APPENDIX I – SUPPORTING INFRASTRUCTURE – TRANSMISSION & DISTRIBUTION

The goal of a sustainable, cleaner energy future depends upon sufficient infrastructure to support delivery of renewable and distributed generation resources and customer reliability. In particular, modernized transmission and distribution systems are critical to our ability to serve our customers in a reliable and safe manner, deliver growing levels of choice, increase renewable energy, meet the challenges of emerging technologies, and take a holistic view of resource planning.

As we actively prepare our distribution system for the needs of the future, we consider the need for thoughtful investments to meet our core obligation, safely and reliably delivering energy to our customers. We also are focused on adopting smarter technologies to further enable distributed energy resources (DER) on our system. We also face new challenges and opportunities for the transmission grid as traditional baseload units retire, large scale renewables significantly increase, and DER are increasingly adopted. In some cases, such as increasing consideration of distribution-level DER on the transmission grid, changes in the market and planning constructs are underway. Other changes are just coming into view and the planning constructs have not yet caught up. We are adapting our planning practices in the interim to ensure reliability and resilience, and we expect substantial new transmission will be needed to support the transformation that is underway.

Overall, we envision building toward an integrated grid that supports the Company's clean energy transition, leveraging the strength of an interconnected system to make the best use of available resources while continuing to serve our customers with resilient and reliable power. We discuss our transmission and distribution systems in greater detail below, including the ways we expect planning to become more integrated over time.

I. TRANSMISSION

The Xcel Energy Operating Companies NSP-Minnesota and NSP-Wisconsin operate an integrated transmission system (the NSP System) comprising more than 8,400 miles of transmission facilities operating at voltages between 23.7 kilovolts (kV) and 500 kV and approximately 550 transmission and distribution substations. The NSP System serves retail customer loads in Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan. The NSP System is wholly within the Midcontinent Independent System Operator (MISO) footprint, which is part of the Eastern Interconnection.

The transmission grid in the Upper Midwest has seen significant development over the last 10-15 years. These changes have increased both resilience and capabilities to transport renewable energy from the geographic locations where it is abundant to customer load centers, such as the Twin Cities Metro area. But, as discussed in this Appendix, in Appendix J1: Baseload Study, and in conjunction with the Reliability Requirement we developed for this Resource Plan (Appendix J2), the grid is facing new challenges as traditional baseload units retire, large scale renewables significantly increase, and distributed energy resources (DER) are increasingly adopted.

Below, we provide a brief overview of the NSP System transmission grid and our transmission planning efforts to ensure we maintain customer reliability as the grid transforms and the lines between distribution and transmission blur. We then discuss the challenges in maintaining reliability in *every hour of every day* when the resource adequacy construct relies on an average contribution for a single future planning year. While this is reasonable for firm, dispatchable resources, it does not adequately recognize the intermittent nature of renewable resources – particularly as penetration levels grow – and as we discuss, results in gaps in meeting customers' energy requirements. We then discuss the Reliability Requirement that we developed for this Resource Plan to address this challenge and better ensure grid stability and resilience, and customer reliability. We also discuss the challenges and opportunities associated with interconnecting and efficiently utilizing the substantial new renewable generation we will need to meet our goals, given the current state of the MISO interconnection queue and transmission limitations. Finally, in the balance of this section, we discuss timely issues and summarize our Baseload Study.

A. Transmission System and Planning Overview

The Transmission Business Unit centrally manages Xcel Energy's transmission systems (i.e., NSPM, NSPW, Public Service Company of Colorado, and Southwestern Public Service Company) so that energy is safely and reliably transmitted from generating resources (both Company-owned and third-party owned) to the distribution systems serving our customers. While transmission planning is considered separately from resource planning, these two functions are necessarily interrelated, just as the generating resources and transmission infrastructure on the grid are interrelated. Transmission needs are driven by multiple factors including increased customer electric demand, new or retiring generator interconnections that adjust the flows on the existing transmission system, and generation resource choices and the availability of transmission to meet the demand for these resources. The interconnected nature of the transmission system also means that neighboring utilities' decisions (either transmission or generation) have impacts on the NSP System. Finally, as DER grows, even small retail customer changes at the distribution level may impact the transmission system.

As demonstrated in the Biennial Transmission Plan we submit to the Commission in odd-numbered years, we are constantly reviewing and studying our system to optimize operations and prepare for the future. We independently—and in conjunction with MISO—analyze different futures to assess the system and determine any necessary build-outs, in both short- and long-term planning horizons. Based on these analyses and subsequent implementation, between 2010 and 2018 we invested more than $3 billion in our transmission system. Much of our transmission investment over the recent past has been in implementing the CapX2020 initiative and participating in MISO Multi-Value Projects (MVP), which substantially increased transmission capabilities in the Upper Midwest.

1. *Planning Initiatives*

MISO and the Company perform ongoing and specialized studies to evaluate necessary projects to address issues in the overall MISO system, including the NSP System.

From these studies and our own technical study efforts in support of the Baseload Study we undertook with this Resource Plan, we believe significant additional transmission development will be necessary as we and other utilities retire baseload generating units and add significant renewable resources to the grid toward our commitment to a clean energy future. We also believe changes to the current planning constructs are necessary to properly reflect the trends underway, to ensure system stability and resilience, and customer reliability.

a. Company Biennial Transmission Projects Report

Pursuant to Minn. Stat. § 216B.2425, every other year, the Company – along with the other Minnesota Transmission Owners[1] – submits a Biennial Transmission Projects Report to the Commission reporting on the status of its transmission system. The Biennial Transmission Projects Report lists specific present and foreseeable future transmission inadequacies; identifies alternatives to address system inadequacies;[2]

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[1] American Transmission Company, LLC, Dairyland Power Cooperative, East River Electric Power Cooperative, Great River Energy, Hutchinson Utilities Commission, ITC Midwest LLC, L&O Power Cooperative, Marshall Municipal Utilities, Minnesota Power, Minnkota Power Cooperative, Missouri River Energy Services, Northern States Power Company, Otter Tail Power Company, Rochester Public Utilities, Southern Minnesota Municipal Power Agency, Willmar Municipal Utilities.

[2] Minnesota Transmission Owners define "inadequacy" as essentially a situation where the present transmission infrastructure is unable or likely to be unable in the foreseeable future to perform in a

identifies general economic, environmental, and social issues associated with the alternatives; and summarizes the input that transmission owners and operators gather from the public and local governments to assist in developing and analyzing alternatives.

The 2017 Biennial Transmission Projects Report was filed with the Minnesota Public Utilities Commission in Docket No. E999/M-17-377 on November 1, 2017, and can be found at the Minnesota Department of Commerce's eDockets website at www.edockets.state.mn.us/EFiling or at www.minnelectrans.com. The 2017 report lists more than 90 separate inadequacies throughout the state, including more than 50 newly-identified inadequacies since the filing of the 2015 Biennial Transmission Projects Report. Of the inadequacies identified, 13 involve Xcel Energy.

b. Ongoing MISO Studies

MISO Transmission Expansion Plan (MTEP). MISO has an annual transmission planning process which results in identification of needed transmission facilities.

MISO Generation Interconnection Studies. MISO performs generation interconnection studies to identify facilities necessary to connect new generation resources.

MISO Economic Planning Studies. As part of its planning process, MISO conducts a *Market Congestion Planning Study (MCPS).* The purpose of this study is to determine whether there are transmission projects that could remove transmission constraints and thus more efficiently use available generation resources. The *MCPS* results are reported as part of the annual MTEP report. During the *MCPS* process, projected economic and power flow models are developed which, when analyzed, determine the total production costs that are incurred to provide energy to the MISO load. Transmission constraints – the transmission elements that limit the amount of power that can be transferred between the unused, lower-cost generation and customers – are identified. Through stakeholder discussions, transmission projects are proposed that could mitigate the constraints. The costs for these proposed transmission projects are determined and compared to the amount of production cost savings that could be realized if those projects were in service. The resultant benefit to cost ratio of the projects indicates whether the proposed solutions should be considered for further evaluation for constructability and reliability analysis. Stakeholder review and comments are compiled, and a decision on whether to recommend a *MCPS* project be included in the upcoming MTEP report is made.

consistently reliable fashion and in compliance with regulatory standards.

c. CapX2020 and MVP Regional Development Initiatives

The CapX2020 initiative was a coordinated transmission development effort by a partnership of 11 regional utilities. The results of this coordinated initiative began to be implemented in 2009 and concluded in late 2017. Including the planning, this initiative spanned 13 years, and involved 800 miles of transmission and $2 billion of investment in Minnesota, North Dakota, South Dakota, and Wisconsin.

The approximate lengths, general locations, and in-service dates (ISD) of the CapX2020 projects are as follows:

- *Fargo – St. Cloud – Monticello (ISD mid-2015).* An approximately 240 mile, 345 kilovolt line between Fargo, North Dakota and Alexandria, St. Cloud and Monticello, Minnesota.
- *Brookings County – Hampton (ISD mid-2015).* An approximately 230 mile, 345 kilovolt line between Brookings, South Dakota and the southeast Twin Cities, plus a related 30-mile, 345 kilovolt line between Marshall, Minnesota and Granite Falls, Minnesota. This project is also a MISO multi-value project (MVP).
- *Hampton – Rochester – La Crosse (ISD late 2016).* An approximately 150 mile, 345/161 kilovolt line between Hampton in the southeast Twin Cities, Pine Island near Rochester, Minnesota, and La Crosse, Wisconsin.
- *Bemidji – Grand Rapids (ISD late 2012).* An approximately 70 mile, 230 kilovolt line between Bemidji and Grand Rapids, Minnesota.
- *Big Stone South – Brookings County (ISD late 2017).* An approximately 70 mile, 345 kilovolt line between Brookings, South Dakota and Big Stone City, South Dakota. This project is also a MISO MVP.

MISO MVP is a project type and cost allocation methodology developed through extensive stakeholder discussions in the 2009-2010 timeframe for portfolios of projects that meet one or more of the following three goals:

- Reliably and economically enable regional public policy needs
- Provide multiple types of regional economic value
- Provide a combination of regional reliability and economic value.

The MVP portfolio was intended to enable the delivery of the renewable energy required by public policy mandates, in a manner more reliable and economic than it would be without the associated transmission upgrades. The initial MVP portfolio was approved in December 2011 and combines reliability, economic and public policy drivers and results in a transmission solution that provides benefits in excess of its costs throughout the MISO footprint.

Xcel Energy was a participant in the following MVP projects:

- Big Stone South – Brookings County 345kV (CapX2020)
- Brookings County – Hampton 345kV (CapX2020)
- La Crosse - Madison 345kV (with ATC, also called Badger Coulee)

With the addition of the CapX2020 projects and MISO MVPs, sufficient transmission capacity has existed for the Company to meet its Renewable Energy Standard (RES) requirements to-date. These projects have improved reliability in the region, addressed local reliability issues, and provided a foundation for the interconnection of new generation resources – particularly the renewable resources that have significantly grown over this timeframe. However, many of these lines planned in the early 2000s and completed over the recent past are already fully- or nearly-fully subscribed.

2. *NERC and MISO are Recognizing Potential Resource and Planning Deficiencies*

The North American Reliability Corporation (NERC) conducts a reserve margin analysis across all system operators in North America in a report called the Long Term Reliability Assessment (LTRA). The December 2018 LTRA indicated that MISO is one of three regions that are projected to drop below their reference reserve margin levels by the year 2023, unless certain measures are taken.[3] This report indicates that inclusion of Tier 2 resources (those that are in more advanced stages of planning but not yet under construction) would likely allow for the MISO footprint to preserve system reliability. However, the unprecedented rate of announced, but not yet evaluated, baseload generation retirements and uncertainty in future firm capacity additions creates a tension between maintaining reliability and transitioning away from baseload generation. NERC also recently concluded a special reliability study on the compound effects baseload generating resource retirements on the grid.

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[3] See "NERC Long Term Reliability Assessment 2018" at 14. Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

3. MISO RIIA Study Initiative

In preparation for an expected future grid with high levels of non-dispatchable renewable penetration and declining baseload generation, MISO is undertaking additional studies with respect to its system's reliability and resource adequacy of its system. In 2017, MISO initiated a special initiative called the *Renewable Integration Impact Analysis* (RIIA) that is still underway. We incorporated insights from these studies into our Baseload Study that informed our Preferred Plan. RIIA study seeks to inform future long-term planning by understanding what the power system will need to operate reliably with these high levels of variable resources – specifically by examining operational adequacy, transmission adequacy, system stability, and resource adequacy limitations.

a. Renewables Integration Becomes Significantly More Complex Between 30 and 40 Percent Penetration Levels

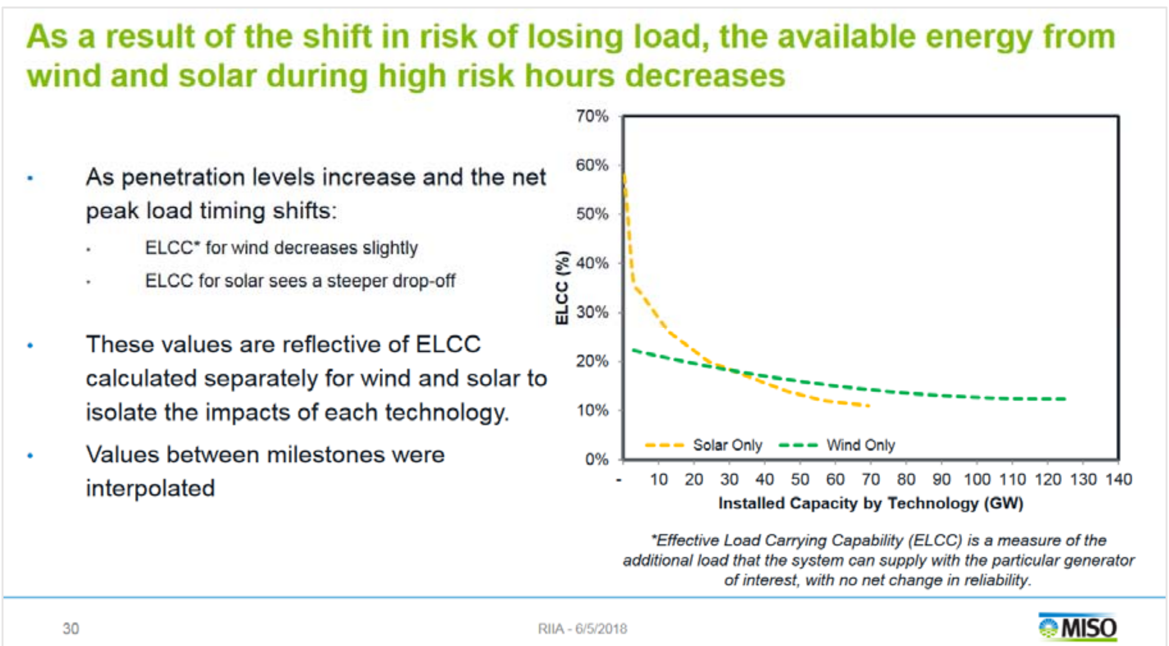
In Phase I, the study examined a scenario in which variable generation achieves a 40 percent share of the total capacity on the MISO system. It found that the complexity of operating such a system reliably is significantly higher than that of even a system with 30 percent variable resources. Under the circumstances studied, the system experienced more dynamic stability issues and other operational stressors, and resource adequacy requirements increased. For example, the modeled system exhibited high levels of energy curtailment and very high ramping rates in the hours when variable resources were not always available to meet demand. In this scenario, loss of load projections were narrowed to fewer likely hours during the year, but the probability of occurrence increased significantly over the current state. This points to the value that flexible, dispatchable resources supporting grid stability continue to provide in these circumstances; while they will run for fewer hours as renewable levels on the grid increase, they are needed – and must be able to respond quickly, moving from minimum generation levels to higher levels of output to meet these fluctuations in net load quickly.

b. Peak Value of Renewables Declines at High Penetration Levels

At high levels of wind and/or solar adoption, the RIIA study found that the accredited capacity values assigned to these resources for resource adequacy purposes degraded – sometimes significantly from current levels. As discussed below, MISO's resource Effective Load Carrying Capability (ELCC) is currently evaluated as an annual average, and forward values are not projected. In reality, however, the capacity value these resources provide to the grid is not consistent – and, as we and other industry members are learning – the capacity values are also subject to diminishing marginal returns. When a single variable resource type increases its penetration level on the grid, each incremental unit of capacity inherently provides a little less capacity benefit to the system than the previous unit.

The appropriateness of these values in reflecting actual grid conditions is therefore dependent on the pace at which wind and solar penetration increases on the grid – and subsequently, how MISO conducts review and adjusts the values. For example, MISO's RIIA study estimates that solar in particular would experience steep ELCC reductions within the first 10 gigawatts installed – and this value continues to drop off at higher levels of adoption.[4] Further, in particular for these variable assets, the realized capacity value may change throughout the year in accordance with seasonally variable environmental conditions.

Figure 1: Modeled wind and solar ELCC as penetration increases[5]



The operational realities surrounding future variable resource additions and their seasonal aspects aside, we continue to use the MISO-determined accredited capacity levels in our planning. As MISO's planning construct is currently limited to one forward-looking value, this presents a risk as we plan our future system. Applying this single value to a 15-year planning period – now knowing that the value of these resources will degrade as we and others add variable renewables to the MISO system

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4 https://cdn.misoenergy.org/20180418%20PAC%20Item%2003d%20174068%20RIIA190532.pdf

5 MISO. "Renewable Integration Impact Assessment" Workshop presentation June 5, 2018. Available at: https://cdn.misoenergy.org/20180605%20RIIA%20Workshop%20Presentation213125.pdf

– what appears to be a net capacity surplus today, may look quite different in future assessments.

We additionally note that we may encounter other changes to current resource adequacy accreditations for other use-limited resources in the future as well. In general, resources such as demand response (DR) and energy storage would be subject to declining ELCC values as they become more prevalent on the system, in the same way wind or solar ELCCs realistically decline.[6] Notably, MISO is also considering changes to how it accounts for DR capacity accreditation overall, such as enforcing more stringent testing requirements. MISO is also following up on actual performance during DR events, which may result in accredited value reductions going forward. Both these factors mean that the DR we currently register with MISO and depend on as a baseline resource in our portfolio may not yield the same benefits in future years as we have historically expected.

We see emerging challenges and uncertainties in the broader MISO market and industry that indicate that the present planning constructs to ensure reliability are not fully equipped to address. Large numbers of renewable generation projects are in the MISO queue for interconnection study and facing substantial upgrade costs to connect to the grid. We are also facing a transition on the grid, with many of the current abundant baseload/large central generating stations retiring, and high levels of renewable resources coming online and pending in the MISO interconnection queue – and perhaps long-term, DER. This generation transformation changes the flows and impacts the reliability attributes of the grid in ways we and the industry are just beginning to understand. We discuss these issues in greater detail in the following sections.

B. Current Regional Planning Constructs Must Adapt

MISO is charged with several responsibilities, chief of which is overseeing wholesale energy markets in the member region and planning for bulk system reliability (i.e. transmission planning, generator interconnection, and ensuring sufficient reserve margins). Many aspects of MISO's operations affect how we conduct resource planning, but here we focus primarily on system reliability constructs that will be increasingly tested as we and others transition to a fuel mix that relies on high levels of variable renewable resources.

As we have discussed, MISO and its system reliability oversight organization, NERC,

[6] See Appendix P2: RESOLVE and RECAP Low Carbon Scenario Analysis (E3) for further discussion on how marginal ELCC for DR and energy storage resources may decline as adoption increases.

undertake studies to determine the appropriate level of reserve capacity that should be maintained, what effect a resource retirement has on the broader system, and how increasing renewable adoption will change how they analyze and ensure grid reliability. All of these studies point toward an increasingly complex grid that will have to be carefully managed through the transition to a lower-carbon future. Trends are emerging that raise questions regarding whether and how planning constructs may need to adapt to ensure the system remains reliable as baseload generating units continue to retire and be replaced by carbon-free, but variable, renewable energy.

One of MISO's core responsibilities includes administering resource adequacy requirements to enable the Company and other Load Serving Entities (LSEs) across the region to fulfill their obligation to serve customers reliably. MISO's Planning Reserve Margin (PRM) analysis is one important piece of the current reliability planning paradigm. The PRM is an estimation of how much generating capacity, over and above expected customer load, needs to be present on the system to ensure reliability in all but the most extreme circumstances (called a 1-in-10 year Loss of Load Expectation or LOLE). In the 2018 LOLE report, MISO established reference PRM values for both installed capacity (ICAP) and a value that derates the installed capacity value to account for potential outages (UCAP). These UCAP values are also called "accredited capacity." The UCAP PRM for the NSP System for the 2018-2019 planning year was 8.4 percent, which means that the total available capacity on the system needs to be 8.4 percent higher than the expected system peak load to ensure reliability.[7] LSEs, including the Company, apply this PRM to their system planning to determine their capacity obligation to MISO.

MISO bases the accredited capacity values on the expected average contribution each resource will provide to the grid. For firm dispatchable resources, the UCAP values are determined based on historical individual unit operational performance. For intermittent, or variable resources, UCAP values are based on the average performance of each wind or solar resource project/farm. MISO also performs probabilistic analyses of how much capacity from variable resources can be counted on to contribute to peak demand across the year, and captures this in the ELCC. These administratively-set values have a significant impact on how we achieve our carbon reduction goals while maintaining affordable and reliable service. Currently, MISO assigns our wind generation an average ELCC value of 15.7 percent, meaning that for every 100 MW nameplate of installed wind, only 15.7 MW can be counted as capacity toward the PRM. For new solar resources, in the absence of an observed

[7] Note that these are 2018/2019 values. We discuss these two measures of PRM and how we apply them to the NSP System for this Resource Plan in the Minimum System Needs section.

historical value, MISO assigns the current initial year default ELCC of 50 percent.[8]

There are two primary issues with the current resource adequacy construct that we believe have the potential to impact reliability and resilience, and for which we have taken steps in this Resource Plan to mitigate. First, the PRM relies on an average capacity value for each resource. The variable and intermittent nature of renewable resources means that they are not available at all at times. Relying on them to perform 24 hours a day, 7 days a week – particularly as renewable levels rise and current baseload units retire – presents an unacceptable risk to reliability. Second, with significant increases in renewable resources underway, the industry is beginning to recognize that renewable resource contributions to meeting the system peak declines as their levels increase.

MISO's present resource accreditation process only establishes the ELCC for the next planning year. This short-term approach fails to account for the declining value those resources will provide toward meeting customers' needs over the long-term. Average capacity values for variable resources will not ensure sufficient energy for our customers every hour of every day. Instead, maintaining an adequate level of flexible, dispatchable resources is necessary to effectively integrate high levels of renewables is necessary.

We also know that high levels of renewables result in a declining peak contribution and can create system instability. As MISO has studied high levels of renewable penetration on the grid with its RIIA study, it has recognized that its capacity accreditation framework – the manner by which it assesses variable renewables' ability to contribute to peak demand needs – will likely change as these resources become more prevalent on the grid. However, MISO has not yet developed sufficiently robust forward guidance for resource planning processes to account for how those values might change in the future, creating uncertainty in the resource planning process.

C. Reliability Requirement

In response to the planning gaps identified above, we developed a Reliability Requirement, which we discuss in detail in Appendix J2 and summarize below.

As the Company increases the amount of renewable generation in our system, it is

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[8] We performed a solar ELCC study, which was designed to determine potential ELCC values for incremental small scale solar generation installations. *See* Xcel Energy Compliance Filing, Docket No. E999/CI-15-115 (August 17, 2018).

important to recognize that these resources cannot alone reliably provide customers the energy they demand every hour of every day, or maintain the stability of the grid. Until such time as new technologies develop to fully transition the grid to carbon-free resources, some level of load-supporting, firm dispatchable resources is necessary for grid resilience and customer reliability.

As noted above, renewable resources like wind and solar are inherently variable and intermittent, and as penetration of these resources increases, their value to meet peak customer needs decreases. These concerns are not limited to the NSP System, but rather run throughout MISO's footprint – and in other regions with increasing levels of renewables. Within MISO and on the NSP System specifically, the gap between renewable resource performance and customer needs has been most pronounced during (but is not limited to) winter months. Although MISO is beginning to recognize these challenges, its current planning constructs do not yet incorporate any measures to address them. We have therefore developed a Reliability Requirement to inform this Resource Plan and mitigate risks to customer reliability and system resilience as MISO determines how to incorporate these issues into its planning process.

The Reliability Requirement we developed for this Resource Plan ensures we have the right mix of resources on our system every hour of every day to meet our customers' needs. We apply the Requirement in our Strategist modeling, and note that while this concept is essential until MISO evolves its capacity construct to provide better direction – the Requirement has little effect in our modeling for this Resource Plan. The model does not select any firm dispatchable additions as a direct result of the Reliability Requirement until 2031. Figure 2 below outlines the general calculation of the Reliability Requirement.

Figure 2: NSP System Reliability Requirement Calculation – 2020 Example

Peak Demand Proxy – 6,400 MW

Minus Firm DR (Winter) Proxy – (200) MW

Minus Firm Market Supply Proxy – (500) MW

Reliability Requirement – 5,700MW

(Firm dispatchable resources)

We discuss the Reliability Requirement in detail in Appendix J2.

D. Regional Transmission Capabilities are Limited

The current state of grid interconnection processes and transmission capabilities in MISO introduces complexity to our planning processes and how we execute on the plan. An overflowing project queue, delayed interconnection studies, and transmission system limitations impose challenges to the economic viability of new renewable generation, and by association – our ability to execute on our clean energy transition plans. MISO is taking action to address a number of these challenges. There are some mitigation measures we expect to utilize in the near-to-medium term, which include carefully managing our interconnection rights at existing sites. In the longer term, however, we see a lack of new transmission development as a barrier to achieving our clean energy goals.

1. Generator Interconnection Queue Delays and Interconnection Costs

The MISO generator interconnection process is designed to allow generators reliable, non-discriminatory access to the electric transmission system, in a timely manner, while maintaining transmission system reliability. Recently, as the number of proposed projects in MISO has expanded significantly, this process has been mired in delays. Delay impacts are particularly evident in the Definitive Planning Process (DPP) phases, where MISO undertakes generation interconnection studies. Current studies are a number of months behind due to the large number of projects in the queue, and a generator interconnection process that allows late withdrawals from the queue.

Despite some recent process reforms, MISO has not been able to keep pace with the expanding queue. And when projects do make it through the DPP, they are sometimes assigned high transmission system upgrade costs that challenge the projects' economic viability. As of early June 2019, there was over 100 GW of new capacity in the active MISO queue, the vast majority of which was of wind and solar projects.[9] Each cycle of the DPP is handling expanding levels of requested capacity. For example, the recently completed cycle for the MISO West region started out with 31 projects totaling 5,700 MW. The April 2019 DPP study cycle, scheduled to begin in March 2020, includes 58 projects totaling 8,800 GW in the same area.[10] While the level of proposed new renewable projects is a positive indication of aspirational renewable development in the region, MISO has also indicated that a substantial amount of this capacity is speculative, in early stages of project development, or

[9] MISO "Generator Interconnection: Overview." Updated as of June 1, 2019, at: https://cdn.misoenergy.org/GIQ%20Web%20Overview272899.pdf
[10] *See* MISO "Definitive Planning Phase Estimated Schedule." Updated as of June 1 2019. Available at: https://cdn.misoenergy.org/Definitive%20Planning%20Phase%20Estimated%20Schedule106547.pdf

duplicative requests.

Further, the existing transmission system's capability to interconnect new projects without substantial infrastructure upgrades is limited, and thus, the generation interconnection planning studies indicate there will likely be costly upgrades assigned to the prospective generators. In the past, initiatives such as CapX2020 and MISO MVPs socialized a substantial level of transmission infrastructure investment across a large swath of benefitting MISO members, and created the ability to integrate large amounts of new renewable energy. However, renewable resources, and wind power in particular, expanded on the MISO grid faster than expected. As a result, the capacity that CapX2020 and the MVPs created has been largely used. Since these early initiatives, few new transmission lines have been proposed or approved for the purposes of renewable integration.

Generally speaking, this translates to substantial transmission upgrade costs being assigned to the generation projects in the queue. To illustrate, in the recently completed MISO West DPP cycle, the 5,700 MW of studied projects were expected to incur approximately $3.2 *billion* in transmission upgrades if all of them were to interconnect to the system.[11] Such high transmission system upgrade costs can render projects uneconomic, forcing them to withdraw from the queue and requiring additional MISO study on the remaining projects.

2. *Physical and Process Limitations between Regions Further Slows Progress on Clean Energy Development*

Limitations on transmission infrastructure and coordination, both within MISO and between MISO and the Southwest Power Pool (SPP), illustrate further challenges. Within MISO, the transmission system is showing constraints and thus slowing progress toward a cleaner energy future across the Upper Midwest system. Currently, wind generation from the western part of MISO flows toward the load centers in the east, such as the Twin Cities Metro area and load centers beyond the transmission interconnection between Minnesota and Wisconsin. However, existing west-to-east transmission capacity is, at times operating at its limit. The transmission interface across the Minnesota-Wisconsin border in particular is currently stability-limited, and trying to force additional renewable energy through these lines could result in voltage collapses in Northern Wisconsin that would destabilize the grid. Curtailing this energy at its source in the west is operationally and economically inefficient – keeping

[11] *See* "MISO DPP 2016 August West Area Phase 1 Study." Report Number: R008-18. Siemens, September 20, 2018, at xvii.
https://cdn.misoenergy.org/GI_DPP_2016_Aug_West_Phase1_SIS_Report277263.pdf

us from fully utilizing the inexpensive and clean energy to which we have access. However, without additional transmission development, we will more frequently encounter this problem as we add more renewable generation to our system.

Further, coordination (or historical lack thereof) between MISO and SPP introduces challenges to increasing and utilizing more clean energy. First, for projects that can be considered interregional in nature, a project must currently meet economic benefit hurdles in a joint review, as well as separate MISO and SPP regional evaluations. This slows the process significantly, and may overestimate the amount of interconnection upgrades required, adding to project uncertainty and cost. Second, although our load and generation are fully within MISO, the nature of power flows inevitably results in some of our energy entering the SPP system. In turn, both MISO and SPP may charge to transmit that energy from the point of generation to the load, challenging a project's economic viability or raising customer costs for projects already online.

Finally, MISO and SPP disagree on what should happen when one region or the other has to "lean" more on the system than its contracted delivery amounts for a certain time. Where SPP would levy penalties in this scenario, MISO views this situation as a normal and acceptable result of an integrated grid. All of these issues increase transaction costs and uncertainty for a given generation project coming online, and represents a potential barrier to efficiently bringing additional renewable generation to the grid.

3. *MISO is Taking Action to Address the Current Process Issues*

In response to direction from FERC and a recognition of the challenges described above, MISO is undertaking several actions that could serve to mitigate challenges to bringing new, clean resources online. In essence, these actions allow generation owners to leverage existing interconnection agreements to maximize utilization, and fit renewable additions into the relatively few remaining open spaces on the grid. While we expect these processes to mitigate some of the near-term challenges to additional renewable capacity, they do not address all challenges – in particular, our ability to depend on neighboring regions for renewables and maintaining reliability; we expect that longer term solutions will eventually need to be developed.

a. Generator Replacement Process

Interconnection study delays and speculative queueing are challenges not only to projects that are actually commercially-viable, but also to generation owners who are looking to retire aging assets. Companies that are required to meet a certain level of reserve capacity, like Xcel Energy, face potential compliance and commercial risk if we retire existing assets without the ability to re-utilize that interconnection capacity.

Recognizing these issues, MISO filed, and in May 2019 received approval for, a proposed Replacement Generator Process as part of its Attachment X tariff. This modification intersects with Attachment Y with regard to generation replacement and interconnection rights of current generation owners when a resource retires. The change to Attachment X allows current generation owners to retain and reuse the interconnection rights when a resource retires, within certain technical and timing limitations on the new generator.[12] The new generating units could be developed on the same site, or on a site in close proximity that uses the same grid interconnection point. Per the new tariff language, the replacement generation resource would need to go into service not later than three years after the existing generator retires. Importantly, these replacement projects would be studied outside the traditional DPP timeline, because the transmission infrastructure in the area was built to accommodate the large amount of generation associated with the current generating facility – and customers should be able to continue to take advantage of this infrastructure that they have already paid for rather than fund alternative network upgrade costs. This avoids the significant delays and costs associated with the DPP process.

Maximizing use of existing interconnection rights is essential to timely and cost-effective achievement of the fleet transformation that we set in motion with this Resource Plan. This Tariff change is an important development that will help to facilitate the transformation in a timely and cost-efficient manner for our customers.

b. FERC Order 845 Opens Additional Opportunities for Generation Owners

In 2018, FERC issued Order 845, *Reform of Generator Interconnection Procedures and Agreements*, that also opens additional opportunities for generation owners to add resources to the system outside the normal interconnection queue process.[13] First, the Order directs all transmission providers to develop a procedure to allow interconnection customers to use surplus availability at an existing point of interconnection without that new project entering the full MISO queue and planning process, within certain technical limitations. MISO has referred to surplus interconnection availability as "Net Zero" interconnection because the addition of

[12] In summary, these changes allow for transfer of interconnection rights from a retiring generation resource to a replacement resource that: (1) is located at the same point of interconnection as the retiring resource, (2) is less than or equal to the generating capacity of the retiring resource, and (3) does not result in an adverse impact to the transmission system. *See*: https://www.ferc.gov/CalendarFiles/20190515181059-ER19-1065-000.pdf

[13] *See:* https://www.ferc.gov/whats-new/comm-meet/2018/041918/E-2.pdf

this new project would not result in an overall increase to the interconnection capacity requirements of the site; rather, it would be expected to increase the overall *utilization* of the interconnection site. While MISO allowed Net Zero resources prior to FERC 845, the new Order also allows existing interconnection rights owners the first right to utilize the surplus availability on that interconnection. It also revises the definition of a generating facility to explicitly include energy storage resources. These actions work to support generation owners increasing renewable utilization on existing interconnections, and could support future project hybridization (e.g. solar and storage or wind and storage).

c. Substantial Challenges Remain

We expect that generator replacement, Net Zero, and other FERC Order 845 implementation efforts will alleviate some of the barriers to planning and executing on a future with substantial renewable additions. However, these do not address the underlying challenges around queue length and timeline, intra-MISO and interregional seams congestion challenges, and integrating high levels of renewables reliably and affordably. MISO has recently attempted to mitigate the queue volume challenge by proposing process reforms that increase the stringency of entering this phase of interconnection process; however, while recognizing the challenges MISO faces, FERC recently rejected the proposal.[14] While the Company and others have begun contemplating new MVP-like projects, the lack of alignment across MISO and long lead-times required for such projects mean that these challenges are unlikely to be sufficiently resolved in the near-term.

E. Summary – 2020-2034 Upper Midwest Resource Plan Baseload Study

With this Resource Plan we provide a Baseload Study as Appendix J1. We undertook this study as an outcome from our most recent Resource Plan in which the Commission required the Company to continue its study of potential baseload resource retirements.[15] We started this work as part of our last Resource Plan, as we took action to transition our fleet to achieve dramatic reductions in carbon emissions. Specifically, we studied the technical implications of retiring two of our coal plants – Sherco Units 1 and 2. In conjunction with this Resource Plan, we performed technical analyses to more broadly examine the issue of orderly retirement of our remaining baseload generating units – namely, A.S. King, Sherco Unit 3, Monticello Nuclear, and Prairie Island Units 1 and 2.

[14] *See* FERC "Order Rejecting Tariff Revisions re: Midcontinent Independent System Operator, Inc. under ER19-637." Available at: https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20190319-3076

[15] *See* Docket No. E002/RP-15-21, Order Point 14(a) (January 11, 2017).

To understand the technical impacts of retiring one or more baseload generating units, we perform engineering analyses on simulations of the Unit changes that assess the results against established industry reliability and operating criteria. When performing technical studies, we simulate a number of varied conditions that can consider changes in customer loads, projected changes to the generation mix, and ways to use the transmission system most efficiently.

The Baseload Study in this Resource Plan is comprised of four primary components:

- **Midcontinent Integrated Systems Operator (MISO) Attachment Y2 preliminary retirement studies**, which assessed various single Unit and combined Unit retirement scenarios for thermal and voltage concerns,
- **Xcel Energy Transmission Reliability studies**, which examined system stability and response impacts associated with baseload generating resource changes on the NSP System and on neighboring systems,
- **Industry insights**, including the North American Electric Reliability Corporation (NERC) *Generator Retirement Scenario Special Study* and the MISO *Renewable Integration Impact Analysis* (RIIA), which provide important insights into the combined effects of baseload generator retirements in a region and grid impacts at increasing levels of renewables penetration, and
- **A focused Strategist analysis**, which examined the economic implications of various Unit and combined Unit retirements at different points in time.

The technical studies generally analyze the way power flows over the grid and search for places where the system might overload or fail, assuming specific circumstances. While these studies are essential and provide important insights, our decades of operating and studying the existing system also provides valuable insights and perspective toward assessing potential impacts from NSP System grid changes. We incorporated this experience into our analysis of impacts. We also supplemented our technical study efforts with relevant industry initiatives that examine the compound impacts of aging baseload retirements and increasing levels of renewable generation – similar to the issues facing the NSP System. The studies use the best available information at the point in time that they were conducted. However, the grid is dynamic, and expected conditions will change when new generation comes online, existing generation retires, new transmission lines are constructed, or existing lines are reconfigured; in addition, reliability measurement criteria may change. The results therefore are a point-in-time representation of the technical issues we expect would occur in a studied scenario.

The MISO Y2 and our Reliability Studies identify grid impacts and potential transmission mitigations necessary to resolve the respective issues the studies identified. MISO performed its Y2 Studies in accordance with their Business Practice Manuals, which generally focus on thermal and voltage issues.[16] We used the MISO planning level estimated mitigation costs from the Y2 studies as an input to our Strategist modeling of the baseload unit retirements. While these may not be the final mitigations, they provide a proxy of potential costs to inform the economic aspect of our Baseload Study. Our technical studies supplemented the MISO analysis to examine traditional NERC reliability measures such as system stability and response. This is an important complement to the MISO Y2 studies to provide a more robust look at potential impacts from baseload changes on the NSP system and regional MISO grid.

The results of our Baseload Study informed the Preferred Plan we propose in this Resource Plan, which includes the following baseload actions: (1) Retire our remaining two coal units early – King in 2028 (nine years early) and Sherco 3 in 2030 (ten years early), and (2) Extend the operation of Monticello nuclear 10 years through a license extension, to 2040.

Other conclusions and insights from this Study include:

- The retirement of our current baseload units must be orderly, and will be impacted by decisions other MISO generation owners make regarding their baseload units.
- We must maintain sufficient firm dispatchable, load supporting resources to ensure customer reliability and to support integration of higher levels of renewable resources.
- Changes in the MISO planning construct are necessary to properly recognize the inherent variable and intermittent nature of renewable resources in meeting customer needs every hour of every day.
- Significant new regional transmission development will be necessary to support increased levels of renewable resources and to support the retirement of baseload units.
- From an economic perspective, the scenarios that included early coal retirements and nuclear extensions had the most favorable present value.

Insights gained from this Study also helped to inform our development of a Reliability

[16] *See* MISO Business Practice Manual BPM-020 at: https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

Requirement (discussed in Appendix J2), which bridges the gap between current regional planning requirements and necessary changes to account for: (1) the variable contribution renewable resources provide to the system, (2) the lack of long-term regional system planning guidance for the expected contribution of renewable resources as penetration levels rise, and (3) the need for sufficient firm dispatchable, load supporting resources to reliably integrate increasing levels of renewable resources.

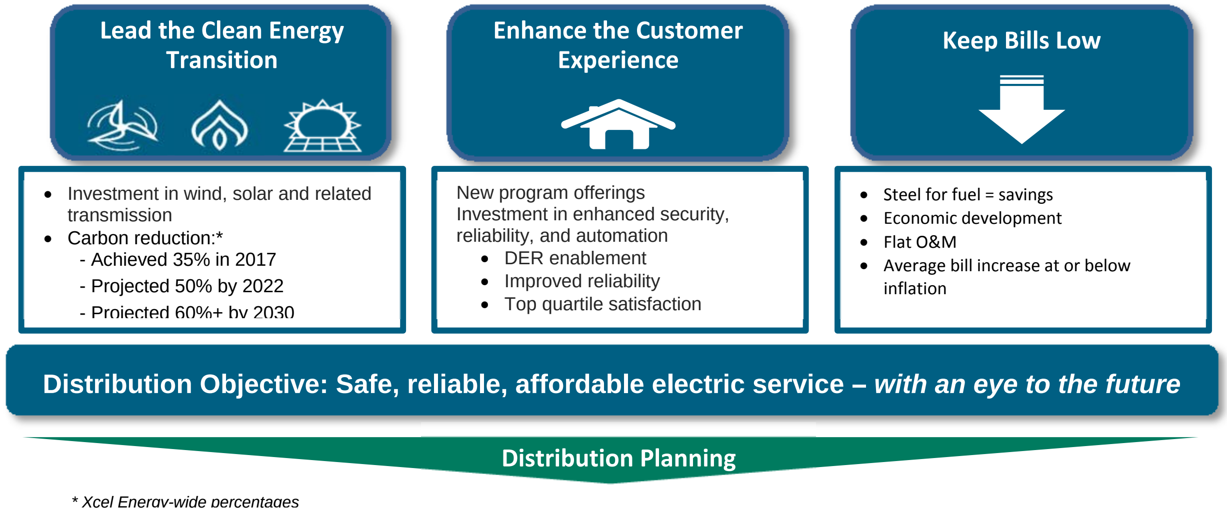
II. DISTRIBUTION

The electric utility industry is in a time of significant change. Increasing customer expectations and technological advances have reshaped what customers expect from their energy service provider, and how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, electric vehicle (EV) chargers, smart home devices, and even smart phones, are evolving at a fast rate. Influenced by other services, customers have come to expect more now from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use.

At the same time, major industry technological advances provide new capabilities for utility providers to manage the electric distribution grid and service to customers. Electric meters are now equipped to gather more detailed information about customer energy usage, which utilities can leverage to help customers better understand and manage their usage. Other advanced equipment on the grid is able to sense, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customer-connected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

The foundation on which these capabilities rest is safe, reliable energy. Our strategic priorities of enhancing the customer experience, leading the clean energy transition, and keeping customer bills low are embedded in everything that we do – including the way that we plan our distribution system.

Figure 3: Xcel Energy Strategic Priorities – Applied to Distribution



Distribution planning has historically – and still largely today –involved analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels, and utilization rates of major system components such as substations and feeders. Customers traditionally have had limited information about their energy usage and few choices in how they received information, had questions answered, and paid utility bills or conducted other necessary business with their utilities. For the most part, customers were content to receive a monthly paper bill from their utilities and were unaware and unengaged in whether the energy came from renewable or non-renewable sources.

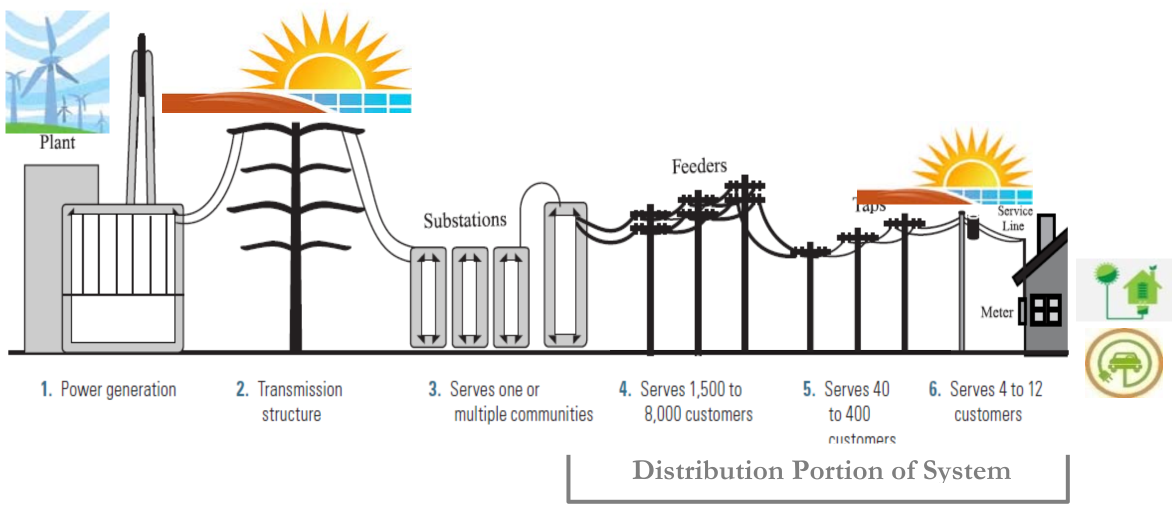
Now, instead of planning just for load, utilities will need to analyze the system for future connections that may be load *or* generation. Also, utilities will increasingly need to view their operations and customer tools from their customers' perspectives. This step change in the distribution utility business will require utilities to plan their systems differently, which will involve not only new processes and methodologies but also new and different tools and capabilities.

Like other aspects of the industry that are transitioning and advancing, we are on the forefront of integrated distribution planning. We submitted the first Integrated Distribution Plan (IDP) in Minnesota November 1, 2018 – which was also among some of the first IDPs nationally. We are taking steps to align and integrate our distribution, transmission, and resource planning processes. We also are in the process of evaluating and procuring the next generation of distribution planning tools, which are needed to increase our forecasting and analysis capabilities and impact the integration of planning processes.

A. System Overview

The electrical grid is composed of generating resources, high voltage transmission, and the distribution system, which is the vital final link that allows the safe and reliable flow of electricity to serve our customers. We provide an illustration of a modern electrical grid below.

Figure 4: Illustrative Electrical Grid



The poles, lines, and cables that comprise the distribution system connect individual residents and business to the larger electrical grid. The system has been developed for the efficient distribution of power, with lines routed as directly as possible. Geography, however, plays a dominant role in the ultimate design of the system; the location of lakes, road and developments dictate the siting of much of the distribution infrastructure.

Distribution substations are sized for anticipated load at a particular site, and often consist of one to three transformers. Site selection for substations is based on the availability of a transmission source, proximity to the load being served, total ownership costs and reliability considerations. Incremental transformers and feeders may be planned at substation sites to meet future load demand. Where possible, redundancy is built into the system to maintain reliability. Taps are the smaller line segments that leave the mainline and fuses or reclosers are installed at those connection points, which open if a fault develops on the tap. This prevents the remainder of the system on that feeder from having their service interrupted, thus isolating the outage to just the customers beyond that fuse. At the customers' site, service transformers feed lower voltage secondary conductors. These conductors deliver the low voltage power to meters at customers' homes and businesses.

The NSPM electric distribution system serves 1.5 million customers (1.3 million in Minnesota) – and is composed of 1,177 Feeders, approximately 15,000 circuit miles of overhead conductor, and over 11,000 circuit miles of underground cable.[17] The distribution portion of the grid, and the services that the Distribution organization provides, are generally the aspects of our electric service that are most visible to our customers. In terms of reliability, we rank nationally in the 1st quartile.[18]

Key Distribution functions include operating the distribution system, restoring service to customers after outages, performing routine maintenance, constructing new infrastructure to serve new customers, and making upgrades necessary to improve the performance and reliability of the distribution system. We are also out in the community during and after severe weather events as part of our industry-leading storm response efforts to ensure safety, and to promptly restore service to customers.

Key overall Electric Distribution business priorities are:

- *Operational Excellence.* Improve reliability performance level.
- *Grid Modernization.* Install key equipment and systems to operate the new modern grid including monitoring and control, Advanced Distribution Management System, and system efficiency. Targeted renewal of aging, unreliable, or obsolete components and systems (i.e. underground cable, poles, 4kV systems)
- *System Health.* Targeted maintenance of key assets designed to improve reliability and safety – wood poles, substations transformers & breakers, vegetation management.
- *System Capacity Additions.* Installation or reinforcement of key substations and feeders to serve new load and provide backup under emergency conditions (focus on high consequence events).

Distribution priorities and budgets recognize that customers want reliable and uninterrupted power. We therefore must not only proactively maintain our system by making capital improvements when necessary to improve reliability and safety for our customers – we must also manage our budgets to be able to respond to outages

[17] In this context, the number of customers is based on the number of electric meters.
[18] Results for the NSPM operating company, as measured by SAIDI and SAIFI. *See IEEE Benchmark Year 2018, Results for 2017 Data* at:
http://grouper.ieee.org/groups/td/dist/sd/doc/Benchmarking-Results-2017.pdf

caused by severe weather, mandatory work such as relocation of our facilities, and other conditions that cannot be foreseen with a high degree of accuracy. While the immediacy of customer reliability is a reality and a primary focus, in addition to these core activities, our investment plan reflects strategic investments to advance distribution grid capabilities, increase our system visibility and control, and enable expanded customer options and benefits. We are also planning for enhanced distribution planning tools that will equip our system planners with the capabilities to perform DER scenario analysis in our annual planning processes, better facilitate our incorporation of non-wires analysis (NWA) into the analysis we perform to ascertain the best way to meet system capacity needs, and begin in earnest the integration of planning activities at all levels of the grid.

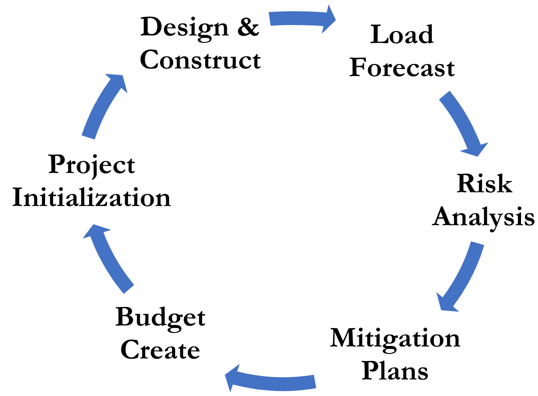
B. System Planning

An important aspect of distribution planning is the process of analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels and utilization rates of major system components such as substations and feeders. We also consider Hosting Capacity analysis an important aspect of our system planning. We discuss both of these planning activities in this section.

1. Annual System Planning

We do this annually, and additionally conduct analyses during the year in response to new information, such as new customer loads, or changes in system conditions. The process begins with the forecast of peak customer load and concludes with the design and construction of prioritized and funded capacity projects, as illustrated in the below Figure.

Figure 5: Annual Distribution Planning Process



Planning Engineers rely on a set of tools to perform the annual full system snapshot, ongoing distribution system assessments – including assessment of specific DER interconnections – and long-range area assessments. We see our planning practices evolving to analyze future electricity *connections*, rather than just loads. However, we will need to advance our planning tools and capabilities to facilitate greater capabilities to factor-in DER and to more systematically be able to evaluate NWA. Enhanced planning tools have started to emerge in the industry, but will take some time to mature. Toward that end, we have been participating with others in the industry to examine the types of capabilities that may be needed. We also are in the process of evaluating and procuring the next generation of distribution planning tools, which are needed to increase our forecasting and analysis capabilities and impact the integration of planning processes.

2. Non-Wires Alternatives

Non-Wires Alternatives (NWAs) are emerging as another advanced distribution planning application. While a nascent concept only a few years ago, the United States has seen a significant rise in the number of NWA projects proposed and being implemented. States with high DER penetration and/or aggressive regulatory reform, like New York, California, Oregon, and Arizona, are leading the way. Decreasing DER costs in combination with slow or flat load growth may present opportunities for utilities to address pockets of load growth using DER over traditional build out of distribution infrastructure, like reconductoring, transformer replacement, or even new substations. Unlike traditional infrastructure projects, which typically offer fixed capacity increases at known locations, non-traditional solutions often have varying operating characteristics based on their location or the time of day they are used.

More tactically, NWA analysis processes consider several things: a set of criteria for determining which traditional projects are suitable candidates for NWA, processes to develop portfolios of solutions (including both third party resources and non-traditional utility assets), a mechanism to evaluate the costs and benefits of the NWA relative to the traditional solution, procurement processes, and standards to ensure equitable reliability and performance. For implementation and deployment, currently we are seeing NWA solutions which require a disparate set of systems to separately operate the different elements of equipment that would comprise an NWA portfolio solution (e.g. a battery- only platform or demand response- only mode).

Without integration across different systems, this makes the facilitation of NWA a custom, one-off solution that requires extensive oversight and management. To-date, analysis we have performed has determined that the cost of incorporating DER as the primary risk mitigation is at this time still more costly than traditional solutions. However, as technology advances and manufacturing evolves, DERs have the potential to quickly become a cost competitive option. As such, we are working diligently with research groups, internal and external stakeholders, and other utilities that are also incorporating DER planning in order to refine the process of having NWAs solve traditional distribution system deficiencies.

3. Hosting Capacity

We recognize hosting capacity as a key element in the future of distribution system planning. We anticipate it has the potential to further enable DER integration by guiding future installations and identifying areas of constraint. In compliance with Minn. Stat. § 216B.2425 and by order of the Commission, we conducted and submitted annual hosting capacity studies in 2016, 2017, and 2018.[19] We use the EPRI DRIVE tool for our analysis. EPRI defines hosting capacity as the amount of DER that can be accommodated on the existing system without adversely impacting power quality or reliability – and introduced the DRIVE tool as a means to automate and streamline hosting capacity analysis. Our studies have provided hosting capacity results by feeder to serve three purposes: (1) provide an indication of distribution feeder capacity for DER, (2) streamline interconnection studies, and (3) inform annual long-term distribution planning.[20] We expect to continue to evolve our hosting capacity analysis to meet emerging trends and customer needs.

[19] *See* Distribution System Study, Docket No. E002/M-15-962 (December 1, 2016), Hosting Capacity Report, Docket No. E002/M-17-777 (November 1, 2017), and Hosting Capacity Report, Docket No E002/M-18-684 (November 1, 2018).
[20] See Integrated Distribution Planning Report Prepared for the Minnesota Public Utilities Commission, ICF International (August 2016).

C. Distributed Energy Resources

We continuously evaluate new technologies, new system designs, new equipment, and new operational methods in order to continue to meet the needs of the distribution system in a changing energy environment. These new technologies include emerging advanced grid tools or other advanced field devices with monitoring, controlling, and other capabilities that better enable DER and provide for a more adaptable system.

Some customers are choosing DER, which can reduce customer consumption and even provide energy back to our system from decentralized locations on the grid. Examples of DER include, but are not limited to: rooftop solar panels, energy storage, community solar gardens, or the energy efficiency and demand response enabled by a smart thermostat or time of use electric rate. We are anticipating and preparing for increasing DER penetration levels on our system.

Our customers' adoption of DER and new types of load mean that consumption patterns from our centralized power system are changing. This can represent an opportunity: if we can harness the benefits of these resources to make demand more flexible, we can use this to better match demand to energy production from our large, variable renewable resources. For example, we could utilize managed or "smart" charging of electric vehicles (EVs), to delay charging to off-peak hours or to times when renewable output is the highest. We could also use advanced metering technology alongside customer programs and tariffs to more readily enable load shifting away from peak hours.

DER is also coming onto our system in the form of electric transportation options – enabling not only flexible load opportunities but also broader economy-wide emissions reduction – and we have developed several programs and rate options to encourage that adoption. However, we still often do not have visibility into which technologies, and at what pace, customers will adopt and thus, how we should plan for that changing load to affect our grid needs in the future. While the opportunities are exciting, it is also important to recognize that customer adoption of DER and new types of load behind the meter introduces uncertainties in our planning processes, particularly if we do not have adequate visibility into how and when that new DER or demand is coming onto our system.

The distribution system was initially built to support one-directional flows of energy. Increased DER penetration levels pose new challenges to the distribution system to accommodate two-directional flows. As DER installations increase in an area, feeders or substations may require further analysis to ensure this equipment is adequate to continue providing sufficient power quality and reliable service. Safety is a key concern with higher volumes of distributed energy, as are operational challenges presented by the variability of sources like solar photovoltaic and electric vehicles. DER is also increasingly expected to impact the transmission system, so distribution and transmission planning processes are becoming increasing interrelated.

The Federal Energy Regulatory Commission (FERC) has engaged in the DER trend through its Order No. 841, which addresses participation of storage resources at the transmission and at the distribution level in wholesale markets. We support Order No. 841 as it relates to resources interconnected at transmission level, but have concerns about its implementation as it relates to storage resources interconnected at distribution level.[21] We also have concerns about FERC's proposal in Docket No. RM18-9-000, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, which would expand the requirements of FERC Order No. 841 to all types of DER interconnected at distribution level, not just storage resources.[22]

We addressed what we see as current challenges, which become more significant at higher penetration levels, in comments submitted to FERC. These challenges include:

- *Metering*. Participation of distribution-interconnected storage resources raises the question about how metering will distinguish between charging for wholesale purposes as opposed to charging for retail usage in the case of dual-use facilities. Charging for retail usage should be subject to state-regulated retail rates while charging for wholesale purposes would, under Order 841, be subject to FERC regulated wholesale rates. We are not aware of any metering arrangement that can distinguish between charging for wholesale purposes and charging for retail purposes in the case of a dual-use facility. It should be incumbent upon the resource owner to provide sufficient documentation to ensure that any dual-use resource can be metered in a manner that can distinguish between charging for retail use as opposed to charging for wholesale use. Otherwise, cost shifts to other retail customers will occur as a result of such a resource avoiding payment of full retail rates when it is charging a storage resource for what will ultimately be usage for a retail purpose.

[21] XES filed a request rehearing of various aspects of FERC Order No. 841 as it relates to resources interconnected at distribution level. A copy of XES's request for rehearing is available at this link: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14651369

[22] A copy of XES's comments in FERC Docket No. RM18-9-000 is available at this link: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14682284. These comments largely capture input provided in XES's original comments in Docket Nos. RM16-23-000 and AD16-20-000 and XES's request for rehearing in those dockets. FERC declined to accept these comments into the record in Docket No. RM18-9-000 because FERC deemed they were duplicative.

- *Distribution Operations.* Distribution system operators (DSO) need to have the capability to monitor activities of DER in the wholesale market and potentially take action to curtail market sales if such sales will impair reliable distribution system operations. The need for such capabilities will increase as DER penetration increases. The mechanisms to manage these operations will require enhanced communications systems between the DSO, DER, and market operator; software that can monitor distribution system impacts and identify reliability issues and solutions; and additional operations personnel to effectively manage the impacts of DER participation in markets. Cost causation principles dictate that the DER owners and operators should be responsible for the costs associated with these enhancements because such costs would not be incurred "but for" the participation of DERs in wholesale markets. However, absent fairly significant DER penetration levels it is not clear how these costs can be effectively allocated and recovered. At low penetrations there will simply be an insufficient number of customers to bear the costs of these infrastructure upgrades. FERC has not proposed a mechanism to address this issue. In the meantime, DSO will have to find ways to manage DER resource participation reliably, cost-effectively, and in a manner that does not shift costs to other customers.

- *Distribution system upgrades.* Existing distribution systems were not built to manage large outflows of energy that would be associated with market sales. Further, distribution systems are not as flexible as transmission systems and therefore are less able to effectively handle the types of system flows that will occur with DERs participating in markets. Distribution interconnection studies will be more complex and will identify potentially significant feeder and substation upgrades needed to enable market participation by DERs. The costs of such upgrades should be directly assigned to the DER causing such costs to be incurred.

- *Wholesale market issues.* In addition to the direct distribution-level impacts of DERs participating in markets, there are a variety of other issues that must be addressed at the wholesale market level. These issues include the ability to determine where individual DERs involved in an aggregation are located in order to ensure that resources are paid the appropriate nodal price, whether technology exists to effectively manage the state of charge of storage resources, and whether market software can effectively be deployed to manage large numbers of relatively small resources.

MISO was required to make a compliance filing with FERC by December 3, 2018 and has a year thereafter to implement provisions of its compliance filing. One of the key aspects of MISO's compliance filing was relationship between MISO, the DER, and the applicable DSO. FERC is currently evaluating MISO's plans to implement Order 841. Implementation is required by the end of 2019 absent an extension. The Company is also evaluating whether additional steps may be needed to handle the interface between itself, the owners of DER resources, and MISO. Issues that the Company is evaluating include direct assignment of distribution system upgrade costs incurred due to DER participation in wholesale markets, distribution wheeling rates, the need for a DER to establish to the satisfaction of the utility that it has metering capability needed to ensure that it does not charge a storage resource at wholesale rates for retail usage, mechanisms to limit DER output to the extent that reliability of the distribution system is compromised by the DER's activities, and cost recovery for services provided by the distribution system operator to the DER.

We plan to evaluate this issue further and take appropriate steps to move forward to ensure that DER participation in wholesale markets is not subsidized by other retail customers and that such participation is conducted in a manner that does not threaten reliability of the distribution system.

We are taking action to improve our planning tools and modernize our system to more readily integrate increasing levels of DER that we believe are inevitable. We discuss these plans as part of our overall advanced grid initiatives in Part _ below.

D. Advanced Grid Initiative

We are on the forefront of many of the issues and changes underway in the industry and have developed our advanced grid initiative to address them. In addition to the significant steps we have taken to implement and improve our hosting capacity analysis, we are in the process of implementing an Advanced Distribution Management System (ADMS). The ADMS is foundational to advanced grid capabilities that will provide the visibility and control necessary for enhanced planning and significant DER integration. We are also implementing a Time of Use (TOU) pilot, which implements new residential TOU rates, and the installation of Advanced Metering Infrastructure (AMI) meters, in two communities in the Twin Cities metropolitan area, providing select customers with pricing specific to the time of day energy is consumed. This pilot also provides participants with increased energy usage information, education, and support to encourage shifting energy usage to daily periods when the system is experiencing low load conditions.

We also are poised to propose further foundational advanced grid capabilities, including a full AMI implementation, a secure and robust Field Area Network (FAN), and significant reliability improvements for customers through Fault Location, Isolation, and Service Restoration (FLISR). In addition to transforming the customer experience, these foundational investments will allow us to advance our technical abilities to deliver reliable, safe, and resilient energy that customers value. As an example, FLISR and ADMS will reconfigure the grid to reduce the numbers of customers affected by an outage and provide better information to outage restoration crews to speed up their response or avoid those outages in the first place. These foundational investments also lay the groundwork for later years. The secure, resilient communication networks and controllable field devices deployed today through these investments will become more valuable in the future as additional sensors and customer technologies are integrated and coordinated.

We envision that our customer strategy will leverage the more refined customer usage data captured by AMI meters and communicated to utility systems through the FAN to enable new rate, billing, and program options that allow customers to adjust their usage to save money or participate in cost saving programs, using their devices. AMI and FAN also will improve our existing customer portal (MyAccount) information to provide more personalized insights to help customers understand how and where energy is being used and provide ways to help them save money.

However, fundamentally we must replace our present Automated Meter Reading (AMR) system. While it has delivered substantial value for customers since it was implemented in the mid-1990s, our vendor has announced that the technology will no longer be supported after the early-2020s – and they plan to discontinue support for AMR technology entirely in the mid-2020s. At the same time, the AMI technology and market have matured, which has driven many other vendors to also discontinue support of AMR. According to the U.S. Energy Information Administration, AMI adoption surpassed AMR in 2012, and the gap has widened as AMR rollouts have flattened.

We expect three primary outcomes from our deployment of advanced grid infrastructure and advanced technologies: (1) a transformed customer experience, (2) improved core operations, and (3) facilitation of future capabilities.

Transformed customer experience. Advanced grid investments combine to provide greater visibility and insight into customer consumption and behavior. We will utilize this information to transform the customer experience through new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications. These options will provide customers greater convenience and control to save money, access to rates and billing options that suit their budgets and lifestyles, and more personalized and actionable communications. We expect our early initiatives will focus on the execution of services that benefit all customers. Other customer choice programs enabled or enhanced by advanced grid initiatives may include smart thermostats, home area networks, rooftop solar, community solar gardens, optimized EV charging, and other DER offerings.

Improved core operations and capabilities. We also will improve our core operations, making investments to more efficiently and effectively deliver the safe and reliable electricity that our customers expect. While we have historically provided reliable service, we need to continue to invest in new technologies to maintain our performance in the top third of U.S. utilities, particularly as we deliver power from more diverse and distributed resources, and as industry standards continue to improve.[23] Our advanced grid investments provide technologies to manage the complexities of a more dynamic electric grid through additional monitoring, control, analytics, and automation. This will benefit customers through less frequent, shorter, and less impactful outages; more effective communication from the Company when they are impacted by an outage; and reduced costs from our more efficient use and management of assets.

Facilitation of future capabilities. Designing for interoperability enables a cost-effective approach to technology investments and means we are able to extend our communications to more grid technologies, customer devices, and third-party systems in a stepwise fashion, which unlocks new offerings and benefits that build on one another. This building-block approach, starting with the foundational systems, is in alignment with industry standards and frameworks (such as the Department of Energy's Next Generation Distribution Platform (DSPx) framework).[24] It also allows us to sequence the investments to yield the greatest near- and long-term customer value while preserving the flexibility to adapt to the evolving customer and technology landscape. By adhering to industry standards and designing for interoperability, we are well positioned to adapt to these changes as the needs of our customers and grid evolve.

Adherence to industry standards also allows us to better secure the grid and the devices we have connected to it. The increasing number of interfaces associated with grid modernization increases our cybersecurity exposure. As we move forward into the next generation of intelligent, interactive electric distribution, every facet of the electric network must be evaluated for cybersecurity risk. All aspects of the advanced grid must be inventoried, securely configured, and monitored regularly and

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[23] See Leading the Energy Future 2017 Corporate Responsibility Report, Page 85, Xcel Energy (May 2018).
[24] See Modern Distribution Grid, Volume III: Decision Guide, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (June 2017).

thoroughly.

These investments also will produce a wealth of customer and grid data, which will, in turn, enable us to provide the new services described here and enhance existing services. These data-related efforts have begun, and next steps will include identifying the analytics capabilities needed to add additional value to customer offerings or improve utility operations. Data analytics in the utility industry continues to mature, so as grid modernization investments are deployed, these capabilities will evolve as well.

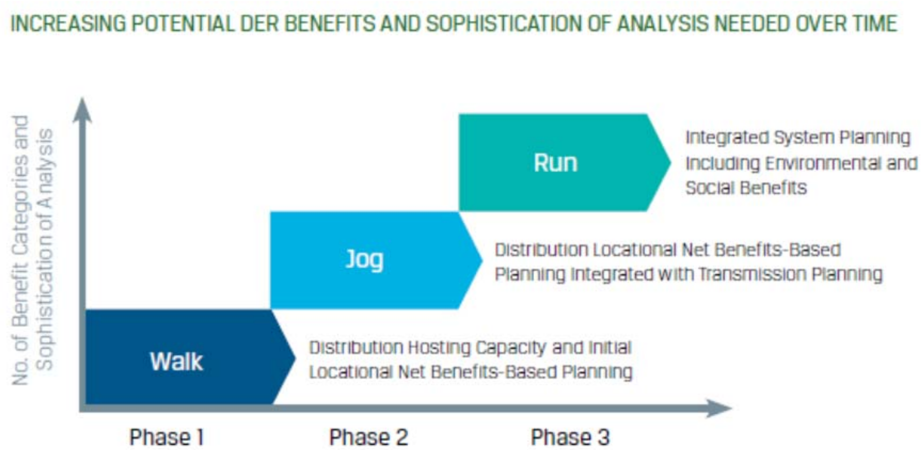
E. Transmission and Distribution Planning are Becoming More Interrelated

Although increasing DER penetration levels will drive integrated resource planning and distribution planning closer together, there are fundamental differences in how these two planning activities assess and develop plans to meet customers' needs. Distribution planning, like Integrated Resource Planning (IRP), charts a path to meet customers' energy and capacity needs, but is more immediate and subject to emergent circumstances because distribution is the connection with customers. Unlike IRPs, five-year plans are considered long-term in a distribution context; and, IRPs are concerned with size, type, and timing, whereas the primary focus of distribution planning is location. Thus distribution loads and resources are evaluated for each major segment of the system – on a feeder and substation-transformer basis – rather than in aggregate, like occurs with an IRP. Before a greater integration of distribution planning, transmission planning, and IRP can occur, distribution planning will need to become even more granular than it is today to address the challenges – and harness the benefits – of DER.

Today, the distribution and transmission planning groups work together as their respective planning processes impact or rely on one another. For example, distribution planning supplies transmission planning with substation load forecasts that are an input into the transmission planning process. These two groups also interact when distribution planning identifies the need for additional electrical supply to the distribution system – and similarly with interconnections, distribution is on point, and involves the appropriate planning resource as needed. The work that we are doing now on customer adoption-based of DER and electrification is helping to bring these planning processes closer together – and we believe will result in better informed sensitivities to ultimately inform both IRP and IDP. However, there are fundamental differences in these planning processes that will continue to challenge integration, at least in the near-term.

Minnesota is among a few states, including California, New York, and Hawaii, on the forefront of advancing its distribution planning as part of its grid modernization efforts. However, each is driven by differing policies and considerations; each is taking a different approach; and, each may result in its own solution that may not fit the circumstances elsewhere. While there are no definitive answers at this point, experts generally agree that a deliberate, staged approach to increased sophistication in planning analyses – commonly referred to as "walk, jog, run" – is important. The below Figure illustrates he stages below.

Figure 6: Staged Approach to Enhanced Planning Analyses



(*Source*: ICF White Paper, *The Value in Distributed Energy: It's all About Location, Location, Location* by Steve Fine, Paul De Martini, Samir Succar, and Matt Robison.

Movement from one stage to another is generally driven by growth in volume and diversity of distribution-connected, DER, the level of evolution of supporting planning practices and tools, and integration with other planning efforts, such as transmission, or resource planning.

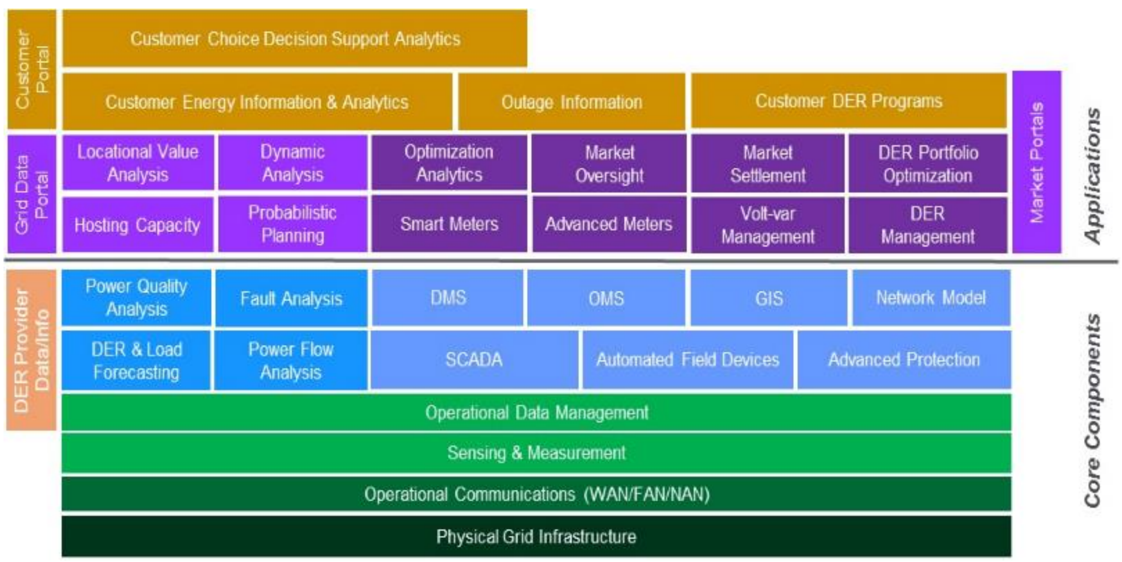
Similarly, the Berkeley Lab report, *Distribution Systems in a High Distributed Energy Resources Future, Planning, Market Design, Operation and Oversight* proposes a three-stage evolutionary structure for characterizing current and future state DER growth, with stages defined by the volume and diversity of DER penetration – plus the regulatory, market and contractual framework in which DERs can provide products and services to the distribution utility, end-use customers and potentially each other.[25] The report emphasizes the need to ensure reliable, safe and efficient operation of the physical electric system, DERs and the bulk electric system, which correlates to Minnesota utility requirements under Minn. Stat. § 216B.04 to furnish safe, adequate, efficient,

[25] Future Electric Utility Regulation series (Report No. 2), by Paul De Martini and Lorenzo Kristov (October 2015). *See* https://emp.lbl.gov/publications/distribution-systems-high-distributed

and reasonable service. The report describes Stage 1 as having low adoption of DERs, where the focus is on new planning studies when DER expansion is anticipated, which also correlates to where we are in Minnesota presently.

The U.S. Department of Energy (DOE), as part of its collaboration with state commissions and industry to define grid modernization in the context of states' policies is developing a guide for modern grid implementation that similarly recognizes foundational elements upon which increased utility tools and information and changes in infrastructure planning, grid operations, energy markets, regulatory frameworks, ratemaking, and utility business models rest, as shown in the below Figure.

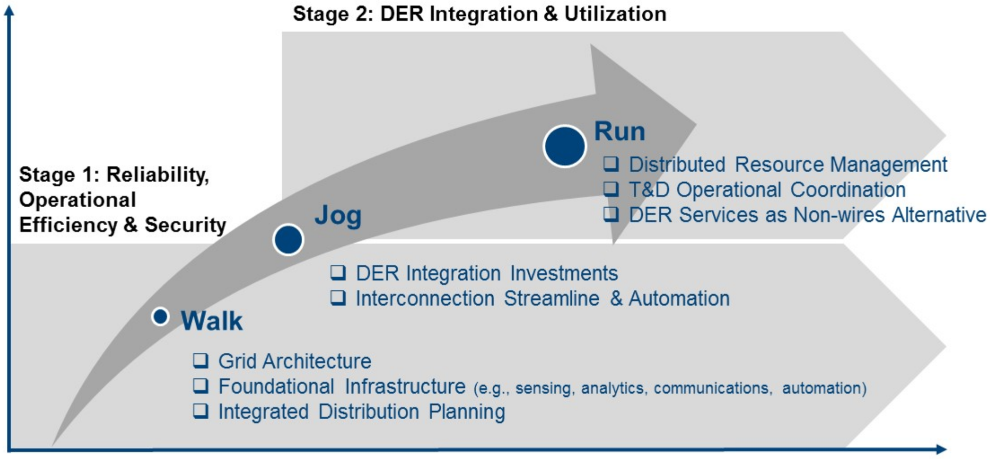
Figure 7: Platform Considerations



Source: *Considerations for a Modern Distribution Grid*, Pacific Coat Inter-Staff Collaboration Summit by DOE Office of Electricity Delivery & Energy Reliability (May 24, 2017).

The DOE's efforts also recognize timing and pace considerations, as shown in Figure 8 below.

Figure 8: Timing and Pace Considerations



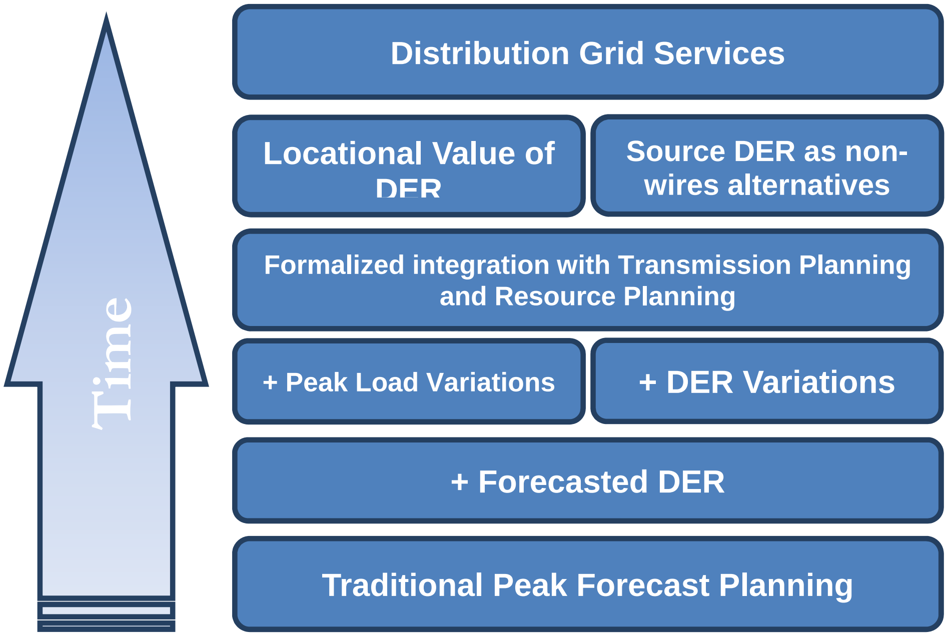
Source: *Considerations for a Modern Distribution Grid*, Pacific Coast Inter-Staff Collaboration Summit by DOE Office of Electricity Delivery & Energy Reliability (May 24, 2017).

As part of the May 24, 2017 Pacific Coast Inter-Staff Collaboration Summit, DOE observed that the U.S. distribution system is currently in Stage 1, with the issue being whether and how fast to transition to Stage 2. Underlying this question however, is the issue of identifying customer needs and state policy objectives – with a goal to implement proportionally to customer value – all of which will differ significantly across states. We agree that Minnesota is in Stage 1. We are focused on foundational infrastructure and starting to evolve our planning tools to enable integrated distribution planning.

A potential progression in planning practices could involve the evolution shown in Figure 9 below, with the drivers of progress being:

- Customer value, such as need, public policy, and cost/benefit,
- Utility readiness, including proper foundational tools and systems, and
- Supporting regulatory frameworks that address cost recovery, and any changes in federal or state market operations, etc.

Figure 9: Potential Evolution in Planning Practices



We expect this progression will need to occur over time as tools improve, policy drivers become clear, and customer value is determined.

Evolving distribution planning to be more like integrated resource planning will need to be thoughtful and planful. Today, IRPs are grounded in Minnesota statutes and rules – and chart a long-term direction of how load can be served in a broad service area. The IRP process is grounded in Minn. R. 7843, which prescribes the purpose and scope, filing requirements and procedures, content, the Commission's review of resource plans, and plans' relationship to other Commission processes, including certificates of need and the potential for contested case proceedings.[26] These processes work for IRPs due to the long-term nature of macro resource additions and changes.

However, distribution planning is more immediate; its full planning horizon correlates to the five-year action plan period of an IRP, which is generally a continuation of past

[26] Minn. R. 7843.0500, subp. 3 prescribes the factors for the Commission to consider in reviewing IRPs. "The Commission shall consider the characteristics of the available resource options and of the proposed plan as a whole. Resource options and resource plans must be evaluated on their ability to: maintain or improve the adequacy and reliability of utility service; keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints; minimize adverse socioeconomic effects and adverse effects upon the environment; enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control."

IRPs. Distribution systems are utilities' point of connection for customers. While an unexpected loss of a macro system component, such as a power plant, can often be covered by the MISO system without interruption of power to customers, loss of a distribution system component often results in a power outage to the customers it was serving. While there is some redundancy in the system to avoid this circumstance, the types of issues addressed by distribution planning are typically much more immediate than IRPs – and do not have a back-up like MISO. Therefore, evolving distribution planning practices will need to be thoughtful – and ensure the focus remains on the immediacy of customer reliability.

While the timeline remains uncertain, it is clear that the distribution grid of the future will look and perform differently than it has over the past 100+ years. Minnesota is in the forefront on the issue of advancing its distribution planning practices with other leaders such as California, New York, and Hawaii. Lessons learned from these states that Paul De Martini, ICF International, shared as part of his presentation at the Commission's October 24, 2016 grid modernization distribution planning workshop included:

- Changes to distribution planning should proactively align with state policy objectives and pace of customer DER adoption.
- Define clear planning objectives, expected outcomes and regulatory oversight – avoid micromanaging the engineering methods.
- Define the level of transparency required for distribution planning process, assumptions and results.
- Engage utilities and stakeholders to redefine planning processes and identify needed enhancements.
- Stage implementation in a walk, jog, run manner to logically increase the complexity, scope, and scale as desired.

No one state has yet figured out the progression of distributing planning enhancements; each is taking a different approach to address the complexities inherent in implementing changes at the right pace and that is proportional to both customer and grid needs – and that realizes net value and benefits for all customers. While the national perspective and other state actions provide helpful points of reference, Minnesota has long been a leader in developing supportive regulatory frameworks to align achievement of policy objectives with business objectives. The increasing complexity of our industry requires a rethinking of the current framework to ensure it is still aligned.

We support the evolution of the grid, and are taking actions to evolve our planning tools and improve our foundational capabilities to support our customers' expanding energy needs and expectations. We support a shift toward more integrated system planning, where utilities assess opportunities to reduce peak demand using DER and to supply customers' energy needs from a mix of centralized and distributed generation resources. However, at a measured pace that correlates to Minnesota policy objectives and customer value.

We are currently evaluating our existing planning processes and tools to determine how to better align and integrate the distribution, transmission, and resource planning processes in the future. Fundamentally, they are rooted in contradictory planning paradigms – with resource planning concerned with size, type, and timing, distribution concerned with location, and transmission somewhere in between. In the near term, we are using the same customer adoption-based DER forecasts and electrification in the IRP and the IDP to the extent practicable – with the IRP having the ability to consider sensitivities. As these planning processes continue to evolve together, it will allow greater ability to consider more potential outcomes – and think about how we can design an optimal portfolio of resources that best meets our overall customer load needs under a range of potential outcomes.

III. CONCLUSION

Our transmission and distribution systems are critical to our ability to serve our customers in a reliable and safe manner, and to deliver growing choice and increasing renewable energy. As we actively prepare our distribution system for the needs of the future, we consider the need for thoughtful investments to meet our core obligation, safely and reliably deliver energy to our customers, and adopt smarter technologies to further enable DER on our system. We recognize and will continue to respond to customer interest in increased DER.

The transmission grid is also facing new challenges and opportunities as traditional baseload units retire, large scale renewables significantly increase, and DER are increasingly adopted. In some cases, such as increasing consideration of distribution-level DER on the transmission grid, changes in the market and planning constructs are underway. Other changes are just coming into view and the planning constructs have not yet caught-up. Overall, we envision building toward an integrated grid in the future that supports the Company's clean energy transition – leveraging the strength of an interconnected system to make the best use of available resources and continue to serve our customers with resilient and reliable power.