



August 25, 2021

Will Seuffert, Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, MN 55101-2147

Subject: Dakota Electric Association Comments

***In the Matter of Updating Generic Standards for Utility Tariffs for
Interconnection and Operation of Distributed Generation Facilities Under
Minn. Stat. §216B.1611***

Docket Nos. E-999/CI-16-521 and E-999/CI-01-1023

Dear Mr. Seuffert:

On July 16, 2021, the Commission issued a Notice of Comment Period (Notice) in the above-referenced dockets. This Notice stated that the issues to be addressed in Comments are:

“Should any of the suggested changes identified in the Distributed Generation Workgroup (DGWG) subgroups’ final reports be adopted by the Commission related to:

- a) Group System Impact Study option for long interconnection queues or for capacity constrained feeders or substations;
- b) Interconnection queue management proposals; such as, Distributed Energy Resource (DER) capacity planning limits, feeder capacity reservations, and cost sharing mechanisms for customers with small DER; and
- c) DER dispute resolution processes?”

This Notice further identified the following topics open for comment:

1. Do the suggested changes advance the purpose of interconnection standards outlined in Minn. Stat. §216B.1611 or the Minnesota Distributed Energy Resource Interconnection Process or Agreements (MN DIP/DIA)?
2. Do the DER dispute resolution process clarifications comply with MN DIP Sec. 5.3?
3. Will the suggested changes improve the interconnection process for customers and the utility, including reducing the time needed to approve interconnection applications?
4. Should the Commission require a specific utility or utilities to implement the changes or adopt the practices for all utilities in Minnesota?
5. Does Commission adoption require an update to the MN DIP/DIA?
6. Are there other issues or concerns related to this matter?

Introduction

Dakota Electric Association® (Dakota Electric or Cooperative) submits these comments in response to the Commission's July 16, 2021 Notice in the above-referenced docket. Dakota Electric's focus in these comments will be on the identified issue to be addressed and the topics open for comment. Dakota Electric has been an active participant in the Distributed Generation Working Group (DGWG) since its formation and is appreciative of the collaborative efforts by parties as they relate to various distributed generation issues. The efforts of the DGWG have aided and improved Minnesota's interconnection and development of distributed resources. Although Dakota Electric was less involved with subgroups the past year, since the subgroups formed related primarily to issues currently specific to Xcel Energy (Xcel), the Cooperative has followed these subgroups and their recommendations. Dakota Electric appreciates the possibility to respond in these comments and provides its response and analysis below.

Dakota Electric Comments

The DGWG has been a great place to develop a common set of processes and procedures for interconnection of DER to the electrical distribution systems in Minnesota. Over the past year approximately, the DGWG members participated in several different subgroups working on key issues identified by the Commission and members of the

DGWG. Each subgroup was assigned to work on a specific issue or sets of issues. The subgroups were organized as follows:

Table 1: DGWG Subgroups

Subgroup	Membership	Facilitator
MN DIP Reporting	All Energy Solar, Xcel Energy, TruNorth, Dakota Electric, Otter Tail Power, Minnesota Power, IREC	Hanna Terwilliger
Interconnection Completeness Review	Xcel Energy, Sundial Solar, Sunrise Energy Ventures, TruNorth, All Energy Solar, MNSEIA	Alan Urban
Cluster Studies	Xcel Energy, Sunrise Energy Ventures, IREC, Fresh Energy, MNSEIA	David Shaffer
Study Results	Xcel Energy, Sunrise Energy Ventures,	Alan Urban
Interconnection Review in Queues [Projects “on hold”]	Xcel Energy, Fresh Energy, IREC, Sunrise Energy Ventures, TruNorth, All Energy Solar, MNSEIA	Isabel Ricker
Attachment 3 Interconnection Application	Minnesota Power, Dakota Electric, Xcel Energy, Sunrise Energy Ventures, MREA, TruNorth	Kristi Robinson

The MN DIP reporting and the Attachment 3 Interconnection Application subgroups each developed a final report which included an agreed upon set of updates or recommended changes. For these two subgroups, the recommendations were then presented to the complete DGWG and received review and approval from the entire DGWG. Dakota Electric was pleased with how well the sub-groups collaborated on these issues and developed useful solutions to the issues. The Commission has since acted upon these recommendations and the changes noted by these subgroups are now being implemented. Dakota Electric views these subgroups as completed, and we will be submitting an updated MN DIP for DEA later this year in support of these recommended changes.

The four other subgroups were focused upon process issues and experiences with interconnection to Xcel’s distribution system. No utility representatives from other Minnesota utilities participated in these four subgroups. None of the recommendations which resulted from these subgroups have been fully vetted and discussed by the full

DGWG. As such, Dakota Electric notes that any recommendations brought forth by these subgroups do not include the opinions, ideas, or input of the other regulated utilities.

Dakota Electric responds separately to each of the Commission's areas of notice and topics open for discussion below.

System Impact Study (Study Results) Subgroup results

The Commission's Notice requested information regarding group System Impact Studies. The DGWG formed a subgroup in 2020 to respond to this issue after concerns noticed on the Xcel system. This subgroup appeared to focus on Xcel's internal process and reporting formats for study results. The only utility member of this subgroup is Xcel. The resulting recommendations from this subgroup appear applicable to Xcel and thus should not be applied to any of the other regulated utilities. Dakota Electric reviewed the MN DIP and concludes that no modifications to the MN DIP that affect other regulated utilities should be implemented.

Interconnection Review in Queues

Within the Interconnection Review in Queues Subgroup, there was no representation from regulated utilities other than Xcel, and the proposals and recommendations resulting from the subgroup were focused on existing Xcel issues. This subgroup addressed several different topics. Dakota Electric discusses and responds to these topics separately below.

Handling Applications which are in Queue "on hold" behind a larger system is being studied: Dakota Electric has not experienced the need to put applications on hold, but it can envision a circumstance in the future where this may occur. Once a feeder or substation has limited or no hosting capacity, the next DER applicant is responsible for the full upgrade costs to support that proposed interconnection. The review and finalization through studies of that applicant's cost contribution, and the subsequent commitment of that applicant to pay for the identified upgrades, is needed before the next applicant in the queue can be fully studied. While there will be cases where a small behind the meter system on the same feeder could be allowed to proceed through the process (it is important to note that this does not currently comply with the MN DIP), and not impact the larger

DER study, there will also be times when there is zero hosting capacity available. In that instance, the first applicant must agree to pay for upgrades before any other applications can be approved. In many cases, the cost causation method for recovery of upgrade expenses is the driver for the need to maintain the strict queue management.

As DER penetration increases on the Dakota Electric system, there are several substations which will reach hard limits on DER integration. The limit is caused by the inability of the existing transmission system to safely accept back feeding of the transmission line. Once that substation reaches its hosting capacity limit, the next applicant will be subject to a multi-million-dollar transmission upgrade requirement. Dakota Electric is exploring options to help manage this identified issue, but our current assessment is that any solution involving modifications to the transmission system carry significant implementation costs.

Application Screening in Parallel: Xcel's proposal to screen applications in parallel is appropriate for Xcel because they have multiple personnel screening DER applications. However, at Dakota Electric, we have one person responsible for screening DER applications. While we have multiple people performing different tasks in the DER interconnection process (*i.e.*, application review, engineering screens, field testing), most of these areas have one person handling these tasks; thus, all applications at Dakota Electric are necessarily handled in series.

Planning Limits for DER capacity: There was limited discussion at the DGWG meeting when this concept was presented as there was disagreement among the work group membership about how these planning limits would be applied. Based on the information available, it appears that the subgroup has ongoing concerns about this proposal and does not recommend implementation at this time. It is important to note that Dakota Electric does not have a separate planning limit for DER capacity. Dakota Electric uses the equipment ratings for the capacity limits.

Capacity reservation for customer-sited projects: Xcel discussed an idea to reserve some level (25%) of a feeder / substation capacity for behind the meter, customer-sited projects. There was limited discussion at the DGWG meeting when this concept was presented as there was disagreement among the subgroup membership for this proposal. Dakota Electric understands Xcel's approach because it provides smaller residential and

business systems with the ability to utilize the existing “free” hosting capacity before it is all gone. By reserving this capacity for smaller systems, it would initially help those systems be able to interconnect. However, in the long run, once this reserve capacity is used up, we would return to a fully utilized feeder/substation and the same issues we have now would exist. Today, Dakota Electric has a limited number of solar garden systems consuming large amounts of the available hosting capacity; Dakota Electric does not see the need for this blanket reserve capacity on our distribution system at this time.

IREC and Fresh Energy proposed to establish a new mechanism for paying for grid upgrades: Since Dakota Electric was not a subgroup participant, and given limited information provided by the subgroup on this topic for the DGWG, Dakota Electric recommends not adopting this recommendation at this time. Dakota Electric does, however, agree that a different mechanism for providing cost recovery for distribution system costs in support of DER interconnections is a worthwhile discussion. Dakota Electric notes that this will likely be a difficult discussion because, presently, DER systems which utilize the distribution system to export excess generation do not pay for the costs to support and maintain the distribution system. Currently 100% of the support and maintenance costs for the distribution and transmission system are paid for by the consumers of electricity. Further, since Dakota Electric is still in the “free capacity” phase of DER adoption, where the distribution system is fully available to DER adopters, we have not reached the point of incurring the high costs involved with upgrading the distribution and transmission system. At several Dakota Electric substations, once we reach a point where we back feed the transmission system, we will either need to stop all further DER integration or find a method to pay for costly transmission upgrades.

Allowing DER systems to interconnect and operate under existing cost structures has worked due to the low percentage of homes and business with DER generation systems. As more people install DER systems, and pay less or stop paying for the operation and maintenance of the distribution system, the remaining users of electricity who are unable or cannot afford a DER system will be the ones paying for on-going operation and maintenance costs. This issue is just beginning in Minnesota, but this shift in distribution system costs has already started in other parts of the country. Dakota

Electric believes it may be worthwhile to analyze this subject in detail before widespread cost shifting expands further in Minnesota.

Dakota Electric does not have a firm recommendation or position at this time, but a change in the process for compensating a utility for distribution system upgrades and annual system costs may be worth considering. For example, considering a monthly fixed or energy charge for excess energy exported to the distribution system may be a way to mitigate or resolve many of the current issues Dakota Electric and other utilities are facing while encouraging more DER integration and fairly allocating upgrade costs among DER applicants.

Levelized Costs for the Consumer: Currently, when there are charges for upgrading the distribution system to interconnect a new DER system, the total costs, big or small, must be paid by the applicant up front. The ability for a distribution utility to capitalize the costs of the distribution system upgrade, and then charging a monthly rate for the DER, would levelize costs to the consumer and DER developer. This is another potential solution or discussion point that the DGWG may wish to consider.

Support Efficient Planning: As noted at several times in these comments, the DER applicant currently pays for the cost of any distribution system upgrade attributable to their system installation. If the utility would upgrade a line or portion of their system ahead of time, when the DER application comes in, there is no method to recover the costs of the upgrade. The existing users of the distribution system will pay for 100% of an upgrade that they may not need. Presently, there is no recovery method for a utility to address both system deficiency needs and upgrades which support future DER interconnections. If a utility would be compensated by the DER systems in the same way that they are compensated by users of energy, then the utility would have support for planning and upgrading the system to support forecasted DER integration. If everyone who uses the distribution system for energy flow, including DER users, pays a little each month in support of the distribution system, then everyone would pay their share.

Dakota Electric does not currently support a one-time charge for small DER interconnects as the cost of interconnecting future DER systems to the distribution system will likely continue to increase with greater DER penetration. While current DER systems

that are interconnecting are incurring few upgrade costs, once the DER penetration level reaches a point, those upgrade costs will rise dramatically. It is also important to note that there are on-going distribution system costs caused by DER interconnection which are not recovered through a one-time interconnection payment. If these on-going costs are not considered, then other ratepayers will assume these costs and DER developers, and those members using DER, will not pay their fair share of costs. Some examples of these on-going costs are:

- 1) When the distribution transformer is replaced with a new larger unit;¹
- 2) Additional personal property taxes;²
- 3) Maintenance;³ and
- 4) Operational Costs.⁴

¹ When a larger transformer is installed, the energy required to keep the transformer energized 24/7 is increased. Approximately 50% of the total energy losses on the Dakota Electric system are due to transformer no-load losses. Changing out a typical residential 25kVA pad mounted transformer for the next size unit (37.5 kVA) increases the no-load losses by 30-40%. These energy losses occur 24 hours a day. While the annual cost per individual transformer in additional energy purchases is small, increasing the size of many transformers to support DER interconnections will add up if large numbers of transformers require upgrade. These energy losses are ultimately recovered from all members.

² Dakota Electric pays personal property taxes based, in part, on the value of the facilities it has installed. Increasing the value of the electrical plant through DER upgrades, increases the annual tax payments required. These increased property taxes are included in rates charged to all members.

³ As the result of DER system integration, new control systems will need to be installed to regulate the operation of the feeder to support DER, such as for distribution voltage regulation. Dakota Electric personnel will be involved with maintaining and periodically replacing this equipment. Dakota Electric crews are also involved with resolving operating issues with the DER. All else being equal, Dakota Electric expects an increased cost of labor and materials for this support.

⁴ With the installation of DER systems, the distribution system changes from a one way to a two-way flow of energy and one with variable levels of generation. This change greatly increases the complexity of operating the distribution system. This change results in additional labor and systems to support the more complex operation. For example, when switching is required to back feed, or otherwise resupply a portion of the distribution system, additional studies and coordination is required. Other examples of additional operational costs include: time involved communicating and coordinating with the DER operator to inform them of the potential curtailment of their system, additional personnel in the field to perform more complex switching, and additional engineering studies prior to the switching to ensure the safe operation of the system in the new configuration. It would be easiest to simply fully curtail the DER when any non-normal configuration of the distribution system occurs, but Dakota Electric tries to keep the DER systems operating as much as possible so that members can benefit from their DER installations. This approach takes additional labor to monitor the system to ensure that voltages are within acceptable ranges and equipment is not overloaded. As more DER systems are integrated, the complexity of the distribution system operations will continue to increase and additional issues required to be monitored and resolved will also increase.

Dakota Electric appreciates the discussion and work conducted by the workgroup on this topic, but it concludes that any attempt to apply recommendations to other utilities or changes in the MN DIP are not appropriate at this time. Although Dakota Electric believes this is an important topic, and one with significant issues that will likely need to be addressed in the future, there is not sufficient information available at this time to support a change in guidance or standards for utilities, other than Xcel, since they were not represented in the workgroup.

Interconnection Dispute Resolution

The Commission's Notice requested discussion on the suggested changes identified in the DGWG subgroups' final report regarding DER dispute resolution. In terms of topics open for discussion, the Commission asked whether the DER dispute resolution process clarifications comply with MN DIP Section 5.3? None of the subgroups directly discussed the issue of dispute resolution, but Commission Staff provided discussion and analysis on this topic in its March 19, 2021 DGWG MN DIP Review.⁵ However, the process to resolve disputes between developers and the utilities is an important topic that requires further discussion and may require modification going forward. Dakota Electric has been fortunate to date that it has not had a dispute, or complaint filed, with a DER developer; however, this may be a function of the fact that the Cooperative currently has available hosting capacity. Dakota Electric does however see a future where dispute may occur; as such, it welcomes the chance to respond to the Commission's request for comment on this topic.

Dakota Electric begins its response by noting that it is unclear whether formal process clarification recommendations were made as discussed in the Notice. That being said, Commission Staff raised important discussion questions in its March 19, 2021 DGWG MN DIP Review presentation. The most important takeaway from Commission Staff's analysis is that the number of interconnection disputes have increased in recent years and the number of formal complaints being filed with the Commission has also increased. The MN DIP allows parties to file a formal complaint at any time, so parties are

⁵ These slides were filed in eDockets on May 11, 2021.

well within their rights to do so. However, it is also important to note that these formal complaints stop the interconnection queue and may ultimately slow DER development.

Commission Staff presented the DGWG with three important questions regarding dispute resolution:

1. Should the MN DIP or utilities/PUC have different dispute resolution requirements depending on the type of interconnection customers?
2. Should the MN DIP address what happens to the queue when a project ahead in queue has a dispute?
3. Are there models of interconnection dispute resolution that should be considered by PUC or Minnesota utilities?

The Cooperative discusses each of these questions separately below. Before responding to these questions, Dakota Electric notes that the idea of separate interconnection queues and how to deal with small and large generators is not a new concept. In fact, the Commission did not establish an interconnection queue when the 2004 standards were approved because there were concerns that smaller generators would be at a disadvantage relative to larger generators.⁶

The first question raised in the notice is whether there should be different resolution requirements depending on the type of customer. This is a difficult question and ultimately comes down to a policy decision, namely, whether there is a preference between the interconnection of the greatest number of projects (smaller projects, individual customers) or the greatest level of overall DER capacity (larger projects, solar gardens). Absent additional analysis and discussion by the DGWG, Dakota Electric does not have a firm position on this matter; however, if the Commission contemplates a bifurcated dispute resolution process, it is likely that modification to the MN DIP will be required. The current MN DIP, and Section 5.3 which governs disputes, does not contemplate a separate queue or dispute resolution process. Although the current language in Section 5.3 may be able to accommodate a separate process, Dakota Electric believes, at this time, that a clarification of this section is likely necessary so that the different tracks are well defined.

⁶ Dakota Electric, August 19, 2016 Comments, Page 3.

The second question is whether the MN DIP should address what happens to the queue when a project is in dispute. As with the first question, this also comes down to a policy decision from the Commission. As currently constructed, the MN DIP and DER connection process in Minnesota assumes a fully serial approach to processing applications. Simply put, it is a first come, first served system. For example, if a feeder has 150 kW of open hosting capacity and Developer A proposes a 225 kW project and a dispute or complaint occurs, Developer B proposing a 5 kW rooftop installation and Developer C proposing a 10 kW installation are effectively put into limbo awaiting resolution of the dispute even though there is adequate hosting capacity to interconnect these projects with limited impact to Developer A. If the Commission believes a pragmatic approach to DER interconnection for smaller developers is appropriate, then Dakota Electric believes that the MN DIP should be revised to address this sort of situation.

The final question posed by Commission Staff is whether there are other interconnection dispute resolution models that should be considered. Dakota Electric does not have a firm recommendation, or example, for this matter, but the history of interconnection disputes in recent years suggest that improvements or other methods may be worthwhile. Currently, disputes typically fall into two buckets, interconnection issues and technical/engineering issues. Unfortunately, both of these types of disputes have experienced inefficiencies and issues recently that have slowed the interconnection queue for other projects waiting for a dispute or complaint to be decided.

On the engineering or technical side, the primary concern is a question of available regulatory resources. In its presentation, Commission Staff noted that it only has one engineer on staff and this individual is responsible for issues beyond DER and dispute resolution. In addition, several years ago, the independent engineer process, which was administered by the Department, did not function properly because of difficulty obtaining qualified engineers and was ultimately discontinued. The issue on the technical side is that a well-defined, independent, and fully qualified dispute resolution mechanism does not exist, which raises the possibility of slowing the interconnection queue or the possibility of formal Commission complaints. Dakota Electric notes that, in general, recent disputes have been more queue related and less technical in nature; however, this does not mean

that the deficiency in technical analysis should be ignored. Dakota Electric believes it is worthwhile for the DGWG to discuss this issue in greater detail and attempt to create an independent dispute resolution process for technical issues.

As noted in the previous paragraph, Dakota Electric has observed that many recent disputes are queue interconnection related. Although potentially less technical than engineering issues, these disputes still require detailed analysis and require significant resources from the complaint parties and regulatory agencies. Dakota Electric believes that when the DGWG considers other queue issues noted in these comments, it is also important that dispute resolution in general be considered. The Cooperative believes that working toward a method or process where parties have access to an unbiased, qualified expert is important and may reduce the risk of formal complaints being filed with the Commission.

Cluster Study Subgroup Recommendations

The Cluster Study Subgroup was tasked to resolve a difficult issue, which is underlined by the final report filed on July 16, 2021. In this final report, there remained a considerable difference of opinion between the subgroup members as to how a cluster study should be performed and what results are expected from a cluster study. In particular, the meeting notes stated:⁷

The parties did not agree on a common understanding of where clusters should be used... There was also disagreement about where Xcel's Cluster Study pilot would yield useful results given that it is nonmandatory and would rely on full cooperation between Xcel and each participating developer.

These conclusions suggest that additional discussion and analysis on this topic is needed.

The Cluster Study Subgroup also filed meeting notes on June 9, 2021. These meeting notes discussed cluster studies and their relation to the MN DIP. Although there may be dispute regarding how cluster studies work or are applied, these notes concluded that the MN DIP currently supports cluster studies. Based on this information, Dakota

⁷ July 16, 2021 Subgroup SIS Report, Page 5.

Electric concludes that no modification to the MN DIP is required at this time regarding cluster studies. Since the subgroup's final report raised more questions than answers on the subject, no modification to the MN DIP is warranted and any changes may result in further dispute or confusion.

The issue of studying a cluster of DER integration applications is in response to existing individual studies taking a long time, and the use of cluster studies is an attempt to speed up the integration process. Conducting a cluster study of multiple developments appears like an attractive solution, but it is not without its own issues. The problem is the complexity of a cluster study and the additional effort required to coordinate among the different parties. This increased coordination may increase the amount of time and labor required to complete the DER application review. Dakota Electric currently does not face the need to consider using cluster studies. However, this is only because we do not have a high penetration of DER system interconnections to our distribution system and, in most cases, there is available hosting capacity on our feeders for additional interconnections. When hosting capacity is available, which can be utilized without distribution system upgrades, the need to conduct, and the potential benefits of, a cluster study do not exist. Dakota Electric acknowledges that once the penetration levels for DER installations reach the point where excess hosting capacity does not exist, it will have many of the same issues studying and processing DER applications that other utilities are experiencing.

In the Cluster Study Subgroup's June 9, 2021 final report,⁸ there were many complex issues which were identified and remain unresolved. For example, pages 2 and 3 of the subgroups final report noted timing, geographical scope, requirements for participation, excluding small projects, and single application groups as topics where consensus was not reached. Each of these topics include complex issues and the potential solutions are problematic.

Looking at the topic of requirements for participation, there is the possibility that an applicant could game the system to arrive at a possible solution. Under the current interconnection process, if an applicant becomes aware of the possibility of a cluster study, the applicant can simply withdraw their application and avoid the cluster study. This strategy is possible because system upgrades are not precise and there can be significant

⁸ This report was filed in eDocket on July 16, 2021.

additional hosting capacity available after an upgrade is complete. As such, after the cluster study is completed, and upgrade costs assigned, it is possible for the withdrawn applicant to simply reapply for interconnection. Assuming sufficient capacity is available, the “new” applicant could interconnect without paying for any upgrade costs. This creates a serious equity issue.

Dakota Electric also notes that the current method of assigning interconnection costs is part of the issue contributing to inefficiencies in the interconnection queue and the complexity of cluster studies. As noted earlier in these comments, the current practice requires the next DER interconnection which causes a distribution or transmission system upgrade to pay for the full cost of the upgrade. This method is workable in an environment where the DER additions occur slowly, are adequately spaced out, and are relatively low cost. However, in a dynamic, or higher cost, DER market, this method becomes less efficient and is prone to accusations of free ridership by other developers. Under the current system, when one system crosses the distribution or transmission upgrade line, then that one DER integration application becomes a bottle neck. Since this application will be responsible for all upgrade costs, they need to be studied to identify the upgrade costs. If the upgrade costs are high, it is likely that this development will push back and request additional support for the upgrade cost estimates. Based on the current structure of the MN DIP, this application will hold up any following applications, some of which may be sufficiently small to allow interconnection without issue, for the substation and/or feeder while the issue of upgrade costs is resolved.

In this situation, it is possible to move beyond the single development study and look to a cluster study. The cluster study, in theory, acknowledges that many DER systems are interested in a substation and/or feeder and attempts to quantify this demand and fairly allocate costs. Theoretically cluster studies appear to be a solution to parallel the study and interconnection of multiple DER systems; however, in practice, it is in fact a potential multiplier of issues. Dakota Electric discusses three issues created by a cluster study below.

1. Cluster Study Commitment: Under the current set up, members of a cluster study can drop out at any time. This arrangement can result in a failed cluster study and the need to restudy since the cluster group changed. Dakota Electric believes it is

unreasonable to require a developer to commit upfront to the unknown results and resulting upgrade costs from a cluster study. As a result, even if participants remain in the study for its duration, once the results of the cluster study are known, if the costs resulting from the study are too great for any of the cluster study developers, they can withdraw their application. If this occurs, then the results of the study may be useless.

2. How are the upgrade costs for a cluster study allocated to the cluster study participants? One could allocate the upgrade costs for each system based upon their DER system rating, but even that could be contentious or considered unfair. Let us consider an example where two DER systems are the same size and want to interconnect to a distribution system. If one DER is interconnecting close to the substation, it may only need ¼ mile of line rebuilt, but a second member of the cluster study located further from the substation may need two miles of line rebuilt. Under a division of costs based upon DER kW rating, this is unfair. This raises the important question of how upgrade costs should be split. Even with a cluster study, it is still necessary to study each DER interconnection and understand their individual impacts to the distribution system.
3. Timeframes: A cluster study requires coordination among multiple developers, each with a different priority for their project. At the outset, this coordination takes time, and all it takes is one cluster study participant to delay sending back the cluster agreement to hold up the study. In addition, the overall complexity of the cluster study contributes to the length of time. These studies require an understanding of how costs will be allocated among the study membership and what each member of the study will pay for the study and also for the upgrade costs; these all contribute to increased timeframes. As noted in the subgroup report, this coordination takes time and “will take significantly longer than the study process timeline developers are familiar with.”⁹ The overall timeframe will also be impacted if the cluster study requires a transmission impact study in addition to the distribution study.

⁹ July 16, 2021 Subgroup SIS Report, Page 7.

Dakota Electric believes that cluster studies have value and are an important tool in certain circumstances. However, these studies are not without their own concerns and issues regarding interconnection, especially considering the current interconnection process. The Cooperative is fortunate that it currently has available hosting capacity, so it has not experienced the need to consider cluster studies, but it is likely that this is something that we will need to consider in the future. Given this future consideration, Dakota Electric believes it is important that the DGWG review this issue in greater detail and potentially consider modifications to the MN DIP to improve the cluster study process.

General Discussion and Other Areas Open for Comment

Dakota Electric has been an active participant in the DGWG, although not as much for the most recent topics because these issues are not currently impacting our operations. That being said, Dakota Electric believes some general discussion on DER interconnection is necessary in light of the experiences of other utilities and DER developers. As discussed earlier in these comments, IREC and Fresh Energy raised the prospect of different costs depending on the type of project proposing interconnection. The current method used to allocate costs for new DER interconnections involves the DER application that trips the need for the upgrade to pay the entire cost of the upgrade. This method is different than how the distribution system is planned and constructed for new homes or business. When the distribution system is constructed, as new homes and business are added, they pay for the distribution upgrades as part of the monthly electrical bill. If a new service requires distribution system upgrades in excess of the expected costs that will be recovered through the monthly electrical bill, these customers are charged a “Contribution-in-aid-of-Construction” (CIAC). This CIAC is generally collected upfront and is used to offset the costs above and beyond the normal costs of extending service to the home or business. When a DER requires distribution system upgrades though, the standard cost recovery process is not applicable, and all the costs of any system modification must be collected at the time of the interconnection. If a distribution system upgrade is made and paid for by the DER installation that trips the need for an upgrade, and this upgrade creates additional

capacity on the distribution system, the next DER system may be able to interconnect without any upgrade costs. However, if there was a monthly usage charge for each DER which is using the distribution system, then some portion of the distribution system upgrade costs resulting from the need to increase capacity for interconnecting DER could be allocated to all the DER systems which use the distribution system. In the simplest sense, all prospective DER developers will know that an interconnection fee will be necessary to complete a project and that it is a specific cost of doing business.

As noted in the previous paragraph, for the connection of typical new services, the cost causation method is not used. The distribution system upgrades costs are capitalized and recovered over time through monthly rates. The cost recovery of new services is accomplished through a combination of fixed and variable charges. If there was a similar cost recovery method for DER interconnection costs in place, it could resolve some interconnection process issues.

The following are some examples of areas that could be improved if there was cost recovery for DER integration upgrades through DER distribution system usage rates.

- 1) Some DER applicants may not be required to pay a large upfront cost to upgrade the distribution system and instead the utility would be compensated through a monthly cost recovery method.
- 2) The first in, first out queue management would no longer include most cost issues and would remove the issue of applications be held up by other applications ahead in the queue. Instead, the queue would be for allocating limited engineering and review labor to ensure the applications are processed in the order they are received.
- 3) The idea of studies for individual applications or clusters would be focused and driven by the utility to identify the lowest cost long term solution, to the benefit of all ratepayers, not the lowest cost short term solution for the one applicant or the members of the cluster study. This will result in lower long-run system costs and reduces the risk of inefficient project analysis.
- 4) A DER application that is filed after a distribution upgrade is paid for by another applicant would pay their share of the overall distribution system upgrade costs.
- 5) If DER specific costs are tracked and charged to all DER developers, the utility could be proactive and take advantage of current upgrade opportunities, such as

feeder rebuilds due to road construction, for the distribution system to support future DER interconnections. The current process, and standard ratemaking, does not allow utilities to incur expenses for system upgrade until there is an active DER interconnection application.

- 6) Distribution system voltage management would not need to be implemented piece by piece in response to new DER installations, but instead could be designed as a complete system to optimize the overall operation of the distribution system.
- 7) DER systems are presently designed to be interconnected and operated with one feeder and one substation. Monthly DER system usage rates would allow the utility to accomplish upgrades required to allow optimization and reconfiguration of the distribution system to support the operation of the DER on other feeders and/or substations. This benefits all users of the distribution system, the efficient operation of the distribution system, and helps create additional options for supporting future DER interconnections.
- 8) Rates could be designed so the member's monthly cost are directly related to the amount or level of energy which flowed, in or out, of their service. This type of rate structure would incentivize the consumer to align the time periods of the usage of electricity with the DER generation of electricity. The result would be less energy and demand placed upon the electrical system, which could directly impact the amount of distribution and transmission system facilities required to be built and maintained.

Dakota Electric does not have a recommendation at this time regarding the level of these potential charges. That being said, it is clear that potential benefits exist with spreading the costs of distribution system upgrades across all interconnected DER systems. The Cooperative looks forward to discussing this issue and potential solutions in the future.

Conclusion

Dakota Electric appreciates the opportunity to provide comments on this matter. The DGWG has been an effective tool in the creation, maintenance, and improvement of the DER interconnection process in Minnesota. Dakota Electric reviewed the work of the DGWG over the past year and concludes that certain topics as they relate to DER interconnection require discussion and analysis. Dakota Electric believes addressing these concerns on a going-forward basis through the DGWG is necessary and an important step in the continued development of DER in Minnesota. If you or your staff have any questions about these comments, please contact me at 651-463-6258 or aheinen@dakotaelectric.com.

Sincerely,

/s/ Adam J. Heinen

Adam J. Heinen
Vice President of Regulatory Services
Dakota Electric Association
4300 220th Street West
Farmington, MN 55024

Certificate of Service

I, Melissa Cherney, hereby certify that I have this day served copies of the attached document to those on the following service list by e-filing, personal service, or by causing to be placed in the U.S. mail at Farmington, Minnesota.

Docket Nos. E-999/CI-16-521 and E-999/CI-01-1023

Dated this 25th day of August 2021

/s/ Melissa Cherney

Melissa Cherney