White Paper: Grid Modernization

Introduction

The basic design of the electric grid has remained largely the same since the first commercial power plant in the U.S. went into service in 1882. Electricity has been mostly generated remotely at large central stations, transmitted long distances with high-voltage transmission lines, and then reduced in voltage for local distribution and delivery to customers.

Today, one might think of the shift we are experiencing in the electricity sector as being similar to the shift from large, centralized mainframe computers that once filled entire rooms to the highly distributed system of laptops and smart phones that have now put computers quite literally in nearly everyone's hands. With the emergence of distributed energy resources (DERs) of many kinds, the electricity sector is going through much the same decentralizing transformation.[22] This trend toward a more distributed electric system is not to the exclusion of central power plants but in addition. Indeed, the vertically integrated electric system has been evolving for years to be cleaner and more efficient, and has integrated more renewable resources in a cost-effective manner. To effectively manage this paradigm shift toward a more decentralized system will require a modernized electric grid. According to the U.S. Department of Energy's *Quadrennial Energy Review,*[23]

> A revolution in information and communication technology is changing the nature of the power system. The smart grid[24] is designed to monitor, protect, and automatically optimize the operation of its interconnected elements, including central and distributed generation; transmission and distribution systems; commercial and industrial users; buildings; energy storage; electric vehicles; and thermostats, appliances, and consumer devices.

In other words, we are headed for a more networked grid that is able to respond and adapt to rapidly changing technologies being deployed by customers at the so-called grid edge and that can function in new and untraditional ways.

The Minnesota Public Utilities Commission's (PUC's) working definition of a modern grid was put forth in a March 2016 staff report on grid modernization.[25]

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[22] Distributed energy resources are supply- and demand-side sources of electricity that can be used throughout an electric distribution system (i.e., on either the customer side of the customer's meter or the utility side) to meet electricity and reliability needs of customers. Distributed energy resources include end-use efficiency, distributed generation (solar photovoltaics, combined heat and power, small wind), distributed flexibility and storage (demand response, electric vehicles, thermal storage, battery storage), and distributed intelligence (communications and control technologies).

[23] *Quadrennial Energy Review: Energy Transmission, Storage, and Distribution Infrastructure* (U.S. Department of Energy, 2015).

[24] Smart grid technologies include: distribution system management systems, energy efficiency, combined heat and power, fuel cells, gas turbines, rooftop solar photovoltaics, distributed wind, plug-in hybrid and all-electric vehicles, distributed storage, demand response, and so-called transactive building controls.

[25] *Minnesota Public Utilities Commission Staff Report on Grid Modernization*, St. Paul, MN (2016). http://morethansmart.org/wp-content/uploads/2015/06/MNPUC_Staff_Report_on_Grid_Modernization_March2016.pdf.

The PUC defined an integrated modernized grid as one that

a. ensures continued safe, reliable, and resilient utility network operations
b. enables Minnesota to meet its energy policy goals, including the integration of variable renewable electricity sources and DERs
c. provides for greater system efficiency and greater utilization of grid assets
d. enables the development of new products and services
e. provides customers with necessary information and tools to enable more informed control and choice regarding their energy use
f. supports a standards-based and interoperable utility network

Benefits of a Modernized Grid

For Customers

a. gives customers the information they need to manage their electricity use and help control or contain costs
b. gives customers more electricity options (renewable energy, time-of-use rates, etc.)
c. allows utilities to pinpoint outages rapidly, and sometimes in advance
d. enables customers to use demand response products and services (where customers are paid to use electricity at specific time intervals or in response to grid conditions and needs)
e. optimizes the efficient use of the existing electric system while maintaining its resilience (e.g., meets demands for electricity drawing on both supply-side and demand-side resources in ways that minimize the need to build new “peaking” plants and help keep costs down for all by potentially deferring infrastructure investment)
f. provides very high-quality power to those customers who need it in an increasingly digital economy (electricity with few sags in voltage or frequency)
g. coordinates the use of all types of electricity resources, from central power plants to DERs (e.g., solar, electric vehicles, and other forms of energy storage), allowing interested customers to interact effortlessly with the electric system
h. enables the mass deployment of electric vehicles

For the Utility and Grid Operator

a. has lower costs for repair and replacement of equipment because it alerts utilities about equipment predicted to fail (asset performance management) rather replacing old equipment on a set schedule whether it needs it or not
b. can “heal” itself after a disturbance (e.g., from storms)[26]
c. provides greater visibility about what’s happening at the grid edge
d. provides people with price information and signals that provide economic incentives to utilize electricity in a manner that optimizes system operations, leading to lower costs for all
e. enables more distributed, clean energy technologies paired with energy storage devices that make the grid more resilient

[26] This requires a system of sensors, automated controls, and advanced software that relies on real-time data to detect and isolate faults and to reconfigure the distribution network to minimize affected customers.

In the e21 Initiative's consensus phase I report, participants agreed that the rapid improvement and declining costs of distributed energy technologies, such as solar, along with new customer demands and public policy requirements are driving the need for a modern grid that is cleaner and more intelligent, efficient, reliable, resilient, safe, and secure; and a grid that is more flexible in its ability to integrate a wide diversity of DERs and that enables customers to manage (and potentially reduce) their electricity costs.

To achieve such a system, the e21 Initiative's phase I report recommended that Minnesota

- develop a transparent, forward-looking process for modernizing the grid (which the Minnesota PUC now has underway)
- identify ways to achieve a more flexible distribution system that can efficiently and reliably integrate cost-effective DERs (e.g., efficiency, demand response, distributed generation, energy storage, electric vehicles, distributed intelligence)
- pursue opportunities to reduce customer and system costs by improving overall grid efficiency and better utilizing existing system assets (i.e., improving the grid's load factor).

Charge of the Grid Modernization Subgroup

The grid modernization subgroup aimed to contribute to the implementation of the above three recommendations by

a. proposing a set of objectives for grid modernization in Minnesota and outlining the functions and technologies a modern grid will need
b. suggesting an overall approach to grid modernization
c. offering next steps and recommendations that can usefully complement the Minnesota PUC's ongoing grid modernization process.

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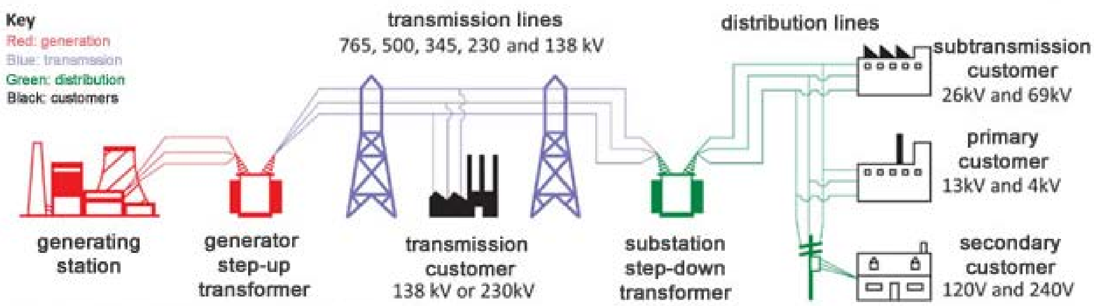
** An asterisk indicates they are no longer at their organization and are no longer participants in e21. Also note that participants that have changed organizations since the start of e21's phase II have their new position and organization in parentheses.*

Section I:
Why Modernize the Electric Distribution Grid?

The electric distribution system that we all rely upon daily has had a relatively simple design for more than 100 years (see Figure 1), and its job was straightforward: to take electricity produced at large centralized power plants, send it long distances over bulk transmission lines, and then, in one direction, send it through distribution lines to end users such as factories, businesses, and homes.

Figure 1. The Electric Grid: Generation, Transmission, and Distribution



Source: Adapted from North American Electric Reliability Corporation

Our electric system has worked so well that most of us take it for granted. However, today it faces a long list of pressures including aging infrastructure (much of it was built in the 1960s and 1970s), demands from some customers for greater reliability and cleaner energy, and the emergence of a wide range of new distributed technologies that the traditional electric grid was not designed to accommodate (see the box below for a list of the key drivers for grid modernization).

Drivers Spurring the Need to Modernize the Grid

Changes in Customer Preferences and Behavior

a. Customer preferences are growing for increasingly clean electricity and the option to produce it themselves, purchase Renewable Energy Credits, and/or buy it directly from a renewable energy facility that either a utility or third party owns and operates.

b. Customers are increasingly interested in better understanding their electricity use and costs, and therefore are increasingly interested in easy access to their real-time, detailed electricity use data.

c. Customers are becoming more energy efficient. This reduction in electricity sales calls for reexamination of how best to cover the cost of maintaining and reinvesting in the grid.

d. Some customers desire even higher quality and more reliable power supply, due to the greater reliance on electricity in our more digital economy.

Changes in Energy and Information Technology

e. Rapidly emerging DERs, declining in cost, need to be integrated into the grid. While DER penetration differs significantly by state and by utility, according to the Institute of Electrical and Electronics Engineers, “the vast majority of new generation currently being connected to the grid is through the distribution system.”

f. The emergence of the “internet of things” means that a growing number of appliances have the ability for two-way communication with the electric grid and can be controlled remotely. This “distributed intelligence,” in the form of communications and control technologies, enables nearly every grid element to send and receive information, and begs for a much more robust, interoperable communications network and cyber-security strategy than currently exists.

Changes in Public Policy

g. Existing public policy calls for more renewable energy and significant reduction in greenhouse gases.

h. Recent policies and programs are being implemented to encourage DERs and help overcome market and regulatory barriers to implementation.

i. There is constant pressure to reduce overall costs while improving the electric grid’s resiliency, reliability, and security.

Among these drivers of change, perhaps the most influential is the emergence of DERs, including generation resources such as solar. As the penetration of DERs increases on the distribution grid, we are moving from a highly controlled, centralized system—where the independent system operator coordinated which power plants to switch on and when—to a much more decentralized system in which distribution grid operators may need to coordinate the dispatch of DERs. e21 participants recognized that there is also substantial opportunity for adoption of DERs (such as demand response) for large customers that may connect directly to the transmission system as opposed to the distribution system. While many principles discussed below may apply to these larger-scale DER opportunities, for focus and clarity this white paper deals with the distribution system.

The emergence of distributed energy technologies also means that the grid—which was originally designed to carry electricity in only one direction—must now operate more dynamically in a multi-directional manner: electricity now flows not only from the transmission system down to the distribution system, but also sometimes flows back into the transmission system from generation technologies connected to the distribution system. The impacts of this decentralization of electricity production are most acute on the distribution system due to the nature of DERs, which are sometimes controlled by someone other than the utility.

The local distribution system for electricity is, itself, undergoing changes too. The distribution system has traditionally operated as a collection of independent radial feeders with all of the power coming from one source, the transmission grid. Increasingly, though, the hub-and-spoke system is being reshaped by customer density and the interconnection of new distributed resources throughout the distribution system. These new DERs include customer-driven generation, load management, energy efficiency, and advanced monitoring, and their diverse placement throughout the distribution system creates a very complex and dynamic distribution grid.

While connecting more electricity resources to the distribution grid may sound simple, a large number of factors determine the characteristics of a given location on a distribution system feeder. A key motivator for modernizing the grid is to allow distribution planners and operators to more proactively address some of these considerations, which include:

Maintaining power quality within a more dynamic system. DERs and loads must interact with each other so as to not cause nuisance or damaging impacts, as may happen if harmful voltage levels, harmonic content, or flicker are allowed to develop. Thus, it is important to develop and implement tools and systems to help enable the desired interconnections and maintain required frequency and voltage.

Designing distribution circuits to accommodate DERs. Considerations here include: How the size of electrical loads are matched with the size of DERs (what amount of generation will be put back on the grid). The size and type of the distribution transformer supplying that location (generally, smaller transformers can be overloaded by distributed generation systems back-feeding the distribution grid). The size and length of the wires supplying that location (generally, smaller wires have less capacity and more dynamic voltage swings).

Ensuring that transmission and substation characteristics can accommodate DER. This includes paying attention to

- the distance between the DER and the substation (the farther the interconnection location the greater the voltage swings can be)
- the capacity of the substation (larger substations can typically support larger distributed generation systems)
- the "stiffness" of the transmission system supplying the distribution substation (a stiffer transmission system reduces voltage dynamics)[27]
- the capacity of the substation, and whether there is hosting capacity available for DERs. Hosting capacity is defined as the amount of DER that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades to the primary line voltage and/or secondary network system[28]
- the electric protection system—causes of trips and equipment failure in that section of the feeder (i.e., size and type of the fuse or breaker)

This is just a partial list and does not include customer-driven solutions such as smart inverters. While none of these considerations are deal-breakers for moving to a more decentralized system of electricity generation, they do illustrate the non-trivial factors that grid planners must take into account if we are to maintain a safe, reliable, and cost-effective electric system going forward. Utilities are, and will continue to, evolve the electric grid to meet the needs of users. **The original job that electric distribution systems were asked to do—move electricity in one direction from the transmission grid to the end user—is changing dramatically; and the way we plan, design, and operate the system will need to be modernized to match the new demands of the day.**

[27] In rural areas, transmission systems are typically weaker than urban areas, and the electric grid cannot always support larger distributed generation systems due to larger voltage swings.

[28] *Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State* (Palo Alto, CA: Electric Power Research Institute, 2016).

Section II: An Approach to Modernizing the Electric Grid

Having established the reasons why Minnesota should modernize its electric grid, in this section we outline an approach for doing so. Its five basic elements are the following:

a. **Set clear objectives**. An essential first step toward grid modernization is for Minnesota to be clear about its objectives for doing so. In other words, what do we want a modern electric grid to do besides deliver the electricity that it always has? Early clarity on objectives is critical since they will inform how all other issues are handled.

b. **Identify the key functions the grid must have to achieve each objective**. Much discussion around grid modernization to date has focused on individual technologies, such as advanced metering or distributed solar photovoltaics. The approach presented here explicitly elevates the *functions* that various technologies can fulfill (i.e., what problems can they solve) above the individual technologies themselves. Which functions are needed, and when, will differ based on the penetration of DERs on the distribution system, the nature of the customer base in a given utility service territory, and other factors. But the salient point is simply that each function should contribute to one or more grid modernization objectives (see ‘a’ above).

c. **Identify and invest in those foundational technologies that enable the desired grid functions, and assess technology performance over time to ensure the technologies are being harnessed to meet explicit objectives and functions**. Here, too, which technologies are needed, and in what order, will depend largely on the degree of DER penetration on a given distribution grid and how complex the market and operational characteristics of the distribution grid have become (see Fig. 1 below).

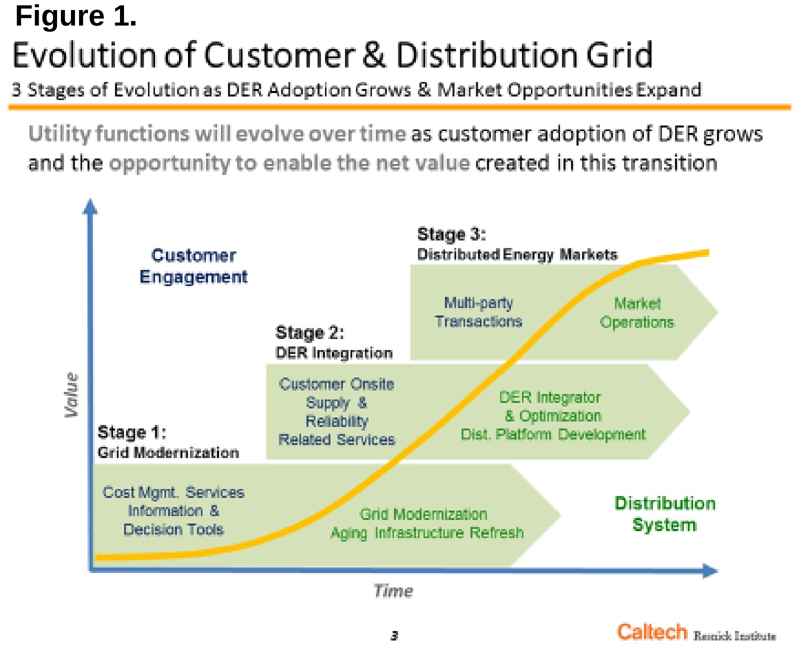
d. **Facilitate comprehensive, coordinated, transparent scenario-based distribution system planning**. Distribution system planners are currently faced with the challenge of planning for the pace and location of DER growth, which to date has been treated as an external condition to react to, rather than a resource to be planned for and harnessed. Yet ever-more accurate forecasts of DER growth can be developed, similar to how forecasting of wind resources has improved. There is also an opportunity to use probabilistic scenario planning and a standard set of DER growth scenarios (much the way transmission planners have done) to create long-term plans for accommodating the scale and location of DERs on the distribution system. Such scenario planning works best at a scale where a significant diversity of DERs is present and will be less accurate for smaller systems. Unlike transmission planners, who have the benefit of long lead times planning for transmission investments, most distribution planners must react more rapidly to local changes on the distribution system, such as the addition of new businesses and housing developments.

In addition to better forecasts and scenarios, utilities will need to perform systematic hosting capacity analysis of each distribution feeder and substation—as a screening tool—to quantify the level of DERs possible on the distribution grid. Utilities will also need to conduct locational value mapping to determine where DERs can help solve problems on the grid, where they may cause problems, and/or where adding them may prompt the need for additional investment (such as upgrading a transformer or substation).

Lastly, in addition to developing longer-term scenarios that attempt to capture the likely range of potential DER penetration on the distribution grid, utilities may also need to conduct periodic—perhaps annual—hosting capacity reviews to avoid operating with out-of-date information (or providing out-of-date information to interested third parties), given that conditions on the ground are always changing.

e. **Identify the current stage of grid evolution and decide on an appropriate operational model for the distribution grid, including how it will interact with the bulk transmission system and the regional electricity market, and how it will handle market transactions if/when necessary**. In their paper for Lawrence Berkeley National Laboratory, *Distribution Systems in a High DER Future: Planning, Market Design, Operation and Oversight,* Paul De Martini (California Institute of Technology) and Lorenzo Kristov (California Independent System Operator) offer a useful way of conceptualizing the evolution of the distribution system as customer adoption of DERs grows (Figure 1). The stages of DER penetration may not be neatly sequential, nor does Figure 1 suggest that stage 3 is the inevitable or desired destination. The point is for states to understand where on this continuum they are (most are at stage 1) and then choose where they wish to be and prepare accordingly. The authors lay out several different models for who could be made responsible for managing grid operations, market transactions among utilities, customers, and third parties, and interactions with the transmission system operator. The options range from the transmission system operator managing all transactions for both the transmission and distribution system, to a model in which the operator of the distribution system manages all operations for its distribution service territory and coordinates a single

Figure 1.



aggregate of all DERs at each point where the distribution system connects with the transmission system (the transmission/distribution interface).

Finally, the authors usefully identify two key ways that states can prepare for higher penetrations of DERs. States can

- use the replacement of aging infrastructure and investments needed for electricity reliability reasons to increase the distribution grid's ability to accommodate more DERs (for example, standardizing on fewer, but slightly larger, equipment/wire sizes when replacing old ones)
- make prudent investments that can lay the foundation for the future as well as provide immediate benefits. These potential investments include
    - advanced metering infrastructure
    - advanced distribution management systems
    - distribution sensing, visualization, and analytics
    - field switch/device automation
    - higher bandwidth/lower latency operational communications networks

Objectives for Grid Modernization in Minnesota. After careful thought and discussion, e21 participants propose the following objectives for grid modernization in Minnesota:

Objective 1: Maintain and enhance the reliability, safety, security, and resilience of a more distributed, dynamic, and complex electric grid, as and where needed

Objective 2: Enable greater customer engagement, empowerment, and options, including the ability to manage and potentially reduce electricity costs for all customers

Objective 3: Enhance the system's ability to integrate DERs and other new products and services in a cost-effective and timely way

Objective 4: Improve the environmental performance of electricity services

Objective 5: Promote optimized and cost-effective utilization of grid assets

The remainder of this section takes each of these objectives in turn and briefly outlines the grid functions and technologies needed to achieve them.

Objective 1: Maintain and enhance the reliability, safety, security, and resilience of a more distributed, dynamic, and complex electric grid, as and where needed.

Background. This first objective is largely about identifying the features of the existing electric distribution system that we value and still need while accommodating DERs. To achieve this objective, utilities will need efficient, cost-effective, real-time ways to anticipate infrastructure repair and replacement needs, detect and repair faults and outages on the distribution system, and reduce the impact of prolonged outages by improving their speed in restoring service after extreme events (for example, weather or cyberattacks). Per the discussion in section I, meeting this first objective will also require utilities to map where on the system DERs can provide the greatest benefit (sometimes called locational value mapping) and will require regulators to establish a compensation framework that encourages DERs to locate in those places. Channeling DERs to the best locations will contribute to several aspects of this objective, including safety and reliability.

As for achieving a grid that is both resilient and secure, the shift toward more DERs is double-edged. On one hand, such resources, almost by definition, make the electric grid more resilient by virtue of being distributed and therefore less susceptible to any single disruption (the parts of New York that were still illuminated after Superstorm Sandy were generally those served by DERs). On the other hand, managing a more complex, more highly distributed system will require a new communication system linking its many elements. Such an extensive communication system will, by design, create thousands (or millions) of potential access points for cyberattack (much as we already see on the internet).

While we recognize the fundamental importance of ensuring cybersecurity, this white paper will not address it in any depth. e21's discussion and recommendations presuppose that all parties interconnecting with the grid will employ and maintain robust cybersecurity measures, and we recognize the Minnesota PUC's role in supporting such requirements.

Lastly, it is important to note that different types of electricity customers desire different levels of reliability, security, and resilience. For example, the level of power quality and reliability that a homeowner finds acceptable will be quite different from the level acceptable to a data center, for which even small fluctuations in voltage can cause problems. Therefore, achieving objective 1—and the additional investments it will require—should be tempered by what different customer classes need and are willing to pay for.

Key functions that a modern grid must have in order to achieve objective 1 include utilities having the following capabilities and conditions

a. incipient fault detection
b. automated fault detection
c. fault location and isolation, and service restoration
d. operational standards, including how the distribution system will interact with the bulk electricity market managed by the Midcontinent Independent System Operator (MISO)
e. workforce optimization (e.g., having the right people in the right place at the right time)
f. situational awareness for field crews
g. remote preventive maintenance inspection (will be different by utility)

Foundational technologies that enable these functions include

a. intelligent field devices (e.g., digital relays and controls)
b. field area networks
c. distribution management systems
d. better information from global information systems
e. field mobility tools (e.g., a tablet that shows real-time state of the system on power flows and location of field crews)

Objective 2: Enable greater customer engagement, empowerment, and options, including the ability to manage and potentially reduce electricity costs for all customers.

Background. A modernized grid must enable customers to gain greater insight into the sources of their electricity and understand their electricity use profiles and costs. Making more information easily accessible and understandable will facilitate customers' ability to understand and manage their costs, reduce their environmental impact, take advantage of new technologies, and generally manage their individual electricity preferences.[29]

Two interrelated prerequisites for accomplishing this objective are advanced meters and improved customer access to their electricity usage data. Today's advanced digital meters are able to collect electricity usage information at hourly or 15-minute intervals, whereas current metering infrastructure for most customers is only able to provide data once a month or once a day. An integral part of customer engagement and empowerment is giving customers easy access to their electricity usage data since without the necessary information it is impossible for them to make informed decisions about their electricity use. The Minnesota PUC's recent proceeding[30] on the use and availability of customer electricity usage data addressed fundamental questions about how the data could be made available, while safeguarding customer privacy and the anonymity of that data.

The proliferation of new technologies and devices is making it easier to manage electricity use in near real-time, and they are increasingly available directly to customers, at declining costs. Smart thermostats and home area networks can help customers manage their electricity use and provide automated control and convenience by connecting to and communicating with the digital devices throughout the person's home—from lights and appliances, to the heating and cooling system—to optimize their efficient use. Pairing these programmable energy management technologies with time-of-use rates could enable customers to effortlessly control their electricity costs, while helping to optimize grid operations.

Other enabling technology, such as advanced metering infrastructure, can communicate cost and pricing information to a customer's automation and control systems at their home or business, again making more transparent the utility's costs of providing electricity service at any given time. The promise of these technologies is that they will allow customers to manage their electricity use and their interaction with the grid without thinking about it. A customer can automatically charge an electric vehicle or cycle a refrigerator off and on (without affecting the inside temperature) on a schedule that reduces demand on the electric system or shifts it to a more optimal time, dramatically improving the efficiency of the entire system and reducing costs

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[29] Or the ability of a customer's authorized third party who may be assisting them.

[30] See *In the Matter of a Commission Inquiry into Privacy Policies of Rate-Regulated Energy Utilities*, Minnesota Public Utilities Commission Docket No. E,G-999/CI-12-1344 (Order based on December 1, 2016 hearing is forthcoming).

for all customers. While not everyone may want, or be able to afford, some of these technologies and services, making them available to people at all income levels would make it both possible and easy for customers to use electricity at the most affordable times and operate their homes or businesses as efficiently as possible.

Many customers will be happy to stick with conventional grid electricity produced with an evolving mix of fuels—increasingly natural gas, wind and solar, some remaining coal and nuclear—and other customers will want to invest in producing their own power (for example, from solar, either directly on their roof or through shares in a community solar project), and a modernized grid must accommodate them all.

Finally, achieving the customer engagement called for in objective 2 will require utilities to develop an even more nuanced understanding of what their various customers want, develop more sophisticated ways of meeting those needs, and educate their customers about changes to electricity services and the grid.

Key functions that a modern grid must have in order to achieve objective 2 include

a. the ability to handle two-way flows of information among the actors and connected devices on the system. Examples of relevant information are real-time prices and electricity use, control parameters such as voltage and power factor, and information designed to educate and inform customers of their options and opportunities for savings and reduced environmental impact

b. the ability to effectively manage two-way flows of electricity

Foundational technologies that enable these functions include

a. user-friendly customer portal/hub that displays relevant electricity and price information

b. home area network at the customer's site

c. advanced metering infrastructure and communication networks including field area networks

d. a secure protocol via the internet or cellular option

Objective 3: Enhance the system's ability to integrate DERs and other new products and services in a cost-effective and timely way.

Background. We are evolving from an electric system with relatively few actors on it, characterized by large centralized power plants sending electricity in one direction to the end user, toward a system with potentially thousands of "prosumers" participating in it (sometimes acting as *consumers*, using electricity from the grid and sometimes acting as *producers*, making their own and selling the excess back to the grid). In this more complex, highly distributed system there will be increased need for a real-time orchestra conductor to coordinate activities on the system minute-to-minute and ensure that it operates efficiently, safely, reliably, cost-effectively, and securely. In Minnesota, that function is provided by the local utilities.[31]

In any case, achieving objective 3 will require changes in how we operate the grid, compensate DER providers (e.g., solar), determine who has access to information about the best locations for DERs on the grid, institute changes to the interconnection process and tariffs charged for

[31] As distribution systems evolve, some states may choose to establish a separate entity to manage distribution grid operations.

connecting to the distribution grid, and modify the interoperability standards that allow different elements of the electric system to talk with one another seamlessly.

Taking these in turn, the way we operate the electric grid is already changing. Since there are many sources of variability on the system—level of demand, net imports and exports of electricity, distributed generation such as wind and solar, etc.—system operators use a variety of supply- and demand-side resources to meet the net load at any given time of day (the amount of electricity demand that still needs to be met by centralized generation after accounting for all of these variables). In the future, system operators won't only match generation to meet the load, but will increasingly manage the load to match available electricity generation. In other words, the legacy terms of "baseload," "intermediate," and "peaking" no longer reflect how grid operators think of balancing supply and demand.

Today's large, liquid electricity markets can re-match net demand with net supply every five minutes across the entire MISO region. On the distribution grid, this reconciliation between supply and demand will be done by the operator of the distribution system. Information from the distribution operator will need to flow up to the transmission operator and vice versa.[32] A more integrated, networked, and intelligent electric grid makes this kind of coordination possible, and it paves the way for energy resources at the customer and distribution grid level to contribute to the reliability of the regional electric system. The goal will increasingly be to find ways to optimize and extract value from one end of the electric system to the other, from end-use customers through distribution systems, regional transmission systems, and centralized power plants.

Next, achieving objective 3 will require accurately compensating DER providers for the full value they deliver to the grid and charging them fairly for the costs they impose from being connected to it. The current net energy metering model of reimbursing providers of DERs, such as solar, at the retail electricity price by crediting against a customer's electricity consumption is leading to heated debates about whether DER providers are paying their fair share of grid infrastructure costs and whether there are unfair cross-subsidies taking place. These debates are a symptom of stakeholders in the electric system not yet having worked out what the appropriate rate design and compensation methodology should be between DER providers and utilities.

Current net energy metering programs focus solely on the total production of a DER without taking into consideration the location of the asset or what the grid's needs are at any given time (for energy, capacity, voltage support, frequency regulation, etc.). Minnesota's value-of-solar tariff is an example of trying to capture solar's full range of costs and benefits in the price solar providers get. Minnesota will need to determine whether to implement a suite of technology-specific tariffs for each form of DER or identify a set of services necessary to maintain the distribution grid and then allow DERs to compete to provide those services. Minnesota will need to determine the tradeoffs and benefits of each option in order to meet this objective.

Next, data about the distribution grid itself will also be essential to optimally integrating more DERs, including where the best locations are for adding DERs and when the system is likely to need energy, capacity, demand response, or ancillary services such as voltage support and frequency regulation. When customers, developers, and other third parties have access to relevant grid-level information they will more naturally locate DERs in the best places on the grid if there are tariffs that reward them financially for doing so and penalize them for locating in

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[32] See Paul De Martini and Lorenzo Kristov, *Distribution Systems in a High Distributed Energy Resources Future, Future Electric Utility Regulation, Report No. 2* (Berkeley, CA: Lawrence Berkeley National Laboratory, 2015).

places where more DERs would impose net costs on the system. When relevant transparent information is paired with accurate prices, an efficient market can start to function.

Minnesota could also benefit from updating its interconnection standards and tariffs for DERs. A more open, streamlined, and transparent interconnection process utilizing more information about the state of the grid can alleviate delays and complaints and result in savings to the customer and the grid. As for updating current tariffs, efforts such as California's Rule 21 and the Federal Energy Regulatory Commission's small generator interconnection procedures tariffs provide Minnesota examples to draw from.[33]

Along with updating the tariffs, adding new grid functionalities that are now mainstream can enable additional benefits to the utility and the customer. For example, smart inverters can enable two-way communications between grid operators and DERs, and they can provide low-voltage and low-frequency ride-through, volt-VAR support, black-start capability, and islanding that will allow microgrids to function alone or connected to the larger grid. Given their wide range of functions, smart inverters are increasingly seen as a de facto part of any customer-sited resource.[34]

Finally, since the electricity sector is a standards-driven industry, having open and transparent standards must be a bedrock principle of grid modernization. These standards support interoperability of devices, on both the utility and customer side of the electric meter.

Interoperability and use of open standards help utilities avoid being locked into a single vendor for a given technology, which ensures an open, innovative, and competitive market for utility- and customer-focused products. When utilities, regulators, and other stakeholders identify and agree upon these foundational standards early, such as IEEE 1547, UL 1741, and IEC 61850, this can lower barriers to entry for new products and services, and lower overall costs to the utility by allowing for competition among vendors. Cost savings can then be passed through to customers.

[33] California's rule concerns the technical requirements for interconnecting solar to the grid. On the Federal Energy Regulatory Commission's tariffs, see http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp.
[34] The current standards supporting the interconnection tariffs IEEE 1547 and UL 1741 have been updated or are currently being updated to allow for the advanced functionality from smart inverters. Work continues on communication standards (DNP 3 and IEC 61850) that can help ensure that the utility is in communication with its equipment as DERs begin to impact the distribution grid.

Microgrids as Another Feature of a More Distributed Electric Grid

One might think of microgrids as a larger distributed energy resource. Microgrids are collections of electricity users (loads) and distributed energy resources to serve them (think university campus). Microgrids operate to provide electricity during storms, at times of peak load, or when equipment in the area fails or is out for maintenance. Their key features are that they

- are locally controlled
- can function in two modes, connected to the traditional grid or as an electrical island

This "islanding" function can be especially beneficial in situations when severe weather or other disruptions have caused the main grid to lose power. That said, disconnecting and reconnecting to the main grid requires special planning and sophisticated software to ensure that it is done safely and without compromising the functioning of either the microgrid or the main distribution system.

The main barrier to greater microgrid deployment is simply the cost to implement the distributed generation and required storage, but as the costs of both fall, microgrids will likely become even more common. For example, Dakota Electric in Minnesota has roughly a dozen microgrids in places where a member's campus is isolated from the rest of the Dakota Electric system.

Lawrence Berkeley National Laboratory cites the many benefits of microgrids for both utilities and customers, including "improved energy efficiency; minimization of overall energy consumption; reduced environmental impact; improvement of reliability of supply; network operational benefits such as loss reduction, congestion relief, voltage control, or security of supply; and more cost-efficient electricity infrastructure replacement."

For more information, see:

- Lawrence Berkeley National Laboratory: https://building-microgrid.lbl.gov/about-microgrids
- "Minnesota Microgrids: Barriers, Opportunities, and Pathways Toward Energy Assurance." 2013. Prepared by the Microgrid Institute for the Minnesota Department of Commerce. http://mn.gov/commerce-stat/pdfs/CHP pdfs/MN-Microgrid-WP-FINAL-amended.pdf
- California Public Utilities Commission. 2014. "Microgrids: A Regulatory Perspective." http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPDMicrogridPaper414.pdf

Key functions that a modern grid must have in order to achieve objective 3 include

a. real-time, model-based control systems for grid operators
b. additional work on uniform standards (e.g., smart inverter and communications standards)
c. interoperability among components connected to the grid
d. the evolution of market rules in ways that improve system flexibility including:
    - improved system scheduling and dispatch
    - improved procurement
    - payment for ancillary services
    - incentives for load following and ramp management
e. hosting capacity assessment
f. development of distribution-level locational marginal prices

Foundational technologies that enable these functions include

a. advanced metering infrastructure
b. demand response mechanisms such as automated load control/response and real-time pricing
c. DER management system
d. energy storage
e. field area networks
f. smart inverters

Objective 4: Improve the environmental performance of electricity services.

Background. Minnesota has established ambitious statutory goals for reducing greenhouse gas emissions to 15 percent below 2005 levels by 2015, 30 percent below those levels by 2025, and 80 percent below by 2050.[35] In addition, as cited in the *Minnesota PUC Staff Report on Grid Modernization*, "the 'reasonable rate' statute requires the [Minnesota Public Utilities] Commission to set rates to encourage energy conservation and renewable energy 'to the maximum reasonable extent'; and the energy savings policy goal states that cost-effective energy savings 'are preferred over all other energy resources' and 'should be procured systematically and aggressively.'"[36]

Grid modernization can help achieve these policy goals by creating a platform for optimizing the environmental performance of the electric system as a whole. This includes better integrating distributed renewable generation technologies, increasing the responsiveness of customer loads, and giving customers new tools to save electricity, as well as optimizing the use of large-scale renewable energy assets and doing better forecasting and planning to integrate more renewable and low-carbon resources.

Grid modernization technologies also facilitate more accurate measurement of energy savings from efficiency improvements, and these can help verify the consistency and persistence of those energy savings over time. The new data collection and communication capabilities of a modern grid may also help identify specific new energy efficiency opportunities and ways of operating at the systems level that improve the efficiency and environmental performance of the electric grid overall.

This objective poses an important policy question for Minnesota about the role of DERs in achieving the state's environmental goals. Most DERs, such as energy efficiency, solar, or demand response, reduce greenhouse gas emissions.[37] Yet when it comes to generation technologies, economies of scale still often favor utility-scale renewable energy facilities over smaller, more decentralized distributed generation in terms of cost and integration with the grid. However, if only the avoided cost of DERs is taken into consideration, this may not appropriately identify and allocate the non-generation, time- and location-specific benefits they can provide, such as peak reduction, voltage, and frequency regulation or grid resilience. Clarifying the environmental objective of grid modernization allows policymakers to assess which distribution grid technologies will have the highest environmental benefit from a systems perspective.

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[35] Minnesota statute §216H.02

[36] Additional quotations are taken from Minnesota statute. See *Minnesota PUC Staff Report on Grid Modernization* (p. 11) for details.

[37] However, the use of diesel-fired back-up generation may have local impacts.

Achieving objective 4 is about increasing and optimizing the mix of cost-effective energy efficiency and zero- or low-carbon electricity resources on the electric system, including customer-driven and community-scale DERs. The essence of this objective is for Minnesota's electric system to provide safe, reliable, affordable, and secure electricity service with a declining environmental footprint that, at a minimum, achieves the state's statutory goals.

Key functions that a modern grid must have in order to achieve this objective include

a. the ability for loads that are flexible (i.e., loads that don't care when they receive electricity) to take advantage of renewable energy generation by receiving signals telling them when there is excess renewable energy available or, more generically, low market prices. Examples of flexible loads include water heating, electric vehicle charging, large appliances (e.g., refrigeration including defrost), limited scheduling of heating and cooling, and energy storage.
b. distribution grid operators are able to "see" the distribution-level-connected resources on the system (end-to-end visibility)
c. dynamic voltage control
d. load management, including demand response, that reduces overall electricity used or shifts supply to lower-carbon electricity sources
e. new communications, metering, and control technologies that open up new market segments for intelligent and systems-based energy efficiency
f. the ability to maximize reliable penetration of renewable distributed generation and accelerate interconnection of those technologies
g. the ability to monitor and verify the performance of energy saving and renewable production technologies

Foundational technologies that enable these functions include

a. advanced metering infrastructure
b. field area networks
c. home area networks
d. model-based control systems
e. more intelligent energy management systems that better match up renewable generation resources with load

Objective 5: Promote optimized and cost-effective utilization of grid assets.

Background. Utilities have planned and operated the electric system to meet the peak demand in any given year and to handle the instantaneous demand of customers—plus a little extra (the reserve margin) to make sure there is always enough electricity available, including when there are unexpected power plant and/or transmission line outages.

This means that most of the time there is significant excess electricity-generating capacity—though much of that capacity is composed of peaking units that are not meant to run full time—a bit like building a parking lot big enough to accommodate a few weeks of holiday shopping per year. If peak demand (e.g., when everyone is flipping on their air conditioning in the summer) could be reduced and/or shifted, it would save both utilities and customers money because we could avoid building additional generating capacity to meet that peak demand.

Therefore, objective 5 is about (1) optimizing the alignment between generation and load to better utilize the existing system, and (2) continuing the evolution toward more fully using both customer-driven resources (such as distributed generation, energy storage, and demand response) and the utility's resources to meet demand at any given time. This will improve the electric system's load factor so that power usage is relatively constant (with fewer peaks) and thus help avoid needing to build additional power plants.

Another potentially cost-effective opportunity for meeting customer load is demand response. Traditionally, this involves paying some customers to reduce their electricity use during the most expensive times, for the utility, of peak demand. The simplest form of demand response, particularly from a resource planning perspective, may be to compensate large load customers (>10 megawatts) to reduce their electricity usage during system peaks. Many large customers are interconnected to the transmission grid as opposed to the distribution grid and, therefore, were not the focus of e21's phase II deliberations. Another form of demand response with a similar outcome would be for many smaller customers to aggregate their load, but this may require changes in rules or regulations in Minnesota to allow for load aggregation that, for example, could be bid into MISO.[38] Implementing either kind of demand response could reduce greenhouse gas emissions and minimize the costs of the system for everyone by meeting peak demand via conservation rather than generation of more coal- or natural gas-fueled electricity.

Demand response, however, is not limited only to peak-time reductions in electricity use. As demand response becomes even more integrated into utility operations,[39] it can serve a wide variety of other uses, including automatically *increasing* consumption if there is excess renewable electricity available. Certain kinds of commercial and industrial loads, for example, may be well suited to particular renewable generation (e.g., nighttime operations when wind generation is high). It is worth noting that Minnesota already leads the nation in load management, with many utilities having had significant load management for 30 or 40 years, and some since the 1950s.

In addition to avoiding the building of underused or unneeded power plants, Minnesota has an opportunity to further right-size its electric distribution system. Doing so could avoid costly system upgrades and reduce system losses,[40] as generating and moving electricity inevitably

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[38] Minnesota Public Utilities Commission Docket No. E-999/CI-09-1449, "In the Matter of an Investigation of Whether the Commission Should Take Action on Demand Response Bid Directly into the MISO Markets by Aggregators of Retail Customers Under FERC Orders 719 and 719-A" (April 16, 2013); Minnesota Public Utilities Commission Docket No. E-999/CI-09-1449, "Order Accepting Filings, Requiring Expanded Cost-Effective Demand Response Investments, and Soliciting Further Comments" (August 31, 2012).

[39] This discussion is largely limited to utility demand response programs. As identified in the *Minnesota PUC Staff Report on Grid Modernization*, the potential role of third-party demand response providers may also enable greater demand response potential. Although Minnesota PUC policy currently prohibits third-party demand response providers, stakeholders in the Minnesota PUC grid modernization proceeding noted that it may be time to reconsider that decision.

[40] See the following presentations at the Minnesota PUC Grid Modernization Meeting, October 30, 2015 (https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={F39616C8-E8F7-4F4C-B704-80D9C84B7101}&documentTitle=201510-115146-01): Chris Neme and Rich Sedano, "U.S. Experience with Efficiency as a Transmission and Distribution System Resource" (Hinesburg, VT: Energy Futures Group; Montpelier, VT: Regulatory Assistance Project; 2012), http://www.raponline.org/wp-content/uploads/2016/05/rap-neme-efficiencyasatanddresource-2012-feb-14.pdf; Damian Sciano, "Reforming the Energy Vision and its Implications for Distribution System Planning" (ConEd presentation on Brooklyn-Queens Demand Management Program, 2015); and Jeff Smith, "An Integrated Approach to Distribution Planning" (Electric Power Research Institute presentation on the Tennessee Valley Authority and other projects, 2015). Further examples are listed in GreenTech Media, "Demand-Side Resources Can Be Cheaper than Large Infrastructure Upgrades" (2014), http://www.greentechmedia.com/articles/read/distributed-resources-gain-traction-to-avoid-grid-upgrades.

means some losses at each transition step, given the laws of physics. Building only as much distribution infrastructure as necessary, and in the right places, will save everyone money and make the system work most reliably. This is why it is so important to understand where DERs are most beneficial on the distribution system and encourage them—through price signals—to locate there.

Finally, while outside the scope of this white paper, achieving objective 5 will likely require some form of time-variant pricing that gives customers accurate information about the cost of using electricity at any given time of day. Electricity is one of the few products that consumers use without knowing the price at the time of use. If applied fairly and with some advance notice, time-of-use rates can optimize the alignment between generation and load to better utilize the existing system, shift electricity use to less expensive times of the day, and avoid the need for new power plants.

Key functions that a modern grid must have in order to achieve this objective include

a. the ability to optimize the alignment between generation and load using rates and technologies that can reduce the costs of the system for everyone
b. the ability to effectively forecast DERs at the distribution level

Foundational technologies that enable these functions include

a. advanced metering infrastructure
b. dynamic voltage/VAR control
c. more intelligent energy management systems that better match up renewable generation resources with load
d. the labor and big data tools (meter data management) with which to analyze the huge amounts of data utilities have—and will have more of) —in order to find ways to optimize the system (e.g., loss analysis on a feeder)

Evolving the Planning of the Electricity Distribution Grid to Meet these Objectives

Achieving the five grid modernization objectives outlined above will require comprehensive, coordinated, and transparent scenario-based distribution system planning. Utilities are already taking steps to plan for a more decentralized electric system. Cost-effectively modernizing Minnesota's electric grid will require additional changes to the way utilities plan for the expected growth in DERs. This planning approach will need to include the following:

a. proactive, scenario-based, probabilistic distribution engineering analysis that is better able to anticipate the inherently hard-to-predict location, size, and operational characteristics of a wide range of DERs
b. DER interconnection studies with new criteria, including hosting capacity and locational value
c. DER hosting capacity analysis
d. DER locational value analysis
e. integrated transmission and distribution planning so that both ends of the system understand the implications of DER penetration on the distribution grid

While scenario-based planning would be new for the distribution system, planners have long used it to plan a transmission system capable of serving the most probable future conditions. Transmission planning today is done by considering a number of highly likely system states. Since there is a potentially limitless number of such system states, transmission planners chose "bookends" to reasonably limit the study scope and identify the most important factors to plan around, and this approach could be adopted for the distribution system as well. That said, there are important differences in the nature of transmission and distribution systems, including the fact that individual distribution systems can be quite different from one another, potentially making the establishment of the bookends of a distribution system somewhat more challenging. Nevertheless, a scenario-based approach to planning may offer the best hope of accommodating the inherently unpredictable growth of DERs.

It's also important to note that the evolution of distribution planning cannot just be about changes in the behavior of utilities. New protocols must also stipulate how all actors on the system will need to behave differently as more DERs connect to the distribution grid. For example, DERs interconnecting to the distribution grid will need to have new responsibilities for ensuring that the operation of their DER contributes to a reliable, affordable, economically efficient system for ratepayers, and regulators will need to clearly establish what those responsibilities are, as conditions of interconnection to the grid.

To speed learning and knowledge transfer it would be valuable to establish a regular opportunity for utilities to share their DER integration experiences with one another and with other stakeholders. This could be part of the annual/biennial systems planning workshop proposed in the *e21 Integrated Systems Planning White Paper*. While utilities are often required to sign nondisclosure agreements with DER providers to protect proprietary information, having a regular forum for exchanging experiences and lessons learned could enable regulators, utilities, intervenors, and other interested parties to develop a shared understanding of the opportunities and challenges that grid modernization presents.

Key functions that a modern grid must have to achieve this evolution toward modernization include

a. an updated distribution planning process that anticipates and accounts for rapid changes on the distribution system, not all of which are controllable by the utility (e.g., where on the system DERs are deployed)
b. a comprehensive, scenario-driven, multi-stakeholder process that standardizes data and methodologies to address locational benefits and costs of DERs (this will require the development of standard scenarios as we have for the transmission system)
c. a thorough assessment of DER hosting capacity by substation, perhaps down to the individual feeder (understanding what the true load is behind the meter and for each feeder)
d. better forecasting of DERs, including
    - distributed generation—location, quantity, and dependability
    - storage—power and electricity availability, and ancillary services
    - demand response—load control availability
    - conservation and time-shifting
    - adoption and impacts of electric vehicles
    - moving from peak-only forecasting to 24/7 forecasting
e. clarity on the value of various DERs and how to compensate them, as well as ways to encourage them to locate on the grid where they are most beneficial to the system as a whole
f. ways of calculating the optimal investment in both wires and non-wires options for meeting system needs

g. decisions on whether and how DERs will participate in wholesale markets and resource adequacy

Foundational technologies that enable these functions include

a. planning tools and an agreed-upon planning process that takes into account all the functions outlined in this white paper
b. intelligent tools to increase hosting capacity
c. accepted industry practices for identifying hosting capacity and interconnection requirements (as they currently differ considerably by utility)

Section III: Recommendations

As evidenced by this white paper, grid modernization is a sprawling and complex topic. To help manage this complexity, we have organized our recommendations into three categories: planning, customer services and engagement, and operations of the physical system.

Planning

A. **The Minnesota PUC should provide guidance for utilities on developing standard information sets and platforms for the sharing of hosting capacity.[41]** We ask the Minnesota PUC to issue guidance on providing this information via the web (balanced with security concerns) and determining how frequently the information should be updated (balancing cost and value, as more static systems may require less frequent analysis). We recommend that the more detailed hosting capacity information, beyond that which is available through the publicly available methods, be provided through the interconnection process.

B. **The Minnesota PUC should review and update Minnesota's interconnection standards[42] and processes to make the interconnection process more predictable, transparent, timely, and consistent**. As noted by PUC staff in their March 2016 grid modernization report, considerable work has been done on best practices for interconnection of distributed generation upon which to build an updated interconnection approach in Minnesota.[43]

C. **Distribution planners should employ scenario-based planning, where beneficial, to plan for and manage the inherent uncertainty of the size, scale, and location of DERs on the distribution system**. In addition to the current set of considerations, distribution planning scenarios should include the implications and opportunities of location-specific siting and operation of DERs (such as electric vehicles, energy storage, distributed generation, demand response, and others). Planning for the addition of DERs on some distribution systems will require moving from peak-only forecasting to detailed forecasting—potentially hourly—to model the net load characteristics on the different parts of a feeder. The Minnesota PUC should require utilities to develop or acquire appropriate tools and processes to enable such planning.[44]

Customer Services and Engagement

D. **The Minnesota PUC should use a multi-interest stakeholder process to determine the services and benefits that DERs receive from the grid and can provide (including environmental benefits) to meet the electric grid's needs, recognizing that the**

[41] Among the issues for consideration is how best to allocate hosting capacity among DER providers in a transparent way.
[42] Minnesota Public Utilities Commission Docket No. E-999/CI-16-521, "In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611" (June 21, 2016).
[43] See reports by the Interstate Renewable Energy Council and the Electric Power Research Institute, as well as the Federal Energy Regulatory Commission's small generator interconnection process.
[44] Since scenario planning requires the use of sensitive information, the PUC will need to decide which types of information should be made available to the public and which should remain non-public.

services and benefits will differ by DER type, location on the grid, and time of day. This is a prerequisite to assigning value to the grid services that DERs may provide to the grid and to grid services that DER providers benefit from by virtue of being connected to it. Developing a clearer and fuller understanding of the types of services and values DERs can provide will enable the grid operator to extract greater benefits from DERs and potentially mitigate increased costs to the distribution grid. Clarity on the services and values DERs can provide will allow the grid operator to better optimize the system's operation and design and plan future upgrades to the distribution grid.

E. **Utilities should establish price signals and payment options that direct DERs to optimal locations on the grid and that provide customers signals for optimal times of electricity use.** The goal should be to strike a balance among objectives that are inherently in tension, including economic efficiency, reliability, simplicity, and fairness.

F. **Utilities should provide customers with convenient and timely access to as much of their own data as possible, in a consistent format, to enable them to make informed decisions about the timing and amount of their electricity use.**

G. **The Minnesota PUC should take steps it deems necessary to make sure that utilities implement best practices in all areas of cybersecurity to ensure the availability and confidentiality of information, and the integrity and security of the system**.

H. **The Minnesota PUC should allow utilities to establish a specific budget to conduct research and development, rather than relying solely on pilot programs to innovate.** As noted in the PUC staff paper on grid modernization:

> With the changes anticipated for the grid over the next decade, and the general pace of utility investment decisions (including rate cases), it may be challenging for the distribution utility to keep abreast of the fast turnaround time of the market. Allowing the utilities the opportunity to trial technologies and prove the benefits may be more useful than relying solely on utilities to show that certain investments are cost-effective from day one. The grid, available technologies, and customer expectations are changing rapidly, but keeping the utilities stuck in an existing regulatory program puts the utility in an untenable situation of being unable to effectively respond to these changes. Allowing the utilities to utilize some amount of funds to trial these new technologies will help the utility and the state to pro-actively test out the abilities, costs, and benefits of these new technologies at the start.[45]

Minnesota's Statewide Conservation Applied Research and Development (CARD) grant program is a useful example of how research and development can identify new markets, technologies, and savings. Approving a specific research and development budget for some level of experimentation would fit well with the outcome-focus of multi-year rate plans.

Operations

I. **The Minnesota PUC should ask utilities to adopt cost-effective voltage and volt-ampere reactive optimization appropriate for each utility's system** (often called volt-VAR optimization, or VVO). Volt-VAR optimization is an energy efficiency measure that can lower electricity use without any change in customer behavior. Volt-VAR optimization

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[45] *Minnesota PUC Staff Report on Grid Modernization.*

technologies offer more precise voltage regulation and more efficient power flow than used to be possible or practical.[46]

J. **Utilities should draw on the existing body of regulation and experience to develop a strategy to utilize smart inverters.[47]** Smart inverters and new high-speed voltage-regulating systems can continuously monitor and quickly respond to voltage deviations, allowing the effective management of inherently variable DERs and contribute to system stability.

K. **The Minnesota PUC should establish procedures and tariffs for how and when a distribution grid operator may dispatch and curtail DERs to enable the near real-time matching of generation and load using both supply-side and demand-side resources.** This would include how aggregated demand response will be accomplished and dispatched. The goal should be reliable operation of the distribution system and economically efficient dispatch of DERs for the benefit of all customers.

L. **The Minnesota PUC should enable utilities to implement appropriate and cost-effective enabling technologies that are prerequisites to achieving grid modernization objectives**. Such systems may include supervisory control and data acquisition (SCADA); advanced metering infrastructure; high-speed and high-capacity communication systems to collect, sensor, and send metering data from the field and communicate control actions to DERs; planning tools; and advanced distribution management systems that use real-time modeling to allow grid operators to effectively manage the dynamic operating conditions that the integration of DERs will create.

M. **The Minnesota PUC should ensure the use of national standards necessary for effective integration of DERs and interoperability of the grid's communication systems**. These standards include interoperability standards to ensure that devices connected to distribution systems can talk to one another; advanced inverter operational standards; control center-to-control center communication protocols; and utility-to-home area network communication standards. Common standards can reduce total costs and facilitate cybersecurity across the electric system while allowing utilities to implement technologies at different paces based on the technologies' particular characteristics.

N. Utilities should use digital and automated communication and monitoring technologies to more accurately evaluate the environmental impact and effectiveness of efficiency and clean energy programs.

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[46] *Minnesota PUC Staff Report on Grid Modernization*, 24–25.

[47] For certain types of electricity generation, such as solar photovoltaics, that produce direct current, inverters change it to alternating current to allow the electricity to travel over the distribution grid. Smart inverters have bidirectional communications capability and are able to provide the grid with other ancillary services such as volt-VAR support and islanding. According to the Electric Power Research Institute, smart inverters can double the amount of DER that can be reliably integrated onto the grid, depending on the location; see *Minnesota PUC Staff Report on Grid Modernization*, 17.

Section IV: Conclusion and Next Steps

The Minnesota PUC has launched a process to explore grid modernization in Minnesota, in part inspired by the early work of the e21 Initiative and its diverse stakeholders. With this white paper and the initiative's ongoing work, e21 aspires to complement—and continue to inform—that PUC process.

To date, the Minnesota PUC has held a series of grid modernization workshops to answer some key questions, including:

a. What objectives and principles should guide grid modernization in Minnesota and an integrated distribution planning process?
b. What pathways, both procedural and substantive, are necessary for the PUC to take?
c. What are the benefits and costs that could result from grid modernization? Are there regulatory steps the PUC should take to balance the costs and benefits for the public interest?
d. What specific regulatory barriers exist for utilities, customers, or other participants?

In March 2016, PUC staff issued a report summarizing feedback from these workshops and comments submitted from a wide range of interests. The report proposed that the PUC take the following three-phased approach to addressing grid modernization:

Phase 1	Adopt a definition, principles, and objectives for grid modernization
Phase 2	Prioritize potential action items
Phase 3	Adopt a long-term vision for grid modernization

On March 29, 2016, Minnesota PUC staff presented their grid modernization report to the Commission, after which the commissioners adopted the report's recommended working definition and principles for grid modernization and generally accepted the staff report as a helpful foundation for its on-going work on the topic. **The Commission also agreed to**:

a. **Organize and host additional stakeholder engagement and comment opportunities in the fall of 2016 to foster a distribution-grid planning framework and process well-tailored to Minnesota.**
b. **Draw on outside technical expertise and best practices to inform Minnesota's approach to grid modernization and distribution grid planning**. For example, thanks to Minnesota's early leadership on regulatory reform, at the request of the MN PUC the U.S. Department of Energy contracted with ICF International to prepare a report on how Minnesota might conduct integrated distribution planning[48]. The Department of Energy views Minnesota as being enough like many other states that what we learn here can be useful to those similar states. Minnesota also has commitments from Lawrence Berkeley National Laboratory to help inform a distribution planning process in Minnesota (the

[48] ICF International. *Integrated Distribution Planning*. Prepared for the Minnesota Public Utilities Commission. August 2016.

laboratory has produced a Future Electric Utility Regulation Series of white papers, and Minnesota Public Utilities Commissioner Nancy Lange serves on the series' advisory group).[49]

c. **Issue a guidance document on distribution planning in 2017**. This guidance document will not necessarily be a commitment to rule-making or other formal action, but should be helpful in clarifying Minnesota's grid modernization approach.

As an ongoing multi-interest learning and sharing platform, the e21 Initiative would like to continue supporting the Minnesota PUC's grid modernization efforts, and toward that end e21 proposes to

a. identify opportunities in upcoming dockets to begin to address foundational and no-regrets actions
b. take up issues that PUC technical workshops won't be well equipped to foster an on-going conversation about and feed the results back into the PUC process
c. take up issues just beyond the PUC's current focus with the aim of offering definition and depth on topics likely to be next up for consideration (this will obviously require close coordination and communication with the PUC and regulatory staff)

[49] https://emp.lbl.gov/future-electric-utility-regulation-series

Appendix A: Principles for Modernizing the U.S. Electric Grid

As listed in the U.S. Department of Energy Quadrennial Energy Review, April 2015

1. **The future grid should encourage and enable energy efficiency and demand response to cost-effectively displace new and existing electric supply infrastructure, whether centralized or distributed**. The policies, financial tools, and pricing signals that enable customers to save money and energy while enhancing economic growth should be preserved and strengthened as business models evolve.

2. **The future grid should provide balanced support for both decentralized power sources and the central grid**. As the costs of decentralized power sources and storage continue to fall, there will be increased opportunities for end users to partially or completely supply their own electricity. At the same time, the vast majority of American homes and businesses will continue to rely on the power grid for some or all of their electricity. It is essential, then, that investment in both centralized and decentralized systems occur in a balanced manner, preserving high-quality service for all Americans while simultaneously enabling new options and services that may reduce energy costs or climate impacts. Similarly, access to renewable energy, energy efficiency improvements, and new energy-related services should not be limited to isolated customer groups, but rather become an integral part of the universal service that both decentralized and centralized grid customers enjoy.

3. **In the future grid, new business and regulatory models must respect the great regional diversity in power systems across the United States, as well as the critical roles played by state, local, tribal, and regional authorities, including state public service commissions and regional grid operators.** The drivers of change in the power system cut across the traditional boundaries of state and federal regulation and thereby introduce new challenges in designing and overseeing new business and regulatory models. An unprecedented amount of consultation and collaboration will be necessary to ensure that national objectives are met alongside complementary state policies in power systems that are inherently regional in their scope and technology.

4. **Planning for the future grid must recognize the importance of the transmission and distribution systems in linking central station generation—which will remain an essential part of the U.S. energy supply for many years to come—to electricity customers.** Transmission and generation both benefit from joint, coordinated planning. Transmission can allow distant generation—where there may be excess capacity—to supplement local supply and avoid the need to build new plants. New generation sometimes requires new transmission, especially remotely sited renewables or new nuclear plants. Utility and regional transmission organization planning processes and tools should continue to evolve to evaluate transmission, generation (both central and distributed), and demand-side resources holistically.

5. **Finally, the careful combination of markets, pricing, and regulation will undoubtedly be necessary in all business and regulatory models of the future grid.** While the precise nature and scope of the market structures in the future grid may vary considerably, there is little doubt that markets in one form or another will be an important means of providing access to new technologies and services. Even in settings where prices are regulated, novel approaches can allow beneficial new pricing and service structures.

Moreover, both new and traditional financing options provided by capital markets will be an important element in the future industry landscape.

Appendix B: The Federal Grid Modernization Multi-Year Program Plan

Grid Modernization Multi-Year Program Plan. In January 2016, the U.S. Department of Energy announced the release of its Grid Modernization Multi-Year Program Plan, a blueprint for modernizing the U.S. grid and solving the challenges of integrating conventional and renewable sources with energy storage and smart buildings, while ensuring the grid is resilient and secure to withstand growing cybersecurity and climate challenges. The plan aims to support critical research and development in advanced storage systems, clean energy integration, standards and test procedures, electric vehicles, solar systems, and a number of other key grid modernization areas. Available research and development funding will fall under the Grid Modernization Laboratory Consortium, which includes 14 Department of Energy labs and dozens of industry, academic, and state- and local-government partners across the country.[50] Expected outcomes of the effort include:

- a national network of laboratory facilities for use in testing and validation of emerging grid-related technologies and systems
- new common standards and test procedures to ensure that emerging grid technologies can communicate with one another and work together to provide energy services to customers
- new decision-support tools for integrated planning and operation of distributed energy technologies, such as solar, demand response, and smart consumer appliances
- advances in grid design and planning tools to take into account the increasing number of emerging technologies being deployed on the grid in homes, businesses, and communities
- optimal approaches for integration of wind turbines, solar photovoltaic systems, smart buildings, electric and fuel cell vehicles, and hydrogen technologies into a modernized grid
- a new testbed for development of advanced distribution management systems that will allow grid operators to more effectively utilize grid assets, increase resilience and reliability, and enable a wider choice of energy services for customers

[50] http://energy.gov/articles/launch-grid-modernization-laboratory-consortium