

Notes: *MP accepts wire transfers for engineering studies of large systems. ** XE's Solar*Rewards Community program deposits can occur either via online check/wire or via US Bank escrow agreement.

All of the utilities either comprehensively list interconnections in their GIS systems or are in the process of doing so. GIS updates are generally a part of the design process, during which modifications are made to accommodate new interconnections. During this process, staff at the assessed utilities uniformly update their GIS data manually (e.g. DER type, location, capacity, power factor) and typically publish the updates within a few days of project commissioning. The GIS systems do not "talk" with the databases that house other customer and DER data.

That said, some utility GIS systems are more integrated with simulation tools than others. For example, the GIS's for OTP and XE integrate with Synergi Electric distribution modeling software through a custom program called "middle link"; they do not directly integrate with PSSE, thus creating inefficiencies. Meanwhile, MP is currently transitioning to a new GIS tool that will replace an Excel spreadsheet that it currently uses to track and document DER interconnections. In the future, it plans to integrate the tool with a forthcoming WindMil model to analyze circuit power flows.

Generally, there is little integration of the utilities' software tools for modeling the power system. Developing the appropriate models for study often requires an engineer to input varying amounts of system data; it largely remains non-automated for utilities across the country.

Generally, there is little integration of the utilities' software tools for modeling the power system.

3.1.10 Application Status and Queue Management

With the exception of XE, five of the six interviewed utilities do not provide a public queue or customer-accessible mechanism for tracking application status. The consensus among these utilities is that a public queue provides little customer benefit given the limited number of interconnection applications received and the insignificant amount of time typically needed to process them. Instead, these utilities instruct applicants to check in directly with their respective interconnection coordinators, either verbally or otherwise, to track application status.

These same five utilities tend to flexibly administer a "first come, first served" queue structure. Application requests are sufficiently sparse so that projects can generally be reviewed concurrently without triggering adverse effects or requiring infrastructure upgrades (i.e. a delayed project will not typically impede the advancement of others in the queue). In some cases, "first come, first-served" queue processing is more important for managing rebates rather than feeder capacity.

Removal from the queue is likewise largely arbitrary for these five utilities; there are no enforced hard deadlines. For utilities that define timelines, unresponsive applicants are usually removed after 6-12 months of inactivity, and a courtesy reminder is often emailed to applicants several months ahead of time to notify them about their application status. Rebate-related deadlines can be a driver of project development timelines and advancement through the queue.

By contrast, XE's Salesforce platform permits customers to track the status of their applications through the online platform. Tracking is conveyed and categorized along the primary steps of the interconnection process (e.g. confirmation of application receipt, engineering review, comments/approval, and meter orders). Applicants cannot see where they stand in the queue through Salesforce, however. Community solar developers only have the option to check a publicly-available DG-CSG queue report that the utility publishes monthly under mandate from the PUC. This report relates the statuses of community solar garden projects on a per feeder basis. The three distinguishing statuses are 1) under study, 2) have executed an interconnection agreement, 3) are in detailed design phase.

XE more strictly adheres to a queue to manage its high volume of interconnection applications. Generally, applicants are locked into their queue positions so long as their applications are technically active and paid for. The utility follows the "first come, first served" approach.[34] For larger community solar garden applications which are more likely to cause grid impacts and require upgrade costs, XE will study the projects strictly according to their order in the queue. It has a 50-day timeline to complete detailed engineering studies, regardless of how many applications are in the queue simultaneously. To meet tariff timelines, XE's queue processing approach is to study a project and then assume that it will move forward at maximum size in order to begin processing the next in-queue project. Making these assumptions causes significant process inefficiencies due to the large number of resulting restudies.

XE has, to date, rarely removed a project from the queue because the current rules do not define reciprocal timeframes for applicants. However, applicants that do not pay the cost of a statement of work within 30 business days of receiving engineering review results can be removed as soon as another project is added to the same queue (on that feeder). The Community Solar program rules state that projects must be mechanically complete within two years of submission (or potentially longer with an extension). The utility's recently implemented

[34] The concept applies to all projects, but is only a practical consideration for large projects and small projects in high-penetration areas.

pre-application process has separately been successful in reducing queue congestion and bottlenecks.

3.1.11 Customer Information: Privacy and Security

All of the utilities employ protection measures to safeguard customer information and privacy. Physical applications or other hard-copy documents are kept on-site in locked filing cabinets or other secure areas. Digital interconnection data are treated similarly to other sensitive customer information; most of the utilities store it in private, local servers behind a firewall. Salesforce maintains the central hub for interconnection document management, including XE's online web portal. XE utilizes built-in security functions within the software to ensure data privacy. To further bolster security, Salesforce additionally requires applicants to establish unique usernames and passwords. It also generates unique project IDs that are sent to applicants via email which are required to access customer project status/information.

Internally-instituted utility privacy measures include training of personnel regarding the appropriate handling of customer information, formal sign-off by customers authorizing utilities to share information with developers, and data transfer and database access protocols. In general, a majority of the utilities restrict access to interconnection customer data to a limited number of staff in order to further reduce the possibility of improper data breaches. Data in Salesforce is only accessible to select XE employees (account managers, engineers, etc.) and Salesforce staff. AEC, MP, OTP, and RPU also limit access (using permission settings) to a select group of employees. Interconnection documents are, meanwhile, currently accessible to all LREC staff. Utility IT system architecture commonly provides another line of defense against compromise of customer information.

3.1.12 Electronic Mapping and GIS

	Distribution System Mapped	DG Systems Mapped	GIS Integrated w/CIS or Other DB	GIS Integrated w/Load Flow Analysis Tools	Method for Adding DG Data to GIS	Hosting Capacity Maps Available
AEC	Yes	Yes	No	No	Manually	No
LREC	Yes	Yes	No	No	Manually	No
MP	Yes	Yes	No	No, in development	Manually	No
OTP	Yes	Yes	No	No	Manually	No
RPU	Yes	Yes	No	N/A	Manually	No
XE	Yes	Yes	No	Yes	Manually	Yes

Table 3-10. Electronic Mapping and Degree of GIS Integration
Source: In-depth utility interviews conducted by EPRI.

All of the utilities have or are in the process of developing electronic maps detailing their distribution systems, largely for internal use only, and are manually incorporating DG installations into their mapping on a fairly consistent basis. Some are further along in this than others. As a regular practice, all of the utilities make updates to their GIS mapping soon after DG projects are commissioned.

Few of the utilities' GIS tools are presently automatically integrated with simulation software and customer information systems (or similar databases),[35] signaling a potential opportunity to streamline interconnection processes. MP is currently transitioning from a DG database (essentially an Access database) to a GIS process that is scheduled to launch in Q3 2017. As part of this effort, the utility is transferring data into a GIS that can then illustrate DG sites on a map (e.g. Figure 3-1) and be exported as a layer to other mapping systems for use by a range of utility personnel. As shown in Table 3-10, data will initially be manually input into the GIS tool, such as dates that convey when interconnection milestones are met, and the tool will relate color coded points that indicate the status of applications/systems. For future development, MP aspires to engineer the GIS tool to auto populate with new application data.

[35] For some, Middlelink performs this function.

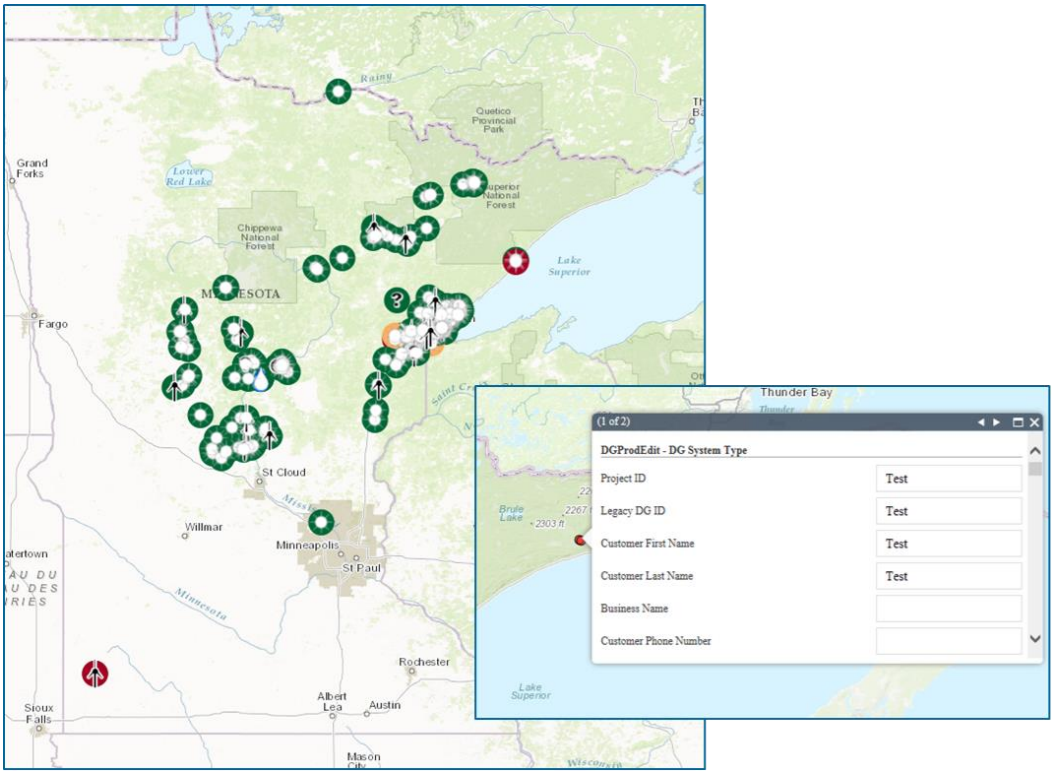

Figure 3-1. Screenshot of Minnesota Power's GIS-Powered DG Map
Courtesy: Minnesota Power
Note: The larger graphic in the figure depicts a screenshot of MP's GIS-powered DG map. Each identified DG system is color-coded on the map to indicate its interconnection status. The inset graphic in the figure shows the information fields that are associated with each system on MP's DG map.

Likewise, XE's GIS currently contains most of the information needed for modeling DER on a feeder, and the company is exploring approaches for further connecting the utility's different information sources.

Although all of the utilities are, to varying degrees, incorporating their DG installations into GIS and electronic mapping, only XE is leveraging this activity to provide online hosting capacity heat maps.[36] The maps initially convey hosting capacity analyses that consider interconnected DER as well as DER with a signed interconnection agreement. Looking ahead, XE plans to manually update the maps on an annual basis, and iteratively evolve them over the coming years. Other utilities have not, to date, implemented hosting capacity maps given their perceived value in environments with low DG demand, the expense required to further integrate their GIS tools with back office platforms, and other resource constraints.

[36] XE is able to export GIS data into its Synergi power flow programs.

3.1.13 Metering Procedures

The process for swapping out meters to accommodate new DG installs varies among the utilities due mainly to metering technology already in the field. Once customer applications have been approved, systems have been commissioned, and contracts have been signed, it is typically up to the customer to contact the utility to either schedule a meter swap or remote push of new settings to AMI equipment. Most of the utilities will manually send an email to customers to confirm that meters have been ordered and/or lay out next steps. XE's Salesforce portal transmits an auto-generated email communicating meter-related next steps to Solar*Rewards program applicants.

The process for swapping out meters to accommodate new DG installs varies among the utilities due mainly to metering technology already in the field.

OTP, RPU, and XE physically replace the conventional meters installed throughout their service territories in order to accommodate bi-directional power flows. Of those, XE charges their customers for this service through monthly metering fees that depend on the customer tariff.[37] RPU does not charge for a meter swap. Meanwhile, MP is in the process of equipping all of the meters in its territory with AMI.[38] It views the meter swap that comes with PV interconnection as "killing two birds with one stone" and thus does not charge an associated fee.[39] LREC and AEC have recently completed (or are nearly completed) converting all of the meters in their service territories to multi-register AMI meters. As a result, no swap is required with PV system grid interconnection; only a firmware upgrade is necessary, avoiding the need for truck rolls by metering personnel. Consequently, LREC and AEC also do not charge a metering exchange fee.[40]

Note: XE has deployed automated meter reading (AMR) throughout its service territory and plans to deploy AMI in the future. And although RPU does not have immediate plans to deploy AMI, it has installed "bridge meters" on newer commercial locations that work with existing radio reading tools and would be compatible with AMI following a firmware update.
As part of the PV interconnection process, some of the utilities, such as MP and XE, install sub-metering to better discern DER production and feeder load levels (not just net load). XE

[37] XE charges a fee to install additional metering needed for larger systems, which can cost between $400 and $5,000, depending on voltage class.
[38] As of this writing, MP has equipped 57,000 of its 144,000 meters with AMI. Full AMI deployment is scheduled for 2025.
[39] Most of MP's solar customers have already been outfitted with an AMI meter prior to purchasing and interconnecting their PV systems. In these cases, the utility has had to physically pull the AMI meter and replace it with a different unit that has been programmed for bidirectional power flow.
[40] Prior to its full AMI deployment, LREC used to charge a flat fee of $200 to swap out meters in its service area.

requires all Solar*Rewards program rooftop systems as well as all systems greater than 40 kW to be affixed with two meters in order to better inform distribution planning. MP has required that sub-meters be installed on all new systems since 2014.[41]

Most of the utilities offer a checklist for all on-site inspections. Some are publicly accessible to customers and contractors, and are intended to support greater transparency and process efficiency. Others are for in-house use only. Notably, XE recently uploaded a new step-by-step checklist for all DER that is public facing. It provides examples of each step showing "what it should look like".

After new meters have been installed or their settings remotely updated, customers will typically receive a utility email providing them with a permission to operate (PTO). Per Table 3-11, none of the interviewed utilities have PTO timelines in their interconnection procedures. For smaller systems, XE will typically provide PTO within five business days of successful commissioning.

	PTO Timeline	Utility Commissioning Checklist
AEC	No	Yes, public
LREC	No	No
MP	No	Yes, internal
OTP	No	Yes, public
RPU	No	Yes, internal
XE	No; typically, within 5 business days of commissioning	Yes, public

Table 3-11. Permission to Operate (PTO) to Operate Timelines and Utility Commissioning Checklist
Source: In-depth utility interviews conducted by EPRI.

3.1.14 Reporting

Minnesota's existing 2004 interconnection standards contain stipulations that state utilities report interconnection data to the Minnesota Public Utilities Commission and/or the Minnesota Department of Commerce.[42] These public reports are delivered on annual and/or monthly bases and are mandatory. Each electric utility is responsible for providing a DG interconnection report for the preceding calendar year that identifies new interconnections (and disconnections), their associated capacity, and their location on the utility system. Typically, the

[41] A recent commission Order now requires that MP install production meters on all systems greater than 40 kW as well as on systems less than 40 kW that receive an incentive from either the utility or the Made In Minnesota (MIM) program.
[42] DG interconnection reporting requirements emanate from Minnesota statute 216B.1611.

utilities will file reports with the PUC and Commerce that respectively focus on either DG systems or larger community solar systems. For example, MP, provides annual reporting on DG systems to Commerce, and a broader solar-specific report that describes system installs, renewable energy credit issues, and compliance-related matters to the PUC, among other things. The utility also files an interconnection report with both agencies annually.

XE is the only utility that must report compliance with application processing deadlines as part of its reporting responsibilities. It furnishes the Minnesota PUC with monthly status and compliance reports for its Solar*Rewards Community program, as well as an annual report detailing DG interconnections. It also annually publishes a report on the status of its Solar*Rewards program for the Minnesota DOC, which oversees the program.[43] These reports arguably help to further portray interconnection volumes, as well as process-oriented successes and challenges. For example, issues detailed by XE in its monthly Solar*Rewards Community program report include the number of solar-garden applications that have either not been processed within required timelines or in which timelines needed to be restarted, along with reasons. Also described are instances in which applications have been deemed incomplete or otherwise returned to the applicant for additional information, along with stated rationales for doing so.

3.1.15 Process Automation and Online Portal

For many of the utilities, the low level of interconnection activity does not justify the expense and effort to automate processes and/or develop a fully-integrated online portal at this time.[44] To date, only XE has developed an online portal (see Figure 3-2). MP has, however, received budget approval to explore customer-facing solutions that can be integrated with its backend platform. RPU also expects to implement a flexible front-end customer software platform by 2018 that could potentially integrate with the utility's PV interconnection process, though this latter step is not currently planned.

For many of the utilities, the low level of interconnection activity does not justify the expense and effort to automate processes and/or develop a fully-integrated online portal at this time.

[43] XE's compliance reporting requirements for the Solar*Rewards Community and Solar*Rewards programs are stipulated in Docket Nos. E002/M-13-867 and E002/M-13-1015.

[44] Some rural utilities are concerned that process automation could erode the strength of their existing customer/member relationships.

XE's Salesforce platform handles front-end application submittal and processing, payment processing, application and customer relationship management, and progress and deadlines tracking. It also serves as a central repository for storing applications, contracts, and supporting documents (single line diagrams, site plans, etc.), and automatically generates and populates small interconnection agreements. (Larger system agreements are more specific and are thus created manually.) As of this writing, the utility is exploring avenues for improving the portal by, for example, further integrating it with engineering functions related to the screening and technical review process to introduce greater streamlining and/or automation. It is also considering options for assimilating other underlying back office processes into the online portal.

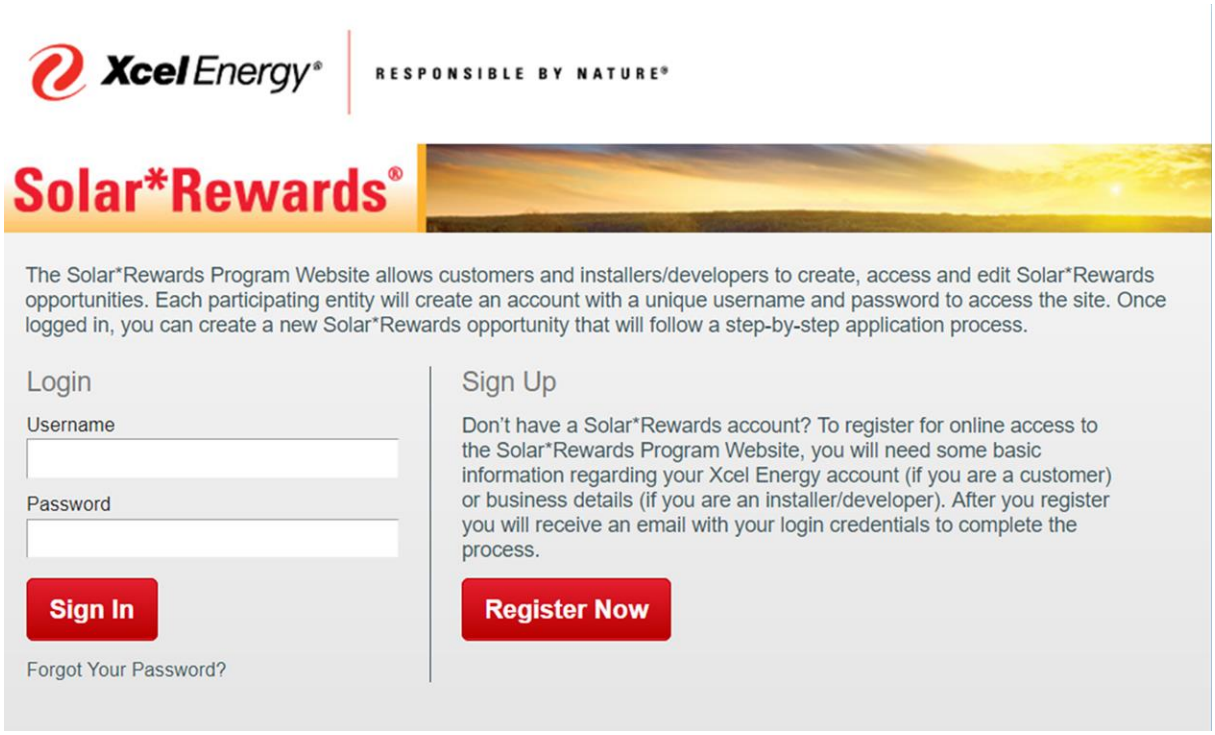

Figure 3-2. Screenshot of the Gateway into XE's Salesforce Portal
Courtesy: Xcel Energy

XE and MP have both made strides to integrate their GIS tools with simulation software and customer information systems. As described above, MP is transitioning to a GIS process that will be able to illustrate DG data on maps that can be accessed for multiple uses. Although the data will initially be manually input into the GIS tool, future development may include engineering the GIS tool to auto populate with new application data.

Otherwise, nearly all of the utilities' screening and technical review processes are manual. One identified exception is the in-house screening tools developed by OTP and XE to help expedite and simplify their processes. These screening tools require manual data entry, but offer potential to be further adapted and automated. They run on Excel spreadsheets and are engineered to calculate simple pass/fail of various screens based on user inputs (e.g. minimum load for a feeder, fault current, etc.) and established thresholds.

Likewise, XE has also created a unit cost estimator spreadsheet tool to determine the indicative costs of required upgrades identified in detailed technical studies. A cover letter template has been developed and paired with the cost estimator tool to help area engineers more efficiently relate the scope of the cost estimates and their various components. The utility has incrementally added details to its templates to make them more comprehensive and accessible. Though not an automated process, the templates offer a more streamlined way to review technical studies and have the potential to be automated in the future.

4 Utility Self-Assessments

To help frame the range of utility interconnection practices being utilized in Minnesota today, this chapter provides high-level summaries of the processes each of the six utilities interviewed for this research project are employing today. These summaries also convey existing challenges as well as areas identified for future improvement.

Written in the utilities' own words, the self-assessments relate the specific circumstances surrounding each utility, characterize current protocols and tools used to govern interconnections, and reflect upon near- as well as long-term visions for process enhancements. By incorporating the utilities' perspectives about the practicality and merits of their existing interconnection processes as well as the priority given to further procedural development, this chapter aims to provide further context regarding the various opportunities for streamlining and optimization discussed in Chapter 5. Following are the utility self-assessments, presented in alphabetical order.

4.1 Arrowhead Electric Cooperative

Customers in MN	Service Territory in MN (sq. miles)	DG Systems (Capacity) Installed[1]	Apps Processed in Last 12 Mos.[2]	Assigned Staff[3]	Notes
3,530	3,340	27; (0.2 MW)	8	Application processing: 2 Technical review: 1	Recently implemented internal file and application tracking, checklists, and revised commissioning tests. Planned improvement: outward-facing communications with interconnection applicants.

Table 4-1. Utility Snapshot: Arrowhead Electric Cooperative
Notes: Values are approximations. [1]DG systems and capacity installed as of June 2017; [2]Applications processed from June 2016-June 2017; [3]Assigned staff includes utility employees who dedicate their labor time to interconnection on either a full- or part-time basis.

Arrowhead Electric Cooperative (AEC) is located in northeast Minnesota and has been serving the residents of rural Cook County since 1953. AEC serves 3,528 electric members, 2,261 broadband subscribers, and services over 1,200 miles of electric and broadband distribution lines. We employ a staff of 18 for both electric and broadband services and have a net utility plant of approximately $41 million.

Just over 1% of all active AEC members own a solar or wind energy asset. Meanwhile, another subset of Arrowhead members (around 0.5%) subscribes to our community solar program. There are some additional accounts that subscribe to the Great River Energy EnergyWise program, which lets members allocate their usage from renewable resources. In total, about 1.5% of AEC members have direct distributed generation (DG) interconnections or are subscribed to a community solar installation.

Since 2014, AEC has seen a relative rise in the number of DG assets installed per year. On average, the number of installations has risen from two annually to four or more per year. In 2017, we anticipate six new installations, which will seemingly continue the upward trend of DG interconnection applications in our service area. Of our DG assets, 30 are solar systems, and one is a small wind turbine. By and large, we attribute the increase in installation numbers to reductions in solar equipment prices (i.e. lower solar panel prices), the continuation of investment credits, and a growing population of Cook County residents who are able to pay for the upfront solar premium. With the relative rise in DG assets in the Arrowhead service territory we recognize a need to update and refine our internal processes and protocols.

Arrowhead Electric Cooperative currently uses a manual process to receive, track, and process all DG interconnection requests. While our processes may very well remain manual given the relatively low number of applications we receive annually, we do recognize the opportunity to update, refine, and improve upon them. Our objective is to provide safe and reliable electric services. We believe that environmentally friendly utility service is part of our core mission. Our process for working with distributed generation applications follows Minnesota statute and has, to date, been fairly simple. AEC reimburses DG members at full retail rates which is above the Minnesota Average Retail Cooperative Energy Rate (ARCER), as specified under state statute. This decision was made by our Board of Directors and has led to strong relationships and interactions with our DG members.

While our processes may very well remain manual given the relatively low number of applications we receive annually, we do recognize the opportunity to update, refine, and improve upon them.

We are continuously working to improve our interconnection process and the way in which we interact with our DG members. Over the last year, we have implemented some additional internal processing mechanisms, including internal file tracking mechanisms, an interconnection tracking spreadsheet, a project checklist with several milestones embedded for each DG application, improved protocols (verbal and in-person) for communicating various

aspects of the interconnection process, and a modified format for conducting our anti-island field tests.

While we are pleased with the improvements that have been made over the past 12 months, we recognize that additional changes to the internal- and external-facing portions of our interconnection process can be made to further increase the service we provide to our members.

We see opportunity to improve the communication we have with contractors and DG members as they enter the application process with us. Such improvements include a revised FAQ, member and contractor checklists, a revised list of project requirements, and a revised interconnection standard and wiring/metering configuration. We would also like to improve our notification process with DG applicants. This is done manually at present, but there are no milestone triggers for when we communicate with members or get or give project updates. Our greatest challenges have surrounded the timely processing of DG interconnection requests.

This has largely been due to staff availability constraints. In addition, not all internal records are complete for some of the older projects on our distribution lines. In the future, we intend for our processes to better reflect all the necessary or required items for finalizing DG asset interconnection. Although better tracking mechanisms can be built, we expect that Arrowhead's process will remain largely manual, with a primary internal project owner and a secondary internal processor as back-up. Interfacing with our operations, accounting, and customer service teams will all be required to ensure internal best-practice processes going forward.

Presently we do not typically engage an electrician or engineer internally as our staff has enough general knowledge to assess most interconnection requests. However, in the future we would like to have a NABCEP-certified electrician on staff who is trained in DG solar and wind methods and electrical codes.

Ultimately, we believe that there are some simple processes and best practices that can be built into our DG interconnection process that will improve internal functions and make the interaction process for our members more accessible and easier to navigate. We plan to make a clearer delineation of the steps in the process, the status of the process, and the requirements for installing distributed generation assets on Arrowhead Electric Cooperative's distribution system.

4.2 Lake Region Electric Cooperative

Customers in MN	Service Territory in MN (sq. miles)	DG Systems (Capacity) Installed[1]	Apps Processed in Last 12 Mos.[2]	Assigned Staff[3]	Notes
26,730	3,200	34; (0.45 MW)	1	App processing: 1.5 Technical review: 1 (outsource detailed studies)	Given limited interconnection demand, prioritizing hands-on customer assistance over process automation and personalized online offerings.

Table 4-2. Utility Snapshot: Lake Region Electric Cooperative
Notes: Values are approximations. [1]DG systems and capacity installed as of June 2017; [2]Applications processed from June 2016-June 2017; [3]Assigned staff includes utility employees who dedicate their labor time to interconnection on either a full- or part-time basis.

Lake Region Electric Cooperative (LREC) is located in the northwestern area of Minnesota, primarily covering Otter Tail County as well as parts of the surrounding counties. We have over 5,000 miles of distribution line and serve approximately 27,000 members. The region is predominately agricultural based with a significant seasonal component as there are more than 1,000 lakes in the service territory.

LREC has not had a significant demand for DG interconnections within our system. To date, we have a total of slightly over 30 interconnections, roughly split between wind and solar. We have developed our own community solar offering to members, the generation for which is provided by two PV projects that are both sold out. Meanwhile, the cooperative is directly selling, installing, and maintaining small ground-mounted solar arrays to cooperative members through our GoWest program.

In general, there has been limited demand for interconnections on the Lake Region distribution system and, as such, the cooperative simply makes use of the statewide interconnection rules and makes associated documents available on our website.

Today, our member or developer would simply contact our Energy Management department – either via email, phone, or in-person – with a request to discuss an upcoming project. At that point, we'd discuss the project, location, timelines, and requirements with the

member/developer and provide them with the forms, or links to the forms, to begin the interconnection process.

With the limited demand for interconnections, there is not a significant desire to automate the process at this time. As noted, LREC works closely with our members and offers personalized site visits and other guidance with respect to proposed projects. The forms that are presently available could, however, perhaps be streamlined to eliminate some confusion as it's a one-size-fits-all package from the State. But again, our assistance and walk through of the existing forms aids in the process. Meanwhile, developers who have experience with the overall process do not tend to have issues, as they have worked with the standard forms for some time. Because LREC has not had a significant demand for development given its rural nature and limited membership, only a few developers have engaged with us in the interconnection process (and thus have a good understanding of the process).

Lake Region follows the State guidelines as it relates to interconnections. As such, each member or developer is treated in the same manner and receives direct communication and follow-up. Our hands-on approach is a value add for our members, as we're able to address potential issues with location and other factors that they may not have considered. That said, a more tailored approach to various sized projects could simplify the paperwork required which would be advantageous from an ease-of-use standpoint.

Lake Region has limited resources; therefore, in the event of high demand, it would be possible that responses could be delayed. We outsource certain engineering functions at times. Timing considerations could come into play dependent on resource availability.

Today, given the limited demand that we see for interconnection requests […] we feel that the process that is in place works well.

Today, given the limited demand that we see for interconnection requests and to the extent that the cooperative is directly representing, installing, and supporting local solar installations, we feel that the process that is in place works well. Over time, as additional demand potentially develops, more resources would need to be assigned to support the inflow and design components. The cooperative's goal of being the trusted energy provider and resource would still entail maintaining a hands-on approach, so an automated online portal that would limit or eliminate that interaction is not something that would be perceived as providing a great benefit.

4.3 Minnesota Power

Customers in MN	Service Territory in MN (sq. miles)	DG Systems (Capacity) Installed[1]	Apps Processed in Last 12 Mos.[2]	Assigned Staff[3]	Notes
145,000	24,000	203; (2.5 MW)	55	App processing: 2 Technical review: 2 (plus 1-2 meter techs for info gathering)	Recent customer experience improvements: established single-point of contact, PV consultations, increased online resources. Migrating to GIS-integrated database to streamline application tracking and mapping. Exploring customer portal software solutions.

Table 4-3. Utility Snapshot: Minnesota Power
Notes: Values are approximations. [1]DG systems and capacity installed as of June 2017; [2]Applications processed from June 2016-June 2017; [3]Assigned staff includes utility employees who dedicate their labor time to interconnection on either a full- or part-time basis.

With 145,000 customers over 26,000 square miles in northern Minnesota, Minnesota Power has a long-standing history of encouraging the adoption of customer-owned renewable energy systems through its SolarSense rebate program—introduced in 2004, well before any state mandates. With over a decade of experience offering solar programs and interconnecting customer solar systems, Minnesota Power has identified important factors that are necessary to achieving successful distributed generation (DG) interconnection, the most important of which is the customer experience. Minnesota Power has taken a number of steps over the last several years to improve the customer experience through the DG interconnection process. These steps include:

- **Establishing a Main Contact:** Minnesota Power created a dedicated Renewable Programs group within the company in 2014 to serve as the main point-of-contact for customers with questions about renewable energy and/or the interconnection process. The need for this group was identified through an internal solar strategy exercise that recognized a communication gap in the process at the time. Prior to the creation of this dedicated group, customers installing renewable generation were often in communication with multiple different departments at Minnesota Power, which led to confusion for the customer. The Renewable Programs group has resolved this inefficiency by providing a single point-of-contact to help streamline and improve the customer experience.

- **Creating the Solar Energy Analysis (SEA) Pilot Program.** Minnesota Power initiated its innovative Solar Energy Analysis Pilot Program in 2015 to allow Minnesota Power customers, at no cost to them, to explore the suitability of installing a solar energy system at their home or business. During an SEA, a Minnesota Power representative consults with interested customers about their energy usage, answers questions they have about solar energy, visits their site to analyze how solar may benefit them, and identifies site-specific conditions that may affect a potential installation. A summary of findings is then shared with the customer and they are encouraged to share that information when searching for or working with a solar installer. The SEA pilot program allows Minnesota Power to inform customers very early in the process about any potential upgrades that may be needed and provide useful information to help them navigate the solar interconnection process.

- **Lean Six Sigma Process Improvements.** In 2015, Minnesota Power assembled a team to apply the Lean Six Sigma method to the interconnection process with the goal of identifying ways to improve prevailing practices. Lean Six Sigma is a tool that reviews existing processes to identify problems and implement solutions that can increase the efficiency of the process. Performing the Lean Six Sigma method on the interconnection process allowed Minnesota Power to identify and remove unnecessary steps, recognize deficiencies in customer communications, and implement solutions that benefit both the customer and Minnesota Power. Ultimately, this allowed Minnesota Power to shorten the DG interconnection process time and reduce unnecessary steps both for the customer and Minnesota Power employees.

Performing the Lean Six Sigma method on the interconnection process allowed Minnesota Power to identify and remove unnecessary steps […] and implement solutions that benefit both the customer and Minnesota Power.

- **Providing Tools and Resources to Customers.** Minnesota Power places significant importance on streamlining and clarifying the interconnection process for customers. However, it is important to acknowledge that the interconnection process is one of the more complex interactions that Minnesota Power has with customers who currently represent a small portion of the residential and commercial classes. A successful interconnection requires collaboration between many different parties including

customers, solar installers, inspectors, building and city officials, the utility, and others. To ensure a positive customer experience, Minnesota Power has created tools and resources to help customers better understand the interconnection process. These resources include a Customer Solar Guide that explains how solar works and how to interconnect to Minnesota Power, a Solar Energy Analysis offered free to customers, clear and concise documentation of the interconnection process on Minnesota Power's website, and a modified version of the state interconnection application to increase customer usability.

While Minnesota Power has made a number of improvements to the interconnection process in the last several years, we continue to look for opportunities to further streamline and enhance the process. Process improvement activities that Minnesota Power is currently pursuing include:

- **Statewide Interconnection Standards Development.:** On January 24, 2017, the Minnesota Public Utilities Commission issued its Order Establishing a Workgroup and Process to Update and Improve the State Interconnection Standards.[45] The current statewide interconnection standards were established in 2004 and portions have since become outdated. Minnesota Power is currently participating in the associated DG Working Group, in collaboration with other stakeholders in Minnesota, to identify solutions for modernizing the state-wide interconnection standards.

- **Software Solutions.** Minnesota Power has explored the need for a software solution to automate portions of the interconnection process numerous times over the last several years. While further automation of the process would help to improve the customer experience, it has been difficult to justify the cost of a software solution given the relatively low number of interconnection applications that Minnesota Power receives on an annual basis.

  Minnesota Power received approval for its new SolarSense customer solar program in January 2017. The approval includes a significant increase to our annual solar rebate budget, which we expect to lead to an increase in the number of interconnection applications we receive annually. To manage the anticipated rise in interconnection application activity, Minnesota Power also requested and received approval to obtain a software solution. We are currently in the process of reviewing options to introduce a

[45] Docket No. E-999/CI-16-521

software tool that will serve as a customer portal, allowing customers to submit an interconnection application online, check the status of applications, and receive automatic communications from Minnesota Power regarding application issues. We are hopeful that this customer portal tool will help to further increase the transparency and efficiency of the interconnection process.

- **Database Updates.** While a software solution has not yet been selected for a customer portal, Minnesota Power has identified a solution for tracking the interconnection process internally. Minnesota Power is currently in the process of replacing its existing Microsoft Access database with a custom-built database integrated with our Geographic Information System (GIS). The new GIS database will allow Minnesota Power to track the status of interconnection applications from submission to approval and will automatically map those points in the Company's GIS system. This will help to further streamline the process by removing the need to manually map and maintain the points within the GIS system. The new database will also include a dashboard functionality to improve Minnesota Power's reporting and data tracking capabilities.

The new GIS database will allow MP to track the status of interconnection applications from submission to approval and will automatically map those points in the Company's GIS system.

Minnesota Power is continuously looking for opportunities to further streamline the interconnection process to enhance the customer experience. As the number of interconnection applications received each year increases, it will be more important than ever that the interconnection process be transparent and easy for both customers and installers to understand. Minnesota Power is dedicated to implementing ongoing process improvements to further streamline the interconnection process, enhance communication materials, and build the infrastructure needed to accommodate increased interconnection activity. We value collaboration with interested stakeholders to identify opportunities, in addition to those listed above, for further enhancing the interconnection process for our customers.

4.4 Otter Tail Power

Customers in MN	Service Territory (sq. miles)	DG Systems (Capacity) Installed[1]	Apps Processed in Last 12 Mos.[2]	Assigned Staff[3]	Notes
61,100	70,000[4]	56; (7.9 MW)	8	App processing: 2-3 Technical review: ~5	Recently established single-point-of contact, transitioned screening responsibilities to distribution planning for greater efficiency, simplified documentation/instructions and made them available online.

Table 4-4. Utility Snapshot: Otter Tail Power

Notes: Values are approximations. [1]DG systems and capacity installed as of June 2017; [2]Applications processed from June 2016-June 2017; [3]Assigned staff includes utility employees who dedicate their labor time to interconnection on either a full- or part-time basis. [4]Encompasses OTP's total service territory in Minnesota and beyond.

Otter Tail Power Company is an investor-owned electric utility that provides electricity for residential, commercial, and industrial customers in Minnesota, North Dakota, and South Dakota where we serve 131,500 customers in 422 communities stretching across 70,000 square miles, with a typical community size of less than 300 residents. Due to our rural nature and size, community involvement is an important value. We pride ourselves on building strong personal relationships with our customers.

Our mission is to produce and deliver electricity as reliably, economically, and environmentally responsibly as possible to the balanced benefit of customers, shareholders, and employees and to improve the quality of life in the areas in which we do business. Given the nature of our service area and customer base, our interconnection philosophy is to assist our customers through the process every step of the way. With this in mind, we provide interconnection applicants with the information they need in stages, so that they can make an informed decision on their project before proceeding to the next stage of development.

Our customer-focused philosophy means that we rely mostly on personal communication rather than automation, while making information available on our website (https://www.otpco.com/help-center/how-to-connect-to-our-power-grid/minnesota-interconnection/). An Interconnection Coordinator serves as a single point-of-contact to applicants as well as the chief liaison with internal utility staff.

Over the past three years, we've averaged just seven installations of distributed generation onto our system per year. This amount of interconnection combined with our local community presence further enhances our ability to communicate personally with each customer and help them through the process in stages.

[The low amount of interconnections] combined with our local community presence further enhances our ability to communicate personally with each customer and help them through the process in stages.

The Minnesota Public Utilities Commission has created a distributed generation working group that is reviewing the interconnection process and requirements. We're engaged in this process and plan to take the result of this effort into consideration if we need to make any changes to our current interconnection process. If a significant increase in distributed generation interest occurs, we would review any potential technology benefits, customer service benefits, and possible change in cost to our customers to determine if we should pursue enhancements to our process.

That being said, we have instituted some changes over the last few years that are intended to enhance our interconnection process because of the limited number of interconnections we receive. For example, to promote greater efficiency, we have transitioned screening responsibilities from our field engineers to our distribution planning area.

4.5 Rochester Public Utilities

Customers in MN	Service Territory in MN (sq. miles)	DG Systems (Capacity) Installed[1]	Apps Processed in Last 12 Mos.[2]	Assigned Staff[3]	Notes
54,000	65	81; (0.9 MW)	13	App processing: 2 Technical review: 2	Due to dense customer load and minimal DG penetration, capacity checks eased to quick screens listed in MN 2004 statute. Application records all stored digitally for future use.

Table 4-5. Utility Snapshot: Rochester Public Utilities
Notes: Values are approximations. [1]DG systems and capacity installed as of June 2017; [2]Applications processed from June 2016-June 2017; [3]Assigned staff includes utility employees who dedicate their labor time to interconnection on either a full- or part-time basis.

Rochester Public Utilities (RPU) is a municipal utility that covers a little over 65 square miles and reaches approximately 54,000 customers. RPU has seen steady but slow growth in solar installations. Currently there are 63 residential installations and 13 commercial installations with a total capacity of 855.7 kW in our service area. All of the interconnected systems are small – they average 7 kW – and their output is mostly consumed by local loads. RPU is a strong supporter of solar and since 2010 has offered an incentive for solar installations, with nearly all of the installations qualifying for the rebate.

Our interconnection process is fairly manual and basic, but with the relatively low number of applications we receive in a year, we find it works well. All of the application materials are available on our website (https://www.rpu.org/construction-center.php), though usually contractors, who have familiarity with the process and forms, assist customers with the interconnection process. If a customer makes an inquiry, we will follow up with them within 24 hours either by phone or email and provide them with pertinent interconnection information, the application, rebate information, and a list of contractors.

All applications may be submitted by mail, in person, or via email. We do not charge an application fee for any systems less than 40 kW, and we assess a $250 fee for systems greater than 40 kW. Application fees can be paid via cash, check, or credit card.

Two staff members, a respective residential and commercial account representative, process and administratively facilitate all of our interconnection applications. Each application requires only a couple of hours of their time. Meanwhile, engineering staff perform interconnection

screens. These screens typically take less than an hour to complete per application due in large part to the ease of performing engineering checks on feeders with limited DER penetration.

Once we receive an application, we review it for missing information. Most applications we receive are residential and below 15 kW, so a lengthy analysis isn't required. Review for these systems essentially includes examination of the one-line diagram, metering inspection, and confirmation of proper equipment certification. When technical assistance is required, RPU staff may perform on-site visits to confirm sufficient capacity and check for any additional apparent concerns.

For larger systems, we review with engineering to make sure there aren't any infrastructure concerns or other issues associated with the proposed installation. There are screens we use based on those listed in the Minnesota's 2004 state interconnection guidelines to flag a system based on system size, % of feeder load, etc. We have the capability and software tools to do a full engineering analysis, but to date have not received an application for a system of sufficient size that requires an engineering study. If it was required, RPU would most likely outsource an engineering study due to the workload of current staff.

We organize all received application materials into a digital folder repository on a local server (physical documents are scanned in). We use an internal checklist to manually track applications, as well as document basic project information and relevant dates. In general, communication with applicants is based on customer preference throughout the review and approval process.

We have the capability and software tools to do a full engineering analysis, but to date have not received an application for a system of sufficient size that requires an engineering study.

With the current level of installations, we don't see too many challenges. As we encounter an increased level of applications we understand that there will be a need for process improvements. This may include additional staffing, automation, and more thorough analysis of even small installations. For now, our current process has worked well and with the current low application and penetration rate, we do not anticipate significant changes to our current system.

We are very customer focused and ultimately want to provide customer satisfaction, be stewards to the environment, and be fiscally responsible. This requires a balance that we feel we are achieving at a high level.

4.6 Xcel Energy

Customers in MN	Service Territory in MN (sq. miles)	DG Systems (Capacity) Installed[1]	Apps Processed in Last 12 Mos.[2]	Assigned Staff[3]	Notes
1,230,520[4]	29,000	2,977; (432 MW)	634	App processing: ~6 (for both comm. solar and DG programs) Technical review: ~7-8 (plus 5-6 external contractors)	Offers a hosting capacity map, a pre-application report, as well as an online portal that allows for digital application (and payment) submission, links to relevant info, and tracking. Exploring revisions to procedures, tools, and guidance documents for improved process efficiency and consistency.

Table 4-6. Utility Snapshot: Xcel Energy

Notes: Values are approximations. [1]DG systems and capacity installed as of June 2017; [2]Applications processed from June 2016-June 2017; [3]Assigned staff includes utility employees who dedicate their labor time to interconnection on either a full- or part-time basis. [4]Figure represents total number of customers in utility's Minnesota territory.

BACKGROUND

Xcel Energy's overall territory covers portions of eight states and serves over 3.5 million electric customers in total. The Minnesota operating company (Northern States Power – Minnesota, NSPM) serves over 1.4 million electric customers in Minnesota and the Dakotas. Of those, 1,230,524 customers reside in Minnesota and Xcel Energy's footprint is approximately one-third of the overall state area.

The most significant penetrations of solar interconnections on Xcel Energy's system are in Minnesota and Colorado. Our Public Service Company of Colorado (PSCo) operating company has received approximately 4,000 rooftop applications since the start of 2016. Minnesota has, meanwhile, completed nearly 3,000 rooftop or on-site solar installations, and has a robust queue of community solar gardens. NSPM has received over 2,000 community solar garden applications since the program began in 2015; over 850 applications, totaling 782 MW, are currently in the queue with status ranging from initial application/completeness review through to final garden operation. As of November 1, 2017, 176 community solar garden applications, covering 49 sites (140 MW), have been approved and interconnected.

Drivers for these volumes include favorable markets, availability of Company programs/incentives, and a motivated consumer base. Chief obstacles to program success are 1) high volumes of applications, which have contributed to sizable queues at many desirable locations, and 2) complexities with automating portions of the application review and engineering study processes. With regard to our community solar garden program – Solar*Rewards Community – other areas of concern include the dispute resolution process and some aspects of queue management/reciprocal timelines. Further details are provided below.

CURRENT PROCESS

Xcel Energy strives to maintain safety above all else, with regards to both Company employees and the general public. Other chief objectives in the interconnection process are reliability of the electric distribution system and power quality.

In Minnesota, solar interconnections are currently administered and processed by 3-4 people in our Customer Choice Program office, and by 2-3 primary contacts in the Distributed Energy Resource (DER)/area engineering team. In the Program office, 2 full-time staff coordinate the Company's DG program, and 2 staff members oversee the community solar garden program. The Program office is the primary contact for solar developers and facilitates all work associated with interconnection applications amongst the various internal Company stakeholders.

To provide greater customer guidance and help make the interconnection process more efficient, Xcel Energy offers a pre-application report in the form of a capacity screen to both community solar gardens and non-community solar garden applicants. Over 500 pre-applications have been requested since late 2015, and more are expected as grid penetration increases. We believe that pre-applications have provided real value by helping to qualify for applicants whether to pursue, adapt, or discontinue proposed system interconnections.

Xcel Energy also utilizes an online application portal for all distributed generation interconnections across its service territories.

Xcel Energy also utilizes an online application portal for all distributed generation interconnections across its service territories. Online developer/customer portals provide links to relevant state and federal regulations. The Company's interconnection request process is outlined, and tariffs are provided in addition to interconnection applications and contracts.

Detailed guidance documents are also published on the developer portals, including procedures, checklists, and example drawings and calculations.

While the front-end facing portal is entirely web-based, it contains limited automation at this time. Workflows within each interconnection process are generally not automated (alerts can be triggered but the underlying process still requires manual updates). Almost all of the initial technical checks/interconnection screens are manual, as there is limited interface among the various utility data systems and no detailed analytical tools built into the current front-end portal. While Xcel Energy strongly believes that engineering judgment is required throughout the technical interconnection review and advocates having appropriate staff review applications, there is a recognized opportunity regarding the existing level of automation.

Engineering study and screening tools were refined during the surge of solar garden applications and continue to be refined.

TOOLS

Our Salesforce interconnection portal works very well as a front-end tool. It is able to collect and store application documents, process payments, and store general application information as well as initial technical information. Other software programs are used to support various aspects of the engineering technical reviews; however, Salesforce is the system used to track the overall process flow.

Interconnection workflow and timing is governed by state regulations created by the Public Utilities Commission and documented in applicable Xcel Energy tariffs (e.g. Section 9 and Section 10 tariffs). Salesforce has steps that correspond to these major process segments. The use of this online portal greatly streamlines initial application receipt and simplifies overall queue management. To foster information transparency and improved queue management, Xcel Energy also posts a publically available queue for community solar garden applications, along with those of other large projects, which we update monthly.

Xcel Energy uses in-house tools for manually screening interconnection applications that are eligible for screening. Detailed studies are performed using commercial power flow software and an in-house estimation tool.

CHALLENGES

As the overall distributed generation interconnection process matures across Xcel Energy, there are a number of process improvements that can be addressed. Further developing the online

portal is discussed at some length above. In addition, a small DER integration team has recently been formed with the express goal of creating consistent, streamlined interconnection procedures, tools, and guidance documents that can be used across all of Xcel Energy's territories and operating companies. The team's work is also focused on statewide interconnection standards rulemakings with both the Colorado and Minnesota Public Utilities Commissions. These proceedings have the potential to significantly improve the interconnection framework.

As interest in DER and interconnection processes continue to evolve at the state and national levels, the work volume and responsibilities of both the planning and area engineering groups are changing. Providing timely guidance on process, technology, and tools to the impacted groups can be challenging at times.

Future Vision

Xcel Energy is focusing on continued integration of DER processes and tools with existing planning and operational systems. We find much value in our online application portal. In the future, it is anticipated that this tool will be further developed or augmented to provide greater automation and high level analysis of incoming applications. Also, Xcel Energy has recently introduced online Hosting Capacity mapping. Future enhancement may also include more holistic reporting that accounts for all of the Company's DG interconnections in one place. (Currently, reporting is only feasible on a program-by-program basis.)

Xcel Energy has recently introduced online Hosting Capacity mapping.

Overall, the general trend Xcel Energy is seeing with regards to DER is that the market is developing in parallel on several fronts. New technologies continue to come to market, and existing products mature and become more affordable to a greater cross-section of customers. We expect that the number of interconnection applications will continue to rise and that the technical complexity of these requests will increase along with grid penetrations and the widespread acceptance of storage technologies.

The Company's current process generally works well but has some areas where improvements can be made to reduce staff time and increase workflow tracking. Tools and processes are being explored to address these issues. Any such enhancements will be implemented with an eye towards flexibility and longevity moving forward. Near term strategies focus on knowledge transfer and process standardization, while longer term endeavors will strive to embrace new technologies and the automation benefits of software integration.

5 Interconnection Process Streamlining Assessment

The current interconnection practices employed by this project's six participating utilities, and summarized in Chapter 3, provide a baseline understanding of the interconnection landscape in the State of Minnesota. As described, the Minnesota utilities carry out similar processes, but each applies unique approaches that are tied to utility-specific rationales. Moreover, for an assortment of reasons, the level of process automation varies across the utilities. Many interconnection-related areas were found to be well positioned to accommodate the anticipated growth of DG interconnection requests in the state. Some areas can, however, be improved to help further streamline interconnections. This chapter documents the baseline status of interconnection processing for the evaluated utilities and serves as preamble to the potential procedural enhancement opportunities delineated in Chapter 6.

Among the aims of the MN Solar Pathways research effort is the development of streamlined utility interconnection processes to grid-integrate greater penetrations of PV both safely and reliably. At the same time, the processes also need to protect utility customers from absorbing excessive system upgrade costs when they are necessary to accommodate PV adoption. To these ends, streamlining efforts can reduce utility administrative burden, increase procedural transparency, and prepare for increased amounts of distributed generation deployment.

Based on prior experience, EPRI defined process objectives to serve as the basis for assessing utility interconnection practices and protocols. These objectives were developed based on previous research contributions made by EPRI toward several state-level efforts to address a range of technical and administrative interconnection issues.

For the project, utility interconnection processes were evaluated to discern the degree to which they are streamlined through procedural consistency, automation, and a utility-customer engagement Web platform (i.e. an online application portal). Documented utility practices were then compared against seven functional elements to diagnose their general progress toward meeting the overarching goal. These functional elements include:

- The ability to respond to interconnection applicants in a consistent and timely manner
- Interconnection application process transparency
- Support for application status tracking
- Sharing of non-identifying information via a publicly maintained queue
- The ability for utility customers to apply for interconnection online

- Automated management of the application approval process
- Identified opportunities for increasing the automation of technical screens

Considering the current status and landscape of the utilities' interconnection approval processes, and with these functional elements in mind, this chapter provides a high-level assessment of existing utility interconnection practices. It addresses the degree to which contemporary practices are optimized through three indicator types: numerical, process (two parts), and functional.

5.1 Optimization Indicators

To provide a streamlining assessment, EPRI analyzed utility practices across three analytical lenses, or indicators, and leveraged findings to measure the degree to which the seven functional elements have been met. These three indicators are further defined as follows:

- Numerical Indicators – provide numerically-focused insight into the available resources and general capacity for processing applications (e.g. number of staff available to process applications).

- Process Indicators I: Application Management – provide insight into the tools, resources, and services offered to applicants; administrative procedures in place, as well as their level of automation (e.g. presence of online portal for application submission).

- Process Indicators II: Technical Review – provide insight into the experience, tools and data, and level of automation applied to the technical review process (e.g. availability and validity of field data necessary for hosting capacity analyses or technical screening).

Note: while the metrics and information within each analytical area allude to the makeup of current interconnection practices and approaches, important utility context can be found in Chapter 2, and more detailed explanations of the utility practices themselves may be reviewed in Chapter 3.

5.1.1 Numerical Indicators

The numerical readiness indicators offer insight into the number of applications and resources the utilities assign to the interconnection process. The number of applications received cumulatively and in the last 12 months provides a baseline for discerning how many are processed, how quickly they are processed, and the amount of resources assigned (both staff

and systems). Each utility has a certain number of staff identified to fully or partially support application processing and technical review. Some utilities employ staff who are dedicated to processing DG applications, while others have developed cross-functional teams to satisfy various steps of the interconnection application process. In addition to staffing numbers, the speed with which applications are processed (in particular those that do not require engineering review) provides an indication of potential gains in efficiency that may be achievable. Table 5-1 summarizes some of the metrics that can be used to characterize how application processing and technical screening at the utilities interviewed are currently managed.

As stated above, please see Chapter 2 to review the utility context that colors the metrics and information conveyed in the below table. More detailed explanations of the utility practices themselves may be reviewed in Chapter 3.

Indicator	AEC	LREC	MP	OTP	RPU	XE
Staff for application admin./processing	2*	2*	2*	2-3*	2*	~6 (comm. solar + DG programs)**
Number of applications processed in last 12 months	8	1	55	8	13	634
Cumulative number of applications processed	27	34	203	56	81	2977
Typical screening response time† (business days)	5-10	2	<15	<10	Do not track	<15 for DG; <60 for CSG
Staff for technical screens & engineering studies	1*‡	1*‡; outsource detailed studies	2, plus 1-2 meter techs for info gathering*	~5*	2*‡	~7-8*, plus 5-6* external contractors
Typical time required to complete detailed study	N/A	N/A	<90 days	4-6 weeks, <90 days for facilities study	N/A	<50 business days (solar gardens only), otherwise <90 days
Remote meter update possible via AMI (% multi-register AMI deployment)	Yes (~99%)	Yes (~100%)	Sometimes (~40%)	No, physical meter swap required	No, physical meter swap required	No, physical meter swap required

Table 5-1. Numerical Indicators

*Notes: *Interconnection application processing or technical review is a collateral duty/responsibility of existing staff rather than primary focus.*

***In MN, 3 XE employees handle interconnection application and processing on a full-time basis, while others contribute on a part-time basis.*
† Defined as time between application receipt and utility response (i.e. application approval or follow-up notice).
‡ Number of staff does not include staff for more detailed studies.

5.1.2 Process Indicators I – Application Management

The first grouping of process indicators considers the capability of each utility to efficiently carry out the application management process. These indicators are comprised of the steps, tools, and procedures used to manage DG applications—from submittal to approval. While no one utility practice or automated procedure can by itself result in a streamlined process, the more well-developed a utility's portfolio of indicators, the lower the marginal cost of application management.

Table 5-2 summarizes the tools, resources, and services offered to applicants, as well as the degree to which automation exists in multiple aspects of the application management process. Of note is the manner in which utilities accept and review applications, as well as the methods in which they communicate with applicants and track applications. Generally speaking, the smaller utilities with lower application volumes have taken a more hands on approach, whereas those with relatively higher application volumes have transitioned a greater portion of the interconnection process online and instituted a larger degree of process automation.

Indicator	AEC	LREC	MP	OTP	RPU	XE
Pre-application report	No	No	No	No	No	Yes (500+)
Online reference materials and forms	No	Yes	Yes	Yes	Yes	Yes
Online application submission	No	No	No, considering web portal	No	No	Yes, online portal
Automated/online application tracking by customer	No	No	No	No	No	Yes, via Salesforce
Internal application status tracking (primary tool)	Manual (Excel)	Manual (Excel)	Manual (Excel) Semi-automatic ArcGIS in development	Manual (Excel) Platform update planned	Manual (Excel)	Automatic (Salesforce & SharePoint)
Payment options accepted	Cash, check, credit card	Check, credit card	Cash, check, wire transfer*	Check	Cash, check, credit card	Online payment or paper check**
Public queue	No	No	No	No	No	Yes, community solar gardens only

Indicator	AEC	LREC	MP	OTP	RPU	XE
Designated utility point of contact	Yes	Yes	Yes	Yes	Yes	Yes (separate contacts for DG and community solar)
Automated steps in application mgmt. process	No	No	No, but planned ArcGIS upgrade	No	No	Yes, some as part of Salesforce
PTO timeline incorporated into procedures	No	No	No	No	No	No; typically, within 5 days of commissioning
Regulatory reporting required per MN statute	Yes	Yes	Yes	Yes	Yes	Yes, plus cost and deadline compliance

Table 5-2. Process Indicators: Application Management

*Notes: *MP can accept wire transfers for engineering studies of large systems.*
***XE's Solar*Rewards Community program deposits can occur either via online check/wire or via US Bank escrow agreement.*

5.1.3 Process Indicators II – Technical Review

The second grouping of indicators relating to interconnection process efficiency involves technical review practices. Screening practices and detailed engineering studies are a common aspect of the interconnection process, though some utilities have applied them more than others. They can dominate processing time due to their complexity and human engineering component, and offer substantial opportunity for streamlining.

Table 5-3 delineates utility experience, tools and data, and the degree of automation incorporated into the technical review process. Of note is the availability and accessibility of data that is needed to complete the technical studies. This data is fundamental to completing such studies and to potentially allowing computer-aided analysis – provided by existing and/or new tools – to contribute to reviews. Moreover, none of the utilities has fully integrated their software tools with the databases containing the requisite information for carrying out technical review, though some are currently taking steps to automate parts of the process.

Indicator	AEC	LREC	MP	OTP	RPU	XE
Detailed technical studies performed	None	None	Few	Few	None	Many
Necessary data available for technical studies	N/A, yet to complete	N/A, yet to complete	Mostly yes; data spread across multiple systems	Mostly yes; data spread across multiple systems	N/A, yet to complete	Mostly yes; data spread across multiple systems

Detailed studies outsourced	N/A, but would consider	N/A, but would consider	Rarely (~1% of studies)	No	N/A, but would consider	Yes, ~90%, but reviews all results
Data from mapping tools integrated with analysis tools	No	No	Planned	Indirectly, "middle link" required	No	Partially, exports directly but not automatically
Hosting capacity maps	No	No	No	No	No	Yes
Automated screening or detailed study process	No	No	No	Partially – in-house pass/fail tool developed	No	Partially – in-house pass/fail tool developed
Key software tools used for detailed technical reviews	N/A	N/A	SINCAL, PSSE, voltage drop calculators, others; migrating to Milsoft's WindMil software	Aspen (for impedance records), PSSE, Synergi	N/A	Synergi, SAP (load forecasting), CRS (meter billing), Projectwise (transformer data), OpenDSS (distribution modeling), SKM (transient modeling)

Table 5-3. Process Indicators: Technical Review

5.1.4 Functional Elements

The functional elements comprise more general qualitative barometers of process streamlining. They are informed by the analytical indicators described above (Numerical, Process I – Management, and Process II – Technical), and represent sub-components that combine to form the project's overarching goal (i.e. streamlined utility interconnection through procedural consistency, automation, and an online portal). Addressing each of the functional elements results in measureable achievement of this project's streamlining goal.

Table 5-4 provides insight into how the current interconnection procedures of the project utilities map to full achievement of the interconnection streamlining goal. It presents broad evaluations for each functional element. Note that while these are meant to represent general trends across the utilities interviewed, XE is, in many cases, highlighted because of the volume of interconnection requests it receives and, as a result, the greater degree to which its interconnection process has evolved. For metrics more specific to each utility and broken down by category, please refer to Chapter 3.

Functional Element	Key Utility Processes
Respond to interconnection applicants in a consistent and timely manner	• "Confirmation of receipt" email sent by 4 of 6 utilities—only XE's is automatic.

	• All utilities track application status, submission dates, and maintain an internal process checklist, largely manually via Excel spreadsheet. • Automated workflow management software implemented only by XE. • Single point-of-contact (POC) supervising interconnection process designated by all utilities. • Screening response time < 15 business days for the five utilities that track it. • First-in-first-out queue structure is default for all utilities, but is not strictly enforced, esp. by utilities with sparse applications. • No expedited process is explicitly defined by any of the utilities; it is not viewed as a barrier to PV adoption by most of the utilities.
Enable transparency into the interconnection application process	• Interconnection resources, applications/instructions available on 5 of 6 utility websites. • Pre-application consultations provided by all utilities, though only XE offers formal pre-application report. • Online/automated application status check by customer only available through XE. (Others provide informal status tracking via phone/email when contacted by applicants.) • Publicly-available queue only offered by XE (mandated). • Half of the utilities have or are developing customer-facing application checklists (or similar). • PTO timeline is not incorporated into any of the utility procedures.
Support for application status tracking	<u>External</u> • Single POC designated by all utilities. • Confirmation of receipt sent by some utilities, but only automated by XE. • Online application tracking only available by XE. • Automatic applicant reminders or status notifications absent from all utilities, except XE (partial). <u>Internal</u> • Application status manually tracked in Excel spreadsheet by most utilities. • Automated reminders absent from all utilities except XE (some via Salesforce). • Publicly-available queue posted monthly by XE only.
Share non-identifying information via a regularly maintained public queue.	• Identifying application information in the queue kept confidential by all utilities. • Publicly-available queue only offered by XE (manually updated monthly). • Queues not automatically updated/posted by any of the utilities.
Provide utility customers with the ability to apply for interconnection online	• Only XE currently accepts applications online via its Salesforce portal. All other utilities receive applications through mail, email, or in-person. • Electronic/online payment of application fee is not accepted by any of the utilities except for XE.
Automate management of the application approval process	• Automated features such as internal and external email/text reminders are not yet implemented by the utilities, except for XE through its Salesforce portal. • None of the utilities have GIS systems that auto-populate with application data. • Template emails/letters implemented at about half of the utilities.

Identify opportunities for increasing the automation of technical screens	• Auto population of technical review software inputs is not done by any utility, though XE can export directly and OTP can export indirectly. • Hosting capacity maps are not yet available at most of the utilities. XE has recently made these available online. • Mathematically-defined pass/fail requirements for technical screens are not fully implemented by many of the utilities.

Table 5-4. Functional Elements Mapped to Leading Utility Practices

With these indicators in mind, the following chapter offers an assortment of recommendations for streamlining utility interconnection processes and protocols.

6 Potential Pathways Forward

This concluding chapter provides a range of potential opportunities for streamlining utility interconnection processes and protocols. The recommendations are based on a combination of EPRI findings captured during utility interviews, observations from prior interconnection-related EPRI research efforts, as well as ideas stemming from a number of external sources listed in Appendix A.

The variety of suggested possibilities is intended to present utility companies and state regulators with a range of options for broadly achieving the core objectives of the Minnesota Solar Pathways project and like initiatives. That said, practices are currently evolving throughout the United States to accommodate both common and contextually-specific interconnection issues. For example, efforts are either planned or underway to determine optimal approaches for incorporating revisions to IEEE 1547. As such, the development of "leading practices" for DER interconnection and the assignment of their priority is a work in progress.

Moreover, as discussed below, there are a number of cost-benefit tradeoffs associated with different interconnection process reforms that require careful consideration. No formal quantification of the value of each opportunity described in this chapter has been conducted primarily because actual implementation costs and benefits will vary across utilities due to their respective circumstances.

6.1 Cost-Benefit Considerations

Few, if any, interconnection processes are "perfect." Numerous opportunities for their improvement exist, however many identified implementation opportunities are not equally feasible or beneficial. Generally speaking, there are tradeoffs to consider when evaluating streamlining options such as adopted practices, tools, and/or automated processes. Some streamlining efforts may provide direct benefits like cost and time savings and/or indirect benefits such as improved customer relations. Others may introduce costs that exceed perceived benefits.

The value assigned to a procedural enhancement is often dependent upon the utility context, the level of interconnection activity in a service area, and statutory mandates, among other things. It can be weighted differently, or even antithetically, according to a range of utility circumstances. Table 6-1 provides an accounting of potential cost-benefit considerations.

Cost-Benefit Consideration	Definition
Potential Benefits	
Labor Savings	Avoided labor hours and associated payroll savings resulting from procedural efficiency improvements and automation.
Applicant Convenience	Improved speed, availability, and ease of use enabled by process improvements for the applicant pool.
Procedural Transparency	Increased accessibility of the constituent steps of the interconnection process to customers (and potentially regulators).
Customer Relations	Improvements to the utility-customer relationship through enhanced service.
Data Accuracy	Greater data integrity and risk reduction achieved through process implementations.
Relative Customer Impact	The volume of interconnection applicants positively affected (today and in the future) by process streamlining/automation.
Potential Costs	
Procurement	The upfront cost associated with purchasing, delivering, and/or installing a procedural improvement.
Labor Costs	Staff resources expended (including operating and reoccurring costs).
Potential for Cultural Conflict	Practices or decisions that may conflict with the company vision, customer preferences, or other interests.
Automation Risks	Tradeoffs of substituting automation for human engineering judgment.
Data Availability/Validation	Time and money required to find, measure, and potentially integrate necessary data into a single software program.
Training/outsourcing	Time and money associated with hiring contractors and/or providing special training to existing employees.
Securing Capital Funding	Time and money associated with obtaining the necessary funds for an improvement.

Table 6-1. Cost-Benefit Considerations that Inform the Value of Pursuing Interconnection Process Improvements

For a number of reasons, the scope, comprehensiveness, and degree of automation embedded in utility interconnection procedures frequently varies. As such, so too does the level of need for the utility to reform and update practices. Current and expected levels of interconnection activity will, for example, greatly influence the labor and avoided cost savings that can be achieved through investments in process enhancements. They will also affect the value and priority utilities assign to process implementations that can improve customer relations in the form of reduced applications costs (i.e. soft cost reductions), time savings, and open

communication. Cost-benefit tradeoffs likewise exist regarding the introduction of automated processes to either partially or fully replace engineering judgment during technical reviews.

The existence of synergies with other in-house or commercial solutions (e.g. utility software and/or hardware platforms), degree to which data is accessible, and the available mechanisms for funding capital improvements can, meanwhile, affect practical scheduling. As a result, the timing and urgency affixed to interconnection streamlining initiatives necessarily varies. Cultural considerations may also exist. For example, some utilities, particularly rural electric cooperatives, espouse a cultural ethos of in-person interaction that process automation can undermine.

All told, optimal pathways for streamlining the interconnection process are likely to be driven by utility- and customer-specific needs. As such, the generalized recommendations that follow aim to provide a canvas from which individual utilities can be empowered to determine the relative merits of the specified implementation opportunities according to their existing needs and priorities.

6.2 Opportunities for Streamlining and Optimization

EPRI has categorized possible streamlining opportunities, broadly generalized for potential implementation across the state of Minnesota, into three categories based on an interpretation of their relative resource intensity (see Figure 6-1):

- **Low-hanging fruit** – Opportunities requiring the least amount of resources either due to their relative simplicity or because they have already been partially put in place and thus only require small tweaks or upgrades to realize the benefit of full implementation.
- **Moderate intensity** – Opportunities requiring more pronounced resources dedicated to their implementation that can potentially be implemented in a medium-term timeframe.
- **Stretch goals** – High-intensity, longer-term opportunities that demand greater dedicated project resources and potentially external skillsets to implement.

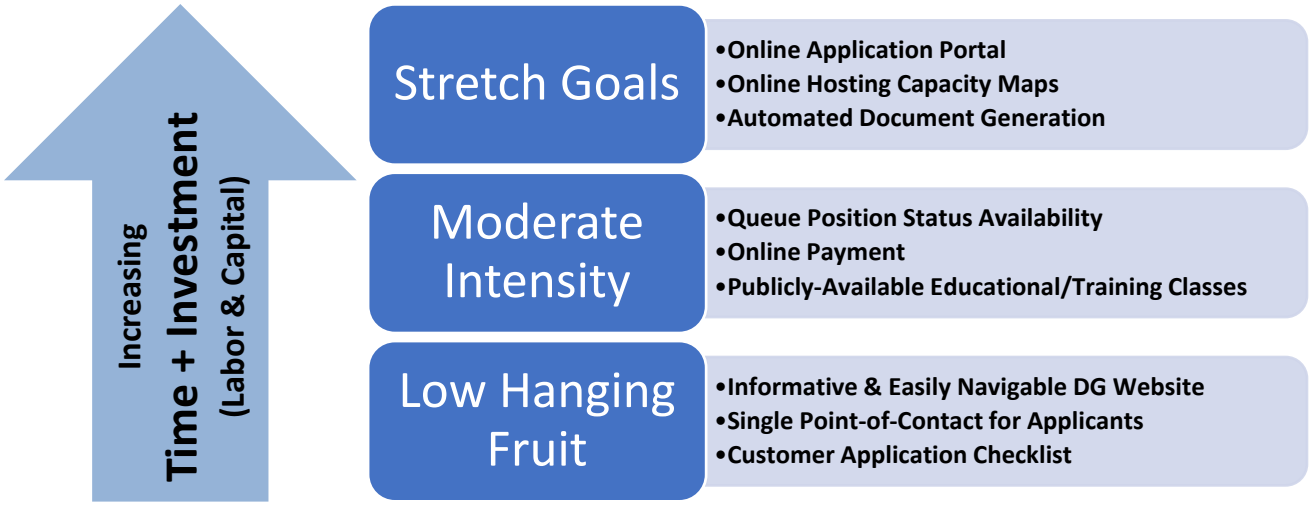

Figure 6-1. Scheme for Designating Streamlining Opportunities along with Representative Example Opportunities
Source: EPRI

The opportunity categories are intended for a broad utility audience. They are meant to provide utilities with a loose framework for considering viable pathways forward for improving interconnection practices according to their individual circumstances. Each of the opportunities discussed below contains four components:

1. Opportunity title – the label of the proposed practice.
2. Narrative description – a more detailed description of the opportunity and why it is relevant.
3. Key rationale(s) – noted benefits and, in some cases, caveats associated with an implementation.
4. Functional elements addressed – elements of the project's aspirational goal that an implementation addresses.

6.2.1 Low-hanging Fruit Opportunities

Again, the opportunities listed in this organizing category are expected to require the least amount of resources from a typical utility in Minnesota. In all likelihood, many utilities in the state have already partially implemented some of these solutions and thus only need to institute small tweaks or upgrades to realize the benefit of their full implementation.

Opportunity	Informative and Easily Navigable DG Website
Narrative Description	Create a page or area on the utility website that is dedicated to the DG interconnection process. This online area can serve as a one-stop destination for interested parties to review pertinent information (e.g. process overview, program and incentive material, FAQs, North American Board of Certified Energy Practitioners [NABCEP] or Underwriters Laboratories [UL]-certified installer list, etc.), links to

	other resources (e.g. state statutes or solar calculators), and downloadable material (e.g. application forms, checklists, etc.). The DG web area should be easily accessible through internal links (perhaps on a universal navigation bar) and/or dropdown menus throughout the broader utility website.
Key Rationale(s)	• Providing information and forms online enables customer self-sufficiency by allowing them to educate themselves about interconnection, set reasonable expectations about the process, and initiate the process on their own. This capability can save the utility labor, time, and money for each prospective applicant.
Functional Element(s) Addressed	• Application process transparency • Consistent and timely responses

Opportunity	**Single Point-of-Contact for Applicants**
Narrative Description	Designate a single point-of-contact to applicants who will act as a chief liaison with internal utility staff involved in the interconnection review process.
Key Rationale(s)	• Assigning a dedicated person or team (or partially dedicated depending on volume of requests) who is both responsive to customers and educated about the interconnection process can improve procedural efficiency and ensure that milestone deadlines are achieved. An effective point-of-contact can communicate external and internal expectations in a timely manner and actively supervise the overarching interconnection process. • Availability to share information on-demand can demonstrate high levels of service and improve utility-customer relations. • Caveat: Beyond simply designating a central point of contact, developing procedures for coordinating the interconnection process can be resource intensive in high volume application environments. Implementing procedures and guidelines is particularly important for a positive customer experience in instances where a team is assigned to coordinate interconnections.
Functional Element(s) Addressed	• Application process transparency • Consistent and timely responses

Opportunity	**Customer Application Checklist**
Narrative Description	Provide a customer-facing checklist of informational elements, documents, and/or steps required to complete application submission and successful interconnection.
Key Rationale(s)	• Sharing a public-facing procedural checklist allows interested parties to better understand and prepare for all of the necessary steps in the process, and set expectations. • Simplifying the process into simple “complete”/ ”incomplete” steps makes it more accessible to those less familiar with interconnection requirements. A checklist paired with guide documents can provide a particularly high level of customer support. • Defining concrete and specific tasks or necessary pieces of data – such as GPS coordinates that relate a proposed project’s location and dimensions – can help facilitate submission of a greater percentage of complete and verifiable applications, reducing the need for utility follow-up and potentially lessening the number of applications that are rejected. • Including a requirement/checkbox indicating applicant site ownership and construction rights can reduce the number of application changes or cancellations, as well as avoid associated processing delays and labor costs (e.g. from having to redo engineering studies due to changes of venue).

Functional Element(s) Addressed	• Application process transparency

Opportunity	**Internal Application Review Checklist**
Narrative Description	Establish a defined list of internal processing steps and quality checks that each incoming application must pass to arrive at a decision. Internal review checklists also assign utility staff/departments responsibility for performing identified items on the list as well as associated timelines for completing them. They may be set up as fully manual or include differing levels of automation (e.g. macros in Excel, algorithms embedded in an online checklist, etc.) to track progress and communicate next steps.
Key Rationale(s)	• Ensures thoroughness of the application review process—no aspect of the review will accidentally go unchecked. • Promotes timely review • Consistency across application reviews. • Removes ambiguity surrounding who is responsible for each step of review and sets expectations internally to enable efficient processing.
Functional Element(s) Addressed	• Consistent and timely responses • Support for application status tracking

Opportunity	**Standardized Template for Engineering Study Report**
Narrative Description	Develop a standard template with defined fields for communicating engineering study results and next steps to applicants. Include template flexibility that allows for unusual study results to be reported (i.e. avoid designing a report template that is 100% plug-and-play and could thus preclude entry of important observations that do not fit cleanly in the predefined parameters of a template).[46] Templates can include macros that introduce automation capability (e.g. integration of calculated study costs).
Key Rationale(s)	• Standardization promotes consistency across engineering reviewers • Reduced labor and costs generated via process efficiencies that eliminate repetitive work required to draft a report, often done manually. • Standardized formatting can increase the consistency of detailed studies completed in-house and externally through third-party contractors, thus reducing labor time spent on quality assurance review. • A standard template can serve as a technical screening checklist, ensuring that all important fields are addressed for every application.
Functional Element(s) Addressed	• Consistent and timely responses • Technical screening automation

Opportunity	**Pre-Application Consultation**
Narrative Description	Before almost any other aspect of the interconnection application, prospective applicants may have questions or concerns about the process or feasibility of installation/interconnection. Enable customer access to a central point of contact in order to have customer inquiries answered on-demand via telephone or email.
Key Rationale(s)	• Answering customer questions can improve utility relations and customer understanding/expectations of the process.

[46] *External Consultant Report on Xcel Energy Minnesota Solar*Rewards® Community® Interconnection Process*. ICF Consulting, Fairfax, VA: December 2016.

	• Discussions may help to proactively address or filter out easily identifiable system design shortcomings or system placements that will incur high interconnection costs. • Caveat: Site visits can be prohibitive and expensive for environments with higher application volumes.
Functional Element(s) Addressed	• Application process transparency

Opportunity	**Pre-Application Report**
Narrative Description	Before submitting a full interconnection application, prospective applicants may, for a fee, request a formal pre-application report for a planned project. The utility then identifies the substation/bus/circuit likely to serve the proposed DG installation and provides the applicant with known information about the existing feeder (e.g. nominal voltages, peak and minimum loads, queued generation on that feeder, etc.).[47]
Key Rationale(s)	• Improved customer relations. • Providing developers with pre-application data can aid in their understanding of utility technical requirements. • Labor and cost savings can be achieved by reducing site assessment costs for developers and by avoiding submission of applications that have a likelihood of requiring extensive technical review and system impacts.
Functional Element(s) Addressed	• Application process transparency

Opportunity	**Commissioning/Meter Swap Checklist**
Narrative Description	Develop a checklist that can be used internally, and shared publicly, to ensure that field engineers and/or meter technicians perform all necessary checks when inspecting newly-built systems.
Key Rationale(s)	• Guarantees transparency as well as thoroughness and consistency of the commissioning/meter swap process. • Educates applicants, contractors, and/or developers about commissioning requirements.
Functional Element(s) Addressed	• Application process transparency

Opportunity	**Restricted Internal Access to Customer Information**
Narrative Description	Virtually all utilities currently secure interconnection applications or other confidential customer data in a private and secure (i.e. password-protected/encrypted) database or folder. Internal access should be limited to utility staff with direct relevance to the interconnection process and to those whom the customer appoints as authorized agents.
Key Rationale(s)	• Protects sensitive customer data from potential data breaches (malicious or accidental). • Caveat: May cause internal inconvenience to access files.

[47] Note: A pre-application report is different from a feasibility study. Per applicant request, the latter requires the utility to conduct engineering studies or other analysis of the proposed DG project. The applicant typically pays for the full cost of the feasibility analysis.

Functional Element(s) Addressed	• Support for application status tracking

6.2.2 Moderate Intensity Opportunities

Opportunities listed under this heading are expected to require more pronounced resources dedicated to implementation. They can potentially be realized in a medium-term timeframe, depending on their degree of pre-existing development, funding availability, and other factors.

Opportunity	Mathematically-Defined Technical Pass/Fail Screening Requirements
Narrative Description	Create technical review checklists that have clearly-defined pass/fail screens based on numerical data/models and mathematical formulas obtained from industry codes or other references, as opposed to soft qualitative metrics that lack clarity, such as "will not cause voltage rise issues" or "must not have power quality problems."

Key Rationale(s)	• Predefined screens based on industry standards can help avoid time consuming and/or costly dispute resolutions.
	• Mathematical functions and definitions are necessary for automating technical screens.
	• A fixed list of necessary input parameters may expedite data gathering.
	• Caveats:
	  ○ Rigid mathematical formulas may not be able to accommodate non-standard circumstances.
	  ○ Engineering judgement has, to date, been a critical component of the technical review process.

Functional Element(s) Addressed	• Consistent and timely responses • Application process transparency • Technical screening automation

Opportunity	Automated Email Response Confirming Application Submission
Narrative Description	When customers submit their applications either via email or an online portal, set up a mechanism for confirming receipt through an automatic text/email response. Beyond confirmation of application receipt, this communication can also outline next steps and milestone timelines using boilerplate language. A more comprehensive approach involves automating customized responses based on application type or level of application completion.
Key Rationale(s)	• Incorporating automation into the initial step in the application process reduces the labor time and effort required to manually respond. • A text/email confirmation may reduce "check in" phone calls from customers. • Reiterating the schedule and timeline associated with the interconnection process can help set customer expectations and general efficiencies.
Functional Element(s) Addressed	• Consistent and timely responses • Application process transparency • Support for application status tracking • Application management automation

Opportunity	Availability of Public Queue Position and Status
Narrative Description	Allow customers to check the status of their applications relative to others in a public queue. The queue should be sufficiently anonymous to protect project identities of other projects.
Key Rationale(s)	• The ability to check the status of a queue position greatly enhances process transparency. • Caveat: Queues can be resource intensive to manage at high volumes; they may be easier to maintain if automated.
Functional Element(s) Addressed	• Application process transparency • Publicly available interconnection project queue

Opportunity	Streamlined Flagging of Potential Interconnection Application Issues
Narrative Description	Digitally scan interconnection applications for potential problems and flag instances needing manual review. Examples could include duplicate applications (same application submitted multiple times), multiple applications for the same address, gaps in information provided, or inactive applications.

Key Rationale(s)	• Automated cross referencing of existing applications can help manage application timelines and queues, especially in jurisdictions with significant interconnection requests.
	• Early detection of problems can avoid unnecessary work and frustration.
	• Caveats:
	  ○ Automation provides greater benefit in situations that support digital application submission. Most utilities today manually enter hard copy and/or PDF application data into a database.
	  ○ Automatically scanning one-line and site plan drawings for errors is not feasible; scans may also be unnecessary based upon the manner in which a portal has been designed to vet and accept application submissions.

Functional Element(s) Addressed	• Consistent and timely responses • Application management automation

Opportunity	Online Payment
Narrative Description	Allow customers to securely pay application fees and potential costs associated with various levels of technical review online to increase convenience and processing efficiency.

Key Rationale(s)	• Online payment provides greater convenience to applicants, especially those submitting their applications online as well.
	• Electronic payment processing can be more easily automated, cutting down on utility processing time.
	• Caveats:
	  ○ Online payment may require significant modification to back-office procedures as well as investment to integrate with existing online payment systems that collect monthly retail billing payments.
	  ○ The value of setting up an online payment system may depend on the volume of annual utility interconnections being processed, particularly if the utility doesn't already accept online payments for other services.

Functional Element(s) Addressed	• Support online interconnection application • Application management automation

Opportunity	Publicly-Available Educational/Training Classes
Narrative Description	Proactively educate potential customers/developers and government officials via training sessions, workshops, webinar presentations (digitally recorded for future reference) and associated written materials on a range of informational topic areas relevant to the interconnection process to increase their general fluency. Relevant subject matter could include the fundamentals of solar power, information about available incentive programs, an overview of interconnection process 101, along with common questions and pitfalls, roles and responsibilities, among others. Working group meetings with developers, convened at an agreeable frequency, can also serve as a forum for discussing issues and challenges that are impeding the interconnection process. Supported utility educational activities can complement other available resources to provide customers with a more holistic understanding of solar technology and grid connection.
Key Rationale(s)	• Informed applicants are more likely to consistently submit complete and accurate applications, and more easily navigate the interconnection process from beginning to end, thereby reducing utility labor costs. • Utility availability can improve customer relations. Through these programs, the utility regularly interacts with developers, enabling both to better understand each other's practices, perspectives, and challenges. For example, working group meetings can help clarify process improvement priorities. Information share can also help to set expectations with government planning officials and open up channels of communication that can make the interconnection process more efficient. • Caveat: Classes and seminars can require considerable investments in time and resources that may not generate significant payback, especially if application activity is low; value will likely be more indirect.
Functional Element(s) Addressed	• Application process transparency

6.2.3 Stretch Goals

Opportunities in this category consist of higher-intensity, longer-term practices that will likely demand the greatest amounts of dedicated project resources.

Opportunity	Online Application Portal
Narrative Description	Develop an online interconnection portal that allows applicants to, among other things, securely submit applications (with electronic signature), pay associated fees, and check application status. Internally, the portal can include functionality to, for example, manage forms and documents, automatically transfer data into a DG database, send automated communications to applicants and utility staff, and integrate with back office utility hardware and software platforms (e.g. process management tools, databases, GIS, etc.) to facilitate greater information access and expedited data review.
Key Rationale(s)	• Leverages back-office automation that can effectively gather digitally available data from multiple databases and tools. • Integrates documents and process steps across the entire interconnection lifecycle that can then be drawn from for reporting purposes and measuring performance (e.g. % completion, timeliness, etc.).

	• Reduces utility staff workload by eliminating manual data entry or partially off-line processes, helping to minimize data transcription errors and inconsistencies.
	• Allows applicants to be guided through interactive questions to ensure that they apply to the appropriate programs/incentives and submit the correct information.
	• Electronic payment processing increases convenience and efficiency.
	• Automatic notifications to applicants and internal staff facilitate timeliness and aid in complying with deadlines.
	• The ability for applicants to check the status of their application at any time increases procedural transparency.
	• Online application submittal is more efficient than scanning physical application forms or uploading digital data.
	• Import and availability of digital data can be efficiently incorporated into screening tools and help facilitate automation.
	• Caveats:
	  ○ Cybersecurity vulnerabilities can be created if third-party solutions providers store/access data remotely (from outside of the utility)
	  ○ Development of an online application portal requires considerable investment in both time and resources.

Functional Element(s) Addressed	• Consistent and timely responses • Application process transparency • Support for application status tracking • Publicly available interconnection project queue • Support online interconnection application • Application management automation • Technical screening automation

Opportunity	**Automated Document Generation**
Narrative Description	At key points in the interconnection process, utility systems can automatically generate documents that would otherwise be created manually (e.g. meter exchange orders, application review letters, final authorization letters).
Key Rationale(s)	• Automation of document creation can save staff time filling in form letters (or drafting letters from scratch).
Functional Element(s) Addressed	• Consistent and timely responses • Application management automation

Opportunity	**Automated Workflow Reminders and Application Status Updates**
Narrative Description	Reminders tied to a fixed timeline (relative to a submission date) can be automatically emailed or text messaged to the appropriate utility staff for tasks marked incomplete. The same or similar approach can be extended to automate external reminders for applicants to notify them about when key steps in the application process have been reached (i.e. milestone updates and status changes) or when a response is required to move forward with the interconnection process (e.g. decision to pursue engineering study).
Key Rationale(s)	• Reminders can safeguard against applications review delays, and ensure that they are completed in a timely manner. In some cases, reminders can help assure statutory compliance.

	• Reminding applicants with status updates at regular intervals can help accelerate interconnections. • Customer notifications provide transparency into the process.
Functional Element(s) Addressed	• Consistent and timely responses • Application process transparency • Support for application status tracking • Application management automation

Opportunity	**Automated Preliminary Screens**
Narrative Description	Define mathematical pass/fail requirements, centralize necessary data, and integrate technical screening tools with application and mapping databases to enable automated application initial and supplemental screening with limited need for human engineering judgment.

Key Rationale(s)	• Reduced labor and response time via automation.
	• Potential for reduced human error
	• Caveats:
	  ○ Potential for increased utility risk associated with removing the element of engineering judgment from each screening scenario.
	  ○ Requires that utilities have appropriate data that is updated regularly through back office integration in order to ensure information being used is accurate and up to date with operating conditions.

Functional Element(s) Addressed	• Consistent and timely responses • Technical screening automation

Opportunity	**Online Hosting Capacity Maps**
Narrative Description	Hosting capacity maps illustrate the degree to which different circuits in a utility service territory are able to accommodate DER. They are informed by calculations that convey the maximum allowable penetration of DER a circuit can handle without exceeding power quality, voltage, frequency, and thermal limits. The maps, if made publicly available, enable applicants/developers to recognize grid areas that are more and less capable of accepting new interconnections without triggering mitigation requirements (i.e. choose less costly sites).

Key Rationale(s)	• Particularly for larger scale installations like community solar gardens, hosting capacity maps can help direct developers to grid areas that are more technically suitable for interconnection.
	• Proposed projects targeted at higher hosting capacity locations can save utilities time and effort from otherwise analyzing applications sited at lower hosting capacity areas.
	• Applicants/developers who choose to site their projects at locations with insufficient hosting capacity can anticipate infrastructure upgrades or mitigation measures (and costs) that will be required if they proceed.
	• Caveats:
	  ○ The effort associated with developing (and updating) hosting capacity maps may not make economic sense if interconnection activity is marginal, the maps are not frequently utilized, and they are not effective in expediting interconnection processing.
	  ○ Maps require that utilities have appropriate data that is updated regularly through back office integration in order to ensure information being used is accurate and up to date with operating conditions.

Functional Element(s) Addressed	• Application process transparency • Consistent and timely responses • Technical screening automation

Opportunity	**Integrated Application Data with Mapping Tools**
Narrative Description	Automatically populate fields in a GIS mapping system with verified information from proposed/approved applications and/or CIS databases to more thoroughly identify DER installations throughout the utility service territory and, in turn, aid in distribution planning
Key Rationale(s)	• Reduced labor associated with data transfer between systems and elimination of repetitive data entry. • Accelerated data transfer into mapping systems and continuous update. • Reduced/eliminated human error associated with data entry/copying (e.g. typos or copy paste errors).
Functional Element(s) Addressed	• Application management automation

Opportunity	**Integrated Mapping Tools with Analysis Tools**
Narrative Description	Automatically populate fields in analysis software (e.g. power flow analysis) with technical information found in GIS mapping software and/or other physical asset information databases.
Key Rationale(s)	• Efficiencies derived from automatically compiling the latest DG and system asset information. • Accelerated data collection for technical screening/studies. • Reduced/eliminated human error associated with data entry/copying.
Functional Element(s) Addressed	• Technical screening automation

Opportunity	**Capability to Remotely Update Meter Settings**
Narrative Description	Upgrading retail electric meters in a utility service territory to multi-register AMI meters enables, among other things, the ability to remotely push new settings required for measuring bidirectional power flows. As a result, truck rolls and associated costs of completing meter swaps can be eliminated. A phased deployment approach can consider upgrading meters for retail customers in areas where DER adoption is more likely. Note: remote meter setting update alone is insufficient to justify AMI investment; it is one of multiple functions that can be enabled by AMI.
Key Rationale(s)	• AMI firmware can be upgraded remotely, eliminating the need for a meter swap and dedicated truck roll for new interconnections. • AMI can provide more granular information about the point of interconnection than a substation meter or other non-local metering. • Caveat: AMI deployment is a significant investment that likely needs to be tied to broader initiatives in order to justify the investment.
Functional Element(s) Addressed	• Technical screening automation • Consistent and timely responses

6.2.4 Summary of Opportunities

The table below provides a summary overview of the streamlining/automation opportunities identified in this report. The opportunities are divided amongst the three organizing categories – low hanging fruit, moderate intensity, and stretch goals – used to denote a generalized level of resources to implement them. Each is mapped to the seven functional elements used to define a streamlined interconnection process. The consolidated list offers a convenient way to compare recommendations and evaluate their relative contributions to enhancing interconnection practices.

As a reminder, the functional elements called out in the table are:

1. The ability to respond to interconnection applicants in a consistent and timely manner
2. Interconnection application process transparency
3. Support for application status tracking
4. Sharing of non-identifying information via a publicly maintained queue
5. The ability for utility customers to apply for interconnection online
6. Automated management of the application approval process
7. Identified opportunities for increasing automation of technical screens

Table 6-2. Summary Table of Streamlining Opportunities including the Functional Elements Addressed

Opportunity	FE# 1	FE# 2	FE# 3	FE# 4	FE# 5	FE# 6	FE# 7
"Low-hanging Fruit" Opportunity							
Informative and Easily Navigable DG Website	X	X					
Single Point-of-Contact for Applicants	X	X					
Customer Application Checklist		X					
Internal Application Review Checklist	X		X				
Standardized Template for Engineering Study Report	X						X
Pre-Application Consultation		X					
Pre-Application Report		X					
Commissioning/Meter Swap Checklist		X					
Restricted Internal Access to Customer Information			X				
Moderate Intensity Opportunity							
Mathematically-Defined Technical Pass/Fail Screening Requirements	X	X					X
Automated Email Response Confirming Application Submission	X	X	X			X	
Availability of Public Queue Position and Status		X		X			
Streamlined Flagging of Potential Interconnection Application Issues	X					X	
Online Payment					X	X	
Publicly-Available Educational/Training Classes		X					
Stretch Goals							
Online Application Portal	X	X	X	X	X	X	X

Automated Document Generation	X				X	
Automated Workflow Reminders and Application Status Updates	X	X	X		X	
Automated Preliminary Screens	X					X
Online Hosting Capacity Maps	X	X				X
Integrated Application Data with Mapping Tools					X	
Integrated Mapping Tools with Analysis Tools						X
Capability to Remotely Update Meter Settings	X					X

Appendix A: References

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Appendix B: In-Depth Interview (IDI) Transcripts

MN Solar Pathways: Interconnection Streamlining Assessment

In-depth Interview Topic Guide

Respondent Name(s):	Yusef Orest, Member Service Manager – DG Coordinator
Company Name:	Arrowhead Electric Cooperative (AEC)
Date / Time of Interview:	June 30, 2017 @ 8:30am – 12pm
EPRI Interviewer(s):	Nadav Enbar, Alex Magerko

I. Background & Perspective

1.1 How many customers does your utility serve and what is the physical size of your utility's distribution footprint in Minnesota?

AEC has 3,528 members, 4,285 accounts, 607 miles of distribution line (Cook County is 3,340 sq. mi). In addition to electricity, the utility also provides broadband service to over 2,000 subscribers. The utility is winter peaking (in electricity demand) and the peak typically occurs starting at 4am.

AEC's residential rates range from $0.127 (winter) to $0.142/kWh (summer). Commercial rates span from $0.117 (winter) to $0.132 (summer). AEC also offers lower rates for various off-peak appliance usage (e.g. heat pump, peak shaving water heater, or other thermal storage units; $0.0653 for duel fuel). As with a number of other co-ops in the state, AEC is required to buy all but 5% of its wholesale power supply from Great River Energy (GRE), a generation/transmission (G+T) supplier.

Demographics: 40% of homes within AEC's territory are inhabited by seasonal residents (those with second homes) who have significant disposable income. People also generally want to live in greater harmony with nature, though often economics will trump environmentalism.

A local democracy bill (216b.164, https://www.revisor.mn.gov/statutes/?id=216b.164) was recently enacted that clarifies NEM terms by granting electric co-ops the right/responsibility of resolving internally disputes related to DG. Now a mediator can be hired, but disputes will no longer go to the PUC. The bill makes dispute resolution more cost effective for co-ops and may change the way in which cooperatives work with

their members. Note: The MN PUC has historically not had significant oversight of co-ops related to grid access and fixed cost recovery.

1.2 What size (kW) classifications do you use to segment interconnection applications?

Specifically, for DG:

- <40 kW (the NEM limit in which excess generation is sold directly to AEC),
- 40-100 kW (in this size range producers are guaranteed an off-take contract, but with AEC's wholesale supplier, at avoided cost),

1.3 Are there any tools or processes you have implemented or are developing to help make interconnection faster/cheaper/better? If so, please elaborate.

AEC is presently working on revising its interconnection packet and wiring/interconnection standard to both assist its members and create best practices at the utility. It is currently in a research and scoping phase of this effort.

AEC presently supports a simple process that requires internal approvals from Member Services and Operations. It does not currently have a website area dedicated to DG interconnection but would like to develop one. It has developed hard copy/PDF files for the interconnection application, as well as a related handbook and FAQ. These are "vanilla" and AEC wants to rework them to make them more customer-centric. It also wants to develop a technical document intended for contractors. In addition, AEC has not yet developed an interconnection manual that lays out its interconnection process, provides a checklist for requirements, details engineering/interconnection standards, and presents a wiring standards/guide.

In general, AEC would like to emulate an interconnection process similar to Agralite Electric Cooperative's online approach: http://agralite.coop/content/distributed-generation.

Separately, the utility tends to have trouble with grounding. It requires a pilot light be installed with a system as a safety precaution in order to know when there is power present (flowing in either direction). It would also like to implement an automatic switching product (but that product is not commercially available [yet]).

1.4 What are the most significant issues you have experienced in processing interconnection applications to date?

Inconsistent internal practices and the need for a true interconnection manual. Nobody at AEC has been focused on the issue, and that has been compounded by position

vacancies. AEC recently re-hired a member services manager and is still seeking a GM; both positions have been vacant or inconsistently staffed for 4-5 years.

1.5 What tools do you use to ensure the privacy and security of your customers' information?

AEC uses the same internal privacy standards and auditing for all membership data. It has a NISC electronic records system and it locks all other private customer data as applicable when in physical form. It is fully PCI DSS (Payment Card Industry Data Security Standard) compliant as well.

1.6 Please complete the below table to provide background on historical/anticipated interconnection applications received by your utility:

AEC has a total of 31 active DG systems (mostly small PV systems, 3-8kW; and a small wind turbine); 8 applications are currently waiting to be reviewed. By end of 2017, AEC estimates that 1.5% of all of its accounts will have solar. No commercial or industrial customers currently have solar.

Beyond grid connected PV, ~10-20 off-grid systems have been installed in AEC's footprint. In some cases, this has been done based on the cost of extending a single phase line to a residence (in some situations, it can be in excess of $1M/mi). Two customers have since transitioned from off-grid back to interconnected status.

AEC's attitude toward DER: "socialize the costs, privatize the benefits." AEC pays out NEM at the retail rate and does not charge a grid access fee. (The grid access fee is socialized between a service charge and rates.) AEC believes that a relative onslaught in DER applications will arrive over the next 1-5 years given falling prices and improving technology.

Question	< 10 kW	10-40 kW	40-500 kW	> 500 kW
How many MW of PV and non-PV DER[48] are currently interconnected	PV= .09732 non-PV= .003	PV= .0457 non-PV= 0	N/A	N/A
How many PV and non-PV DER systems are currently interconnected	PV= 24 non-PV= 1	PV= 2 non-PV= 0	N/A	N/A
How many applications did you process in the last 12 mos. *(May '16 - May '17)?*	8 total	N/A	N/A	N/A
What % of all applications in the last 12 mos. were incomplete when received *(May '16 - May '17)***?**	25%	N/A	N/A	N/A

[48] DER = Distributed energy resources and includes PV and other small generators.

What % of applications in the last 12 mos. have been approved *(May '16 - May '17)***?**	All, or are pending final anti-island test	N/A	N/A	N/A
What % of applications approved in the last 12 mos. have been installed *(May '16 - May '17)***?**	All	N/A	N/A	N/A
Do you conduct a preliminary technical review for each of the project size categories (Y/N)	Yes, one line review only	N/A	N/A	N/A
In the next 3 years, what are your projections for the level of interconnection applications received? (If possible, please break out for each year.)	10-20 per year	N/A	N/A	N/A

1.7 How many community solar installations, if any, are currently interconnected in your service territory and what is their cumulative capacity? How many community solar projects are in the queue? How many community solar projects have, over the last two years, been canceled?

AEC hosts one (40-kW) community solar system on its system. It was installed in 2015 on AEC's HQ property and is membership-owned. The utility handled site prep and contracted a third party to build the array. Forty panels out of 144 have been purchased by 20 or 25 people (~30% of panel purchasers financed their investment). Unsubscribed panels are a reflection of modest payback relative to other economic investments (despite the presence of financing options). No other projects are currently planned, due in large part to the apparent lack of interest/commitment. (Grand Marais PUC has discussed an option for its customers.)

The development of the array was a forward-thinking board decision. AEC would like to potentially develop new service line areas beyond community solar (i.e. ancillary services) to expand its business. For now, it is manually building relationships and examining opportunities to develop a business case to sell solar systems, handle O&M, have an electrician on staff to develop ancillary revenues (non-operating) costs/revenues, etc.

GRE also owns a 20-kW community solar array that is adjacent to the AEC community solar system and is separately metered.

1.8 Are there private sector community solar project(s) in your service territory? If so, do they use the same interconnection procedure as individual applicants?

None.

1.9 For approved project applications (both installed and not pursued) in the last 12 months (May '16 - May '17), what number and percent have required utility infrastructure upgrades (categorized by cost)?

There has been very little upgrade needed thus far, though records are not extensive… maybe one upgrade to a transformer.

Cost of Upgrade	Number of Projects Requiring Upgrade	Percent of Total # of Apps
$0-$9,999	None to date	N/A
$10,000 to $49,999	None to date	N/A
$50,000 to $100,000	None to date	N/A
>$100,000	None to date	N/A

1.10 Have the values entered into the table in Question 1.9 significantly changed from prior years? If so, in what way?

N/A.

1.11 For all approved project applications in the last 12 months, what number and percent were not pursued by the customer due to upgrade requirements as a condition of interconnection?

Unknown.

1.12 What tools and systems (business and technical) are used in your utility's interconnection process?

One person in Member Services uses a spreadsheet that tracks the interconnection process and status. There is no distinct work flow, AEC employs service orders to document actionable items. Customer details are kept in a NISC system customer mgmt. system (CIS).

AEC's entire service area is mapped. Info is housed in the CIS and ArcGIS systems. In the future, DG could be called out in GIS, but for now DG-related info is referred to in the notes of a specific service location. The GIS doesn't "talk" to the CIS. Everything is manual. The GIS is in its own vertical.

Process	Tool/System	How do you use it?	Used for something other than PV/DG?	In House/ Commercial
Business Management Systems	Internal Tracking Spreadsheet (Excel)	Track system elements and dates in process and interconnection	No	In-house

	Internal Sign-off	Member Services and Operations sign-off on document	No	In-house
	CIS	NISC system (manages customer details)	Yes	Commercial
Systems for Technical Review	ArcGIS	Record keeping of installed systems (in notes field)	Yes	Commercial

1.13 How many utility staff are currently available to perform *administration and processing* of interconnection applications? What is the estimated total staff-hours (alternatively: staff-years) for this effort?

Two staff members in member services. A total of 30-50 hours is required per year to handle tracking and administrative issues, ~4-5 hours per project. Line crews expend ~10-20 hours per year for field work (e.g. commissioning/line testing.)

1.14 How many utility staff are currently available to perform *screening and detailed studies* of interconnection applications? What is the estimated total staff-hours (alternatively: staff-years) for this effort?

1 FTE. The operations manager (AKA "line superintendent") gives an operational sign-off (screening) e.g. quick check of transformer sizing. AEC has not used external sources to date.

There has not been cause for in-depth engineering studies, partially because AEC is a winter peaking utility and most of AEC's transformers are rated at 30 kVA so the utility can safely overload them due to operational efficiencies in the cold.

II. Interconnection Process – Getting into the Details

Pre-Application

2.1 Does your utility provide a pre-application report when requested? If not, please skip down to the "Receiving Application" section of the questionnaire.

AEC does not provide a pre-application, but offers a consultation, which includes calculating simple paybacks, price per W, answers to equipment/interconnection questions, etc.

2.1.1 If so, how much does a pre-application report cost and how quickly does your utility provide the report to requesters?

$0. Consultations are both informal and free.

2.1.2 Is a non-disclosure agreement (NDA) required to provide the pre-application report data? If so, is the NDA partial or comprehensive?

No.

2.1.3 Is an aerial map needed to complete a pre-application report?

AEC just asks for an address so it can do a site visit. Otherwise, no.

2.1.4 Approximately how many applicants have requested a pre-application report to date?

N/A

Receiving Application

2.2 What is the fee to submit an interconnection application?

$537 covers clerical work/interconnection processing, truck roll, anti-island testing, inspection, etc. An addition fee (at cost) would be charged for any engineering studies above and beyond initial screening. (PSE is the engineering firm of record.) The application fee was previously arbitrarily set at $1,000.

2.3 What are the different means by which you can accept interconnection payments from customers (e.g. application fees, study fees, etc.)? In what form are payments typically submitted?

Associated fees are typically paid by check or cash (credit card could be accepted in person or potentially called in). No online payment is currently available. AEC does provide an online payment (SmartHub) option for standard electric bills (~30% of members have signed up, 20% actively use it), but interconnection billing has not been integrated into online payment.

2.4 How does your first contact with the DER customer typically occur? Which utility department is responsible for replying to initial customer inquiries, and what is their standard procedure? Do you designate a single point of contact for the applicant? At what point in the process is this designation made?

Member Services usually takes a call (occasionally receives email) from an interested member; sometimes it is from the solar installer. After a discussion, AEC will snail mail or email a packet of forms and information (application [Schedule D contract],

interconnection form, FAQ document) and communicate an informal timeline. Member Services remains the central contact throughout the process.

2.5 What are the possible ways applications can be submitted for different PV system/size classifications (e.g. online, by mail, in person, etc.)? Can customers attach supporting documents and use an electronic signature?

Usually by mail and in person; there is no web-form available. Applicants can attach supporting documents to email, but digital signature is not accepted.

2.6 Are application forms available online, along with clear, step-by-step instructions? Is a checklist available online (or otherwise) to help customers and contractors complete DG applications?

No. Revision is underway by AEC to make the process less passive.

2.7 Can contractors fill out applications on behalf of customers? If so, do you train contractors to fill out the applications and go through the interconnection process?

Yes, contractors can fill out applications on behalf of clients, but no training is provided by AEC. Ultimately, member signature is required.

2.7.1 Are training materials published and events hosted to train new and existing contractors?

No, but AEC has been working with the same installer group which has lent familiarity to the interconnection process.

2.8 Who reviews the application for completeness and approval (if different)? Who contacts the customer to inform them whether the application is completed adequately and/or whether it has been approved? Is this process automated in some way?

The Member Services Manager manually checks applications for completeness and liaises with applicants. There is no automation.

2.9 What is your typical response time to customers after receiving complete and incomplete applications? What factors most affect this response time?

It typically takes 1-2 working weeks for AEC to complete initial application screens. One person essentially handles the entire administrative process, so there is variability in processing time based on that person's availability.

2.10 After an application is received, what tools are used to store and access its information? Who has access to the application once it is received (or in your database)?

AEC uses the same internal privacy standards and auditing for all membership data. It has a NISC electronic records system and locks all other private customer data as applicable when in physical form. AEC does believe, however, that it needs to change its interconnection installation records, which currently reside in one binder for everything.

2.11 Can the customer/contractor access their application information online? If so, what project details and status information are accessible?

No.

2.12 How do you communicate to customers (verbal, written, email) and at what steps of the application process? What level of detail is provided and at what point is this communicated (e.g. application completeness check, preliminary response, status update)?

Member services will informally email/call applicants to let them know they have received their application, whether there is anything missing, etc. This is an informal back-and-forth, entirely manual procedure (i.e. no automation), and is not tied to defined timelines. There is informal communication that occurs throughout the entire process.

Beyond communicating the specifics of the interconnection process, AEC will also answer more general questions as needed (e.g. rooftop access vs. ground mount, safety tips, economics [show pro forma on project performances, amortization]). These conversations often occur after submission of the application as customers dive into more of the details of the process and more technical questions arise.

2.13 Are applications added to the queue on a first-come-first-serve basis? Under what circumstances, if any, are applications rearranged in the queue? (e.g. if a material modification were made)

AEC supports first in, first out processing, but it will not hold others in the queue back if one project is delayed. The utility supervises 5 substations, 1 or 2 of which are closer to capacity limits, but none of which are likely to require upgrades soon.

2.14 Does your utility post a single publicly available queue? If so, how frequently is it updated?

No.

2.15 What, if any, policy does your utility adhere to for defining when timelines on application deadlines can be extended? Does the utility apply a blanket policy for extending timelines?

It is arbitrary. The utility has a 1-2 week turnaround goal because of the brief construction season. (Most people with systems <40kW anticipate a "pass" on their application anyway.)

2.16 Does your utility provide guidance on interconnection costs that improves cost predictability and certainty (e.g. unit cost guides, interconnection cost envelope)?

N/A. AEC has not yet encountered a need for an engineering study, but the plan is to charge detailed studies at cost, and AEC will provide the customer with their best cost estimate in advance.

Expedited / Fast Track / Screening Process

Note: These processes may go by different names and contain a range of nuances, but they usually comprise a simplified application path for smaller (often inverter-based) generation systems (<50kW) that do not require in-depth engineering studies. They usually include the following general steps:

a.) Initial communication with potential applicant
b.) Utility review to classify proposed project and screening requirements
c.) Application filing
d.) Applied screens (including supplemental screens, if necessary)
e.) System Installation, testing, and inspection
f.) Final acceptance

AEC works through each project on a case-by-case basis, advancing each one as quickly as possible. PQ, load factor, voltage issues tend to be areas that are examined. There are some contextual issues that need to be addressed. For example, one substation goes 60 miles into the wilderness and has efficiency and voltage problems. There is potential for capacitance/voltage issues there…

AEC essentially looks at the wiring one-line from the technical aspect to make sure it fits with its parameters. Additionally, the utility looks at the distribution equipment at a site to verify that the DG system will cause no harm to the system or others. There are no known instances of a system upgrade being required on the Arrowhead system to date

2.17 Does your utility have an expedited application process for reviewing PV projects (i.e. established screens vs. unique engineering judgement for every application)? Please elaborate.

No. There will always be a degree of engineering judgement—some applications will be reviewed more extensively than others.

2.18 If so, at what kW rating do you waive screens and automatically accept an application?

N/A. AEC will always give an application a cursory glance.

2.19 Are there any steps in your expedited interconnection review process that are automated? If so, what is the level of automation for each?

N/A.

2.20 Does your utility contract out interconnection application review (including screening and engineering study) to subcontractors? If so, roughly what percentage of application review is outsourced? What quality controls have been implemented to assure appropriate review?

No.

2.21 Do you use any automated or manual screens for certain PV size classifications?

No, as long as this fits with 216b.164 (https://www.revisor.mn.gov/statutes/?id=216b.164).

Application Approval and Processing

2.22 What tracking tools do you currently use for applications throughout the interconnection process? Do your customers have access to these tools? Is tracking in real-time? Does it contain features such as automatic reminders? Can the tracking tools be integrated into your utility's website (if they are not already)?

AEC manually tracks the process using a simple Excel spreadsheet. There are no customer-facing tools, nor any automated reminders.

2.23 Which steps in the approval process are most commonly not passed the first time? What are the most common reasons for not passing and what measures are typically taken in these situations?

The one-line diagram can be incorrect or interconnection documents may need updating. Often one-line diagrams produced by solar installers are generic and not specific to the site. In some instances, they don't include all of the required disconnects required under different areas of statute: fire code, electrical code, and utility disconnect. Many times interconnection agreements and schedule D documents are haphazardly filled out by DG system owners (or their agents: the solar installer) and require corrections or clarifications.

2.24 What, if any, is your procedure for adding DER into the utility's Geographic Information System (GIS)? At what point in the process does this occur? How often does this happen (daily, weekly, monthly)?

Once commissioned, AEC would like its process to reflect the DER on its GIS and in its CRMS (AEC's CIS serves as its CRMS). This is not currently reflected, but if and when it is, AEC would update it with each new interconnection occurrence.

2.25 What is your procedure for installing new meters? When does that happen? Does your utility charge metering fees when the meter has to be replaced?

New meters are set at the time of anti-island testing/commissioning. AEC has completed a full AMI deployment (99% deployment). As a result, most meters are bi-directional. The utility is able to do a simple settings push from the software headend to change the meter to record as bi-directional. There are no additional chargers or any grid access fees levied on DG producers.

Detailed Study Process

2.26 Please explain criteria that trigger a more detailed study (which entails greater depth of review beyond what is pursued via the expedited or Fast Track process)?

Greater engineering assessment is triggered by systems >40 kW; however, this might not result in a full-blown engineering study as much as a closer look. Issues covered would largely encompass power quality and power flow issues.

Systems < 40 kW typically are well undersized for AEC's transformer sizes. If in the instance that a system > 40 kW came online in the system, this could begin to approach the standard minimum size transformers that AEC places. When the utility makes a determination that a DG system is approaching transformer limits AEC would engage Power System Engineers to complete an engineering analysis for said projects

2.27 What does a detailed study typically involve?

Engineering review. PQ issues, voltage issues, capacity check (transformers, etc.). AEC's system engineers (PSE) would review the size of the DG system and review the distribution transformer, primary and secondary circuits that service a DG facility and the distribution feeder up or down stream of the interconnection point.

2.28 What is your typical completion time for a detailed study?

Engineering analysis will take 1-2 weeks per project (beyond the time taken for initial screens) and does not include paperwork processing time or customer sign-off time (pre-approving the additional time/cost).

2.29 What are the most common obstacles to completing a detailed study in a timely manner?

Resource bandwidth.

2.30 Do you typically have all the information/data you need when you start a detailed study? If not, what missing information is most likely to cause delays?

If detailed analysis were to be performed, work would likely be outsourced to AEC's distribution system contractor PSE (the engineer of record), which would already have most all of the information needed.

2.31 Who communicates with the customer before, during, and after the detailed study process? What is the typical content of these communications?

N/A.

2.32 Are third-party consultants utilized for detailed studies? If so, for what percent of studies?

Precision System Engineering (PSE) would potentially be contacted as they are the engineering firm of record that AEC uses. AEC has not yet been through potential QA issues.

2.33 What tools and resources do you use during the detailed study process? Modeling and load flow analysis tools? Commercially-produced or in-house?

PSE would use their own tools.

2.34 Do you employ electronic maps for your entire distribution system? If no, what percentage is mapped electronically? Can/do the maps feed simulation tools for performing load flow analyses?

The entire AEC service territory is mapped. These do not presently integrate with simulation tools. Info is separately housed in the CIS and ArcGIS systems. In the future, DG could be called out in GIS, but for now DG-related info is referred to in the notes of a specific service location. The GIS doesn't "talk" to the CIS. Everything is manual. The GIS is in its own vertical.

As of yet, AEC's mapping system will tell you that system is there (in the notes section), but cannot "sort" by type to list where all DG is located.

2.35 Is data from all systems stored in a centralized location? If so, is this database integrated with mapping tools and application process? Are all approved interconnection projects incorporated into utility internal mapping tools? Are PV sites added to the maps automatically?

No, the CIS database is not integrated with mapping tools and the application process. See Q2.34 for additional response.

There are common record sets in a "file" folder in AEC's vault. This file would contain all of the minimum data required for interconnection. Additional notes might be kept in AEC's CIS system, in a GIS map file, or in an email note set.

Summary Table

Interconnection Process		Which department performs step?	What Tools/Systems are used?	What data is needed?
All Applications	**Inquiry Received & Responded**	Member Services	Email or paper file	Customer information, basic information about system size
	Application Received	Member Services	Paper file, excel tracking sheet	Completion of system details, one-line diagram
	Application Fee Received (for systems > 20kW)	Member Services	Paper file, excel tracking sheet	Interconnection funds that are clearly tied to the project owners interconnection application
	Application Receipt Notification sent to customer	Member Services	Email or paper file	Confirmation of items received, and any additional information needed requested at this time
	Application reviewed for completeness	Member Services	Paper file, excel tracking sheet, CIS	Completion of system details, one-line diagram
	Application Status Notification sent to customer (complete or incomplete)	Member Services	Email or paper file	Confirmation of items received, and any additional information needed requested at this time
	Application Tracking (communication with customer throughout)	Member Services	Paper file, excel tracking sheet	Status of application and or needed items communicated to member and or installation partner
	Application sent for screening/review	Member Services	Email or paper file	One-line diagram and technical information about system shared

				technical review team
Case 1: Expedited / Fast Track / Simplified Process	**Screening or Technical Review**	Member Services /Operations	Email or paper file	One-line diagram and technical information about system shared technical review team
	Application Approved	Member Services	Paper file, excel tracking sheet, CIS	Internal sign-off that project fits requirements and acceptance of project plan communicated to customer
	Request for Meter Set	Member Services	Email or paper file	Schedule and timing of commissioning with request for metering and billing change made at this time
	Add DG system to utility mapping	Member Services /Operations	Email or paper file	Designation request for asset change in the GIS system made to operations
	Verification Test	Member Services	Email or paper file	This is verification of onsite system set-up, anti-island test, and metering change is complete
	Final Acceptance	Member Services	Paper file, excel tracking sheet, CIS, email	Permission to produce verified, copies of all contract documents shared with member, and internal closeout of workflow is completed
Case 2: Detailed Study	**Preliminary technical review**	Member Services /Operations	Paper file, excel tracking sheet, CIS, email	One-line diagram and technical information about system shared technical review team
	Estimate of detailed study if needed to customer	Member Services	Email or paper file, phone, CIS	Cost of analysis and system upgrades are a pass-through cost and billed at actual rates
	Payment received	Member Services	Email or paper file, CIS	Invoicing and letter form sent to

				member, payment recorded in billing system
	Data request to customer	Member Services	Email or paper file, phone	Additional data needed requested by mail or email at this time.
	Detailed study	Member Services	Paper file, excel tracking sheet, CIS, email	Data needed specified by engineering entity, communicated between engineer, cooperative, member, and DG installer
	Application Approved	Member Services	Paper file, excel tracking sheet, CIS, email	Internal sign-off that project fits requirements and acceptance of project plan communicated to customer
	Request for Meter Set	Member Services	Email or paper file	Schedule and timing of commissioning with request for metering and billing change made at this time
	Add DG system to utility mapping	Member Services /Operations	Email or paper file	Designation request for asset change in the GIS system made to operations
	Verification Test	Member Services	Email or paper file	This is verification of onsite system set-up, anti-island test, and metering change is complete
	Final Acceptance	Member Services	Paper file, excel tracking sheet, CIS, email	Permission to produce verified, copies of all contract documents shared with member, and internal closeout of workflow is completed

2.36 Does your utility have a permission to operation (PTO) timeline incorporated into its interconnection procedures?

No.

2.37 To what degree, if at all, do you provide interconnection reports to a state agency (e.g. MN DOC, PUC, etc.)?

Given recent legislation (Bill 216b regarding net metering), AEC and other cooperatives/municipal utilities are no longer required to report to DG statistics to the PUC and DOC. This would be voluntary, and instead, DG reporting will go to co-op boards on annual basis.

2.38 Do you report on compliance with meeting application processing deadlines?

Reporting on the basics of the process (e.g. start/end dates) is done internally, not externally.

III. Perspective & Expectations: Online Portal

3.1 What steps, if any, have you investigated or taken to streamline the interconnection process? What is the rationale(s) guiding these activities? What have been the greatest obstacles?

AEC would like to develop a contact list for potential applicants, a manual detailing wiring and interconnection standards, and a more defined internal workflow. AEC does these organically but has not formalized them. It also would like to develop better documentation about the process as well as compliance reporting.

3.2 What steps, if any, have you investigated or taken to develop an online portal? What is the rationale(s) guiding these activities? What have been the greatest obstacles?

None. AEC would have a site similar to http://agralite.coop/content/distributed-generation in terms of how information is delivered. In particular, AEC would have a document library as part of the website/portal.

Obstacle: AEC does not have any technical expertise in software development.

3.3 What longer-term (5+ years) aspirations do you have for streamlining the interconnection process?

AEC's aspiration is to have an on-staff electrician who will help with the process, sell, maintain, and work with solar users/interested parties.

AEC would consider piggybacking on efforts undertaken by other cooperatives who have developed a portal (e.g. GRE working on an efficiency web store; 8 coops in IA have a renewables store—Iowa Choice Renewables). It might also consider emulating Dakota Electric's rebate program to incentivize systems sized to match load (or less).

The utility is not far enough along in the process (nor does it have enough applicants) to pursue more involved automation, though incorporating some level of automation is an ambition.

IV. Miscellaneous Questions

4.1 Does your company maintain a checklist for all on-site inspections? If so, are these checklists publicly available to customers and contractors, allowing them to better meet all requirements?

AEC has an external commissioning sheet (it likes to have a signed hard copy for records), but would like to formalize the customer process into a checklist as well.

4.2 If revised standardized interconnection procedures are implemented, what hypothetical requirement(s) would concern you the most as being difficult or impractical to comply with (e.g. communication, reactive power setting, other)? Are there constructive solutions/alternatives that you have developed or would suggest?

AEC would advocate for enacting a matrix of standards that offer flexibility to the process that can better fit with the differing situations of the utilities around the state.

While a website could facilitate automation and ease of access, AEC notes that it would lessen the interpersonal interaction/relationship the utility currently enjoys with its members (through which filtering/guidance is undertaken).

AEC is a proponent of its pilot light requirement as they find it eliminates the need to mandate where an interconnect can reside relative to the meter.

4.3 Some utilities keep a periodically updated map/database of distribution-level PV/DER hosting capacity to easily identify strategic locations for PV. Do you do this? If so, what is your utility's preferred frequency and timing for updating these maps?

AEC does not do this, but is interested in the idea.

4.4 Do you currently have access to interconnected/operational DER performance data? If so, how does such visibility support utility planning or operations? If not, is there value in gaining such visibility (e.g. operational visibility and data resolution) regarding DER performance? At what scale of DER or type of DER is this most relevant?

As a new AMI user, AEC still has a vast amount of data analytics to conduct. This data will likely inform future investment decisions about how to operate a DER and demand response systems (perhaps as a unified "smart" enterprise solution).

AEC is able, to an extent, monitor PV performance through its AMI system. There is some complication with the meter data management system, though. Most meters log every 5 seconds, and the data report that gets pushed to AEC is hourly.

4.5 Do you believe the adoption of smart inverters would provide benefits, e.g. reduce the need for detailed studies?

AEC has not had any experience directly with smart inverters, and as such has not had a chance to assess their benefit to the DG attributes on its distribution network. Further, if these inverters do provide a technical benefit, it is unclear to AEC how this could reduce the need for detailed studies within its footprint.

MN Solar Pathways: Interconnection Streamlining Assessment

In-depth Interview Topic Guide

Respondent Name(s):	Steve Haiby, Manager of Marketing Lloyd Nelson, CFO Dan Husted, VP Business Development
Company Name:	Lake Region Electric Cooperative (LREC)
Date / Time of Interview:	June 23, 2017, 8am – 1pm CT
EPRI Interviewer(s):	Nadav Enbar, Alex Magerko

I. Background & Perspective

1.1 How many customers does your utility serve and what is the physical size of your utility's distribution footprint in Minnesota?

LREC serves rural areas via 5,000 miles of line with about 5 members per mile. LREC doesn't serve cities like Pelican Rapids (where the utility's headquarters are located), rather the rural areas surrounding the cities within the territory. Great River Energy (GRE) is a generation/transmission cooperative (G+T) provider for a number of retail distribution cooperatives, including LREC. LREC has an all-requirements purchase contract with GRE. However, this contract does allow LREC to purchase or self-supply up to 5% of its requirements from renewable resources. LREC is currently examining its sourcing options for this 5% tranche of power; some is coming from recent LREC-owned community solar projects (~60kW total).

Like other Minnesota co-ops in lakes country, LREC serves a customer base notable for its make-up of seasonal versus year-round members. There are numerous higher value lakefront homes (~$200k up to $1m+). The homes are usually second/vacation homes for out-of-towners (Minneapolis/Fargo residents in their 50s/60s). These customers have disposable income and a general interest in solar, dual fuel systems, energy efficiency measures, etc. They can be considered an "opportunity population" (numbering in the hundreds) for solar/DG adoption/sign-up.

LREC's average retail electricity prices: $0.11-0.12/kWh residential, $0.08-0.11/kWh commercial.

1.2 What size (kW) classifications do you use to segment interconnection applications?

None. There are not enough interconnection requests to justify segmentation.

1.3 Are there any tools or processes you have implemented or are developing to help make interconnection faster/cheaper/better? If so, please elaborate.

None. LREC follows MN's statewide 2004 interconnection rules. It has developed and posted static interconnection process documents on its website for contractors and customers to download and use: http://www.lrec.coop/products-service/renewable-energy-interconnection.

1.4 What are the most significant issues you have experienced in processing interconnection applications to date?

None so far. A couple applications have initially been missing forms, one application did not contain payment (check)… but generally, with greater process familiarity, the 1-2 contractors who are completing interconnection applications on behalf of customers are making fewer mistakes. The process seems be working for as little as LREC members use/access it.

1.5 What tools do you use to ensure the privacy and security of your customers' information?

Interconnection applications are kept private on servers behind LREC's firewall (just like monitoring of cyber systems and membership databases). None of the information is ever shared outside of LREC in something like a public queue, for example.

Advanced Metering Infrastructure (AMI) data is currently communicated over power line carrier; this will be updated in the future to more secure mediums. Future communications would be based on radio frequency (RF) or Internet applications and would be safeguarded through encryption technologies.

In the future, distributed generation site locations and details could be shared without providing any customer-related information. Cellular or RF technology could be utilized to communicate directly with consumer appliances based on load usage. The communications package would need specific locations, but that information would be segregated and not made public.

1.6 Please complete the below table to provide background on historical/anticipated interconnection applications received by your utility:

In general, most new solar development projects completed in the near-term are expected to be initiated via LREC initiatives (e.g. utility-owned community solar development, a wind-solar-storage hybrid installation/microgrid, etc.). LREC is motivated to take on PV development as a new revenue generating service, and has

recently launched its GoWest Solar program, a distributed ground-mount initiative in which LREC installs/maintains new PV systems while customers receive savings via a defined, non-NEM rate structure.[49]

LREC has a total of 32 DER interconnections since 2003?

- 14 are PV systems
- 18 are wind (non-PV)

Most of the early development was wind. Solar development didn't start until 2013. In the last 12 months, 1 residential rooftop system (10.9kW nameplate) was interconnected

Question	< 10 kW	10-40 kW	40-500 kW	> 500 kW
How many MW of PV and non-PV DER[50] are currently interconnected	PV= .05682 non-PV= .0201	PV= .0858 non-PV= .179	PV= 0 non-PV= 0	PV= 0 non-PV=
How many PV and non-PV DER systems are currently interconnected	PV= 12 non-PV= 8	PV= 2 non-PV= 10	PV= 0 non-PV= 0	PV= 0 non-PV= 0
How many applications did you process in the last 12 mos. *(May '16 - May '17)?*	0	1 rooftop residential system 10.9 kW	0	0
What % of all applications in the last 12 mos. were incomplete when received *(May '16 - May '17)***?**	N/A	100%	N/A	N/A
What % of applications in the last 12 mos. have been approved *(May '16 - May '17)***?**	N/A	100%	N/A	N/A
What % of applications approved in the last 12 mos. have been installed *(May '16 - May '17)***?**	N/A	100%	N/A	N/A
Do you conduct a preliminary technical review for each of the project size categories (Y/N)	Y	Y	Y	Y
In the next 3 years, what are your projections for the level of interconnection applications received? (If possible, please break out for each year.)	If LREC installs a number of GoWest Solar systems in the coming years, it could see an increase in the number from 1 or 2, to a handful per year.			

1.7 How many community solar installations, if any, are currently interconnected in your service territory and what is their cumulative capacity? How many community solar

[49] The GoWest Solar Program is intended for westward-facing (240°) arrays to help LREC offset peak load. Estimated payback is ~11 years (~10% rate of return), with tax credit and via rate schedule remuneration.
[50] DER = Distributed energy resources and includes PV and other small generators.

projects are in the queue? How many community solar projects have, over the last two years, been canceled?

There are 2 installed community solar installations, one 40 kW (commissioned in 2013) and one 24 kW (commissioned in 2015). Both installations are co-located on LREC's HQ premises (adjacent to one another) and are fully owned and operated by the utility. The program is fully subscribed with a total of 120 panels sold to 120 subscribers, a process that proceeded quickly after financing was offered.

LREC sold out about half of its community solar capacity within 6 weeks, but further interest quickly tapered. To sell the remaining subscriptions, it offered an "EasyPay" interest free financing option to customers, where a monthly fee was added to customer electric bills. With this option, all remaining subscriptions sold out quickly.

There is interest within co-ops to continue with community solar projects, but there is no imminent project in the queue. In general, most new solar development projects completed in the near term are expected to be initiated via LREC initiatives (e.g. utility-owned community solar development, a wind-solar-storage hybrid installation/microgrid, etc.). LREC is motivated to take on new PV development as a new revenue generating service (instead of ceding that opportunity to a developer). It wants to be the energy services provider of choice and have revenue and margins funneled through its co-op... especially given flat load growth/sales. Community solar represents a new opportunity. LREC does everything itself – it uses internal people/resources to build/maintain the arrays – and capitalizes that into the cost of the solar garden (ultimately allowing the co-op to be reimbursed).

Terms of community solar agreement: Customers lease panels for 20 years, paying them off over 3 years and benefitting from their generation thereafter. Payback is 16-17 years, and customers may only purchase as many panels as would equal their average energy usage.

1.8 Are there private sector community solar project(s) in your service territory? If so, do they use the same interconnection procedure as individual applicants?

No. LREC keeps all community solar projects in-house.

1.9 For approved project applications (both installed and not pursued) in the last 12 months (May '16 - May '17), what number and percent have required utility infrastructure upgrades (categorized by cost)?

Zero. The lone upgrade did not occur in past 12 months. It was associated with the community solar array installations. As part of the interconnection, LREC added a new service with metering, a single phase distribution line, and pad mounts, at a cost of ~$5-

10k. The infrastructure upgrade costs were incorporated into each community solar project price and subsequently spread out among subscribers.

Most of the other interconnection projects were too small to require upgrades. In general, LREC has only had to do a couple of upgrades for larger capacity DG (usually wind turbines) to increase transformer capacity from 15kVA to 25-37.5 kVA, at a cost of $400-750 per transformer.

Cost of Upgrade	Number of Projects Requiring Upgrade	Percent of Total # of Apps
$0-$9,999	1	100%
$10,000 to $49,999	N/A	N/A
$50,000 to $100,000	N/A	N/A
>$100,000	N/A	N/A

1.10 Have the values entered into the table in Question 1.9 significantly changed from prior years? If so, in what way?

N/A

1.11 For all approved project applications in the last 12 months, what number and percent were not pursued by the customer due to upgrade requirements as a condition of interconnection?

None.

1.12 What tools and systems (business and technical) are used in your utility's interconnection process?

The primary tool used is an Excel spreadsheet which relates relevant project details and dates.

Process	Tool/System	How do you use it?	Used for something other than PV/DG?	In House/ Commercial
Business Management Systems	Excel	Keep track of timeline/process (e.g. when app is received)	No	In House
	NISC	Utility bill payment		
Systems for Technical Review	TWACS	Meter communication		
	Load Management			

	Data retrieval			
	SCADA			

1.13 How many utility staff are currently available to perform *administration and processing* of interconnection applications? What is the estimated total staff-hours (alternatively: staff-years) for this effort?

1.5 FTEs work extensively on the GoWest Solar program (one person does the solar design, another does engineering study, if needed) and both will divert attention to interconnection requests as they come in. Both are engineers. One FTE will coordinate just about everything in the process, but perform other work most of the year. 15-20 staff-hours needed per project.

1.14 How many utility staff are currently available to perform *screening and detailed studies* of interconnection applications? What is the estimated total staff-hours (alternatively: staff-years) for this effort?

1.15 LREC has, to date, not done any detailed engineering studies. It has 1 FTE engineer to perform such studies, but depending on workload, detailed studies would likely be contracted out to an engineering consulting firm. LREC uses consulting engineering firms for non-interconnection-related tasks; it already has a blanket NDA with them in place.

II. Interconnection Process – Getting into the Details

Pre-Application

2.1 Does your utility provide a pre-application report when requested? If not, please skip down to the "Receiving Application" section of the questionnaire.

LREC has not been asked for or issued a pre-application report to date. It intends to provide a site visit, solar assessment, and courtesy report free of charge for its new GoWest Solar offering, but this would be different than a pre-application.

For pre-application, LREC would likely use its SCADA system to, for example, examine peak load on a line section.

2.1.1 If so, how much does a pre-application report cost and how quickly does your utility provide the report to requesters?

Unsure. Potentially $0 for an initial look at a given site, and then if questionable, LREC would require a full application to be submitted (likely to include an engineering study)

2.1.2 Is a non-disclosure agreement (NDA) required to provide the pre-application report data? If so, is the NDA partial or comprehensive?

N/A

2.1.3 Is an aerial map needed to complete a pre-application report?

N/A

2.1.4 Approximately how many applicants have requested a pre-application report to date?

None.

Receiving Application

2.2 What is the fee to submit an interconnection application?

Per 2004 MN schedule: $100 (<20kW), $500 (20kW-250kW), $0 if certified.

2.3 What are the different means by which you can accept interconnection payments from customers (e.g. application fees, study fees, etc.)? In what form are payments typically submitted?

Check or credit card, either mailed or otherwise brought to the LREC offices.

LREC does accept online payments for retail bills (~40% of customers use this option), so there is an existing back office infrastructure for LREC to potentially integrate a mechanism for submitting interconnection payments online. However, LREC would have to look at the invoice and determine how best to line item the transaction into the bill. It would also need to figure out how to tie things to the work orders, develop a form, establish a way to accept payment, assure data integrity, etc. This process would likely be involved.

2.4 How does your first contact with the DER customer typically occur? Which utility department is responsible for replying to initial customer inquiries, and what is their standard procedure? Do you designate a single point of contact for the applicant? At what point in the process is this designation made?

Customers/contractors can initially contact the utility by phone, email, or in person to ask about the process. LREC used to be contacted more frequently, but, with greater contractor awareness/familiarity with the process, applications are now just coming in without much consultation.

Once LREC receives an application and payment, it goes straight into the review process. Per the 2004 statute, the utility has 10 days to respond to the applicant about whether any changes are needed. LREC typically turns around a letter or email of approval/response in 2 days. The email/letter contains primary LREC contact's information for follow up.

2.5 What are the possible ways applications can be submitted for different PV system/size classifications (e.g. online, by mail, in person, etc.)? Can customers attach supporting documents and use an electronic signature?

Everything is submitted in paper copy. No electronic signature is available.

2.6 Are application forms available online, along with clear, step-by-step instructions? Is a checklist available online (or otherwise) to help customers and contractors complete DG applications?

Yes, application forms are available online, as well as supporting information that provides a procedural step-by-step (mostly all derived from the 2004 standard). LREC does not currently have a summary checklist. This is a potentially low hanging fruit opportunity for improvement.

2.7 Can contractors fill out applications on behalf of customers? If so, do you train contractors to fill out the applications and go through the interconnection process?

Yes, contractors can fill out the application on behalf of customers as well as submit payment on their behalf, but the customer's signature is still required. No training is provided by LREC to contractors.

2.7.1 Are training materials published and events hosted to train new and existing contractors?

No, but LREC is available for a phone calls should a contractor need assistance.

2.8 Who reviews the application for completeness and approval (if different)? Who contacts the customer to inform them whether the application is completed adequately and/or whether it has been approved? Is this process automated in some way?

One person, (an engineer) will review the application, but will not send a confirmation of receipt unless something is missing. The engineer will call the customer/contractor for missing info. There is no automation.

2.9 What is your typical response time to customers after receiving complete and incomplete applications? What factors most affect this response time?

LREC does not confirm receipt of application/check from customers. It responds with approval or follow up notice… typically within 48 hours.

2.10 After an application is received, what tools are used to store and access its information? Who has access to the application once it is received (or in your database)?

Information is input into a database and an Excel spreadsheet containing chronological steps. The spreadsheet and database are accessible to all internal staff.

2.11 Can the customer/contractor access their application information online? If so, what project details and status information are accessible?

No.

2.12 How do you communicate to customers (verbal, written, email) and at what steps of the application process? What level of detail is provided and at what point is this communicated (e.g. application completeness check, preliminary response, status update)?

Every aspect goes through the single engineer/coordinator. Communication can be via letter, email, or phone, as appropriate. If the application is approved as submitted, notification is sent as approved by means of mail or email. If not complete, applicants are notified by either phone, email, or mail. After a quick preliminary review, notification is again sent via email or mail that project has been approved. LREC provides applicants with utility contact person info, any estimated engineering costs if needed, any construction cost estimates if needed, schedule comments, general liability insurance requirements, and the interconnection agreement.

2.13 Are applications added to the queue on a first-come-first-serve basis? Under what circumstances, if any, are applications rearranged in the queue? (e.g. if a material modification were made)

Yes, but the queue is quite flexible; it is sufficiently sparse that projects can be concurrent without any adverse effects. LREC will allow up to 6 months before ultimately kicking an unresponsive applicant out of the queue, but they will send them a reminder at ~5 months (email or call) as a status reminder.

2.14 Does your utility post a single publicly available queue? If so, how frequently is it updated?

No.

2.15 What, if any, policy does your utility adhere to for defining when timelines on application deadlines can be extended? Does the utility apply a blanket policy for extending timelines?

LREC has a very loose timeline to begin with (it keeps applications active for up to 6 months), so it does not have rigid procedures on if/how deadlines can be extended.

2.16 Does your utility provide guidance on interconnection costs that improves cost predictability and certainty (e.g. unit cost guides, interconnection cost envelope)?

It usually costs applicants ~$500 to perform an upgrade. Costs could be more depending on what is required, but since interconnections requiring an upgrade have almost never happened, no additional insurance or envelope has been established as yet.

Expedited / Fast Track / Screening Process

Note: These processes may go by different names and contain a range of nuances, but they usually comprise a simplified application path for smaller (often inverter-based) generation systems (<50kW) that do not require in-depth engineering studies. They usually include the following general steps:

a.) Initial communication with potential applicant
b.) Utility review to classify proposed project and screening requirements
c.) Application filing
d.) Applied screens (including supplemental screens, if necessary)
e.) System Installation, testing, and inspection
f.) Final acceptance

2.17 Does your utility have an expedited application process for reviewing PV projects (i.e. established screens vs. unique engineering judgement for every application)? Please elaborate.

No.

2.18 If so, at what kW rating do you waive screens and automatically accept an application?

LREC does not automatically screen applications.

2.19 Are there any steps in your expedited interconnection review process that are automated? If so, what is the level of automation for each?

No, everything is done manually. There are multiple steps that LREC believes need human judgment/interaction. For example, the actual review of the submitted documents, personal contact with contractor or utility member, etc.

2.20 Does your utility contract out interconnection application review (including screening and engineering study) to subcontractors? If so, roughly what percentage of application

review is outsourced? What quality controls have been implemented to assure appropriate review?

This has not yet been done, but LREC would consider subbing out engineering review work to a contract engineering firm with which it has a relationship.

2.21 Do you use any automated or manual screens for certain PV size classifications?

No, there is no PV size segmentation, nor is there a need at this time.

Application Approval and Processing

2.22 What tracking tools do you currently use for applications throughout the interconnection process? Do your customers have access to these tools? Is tracking in real-time? Does it contain features such as automatic reminders? Can the tracking tools be integrated into your utility's website (if they are not already)?

LREC manually updates an Excel spreadsheet to document and track an application's progression through the interconnection process. Customers do not have access to the spreadsheet.

2.23 Which steps in the approval process are most commonly not passed the first time? What are the most common reasons for not passing and what measures are typically taken in these situations?

Missing documents or application fee.

2.24 What, if any, is your procedure for adding DER into the utility's Geographic Information System (GIS)? At what point in the process does this occur? How often does this happen (daily, weekly, monthly)?

DER is entered manually into GIS on an as needed basis by the GIS department after a system has been installed and commissioned.

2.25 What is your procedure for installing new meters? When does that happen? Does your utility charge metering fees when the meter has to be replaced?

LREC no longer has to swap out the meter since all new meters are "multi-register" AMI meters (they record total flows both into and out of customer loads). Previously, LREC used to charge a $200 metering and equipment charge to swap in a NEM inverter.

Detailed Study Process

2.26 Please explain criteria that trigger a more detailed study (which entails greater depth of review beyond what is pursued via the expedited or Fast Track process)?

The unofficial "screening engineer" (same as interconnect coordinator/engineer) would determine if it needs further study based on 2004 statute guidance.

2.27 What does a detailed study typically involve?

LREC has yet to complete a detailed engineering study.

2.28 What is your typical completion time for a detailed study?

N/A. LREC would comply with a 30-day deadline to turn around a detailed study.

2.29 What are the most common obstacles to completing a detailed study in a timely manner?

N/A.

2.30 Do you typically have all the information/data you need when you start a detailed study? If not, what missing information is most likely to cause delays?

N/A. The only info needed thus far for preliminary review has been one-lines and location. A detailed study has not had to be completed yet at LREC.

2.31 Who communicates with the customer before, during, and after the detailed study process? What is the typical content of these communications?

Prior to the engineering study, the LREC coordinator/engineer would hypothetically provide the customer with a written report of expected costs. Beyond this, no set procedure is known (as LREC has never completed a study).

2.32 Are third-party consultants utilized for detailed studies? If so, for what percent of studies?

They have not yet been needed. In the near term, LREC will use contractors for 100% of in-depth studies that cannot be reasonably handled by quick engineering department analysis.

2.33 What tools and resources do you use during the detailed study process? Modeling and load flow analysis tools? Commercially-produced or in-house?

LREC currently would use its SCADA system to determine peak loading at a given point. For more detailed analysis, LREC would look to its partner, Great River Energy, to utilize what tools it would have available.

2.34 Do you employ electronic maps for your entire distribution system? If no, what percentage is mapped electronically? Can/do the maps feed simulation tools for performing load flow analyses?

Yes, LREC has developed electronic maps for its entire system. These are for internal use only, not for public consumption. Maps could potentially be fed into a simulation tool, but that would need to be evaluated.

2.35 Is data from all systems stored in a centralized location? If so, is this database integrated with mapping tools and application processes? Are all approved interconnection projects incorporated into utility internal mapping tools? Are PV sites added to the maps automatically?

Yes, data is stored on a centralized server inside of LREC. The database of system information does not currently integrate with mapping programs, and approved interconnection projects must be added to utility maps manually.

Summary Table

Interconnection Process		Which department performs step?	What Tools/Systems are used?	What data is needed?
All Applications	**Inquiry Received & Responded**	Service representative or Engineer/ Interconnection Coordinator	None (phone, email, or in-person)	None
	Application Received	Engineer/ Interconnection Coordinator	Excel	Customer & system information and timeline dates
	Application Fee Received (for systems > 20kW)	Interconnection Coordinator/Cashier	Front office cashier or typical ratepayer payment office	Payment information
	Application Receipt Notification sent to customer	Typically, not done	N/A	N/A
	Application reviewed for completeness	Engineer/ Interconnection Coordinator		
	Application Status Notification sent to customer (complete or incomplete)	Engineer/ Interconnection Coordinator	Email, mail	
	Application Tracking (communication with customer throughout)	Engineer/ Interconnection Coordinator		
	Application sent for screening/review	Engineer/ Interconnection Coordinator		
Case 1: Expedited / Fast Track / Simplified Process	**Screening or Technical Review**			
	Application Approved	Engineer/ Interconnection Coordinator		
	Request for Meter Set	Not necessary	N/A	N/A

	Add DG system to utility mapping	Engineering		Precise location. Coordinates?
	Verification Test	Interconnection Coordinator		
	Final Acceptance	Interconnection Coordinator		N/A
Case 2: Detailed Study	**Preliminary technical review**	None (phone, email, or in-person)		
	Estimate of detailed study if needed to customer			
	Payment received	Interconnection Coordinator & Cashier	Front office cashier or typical ratepayer payment office	
	Data request to customer	Engineer/ Interconnection Coordinator		
	Detailed study	Contractor	SCADA system	
	Application Approved	Engineer/ Interconnection Coordinator		
	Request for Meter Set	Not necessary	N/A	N/A
	Add DG system to utility mapping	Engineering		
	Verification Test	Engineer/ Interconnection Coordinator		
	Final Acceptance	Engineer/ Interconnection Coordinator		N/A

2.36 Does your utility have a permission to operation (PTO) timeline incorporated into its interconnection procedures?

No.

2.37 To what degree, if at all, do you provide interconnection reports to a state agency (e.g. MN DOC, PUC, etc.)?

Annually with Great River Energy for their reporting.

2.38 Do you report on compliance with meeting application processing deadlines?

No, but it is fairly easily to conform to deadlines when there are only 1 or 2 applications per year.

III. Perspective & Expectations: Online Portal

3.1 What steps, if any, have you investigated or taken to streamline the interconnection process? What is the rationale(s) guiding these activities? What have been the greatest obstacles?

LREC has usually 1-3 interconnection requests per year, so it has not given much thought to how to streamline the process. It has not experienced any volume-related issues, so process reform is a low priority. Low hanging fruit opportunities might include the development of an online checklist to chart the evolutionary status of applications.

3.2 What steps, if any, have you investigated or taken to develop an online portal? What is the rationale(s) guiding these activities? What have been the greatest obstacles?

LREC does not have a portal or plans to develop one. While it could be done, the utility would be opposed to any mandate requiring the creation of an online portal.

3.3 What longer-term (5+ years) aspirations do you have for streamlining the interconnection process?

LREC can potentially streamline its process by simply doing more interconnections so that they become more familiar with internal requirements. Longer term aspirations might include shorter, simpler application individualized specifically for wind or solar

IV. Miscellaneous Questions

4.1 Does your company maintain a checklist for all on-site inspections? If so, are these checklists publicly available to customers and contractors, allowing them to better meet all requirements?

No, but contactors already know what to do.

4.2 If revised standardized interconnection procedures are implemented, what hypothetical requirement(s) would concern you the most as being difficult or impractical to comply with (e.g. communication, reactive power setting, other)? Are there constructive solutions/alternatives that you have developed or would suggest?

In general, LREC wants to avoid updating MN interconnection standards with mandates and “thou shalt” language. To the extent possible, it’d like to keep the interconnection process for <40kW systems simple (e.g. have a 1-page application form, etc.). LREC would like to see improvements to the 2004 standard that break out the process for each type of generation (e.g. keep the application to one page for PV (of a certain size) and have a separate one-page application specific to rotational devices.)

4.3 Some utilities keep a periodically updated map/database of distribution-level PV/DER hosting capacity to easily identify strategic locations for PV. Do you do this? If so, what is your utility’s preferred frequency and timing for updating these maps?

No, it does not have hosting capacity maps. Investigation is undertaken on a case-by-case basis.

4.4 Do you currently have access to interconnected/operational DER performance data? If so, how does such visibility support utility planning or operations? If not, is there value in gaining such visibility (e.g. operational visibility and data resolution) regarding DER performance? At what scale of DER or type of DER is this most relevant?

LREC only has access to meter data for behind-the-meter PV systems (it cannot isolate an array's total production). It will have separate monitoring installed on all of its GoWest Solar projects.

4.5 Do you believe the adoption of smart inverters would provide benefits, e.g. reduce the need for detailed studies?

LREC is interested more in energy management system benefits, less so on smart inverters (other than how they might be able to control PV as part of an EMS command). It hopes to gain an understanding of when loads occur relative to when PV energy is produced using lots of sub-metering.

MN Solar Pathways: Interconnection Streamlining Assessment

In-depth Interview Topic Guide

Respondent Name(s):	Jennifer Peterson, Policy Manager, Regulatory Affairs Jason Christoff, Electric Meter Engineer Katie Frye, Products & Services, Renewables Paul Helstrom, DG Program Lead Cody Gustafson, Distribution Planning Engineer Kevin McLean, Distribution Engineer
Company Name:	Minnesota Power (MP)
Date / Time of Interview:	June 29, 2017 @ 8am – 12pm
EPRI Interviewer(s):	Nadav Enbar, Alex Magerko

I. Background & Perspective

1.1 How many customers does your utility serve and what is the physical size of your utility's distribution footprint in Minnesota?

Minnesota Power is an investor-owned utility serving customers over a 24,000 square mile service territory. MP, headquartered in Duluth, MN, serves 145,000 residential customers, 16 municipalities and some of the nation's largest industrial customers. MP's footprint is large and supports a diversity of communities. Of the utility's 145,000 customers, 35,000 fall below the federal poverty line. Its load growth center is Duluth. It has 164 substations and the following transmission and distribution lines: 8 miles of 500kV, 29 miles of 345kV, 465 miles of 250kV, 632 miles of 230kV, 43 miles of 161kV, 128 miles of 138kV, 1,221 miles of 115kV and 6,216 miles of less than 115kV.

MP has an inclining 5-tier residential rate that starts at $0.0509/kWh, and rises to $0.07-0.11/kWh). Its GSA rate is ~$0.105/kWh; its small demand rate is $0.0789/kWh; its demand charge is $5.82/kW; its large power rate is $0.04-0.05/kWh, in addition to the demand rate. The low rates have somewhat depressed solar adoption in MP's territory and have also prevented third party operators (e.g. SunRun, Tesla, etc.) from entering

the market. (TPOs are typically looking for markets with residential rates in the $0.15/kWh range.).

MP has offered a SolarSense rebate for grid-tied PV systems since 2004.

1.2 What size (kW) classifications do you use to segment interconnection applications?

MP processes applications under 1 MW using the same general work flow. The utility has little experience with systems >1 MW, and those projects have come through RFP processes. The general process may also be applied to these systems as well. RFP'd projects do not go through the same regulatory process as customer-driven projects; customer- and utility-driven projects are processed in slightly different lanes/channels.

1.3 Are there any tools or processes you have implemented or are developing to help make interconnection faster/cheaper/better? If so, please elaborate.

Yes, MP has implemented work process improvements over the past 3 years and continues to refine its processes. Improvements include making applications available on the utility website (https://www.mnpower.com/CustomerService/DistributedGeneration) as fillable PDFs, mapping the work and customer contacts through process flows, and establishing the roles of key company contacts to acceptance review and approval of applications.

MP manually fills out a number of PDFs that track to the interconnection process:

- A statewide contract
- Preliminary site visit form / Pre-site checklist to verify equipment on site
- Checklist for commissioning test (bi-direction meter, anti-islanding witness test)
- Application acceptance letter
- SolarSense rebate form

1.4 What are the most significant issues you have experienced in processing interconnection applications to date?

Matching resources to the low volume of installations in the past and present while preparing for potential future growth is an issue. MP has since established a single point person (who leads the utility's newly created renewable programs area). How and when to invest in software and other resources is another frequent question (i.e. justifying resources to help automate the process given low levels of penetration). MP is actively pursuing development of tools internally based on perceived need.

1.5 What tools do you use to ensure the privacy and security of your customers' information?

Information submitted to MP is kept inside its networked and secured systems. Private data could only be accessed through express permission from customers. MP has a single point of contact for customers or installers to ask questions about applications.

1.6 Please complete the below table to provide background on historical/anticipated interconnection applications received by your utility:

MP has offered DG customer programs since 2004, and now has as many as 200 DG systems operating in its service territory. In 2016, it interconnected its first ~1 MW PV system, and has since interconnected a 10-MW project. Several additional co-located projects (summing to 400 kW) as well as another 10 MW project are in the pipeline.

Approximately 20-30 new PV systems have been annually installed over each of the last 5 years. Looking ahead, MP expects greater demand to emerge, especially from the commercial/municipal segment, due to improving paybacks, consistent demand, and recent incentive increases. A rate review could also stimulate interest as has been witnessed by MP in the past. In 2018, installs will likely number over 50-60.

Question	< 10 kW	10-40 kW	40-500 kW	> 500 kW
How many MW of PV and non-PV DER[51] are currently interconnected	PV= ~700 kW non-PV= 25 kW	PV= ~550 kW non-PV= ~165 kW	PV= ~55 kW non-PV= 0 kW	PV= ~940 kW non-PV= 0 kW
How many PV and non-PV DER systems are currently interconnected	PV= 150 non-PV= 7	PV= 34 non-PV= 9	PV= 1 non-PV= 0	PV= 1 non-PV= 0
How many applications did you process in the last 12 mos. *(May '16 - May '17)?*	0-40 kW PV- ~55		0	
What % of all applications in the last 12 mos. were incomplete when received *(May '16 - May '17)***?**	15-20%		N/A	N/A
What % of applications in the last 12 mos. have been approved *(May '16 - May '17)***?**	100%	100%	N/A	N/A
What % of applications approved in the last 12 mos. have been installed *(May '16 - May '17)***?**	For 2017 apps: 4/53 so far or 8%		N/A	N/A
Do you conduct a preliminary technical review for each of the project size categories (Y/N)	Yes	Yes	Yes	Yes
In the next 3 years, what are your projections for the level of interconnection applications received? (If possible, please break out for each year.)	Increases each year: 2018 = ~30 2019= ~40 2020= ~50	Increasing yearly: 2018= ~40 2019= ~50 2020= ~60	2018-2020= ~10	2018-2020= ~5

[51] DER = Distributed energy resources and includes PV and other small generators.

1.7 How many community solar installations, if any, are currently interconnected in your service territory and what is their cumulative capacity? How many community solar projects are in the queue? How many community solar projects have, over the last two years, been canceled?

MP's Community Solar Pilot is the only project for shared solar systems, and is not yet fully operational. The pilot program consists of two arrays, an operational 40-kW array in Duluth, MN and a to-be-constructed 1-MW+ array in Carlton County, MN (part of a PPA). There has been lots of interest in the program. Full implementation is anticipated by the end of year, and MP is currently taking subscriptions. MP owns the 40-kW array. The 1-MW array is owned and operated by a solar developer, with the energy contracted for under a PPA.

There are currently no additional community solar projects in the queue and no projects in the last two years that have been cancelled.

1.8 Are there private sector community solar project(s) in your service territory? If so, do they use the same interconnection procedure as individual applicants?

No. Community solar projects are the outgrowth of RFPs issued by MP.

1.9 For approved project applications (both installed and not pursued) in the last 12 months (May '16 - May '17), what number and percent have required utility infrastructure upgrades (categorized by cost)?

Cost of Upgrade	Number of Projects Requiring Upgrade	Percent of Total # of Apps
$0-$9,999	8	~15%
$10,000 to $49,999		
$50,000 to $100,000		
>$100,000		

1.10 Have the values entered into the table in Question 1.9 significantly changed from prior years? If so, in what way?

The cost for solar has decreased, and coupled with incentives may be a driving force of larger systems. This emerging trend seems to push more installations into a transformer upgrade. Currently, about 10% of systems require a transformer upgrade, but this depends on the site and size of the system. Another common upgrade is the changing of meter sockets to MP's standard for lever bypass meter sockets.

1.11 For all approved project applications in the last 12 months, what number and percent were not pursued by the customer due to upgrade requirements as a condition of interconnection?

No customers expressed that upgrade needs were a barrier to completion. Typical upgrades are confined to a meter socket or transformer upgrade, which the customer pays for, but are not a major cost component in the overall cost to install.

1.12 What tools and systems (business and technical) are used in your utility's interconnection process?

MP uses typical office software like Excel spreadsheets, and also GIS for application information, mapping, and eventually tracking progress of applications in process. GIS may also be used for looking at MP system maps.

Process	Tool/System	How do you use it?	Used for something other than PV/DG?	In House/ Commercial
Business Management Systems	Excel			
	Microsoft Access	Used as database of customer information (phased out in favor of GIS)	Yes	Commercial
	ArcGIS			
	Google Earth/maps			
	PDF			
	CC&B (CIS – Oracle)	Work orders, tracking capital and O&M costs		
	No MDM like PI yet (in works for 2018)			
Systems for Technical Review	SINCAL	Analysis of DG system electrical impacts	Yes	Commercial
	PSSE	For large utility scale installations, the impact on the transmission system is evaluated	Yes	Commercial
	Milsoft	Analysis of DG system electrical impacts	Yes	Commercial
	Meter data recording (getting	Max's and min's. Might get waveforms		

	phased out with new AMI meters)	with trips (rarely used)		

1.13 How many utility staff are currently available to perform administration and processing of interconnection applications? What is the estimated total staff-hours (alternatively: staff-years) for this effort?

Two: one person as central contact and coordinator between applicant and company. It typically takes ~4 hours per application to cover all of the administrative/processing work for each application. One person probably needs 15 minutes per app to set up service points and associated work orders.

1.14 How many utility staff are currently available to perform *screening and detailed studies* of interconnection applications? What is the estimated total staff-hours (alternatively: staff-years) for this effort?

Two: one person in electrical engineering, one in meter engineering. Additionally, 1-2 meter techs in each area of MP's service territory (northern, western and central) to gather information needed for the engineering screens/studies.

II. Interconnection Process – Getting into the Details

Pre-Application

2.1 Does your utility provide a pre-application report when requested? If not, please skip down to the "Receiving Application" section of the questionnaire.

There is no formal process. If requested, MP will do informal, preliminary site visits for free through its Solar Energy Analysis (SEA) program. These can be arranged via email and also occur through info exchange during phone conversations. The consultations can be both in-person and via phone consultation, and surround issues regarding load info, seasonal variability, system size and cost, etc. MP will package usage data to potential applicants to illustrate average consumption and billing with and without solar. In addition, it will provide a list of installers.
MP is motivated to offer this consultation service to help customers do what is best for themselves, to improve rapport with customers broadly, to meet the MN 1.5% solar energy mandate, and to help inform future program offerings.

2.1.1 If so, how much does a pre-application report cost and how quickly does your utility provide the report to requesters?

N/A. The consultation is free.

2.1.2 Is a non-disclosure agreement (NDA) required to provide the pre-application report data? If so, is the NDA partial or comprehensive?

There is no need for an NDA unless the applicant is pursuing a rate to share avoided costs.

2.1.3 Is an aerial map needed to complete a pre-application report?

An aerial map is not required, but some sort of address or coordinates is. In talking with a customer, MP will then verify that a Google Earth address or coordinates coincide with the desired location/site and check basics (like significant shading) remotely. Location will later be verified if/when meter techs do a site visit to avoid a scenario seen in the past where installers have submitted applications referencing the wrong property due to a Google Earth error.

2.1.4 Approximately how many applicants have requested a pre-application report to date?

MP has done a total of ~50 consultations, out of which 8-9 folks wound up installing a PV system (~20% hit rate). A few more have applied and a few more are still seriously considering.

Receiving Application

2.2 What is the fee to submit an interconnection application?

There is no application fee for systems <40kW, which represent the majority of applications (system sizes typically ranged 12-20kW). This will probably change if interconnection requests increase and cause greater administrative burden/cost, but MP is not sure at what point it will be worth the upgrade cost to set up an automatic payment system.

Fees are, however, collected for system applications >40kW. This fee covers the initial screens. Engineering study fees are actual cost. MP has, to date, only had to do one engineering study on a large (1 MW) installation and contracted this work out. Other studies requiring a fee required substantially less rigor. The fees charged follow the current (2004) statewide interconnection standards under “other extended parallel

systems:

Generation Interconnection Application Fees

Interconnection Type	≤ 20kW	>20kW & ≤250kW	>250kW & ≤500kW	> 500 kW & ≤1000kW	>1000 kW
Open Transfer	$0	$0	$0	$100	$100
Quick Closed	$0	$100	$100	$250	$500
Soft Loading	$100	$250	$500	$500	$1000
Extended Parallel (Pre Certified System)	$0	$250	$1000	$1000	$1500
Other Extended Parallel Systems	$100	$500	$1500	$1500	$1500

2.3 What are the different means by which you can accept interconnection payments from customers (e.g. application fees, study fees, etc.)? In what form are payments typically submitted?

Typically, paper check or cash are the only accepted payment types for interconnection fee payments. MP can also accept wire transfers for engineering studies of large systems.

2.4 How does your first contact with the DER customer typically occur? Which utility department is responsible for replying to initial customer inquiries, and what is their standard procedure? Do you designate a single point of contact for the applicant? At what point in the process is this designation made?

MP's website contains a solar guide that explains how solar works. (The first version was created in 2015 and is updated every year) It also includes static documents describing the interconnection process and how to hire a contractor. A sample application, bill sample, and list of incentive programs are also available. In addition, the website provides a link to PV Wats.

Very rarely do customers apply directly. MP receives most of applications from contractors (via email).

Once the customer/contractor is ready to proceed, the DG Program lead serves as a main liaison. He/she creates a preliminary review checklist and does an upfront review of shade analysis, one-line site diagram, and other documents. The DG Program lead then enters the application information into an Excel record keeping sheet and instructs the design representative to create a work order number (used for meter tech site visits later on).

2.5 What are the possible ways applications can be submitted for different PV system/size classifications (e.g. online, by mail, in person, etc.)? Can customers attach supporting documents and use an electronic signature?

Applications can be submitted via email (with attachments) or snail mail. Emails go either to a solar email inbox or directly to the DG Program lead's inbox.

Verified electronic signature is not currently available, though digital signatures are accepted as part of fillable PDFs.

2.6 Are application forms available online, along with clear, step-by-step instructions? Is a checklist available online (or otherwise) to help customers and contractors complete DG applications?

Fillable PDFs are available online along with instructions. Instructions are not quite a checklist, but are nearly step-by step.

2.7 Can contractors fill out applications on behalf of customers? If so, do you train contractors to fill out the applications and go through the interconnection process?

Yes, in fact, contractors are typically the ones to complete and submit the fillable PDF applications.

2.7.1 Are training materials published and events hosted to train new and existing contractors?
No, but in general, the process is going more smoothly as contractors are gaining greater familiarity with it. The majority of PV installs in MP's service territory have been developed by 6 installer companies. Interpersonal relationships are also helping.

2.8 Who reviews the application for completeness and approval (if different)? Who contacts the customer to inform them whether the application is completed adequately and/or whether it has been approved? Is this process automated in some way?

The DG Program lead handles all customer-facing tasks. This is all manual and informal.

2.9 What is your typical response time to customers after receiving complete and incomplete applications? What factors most affect this response time?

Once an application is submitted, the DG Program lead will create a file folder and confirm receipt within hours. Within 1-2 days, the file folder will be reviewed for completeness. MP will send an email if anything is missing (e.g. one line, shade analysis, etc.). Subsequently, it will take 1-2 days to establish a work order and set up a service point to order a preliminary review. A preliminary review is typically issued within a few days of receiving an application.

The meter techs will get a formal field activity notice and schedule a preliminary site visit with a truck roll. (MP will try to give meter techs informal, advanced notice, especially if they know the technician will be in the vicinity of an application site already.) During the site visit, the meter techs will collect different data point: wire sizes/lengths, confirmation of service, meter/socket inspection (CT cabinets), voltage checks, etc. They will try to complete the site review within a week, but it depends on their work schedule. (It has never taken a week to schedule an inspection/review.).

Once the meter techs report back their information gather, the application will be submitted to engineering to do the screens. The screens can take 1-4 days. Once the screening report has been issued, it takes 0-2 days to get a notice to the installer either of approval or required engineering study and associated cost. Generally, the process is completed within 15 working days.

Delays to the above process are usually due to staff resource availability (e.g. work load, vacations) or meter techs not being in an area for a while. Another issue is the cyclical nature of the rebate program which tends to lead to clusters of applications just before or after significant dates (e.g. start of year). Most customer complaints have more to do with lack of communication from installers than the interconnection process and status of their applications. (Customer will often ask MP to intervene by contacting installer on customer behalf.)

2.10 After an application is received, what tools are used to store and access its information? Who has access to the application once it is received (or in your database)?

Currently, MP manually types application information into an Excel spreadsheet.[52] The spreadsheet lives in an internal network folder, behind the utility firewall, and requires permission to access.

MP is transitioning from a DG database (essentially an Access database) to a GIS process (in production through internal development efforts—it is scheduled to launch in the July/August 2017 timeframe). MP is transferring data into a GIS that can then present DG sites on a map, and can be exported as a layer to other mapping systems for use by other personnel. Eventually, the intent is field force automation in which field techs with tablets can pull up DG sites on demand.

The GIS tool will contain color coded points that indicate the status of applications/systems (i.e. icons on a map will change color as an application progresses). Dates will be logged to convey when milestones have been met. Email distribution will

[52] The Excel sheet contains the following information: name, account #, address, PVWatts analysis (azimuth, tilt, shade, etc.) for calculating rebate amount, dates (application submittal, preliminary screening date, commissioning date, etc.), and general notes.

inform staff of next steps and responsible parties. Eventually, MP envisions having histograms that illustrate how many applications are at each stage in the process.

Initially, all data will need to be manually inputted. An aspirational goal is to engineer the GIS tool to auto populate with new application data (e.g. enter an account number to have forms self-populate in GIS).

2.11 Can the customer/contractor access their application information online? If so, what project details and status information are accessible?

No.

2.12 How do you communicate to customers (verbal, written, email) and at what steps of the application process? What level of detail is provided and at what point is this communicated (e.g. application completeness check, preliminary response, status update)?

Customers receive a template email indicating when an application has been received by MP and when to expect to see a utility representative. Typically, the next communication to the applicant from MP will be an approval letter along with auxiliary documents (bill of sale to transfer ownership of meter socket to installer, contract, etc.); this letter is usually associated with the local rebate.

Most correspondence is via email, though verbal, in-person, and written forms are also used intermittently throughout the process as well. See Question 2.9 for what is communicated when.

2.13 Are applications added to the queue on a first-come-first-serve basis? Under what circumstances, if any, are applications rearranged in the queue? (e.g. if a material modification were made)

Yes, the default method is first come first serve for MP, though this is usually only important for larger proposed systems. For small scale systems, MP is more concerned with maintaining first come first serve priority as it relates to the rebate rather than feeder capacity. There is no hard deadline for booting anyone out of the queue. Xcel Energy is viewed as blazing the trail for grid queue management… MP has a lot of feeders with low load which could be overloaded pretty quickly. Some have a minimum load of 250kW. In these cases, putting in 600kW system could require pre-emptive mitigation (e.g. system protection equipment to address reverse power flow, adjustments to substation, etc.).

2.14 Does your utility post a single publicly available queue? If so, how frequently is it updated?

No. Applicants can contact the DG Program lead to verbally get an update of application status. There is no outward transparency such as a public queue.

2.15 What if any policy does your utility adhere to for defining when timelines on application deadlines can be extended? Does the utility apply a blanket policy for extending timelines?

The only significant deadline policy for DG applicants pertains to the rebate. Customers have 6 months from the time the rebate has been reserved to complete the installation. MP will grant one extension of 3 months if the applicant can reasonably demonstrate that the project cannot be completed within the original timeline (i.e. equipment unavailable, etc.).

2.16 Does your utility provide guidance on interconnection costs that improves cost predictability and certainty (e.g. unit cost guides, interconnection cost envelope)?

No. Cost estimates are good faith, +/- 10-15%. If a study is getting close to the estimate, MP will let the customer know. Thus far, this hasn't been a problem.

Expedited / Fast Track / Screening Process

Note: These processes may go by different names and contain a range of nuances, but they usually comprise a simplified application path for smaller (often inverter-based) generation systems (<50kW) that do not require in-depth engineering studies. They usually include the following general steps:

a.) Initial communication with potential applicant
b.) Utility review to classify proposed project and screening requirements
c.) Application filing
d.) Applied screens (including supplemental screens, if necessary)
e.) System Installation, testing, and inspection
f.) Final acceptance

2.17 Does your utility have an expedited application process for reviewing PV projects (i.e. established screens vs. unique engineering judgement for every application)? Please elaborate.

Nothing is "expedited" because MP does not see its standard process as a barrier to solar adoption for their customers. MP notes that the application timeline is not a substantial time sink compared to installation.

2.18 If so, at what kW rating do you waive screens and automatically accept an application?

N/A.

2.19 Are there any steps in your expedited interconnection review process that are automated? If so, what is the level of automation for each?

No. All steps are manual because information such as meter socket type might not be reliable, so MP would have to put human eyes on it anyway.

2.20 Does your utility contract out interconnection application review (including screening and engineering study) to subcontractors? If so, roughly what percentage of application review is outsourced? What quality controls have been implemented to assure appropriate review?

Most everything is done in-house, especially if only engineering analysis needed is 8760-like (steady-state) studies.

2.21 Do you use any automated or manual screens for certain PV size classifications?

Nothing is automated. Generally, preliminary screens are applied that examine minimum daytime loading, backfeed issues, transformer kVA vs. solar size, etc. Screens encompass those listed in the 2004 statute, as well as others MP has added (e.g. length of secondary run). The type of full engineering study that may be recommended will depend on violations unearthed by the preliminary screens.

Application Approval and Processing

2.22 What tracking tools do you currently use for applications throughout the interconnection process? Do your customers have access to these tools? Is tracking in real-time? Does it contain features such as automatic reminders? Can the tracking tools be integrated into your utility's website (if they are not already)?

The DG Program lead tracks interconnections through an Excel spreadsheet, and will in the future do so via ArcGIS. See Question 2.10.

MP is also currently reviewing options for a customer portal for interconnection applications. This would allow customers to submit an application online and check the status of the application. Automation of the application process has been considered several times over the last 4 years but due to low levels of penetration, MP has not been able to justify the cost of procuring a software solution. As such, internal solutions have been created. With the recent increase in solar activity due to an increased incentive budget, MP is once again reviewing portal solutions as an option.

2.23 Which steps in the approval process are most commonly not passed the first time? What are the most common reasons for not passing and what measures are typically taken?

Transformer is the #1 source of needed upgrade (extend primary line vs. put transformer closer to the service). The length of the secondary is another. Another common upgrade needed is a new meter socket. All 60 or 100 amp sockets must be upgraded to 200 amp lever bypass. 200 amp sockets are tested to determine if they need to be upgraded as well. Then it's just really about getting info from the customer (i.e. what inverter are you going to use?).

2.24 What, if any, is your procedure for adding DER into the utility's Geographic Information System (GIS)? At what point in the process does this occur? How often does this happen (daily, weekly, monthly)?

MP's GIS tool will soon replace an existing Excel spreadsheet to track/document DER interconnections. The utility will also replace its Access database for storing customer information such as addresses. This is, in part, intended to allow the utility's new construction/design reps team to enter an interconnection into MP's Oracle billing system, set up a production meter, and create a work order for the meter technicians.

Currently, MP is manually entering the same information into both Excel and GIS (a big hold-up from completing the transition to GIS is how to track rebate information – this will require a side tool.) For legacy systems, MP will scan in paper documents to match its current practice of attaching digital versions of important documents to GIS pinpoints. MP will enter information from an application once it reaches commissioning and will try to backtrack and do a few older systems at the same time. It is expected to launch a full GIS roll-out within the next several months. See Question 2.10 for additional details on GIS.

2.25 What is your procedure for installing new meters? When does that happen? Does your utility charge metering fees when the meter has to be replaced?

No fee is charged for a meter swap since the meter would eventually be replaced by MP anyway as they upgrade their infrastructure. Usually 100-amp meter sockets require an upgrade/replacement while 200 A sockets just require a check of operation.

During a meter swap, MP will inform customers of a short downtime needed to install a newer meter and verify accurate meter reads/operation. Any time a panel or the like is replaced, MP treats it as if it is new construction.

A variance request form is available online and must be submitted by the customer/contractor any time a meter is installed in a non-standard location. This form has rarely been submitted to MP as few applications have requested new meter installs in non-conventional locations.

Detailed Study Process

2.26 Please explain criteria that trigger a more detailed study (which entails greater depth of review beyond what is pursued via the expedited or Fast Track process)?

This is a customized process. A facilities study and a load flow analysis (8760 steady state analysis) will trigger a more detailed study.

2.27 What does a detailed study typically involve?

MP will look at a dynamic study (turning on inverter capabilities to rectify observed issues), voltages and capacities (generally isn't an issue), reverse flow (flowing backwards from a regulator, recloser, etc.), cloud-induced flicker, and inverter/distribution system interactions.

If a smaller service, MP will look at transformer capacity, and seasonal demand. There tend to be a lot of secondary runs for people with DG; it can be a lengthy run from the MP meter to a lake house.

2.28 What is your typical completion time for a detailed study?

It typically takes 40 hours to complete a detailed study. The vast majority of time is spent gathering the info required to do the study and the creating an accurate model. MP does not expect the turn-around in detailed study results to exceed 90 days.

2.29 What are the most common obstacles to completing a detailed study in a timely manner?

It is really about getting the info from the customer on what they want. Design can be off, customer may want to change technologies (e.g. initially having inverter x and then switching to inverter y). Once MP has the detailed one-line and a model used for running the analysis, changes need to be immaterial for them not be necessitate a repeat analysis and consequential delays.

Elements of human error will also cause delays – dropping the ball due to workload and lack of reminders, for example.

2.30 Do you typically have all the information/data you need when you start a detailed study? If not, what missing information is most likely to cause delays?

Yes, if applicants stick to their original plans and equipment suppliers. It is important that changes to system sizing, inverter/capabilities, etc. be recognized and noted.

MP will utilize meter techs as they are available since they are already in the field. The techs can gather any missing data needed: transformer data sizes, wire sizes and lengths, meter and sockets inspection, CT cabinets, voltage checks, AMI meter, etc.

2.31 Who communicates with the customer before, during, and after the detailed study process? What is the typical content of these communications?

The interconnection coordinator (DG program lead) is still the contact point. This person will often set up meetings between engineers and the customers, and may lead an internal (scoping) meeting to develop a unified perspective on individual applications.

2.32 Are third-party consultants utilized for detailed studies? If so, for what percent of studies?

Most everything is done in-house, especially when it comes to 8760-like (steady-state) studies. Recently, MP has worked with an external vendor to complete a dynamic study for a MW-scale plant. Contracting an internal vendor to conduct an analysis is dependent on the size and location of a DG installation. Currently about 1% of MP's detailed studies use third-party consultants, but as the size of DG grows larger, that amount could grow to about 5-10%.

2.33 What tools and resources do you use during the detailed study process? Modeling and load flow analysis tools? Commercially-produced or in-house?

The main ones are SINCAL (distribution equivalent to PSSE – owned by Siemens) and PSSE. MP is migrating to Milsoft's WindMil. Also a simple voltage drop calculator is used if evaluating a smaller system.

2.34 Do you employ electronic maps for your entire distribution system? If no, what percentage is mapped electronically? Can/do the maps feed simulation tools for performing load flow analyses?

No hosting capacity is conducted today. In the future, a WindMil model will be fed by GIS, but GIS info is hit or miss. Quality controls in the data have not yet been implemented. As a result, there is fear that if the PUC mandates MP to do hosting capacity, the analyses won't be as accurate as they should be due to existing data limitations. Furthermore, due to the current state of MP's distribution model, it would be a significant effort to perform system-wide hosting capacity analyses.

Hosting capacity maps are not in MP's near term plans. Penetration levels are so low that hosting capacity maps are not viewed as useful to DG customers… though larger developers might derive value. From a capacity standpoint, there may be a few circuits that are capacity constrained, but the vast majority of the MP system is voltage constrained, not capacity constrained. Bottom line: the maps might be useful, but they would require a lot of work to develop (i.e. limited bang for the buck).

2.35 Is data from all systems stored in a centralized location? If so, is this database integrated with mapping tools and application process? Are all approved interconnection projects

incorporated into utility internal mapping tools? Are PV sites added to the maps automatically?

See Questions 2.10, 2.24, and 2.33.

Tools:

- ArcGIS (mapping)
- Google Earth (for interconnection siting/confirmation)
- Excel (for documenting/tracking application process)
- PSS/E/SINCAL/Milsoft (load flow analysis)
- MSWord/PDF (applications and informational materials)
- Customer Care and Billing (CIS – Oracle; work orders, tracking, costs)
- Maxmo (tracking internal capital and O&M costs).
- No MDM implemented at this time (in the works for 2018).
- With AMI coverage expanding, MP is not doing as much sensoring because meters are issuing voltage information. A full recorder not being used as much.

Summary Table

Interconnection Process		Which department performs step?	What Tools/Systems are used?	What data is needed?
All Applications	**Inquiry Received & Responded**	Renewable Programs (RP)	Phone, Email	What is the customer asking about? Where do they live? What is their account number?
	Application Received	RP	Excel, Email, PDF	Customer info, technical specifications (one-line and site plan)
	Application Fee Received (for systems > 20kW)	N/A		
	Application Receipt Notification sent to customer	RP	Email, if none, then phone	Contact information
	Application reviewed for completeness	RP		Application, one line, site plan

	Application Status Notification sent to customer (complete or incomplete)	RP	Email	
	Application Tracking (communication with customer throughout)	RP	Email	
	Application sent for screening/review	Engineering	Email - state guidelines, and engineering software (if needed)	
Case 1: Expedited / Fast Track / Simplified Process	**Screening or Technical Review**	Engineering		
	Application Approved	Engineering		
	Request for Meter Set	RP/Metering		
	Add DG system to utility mapping	RP		
	Verification Test	Metering		
	Final Acceptance	Metering		
Case 2: Detailed Study	**Preliminary technical review**	Engineering		
	Estimate of detailed study if needed to customer	Engineering		
	Payment received	RP		
	Data request to customer	RP		
	Detailed study	Engineering		
	Application Approved			
	Request for Meter Set			
	Add DG system to utility mapping			
	Verification Test			
	Final Acceptance			

2.36 Does your utility have a permission to operation (PTO) timeline incorporated into its interconnection procedures?

No.

2.37 To what degree, if at all, do you provide interconnection reports to a state agency (e.g. MN DOC, PUC, etc.)?

MP provides annual reporting on DG systems to the MN DOC, and a solar-specific report (e.g. number of systems, RECs, compliance, etc.) to the PUC. A DG interconnection report is filed with both organizations annually.

2.38 Do you report on compliance with meeting application processing deadlines?

Currently MP does not. However, customers have the ability to file a complaint (like with all customer service issues) with the Consumer Affairs Office at the MPUC if they feel the interconnection process was insufficient in some way.

III. Perspective & Expectations: Online Portal

3.1 What steps, if any, have you investigated or taken to streamline the interconnection process? What is the rationale(s) guiding these activities? What have been the greatest obstacles?

MP recently looked at its interconnection process thru a Lean Six Sigma process. That exercise produced a lot of streamlining (e.g. pre-screening site visits, sending metering techs out on site visits, ArcGIS implementation, etc.). MP has also improved the manner in which it maintains proper documentation and is working on ways to alert the utility about, for example, solar premises that sell to a new customer ("change of hands" issues). The mechanism for automatic flagging is being explored

The utility would potentially also like to develop online customer service solutions such as checking an interconnection application status. The development of all new efficiencies would be done in-house, not through a 3rd party vendor due to costs and perception of low marginal value.

Moving away from MP's the old DG Access database should be helpful. The old DB was outdated and hard to modify. Transitioning to a GIS-based tool to integrate mapping should be a major upgrade, but the internal development process has taken a long time due to learning curve issues, as well as personnel changes.

3.2 What steps, if any, have you investigated or taken to develop an online portal? What is the rationale(s) guiding these activities? What have been the greatest obstacles?

MP has done a general assessment, but has not quantified a cost-benefit of a fully integrated online portal. The utility received budget approval to look at front-end purchases that can be integrated with its backend platform.

3.3 What longer-term (5+ years) aspirations do you have for streamlining the interconnection process?

MP would like to figure out how to manage interconnection process workflows on an organizational level, given that it touches many cross-disciplinary structures in the organization.

IV. Miscellaneous Questions

4.1 Does your company maintain a checklist for all on-site inspections? If so, are these checklists publicly available to customers and contractors, allowing them to better meet all requirements?

MP does have checklists for field inspections. These are not publicly available.

4.2 If revised standardized interconnection procedures are implemented, what hypothetical requirement(s) would concern you the most as being difficult or impractical to comply with (e.g. communication, reactive power setting, other)? Are there constructive solutions/alternatives that you have developed or would suggest?

MP generally opposes overarching mandates that apply to everyone because each utility has different processes, tools, as well as unique customers and situations. Also, the pool of customers that would pay for a capital investment would be an issue.

As far as timeline requirements, MP believes that a two-day turnaround for receiving and approving an application is arbitrary and something that should not be enforced. A mandated timeline means reporting, which adds cost/time. MP advises not mandating where there is not a problem.

4.3 Some utilities keep a periodically updated map/database of distribution-level PV/DER hosting capacity to easily identify strategic locations for PV. Do you do this? If so, what is your utility's preferred frequency and timing for updating these maps?

MP has not developed a hosting capacity analysis map as it does not currently see value for customers (penetration is low, the system is not capacity constrained), but maybe large developers could derive value. See Question 2.34.

4.4 Do you currently have access to interconnected/operational DER performance data? If so, how does such visibility support utility planning or operations? If not, is there value in gaining such visibility (e.g. operational visibility and data resolution) regarding DER performance? At what scale of DER or type of DER is this most relevant?

57,000 of MP's 144,000 meters have been equipped with AMI (full deployment is slated for 2025). MP can obtain voltage data from past DER installations when they swap out old meters with AMI. AMI has the added benefit of remote disconnect.

Residential meters give hourly data, but could be dropped down to 15 minutes or even 5 minutes… TOU is doing hourly data.

MP has required that sub-meters be installed on any new system since ~2014 to get a feel for DER production.

4.5 Do you believe the adoption of smart inverters would provide benefits, e.g. reduce the need for detailed studies?

No response.

MN Solar Pathways: Interconnection Streamlining Assessment

In-depth Interview Topic Guide

Respondent Name(s):	Jeff McKeever, Principal Engineer Dean Pawlowski, Principal Engineer Nathan Jensen, Sr. Resource Planner
Company Name:	Otter Tail Power (OTP)
Date / Time of Interview:	June 22, 2017, 8am – 12pm CT
EPRI Interviewer(s):	Nadav Enbar, Alex Magerko

I. Background & Perspective

1.1 How many customers does your utility serve and what is the physical size of your utility's distribution footprint in Minnesota?

OTP serves 423 towns at retail and delivers power to ~14 municipal utilities. It has ~130,000 customers, and has a 70,000 sq. mile footprint in Minnesota, North Dakota, and South Dakota. The average town within OTP's jurisdiction contains 320 people with average house values of less than $100k.

1.2 What size (kW) classifications do you use to segment interconnection applications?

OTP treats all generators the same; therefore, it does not use any distinguishing classifications (size, type of generation, etc.) in their applications.

1.3 Are there any tools or processes you have implemented or are developing to help make interconnection faster/cheaper/better? If so, please elaborate.

Yes. Screening used to be handled by field engineers, which was a problem. It has since been pulled into the distribution planning area where there is greater info access. Also, the frequency of review has increased internal proficiency (e.g. awareness of statutes, where to find the correct forms/data for the screening study, etc.). OTP did this because in the last three years it has seen 5-6 interconnections per year DG across its entire system. It provides basic interconnection information on a web page: https://www.otpco.com/help-center/how-to-connect-to-our-power-grid/minnesota-interconnection/.

1.4 What are the most significant issues you have experienced in processing interconnection applications to date?

The most significant challenges OTP faces are the time required to get a response from the applicant when there are follow-up questions and/or issues with one-line diagrams. These can cause delays, especially if OTP has to coordinate among multiple stakeholders (i.e. installer, engineer, etc.) where it can be hard to converse with the right person.

1.5 What tools do you use to ensure the privacy and security of your customers' information?

OTP does not publish any of its applications publicly nor does it have a public queue. Hypothetically, if it did move forward with a public queue, it would keep applicant identities confidential and show projects by queue number.

1.6 Please complete the below table to provide background on historical/anticipated interconnection applications received by your utility:

The table provided below represents the total numbers of interconnections since ~2003 from all three states in OTP's territory. Most of the solar projects are in MN and have been installed in the past 3 years thanks to existing public policies (e.g. "Made in Minnesota")

DG Technology	# Since 2003	Total Capacity (kW)
Wind	24	7,210
Steam	1	315
Solar	28	302
Small IC	1	35
Propane	1	20
Hydrogen	1	60
Total	**56**	**7,942**

**Note: DER systems span across OTP's three jurisdictions in Minnesota, North Dakota, and South Dakota. The majority of the PV installations have occurred in its Minnesota territory.*

Question	< 10 kW	10-40 kW	40-500 kW	> 500 kW
How many MW of PV and non-PV DER[53] are currently interconnected	PV= see above non-PV= see above	PV= see above non-PV= see above	PV= 0 non-PV= unspecified	PV= 0 non-PV= unspecified
How many PV and non-PV DER systems are currently interconnected	PV= see above non-PV= see above	PV= see above non-PV= see above	PV= 0 non-PV= unspecified	PV= 0 non-PV= unspecified
How many applications did you process in the last 12 mos. *(May '16 - May '17)?*	5	3	0	0

[53] DER = Distributed energy resources and includes PV and other small generators.

What % of all applications in the last 12 mos. were incomplete when received *(May '16 - May '17)***?**	Not Available	Not Available	0	0
What % of applications in the last 12 mos. have been approved *(May '16 - May '17)***?**	100%	100%	0%	0%
What % of applications approved in the last 12 mos. have been installed *(May '16 - May '17)***?**	50%*	12.5%*	0%	0%
Do you conduct a preliminary technical review for each of the project size categories (Y/N)	Yes	Yes	Yes	Yes
In the next 3 years, what are your projections for the level of interconnection applications received? (If possible, please break out for each year.)	OTP does not foresee any change that would impact the number of requests it will see. Hypothetically, OTP believes that it would see more applications if funding allocations from the sunsetting of the Made in Minnesota program were shifted to a pure solar project focus.			

*Note: *The percentage of OTP's interconnection applications that have been approved and installed is low because many projects are still under construction/development.*

1.7 How many community solar installations, if any, are currently interconnected in your service territory and what is their cumulative capacity? How many community solar projects are in the queue? How many community solar projects have, over the last two years, been canceled?

None. Current state statute does not allow for non-utility community solar in OTP's territory. (Community solar is allowed if a utility initiates and is involved in the project.) Community solar installs are a possibility in the future as they could help OTP extend solar access to ratepayers while complying with RPS/carve out objectives. Currently, however, there has not been a large number of inquiries to OTP concerning participation in a community solar program. Otter Tail will be performing market research to determine if enough customer interests exist in building a community solar garden.

1.8 Are there private sector community solar project(s) in your service territory? If so, do they use the same interconnection procedure as individual applicants?

No. If there were to be a community solar installation program, OTP would likely own the system.

1.9 For approved project applications (both installed and not pursued) in the last 12 months (May '16 - May '17), what number and percent have required utility infrastructure upgrades (categorized by cost)?

None. The vast majority of applications within the last year have been for small (10-20kW max) installations, and requests are so dispersed that there might not even be

two requests in the same town. However, a very limited number of OTP's ~500 substations could accommodate larger DG installations without significant upgrades.

Cost of Upgrade	Number of Projects Requiring Upgrade	Percent of Total # of Apps
$0-$9,999	N/A	N/A
$10,000 to $49,999	N/A	N/A
$50,000 to $100,000	N/A	N/A
>$100,000	N/A	N/A

1.10 Have the values entered into the table in Question 1.9 significantly changed from prior years? If so, in what way?

No. There has, to date, been little required upgrade. The majority of the upgrades over the past several years have been to allow flow back onto the transmission system.

1.11 For all approved project applications in the last 12 months, what number and percent were not pursued by the customer due to upgrade requirements as a condition of interconnection?

None. No project proposal has yet to require significant upgrade.

1.12 What tools and systems (business and technical) are used in your utility's interconnection process?

OTP uses an Excel spreadsheet to track and perform its screening studies. If more detailed studies are required, it uses:

- PSSE (transmission modeling software)
- ASPEN (a support tool that provides system source strength to run models)
- Stoner software (now Synergi, for distribution planning).
- Power Profiler (pulls interval data from metering management system MV 90); OTP doesn't have a system-wide distribution model.

There is little integration of the software tools. The modeling systems require an external user to input system data.

Streamlining might be possible by integrating metering system data which would provide load data (common info coming from another source). Metering would likely be able to flag adverse impacts of interconnections before problems would arise with additional installations.

Process	Tool/System	How do you use it?	Used for something other than PV/DG?	In House/ Commercial
Business Management Systems	Excel	Track/organize list of projects and project management details	Not in this manner	In-house
Systems for Technical Review	Excel	Have developed algorithms that can provide a rough pass/fail evaluation		In-house
	PSSE	Transmission modeling software for more detailed studies	Yes	Commercial
	ASPEN	System protection (faults) "system source strength"/"support" software	Yes	Commercial
	Stoner (formerly Synergi Electric)	Distribution planning tool – model town by town since systems are isolated/independent	Yes	Commercial
	Power Profiler	Polled interval data from MV 90 metering management system is used to get an idea of loading conditions	Yes	Commercial?

1.13 How many utility staff are currently available to perform *administration and processing* of interconnection applications? What is the estimated total staff-hours (alternatively: staff-years) for this effort?

Although all projects are different, OTP estimates it spends 15-20 staff-hours to process, document, and get a small generator up and running that passes the preliminary screening study. At 5-6 interconnections per year, that equates to 75-120 staff-hours/year or ~4-6% of one full-time employee's annual labor time.

1.14 How many utility staff are currently available to perform *screening and detailed studies* of interconnection applications? What is the estimated total staff-hours (alternatively: staff-years) for this effort?

OTP typically engages ~5 people in the approval and screening process for small generators. If a distributed generator requires detailed engineering studies, the amount of resources and time will depend on the unique circumstances for each project. Staff involved include a coordinator, engineers, administrative assistant, and field personnel.

The goal is to have generator applications that passes the preliminary screening study presented with the necessary paperwork to the customer within in 10 days from the day it is deemed complete.

II. Interconnection Process – Getting into the Details

Pre-Application

2.1 Does your utility provide a pre-application report when requested? If not, please skip down to the "Receiving Application" section of the questionnaire.
OTP does not currently offer a pre-application report.

2.1.1 If so, how much does a pre-application report cost and how quickly does your utility provide the report to requesters?
N/A

2.1.2 Is a non-disclosure agreement (NDA) required to provide the pre-application report data? If so, is the NDA partial or comprehensive?

N/A

2.1.3 Is an aerial map needed to complete a pre-application report?

N/A

2.1.4 Approximately how many applicants have requested a pre-application report to date?

N/A

Receiving Application

2.2 What is the fee to submit an interconnection application?

Interconnection Type	< 20kW	>20 kW & < 250 kW	>250 kW & < 500 kW	>500 kW & < 1000 kW	>1000 kW
Open Transfer	$0	$0	$0	$100	$100
Quick Closed	$0	$100	$100	$250	$500
Soft Loading	$100	$250	$500	$500	$1000
Extended Parallel (Pre Certified System)	$0	$250	$1000	$1000	$1500
Other Extended parallel Systems	$100	$500	$1500	$1500	$1500

2.3 What are the different means by which you can accept interconnection payments from customers (e.g. application fees, study fees, etc.)? In what form are payments typically submitted?

Applicants must pay via check as OTP has not found it cost effective to receive payments from generator customers through an electronic payment process.

2.4 How does your first contact with the DER customer typically occur? Which utility department is responsible for replying to initial customer inquiries, and what is their standard procedure? Do you designate a single point of contact for the applicant? At what point in the process is this designation made?

First contact with a DER customer may occur through several points of contact. These may range from a call to our idea center, contact with our Interconnection Coordinator, or their service representative. Once the customer decides that he/she would like to proceed, the customer submits an application package to the OTP interconnection coordinator. From there, the coordinator checks the application for completeness, screens are applied, if everything checks out, agreements are struck (e.g. PPAs), and the applicant signs the agreement and returns it to OTP. If the application is incomplete, the coordinator will engage the applicant to collect missing information.

2.5 What are the possible ways applications can be submitted for different PV system/size classifications (e.g. online, by mail, in person, etc.)? Can customers attach supporting documents and use an electronic signature?

As stated above in question 1.2, OTP treats all generators the same regardless of size or type. Application and supporting documentation can be submitted via email or in hard copy. However, payment is required before they are deemed complete.

2.6 Are application forms available online, along with clear, step-by-step instructions? Is a checklist available online (or otherwise) to help customers and contractors complete DG applications?

The application and instructions are available online, along with a custom 4-page quick-start guide (https://www.otpco.com/help-center/how-to-connect-to-our-power-grid/minnesota-interconnection/). No step-by-step checklist is currently available to applicants, but one is sent to the generation customer before or at PV system start-up, along with the agreement for the customer to sign.

2.7 Can contractors fill out applications on behalf of customers? If so, do you train contractors to fill out the applications and go through the interconnection process?

OTP can work with contractors, but the customer needs to ultimately sign the agreement. It does not provide training. Generally, OTP has seen an improvement in the quality of applications as developers have become increasingly familiar with the process. For example, greater focus has been given to the one-line diagram. Sometimes, however, contractors do not communicate well with customers and ask the utility questions that should be directed at the applicant.

2.7.1 Are training materials published and events hosted to train new and existing contractors?

No, however OTP is seeing a benefit because of the amount of DG that has been installed in Minnesota, which is helping the developers become familiar with what is required .

2.8 Who reviews the application for completeness and approval (if different)? Who contacts the customer to inform them whether the application is completed adequately and/or whether it has been approved? Is this process automated in some way?

If the application is incomplete, the coordinator – the single point of contact during the process – will engage the applicant to collect missing information. It takes ~5-10 minutes to check for application completeness. There is no automation in the process and all approvals/checks go through the interconnection coordinator.

2.9 What is your typical response time to customers after receiving complete and incomplete applications? What factors most affect this response time?

OTP tries to get back to applicants with a full response (i.e. approval/failure) inside of 10 days. If an application is incomplete, OTP will reach out sooner. As stated above in question , OTP's goal is to provide the customer with a letter in 10 day after the application has been deemed complete. This leter informs the customer if the application has been accepted or if there is a need for further study. The coordinator's contact information is in the letter for follow up. IF the application is deemed incomplete, OTP will call customer to collect the missing info.

After receiving the one-line diagram (usually the primary bottleneck), response time is largely driven by the time needed for engineering investigations (initial screens). OTP usually allows its engineering team a week to turn around the analysis.

Screening used to be handled by field engineers, which was a problem. It has since been pulled into the distribution planning area where there is greater info access. Also, the frequency of review by the same person has increased internal proficiency (e.g. awareness of statutes, where to find the correct forms/data for the screening study, etc.).

2.10 After an application is received, what tools are used to store and access its information? Who has access to the application once it is received (or in your database)?

OTP uses an Excel workbook to check off progress. Employees within OTP can gain access to the application, but no one from the outside, including the applicant, can access or update this information directly.

2.11 Can the customer/contractor access their application information online? If so, what project details and status information are accessible?

No. Questions or check-ins from developers are directed to the interconnection coordinator who can supply a status a copy of the application or associated documentation if the customer misplaced theirs.

2.12 How do you communicate to customers (verbal, written, email) and at what steps of the application process? What level of detail is provided and at what point is this communicated (e.g. application completeness check, preliminary response, status update)?

If an application is missing something, OTP will first call the applicant and then follow up with a letter if the call was unsuccessful. Otherwise, no contact is made before a full response is provided within 10 days of application receipt.

2.13 Are applications added to the queue on a first-come-first-serve basis? Under what circumstances, if any, are applications rearranged in the queue (e.g. if a material modification was made)?

Yes. OTP understands and complies with the first-in-first-out rule.

It may be difficult to define what makes a “material modification”. OTP thinks that if system changes would affect interconnection analysis results or a lowered queued project, this should be deemed material.

2.14 Does your utility post a single publicly available queue? If so, how frequently is it updated?

OTP does not have an on-line public queue. It does not feel that developing a public queue would be a wise investment of time/resources given the current level of applications and future prospects.

2.15 What, if any, policy does your utility adhere to for defining when timelines on application deadlines can be extended? Does the utility apply a blanket policy for extending timelines?

OTP will remove applications from the queue if there has been no response or progress from the interconnection applicant for a year.

2.16 Does your utility provide guidance on interconnection costs that improves cost predictability and certainty (e.g. unit cost guides, interconnection cost envelope)?

In terms of cost estimates for a detailed study, OTP provide a good faith estimate to complete the work with the customer paying for the actual cost of the work. If OTP were to exceed their estimate, they would inform the customer before proceeding. It is a good faith estimate.

OTP believes that there's already a natural tension between wanting to serve their customers and having a formal complaint filed. The parties already come together.

Expedited / Fast Track / Screening Process

Note: These processes may go by different names and contain a range of nuances, but they usually comprise a simplified application path for smaller (often inverter-based) generation systems (<50kW) that do not require in-depth engineering studies. They usually include the following general steps:

a.) Initial communication with potential applicant
b.) Utility review to classify proposed project and screening requirements
c.) Application filing
d.) Applied screens (including supplemental screens, if necessary)
e.) System Installation, testing, and inspection
f.) Final acceptance

2.17 Does your utility have an expedited application process for reviewing PV projects (i.e. established screens vs. unique engineering judgement for every application)? Please elaborate.

No. Every project faces the same initial screen when it passes through the 10-day process. The initial screens are established, and encompass a high level look at if the system has the potential to be a detriment to the reliability of distribution system (PQ, overload, protection, safety, etc.). Essentially every project is fast-tracked unless it fails one of the screens (and thus requires further investigation), in which case OTP would reach out to the customer and inform them of what to expect.

2.18 If so, at what kW rating do you waive screens and automatically accept an application?

Currently, OTP does not have a kW rating threshold for automatic approval—everything goes through a screen. OTP is up for discussing a 10kW automatic approval option, but feels that, regardless of size, every project should get at least a "cursory glance" by

someone in OTP. In part, this is because even a 5 kW generator has an impact to the electrical system.

2.19 Are there any steps in your expedited interconnection review process that are automated? If so, what is the level of automation for each?

Essentially, no. The closest thing to automation for OTP is a crude screening tool (Excel) that performs calculations behind the scenes and outputs a simple pass/fail. The tool has a number of manual inputs that an engineer researches and compiles. For example, through OTP's metering information system, the engineer will determine the minimum load for the feeder and input this into the tool. Another example: OTP can request the fault current from its System Engineering area (System Protection) and enter that into the tool. Once the engineer has entered all the required data, the tool compares the inputs to the thresholds established and returns a pass or fail designation. This software code could potentially become the basis of something automated, but it is not yet comprehensive enough, so it would need more advanced software tools to be integrated with it so that it could import protection attributes, metering information, etc.

2.20 Does your utility contract out interconnection application review (including screening and engineering study) to subcontractors? If so, roughly what percentage of application review is outsourced? What quality controls have been implemented to assure appropriate review?

Due to the unique nature of each system and cost effectiveness at small scales, OTP does not contract out any interconnection work and does not expect to do so anytime soon. However, a distribution study (not related to an interconnection) was recently outsourced as a pilot.

In general, contracting out could be beneficial if there were lots of studies in one area basically several per town per year, but this is complicated by the very integrated transmission and distribution agreements OTP has with other utilities (e.g. OTP has tap other utilities to serve their customers)

OTP is also concerned about the additional cost this could place on the interconnection customer as a consultant may over design the system to protect their interest and the additional time it would take to get a consultant familiar with the system..

2.21 Do you use any automated or manual screens for certain PV size classifications?

No.

Application Approval and Processing

2.22 What tracking tools do you currently use for applications throughout the interconnection process? Do your customers have access to these tools? Is tracking in real-time? Does it contain features such as automatic reminders? Can the tracking tools be integrated into your utility's website (if they are not already)?

The OTP administrator (there is a primary and secondary person) tracks the applications with an Excel spreadsheet. The coordinator will sometimes use internal administrative email/calendar reminders to stay on top of the process and communicate deadlines to staff.

OTP will soon launch a large enterprise platform update of its work flow management, financial management, customer information system, meter information system, GIS, work order estimating tool, and other applications. The utility is in the early stages of this effort, but the update will provide potential opportunity to incorporate tracking, greater automation, etc. to the interconnection process. At this time it is not known what specific hardware/software platforms will be implemented. OTP is at the beginning of the process. It is close to completing an update of its Customer Information System (CIS).

2.23 Which steps in the approval process are most commonly not passed the first time? What are the most common reasons for not passing and what measures are typically taken in these situations?

Application completeness has improved as developers become more familiar with what the requirements are. The one item most often missing from the applicant package is the one-line diagram.

2.24 What, if any, is your procedure for adding DER into the utility's Geographic Information System (GIS)? At what point in the process does this occur? How often does this happen (daily, weekly, monthly)?

OTP adopted its GIS (Esri) ~5 years ago. It is manually updated once the customer is given the approval to interconnect.

2.25 What is your procedure for installing new meters? When does that happen? Does your utility charge metering fees when the meter has to be replaced?

The customer is responsible for contacting a service representative who contacts a meter technician to set up a meter swap. The actual meter swap causes a momentary interruption. The meter technician reviews the installation to make sure the installation matches the one-line, the equipment is UL approved, and that the state electrical inspector has signed off. It also performs a safety check to make sure the generation shuts down by opening the disconnect.

OTP has several different rates for the customer to select from, it depends on which rate they select as to if a production meter is installed and who pays for it.

Detailed Study Process

2.26 Please explain criteria that trigger a more detailed study (which entails greater depth of review beyond what is pursued via the expedited or Fast Track process)?

Triggers may include voltage or capacity thresholds that are exceeded, a protection issue concern (for a fault event), or expected back-feeding to transmission. OTP does not currently look at reactive power flows, power factor, or typical time of day production, but follows guidelines that systems operate between +/- 5% lead/lag.

2.27 What does a detailed study typically involve?

Detailed study involves an analysis of the current state of the feeder using metering data. OTP will check for voltage violations and how much, if any, of the generation may flow back on to the transmission system. There is concern about harmonic distortion that may occur with non-linear inverters, but usually OTP is content as long as the system complies with standards (IEEE 519, 1547, ANSI C84.1, UL 1741, NEC, NESC, among others). Mostly, OTP wants assure that the connection is safe.

2.28 What is your typical completion time for a detailed study?

The biggest challenge in doing the distribution portion of a study is to get a model built. OTP has to take GIS data and input it into middleware to pull a model that can then be used in Synergi analysis. Sometimes field verification is needed, too.

In general, for a detailed study it takes 4-6 weeks to complete a distribution and a transmission study. These studies will provide the customer with a planning level estimate as to the cost to mitigate any issues. If the customer would like more than a planning level estimate, OTP offers to perform a facility study, which can take up 90 days.

2.29 What are the most common obstacles to completing a detailed study in a timely manner?

The most common obstacle is labor bandwidth and balancing responsibilities/priorities as they arise.

2.30 Do you typically have all the information/data you need when you start a detailed study? If not, what missing information is most likely to cause delays?

OTP has most of the information/data it needs to conduct the detailed study. However, it can take time to find the necessary information across different systems. This includes voltage profiles, load information, and customer information (the latter is usually easy to find). In one case, substation metering was simply not available. It also takes time to develop the correct model and verify all of the parameters in the model.

2.31 Who communicates with the customer before, during, and after the detailed study process? What is the typical content of these communications?

The coordinator will generally interface with the customer and field questions. Engineering will contact the applicant directly with specific technical questions and keep the coordinator in the loop about intentions/outcomes.

2.32 Are third-party consultants utilized for detailed studies? If so, for what percent of studies?

No. However, OTP will contact MISO if energy starts to flow back to the transmission system.

2.33 What tools and resources do you use during the detailed study process? Modeling and load flow analysis tools? Commercially-produced or in-house?

Tools or sources of information include metering info, GIS, modeling, Aspen for impedance records (for fault analysis), PSSE, and Synergi.

2.34 Do you employ electronic maps for your entire distribution system? If no, what percentage is mapped electronically? Can/do the maps feed simulation tools for performing load flow analyses?

The utility migrated to a GIS (Esri) 5-6 years ago, and it is still in its infancy. OTP's relative level of fluency with its GIS and the level of the technology's integration with back office platforms would make it difficult to generate documentation or integrate with analysis programs. The utility's ESRI GIS integrates with its Synergi Electric distribution modeling software through a custom program called "middle link." However, PSSE does not integrate with the GIS system. OTP continues to expand the integration of the GIS system through projects and need.

OTP is in the process of getting DG installations mapped into its GIS system. The GIS department is identifying where a DG install is located, its size, nameplate data, connection type. Currently half of the existing DG sites have been mapped. The core rationale for doing this is to inform their field people of the possible generation for safety reasons. This will also aid in developing models by providing the engineers a location to check for generators on our system.

2.35 Is data from all systems stored in a centralized location? If so, is this database integrated with mapping tools and application process? Are all approved interconnection projects incorporated into utility internal mapping tools? Are PV sites added to the maps automatically?

Applications are stored in an electronic document manager/storage system. This database is not integrated with mapping software, and once interconnection systems are commissioned, they must be entered manually into the mapping software.

Summary Table

Interconnection Process		Which department performs step?	What Tools/Systems are used?	What data is needed?
All Applications	**Inquiry Received & Responded**	Multiple departments	Received through multiple channels (phone, email, or in-person)	
	Application Received	Interconnection coordinator	Mail or in-person	Customer and system information
	Application Fee Received (for systems > 20kW)			
	Application Receipt Notification sent to customer	Action not performed	N/A	N/A
	Application reviewed for completeness	Interconnection coordinator	None	
	Application Status Notification sent to customer (complete or incomplete)	Interconnection coordinator	Conducted through formal letter, phone, or email	
	Application Tracking (communication with customer throughout)	Interconnection coordinator	Through letters	
	Application sent for screening/review	Interconnection coordinator		
Case 1: Expedited / Fast Track / Simplified Process	**Screening or Technical Review**	Distribution planning		System design docs (e.g. one-lines), POI location, feeder data
	Application Approved	Interconnection coordinator		
	Request for Meter Set	Customer	None (phone or email)	Metering team contact info
	Add DG system to utility mapping			
	Verification Test	Technician		System design documents, _____ _____
	Final Acceptance			

Case 2: Detailed Study	**Preliminary technical review**	Distribution Engineer	Power Profiler, meter, regulator data, ASPEN, Possibly Synergi (not typical), Excel, GIS	Min and Max feeder load, Fault Current, Protective Devices, Facility capacities, Aggregate DG on feeder and in sub.
	Estimate of detailed study if needed to customer	Interconnection coordinator		
	Payment received	Interconnection coordinator		
	Data request to customer	Interconnection coordinator		
	Detailed study	Engineering department	Excel, PSSE, ASPEN, Stoner, Power Profiler	Min and Max feeder load, Fault Current, Protective Devices, Facility capacities, Aggregate generation in area
	Application Approved	Interconnection coordinator, Distribution Engineer		
	Request for Meter Set	Customer	None (phone or email)	Metering team contact info
	Add DG system to utility mapping	Interconnection coordinator, GIS technician		
	Verification Test	Technician		System design documents, _____ _____
	Final Acceptance	Interconnection coordinator, meter technician		

2.36 Does your utility have a "permission to operation" (PTO) timeline incorporated into its interconnection procedures?

There is no official PTO timeline. OTP sends a letter containing the interconnection agreement that the applicant is responsible for signing and returning. Afterwards, the applicant contacts his/her service representative, to coordinate a meter swap.

2.37 To what degree, if at all, do you provide interconnection reports to a state agency (e.g. MN DOC, PUC, etc.)?

OTP provides annual reporting on interconnections to the MN PUC and MN DOC. This is a requirement for all MN utilities.

2.38 Do you report on compliance with meeting application processing deadlines?

No. OTP has a goal to met the 10-day response time (as stipulated by MN's 2004 interconnection standards) in virtually every instance.

III. Perspective & Expectations: Online Portal

3.1 What steps, if any, have you investigated or taken to streamline the interconnection process? What is the rationale(s) guiding these activities? What have been the greatest obstacles?

Screening used to be handled by field engineers, which was a problem. It has since been pulled into the distribution planning area where there is greater info access. Also, the frequency of review has increased internal proficiency (e.g. awareness of statutes, where to find the correct forms/data for the screening study, etc.). In the last three years, OTP has seen 5-6 DG interconnections per year across its entire system. In addition, OTP is considering acknowledging the receipt of an application through an email notice.

Beyond this, OTP has not investigated any substantial changes to its processes because the economics (cost justifying procedural change) and quantity (not enough demand) do not seem to warrant any. For now, OTP is learning a lot from a broader utility working group that was created several years ago.

3.2 What steps, if any, have you investigated or taken to develop an online portal? What is the rationale(s) guiding these activities? What have been the greatest obstacles?

OTP does not consider the development of an online portal to be appropriate at this time. There's not enough activity to justify the expense.

3.3 What longer-term (5+ years) aspirations do you have for streamlining the interconnection process?

OTP does not have any plans at this point for streamlining the process due to the volume they are seeing.

IV. Miscellaneous Questions

4.1 Does your company maintain a checklist for all on-site inspections? If so, are these checklists publicly available to customers and contractors, allowing them to better meet all requirements?

Yes. This checklist is provided to the customer with the agreements.

4.2 If revised standardized interconnection procedures are implemented, what hypothetical requirement(s) would concern you the most as being difficult or impractical to comply with (e.g. communication, reactive power setting, other)? Are there constructive solutions/alternatives that you have developed or would suggest?

Online apps and distribution maps are too costly right now with the volume they are seeing. A blanket requirement of online maps and applications would be impractical for OTP and there is no obvious distinction such as timeline (implement by X date), utility size, or # of applications that makes sense as a threshold.

4.3 Some utilities keep a periodically updated map/database of distribution-level PV/DER hosting capacity to easily identify strategic locations for PV. Do you do this? If so, what is your utility's preferred frequency and timing for updating these maps?

OTP does not do this at this time. OTP reviews their distribution system capacities on an as needed basis.

4.4 Do you currently have access to interconnected/operational DER performance data? If so, how does such visibility support utility planning or operations? If not, is there value in gaining such visibility (e.g. operational visibility and data resolution) regarding DER performance?. At what scale of DER or type of DER is this most relevant?

No, but OTP is asking a few customers for permission to place OTP-owned monitoring on their DG systems to observe what they are doing.

4.5 Do you believe the adoption of smart inverters would provide benefits, e.g. reduce the need for detailed studies?

OTP does not have enough info to say yet as it requires study. The utility is afraid of alienating customers if the systems cause issues (e.g. curtailment) that prevent their systems from generating (and earning kWh-driven compensation).

MN Solar Pathways: Interconnection Streamlining Assessment

In-depth Interview Topic Guide

Respondent Name(s):	Dru Larson, Energy and Environmental Advisor Dirk Bierbaum, Energy and Environmental Advisors
Company Name:	Rochester Public Utilities (RPU)
Date / Time of Interview:	June 27, 2017, 8am – 10:30am CT
EPRI Interviewer(s):	Nadav Enbar, Alex Magerko

I. Background & Perspective

1.1 How many customers does your utility serve and what is the physical size of your utility's distribution footprint in Minnesota?

Rochester Public Utilities (RPU) serves 53,294 customers that span a relatively compact territory of 65.05 square miles. RPU's average residential retail rate is ~$0.107/kWh. The commercial rate is $0.06/kWh, plus a demand rate with a blended rate from $0.08 to $0.15/kWh.

RPU has a contract with Southern Minnesota Municipal Power Agency (SMMPA) for all power purchases up to 216MW. Any power produced below this load must be sold to SMMPA at LMP rates and then be sold back to RPU. RPU is not subject to MN's RPS, but the board has approved voluntary goals that mirror the state standard. RPU's wholesale supplier, SMMPA, is required to meet the MN RPS.

1.2 What size (kW) classifications do you use to segment interconnection applications?

Thus far, RPU has segmented its interconnection applications into two categories: < 40 kW, and > 40 kW. Any larger future projects may be broken into categories per state statute (250-500 kW, 500-1000 kW, > 1000 kW)… though are not yet seen as necessary by RPU. 40kW is the size limit for NEM; anything above that size operates under a different set of rules.

1.3 Are there any tools or processes you have implemented or are developing to help make interconnection faster/cheaper/better? If so, please elaborate.

The primary tool implemented by RPU is an internal interconnection process checklist. This helps ensure that "next steps" are known and that no step is forgotten, though it is a static list, so it does not include any assistance regarding timeline or reminders. Workflow management is a manual process aided by a MSWord document that assigns tasks to specific RPU groups.

Static documents are online (https://www.rpu.org/construction-center.php) that provide guidelines and information surrounding interconnection at different sizes: 0-40kW, 40-10MW, 10MW+.

1.4 What are the most significant issues you have experienced in processing interconnection applications to date?

The most significant issue for RPU is the lack of experience for interconnecting systems > 40 kW. These systems currently fall under a different set of MN State rules. It is a process RPU has not been through enough times to run more smoothly.

1.5 What tools do you use to ensure the privacy and security of your customers' information?

State statutes, as it applies to municipal utilities, requires that customer data be kept private.

1.6 Please complete the below table to provide background on historical/anticipated interconnection applications received by your utility:

Question	< 10 kW	10-40 kW	40-500 kW	> 500 kW
How many MW of PV and non-PV DER[54] are currently interconnected	PV= 0.403318 non-PV= 0.0026	PV= 0.16782 non-PV=0	PV= 0.29553 non-PV= 0	PV= 0 non-PV= 0
How many PV and non-PV DER systems are currently interconnected	PV= 69 non-PV= 1	PV= 9 non-PV= 0	PV= 2 non-PV= 0	PV= 0 non-PV= 0
How many applications did you process in the last 12 mos. *(May '16 - May '17)?*	9	3	1	0
What % of all applications in the last 12 mos. were incomplete when received *(May '16 - May '17)***?**	0%	0%	0%	N/A
What % of applications in the last 12 mos. have been approved *(May '16 - May '17)***?**	100%	100%	0% (Review in progress)	N/A
What % of applications approved in the last 12 mos. have been installed *(May '16 - May '17)***?**	100%	100%	0% (Review in progress)	N/A

[54] DER = Distributed energy resources and includes PV and other small generators.

Do you conduct a preliminary technical review for each of the project size categories (Y/N)	No	No	Yes	Yes
In the next 3 years, what are your projections for the level of interconnection applications received? (If possible, please break out for each year.)	No projections made	No projections made	No projections made	No projections made

1.7 How many community solar installations, if any, are currently interconnected in your service territory and what is their cumulative capacity? How many community solar projects are in the queue? How many community solar projects have, over the last two years, been canceled?

No community solar installations have been interconnected in RPU's service territory, nor are any in the queue. In large part, this is because of RPU's contract with SMMPA, which makes community solar project economically unfavorable. (RPU's load exceeds 216 MW – the amount that it is required to purchase from SMMPA – only ~10% of the time.)

1.8 Are there private sector community solar project(s) in your service territory? If so, do they use the same interconnection procedure as individual applicants?

No, there are no private community solar projects. (The same generation/interconnection rules would apply to private installers.) RPU is, however, participating in a community solar program in which its joint action agency is working with installers to develop a solar garden outside of RPU's territory. RPU will receive credits that it can then pass on to its customers (via program subscription). The program will kick off in 2018, and contracts will go through 2030. SMMPA is responsible for interconnection.

1.9 For approved project applications (both installed and not pursued) in the last 12 months (May '16 - May '17), what number and percent have required utility infrastructure upgrades (categorized by cost)?

None of RPU's installed PV systems required infrastructure upgrades. All interconnected systems (870kW, spread across 40 different feeders) are small (average size of 7kW) and their output is mostly consumed by local loads. There has yet to be an instance where additional generation could overload a feeder, and voltage or other DER-related issues have yet to be seen given the sparsity (and low power) of interconnected generation.

Cost of Upgrade	Number of Projects Requiring Upgrade	Percent of Total # of Apps
$0-$9,999	0	0%
$10,000 to $49,999	0	0%

$50,000 to $100,000	0	0%
>$100,000	0	0%

1.10 Have the values entered into the table in Question 1.9 significantly changed from prior years? If so, in what way?

N/A. RPU has yet to encounter an instance requiring an upgrade.

1.11 For all approved project applications in the last 12 months, what number and percent were not pursued by the customer due to upgrade requirements as a condition of interconnection?

N/A; 0 and 0%.

1.12 What tools and systems (business and technical) are used in your utility's interconnection process?

RPU organizes all received applications into a digital folder repository on a local server (after scanning in physical documents) and uses Excel to track all applications submitted, as well as document basic project information and relevant dates.

When technical assistance is required, the interconnection coordinator(s) will perform an on-site visit with the engineering department who will use a screen to confirm sufficient capacity and check for any additional apparent concerns.

Process	Tool/System	How do you use it?	Used for something other than PV/DG?	In House/ Commercial
Business Management Systems	Internal server/database	As an application repository	Yes	In-house
	Excel	Summary of applications	Yes	In-house
Systems for Technical Review	Not Answered			

1.13 How many utility staff are currently available to perform *administration and processing* of interconnection applications? What is the estimated total staff-hours (alternatively: staff-years) for this effort?

Two staff members (residential/commercial account reps) are available to process and facilitate interconnection applications. Each application is estimated to require only a couple of hours of labor.

1.14 How many utility staff are currently available to perform *screening and detailed studies* of interconnection applications? What is the estimated total staff-hours (alternatively: staff-years) for this effort?

Two staff members are available. Here too, each application typically takes less than an hour to process. The expediency is due in large part to the ease of performing engineering checks on a feeder with ample capacity and limited DER penetrations.

II. Interconnection Process – Getting into the Details

Pre-Application

2.1 Does your utility provide a pre-application report when requested? If not, please skip down to the "Receiving Application" section of the questionnaire.

No, RPU does not provide a pre-application report, nor has it had a request for one. Free consultations are, however, offered. Any peremptory questions go to staff (account representatives) who will provide a trade ally list that includes local installers (https://www.rpu.org/documents/esp_list_12_15.pdf), information on interconnection, and an email containing the requisite application (based on planned power level).

2.1.1 If so, how much does a pre-application report cost and how quickly does your utility provide the report to requesters?

N/A.

2.1.2 Is a non-disclosure agreement (NDA) required to provide the pre-application report data? If so, is the NDA partial or comprehensive?

N/A.

2.1.3 Is an aerial map needed to complete a pre-application report?

N/A.

2.1.4 Approximately how many applicants have requested a pre-application report to date?

N/A.

Receiving Application

2.2 What is the fee to submit an interconnection application?

RPU does not charge an application fee for any systems < 40 kW. This is a matter of legacy practices and RPU does not see the need to charge a fee any time soon (for small systems). This approach might change if installs accelerate (10-50 per year). RPU charges a $250 fee for systems > 40 kW. Additional costs above and beyond the fee (not including engineering study) are considered capital expenditures.

Generation Interconnection Application Fees

Interconnection Type	< 20kW	>20kW & <250kW	>250kW & <500kW	> 500 kW & <1000kW	>1000 kW
Open Transfer	$0	$0	$0	$100	$100
Quick Closed	$0	$100	$100	$250	$500
Soft Loading	$100	$250	$500	$500	$1000
Extended Parallel (Pre Certified System)	$0	$250	$1000	$1000	$1500
Other Extended Parallel Systems	$100	$500	$1500	$1500	$1500

2.3 What are the different means by which you can accept interconnection payments from customers (e.g. application fees, study fees, etc.)? In what form are payments typically submitted?

RPU will accept the normal "counter payment methods" of cash, check, or credit card. RPU has an electronic payment system for standard rate payments, so there is potential for electronic interconnection payments, but proper invoicing methods have not been established and would prove difficult to implement.

2.4 How does your first contact with the DER customer typically occur? Which utility department is responsible for replying to initial customer inquiries, and what is their standard procedure? Do you designate a single point of contact for the applicant? At what point in the process is this designation made?

Interested customers can send an email to RPU's general inquiry email account and expect a template email response from the marketing department. Often, the customer will be in contact with RPU indirectly via a solar installer. A marketing department representative is the key point of contact from application submission to decision and is assigned as soon as the application comes in.

Utility representatives regularly interact with customers, including via educational classes, and may be the first to discuss the interconnection process with them. In particular, RPU representatives put on two classes per year on the basics of solar installations (for educational purposes only – sales not allowed).

2.5 What are the possible ways applications can be submitted for different PV system/size classifications (e.g. online, by mail, in person, etc.)? Can customers attach supporting documents and use an electronic signature?

All applications, regardless of system size, may be submitted by mail, in person, or by email (payment must be separate). RPU does not have an online application, nor does it use an electronic signature. Supporting documents can be attached to applications submitted by email.

2.6 Are application forms available online, along with clear, step-by-step instructions? Is a checklist available online (or otherwise) to help customers and contractors complete DG applications?

Static application forms are available on the RPU website: https://www.rpu.org/construction-center.php. General information is also available. To date, RPU has yet to implement an external (customer/applicant) checklist, though a document is in the works. Currently, customers are given an RPU contact point via the application form and are expected to call or email with any questions.

2.7 Can contractors fill out applications on behalf of customers? If so, do you train contractors to fill out the applications and go through the interconnection process?

Yes, contractors may fill out the application on behalf of the customer, but RPU does not provide them with any formal training to do so. At most, RPU will direct them to the 2004 Minnesota interconnection procedures and make note of the RPU Solar PV rebate process.[55] Up until now, 1-2 contractors have installed/applied for interconnection for nearly all of the installations within RPU's footprint. (One solar installer has handled 90% of RPU's solar business.) As such, they have become familiar with the process.

2.7.1 Are training materials published and events hosted to train new and existing contractors?

No.

2.8 Who reviews the application for completeness and approval (if different)? Who contacts the customer to inform them whether the application is completed adequately and/or whether it has been approved? Is this process automated in some way?

The marketing representative assigned to the application when it comes in is responsible for checking the application for completeness. No automation is involved in this process.

[55] The rebate applications is completed concurrently with interconnection. Systems must operate at 85-90% of "minimum net effect" to qualify for the rebate.

2.9 What is your typical response time to customers after receiving complete and incomplete applications? What factors most affect this response time?

RPU does not adhere to a strict timeline and will usually not follow-up with a customer if the customer is the one stalling the process. However, within 24 hours of receiving an application, the utility tries to send a confirmation email or give a phone call (mirroring the customer's medium of choice). The email/call will inform the customer of any missing pieces, next steps, and its energy rebate opportunity/requirements.

2.10 After an application is received, what tools are used to store and access its information? Who has access to the application once it is received (or in your database)?

The application is stored in a designated folder on the RPU internal network, so anyone in the department has access.

2.11 Can the customer/contractor access their application information online? If so, what project details and status information are accessible?

No, no part of their application is made visible online.

2.12 How do you communicate to customers (verbal, written, email) and at what steps of the application process? What level of detail is provided and at what point is this communicated (e.g. application completeness check, preliminary response, status update)?

Beyond the initial confirmation of receipt, RPU will follow up with the customer as needed (e.g. to follow up on missing info, such as the rebate application, the required energy audit, proof of insurance, etc.). Communication is largely ad hoc. RPU is planning to use Cayenta (CIS) software to handle applications for rebates (RPU receives many hundreds of these), so if it were to implement an interconnection module, it would probably use the same software package; however, there is no plan to extend the rollout to include interconnection applications at this time.

2.13 Are applications added to the queue on a first-come-first-serve basis? Under what circumstances, if any, are applications rearranged in the queue? (e.g. if a material modification were made)

Essentially yes, though there are not enough applications to warrant officially calling this process a queue.

2.14 Does your utility post a single publicly available queue? If so, how frequently is it updated?

No. Applicants can contact the DG Program lead to verbally check in on application status. There is no outward transparency such as a public queue.

2.15 What if any policy does your utility adhere to for defining when timelines on application deadlines can be extended? Does the utility apply a blanket policy for extending timelines?

RPU has not, to date, encountered any situations in which it has needed to extend application deadlines. It has no formal policy in place.

2.16 Does your utility provide guidance on interconnection costs that improves cost predictability and certainty (e.g. unit cost guides, interconnection cost envelope)?

No.

Expedited / Fast Track / Screening Process

Note: These processes may go by different names and contain a range of nuances, but they usually comprise a simplified application path for smaller (often inverter-based) generation systems (<50kW) that do not require in-depth engineering studies. They usually include the following general steps:

a.) Initial communication with potential applicant
b.) Utility review to classify proposed project and screening requirements
c.) Application filing
d.) Applied screens (including supplemental screens, if necessary)
e.) System Installation, testing, and inspection
f.) Final acceptance

2.17 Does your utility have an expedited application process for reviewing PV projects (i.e. established screens vs. unique engineering judgement for every application)? Please elaborate.

RPU does not conduct engineering reviews for any system < 40 kW, so every application for a system below this threshold is effectively expedited relative to larger systems. Technical review essentially includes the one-line diagram, metering inspection, and confirmation of proper equipment certification. As long as < 40kW systems are outfitted with UL 1741 inverters, they will usually sail thru the review process. Metering techs will look at the systems to make sure they have proper disconnects and signage. The consensus is that 5-10kW systems on a feeder aren't going to make a big difference. In general, RPU has the ability to look at loads through its SCADA system to find feeder load profiles.

2.18 If so, at what kW rating do you waive screens and automatically accept an application?

Anything < 40 kW can be connected without any check besides UL compliance. No extenuating circumstances such as geographic clustering of small systems has yet provided reason to check even transformer ratings.

2.19 Are there any steps in your expedited interconnection review process that are automated? If so, what is the level of automation for each?

No.

2.20 Does your utility contract out interconnection application review (including screening and engineering study) to subcontractors? If so, roughly what percentage of application review is outsourced? What quality controls have been implemented to assure appropriate review?

No part of the application process is contracted out.

2.21 Do you use any automated or manual screens for certain PV size classifications?

No special screens are in place for PV < 40kW. RPU uses a series of screens for larger installations that follow state guidelines.

Application Approval and Processing

2.22 What tracking tools do you currently use for applications throughout the interconnection process? Do your customers have access to these tools? Is tracking in real-time? Does it contain features such as automatic reminders? Can the tracking tools be integrated into your utility's website (if they are not already)?

Tracking is done via internal Excel spreadsheet housed on the utility network. This is an internal document and is not available externally. Customers may call in or email if they are curious about their application status.

2.23 Which steps in the approval process are most commonly not passed the first time? What are the most common reasons for not passing and what measures are typically taken in these situations?

Most of the applications that RPU has received are approved. Missing application information is usually the chief reason for application rejection or delay. Separately, building and electrical inspections are another potential bottleneck. This is handled by a separate department within the City.

2.24 What, if any, is your procedure for adding DER into the utility's Geographic Information System (GIS)? At what point in the process does this occur? How often does this happen (daily, weekly, monthly)?

DER information and locations are added manually, as projects are commissioned, to the ArcGIS system (Azure database). As such, all solar installs are listed in RPU's GIS.

2.25 What is your procedure for installing new meters? When does that happen? Does your utility charge metering fees when the meter has to be replaced?

Meters are installed after an inspection by the building and safety department assuming an accepted application is on file. The customer (or contractor) will contact RPU's metering department to request the meter swap. No charges are billed to the customer for the new meter.

Detailed Study Process

2.26 Please explain criteria that trigger a more detailed study (which entails greater depth of review beyond what is pursued via the expedited or Fast Track process)

At this time, the only criterion that triggers a more detailed study is a large (or otherwise unusual) system, based on screens listed in MN's 2004 state interconnection guidelines.

2.27 What does a detailed study typically involve?

RPU is unable to answer this question at this time as it has yet to perform one. If the system is large enough it would depend on RPU's engineering workload if the utility would do a study internally or externally.

2.28 What is your typical completion time for a detailed study?

N/A.

2.29 What are the most common obstacles to completing a detailed study in a timely manner?

N/A.

2.30 Do you typically have all the information/data you need when you start a detailed study? If not, what missing information is most likely to cause delays?

While not performed, RPU expects that it could find all necessary information internally for a detailed study. One noted exception could be customer side system load data estimates that would be unavailable if the new system were to be part of a new building and/or for a new customer.

2.31 Who communicates with the customer before, during, and after the detailed study process? What is the typical content of these communications?

N/A. It would hypothetically be one of RPU's two Energy and Environment Advisors.

2.32 Are third-party consultants utilized for detailed studies? If so, for what percent of studies?

To date, no; 0%. Depending upon the current workload of the engineering department, RPU would consider contracting out a detailed study, but it could use Synergi's load-flow modeling tools to do the analysis in-house should it become relevant.

2.33 What tools and resources do you use during the detailed study process? Modeling and load flow analysis tools? Commercially-produced or in-house?

N/A.

2.34 Do you employ electronic maps for your entire distribution system? If no, what percentage is mapped electronically? Can/do the maps feed simulation tools for performing load flow analyses?

RPU has mapped its entire system, but it does not know if these maps can export data into analysis tools or how much effort that would require. The utility doesn't have the staff or resources to dedicate to doing this analysis, especially given the limited number of PV systems that have been installed to date.

2.35 Is data from all systems stored in a centralized location? If so, is this database integrated with mapping tools and application process? Are all approved interconnection projects incorporated into utility internal mapping tools? Are PV sites added to the maps automatically?
RPU declined to answer this question citing NERC rules surrounding discussion of where data is stored.

Summary Table

Interconnection Process		Which department performs step?	What Tools/Systems are used?	What data is needed?
All Applications	**Inquiry Received & Responded**	Marketing	Application and interconnection forms	
	Application Received	Marketing	Network	Completed Application
	Application Fee Received (for systems > 20kW)	Marketing	Network	
	Application Receipt Notification sent to customer	Marketing	Email/phone	
	Application reviewed for completeness	Marketing	Email/phone	
	Application Status Notification sent to customer (complete or incomplete)	Marketing	Email/phone	

	Application Tracking (communication with customer throughout)	N/A		
	Application sent for screening/review	N/A		
Case 1: Expedited / Fast Track / Simplified Process	**Screening or Technical Review**	N/A		
	Application Approved	Marketing		Accepted Application
	Request for Meter Set	Device Management		Address and approval from building and safety
	Add DG system to utility mapping	GIS		
	Verification Test			
	Final Acceptance			
Case 2: Detailed Study	**Preliminary technical review**	N/A	N/A	N/A
	Estimate of detailed study if needed to customer	N/A	N/A	N/A
	Payment received	N/A	N/A	N/A
	Data request to customer	N/A	N/A	N/A
	Detailed study	N/A	N/A	N/A
	Application Approved	N/A	N/A	N/A
	Request for Meter Set	N/A	N/A	N/A
	Add DG system to utility mapping	N/A	N/A	N/A
	Verification Test	N/A	N/A	N/A
	Final Acceptance	N/A	N/A	N/A

2.36 Does your utility have a permission to operation (PTO) timeline incorporated into its interconnection procedures?

No.

2.37 To what degree, if at all, do you provide interconnection reports to a state agency (e.g. MN DOC, PUC, etc.)?

Per 2004 statute.

2.38 Do you report on compliance with meeting application processing deadlines?

No.

III. Perspective & Expectations: Online Portal

3.1 What steps, if any, have you investigated or taken to streamline the interconnection process? What is the rationale(s) guiding these activities? What have been the greatest obstacles?

RPU has created an internal interconnection checklist for internal documentation purposes and provided interconnection application forms on its website. It does not believe that its current volume of interconnection applications warrants wholesale investment into a new front-end (customer-facing) interconnection process at this time. That said, RPU is implementing a front-end customer software platform (Cayenta) by 2018. The platform has flexibility and integrating the solar interconnection process into the platform is a potential future development.

In the future, RPU may perhaps develop more dynamic online materials for applicants (and their contractors). To date, RPU emails the steps associated with the process and includes informational attachments. Related, applying for the rebate program is currently static as well; it could be adapted for online (RPU receives 1,000s of efficiency rebates per year).

3.2 What steps, if any, have you investigated or taken to develop an online portal? What is the rationale(s) guiding these activities? What have been the greatest obstacles?

Little time has been spent investigating the merits of an online portal. RPU is neither in favor of developing one on their own nor having the state mandate an online portal for all Minnesota utilities. RPU likes the idea of having local control and would not want to be grouped together with other utilities in a common web portal. It also would also not be comfortable providing its customer data to an outside entity unless done so in an anonymized format such as how it is done with Gopher State One Call (GSOC), a utility locating service.

3.3 What longer-term (5+ years) aspirations do you have for streamlining the interconnection process?

RPU does not have any long-term plans at this point as it does not expect any drastic changes in interconnection demand (within its territory) and it is satisfied with the performance of its current system. The utility's future expectation is low load growth, with steady solar adoption. It has a limited amount of resources to make improvements. The focus is to implement the new CIS, and then integrate the rebate application process into the CIS platform.

IV. Miscellaneous Questions

4.1 Does your company maintain a checklist for all on-site inspections? If so, are these checklists publicly available to customers and contractors, allowing them to better meet all requirements?

There is a checklist used by the meter department when it installs the production meter. The department ensures proper disconnects and signage.

4.2 If revised standardized interconnection procedures are implemented, what hypothetical requirement(s) would concern you the most as being difficult or impractical to comply with (e.g. communication, reactive power setting, other)? Are there constructive solutions/alternatives that you have developed or would suggest?

RPU is partial to guidelines as opposed to requirements, but does not have specific concerns at this time. RPU recommends encouraging/requiring customers to receive an energy audit (addressing energy efficiency measures) before they are allowed to install a PV system.

4.3 Some utilities keep a periodically updated map/database of distribution-level PV/DER hosting capacity to easily identify strategic locations for PV. Do you do this? If so, what is your utility's preferred frequency and timing for updating these maps?

RPU has the tools to be able to create a hosting capacity map, but it has not and does not plan to invest the time and money to do so. It feels that its physically small geographical service area (limited available land for development) and distribution system flexibility lessen the need for a map for installers/contractors.

4.4 Do you currently have access to interconnected/operational DER performance data? If so, how does such visibility support utility planning or operations? If not, is there value in gaining such visibility (e.g. operational visibility and data resolution) regarding DER performance? At what scale of DER or type of DER is this most relevant?

No, RPU only has access to its revenue meter reads; real time data is not available. RPU would find value in data from larger systems and different locations, but it does not yet have the infrastructure and has not yet had a large enough project to make a major impact worth observing more closely.

There are no plans to deploy AMI in RPU's service territory, though RPU has installed "bridge meters" that are intended to bridge the technology gap from radio read to AMI. The bridge meters work with current radio reading tools but would be compatible with AMI following a firmware update in some sort of mesh network. These meters are primarily seen only on new meters at commercial locations.

4.5 Do you believe the adoption of smart inverters would provide benefits, e.g. reduce the need for detailed studies?

RPU is not sure what impact smart inverters will have on the need for detailed studies, but they do see their potential in the long-term future.

MN Solar Pathways: Interconnection Streamlining Assessment

In-depth Interview Topic Guide

Respondent Names & Titles:	Patrick Dalton, Sr. DER Engineer John Harlander, DER Project Manager Alan Urban, DER Engineer Diana Naatz, Assoc, Product Portfolio Manager – Solar*Rewards Community Tom Santori, Assoc, Product Portfolio Manager – Solar*Rewards Community Ed Shannon, Sr. DER Engineer Joel Limoges, Electric Area Engineering Manager Shawn Bagley, Principal Area Engineer Mary Santori, Manager, System Planning & Strategy Chris Punt, Sr. Distribution Planning Engineer
Company Name:	Northern States Power Minnesota (NSPM) dba Xcel Energy
Date / Time of Interview:	June 26, 2017; 8am – 2:30pm
EPRI Interviewer(s):	Nadav Enbar, Alex Magerko

Note: Unless noted or context indicates otherwise, the use of "Xcel Energy" in this document refers specifically to Northern States Power Company – Minnesota, specifically to Xcel Energy's Minnesota business.

I. Background & Perspective

1.1 How many customers does your utility serve and what is the physical size of your utility's distribution footprint in Minnesota?

The Minnesota operating company (Northern States Power – Minnesota, NSPM) serves 1,460,650 electric customers in Minnesota and the Dakotas. Of those, 1,230,524 customers reside in Minnesota and Xcel Energy's footprint is approximately one-third of the overall state area.

1.2 What size (kW) classifications do you use to segment interconnection applications?

Applications are primarily segmented by generation type (wind, solar, community solar, other rotating generation by fuel type). The Company has size (kW) thresholds defined

in its Section 10 Distributed Generation Interconnection Tariff. This Section 10 tariff has a maximum allowable size up to 10 MW. However, distributed generation interconnections above this size have been allowed with permission from the Minnesota Public Utilities Commission. The Company also allows certain distributed generation interconnections for smaller scale net metered type of installations under its Section 9 net metering tariff and the Uniform Statewide Contract that is part of this tariff. This Section 9 tariff has defined levels of costs and study requirements based on the following sizes (kW): 0 - 40 kW, 40-250 kW, 250-1000 kW, and >1 MW.

1.3 Are there any tools or processes you have implemented or are developing to help make interconnection faster/cheaper/better? If so, please elaborate.

Interconnection applications are coordinated by Xcel Energy's Customer Solutions department's Renewable / Choice Programs team. Xcel Energy uses a front-end online portal powered by Salesforce to coordinate interconnection applications, including initial application, electronic document/payment submittal, e-signature, regulatory reporting, application tracking (primary process steps only, such as engineering review comments/approval, meter orders), and application status reporting.

The utility is currently in the early stages of exploring additional technology enhancements, which would help automate some of the processes governing initial technical screening/supplemental review. This effort includes benchmarking of other companies. (Note: Xcel Energy strongly believes in the use of engineering judgement in more detailed engineering studies. It advocates working towards developing accurate information and models, which can be made readily available to internal staff.)

1.4 What are the most significant issues you have experienced in processing interconnection applications to date?

High volumes of moderately-sized solar applications (particularly for community solar in Minnesota) have been challenging. Complications arose as the utility moved from planning models based on more traditional scenarios (load growth and need) to those incorporating more advanced DER capabilities. Availability of experienced external staff resources has also made it difficult to address "waves" or "bubbles" of high application volumes.

Xcel Energy attempted to process all interconnection applications on a one-off basis when community solar started, but it quickly realized that a standardized process was needed. Currently, the most pressing issue is the lack of automation for technical screening, application processing, and document creation as well as the workflow management available for detailed engineering reviews of interconnection applications. The process is highly manual and resource-intensive at this time. Improvements are

being pursued to make the technical review portion of the interconnection process more efficient.

In addition, Xcel Energy formed a DER Integration group in 2017 to address technical and policy issues associated with the onslaught of received solar gardens applications. For context, the group received 400 applications the first day of program availability. Since late 2015, it has received 2,000+ applications. The DER team currently consists of four full-time employees (lead engineer, two engineers, and a project/program manager). The groups' focus is to develop new and streamline existing DER related processes, procedures, and tools across Xcel Energy's various operating companies and service territories.

1.5 What tools do you use to ensure the privacy and security of your customers' information?

Xcel Energy's internal systems are subject to privacy and security regulations and customer data integrity is maintained. The Salesforce application interfaces with Xcel Energy systems and utilizes built-in security functions within the software to ensure data privacy.

1.6 Please complete the below table to provide background on historical/anticipated interconnection applications received by your utility:

Note: response is broken into community solar applications and non-community DG (including both solar and other DG) applications. Community solar gardens data is given in Question 1.7. Data below is for Minnesota DG applications only and are based on data pulled through the end of June 2017.

Non-Community Solar DG Applications				
Question	< 10 kW	10-40 kW	40-500 kW	> 500 kW
How many MW of PV and non-PV DER[56] are currently interconnected	PV= 10.67 non-PV= 0.84	PV= 18.99 non-PV= 0.77	PV= 6.34 non-PV= 12.91	PV= 4.31 non-PV= 277.36
How many PV and non-PV DER systems are currently interconnected	PV= 1,843 non-PV= 26	PV= 721 non-PV= 34	PV= 33 non-PV= 68	PV= 5 non-PV= 141
How many applications did you process in the last 12 mos. *(May '16 - May '17)?*	470	160	4	0
What % of all applications in the last 12 mos. were incomplete when received *(May '16 - May '17)***?**	N/A	N/A	N/A	N/A
What % of applications in the last 12 mos. have been approved *(May '16 - May '17)***?**	86.6% (407)	81.25% (130)	75% (3)	0

[56] DER = Distributed energy resources and includes PV and other small generators.

Non-Community Solar DG Applications				
What % of applications approved in the last 12 mos. have been installed *(May '16 - May '17)***?**	89.36% (420)	95.63% (153)	100% (4)	0
Do you conduct a preliminary technical review for each of the project size categories (Y/N)	N	N	N	N
In the next 3 years, what are your projections for the level of interconnection applications received? (If possible, please break out for each year.)	Unknown	Unknown	Unknown	Unknown

1.7 How many community solar installations, if any, are currently interconnected in your service territory and what is their cumulative capacity? How many community solar projects are in the queue? How many community solar projects have, over the last two years, been canceled?

Xcel Energy's Minnesota Community Solar Gardens (CSG) program, called Solar*Rewards Community, went live in December 2014. As of August 1, 2017, 106 applications, covering 29 sites (100 MW) are interconnected. The current active queue (including stages from initial application/review through final testing) includes 757 applications/311 sites/694 MW. (Note: a number of sites are co-located.) Since inception there have been 1,517 applications withdrawn (1,451 MW of potential capacity) out of a total of 2,380 applications/2,246 MW requested. Xcel Energy provides monthly updates to the Minnesota Public Utility Commission in Docket No. E002/M-13-867 regarding the Solar*Rewards Community program where the most up-to-date information can be found on program statistics.

1.8 Are there private sector community solar project(s) in your service territory? If so, do they use the same interconnection procedure as individual applicants?

Yes. The majority of Solar*Rewards Community projects are by third-party developers, as allowed by Minn. State Statute. The majority of instances in which customers participate in our Solar*Rewards private solar program are by private individuals.

1.9 For approved project applications (both installed and not pursued) in the last 12 months (May '16 - May '17), what number and percent have required utility infrastructure upgrades (categorized by cost)?

Data is not readily available at this time.

Cost of Upgrade	Number of Projects Requiring Upgrade	Percent of Total # of Apps
$0-$9,999		
$10,000 to $49,999		

$50,000 to $100,000		
>$100,000		

1.10 Have the values entered into the table in Question 1.9 significantly changed from prior years? If so, in what way?

Upgrades are assigned to developers/sites based on their impact to the distribution system. For early in queue and/or small sites, generally the grid impact is small and the only required physical equipment is for metering, telemetry, and line extension purposes. As penetrations increase at both a feeder and substation level, the scope and cost of upgrades are correspondingly higher.

Xcel Energy's tariffs for applications in the Solar*Rewards Community program previously limited the dollar amount of upgrades that could be required for distribution line upgrades (a $1M cap per solar garden up to 5 MW), so there has previously been some natural limitation to the extent of major distribution upgrades. Since September 2016, the maximum garden size has been limited to 1 MW and the $1M cost cap has been removed. While Xcel Energy still sees significant penetration on a number of desirable/robust feeders, there are a number of new feeders that are currently being explored by developers.

1.11 For all approved project applications in the last 12 months, what number and percent were not pursued by the customer due to upgrade requirements as a condition of interconnection?

Such data is not readily available at this time. Also, the metrics are clouded somewhat by Solar*Rewards Community customers' revision of their applications to adjust for upgrade requirements. For instance, some applicants will self-curtail in order to avoid costly upgrades in lieu of canceling outright. Also, when a developer cancels a project it frequently does not provide a reason to Xcel Energy.

1.12 What tools and systems (business and technical) are used in your utility's interconnection process?

Process	Tool/System	How do you use it?	Used for something other than PV/DG?	In House/ Commercial
Business Management Systems	Salesforce	Front-end application receipt/processing, high-level status keeping and workflow, overall	Yes, also used for demand side management programs	Commercial

		tracking mechanism, reporting		
	SharePoint	Used for non-records tracking of a subset of DG applications to help coordinate and track engineering reviews	Currently CSG PV only with occasional larger commercial rooftop sites, likely will expand in future	Commercial
	CRS	Meter billing system	Yes, all billing data	Commercial
Systems for Technical Review	Excel spreadsheets	Initial and supplemental technical screens	Yes	Both
	Synergi	Used by in-house and consulting engineers for detailed power flow modeling	Yes	Commercial
	SKM & PSSE	Prior software used for transmission (more simplified modeling)	Yes	Commercial
	SAP	Load forecasting	Yes	Commercial
	DAA	Itron forecasting tool (to be sunset)	Yes	Commercial
	Access database	Stores transformer loading limits	Yes	Commercial
	Projectwise	Stores transformer loading limits	Yes	Commercial
	CAPE	Stores transformer loading/breaker limits (last resort)	Yes	Commercial

1.13 How many utility staff are currently available to perform *administration and processing* of interconnection applications? What is the estimated total staff-hours (alternatively: staff-years) for this effort?

In Minnesota, there are approximately 6 FTEs available to perform administration and processing of interconnection applications, among other responsibilities. Four of these individuals are in Xcel Energy's Customer Choice Program Office, which is the utility's primary contact for solar developers and facilitates all work associated with community solar garden applications amongst the various internal Company stakeholders. An additional two individuals contributee from Xcel Energy's engineering team, andseveral others also work on these programs.

1.14 How many utility staff are currently available to perform *screening and detailed studies* of interconnection applications? What is the estimated total staff-hours (alternatively: staff-years) for this effort?

Detailed power flow modeling studies are performed by a contractor who uses 5-6 primary staff to complete its scope of work. Quality Assurance is then handled by Xcel Energy staff. Thus, while highly dependent on the application/study volume, ~7-8 FTEs are currently available for screening and detailed studies (so far in 2017). Additional internal Area Engineering staff are engaged during the "facilities study" phase of the process based on their expertise with the Company distribution network in specific geographic areas of Minnesota.

II. Interconnection Process – Getting into the Details

Pre-Application

2.1 Does your utility provide a pre-application report when requested? If not, please skip down to the "Receiving Application" section of the questionnaire.

Yes, Xcel Energy will offer a capacity screen to developers who provide a specific location of where they plan to build. With this piece of information alone, Xcel Energy has all it needs to know to produce the report. Below are excerpts from Xcel Energy's Section 9 tariff which details the pre-application process and information provided.

a. *Any Community Solar Garden applicant may enter into a reasonable and customary non-disclosure agreement with the Company to receive distribution infrastructure and load analysis on a per feeder basis, and study results for previously studied projects. A response to such an information request must be fulfilled within 15 business days of the request. Information requests may include feeder specific voltage, concurrent minimum and peak loading analysis, existing distributed generation under operation, amount of distributed generation in the interconnection queue or Study Queue, terminated maximum distance substation, and any other pertinent information for the purposes of interconnection.*

b. *The response to the distribution infrastructure and load analysis on a per feeder basis will consist of the following:*
    i) Substation name
    ii) Distance from Substation
    iii) Substation transformer nameplate capacity
    iv) Substation transformer minimum daytime load
    v) Substation transformer maximum load
    vi) Feeder name

vii) Feeder Voltage
viii) Feeder minimum daytime load
ix) Feeder maximum load
x) Presence of a voltage regulator
xi) Presence of a reclosure
xii) Distributed resources in operation per feeder and substation
xiii) Distributed energy resources in the interconnection queue or Study Queue per feeder and substation
xiv) Conductor size and material

c. *The study results for previously studied projects will consist of the following when available:*
   i) Distributed Energy Resource Type
   ii) Approximate POI distance from substation
   iii) Facility AC Nameplate Requested
   iv) Facility AC Nameplate Approved
   v) Non-unity DER Power Factor Required? (Y/N)
   vi) Line Reconductor or Rebuild Required? (Y/N)
   vii) Protection Upgrades Required? (Y/N)
   viii) Voltage Regulation Upgrades Required? (Y/N)
   ix) Date study results delivered

d. *The applicant at the time of the request for this information must also pay a fee of $250.00 per request, and each request is on a per feeder basis based on the specific location of a proposed Community Solar Garden Site. There is no requirement that there be an actual application submitted in the CSG Application System for the specific location of the proposed Community Solar Garden Site which is the subject of the request. The above 15 business day response time begins upon providing such a request along with the required payment.*

Almost all pre-application report requests were for community solar projects since they are typically larger (1-5 MW) and more flexible in terms of location, but there have been a few requests from other projects.

2.1.1 If so, how much does a pre-application report cost and how quickly does your utility provide the report to requesters?

A capacity screen report costs $250, and the process takes 15 business days (similar to the SGIP guideline).

2.1.2 Is a non-disclosure agreement (NDA) required to provide the pre-application report data? If so, is the NDA partial or comprehensive?

An NDA is required to help ensure that only the developer is the end user of this data and that the data is not used for improper purposes.

2.1.3 Is an aerial map needed to complete a pre-application report?

Often Xcel Energy will receive a full engineering site plan from a developer. Otherwise, the utility requests at least a Google Map with the system layout superimposed and/or a specific latitude and longitude.

Xcel Energy has encountered situations in which site addresses are educated guesses from the developer (e.g. interpolations between known points) rather than confirmed coordinates. Xcel Energy now asks for coordinates. User guides have been written and distributed to internal engineers as well as the interconnection portal to assist the various parties in communicating consistent GPS coordinate information. Developers are responsible for picking their point of common coupling (PCC); Xcel Energy does not provide a PCC location for them as part of the pre-application report.

2.1.4 Approximately how many applicants have requested a pre-application report to date?

Xcel Energy has received over 500 pre-application report requests in Minnesota since late 2015 and is seeing more as grid penetration increases.

Receiving Application

2.2 What is the fee to submit an interconnection application?

Interconnection Study Fees are defined by Xcel Energy's Section 9 and Section 10 tariffs found in the utility's Electric Rate book. Below is a snippet of the company's Section 10 Tariff.

Step 1 Application (By Applicant) (Continued)

Generation Interconnection Application and Engineering Study Fees

Interconnection Type	≤ 20 kW	> 20 kW & ≤ 250 kW	> 250 kW & ≤ 500 kW	>500 kW & ≤ 1000 kW	> 1 MW & ≤ 10 MW
Open Transfer	$0	$0	$0	$0	$250
Quick Closed Transfer	$100	$250	$250	$250	$250
Soft Closed Transfer	$100	$250	$500	$500	$1000
Extended Parallel Non-exporting Pre-certified	$100	$250	$250	$1000	$1500*
Extended Parallel Non-exporting	$100	$250	$1000	$1000	$2000*
Extended Parallel Pre-certified	$100	$500	$2000	$2000	$1500*
Extended Parallel Non-Pre-certified	$100	$1000	$3000	$2000*	$2000*

* Engineering study fees may apply. Firm cost estimate for study will be given at the time of preliminary review, based on scope provided in application. If scope changes after estimate is provided, then firm cost estimate may be updated.

Xcel Energy also has specific fees defined in Section 9 for its customer solar programs. For the Solar*Rewards program (systems < 20 kW), the application fee is $250. For the "Made in Minnesota" incentive program, the fee is $100 for systems < 20 kW and $500 for systems 20 kW-250 kW.

In addition, Solar*Rewards Community aspirants must first submit a $100/kW fully refundable deposit with their online application. They also need to provide necessary documentation: an engineering site plan, one-line diagram, interconnection application, study fee form and payment, and a Certificate of Good Standing. The application subsequently goes into initial review, where area engineers perform screening. As noted above, engineering study fees will also apply for larger systems. For example, for a 1 MW application the study fee is $22,500.

2.3 What are the different means by which you can accept interconnection payments from customers (e.g. application fees, study fees, etc.)? In what form are payments typically submitted?

Private solar/DG customers can make a payment through a Wells Fargo online payment system or paper check (though the latter is now used by a minority of applicants).

Online payments are tracked using unique identification numbers created in Salesforce for each application.

Payment for a Solar*Rewards Community deposit can happen either via online check/wire or US Bank can do an escrow agreement. Escrow was an adaptation that many applicants have used since its inception. Garden operators requested an additional option for funding deposits outside of directly paying Xcel Energy. The escrow program adopted a structured agreement through US Bank in order to accommodate this request. Deposits (either direct payments or escrow accounts) are a program requirement and are held until applications are either operational or canceled/withdrawn.

Interconnection costs are also assessed as detailed in the Section 10 tariff, Sheet 117.

2.4 How does your first contact with the DER customer typically occur? Which utility department is responsible for replying to initial customer inquiries, and what is their standard procedure? Do you designate a single point of contact for the applicant? At what point in the process is this designation made?

Interested parties can find information about solar programs on Xcel Energy's website (www.xcelenergy.com/solar*)* and will be directed there or to an Xcel Energy Expert if calling Xcel Energy's general office.

The web page does not support any interactive tools (e.g. calculator) as of yet, though it does contain a home usage estimator (essentially a simple Excel document with embedded macros). When contemplating their options, applicants can contact Xcel Energy and/or installers (Xcel Energy suggests that customers get at least three bids). Usually customers will choose an installer first, and the installer then often helps their customer handle the application process.

Community Solar Gardens
For Solar*Rewards Community, a Salesforce link from the web page (www.xcelenergy.com/staticfiles/xe-responsive/Energy%20Solutions/Residential%20Solutions/Renewable%20Energy%20Solutions/Solar%20Garden%20Registration.htm) goes to an online form to supply basic info. On the Solar*Rewards Community website, applicants can also send an email to program administrators to ask specific questions, learn how to request a pre-application report, learn more about the program and the application process. There have also been ongoing workgroup meetings to address program rules and developer concerns (see below). Minutes of these workgroup meetings have been publicly filed in the MPUC Docket No. 13-867 and the filings in this docket are available online.

Solar*Rewards (Solar DG program)
Xcel Energy's Solar*Rewards program has a web page with supporting information, including contact info. See:

- https://www.xcelenergy.com/programs_and_rebates/residential_programs_and_rebates/renewable_energy_options_residential/solar/available_solar_options/on_your_home_or_in_your_yard/solar_rewards_for_residences.
- https://www.xcelenergy.com/working_with_us/renewable_developer_resource_center/solar_rewards_developer_resources

2.5 What are the possible ways applications can be submitted for different PV system/size classifications (e.g. online, by mail, in person, etc.)? Can customers attach supporting documents and use an electronic signature?

Salesforce is a third-party, web-based, front-end application for receipt and processing of customer and installer information, system details (arrays, inverters), and solar program enrollment. The online application has different "tabs" such as customer information, installer info, system details, documents and payments, etc. that must be filled in as part of the application. This allows applicants to save their work in case they need to track down a missing piece of information and come back later (before officially submitting it).

In order to get to engineering review, Solar*Rewards Community applicants need a "certificate of good standing" showing that they can do business within the state. Then all of the documentation noted above is required. The site plan, one-line, application, and the payment form may all be submitted online. Application must be submitted online, though the payment may be submitted by mail. Hard copy applications are not supported, but checks are still accepted. Signatures are all electronic.

2.6 Are application forms available online, along with clear, step-by-step instructions? Is a checklist available online (or otherwise) to help customers and contractors complete DG applications?

Xcel Energy tries to guide customers through choices rather than just (statically) list program options. For example, the website might ask, "What type of customer are you?" and the answer will determine the appropriate next page. Relevant application components and information will be available once an applicant gets to a specific program page. Guidance documents, example drawings, and application checklists are provided as references on the various program pages.

The December 2016 ICF report ("External Consultant Report on Xcel Energy Minnesota Solar*Rewards Community Interconnection Process") helped to objectively identify a

number of existing issues and potential pathways for improvement. In fact, its success has encouraged Xcel Energy to pursue a similar effort evaluating the interconnection process for the company's DG/Solar*Rewards program. The Company is pursuing improvements to its developer resource pages:

- https://www.xcelenergy.com/working_with_us/renewable_developer_resource_center/solar_rewards_community_developer_resources
- https://www.xcelenergy.com/working_with_us/renewable_developer_resource_center

2.7 Can contractors fill out applications on behalf of customers? If so, do you train contractors to fill out the applications and go through the interconnection process?

Yes, customers can sign off that the installer can act on the customer's behalf. There are a number of regular contractors that handle most of the installations in Xcel Energy's MN territory.

Xcel Energy provided a developer training last year for contractors still becoming familiar with Solar*Rewards Community procedures, and copies of the training documents are available in the developer information portal. Future training sessions will be established on an as-needed basis. All program updates have been published, provided to Garden Operators, and addressed through various communication channels (monthly workgroup meetings, bi-weekly calls, routine update emails, etc.).

Xcel Energy has also provided training for participating developers in its Solar*Rewards or Made in Minnesota programs. The utility typically provides this training every few years.

2.7.1 Are training materials published and events hosted to train new and existing contractors?

Solar*Rewards Community developers can attend cross-functional working group meetings (previously monthly, now quarterly) where "lessons learned", contentious and generic issues, are all shared. These sessions are generally well attended and provide value to the Company and developer community.

Training materials and step-by-step process details also exist for the application process for the Solar*Rewards (rooftop) program on the Xcel Energy website.

2.8 Who reviews the application for completeness and approval (if different)? Who contacts the customer to inform them whether the application is completed adequately and/or whether it has been approved? Is this process automated in some way?

An application is first reviewed by the Xcel Energy program to which it is sent and assigned an engineering review. An engineer acting as the DG interconnection coordinator and a marketing director (i.e. 2 FTEs) handle all private solar projects (or any non-solar garden DER) and act as the contact points during the application process. Two different full time employees and an engineer are assigned to Solar*Rewards Community projects, but perform similar roles and are also serve as the contact points during the Solar*Rewards Community application process.

Automated emails are not sent as part of either program beyond the notification of initial application submission. However, developers are able to track the updated status of their individual applications, by logging into the Salesforce portal and querying their project(s).

2.9 What is your typical response time to customers after receiving complete and incomplete applications? What factors most affect this response time?

Xcel Energy sticks to a defined calendar and provides applicants with anticipated response times. For Solar*Rewards (rooftop), program approval is determined within three business days, and engineering comment or approval is determined within 15 business days.

For Solar*Rewards Community, Xcel Energy reserves the right to review an application for 60 days from submission (including 30 days for an engineering review/screens) before responding to applicants on next steps. If an engineering study is needed, it then has 50 business days to complete the detailed study process. The applicant/developer has 30 business days to decide whether to proceed with an engineering study. It then takes +/- 16 weeks to complete detailed design (where a developer meets with a designated Xcel Energy designer to discuss needed grid upgrades and costs), and an estimated 12 weeks for construction.

Lots of changes tend to be made in the detailed design stage (often due to permitting issues), which is a primary cause of delays. Xcel Energy has rules discussed in the Solar*Rewards Community workgroup around material modification.

2.10 After an application is received, what tools are used to store and access its information? Who has access to the application once it is received (or in your database)?

Everything related to interconnection lives in Salesforce; it is a central hub for document management accessible only to select Xcel Energy employees (account managers, engineers, and others). Installers/developers have access only to the developer portal. All information is permanent; it can be marked as cancelled, but cannot be deleted.

2.11 Can the customer/contractor access their application information online? If so, what project details and status information are accessible?

Developers can review the application through Salesforce (and will be alerted when it has been uploaded), but they cannot see where they stand in the queue through Salesforce. Instead, for Solar*Rewards Community only, Xcel Energy publicly posts a monthly substation DG/CSG queue report that provides a snapshot of project statuses. The three distinguishing statuses are 1) under study, 2) have executed an interconnection agreement, 3) are in detailed design phase. This report is manually generated and is a stipulation of the Section 9 tariff (https://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/Me_Section_9.pdf).

Note: Xcel Energy is able to download a lot of data out of Salesforce to provide internal/external reporting. Improvements in the consistency and accuracy of data input to Salesforce have clarified these reports, and they are being further refined by users as the need arises.

All solar/DG projects utilize the Salesforce software for application processing. In the future, Xcel Energy recognizes that it will need to determine the best way to operate a holistic queue that includes a range of other projects (e.g. PV, batteries, etc.).

2.12 How do you communicate to customers (verbal, written, email) and at what steps of the application process? What level of detail is provided and at what point is this communicated (e.g. application completeness check, preliminary response, status update)?

The process has auto-generated email communication triggers for some programs. For example, the Solar*Rewards program has the following standard communications:

- Initial welcome email when the application is created.
- Application has been accepted into the program (once the application has been approved by the program manager and incentive, if applicable, has been set).
- Application has been submitted for engineer review (once program manager approval has been received and engineering documents and payments have been submitted)

- Application drawings have been rejected/approved by engineering (includes engineer comments). Multiple communications could be issued if revisions are needed.
- Final contract sent out for e-signatures once engineer approval is given and final information is complete. The e-contract is sent to customer, installer, then Xcel Energy.
- Meters have been ordered (once contract is fully signed by all parties).
- Permission to operate (PTO) after meters have been installed by Xcel Energy technician

Customers are also free to email or phone Xcel Energy for feedback.

As part of the Section 9 tariff, Xcel Energy will set up 30-minute, one-on-one calls with Solar*Rewards Community developers on a bi-weekly basis—so long as they have a project in the queue. The calls are intended to provide developers with answers to technical questions.

Xcel Energy articulates to applicants expected time frames at the beginning of the process: e.g. 60 business days to determine pass, fail, or need for engineering study, 50 business days to conduct an engineering review (if needed), and 30 business days for the developer to make a decision about whether to proceed with interconnection.

2.13 Are applications added to the queue on a first-come-first-serve basis? Under what circumstances, if any, are applications rearranged in the queue? (e.g. if a material modification were made)

Yes applications are added to the queue on a first-come-first-served basis depending upon type and size of application within a particular area. For instance, a wind application and solar rooftop application on one substation may be reviewed concurrently.

In the case of Solar*Rewards Community, applicants have 30 business days to decide on whether to move forward with projects and comply with Xcel Energy engineering judgment (and submit payment). If they do not meet this timeframe, they are subject to removal from their spot in the queue. To meet tariff timelines, Xcel Energy's queue processing approach is to study a project and then assume that it will move forward at maximum size in order to begin processing the next in-queue project.

Separately, applicants cannot pick feeders; Xcel Energy chooses the feeder that serves the location. Today Xcel Energy can look at feeder characteristics such as minimum load, distance from substation, and feeder voltage and pick the feeder that is closest to the

proposed project site, while taking into account indications of hosting capacity. In the next release of hosting capacity results, a hosting capacity map will enable more predictabile and informedsiting.

Xcel Energy will study the projects in order of the queue. For the 50-day timeline to complete a detailed engineering study, for community solar gardens, Xcel Energy starts the clock from the "Expedited Ready" date, regardless of how many applications are in the queue simultaneously.

In general, there is a lot riding on queue positioning because it is directly tied to cost/capacity (i.e. interconnection costs can be initially low and become more expensive as capacity dwindles), or there may be substation or other projects funded by an early-in-queue project that benefits later-in-queue projects. Applicants are locked into their queue positions so long as their applications are technically complete and paid for.

Xcel Energy allocates 11 area engineers, oriented geographically across Minnesota, to the interconnection study process.

2.14 Does your utility post a single publicly available queue? If so, how frequently is it updated?

Xcel Energy posts a publically available queue for the Solar*Rewards Community program only. This queue posting is updated monthly.

2.15 What if any policy does your utility adhere to for defining when timelines on application deadlines can be extended? Does the utility apply a blanket policy for extending timelines?

Application timelines and deadlines are defined by Xcel Energy's Section 9 and 10 tariffs found in the Company's Electric Rate book. Deadlines are rarely extended and dealt with on a project-to-project basis.

While Xcel Energy rarely removes an applicant's project from the queue, applicants that do not pay the SOW cost within 30 business days will get removed as soon as another project is added to the same queue (on that feeder), or upon notice of cancellation due to not meeting tariff timelines – Xcel Energy typically allows a brief cure period prior to cancellation. Xcel Energy is motivated to move to SGIP-like defined reciprocal timeframes to provide explicit justification for when applicants lose their queue position

and minimize inactive projects that could come to life at any moment (potentially causing a lot of work all at one time)[57].

2.16 Does your utility provide guidance on interconnection costs that improves cost predictability and certainty (e.g. unit cost guides, interconnection cost envelope)?

Xcel Energy provides a high level, indicative cost estimate to applicants resulting from the engineering study. The methodology is to use unit cost estimates broken out into labor, material, and equipment.

The utility charges $22,500 upfront for each site for 1 MW+ scale applications, and provides a refund if the entire amount is not used. The $22,500 upfront cost is to administrate the engineering scoping study. At the completion of the study, an indicative cost estimate is provided that gives a more detailed cost breakdown for interconnection. For an application to proceed to design stage, a developer is required to pay the full indicative cost estimate, or pay 1/3 along with an approved Letter of Credit for the remaining balance. Regardless of the indicative estimate, developers are required to fully pay for actual costs of necessary upgrades for Xcel Energy to safely interconnect their system. The PUC has ordered that Xcel Energy provide reporting on the degree of variances (+/- 20%) that have occurred between its estimates and the actual costs.

Expedited / Fast Track / Screening Process

Note: These processes may go by different names and contain a range of nuances, but they usually comprise a simplified application path for smaller (often inverter-based) generation systems (<50kW) that do not require in-depth engineering studies. They usually include the following general steps:

a.) Initial communication with potential applicant
b.) Utility review to classify proposed project and screening requirements
c.) Application filing
d.) Applied screens (including supplemental screens, if necessary)
e.) System Installation, testing, and inspection
f.) Final acceptance

2.17 Does your utility have an expedited application process for reviewing PV projects (i.e. established screens vs. unique engineering judgment for every application)? Please elaborate.

[57] Some developers got into the queue before they had financing lined up.

Xcel Energy continues to work on the level of screening needed for different systems. Today, the screening tool is intended for systems > 40 kW, but if cumulative capacities of all projects in queue are greater than 3 MW (or if any one fails a screen) then a detailed study is performed that evaluates circuit integrity and system safety. Screens are not performed when aggregate generation on a feeder exceeds 3 MW; in those cases, the sites automatically move to detailed study via power flow modeling software. Smaller rooftop or residential systems are screened using a tool to calculate secondary voltage impacts. The transformer sizing and system configuration is also reviewed while screening smaller projects.

2.18 If so, at what kW rating do you waive screens and automatically accept an application?

So far, Xcel Energy does not have any level at which it automatically accepts applications sans screening; however, systems < 10 kW usually receive an expedited review. In these cases, Xcel Energy does a rigorous review of the one-line and inspects the system when doing the meter install (it will almost always at least check transformer sizing).

2.19 Are there any steps in your expedited interconnection review process that are automated? If so, what is the level of automation for each?

No. Currently no part of the interconnection review process is fully automated, though the screening process has been somewhat simplified through a spreadsheet tool which performs calculations based on user inputs.

2.20 Does your utility contract out interconnection application review (including screening and engineering study) to subcontractors? If so, roughly what percentage of application review is outsourced? What quality controls have been implemented to assure appropriate review?

All screening and drawing review is done internally at Xcel Energy, but detailed engineering studies are contracted out roughly 90% of the time, with Xcel Energy engineers performing quality reviews on each study. At one time, a single individual performed all completeness reviews. Now, low-level screens are done in-house by a broader group and guided by a spreadsheet tool. The internal staff have a specific checklist for each specific program type (Solar*Rewards Community or otherwise) to try and improve consistency. The in-house screening tool was formed using SGIP/CA screens considering input from EPRI, NREL, and others. Xcel Energy verified results against ~20 project test cases to develop the spreadsheet into a screening tool.

2.21 Do you use any automated or manual screens for certain PV size classifications?

No screens for PV or otherwise are currently automated. To date, Xcel Energy is seeing residential PV systems capping at 10 kW, and these are usually more straightforward

systems compared to more varied and complex commercial/industrial projects. For example, sometimes a site requires a facility extension, which comes with a set of issues. The utility has, for instance, recently received pushback on siting overhead line in a public right of way. Given the additional complexity, commercial/industrial or utility-scale systems are particularly ill-suited for automated screening processes.

Application Approval and Processing

2.22 What tracking tools do you currently use for applications throughout the interconnection process? Do your customers have access to these tools? Is tracking in real-time? Does it contain features such as automatic reminders? Can the tracking tools be integrated into your utility's website (if they are not already)?

See Questions 1.3 and 2.11. Salesforce provides internal and external tracking with some automated reminders for administrative and technical reviews. Additionally, a SharePoint list is used to internally track in-progress studies with greater granularity than is currently available in Salesforce.

2.23 Which steps in the approval process are most commonly not passed the first time? What are the most common reasons for not passing and what measures are typically taken in these situations?

For Xcel Energy's distributed generation programs (which include rooftop and community solar), a common issue is people submitting incorrect forms and/or information (sometimes repeatedly), or there being missing required information. A checklist of application requirements was recently created with the intent of reducing the number of missed items causing Xcel Energy to return applications for additional information.

2.24 What, if any, is your procedure for adding DER into the utility's Geographic Information System (GIS)? At what point in the process does this occur? How often does this happen (daily, weekly, monthly)?

GIS updates are usually part of the design process. During this process, designers will redline the previous GIS, which will be put into production within a few days of a project being commissioned. All updates are performed manually.

2.25 What is your procedure for installing new meters? When does that happen? Does your utility charge metering fees when the meter has to be replaced?

For Solar*Rewards or Made-in-Minnesota PV systems, Xcel Energy will install a production meter at the same time as it checks the system for any configuration problems. The customer is charged a fee on his/her monthly bill of roughly $3-7/month

for private customers (usually depends upon 1-phase vs. 3-phase) and $5.50 to $8.00/month for community solar systems. For larger scale systems, primary/secondary metering is added (CT meters) which can cost the customer $400-$5,000 to install, depending on voltage class, along with a monthly charge that is tariff specific.

Xcel Energy has automated meter reading (AMR) deployed throughout its service territory today. Full automated metering infrastructure (AMI) will be deployed in the near future.

Detailed Study Process

2.26 Please explain criteria that trigger a more detailed study (which entails greater depth of review beyond what is pursued via the expedited or Fast Track process)?

The primary trigger is aggregate system size on a feeder of 3 MW or more, but any failed screen from initial study will also result in a project being sent for further engineering review.

2.27 What does a detailed study typically involve?

Note: This series of questions about the detailed study refers to the study in Step 4 of the interconnection process as set forth in our Section 10 tariff, Sheet 95, which is for the development of an indicative cost estimate. This is different from a detailed cost estimate developed later in the interconnection process.

A detailed study involves creating a model of the feeder and running a power flow analysis to check for thermal, voltage, and protection violations. Any violations are addressed with mitigations.

Area Engineering receives interconnection study results and pulls feeder/substation maps to read along with the study. In this way, it is able to verify footage for rebuilds and reconductoring, and fill-in cost estimates. It inputs numbers into a unit cost estimator spreadsheet to generate indicative costs and writes into a cover letter template to explain the scope of the estimate and its various sections. Once a packet is put together and approved, it is handed over to administrative staff who then share it with the applicant.

Xcel Energy has been able to iteratively improve the approach and template used by Area Engineering through lessons learned and accrued experience (e.g. conducting a study without doing fuse coordination, assuring coordination occurs between T+D when

evaluating the impacts of DG interconnection on system protection). It has added additional detail to its associated templates

The unit cost estimating tool used by Area Engineering has come a long way and is more in-depth. It includes a greater amount of information (e.g. distance, time of year, breakout of labor/material/equipment).

2.28 What is your typical completion time for a detailed study?

The typical detailed study completion time, including an indicative estimate and interconnection agreement, is approximately 40-50 business days. Xcel Energy works to have analysis complete and study reports with the area engineers well in advance of the deadline to allow the remainder of the process to move smoothly.

2.29 What are the most common obstacles to completing a detailed study in a timely manner?

One limitation is the ability to maintain the "traditional" grid while transitioning to a more flexible and integrated grid using new technologies and generation sources. Another is how to avoid duplicating work while ensuring consistent results. Xcel Energy has internal checklists for its engineers, but is still thinking about the best way to resource engineering studies (i.e. have one engineer assigned to all projects owned by a given contractor (more consistent contact point) or have area engineers have all projects defined within a geographic locality (increased familiarity with distribution infrastructure). See Question 2.13.

2.30 Do you typically have all the information/data you need when you start a detailed study? If not, what missing information is most likely to cause delays?

The primary obstacle is finding the feeder/physical asset information if it is not in transmission or distribution databases (i.e. transformer information, which usually is not stored in the same place). Data may need validation, too.

2.31 Who communicates with the customer before, during, and after the detailed study process? What is the typical content of these communications?

Engineers may contact the developers, via the program manager as necessary, with any questions, but engineers almost always have all the information they need once they get past the detailed information gathering stage.

Generally, the program manager serves as primary contact (for solar installations) overall and sole contact during the preliminary application review stage. Area engineers

serve as the contact for technical questions during the detailed study, and the distribution designers are the detailed contact during procurement and construction work on Xcel Energy's system.

2.32 Are third-party consultants utilized for detailed studies? If so, for what percent of studies?

Yes. All screening and drawing review is done internally at Xcel Energy, but detailed engineering studies are contracted out roughly 90% of the time. Xcel Energy engineers on the DER team review each complete study for accuracy prior to generating the interconnection agreement and proceeding to design and construction.

2.33 What tools and resources do you use during the detailed study process? Modeling and load flow analysis tools? Commercially-produced or in-house?

Detailed studies are never automated, and Xcel Energy does not believe that they should be as engineering judgment is needed.

- Smallworld – GIS
- Synergi – power flow analysis
- SAP load forecasting data
  - Can pull peak manual reads out of SAP (There are 3 different ways of getting load data, but each has different granularity and interval reporting)
- DAA Itron forecasting tool (to be sunset)
  - Pulling EMS/SCADA data from DEMS system PI data
    - PI is the compiling mechanism – pulls from multiple different locations.
- Tollgrade sensors that are going into PI
- CRS – meter billing system. There is integration between customer billing and Salesforce.
- SharePoint – Engineering workflow tracking
- Projectwise – first stop for where to find transformer data
  - Transformer loading database has limits helping engineers identify what component/element of transformer system is the limiting factor
- CAPE data for system protection (breaker settings)
  - Last resort for transformer data

Xcel Energy doesn't currently have an all-inclusive impedance and connectivity model. It can get load data multiple ways through different data channels/tools. A future ADMS development effort is being proposed to address this. The ADMS will would first be developed in CO, and then in MN—it will be phased in across Xcel Energy's OPCOs, and enable the company to integrate everything into a singular system model.

2.34 Do you employ electronic maps for your entire distribution system? If no, what percentage is mapped electronically? Can/do the maps feed simulation tools for performing load flow analyses?

The vast majority of Xcel Energy's system is mapped electronically and in GIS, which allows for exporting into power flow programs (Synergi). Hosting capacity maps are not ready yet – they are in development (see Question 4.3) However, Xcel Energy has already released hosting capacity tables which some developers are currently using.

2.35 Is data from all systems stored in a centralized location? If so, is this database integrated with mapping tools and application process? Are all approved interconnection projects incorporated into utility internal mapping tools? Are PV sites added to the maps automatically?

The utility does not store all its DER information in a common database, though most of the information needed for modeling DER on a feeder is contained in GIS. The Company is exploring approaches for connecting the utility's different information sources. Salesforce contains all of the application data, including requested/allowed capacity and physical location. The DER type, locations, capacity, and power factor are mapped in GIS following completion of individual projects.

Summary Table

Interconnection Process		Which department performs step?	What Tools/Systems are used?	What data is needed?
All Applications	**Inquiry Received & Responded**	Program Office	Salesforce	Application
	Application Received	Program Office	Salesforce	Application
	Application Fee Received (for systems > 20kW)	Program Office	Salesforce	Fee
	Application Receipt Notification sent to customer	Program Office	Salesforce	Application
	Application reviewed for completeness	Engineering	Salesforce	Application and Drawings
	Application Status Notification sent to customer (complete or incomplete)	Program Office	Salesforce	Application
	Application Tracking (communication with customer throughout)	Program Office	Salesforce	Application
	Application sent for screening/review	Program Office	Salesforce	Application
Case 1: Expedited /	**Screening or Technical Review**	Engineer	In-house	Application and System Data

Fast Track / Simplified Process	**Application Approved**	Engineer	In-house	Application and System Data
	Request for Meter Set	Engineer	CRS	Application and System Data
	Add DG system to utility mapping	Engineer	GIS	Application and GIS
	Verification Test	Engineer		Application and System Data
	Final Acceptance	Engineer		Application and System Data
Case 2: Detailed Study	**Preliminary technical review**	Engineer	In-house	Application and System Data
	Estimate of detailed study if needed to customer	Engineer	In-house	Application and System Data
	Payment received	Engineer		Application and System Data
	Data request to customer	Engineer	In-house	Application and System Data
	Detailed study	Consultant or Engineer	Synergi, SKM, OpenDSS	Application and System Data
	Application Approved	Engineer		Application and System Data
	Request for Meter Set	Engineer	CRS	Application and System Data
	Add DG system to utility mapping	Mapping	GIS	Application and System Data
	Verification Test	Engineer		Application
	Final Acceptance	Engineer	In-house	Application

2.36 Does your utility have a permission to operation (PTO) timeline incorporated into its interconnection procedures?

For the DG program (excluding solar gardens), after an application has been approved by engineering and contracts have been signed, meters are ordered. The customer will receive an email from Xcel Energy to call/schedule a new meter install. Once the meter technician completes the meter install, the application moves into the completed stage and the customer will receive a PTO email from the utility. Xcel Energy does not provide a specific period by which PTO will occur, but this typically occurs within 5 business days of successful commissioning.

For Solar*Rewards Community, applicants have two years from the “expedited ready” date to make their systems mechanically complete (“Expedited ready” means the applications has gone through initial engineering review, all documents have been approved, and the garden operator has executed/paid to move into engineering scoping study). Xcel Energy provides a PTO letter when appropriate. Additionally, there is a

contract amendment allowing an extension to the timeframe in certain instances. Xcel Energy can cancel an interconnection application if the 2-year timeframe is exceeded.

2.37 To what degree, if at all, do you provide interconnection reports to a state agency (e.g. MN DOC, PUC, etc.)?

Xcel Energy provides monthly status and compliance reports for Solar*Rewards Community, and an annual report for DG interconnections to the Minnesota Public Utilities Commission. It also furnishes an annual report for the Solar*Rewards program to the Dept. of Commerce.

2.38 Do you report on compliance with meeting application processing deadlines?

Xcel Energy complies with reporting requirements from the Minnesota Public Utilities Commission and Department of Commerce for the Solar*Rewards Community and Solar*Rewards programs. Both can be viewed in Docket Nos. E002/M-13-867 and E002/\M-13-1015.

III. Perspective & Expectations: Online Portal

3.1 What steps, if any, have you investigated or taken to streamline the interconnection process? What is the rationale(s) guiding these activities? What have been the greatest obstacles?

The Salesforce portal handles the front-end processing system, payment, application management, progress and deadline tracking, and serves as a central storage place for applications, contracts, and supporting documents (single line diagrams, site plans, etc.).

An estimating tool and template letters help streamline the process for each project as it requires tweaks rather than recreating the information for each case.

Xcel Energy is contemplating additional streamlining and enhancements to simplify and automate document processing and management.

3.2 What steps, if any, have you investigated or taken to develop an online portal? What is the rationale(s) guiding these activities? What have been the greatest obstacles?

Salesforce has been working well on the front-end aspects of the process (check processing, initial application submittal, applicant check-in), and small interconnection agreements are automatically generated and populated in the online application system, which larger system agreements are more specific and are created manually. There currently are few engineering fields available for input, creating an underlying

back office gap that has not yet been addressed. Filling that gap represents the biggest opportunity for improving Xcel Energy's portal.

Xcel Energy is exploring further integration and automation of the interconnection portal with the initial and supplemental review process. (The current portal was initially set up for other customer programs and was adapted to manage DER applications. Many externally facing functions, such as application payments and refunds, holistic customer relationship management, regulatory reporting and outbound marketing / communications also are based within this portal that fuels the online application process.)

3.3 What longer-term (5+ years) aspirations do you have for streamlining the interconnection process?

Xcel Energy would like to bring forecasted DG interconnections into its DER integration processes.

Reporting is a challenge. Xcel Energy would like to produce a holistic report that accounts for the status of all of its DG interconnections across all of its operating companies. Currently, reporting is only set up on a program-by-program basis.

Solar*Rewards, Solar*Rewards Community, and other DG applications are separate and distinct. There are lots of disparate steps and the processes are different. Some of this is based on program-specific requirments. Long-term, Xcel Energy would like to see all interconnection applications merged into one DER interconnection system with as many similar steps amonst programs and interconnection types as is possible.

IV. Miscellaneous Questions

4.1 Does your company maintain a checklist for all on-site inspections? If so, are these checklists publicly available to customers and contractors, allowing them to better meet all requirements?

Xcel Energy recently uploaded a new step-by-step checklist for all DER (www.xcelenergy.com/staticfiles/xe-responsive/Working%20With%20Us/Renewable%20Developers/MN-Solar-rewards-engineering-checklist.pdf). It also provides examples of each step to see "what it should look like". Prior to this recent revision, Xcel Energy had provided program-specific checklists.

4.2 If revised standardized interconnection procedures are implemented, what hypothetical requirement(s) would concern you the most as being difficult or impractical to comply

with (e.g. communication, reactive power setting, other)? Are there constructive solutions/alternatives that you have developed or would suggest?

Xcel Energy wants to make sure that it does not commit to tighter than feasible timeframes for large volumes of applications or for complex applications such as rotating machines. It is easier to expedite the process for residential than utility-scale applications, the latter of which typically have more variances/quirks. Community solar sites have their own issues, consistent with other large DER projects, such as facility extensions and substation upgrades.

4.3 Some utilities keep a periodically updated map/database of distribution-level PV/DER hosting capacity to easily identify strategic locations for PV. Do you do this? If so, what is your utility's preferred frequency and timing for updating these maps?

Xcel Energy did not offer hosting capacity maps in its initial filing in 2016. It will include an initial iteration (version 1.0) of hosting capacity heat maps as part of its November 2017 PUC filing. These will look different than those offered in NY and CA and offer more of a heat map type of viewThe maps will be manually updated on an annual basis, and Xcel plans on further evolving hosting capacity maps going forward.

This year, the utility will incorporate existing DER in its hosting capacity analysis along with DER that has a signed Interconnection Agreement. Xcel Energy believes the maps will be a big step toward aiding its planning process. The maps should also help further smooth the interconnection process by providing general education. In particular, the maps should alleviate queue bottlenecks. (Capacity screens and pre-applications should help in this regard too.)

4.4 Do you currently have access to interconnected/operational DER performance data? If so, how does such visibility support utility planning or operations? If not, is there value in gaining such visibility (e.g. operational visibility and data resolution) regarding DER performance? At what scale of DER or type of DER is this most relevant?

Xcel Energy puts telemetry on any generation over 250 kW and data is piped through PI and the control center into a database. The utility requires that systems > 40 kW be affixed with two meters to separate out load vs. production in order to capture planning and operational data.

There is a lot of value in knowing how much load (not just net load) is present at any point on a feeder (e.g. to know what "hidden loads" exist). Energy storage systems may require additional metering considerations.

4.5 Do you believe the adoption of smart inverters would provide benefits, e.g. reduce the need for detailed studies?

Smart inverters provide additional options that can be used for remediation but are not seen changing the need to perform detailed studies.