NON-WIRES ALTERNATIVES AS A PATH TO LOCAL CLEAN ENERGY: RESULTS OF A MINNESOTA PILOT

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ACRONYMS AND ABBREVIATIONS

AMI: Advanced Metering Infrastructure

BAU: Business As Usual

CEE: Center for Energy and Environment

CIP: Conservation Improvement Program

CSG: Community Solar Garden

DER: Distributed Energy Resources

DR: Demand Response

IDP: Integrated Distribution Plan

IOU: Investor-Owned Utility

kW: Kilowatt

kWh: Kilowatt-Hour

LCCMR: Legislative-Citizen Commission on Minnesota Resources

MVA: Megavolt-Ampere

MW: Megawatt

NPV: Net Present Value

NWA: Non-Wires Alternative

SCADA: Supervisory Control and Data Acquisition

T&D: Transmission and Distribution

INTRODUCTION

In June 2019, Center for Energy and Environment (CEE) launched a non-wires alternatives pilot in partnership with Xcel Energy to test whether targeted energy efficiency and demand response promotion could defer distribution grid investments. Prior to that point, a growing number of projects had been undertaken in the United States — but there were no Minnesota examples, and most national projects had focused on high-cost transmission or distribution applications. This pilot, funded by the Legislative-Citizen Commission on Minnesota Resources (LCCMR) and the McKnight Foundation, specifically aimed to test the concept in a more typical context, with the idea that non-wires alternatives could be used as a regular part of the distribution planning and investment toolkit to lower costs, increase customer benefits, and drive uptake of carbon-saving distributed energy resources.

Utilities are making significant investments in the next generation of distribution grid technologies. These technologies include smart meters (advanced metering infrastructure); better grid intelligence to identify outages and fault recovery; real-time operational data; and the technology platforms to allow customer loads or generation to respond to grid needs in real time. Utilities are also seeing increased penetration of electric vehicles and rooftop solar panels, both of which can create highly localized changes to capacity needs. Minnesota investor-owned utilities currently spend on average $500 million per year maintaining and expanding their distribution grids, and the recent filing by Xcel Energy, Minnesota's largest investor-owned utility, for their advanced grid package was a proposed $733.5 million over nine years (Dakota Electric Association 2019; Minnesota Power 2019; Otter Tail Power Company 2019; Xcel Energy 2019). In short, this is an era of new investments, which brings new opportunities to forecast and manage costs with the right set of tools. Should non-wires alternatives be one of those tools?

To answer that question, our project team evaluated the ability of distributed energy resources (DERs) to offer value to the distribution grid for a specific project. DERs include any type of energy generation or load that is connected to the grid within the distribution system, rather than the transmission system. DERs include energy efficiency and demand response and are often (though not necessarily) customer owned and operated. This pilot established the following learning objectives:

- What types of distribution system needs offer the best opportunities for DERs?
- To what extent can location-specific targeting with additional customer incentives lead to increased DERs?
- What customer end-use characteristics make for the best opportunities?
- What is the statewide potential for non-wires alternatives to defer distribution upgrades?
- What type of program and policy changes are needed to support non-wires alternatives in Minnesota?

BACKGROUND AND PROJECT CONTEXT

Introduction to Non-Wires Alternatives

Non-wires alternatives (NWAs) describe a set of solutions to reduce customer load in targeted locations using distributed energy resources such as energy efficiency, demand response, solar photovoltaic generation, energy storage, or other nontraditional techniques. These resources manage peak load at a substation or circuit level to defer or eliminate the need for traditional "wires" investments in the transmission or distribution system.[1] These solutions often require enhanced customer incentives within the target region and are cost-effective when they require lower investment than the capital cost of a traditional project.

In the late 1980s and early 1990s, Bonneville Power Administration and Pacific Gas and Electric were early leaders of implementation of non-wires alternatives (Chew et al. 2018). As time progressed, consideration of alternative solutions worked its way from a utility level to a statewide level. In 2006, Vermont's Public Service Board directed a large portion of the State's energy efficiency utility budget toward non-wires alternatives (Navigant 2010).

With these early successes showing proof of concept, other utilities and states followed the example. Maine tested the concept from 2013 through 2015 in the Boothbay Harbor area (GridSolar 2016). National Grid performed a pilot in Rhode Island in 2016 (National Grid 2015). At a larger scale, New York and California integrated non-wires alternatives into the utility regulatory framework for grid modernization. In New York, non-wires alternatives took shape within the Reforming the Energy Vision process and set the stage for the Brooklyn Queens Demand Management project, deferring $1.2 billion in traditional upgrades. In California, non-wires approaches manifested through distribution resource plans and directives from the public utilities commission to procure DERs. Today, more than 100 non-wires alternative projects are in various stages of planning and implementation throughout the United States (Guidehouse Insights 2019).

While non-wires alternatives are growing, there is still a need to show that they are scalable and offer enough customer benefit over traditional grid investments. While nascent experience is helping to build acceptance, there are still some barriers, including:

- A perception that the application of non-wires alternatives is a niche opportunity versus widespread and scalable;
- Lack of confidence that non-wires technologies will be reliably available on peak demand days; and

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[1] To clarify further, DERs would be intended as capacity deferral and would not be intended as a replacement for aging infrastructure.

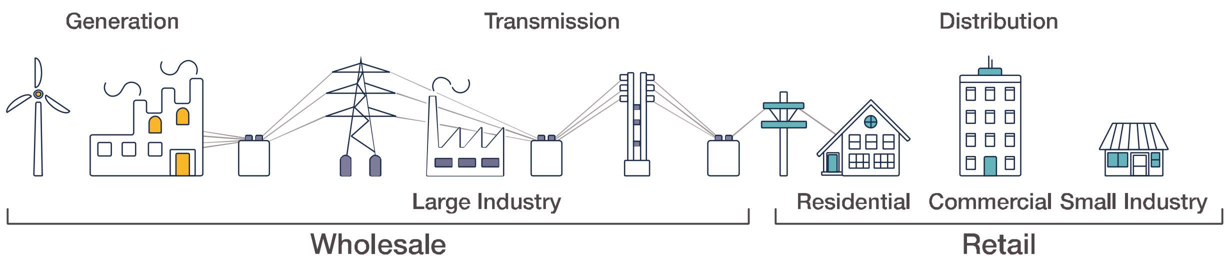
- Lack of familiarity among distribution operators with real-time use of DERs to manage distribution constraints in the system.

While these barriers touch multiple parts of utility operations, distribution planning is an appropriate place to focus on the opportunity to address non-wires alternatives.

Distribution Planning

While non-wires alternatives can be used to defer transmission scale investments, the bulk of recent applications have been in distribution scale projects. Distribution planning differs from transmission planning. Beyond being smaller scale, it is not concerned with generation and bulk power shipments, only with reliably “distributing” electricity to retail customers. Distribution planning also falls squarely within a single utility’s jurisdiction, unlike transmission planning, which might be coordinated or built as a merchant line. Also, the distribution system covers much more territory than the transmission system. Nationally, for every mile of transmission line, there are approximately 13 miles of distribution lines (Warwick et al. 2016). Relatedly, the majority of customer outages originate in the distribution system (Sultan and Hilton 2019).

Figure 1. Basic Structure of the Electricity Grid



Distribution planning consists of forecasting and prioritizing the asset needs of the distribution system to maintain reliability. Projects range from system expansion to meet load growth to new development, replacement of aging equipment, or reconfiguring the system to accommodate local construction projects. Large projects include things like substation expansion or expansion to serve a new development; smaller cost projects might include a feeder reconfiguration to divert power flow during an outage. Costs are driven by the capital cost of the equipment as well as localized factors like land availability, labor costs, and project timeline.

Table 1. Cost estimates for traditional wires solutions[2]

Traditional Wires Solution	Cost Range
Overhead suburban distribution line ($ / mile)	100,000–1,100,000
Transformer cost ($ / MVA)	8,000–15,000
New substation ($)	1,900,000–2,800,000

The forecast of future capacity needs is of primary importance to evaluating non-wires alternatives. This consists of projecting past trends and incorporating known new business to quantify the magnitude and timing of a future capacity need. The further out in the future a projected need is, the less certain it is. Balancing this uncertainty with the length of time it takes to procure non-wires alternatives is a fundamental tension of distribution planning.

As will be discussed in more detail below, additional components of distribution planning that are important for non-wires alternatives are when peak demand occurs (i.e., season and time of day) and how long it lasts. This introduces two additional dimensions (and additional uncertainty) into distribution forecasting for evaluation of DERs.

Minnesota's Utility Landscape

Minnesota poses a unique set of circumstances for non-wires alternatives. Within the distribution system, costs of traditional investments are low compared to denser parts of the United States. For reference, the total distribution budgets of the state's three investor-owned utilities were $460 million in 2018, less than half of the single Brooklyn Queens Demand Management project, and the portion for capacity-related projects was $43 million (Minnesota Power 2019; Otter Tail Power Company 2019; Xcel Energy 2019). While the three investor-owned utilities represent over 60% of total electricity sales, they own less than one-third of the total distribution circuits in the state, most of which reside with cooperative and municipal utilities (EIA 2020b). Given that there is not a blanket case for non-wires alternatives, this increases the importance of guidelines to determine which projects make favorable applications.[3]

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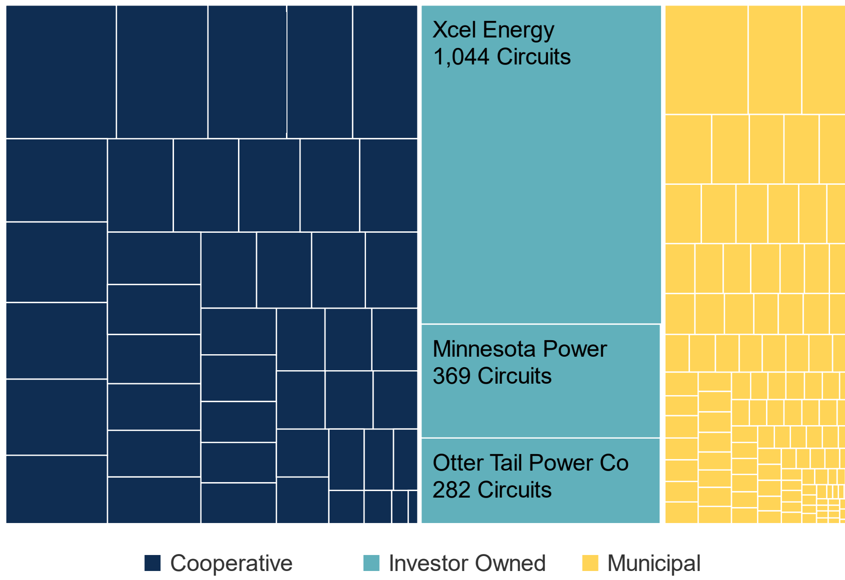
[2] Range of values from distribution lines (Hall 2013) and substation components (Mason, Curry, and Wilson 2012) adjusted based on the cumulative rate of inflation between 2012 and 2020 (13.2%).
[3] This project focuses on the distribution scale. On the transmission side, the state has seen expansion of transmission spending and anticipates the need for more in the future. The primary need, however, is delivering wind energy to load centers, which requires different solutions than reducing peak load constraints.

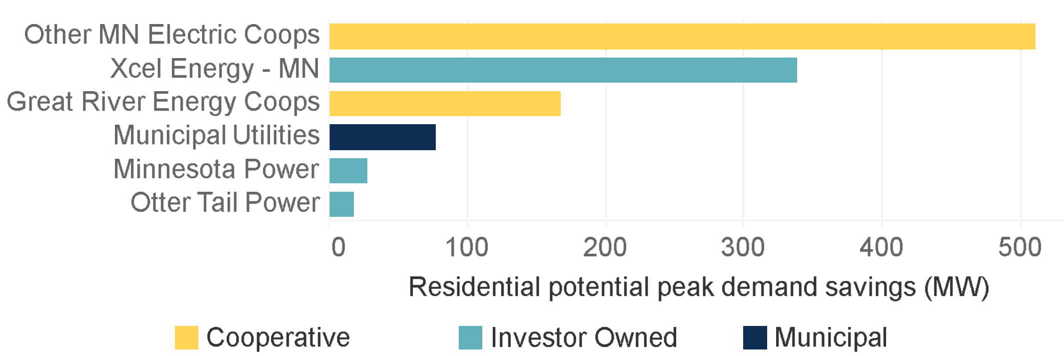
Figure 2. Count of distribution circuits for each electric IOU in MN (EIA 2020b)



Distributed Energy Resources

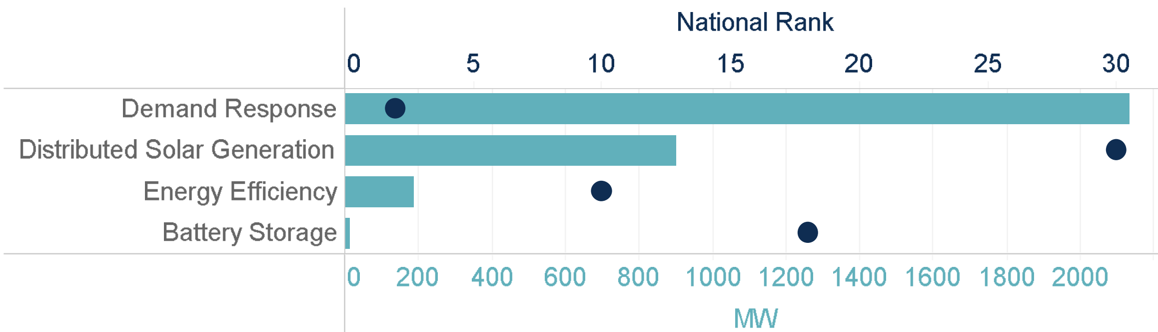
Minnesota has a history of employing a least-cost framework for utility resource planning, which has cultivated the use of low-cost distributed resources such as energy efficiency. Minnesota ranks 10th in the country for energy efficiency savings. Minnesota also has high enrollment in demand response programs, ranking second in the United States for peak demand capacity. Xcel Energy and Great River Energy, which supplies power to Minnesota electric cooperatives, have the 7th and 24th highest potential peak residential demand savings among all U.S. utilities, respectively (Figure 3). In regard to the systems that manage these resources, Minnesota is still developing its advanced metering infrastructure — the state ranks 36th with an advanced metering infrastructure (AMI) penetration of 32% (EIA 2020b).

Figure 3. Residential potential peak demand savings (MW) by MN utility (EIA 2020b)



Minnesota ranks 18th in the United States for nameplate utility-scale battery storage with four plants across two utilities for a total of 16.1 MW. The state ranks ninth for installed nameplate solar capacity, with a total of 901 MW (EIA 2020a). Most of this installed solar capacity is attributed to community solar gardens within Xcel Energy's service territory. As of April 2020, Xcel Energy had 680 MW_{AC} of community solar online across 280 project sites, with 327 sites in the active queue (Xcel Energy 2020). Minnesota has more community solar by both capacity and number of projects than the three other leading states: Massachusetts, New York, and Colorado (McCoy and Farrell 2020).

Figure 4. Distributed energy resources in Minnesota



Current Policy Context

Minnesota has building blocks that can be foundations for NWA policy. Most important are energy efficiency Conservation Improvement Programs (CIPs) requiring annual energy savings equal to 1.5% of annual retail sales (Minnesota Session Laws 2007). Investor-owned utilities are required to provide a CIP plan every three years outlining program goals and details. Minnesota also has least-cost integrated resource planning, with utilities filing plans every two to three years (MN PUC 2019). And more recently, the Minnesota Public Utilities Commission has opened dockets on performance-based regulation and integrated distribution planning (IDP), the latter of which is foundational to utility grid modernization efforts.

In August 2016, Xcel Energy considered the procurement of a solar-plus-storage option to defer a substation upgrade, though project costs were deemed too high for project approval (MN PUC 2016). In autumn of the same year, the Public Utilities Commission launched a series of workshops as part of a grid modernization docket. Emerging from this discussion, in 2017, the Commission created a questionnaire for utilities and stakeholders to better understand the distribution planning process and how it could be improved. Out of these interactions, the Commission created integrated distribution planning filings for the four rate-regulated utilities in Minnesota and opened these up to comments in April 2018. Xcel Energy, Minnesota's largest utility, filed the first plan in November 2018, followed by the three remaining rate-regulated utilities in November 2019. The Commission directed Xcel Energy to include a detailed non-wires alternatives analysis in these filings. The analysis focused on all distribution system projects within five years of the filing year with a cost greater than $2 million (MN PUC 2018b).

THE PILOT

Project Background

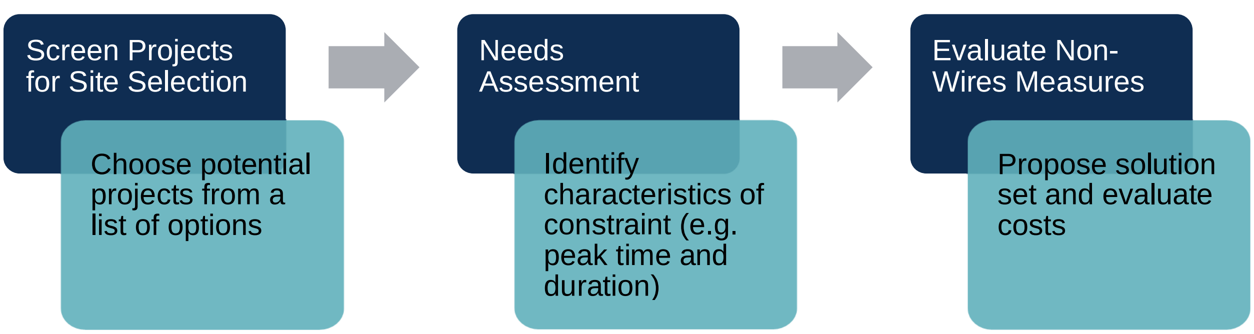
Many non-wires alternative (NWA) projects start through regulatory requirements or a utility-led initiative. This pilot was initiated via a proposal by CEE to LCCMR, which distributes environmental trust monies to mission-aligned projects. In addition to these legislative funds, the project used funds from the McKnight Foundation and from Xcel Energy's existing Conservation Improvement Plan program budget. The project was approved in the summer of 2017. At the same time, the Minnesota Public Utilities Commission opened a docket on distribution planning which included requirements to report on non-wires planning.

This pilot served multiple purposes. As mentioned above, there has been early national experience deploying non-wires alternatives, but Minnesota has its own unique context with relatively low energy costs, a robust penetration of energy efficiency and demand response, and a strong regulatory track record to spur clean energy technology deployment through pilots and evidence-based regulation. As Minnesota approaches a wave of advanced grid expenditures, this pilot provided the opportunity to inform utilities, regulators, and other stakeholders with on-the-ground experience.

Pilot Planning

The pilot began with site selection and pilot planning, which can be broken into three phases, shown and described below.

Figure 5. Stages of non-wires pilot planning



Site Selection

Potential sites came from Xcel Energy's 2017 five-year distribution planning forecast. The forecast encompassed a range of potential projects, not all of which were near term or included in the current budget. CEE identified the following screening criteria to choose a site with strong non-wires potential, and to support pilot research and evaluation needs. For example, one requirements was the availability of supervisory control and data acquisition (SCADA) data at the site.[4] The six screening criteria were:

1. Project need was not a result of reliability needs or asset health.
2. Project need was 3–5 years out.
3. Project served >1,000 customers and project cost was over $500,000.
4. SCADA system was in place at the substation.
5. No large community solar garden was scheduled to be added to location feeders.
6. Load was not dominated by a single large commercial or industrial customer.

These criteria produced nine potential sites for a non-wires alternative pilot, shown in Figure 6 below. These were mostly areas experiencing load growth, including sites that may exceed the load under an N-1 contingency event.[5] Regarding the fifth criterion above, focused on community solar gardens, the objective was to eliminate any external factors that may change the evaluation of before-and-after capacity changes. As will be discussed further below, many community solar gardens did end up getting installed at the pilot site, though these ultimately created additional learning opportunities.[6]

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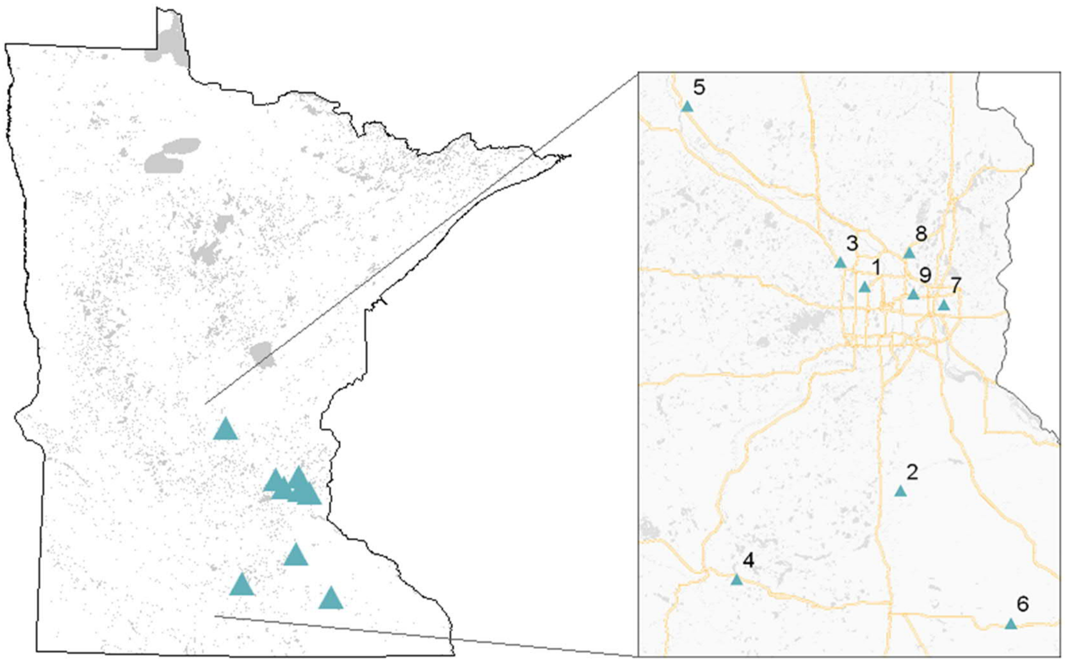
[4] Supervisory Control and Data Acquisition refers to an industrial computer system. In this case, the research team was interested in distribution feeder electric load (MW) at an hourly or sub-hourly level from the SCADA system.

[5] An N-1 contingency event exists when the loss of one grid asset will cause overloading on the remaining assets. Since this initial exploration of project sites, Xcel Energy now prefers N-0 distribution projects as opposed to N-1 distribution projects as viable opportunities for non-wires alternative projects (Xcel Energy 2019).

[6] Xcel Energy has a buy-all, sell-all program that allows third parties to build community solar gardens to which the utility will interconnect and provide a bill credit to their customers. There is no current limit to the number of community solar gardens to be built in the state, which helps explain why many were built in this three-year period.

Figure 6. Distribution projects assessed for NWA suitability



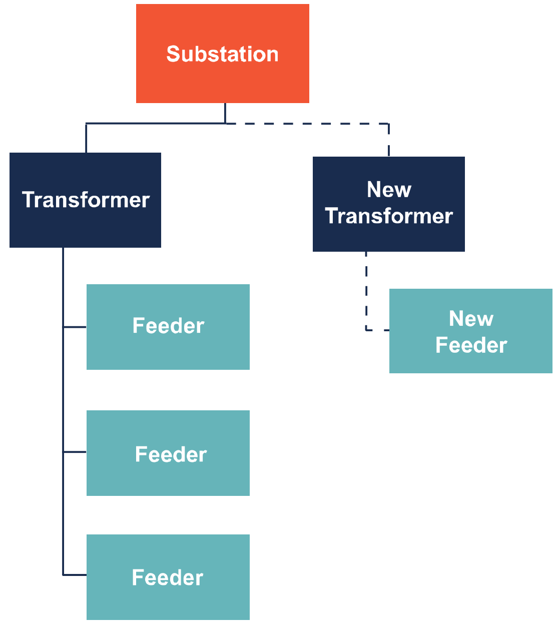
The pilot team ranked the nine sites according to the following metrics of cost, capacity need, and customer count.[7] Customer count was important to this pilot because of the focus on customer-adopted solutions, namely energy efficiency.

1. **Project cost per load at risk** is an overall measure for the dollars available per energy savings of NWAs. Projects with medium- to high-cost per load at risk are preferable.
2. **Load at risk per customer** provides a simple metric for the average savings per customer necessary for NWAs. Projects with low to medium load at risk per customer are preferable and can indicate more options for participants.
3. **Project cost per customer** gives a measure of the budget available per customer to achieve the above savings. Low to medium cost per customer is preferable.

After evaluation, two of nine potential projects met desirable thresholds for all three metrics. CEE proposed to focus on a location outside of the Twin Cities metropolitan area. A useful aspect of the chosen location was that most of the customers on the feeders and the transformers related to the NWA need were located within municipal boundaries. This allowed the pilot to employ a method of marketing exclusively to city residents, which is discussed further below.

[7] Note that while the above metrics are linked, a project's cost, need, and customer count were not necessarily correlated in the list of nine potential sites.

Needs Assessment

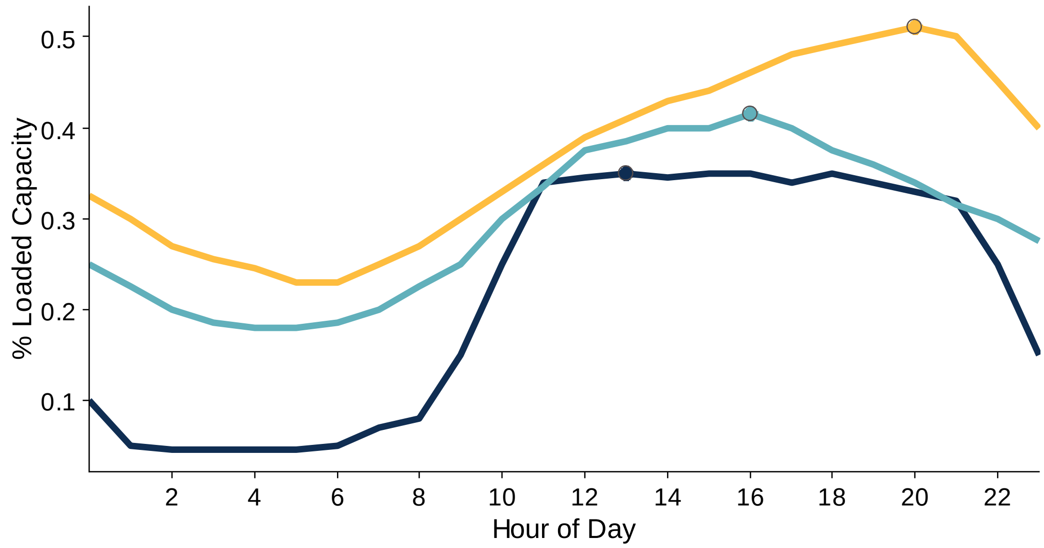


The needs assessment evaluated the duration and magnitude of the local distribution peak. Xcel Energy's 2017 distribution forecast identified the need for a new transformer, new feeder, and feeder reconfiguration in five years (which from the time of the 2017 forecast, was 2022). The non-wires pilot planned for customer implementation in 2019. Due to the short project implementation timeline, a one-year deferral goal of roughly 500 kW in demand reduction was chosen to test the non-wires alternative concept in the pilot area. A second goal to meet 500 kW with existing load management resources was also included and is discussed more below.

The project overall was not yet in Xcel Energy's distribution budget but was part of the midterm forecast. This specific project was chosen as a lower risk opportunity to test the non-wires alternative concept. However, between the initial review and choice of pilot location, the pilot location was removed from Xcel Energy's project forecast. Removal can occur when forecasted load does not materialize, and it is a risk associated with all non-wires alternative projects. Removal can also occur when other projects become a higher priority. In this instance, pilot planning was too far advanced to identify another location, so the pilot continued with the project assumptions identified in the 2017 forecast. This change identifies the value of accelerated planning timelines and non-wires alternatives that can be deployed quickly.

Our analysis of distribution data showed that the individual feeder profiles and peaks varied considerably. As these loads aggregated, they mirrored system peaks — whereas, at the feeder level, loads often closely reflect the underlying customer mix. For example, as shown in Figure 7 below, individual feeders may primarily be industrial, residential, or commercial, and their peak loads reflect the schedule and behavior of those customers. These feeders contribute to system peaks, but themselves may peak at different times of day, and require more specific risk mitigation strategies.

Figure 7. Percentage of loaded capacity on feeders using mock data



The final site analysis identified the site need as a two-hour window from 17:00 to 19:00 (i.e., 5 p.m. to 7 p.m.) on peak summer weekdays.

Avoided Costs

The total project cost was estimated to total $3.275 million, five years in the future. To be cost-effective, the non-wires alternatives must reduce projected load growth at a cost below the comparable cost of the wires investment.

For consistency, we calculated this value using the discrete approach methodology outlined in the Minnesota Transmission and Distribution (T&D) valuation study, and in particular Xcel Energy's example calculations filed as part of the proceedings.[8] This approach places the full capital cost of a proposed upgrade in the project year and calculates the net present value (NPV) of that expenditure. The deferral value is the reduction in NPV if the project is extended by 1 or more years. Our calculations assume the same discount rate as the T&D valuation study, 7.14%, as well as the same project cost escalation rate, 1.0236%. The results for the pilot project are below.

[8] See Minnesota Docket No. E999/CIP-16-541. "In the Matter of Avoided Transmission and Distribution Cost Study for Electric 2017-2019 CIP Triennial Plans Docket."

Table 2. Net present value of deferral using discrete T&D valuation method

BUDGET (TOTAL $)	
	Net Present Value Savings
One-Year Deferral Value	$141,889
Two-Year Deferral Value	$275,678

During the 2018 planning period, this project was reevaluated and assigned a new cost ($4.1 million), as well as a new need (1.6 MVA instead of 2.5 MVA). This both increased the net present value for non-wires alternatives (to $177,632 for a one-year deferral) and decreased the associated kilowatt need corresponding to a one-year deferral (to 320 kW). Ultimately, we moved forward with the original valuation as a target spend for the pilot but included the new data to define an upper range of appropriate costs. This variation is typical for projects prior to being included in a budget.

Non-Wires Measure Selection

Eligible measures were selected from existing energy efficiency and demand response programs filed as part of Xcel Energy's Conservation Improvement Program. Using an approved program portfolio was a simple way to include the pilot within current cost-effectiveness guidelines, absent an existing regulatory framework.

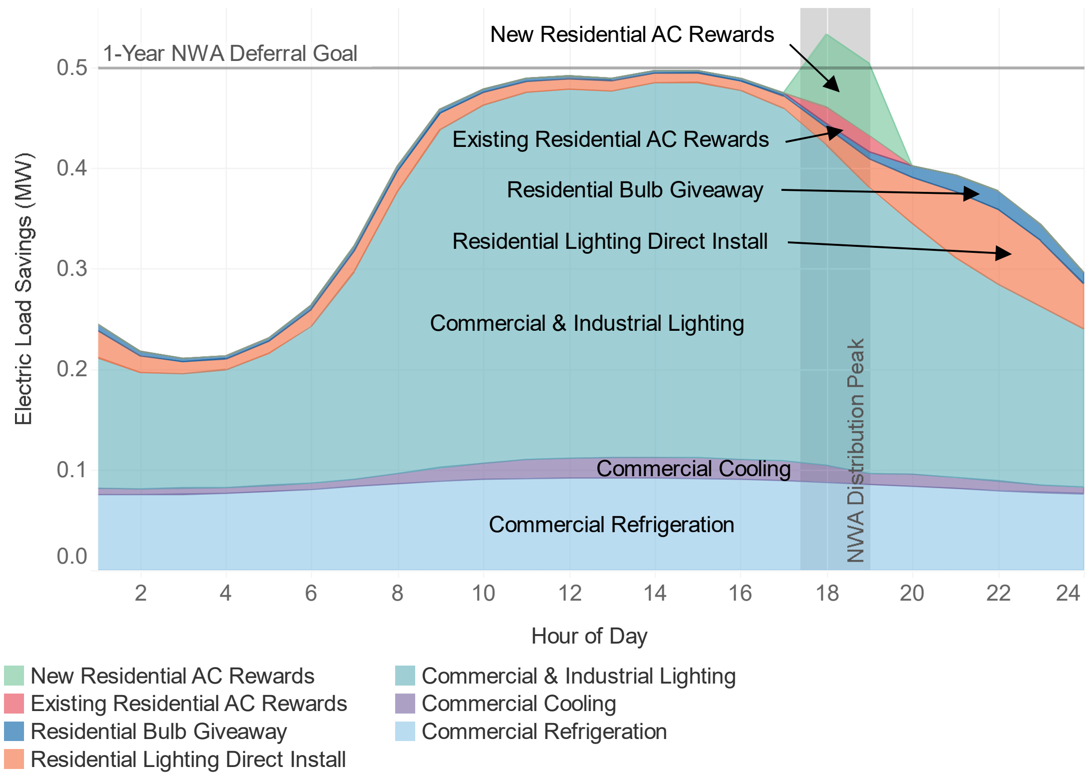
Our evaluation identified measures[9] with summer-coincident capacity savings (kW) where an enhanced incentive was likely to increase program participation in the short term. We evaluated the average historical participation for the previous three-year period for the selected programs to create a baseline, or business-as-usual case for program participation.[10] We then adjusted historic participation to create incremental participation goals for each measure. This stage was iterative and included local knowledge of program potential in the area, given the existing building stock.

The final efficiency and load management measures and the associated load shapes are shown in Figure 8 below. The chart shows that the mitigation window between approximately 17:00

[9] For this project, we use the word "measure" to refer to discrete technologies, approaches, or existing programs that will have an impact on reducing the overall demand. This is somewhat different than how the word "measure" is typically used in the context of energy efficiency programs.
[10] Some historical participation was unknown. For example, light bulb sales, which are rebated at the retail level, are aggregated to a level above the customer, so it is not possible to ascertain a baseline. In addition, another selected program was new, so a target area baseline was undefined.

and 19:00 occurs after commercial lighting savings have peaked, but prior to significant savings from summertime residential lighting. This increased our focus on commercial and residential HVAC savings, especially through smart thermostat programs (i.e., “AC Rewards”). Note that these load shapes are derived from engineering calculations and modeled data and reflect “peak day” load estimations for Minnesota’s climate.[11]

Figure 8. Measures creating the total demand reduction for the pilot



The average annual participants, the business-as-usual case, and the non-wires alternative participation goal add up to the total expected participation value in 2019. Note that **only the incremental participation above the historical baseline participation is appropriate to count toward the 500-kW energy efficiency load deferral**. The business-as-usual participation is already accounted for in distribution load forecasting. However, enhanced

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[11] Load shape data were key to determining the estimated savings for the pilot. The team compared sources such as EPRI’s Load Shape Library, Xcel Energy proprietary data, and load shapes developed through primary research by CEE engineers. In September 2019, after the pilot planning was over, Lawrence Berkeley National Laboratory published the End Use Load Profile Inventory. This resource provides viewers with metadata for 78 different publicly available load profile data sources, which may prove beneficial for future non-wires alternative projects to select from best available end use models to estimate savings. https://emp.lbl.gov/publications/end-use-load-profile-inventory

incentives must be offered to *all* instances of participation. The selected programs, historical participation rates, NWA participation goals, and expected demand reductions are shown in Table 3 below.

Table 3. Selected pilot measures

	Average annual participants (2015–2017)	NWA incremental participation goal	Total assumed 2019 participants	NWA incremental demand reduction (kW)
Residential lighting direct installation	20	130	150	23 kW
Residential light bulb giveaways	—	1,200 (bulbs)	1,200 (bulbs)	6 kW
Residential smart thermostat direct installation and demand response enrollment	18	80	98	72 kW
Commercial refrigeration efficiency	—	7	7	86kW
Commercial lighting efficiency	38	40	78	302kW
Commercial cooling efficiency	7	7	14	14 kW
Total demand reduction				**502 kW**

Incentive Values

The average incentive values were determined based on the kilowatt goal and the total NPV of the deferred project. This took the form of either an increased incentive or lower program participation cost, depending on program structure.[12] As mentioned above, these incentives

[12] While these incentives were drivers toward participation, the primary goal of this pilot was not to study the impact of the correlation between incentive amounts and participation. This could be an area of future focus for future studies and non-wires alternative pilots or projects.

were applied to all participants during the pilot time frame (both the “business-as-usual” and incremental participants).

The cost for residential home visits to perform direct installations of light bulbs and thermostats was reduced from $70 to zero cost for homeowners. Smart thermostats were provided for free when a customer enrolled in a demand response program — a $165 value.[13] In the commercial sector, enhanced rebates were offered at $300 per coincident kilowatt. This coincident kilowatt varied for cooling and refrigeration measures dependent upon the coincidence factor of these measures (i.e., how these load shapes aligned with the distribution peak). This was a custom calculation for each participant. For example, schools and convenience stores have very different operating characteristics both seasonally and by the hour of the day. A school is likely not operating during the summer or is at a limited capacity mostly during the day, whereas a convenience store operates year-round and may be open through the evening.

Existing Demand Response

A useful finding while conducting pilot planning was the high degree of existing enrollment in demand response programs. Over 40% of homes were previously enrolled in a legacy air conditioning direct load control program called Saver’s Switch.[14] Xcel Energy typically deploys these demand response assets at a system-wide level for the purposes of peak cost mitigation and reliability. The project team proposed that these switches be tested at the distribution level, as Xcel Energy has done in the past, because the level of enrollment could reduce peak demand enough to eliminate the need for the traditional-wires solution. This led to a series of localized demand response tests in 2019 and 2020. The outcomes of these tests are discussed below in the Demand Response Results section and in Appendix A.

As the pilot began, Xcel Energy launched a smart thermostat pilot for business customers, which would operate in a similar manner to the residential smart thermostat program included in the pilot measures. While this was not part of the planning process, this new thermostat pilot was incorporated in the outreach strategy, as it represented an additional load reduction that could possibly have a large impact given the many smaller businesses in the area. Business customers were offered free thermostats in exchange for signing up for the pilot. Since the implementation period, the thermostat pilot became a full program, and the pilot participants were incorporated into this new offering.

Marketing and Outreach Plan

The pilot combined increased incentives with geotargeted marketing tactics to achieve results within a six-month window. The marketing and outreach tactics ranged from targeted emails to

[13] Note that these were the customer benefits at the time of the pilot; costs and incentives may have since changed.
[14] The program operates by sending a signal to cycle a customer’s air conditioning compressor on and off during times of need, while allowing the fan to continue to operate for customer comfort.

mailings, tabling at events, and leveraging local leaders to help promote the targeted programs. The campaign was designed under a community-based social marketing framework.

The tables below outline the marketing tactics used in the pilot. The effectiveness of these tactics is discussed in the lessons learned section below. For more information on community-based social marketing tools, see Appendix B.

Table 4. Summary of business outreach tactics

Business Outreach Tactic	Description
Business blitz	Door-knocking campaign through commercial areas promoting business programs and incentives, including leaving behind the flyer with information
Coordination with Cities on promotions	Engaged City leaders to share information about programs and incentives on City website as well as social media accounts
Direct engagement by utility account representatives	Information about the programs and incentives provided to customer-facing utility representatives and call center employees — an email from account managers was provided for larger managed accounts to tell them about the limited time offering.
Direct mail to businesses	A mailing to inform all identified businesses about bonus rebates Postcard mailed to businesses before the business blitz to prepare for upcoming visit and provide general information
Trade ally engagement	Meetings with and promotional materials for trade allies in the target region

Table 5. Summary of residential outreach tactics

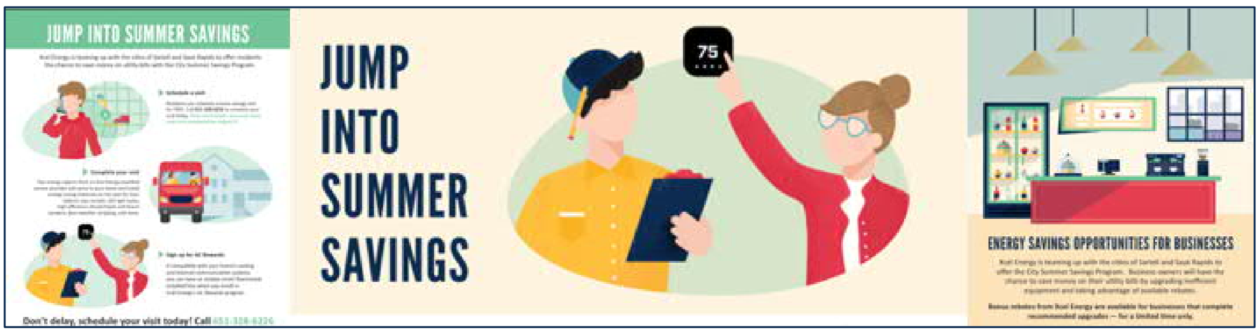
Residential Outreach Tactic	Description
Community ambassador initiative	Early energy assessment visits conducted at the homes of local City leaders to use as ambassadors when promoting the program
Coordination with Cities on promotions	Inform residents about City partnership and special offer through City newsletter — information about programs and incentives on the City website
Direct mail	Information about residential opportunities and incentives mailed to targeted households with high summer usage
Email campaign	Inform Xcel Energy residential customers about energy visits and smart thermostat limited offer
Event tabling	Provide information about the City partnership and special offers at community (e.g., farmers markets) and City events — hand out LEDs at these events throughout the fall
Manufactured home outreach	Information sent through manufactured home park newsletters to inform owners about program, with additional information about income-qualifying programs
Social media	Graphics and text posted throughout the summer through City social media channels and shared by partners including the utility

EVALUATION & LESSONS LEARNED

Pilot Results

The pilot officially launched in June 2019 with a marketing blitz in the participating communities. One of the first marketing tools deployed was social diffusion, leveraging local leaders to help spread the messages, particularly about residential visits. Community leaders receiving these initial visits posted on their social media accounts to help promote others to act. Pilot staff also engaged with community members at local events.

Figure 9. Marketing collateral for residential and business outreach



Commercial and industrial customers were offered free energy assessments. These customers were given one phone number and contact person, and staff members arranged visits to meet the needs of the customer, whether it was an assessment of the refrigeration equipment, lighting, or HVAC systems. The outreach model with a single point of contact streamlined the pilot's customer engagement processes compared to typical program marketing.

The pilot was initially scheduled to end in December 2019. In the business sector, the six-month project timeline proved too compressed to garner participation. There was slower than anticipated uptake from business customers, especially larger businesses, due to the length of the typical sales cycle. Due to the lag in business participation, the deadline for commercial customers was extended through June 2020.

Despite the impacts of the COVID-19 pandemic, which affected program participation in spring 2020, **the pilot yielded total incremental savings of 576 kW of peak demand over the historical baseline on the local distribution system. This exceeded the goal of 500 kW**.

Residential Sector Outcomes

In total, 151 homes participated, resulting in a total of 3,540 LED bulbs and 73 smart thermostats installed. This represented more than a 600% increase in program participation compared to the pilot communities' previous three-year averages. A total of 73 thermostats were installed, just shy of the goal of 80. Out of these installations, six were installed on feeders outside of the pilot area. This is because a small portion of the community was located on a different feeder. This spillover impact is discussed below.

Given the high level of existing demand response participation, 75% of smart thermostat customers were already enrolled in Xcel Energy's direct load control air conditioning program and had to choose one program or the other. This reduced the net savings from residential cooling; however, the kilowatt savings per customer is higher for the AC Rewards program than for Saver's Switch, therefore some savings were achieved for these customers. High level residential segment goals, participation, and savings are shown in Table 6 below.

Table 6. Residential baseline participation, goal, and incentivized participants

	Average annual participants (2015–2017)	Average annual capacity savings (2015–2017)	NWA incremental participation goal	Actual incentivized participants	Actual reduction above BAU (kW)
Residential lighting direct installation	20 participants	3 kW	130 participants	151 participants	20 kW
Residential light bulb giveaways	—	—	1,200 bulbs	1,200 bulbs	6 kW
Residential smart thermostat direct installation and demand response enrollment	18 participants	22 kW	80 participants	73 participants	25 kW

Commercial Sector Outcomes

Commercial savings during the implementation period also exceeded the pilot goal. Commercial program goals were built on a relatively high historical baseline of participation and savings, as shown in Table 7 below (columns 2–3). Though commercial program activity during the pilot met the overall savings goal, the number of commercial projects that filed for bonus incentives were lower than anticipated. There may have been confusion regarding how to take advantage of bonus rebates being offered as part of the pilot. For example, many of the rebates submitted were midstream, instant rebates for products sold by approved distributors. To qualify and receive bonus incentives, pilot participants were asked to contact the program staff implementing the pilot. Although we cannot say definitively, many of the completed projects that did not receive bonus incentives may have been influenced by higher than normal marketing activity that was part of the pilot.

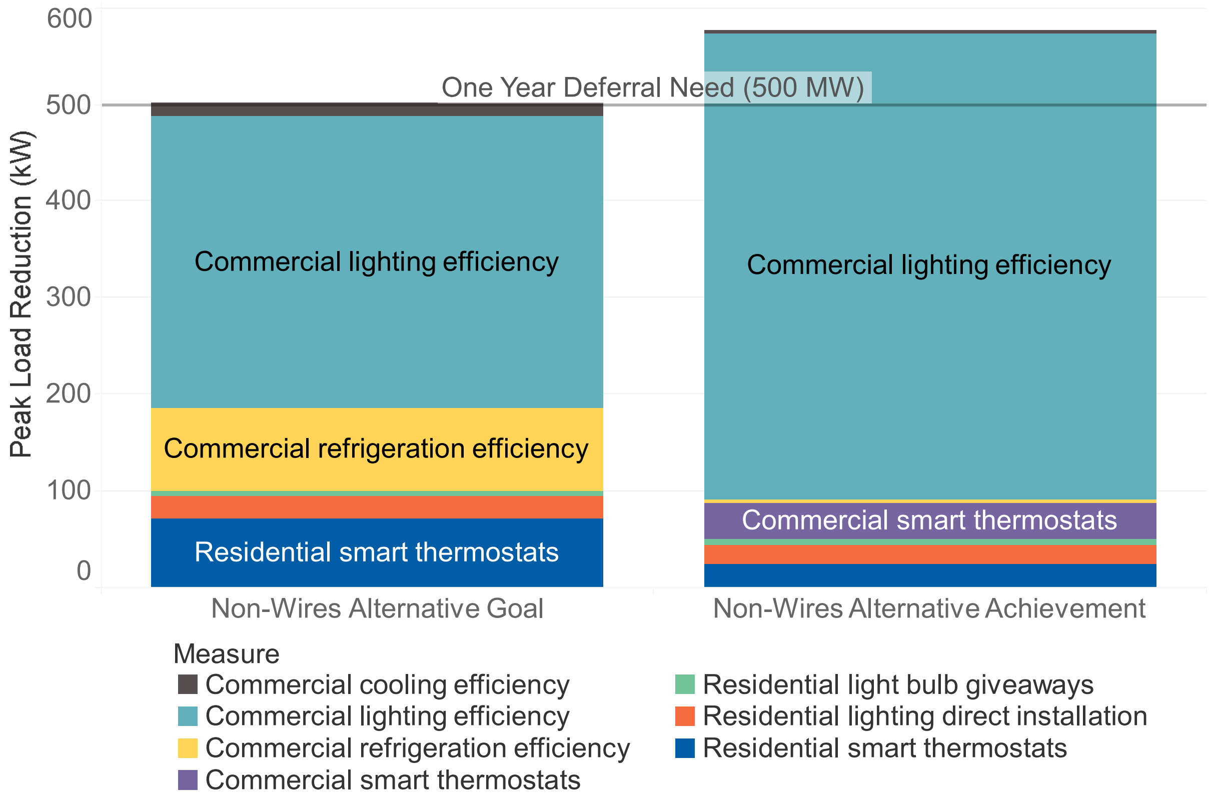
Commercial lighting drove most of the pilot savings. This was expected, and is due to lighting's high technical potential, low project payback times, and well-established contractor network that quickly incorporated bonus incentives into its selling practices. Participation in the commercial refrigeration and commercial cooling programs was below what was expected. The small business refrigeration program is relatively new, so trade ally relationships were still being established, which could have played a role in lower than expected results. In addition, larger kilowatt savings opportunities for both cooling and refrigeration measures are often replaced upon failing, so are difficult to market with bonus incentives. For cooling measures, this challenge is compounded by longer simple payback periods in comparison to refrigeration and lighting measures. In other words, adding a bonus rebate to increase program participation in these programs may not have been enough to convince customers to participate.

Table 7. Commercial baseline participation, goal, and incentivized participants

	Average annual participants (2015–2017)	Average annual capacity savings (2015–2017)	NWA incremental participation goal	Actual incentivized participants	Actual reduction above BAU (kW)
Commercial refrigeration efficiency	—	—	7 participants	4 participants	4 kW
Commercial lighting efficiency	38 participants	272 kW	40 participants	52 participants	481 kW
Commercial cooling efficiency	7 participants	22 kW	7 participants	1 participant	3 kW
Commercial smart thermostat installation and demand response enrollment	—	—	—	4 participants	37 kW

The pilot achievements for both residential and commercial sectors are summarized in Figure 10 below. Further detail on assumptions and savings can be found in Table 3 of Appendix C.

Figure 10. Pilot goals and achievements



Savings spillover

As mentioned above, some participation occurred on an adjacent feeder outside of the targeted part of the distribution system. This was a predicted outcome given that marketing for the pilot defined eligibility as any home or business within city boundaries. This intentional approach simplified the marketing channels, created a clear message, and avoided customer confusion and dissatisfaction. However, it did result in savings spillover where customers received enhanced incentives that were not located on the feeders of interest.

The programs with the most participation showed consistent results in terms of savings spillover. Commercial lighting, residential lighting direct installation, and residential smart thermostat installation all resulted in between 11%–12% participation spillover. These costs are included in pilot costs, though the savings are not. Given the focus on cost-effective efficiency programs, the spillover produced beneficial results regardless of having been outside the target area.

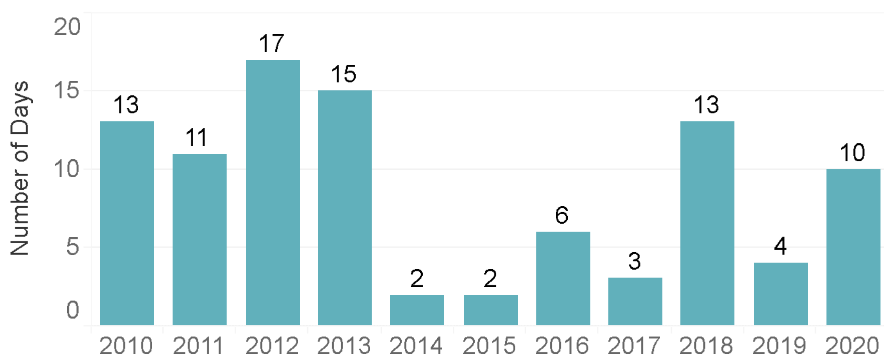
It is worth noting that this marketing approach was successful because the area of need was largely located within city boundaries. Other non-wires pilots will have more cumbersome eligibility requirements.

Existing Demand Response Results

As noted above, over 40% of homes in the pilot area were already enrolled in Xcel Energy's Saver's Switch program. While the traditional use of demand response occurs at the bulk level, this pilot applied existing demand resources at the local distribution level to meet localized grid needs. In summer 2019, the pilot targeted the window of 17:00–19:00. In 2020, we evolved the test protocol to address integration of community solar, which moved the local peak needs to a later time. This is discussed further below, and details of the test protocol are available in Appendix A.

Limited pilot opportunities during the 2019 cooling season (May–September) prevented a robust analysis of the demand response resource at the distribution level. 2019 was noticeably cooler than previous years — temperatures were over 90 degrees Fahrenheit (°F) for only four days in 2019, which may have offered favorable conditions for testing the demand response assets. Those four hot days were at the beginning of the summer season when the demand response protocol was still under development.

Figure 11. Number of days with maximum temperature above 90°F



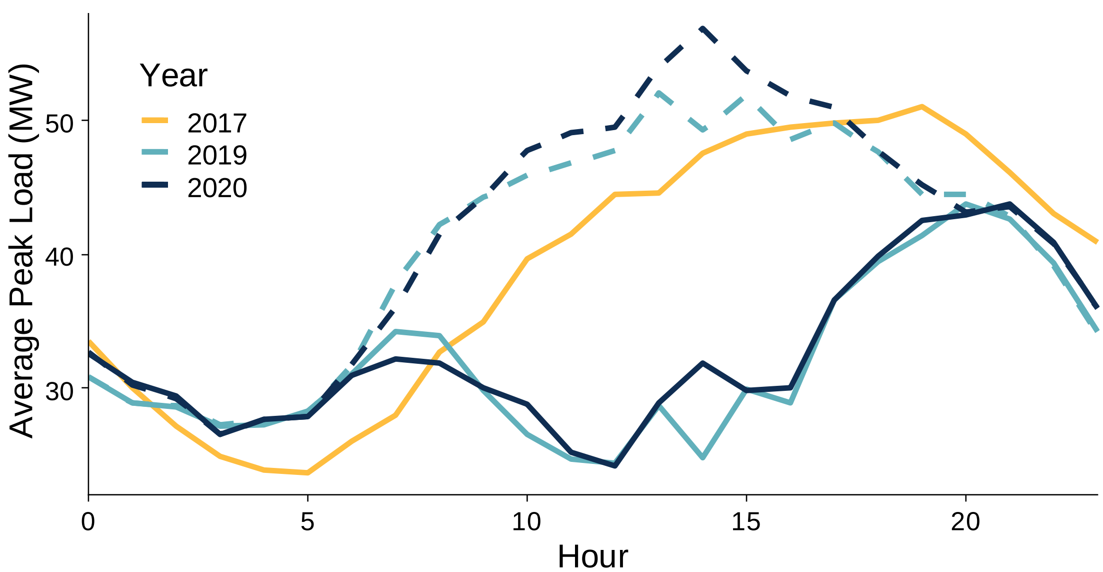
Despite the less than favorable conditions, two events were called in 2019. The first was an event that called upon residential air conditioner-specific demand response resources in the pilot region (Event 1). The second event consisted of a test of Xcel Energy's Northern States Power system resource (Event 2). Analysis of each of these events yielded mixed results. The first event occurred during a dynamic weather period. Rapid changes in weather made it difficult to distinguish natural reductions in air conditioning duty cycles from the reduction triggered by the demand response resource. Conversely, the second event showed a potential load reduction of between 2 MW and 3.2 MW, or 4% to 8% of project area load, during the two-hour event. The upper range of savings during Event 2 was over double the capacity needed for the full three-year NWA project.

In 2020 there were 10 days with a maximum temperature above 90°F, and a total of four events were called. Three of these events were specific to the non-wires alternative area and one was a test of Xcel Energy's Northern States Power system resource. These results are discussed below along with the community solar impact.

Community Solar Garden Impacts

An unforeseen change during the pilot was the development of 30 MW_{AC} of community solar gardens (CSGs) from 22 projects across pilot feeders. This radically changed peaking characteristics on this system and substantially lowered the load at risk. It also shifted the net system peak to later in the day. These changes are shown in Figure 12 below, which illustrates the average load on 10 peak days before and after solar projects were added. During the top 10 peak days of 2019, solar reduced peak loads by 12% and shifted them by four hours, on average. Without solar (shown by the dashed black line), peak loads would have increased modestly and peaked earlier in the day.

Figure 12. The impact of solar photovoltaic generation on transformer load (mock data)



The first-year data show that solar output during the peak window usually exceeded the load at risk by multiples. Between June and August 2019, measured solar output exceeded the load at risk through 18:00 over 99% of the time (all hours except one). By 19:00, the load at risk is exceeded by solar output just 72% of the time.

By itself, this new solar generation is unlikely to satisfy reliability criteria during times of interest. However, by shifting peaks later in the day, these large projects enable new strategies for mitigating peak demand. For example, the shifted peaks have improved coincidence with residential lighting retrofits, one of the successful measures implemented in this project.

Additional CSG monitoring during May through September of 2020 showed that system loads and solar production were very similar to 2019 values on peak days. On days with peak load, high midday CSG output depresses system loads and shifts the peaks into the 20:00 hour. Before 19:00, CSG output consistently exceeds the load at risk. By 19:00, CSG output exceeds the load at risk just 85% of the time, and by 20:00, CSG outputs are very low and the peak load occurs.

Three 2020 geotargeted DR events were called in anticipation of CSG underperformance during evening hours and overcast skies. According to weather and prior CSG observations, cloudy weather was critical to lowering the CSG output to less than load at risk prior to 20:00. We were generally successful in achieving these conditions during 2020 DR calls and each DR call was successfully coordinated with the utility between 0 and 3 days prior to the event. However a variety of circumstances prevented strong conclusions from these events and the magnitude of the DR resource could not be identified from the system data.

The inability to observe the DR resource on the grid was attributed to the following factors. First, the evening event corresponded with lower outside air temperatures than the daily peak temperatures driving the DR scheduling leading to reduced cooling loads. Secondly outside air temperatures generally decreased during the DR event windows commensurate with the advancing weather fronts which caused loads to decline, often by more than the magnitude of the DR resource. Thirdly, the weather fronts also lead to varying cloud conditions such that CSG output varied by magnitudes that rivaled the anticipated DR signal. Lastly, the hourly time resolution of CSG and SCADA data was too coarse for the intended application and synchronicity between CSG data and SCADA data could not be validated.

Despite these challenges, these events demonstrated reliability in forecasting the conditions that would lead to high system loads during underperforming CSG output and successfully coordinated short-notice, geotargeted demand response calls with the utility. We anticipate that future DR research in this area would yield better results with higher resolution data, including real time synchronous CSG data. Despite the lack of statistical confidence attributing load reduction to DR event calls, system loads were less than load forecasts in all but one event. Demand response technologies should continue to be explored as an attractive option to mitigate the load at risk, specifically in their ability to coordinate with local distributed resources to extend load mitigation into the evening hours.

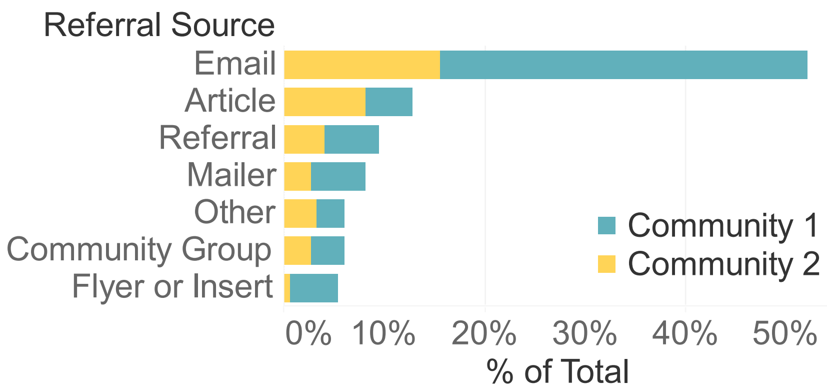
Lessons Learned

This section reviews key pilot lessons for the implementation and operationalization of a non-wires project. We discuss the effectiveness of various outreach tactics, program management and integration challenges, and integration with distributed solar and demand response.

Outreach and Engagement Lessons

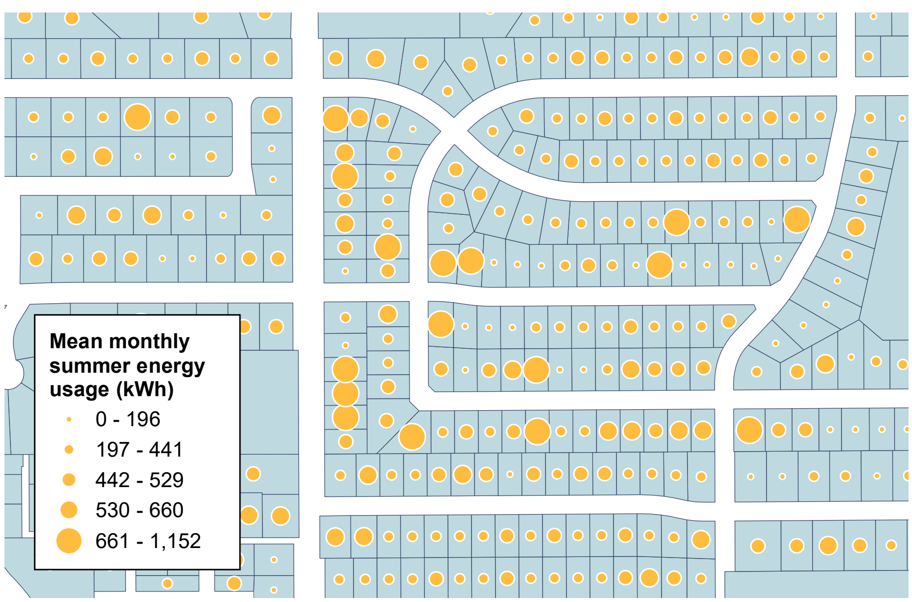
In the residential sector, a variety of outreach and engagement methods were employed within the two target communities. These included postings on City websites, in City newsletters, on social media, tabling at local events, and direct emails to customers from Xcel Energy. While the marketing methods varied by community, email proved to be the most successful at garnering sign-ups for home visits.

Figure 13. Community engagement methods for residential sector participation



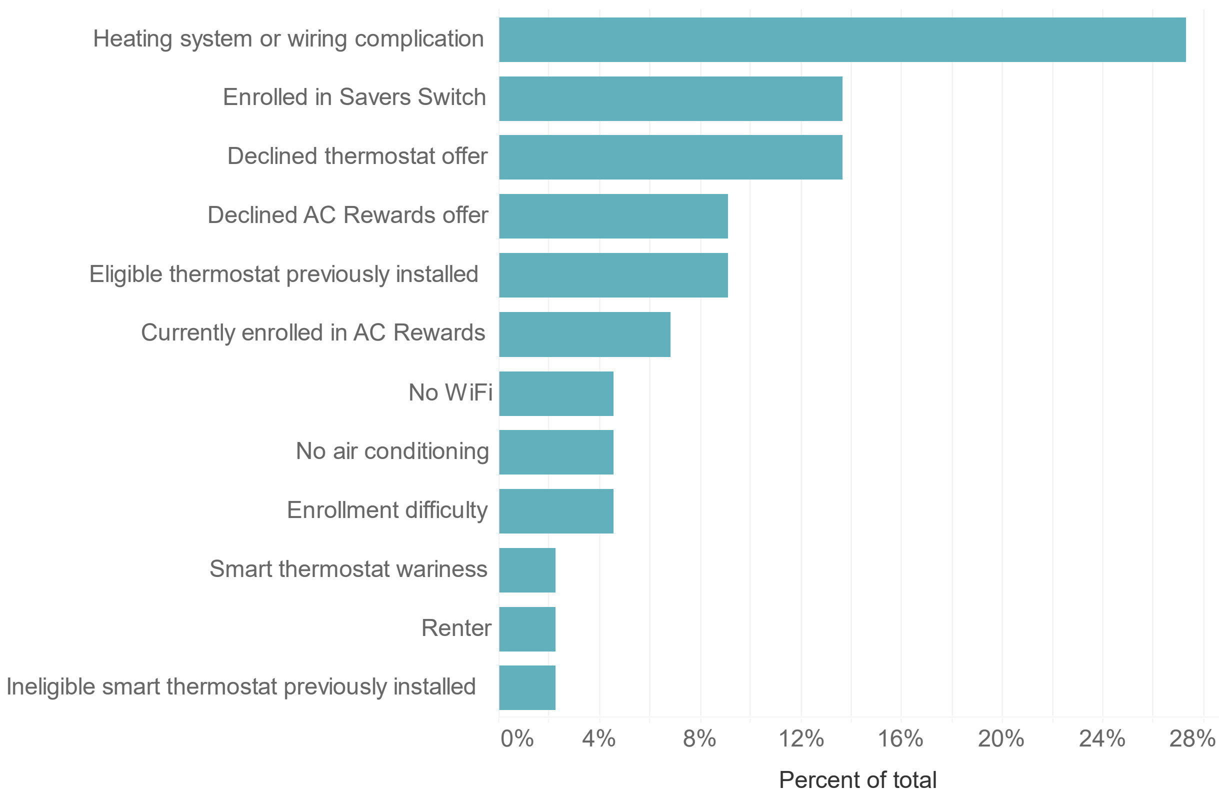
The direct mail campaign was targeted to the subset of households believed to have air conditioning systems in their homes and who weren't already enrolled in cooling-related demand response programs, which was about one-third of all households. We used monthly billing data to identify likely homes with central air conditioning (see Figure 14). Had the mailer been sent to all premises, the numbers in the chart would be more comparable. In addition, while customers reported only the type of outreach that led them to participate in the program, receiving multiple forms of outreach legitimizes the effort and reminds customers of the opportunity for a limited-time offer.

Figure 14. Summer residential energy use on a parcel level displaying mock data



Many customers cited the free smart thermostat as their motivation to participate. However, there were some barriers to a customer receiving a free thermostat in exchange for enrolling in Xcel Energy's AC Rewards program. These barriers are summarized in Figure 15 below. The number one issue was incompatible wiring systems,[15] followed by existing enrollment in the direct load control program. Additional barriers included difficulties with the sign-up process for the program, customer confusion with their WiFi login or logging into the smart thermostat manufacturer's website, or customers who were not interested in the program. The non-install data represents 78 households, or just over one-half of all residential participants.

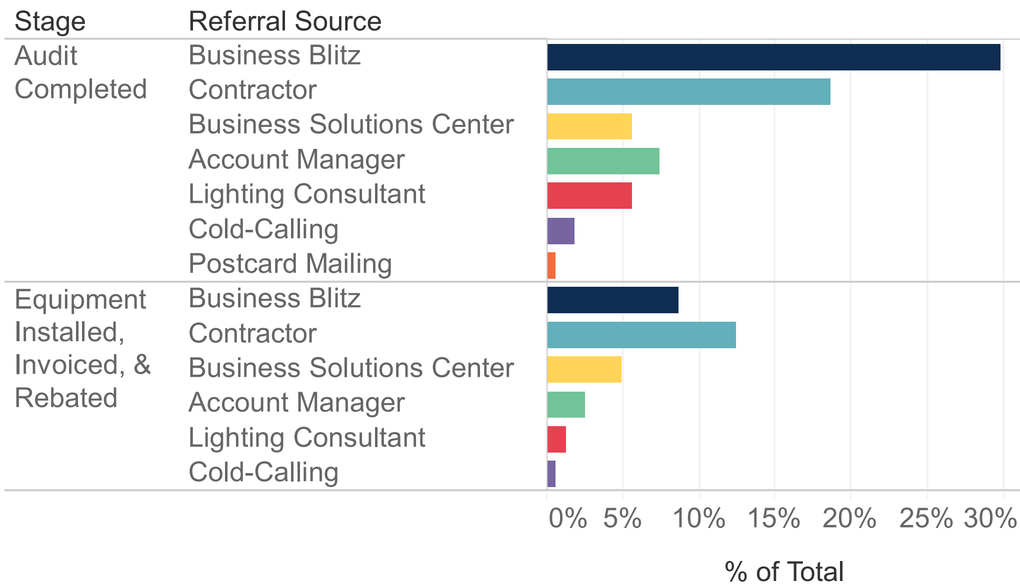
Figure 15. Smart thermostat installation barriers (percentage of total non-installs)



In the commercial sector, a variety of engagement methods took place, including door-to-door canvassing, direct recruitment through Xcel Energy account managers and call center staff, trade-ally engagement, and presentations at City and chamber of commerce meetings. Although email proved very cost-effective for implementation in the residential sector, email addresses were not available for many commercial customers. When these were available, they were often not for the decision makers responsible for energy efficiency improvements. The performance of various business sector outreach methods is shown in the figure below.

[15] Some homes had wires run from the HVAC system to the thermostat that were not compatible with the smart thermostat model installed in homes for the pilot.

Figure 16. Audit and job completion by engagement type



As the chart above shows, contractors were associated with the largest number of completed projects during the pilot window. These existing trade-ally relationships proved key to quickly deploying a bonus incentive program, as many were eager to use the bonus incentive as a tool to sell more jobs. While critical to achieving high savings, relationships with contractors are built on trust and experience, which typically takes time. This timeframe to build trust is often longer than a one-year implementation period. Therefore, investing more in contractor relationships in the near term will have benefits as these projects arise in the future.

One challenge encountered when working with contractors and lighting auditors is that they tend to have a much larger service area than what the program covers, or they may not typically serve the area in general. Therefore, some may not realistically be able to dedicate more time than normal to selling efficiency projects in the non-wires project area.

Program Integration Lessons

This pilot added enhanced marketing and incentives to existing programs, and given that these enhancements were only available in one geographic location, they required additional coordination. Program staff and account managers adapted readily to this change. Nonetheless, there are lessons for improving the integration of non-wires alternatives into existing programs at scale.

First, within the current program operation framework, programs are often historically able to meet annual savings goals without targeted customer participation. When enhanced incentives are used to increase participation, they are offered to all customers. Therefore, channeling additional resources to a specific target area increases complexity without necessarily adding to overall portfolio achievements, especially when the target area is small. To counter this disincentive, the additional value from the distribution deferral could be channeled in part toward internal incentive mechanisms for programs, creating a positive feedback loop.

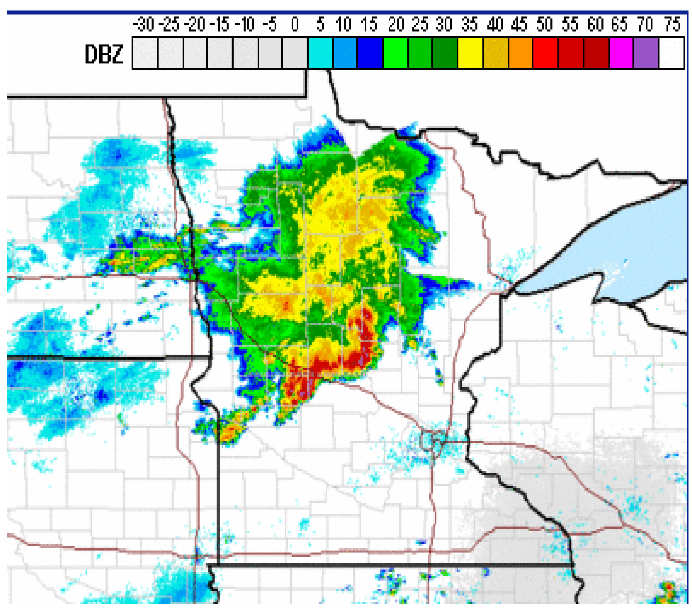
The second takeaway centered around the pilot's length of operation. The initial pilot timeline of six months was too short to meet commercial sales cycles. The extension to a one-year timeline was more realistic, especially for business customers, but this still posed challenges — and would especially for large, complex projects. While the time-limited deadline spurred action that otherwise would not have happened, informal feedback from several commercial customers indicated they would have participated if given additional lead time.

The third finding relates to savings spillover. Spillover in this project was mitigated because the project area fell mostly within municipal boundaries. The spillover of savings out of the non-wires alternative area could be mitigated through a tool that provides eligibility screening. The pilot budget did not allow for this type of expenditure, though if non-wires opportunities were offered at scale, this type of eligibility test could prove cost-effective. Another option to pre-screen customers for eligibility would be to publicly display regions where customers may qualify for an opportunity.

Solar Integration and Demand Response Lessons

One of the most interesting lessons was the impact of community solar on peak characteristics and system needs. While solar reduced the load at risk and pushed the peak window later in the day, it also introduced an additional dynamic element into peak days, given that they are often coupled with extreme weather events. In one instance, cloud cover from storms created large variability in solar output on a demand response (DR) test day.

Figure 17. Minnesota storms on a 2020 test day

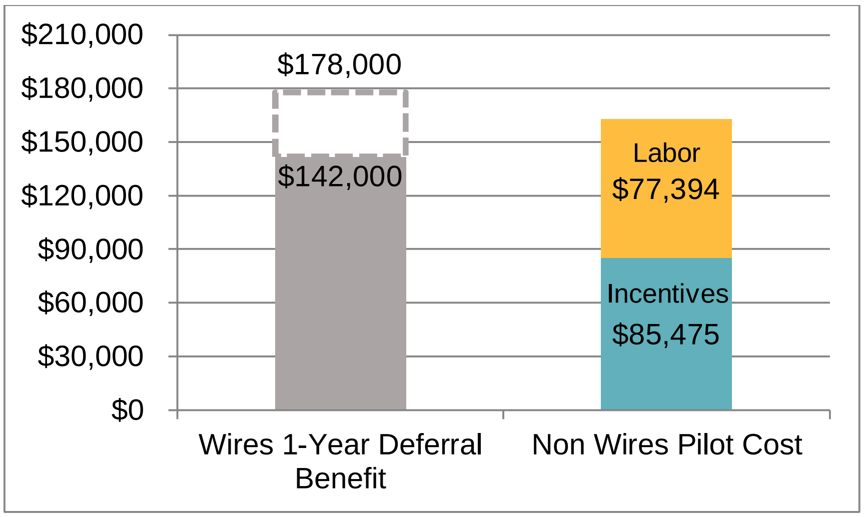


The substantial legacy demand response on the feeders within the pilot area offered enough load reduction to eliminate the original capacity need, as well as provide demand reduction when solar output decreased. Unfortunately, there were too few test days in this pilot to attribute net load effects to either DR or solar with confidence. However, one clear lesson was that tighter integration of these distributed resources will be required for distribution operators to fully harness their benefit. This tighter integration can occur with advanced distribution management systems as well as with the transition from legacy load control to smart thermostat programs.

Pilot Cost Results

Figure 18 below shows results of the pilot costs compared to the avoided costs of the traditional distribution investment. The avoided cost is calculated as the net present value of deferring the distribution investment for one year, which aligns with the 500kW goal. The variation in avoided costs is due to changes in cost forecasts as well as variations in avoided cost methodology. As the figure shows, pilot costs came in at the midpoint of that range, evenly split between bonus incentives and additional labor. One of the drivers for labor costs was that the pilot was located outside of the Twin Cities metro area, which added to travel time.

Figure 18 Comparison of the net present value of traditional and alternative solutions



This pilot proved to be a cost-effective alternative to a traditional wires solution. In this case, conservative assumptions for the value of a traditional deferral were also balanced with more limited accounting of the additional administration costs of the pilot. In particular,

- While we opted to focus on the one-year deferral value, this project likely could have deferred a wires upgrade by two or more years, especially with the inclusion of the existing demand response resource. This would have increased the deferral benefit.
- This pilot did not directly measure the additional administration costs that would be required to manage a non-wires project. These include coordination across the different programs, separate rebate tracking for bonus incentives, and segmentation to deliver marketing to only eligible customers. While these costs could get absorbed into current workstreams and spread over more projects should non-wires projects increase in scale, they are non-negligible.
- Those costs were balanced in part by attributing a larger portion of the labor costs to the pilot, given that staff time was also used to deliver existing energy efficiency programs. In reality, the marginal labor cost to add additional non-wires services would be smaller.
- Not every commercial project in the pilot area took advantage of bonus incentives. Had this been the case, the pilot may have cost more than a one-year deferral value.

Statewide Technical Potential

This section provides an order of magnitude estimate of the statewide technical potential for demand-side management to defer distribution system upgrades. While many of the quantitative results above are specific to this pilot, demand side management programs are in place across the state and are an existing resource to reduce localized peak demand.

This estimate of statewide technical potential has three steps. The first is an estimate of the current budgets for total capacity-related projects across all utilities. Second is an estimate of the percentage of those budgets that would be eligible for non-wires projects. And third is the assumption for the length of time these projects can be deferred, which has a large impact on the net present value of a non-wires alternative. Data on utility spending is derived from filed integrated distribution plans (IDPs) and the 10 potential sites reviewed for this pilot. This information can be improved upon as plans evolve.

Our analysis results in a lower-bound estimate of $1 million and an upper-bound estimate of $4.3 million per year for projects that could be met by non-wires alternatives. This exercise provides a sense of scale based on recent trends in distribution grid spending in Minnesota. There will be large fluctuations year to year, and utilities are still gaining familiarity with non-wires alternatives as a tool to defer investments.

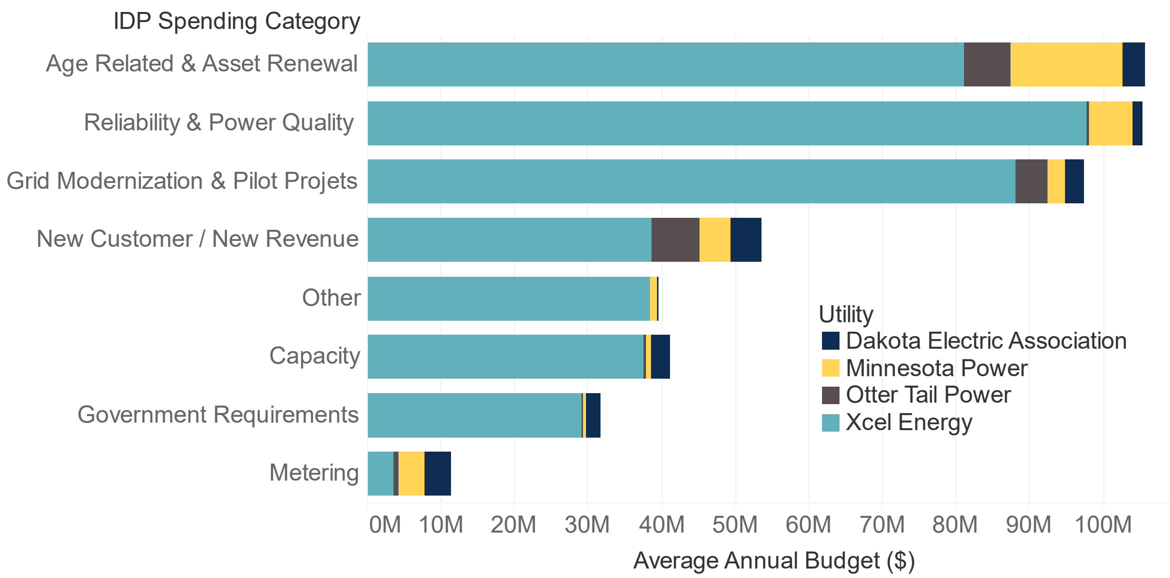
Estimated Distribution Budgets of Minnesota Utilities

As mentioned above, investor-owned utilities and one electric cooperative (Dakota Electric Association) are required to file integrated distribution plans with the Public Utilities Commission. These report the previous spending and projected five-year budgets for distribution projects in several categories.

Capacity-driven projects, which focus on load growth in existing areas such as this pilot, provide the most straightforward non-wires alternative opportunity. However, as discussed elsewhere in this report, there may be additional potential within other budget categories, such as new customer and new revenue projects. These projects bring service to new areas, such as a housing subdevelopment. We have limited this assessment of statewide potential to these two categories of projects. Our lower-bound estimate includes only capacity projects, and our upper-bound estimate includes a portion of new customer projects.

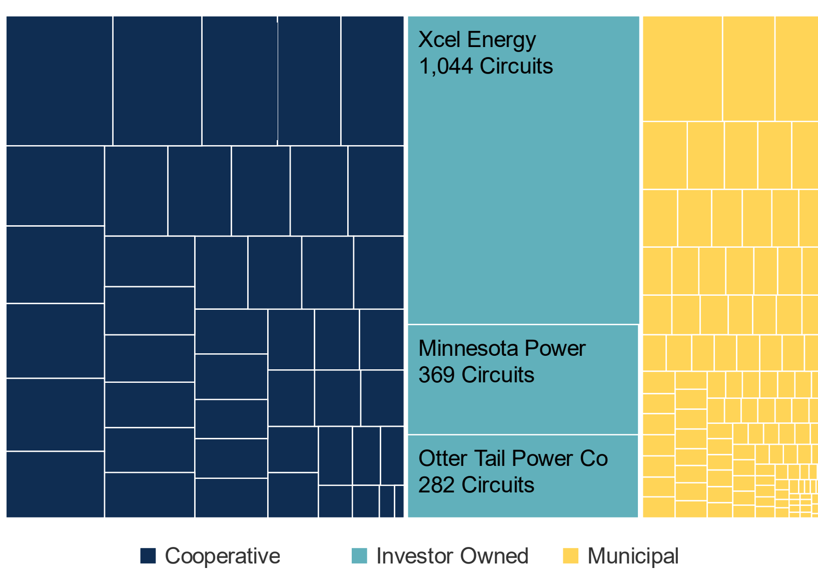
Over the next five years, the four rate-regulated utilities plan to spend an annual average of $41 million on capacity-related projects and $54 million on new customer and new revenue projects. The average annual spending by budget category is shown below in Figure 19.

Figure 19. Distribution budgets by regulated utility in Minnesota



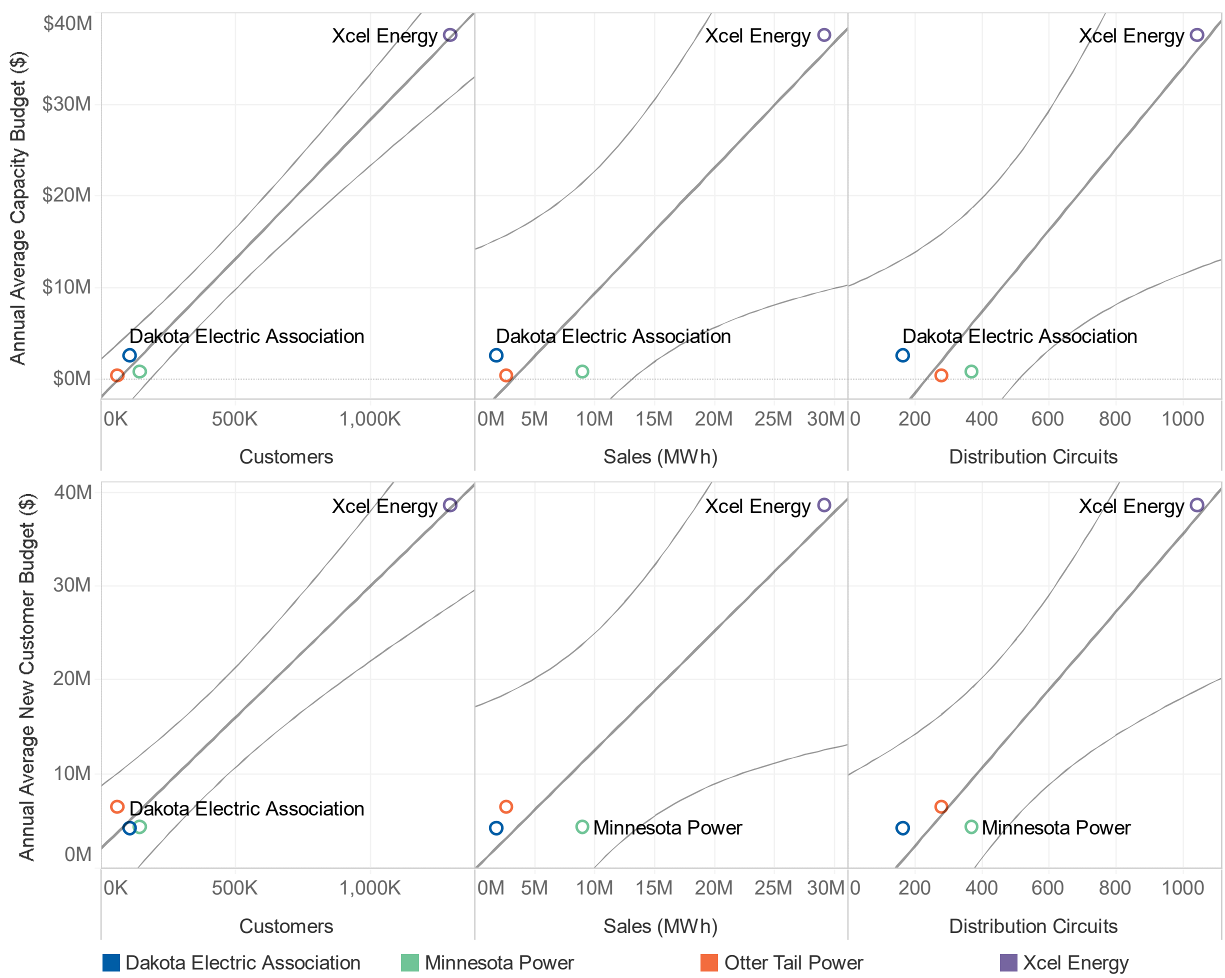
We extrapolated the known spending of these four rate-regulated utilities to estimate the spending by Minnesota's consumer-owned utilities. Consumer-owned utilities are not required to file integrated distribution plans with the Public Utilities Commission, yet these utilities own the majority of the state's distribution circuits. There are 5,472 distribution circuits in Minnesota located within electric cooperative utility territories (see Figure 20). The next largest are investor-owned utilities (with 1,695 circuits), followed by municipal utilities (1,346 circuits).

Figure 20. Count of distribution circuits for each Minnesota electric IOU (EIA 2020b)



We examined the correlation of capacity budgets and new customer budgets with a utility's count of distribution circuits, number of customers, and total retail sales (see Figure 21 below). For these four utilities, distribution spending is most closely correlated with a utility's total customers, resulting in a multiplier of $30 of spending per customer for capacity projects and $28 per customer for new customer projects. We then extrapolated the capacity spending by total customers to include all utilities in Minnesota, a result of $73 million per year. This is a lower-bound estimate of total budgets. For the upper-bound estimate we include one-half of all new customer projects as well, which leads to an estimated annual budget of $120 million statewide.

Figure 21. Correlation of distribution grid spending and utility characteristics



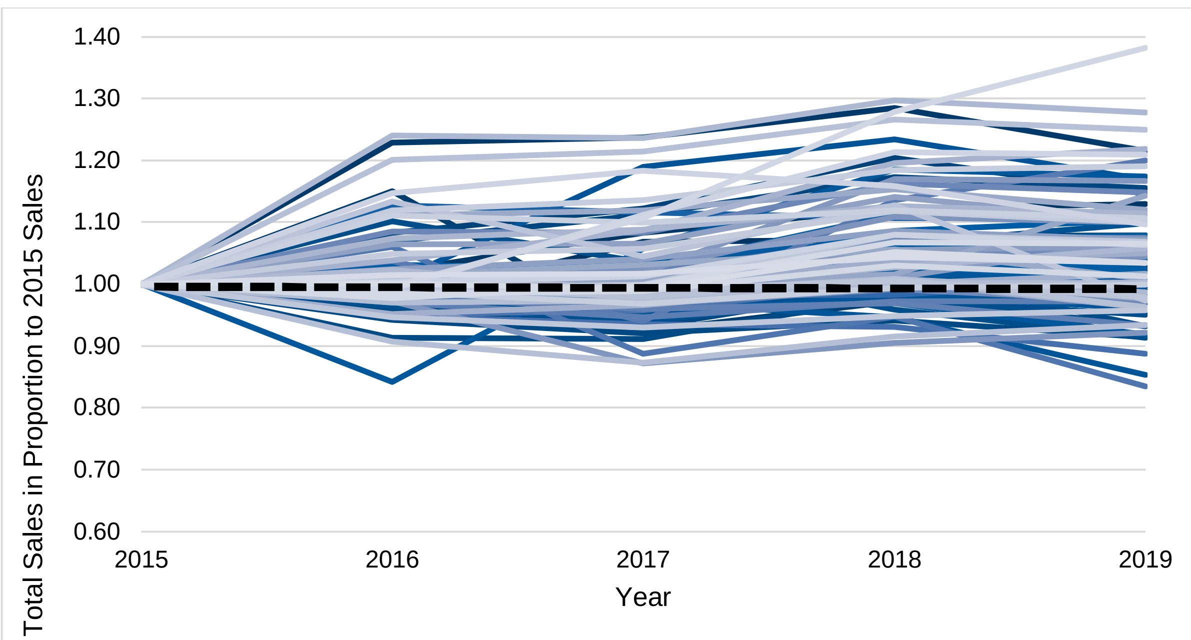
While this extrapolation offers an order-of-magnitude estimate of total budgets, many portions of the state are experiencing a population decline and may have stagnating peak load growth. Both Otter Tail Power and Minnesota Power note this issue in their IDPs. Other consumer-owned utilities, such as those serving growing metro or suburban regions, may be experiencing growth. This is discussed further in the estimation of non-wires eligibility, below.

Non-Wires Eligibility

Only a portion of projects will fit conditions for non-wires alternatives, and this set of conditions has been the focus of discussion in utility IDPs. Xcel Energy outlined an initial set of screening criteria in their 2019 IDP.[16] Of the capacity-driven distribution budget between 2022 and 2024, $30 million worth of projects ($10 million per year) met Xcel Energy's expanded NWA screening criteria.[17] This amounts to 26% of the average annual budget for capacity projects. For another point of reference, this pilot project, which focused only on potential projects in the 2018–2022 forecast, identified 10 potential projects out of a total of 40. These projects represented 20% of estimated budget over the time period.

At the center of eligibility are assumptions around future peak load growth. While some Minnesota utilities see stagnating or reduced sales, a number have increased sales over the past five years (see Figure 22). By number of utilities, 65% have seen growth over this five-year period. If this percentage is weighted by a utility's total sales, 45% of the electricity sold in 2019 was from a growing utility.

Figure 22. Five-year historical sales of Minnesota utilities (Indexed to 2015)



Peak demand will increase with population and business growth, as well as with increased adoption of electric technologies, especially those that are peak coincident when unmanaged, such as electric vehicles. None of the current IDPs account for significant growth from new

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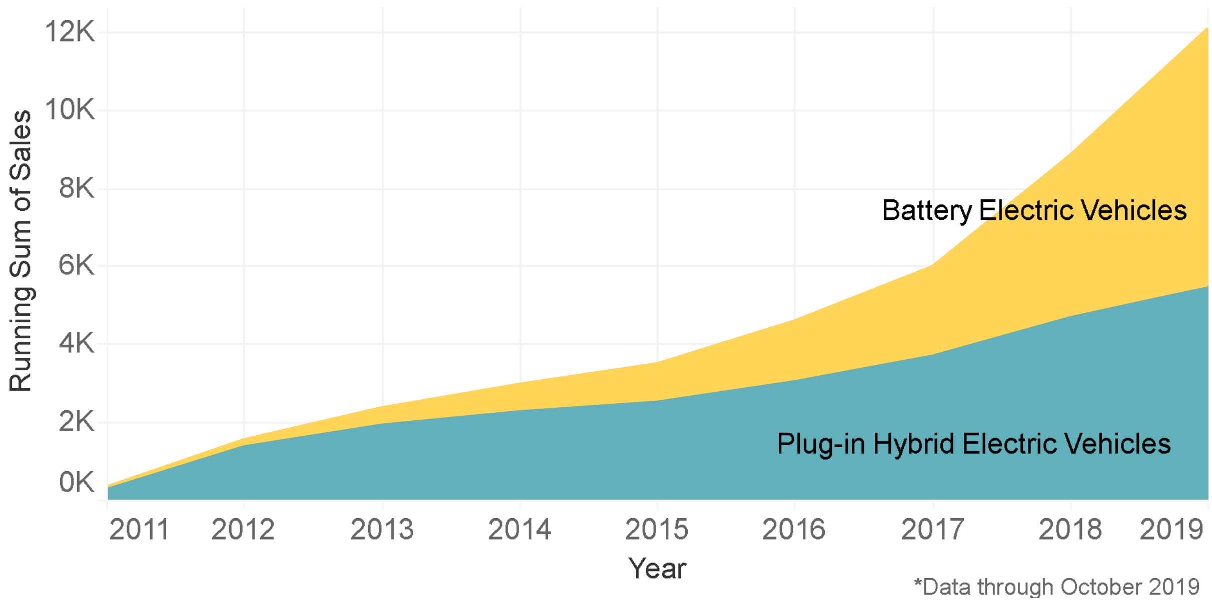
[16] These criteria are capacity projects under $2 million, projects that are scheduled 3–5 years in the future, and projects that include both N-0 and N-1 risks (Xcel Energy 2019 Integrated Distribution Plan, p.97).
[17] See page 98 of Xcel Energy's 2019 Integrated Distribution Plan.

technologies. However, the rapid growth of technologies such as electric vehicles (see Figure 23) means that in all likelihood, future potential for non-wires alternatives will include these applications.

Figure 23. Cumulative electric vehicle sales in Minnesota (AAI 2020)



Given the large uncertainty around eligibility, we include a wide range for our upper- and lower-bound estimates. The lower-bound estimate assumes that 20% of the distribution budget in the relevant categories (capacity and new business) are technically eligible for a non-wires alternative. In the lower-bound, this is applied only to the market size that has seen growth over the previous five years, or 45% of total sales. We assume the remaining 55% of the market has zero eligibility under this conservative case. Applied to the lower-bound estimate for total budget, above, this brings the estimated budget of eligible projects to $6.6 million annually.

The upper-bound estimate assumes that 30% of the projects in the relevant distribution budgets are technically feasible for non-wires alternatives. We also assume that some growth from new technologies and electrification will increase the project opportunities in regions with flat or negative growth over the previous five years. To apply this condition, we increase the market size from 45% to 60% of total sales. Combined with the upper-bound estimate for total budget, above, this brings the estimated budget of eligible projects to $22 million annually.

Project Deferral Assumptions

Finally, the total statewide technical potential will depend on how long, on average, a project can be deferred. This pilot, like several non-wires projects reviewed for this report, is not assumed to avoid an investment entirely. This is a conservative assumption, but, until NWAs are further proven, one that fits with the lessons from early experience.

Our lower-bound estimate assumes that projects can be deferred by three years. The upper-bound estimate assumes projects can be deferred by six years. There is large uncertainty in this assumption. It is possible that a continued application of non-wires alternatives could delay a project indefinitely with underlying growth of 3-4% per year.[18]

The table below summarizes all assumptions and the resulting total estimated statewide technical potential by dollar value.

Table 8. Summary of assumptions for statewide technical potential

	Lower-Bound Estimate	Upper-Bound Estimate
Total Distribution Budget	• Total capacity spending only • Extrapolated to other utilities based on customer count • Estimated at $73 million	• Total capacity spending and one-half of new business spending • Extrapolated to other utilities based on customer count • Estimated at $120 million
Non-Wires Eligibility Budget	• Assume continued growth trends of previous five years and only growth areas are eligible (45% by total sales) • Assume 20% of projects meet eligibility criteria • Estimated at $6.6 million	• Assume accelerated growth due to electrification with increased share of utilities eligible (60% by total sales) • Assume 30% of projects meet eligibility criteria • Estimated at $22 million
Deferral Length	• Projects deferred by three years	• Projects deferred by six years
Total Potential	**$1.0 Million per year**	**$4.3 Million per year**

Again, this range represents an estimate of *technical* potential based on current distribution system budgets. It does not represent an estimate of market potential, as the non-wires alternatives may in some cases be more expensive than traditional solutions. It also does not account for the administrative costs of implementing a non-wires program. Many smaller utilities may face programmatic barriers without the economies of scale available to larger utilities. However, this estimation of technical potential is also rooted in the traditional drivers of distribution system investments. New applications, such as the example of solar integration

[18] This calculation also assumes the traditional project would happen in Year 3 of a utility budget, the mid-point of the 5-year budget forecast. It assumes the same discount rate as used in the pilot itself, 7.14%, or the weighted average cost of capital.

addressed in this pilot, will grow as distributed resources become more actively managed within the distribution system.

Environmental Benefits of Non-Wires Alternatives

Non-wires alternatives bring environmental benefits by increasing the use of clean, carbon- and pollutant-free energy sources. They also reduce impacts on land and water by offsetting production from thermal power plants. This section calculates the potential environmental benefits to the state of Minnesota of pursuing non-wires alternatives.

We use the utility cost of energy efficiency and demand response programs to calculate the total energy savings that would be achieved should all of the budget be spent on energy efficiency. Minnesota's energy efficiency programs cost utilities an average of $0.14/kWh for the first year kWh saved.[19] This utility cost includes both incentives and program administration. A non-wires budget would enhance these expenditures to increase the uptake of energy efficiency in specific locations. While the enhanced expenditures would likely be weighted more towards incentives, we assume for simplicity that the total cost of additional energy efficiency acquired for non-wires applications would be the same.[20]

Avoided air emissions are calculated from the statewide average pollutant output per unit of electricity, based on the current statewide mix of power plants. While the peak demand reduction of non-wires alternatives would most frequently offset a natural gas peaking plant, the environmental benefits of energy efficiency and other DERs accrue all year long. We therefore use statewide annual average values to calculate emissions reductions. These results are summarized below.

Table 9. Potential Air and Greenhouse Gas Emissions Benefits of Non-Wires Alternatives[21]

	Energy Savings	CO_2e Savings (short tons /yr)	SO_2 Savings (short tons /yr)	NO_x Savings (short tons /yr)	Equivalent to…
Lower Bound	7,100 MWh/year	4,000	2.4	2.8	800 passenger vehicles
Upper Bound	31,000 MWh/year	17,000	10.1	12.2	6,000 passenger vehicles

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[19] This is the average utility cost for first-year savings from 2007-2019, for the state's three IOUs.
[20] Current programs spend approximately 45% towards incentives and 55% towards program administration. For non-wires applications the incentives would be higher, but the additional program administration cost to use an existing portfolio would be lower.
[21] Emissions rates are calculated using statewide 2019 plant data from the EPA. This results in an emissions rate of 0.794 lb/MWh for NOx, 0.660 lb/MWh for SO2, and 1,139 lb/MWh for CO2e.

STATE ACTIONS AND POLICIES TO SUPPORT THE DEVELOPMENT OF NON-WIRES ALTERNATIVES

This pilot occurred during an opportune window of policy evolution in Minnesota. Within the two years prior to launch, the Public Utilities Commission began initiatives focused on grid modernization and performance-based incentive mechanisms. Existing regulatory frameworks like Minnesota's Conservation Improvement Programs and integrated resource planning are evolving to address the increase of DERs and intermittent renewable electricity. And integrated distribution planning was launched to align these opportunities and ensure technology investments look forward and achieve all customer benefits. While there are undoubtedly more pilots needed to capture different conditions and technologies, this section discusses how this pilot can inform Minnesota's policy frameworks for non-wires alternatives.

This section first reviews three states that have developed policy regimes for non-wires alternatives. Information was informed through interviews with regulators, utilities, and stakeholders; numerous policy reports; and regulatory filings. Emerging best practices from those states are then compared with lessons from our pilot experience. And finally, we provide recommendations for Minnesota regulators and stakeholders, with an emphasis on integrating non-wires alternatives with existing policy frameworks.

Examples from Other States

Many states have initiated policies to advance the use of distributed energy resources and load management practices, often as part of larger grid modernization efforts. New York, California, and Rhode Island have provided the most comprehensive regulatory approach to non-wires alternatives to date. The section below provides more detail on these three states. We offer this information to inform, but not necessarily guide, Minnesota's actions in this area.

New York

In New York, non-wires procurement occurs through utility distribution system implementation plans, which are filed every two years by New York's investor-owned utilities. New York has approached NWAs through reforms in programs, pricing, and procurement. New York utilities are each required to implement at least one NWA pilot and are required to identify NWAs in their capital investment plans (NY PSC 2015).

The New York Public Service Commission (PSC) has directed utilities to list specific infrastructure projects by location and indicate the potential for DERs to address the forecasted system requirements. New York utilities also publish "heat maps" showing whether other system needs, such as voltage reduction, could be alleviated through deployment of DERs. The PSC established a cost–benefit framework that is used to evaluate all potential investments in the distribution system, including NWAs. This framework supports “portfolio optimization” rather than individual measures or investments to capture synergies among resources (for example, using rate designs alongside DERs). The framework requires that quantified externalities like environmental and economic benefits be included.

To overcome utility resistance to forgoing traditional infrastructure capital investments, as well as the associated rate of return on those investments, New York has experimented with various NWA incentive structures. Initially, the expenses associated with acquiring customer-side resources and NWAs were treated as a regulatory asset, and utilities could earn a somewhat higher rate of return on their NWA investments as compared to capital investments.[22] Today, the financial incentive is based on a shared benefits approach — utilities receive an incentive of 30% of the net benefits (including carbon and societal benefits) generated by the NWA deferral compared to the avoided wires solution. The remaining 70% of the savings must be passed on to ratepayers. If there are no net benefits compared to the traditional solution, then the utility does not proceed with the NWA project.

The PSC has also fostered market signals to align the compensation for DERs with system needs. A DER tariff provides additional compensation to DERs that are located in capacity constrained areas and whose production is generally coincident with the capacity need. This “locational system relief value” is designed to offer “meaningful price signals to incentivize and compensate projects that create actual locational value in constrained areas of the distribution system.” This tariff is part of a larger effort that transitioned away from net energy metering to a value stack compensation designed to compensate DERs based on the actual value provided by those resources (NY PSC 2017).

While New York utilities are prohibited from owning most forms of DER, they are allowed to directly procure energy storage as a distribution asset. All utilities were directed to deploy two storage projects at transformers. Some utilities have requested permission to deploy other storage projects in rate cases.

The most significant NWA project in New York — in fact, in the country -— is Con Edison’s Brooklyn Queens Demand Management project. Through a combination of NWAs, Con Edison is deferring the need for a new $1.2 billion substation. This substation would experience a long duration peak (noon to midnight), so a combination of resources during the day and evening were acquired including solar generation, energy efficiency, demand response, and storage. The load reduction of 52 MW has saved Con Edison’s over half a billion dollars.[23]

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[22] Specifically, an additional 100 basis points on those expenditures, over an amortization period of 10 years. A basis point is one-hundredth of a percent and is added to the return on investment a utility is allowed to earn.

[23] Some other examples of larger projects include, Central Hudson‘s substation deferral project, identified in their 2015 planning process. For this Phillips Road Project, 5 MW of load relief was needed by 2018

California

California has adopted a prescriptive approach to non-wires alternatives that is designed to integrate large amounts of demand side energy solutions and technologies. Beginning in 2014, the California Public Utilities Commission (CPUC) required the state's three investor-owned utilities to develop distribution resource plans. In 2016 the CPUC required a set of demonstration projects through the Competitive Solicitation Framework and Regulatory Incentive Pilot, prescribed four grid services that non-wires alternatives could provide, established a procurement process and fixed incentive, and required utilities to develop between one and four pilot projects. In California, NWAs are acquired through competitive procurement and utilities are able to capitalize the annual payments for the DERs, earning a 4% pre-tax return.

California is now shifting away from pilot-only projects and utilities are filing distribution deferral opportunity reports that reflect potential non-wires alternative opportunities. An annual grid needs assessment shows the locations of needs, planned investments, and candidate deferral projects using online maps and datasets. This assessment describes the performance requirements for any NWA need and flows into the integrated DER solicitation process. A competitive solicitation process was developed for technology-neutral procurement.

In 2016, the CPUC directed utilities to demonstrate a locational net benefits methodology to quantify DER benefits to the transmission and distribution system at a "high level of granularity." The calculation is the basis for determining location-specific avoided costs and benefits and includes a broad range of system and societal benefits (CPUC 2014). The methodology has been refined over time, including replacing system values with local values and broadening the analytical scope to account for additional distribution benefits and uncertainty. Utilities are publishing circuit-specific maps with the results of this analysis, which allow for interactive features such as various DER growth scenarios over near-, mid-, and long-term time horizons.

Rhode Island

In 2016, Rhode Island's legislature mandated that NWAs be considered for all utility distribution reliability upgrades. Following this legislative direction, the Public Utilities Commission established system reliability procurement standards to enable deployment of "cost-effective NWAs to achieve state policy goals, optimize grid performance, enhance reliability and resiliency, and encourage optimal investment by the distribution company." The system reliability procurement process is part of the utilities' distribution planning requirements. The Commission established a framework for utilities to screen for NWA opportunities, which includes the type, size, and minimum cost of projects that qualify for consideration. A procurement plan details the NWA viability when needs passed the initial screening. The

through a targeted demand management program. Additionally, Orange and Rockland Utilities deployed a 17 MW microgrid to defer a substation.

distribution utility shall have an opportunity to propose and earn a shareholder incentive that is dependent on its performance in implementing the procurement plan. This design of this incentive must be “clear and focused, have clear metrics for determining performance, not duplicate incentives, and not provide multiple or different incentives for attaining the same objective” (RI PUC 2017).

Several key revisions were recently made to the system reliability procurement standards. These include: (1) expanding the use of NWAs to address new types of distribution system needs beyond load growth related issues (e.g., voltage performance); (2) applying NWAs to proactively target “high-use” areas of the distribution system (e.g., high EV charging cycles) with a goal of extending the life of existing equipment; and (3) considering partial NWAs that reduce the scope of infrastructure projects, rather than defer the project entirely.

Rhode Island has adapted the total resource cost test that includes environmental and social externalities and the use of location-specific data when available.[24] This framework recognizes that costs and benefits of non-wires alternatives will vary by time, location, technologies, and customers and that the cost-effectiveness methodologies will evolve as quantification of benefits will improve over time.

Like California, Rhode Island utilities are publishing locational value maps and including these as part of a system data portal, which allows third parties access to key information such as peak/load forecasts, capital plans, heat maps, and hosting capacity maps.[25] The Commission is requiring utilities to make customer and system data available, with “proper privacy and security protections in place.” The Commission is also requiring that utilities file their privacy and security protocols as part of their grid modernization filings. The Commission set forth elements of the utilities’ data plan that lays out how customers can access and share their own usage data, and how utilities will make system data as well as aggregated and anonymized customer data available to the public, and what rates the utility may charge in exchange for developing and providing “value-added” data.

Key Lessons from New York, California, and Rhode Island

As New York, California, and Rhode Island demonstrate, policies to advance non-wires alternative projects reflect state-specific approaches, which have evolved over several years. Some key lessons learned from these states are:

Start small and grow. In each state, pilots have revealed the technical, data, and policy gaps that need to be addressed for cost effective NWA projects to advance. These pilots answered important questions into how NWAs perform, how reliability needs are being met with nontraditional solutions, and how persistent these solutions are over the longer term. Pilots have

[24] The total resource cost test is a cost–benefit analysis method that tests whether utility system costs and participant costs will be improved by a solution.
[25] Where possible, the Commission is requiring that these data should be made available in machine-readable format.

offered DER providers and other stakeholders important experience in working with utilities to understand grid needs and design projects that meet these needs. For some utilities however, no projects beyond these initial pilots have advanced.

KEY LESSONS

1. Start small and grow
2. Invest in data quality and availability
3. Expand the pool of potential non-wires resources
4. Align incentives to encourage action and adjust as needed
5. Recognize that local grid conditions change quickly

Invest in data quality and availability. To advance NWAs, extensive attention and resources have been devoted to improving the quality of grid data that is necessary to efficiently design, operate, and evaluate an NWA project. As such, NWA development is closely linked with grid modernization investments. In each state, the quest for location- and time-specific grid data is driving much effort and investment. In addition, data availability for third parties that are engaged in designing and delivery NWAs is under continual refinement. Commissions are assessing whether these data portals are producing the intended result of growing projects at grid-constrained sites.

Expand the pool of potential NWA resources. Once a potential grid project is identified, these states ensure that a wide range of resources are considered as candidates for an NWA. Competitive solicitations are frequently used to produce a suite of DERs to meet the grid requirements. These resources are identified through a combination of procurement from third parties, utility programs, and pricing options and tariffs, which helps to ensure that a cost-effective, tailored NWA is deployed. Each of these procurement approaches requires a regulatory framework to be developed, which takes time and resources. For example, new tariffs for DER resources or procedures for efficient and fair RFPs.

Align incentives to encourage action and adjust as needed. Each of these three states have adopted and modified utility incentives to pursue NWAs. Believing that incentives will spur a utility to undertake NWA projects that it would otherwise not pursue, commissions are working to establish the right incentive metric and level of reward. In all three states, this work continues to evolve.

Recognize that local grid conditions change quickly. At the more granular level of feeders and circuits, grid needs can change quickly. Experience has demonstrated that changes in peak demand due to customer loads, adoption of distributed generation, or system reconfiguration can abruptly create or eliminate a grid constraint. These shifting conditions complicate the evaluation and deployment of NWAs. Improved planning tools can reduce the impact of these unexpected shifts, but, to date, some proposed NWA projects have not materialized due to changed conditions that eliminated the need for the project.

Pilot Lessons for Policy Consideration

The three states above contain several building blocks for non-wires alternatives. This section compares those with lessons from our Minnesota pilot to offer insight into their relevance for Minnesota. The elements discussed below are:

- The role of integrated distribution planning;
- Identification of costs and benefits;
- Disclosure of grid needs, locational values, and data access;
- Investment in grid modernization technologies to support deployment;
- Acquisition of DER through third parties;
- Utility incentives versus mandates; and
- Stakeholder engagement.

Integrated Distribution Planning

New York, California, and Rhode Island all identify and evaluate non-wires projects through a distribution planning process, which allows utilities to take a broad view of their distribution system and ideally realize economies of scale in forecasting and evaluation. This distribution planning generally includes:

- **Screening criteria** for when distribution infrastructure projects trigger a review of NWAs (such as project timing, economic value, or project size)
- **Advanced forecasting and modeling** of circuit and system loads, as well as DER impacts on the distribution system (e.g., rooftop solar)
- **A quantitative assessment of grid costs** and a locational value of where DER deployment can provide grid benefits

While this pilot was launched in conjunction with Minnesota's statewide distribution planning requirements, and therefore was not linked explicitly to criteria or tools set forth in that docket, it was identified as a result of several of the same informative planning steps.

Screening Criteria

The pilot screening process served two functions: it identified projects that were candidates for non-wires alternatives, and it prioritized projects based on their potential benefits and likelihood of success. Both of these were valuable, discrete steps. In particular, project prioritization allowed for a more in-depth evaluation of which criteria mattered for a successful project. Given that future projects will want to expand the pool of technologies and applications for NWA, prioritization criteria are an important consideration.

In other states, screening criteria for when distribution infrastructure projects trigger a review of NWAs is expanding beyond load relief and project size, especially when the traditional solution is expensive. Regulators are asking utilities to expand the project pool to encompass asset relief and reliability. However, the largest number of options continue to be capacity related.

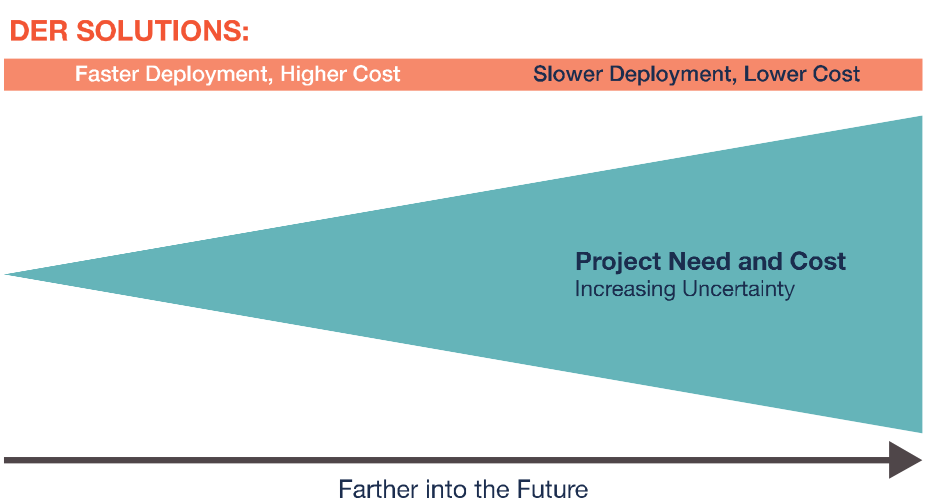
Replacements of distribution system components due to age or poor condition are generally excluded from consideration for NWAs.

Advanced Forecasting

The forecasting of future capacity needs for this project was limited, and this pilot expanded beyond traditional boundaries of how to define the need of a particular site. For traditional solutions, a forecast of peak capacity need is all that is required. But characterizing the need for demand-side solutions must include the full demand profile at each site, giving not just peak needs but the time, duration, and frequency of those needs. One opportunity is to conduct load forecasting using more robust hourly or sub-hourly historical load data. This level of detail does not need to happen at the project screening stage, but is valuable after a site has been chosen.

Forecasting for this pilot projected load growth based on historical trends, in line with traditional distribution planning. Our pilot experience aligned with that of other states in that the forecasted capacity need declined in subsequent forecasts, obviating the need for any NWA project. This issue could also apply to traditional assets, which are also built in anticipation of a need. However, these traditional infrastructure solutions require less lead time. As a resolution to this issue, projects with less certainty, which tend to focus farther into the future, should focus on the most cost-effective solutions such as energy efficiency and demand response.

Figure 24. Project need and cost over time



Forecasting tools that can project a variety of scenarios will help identify likely areas of need. As DERs grow, forecasting tools that incorporate projected impact of new loads (e.g., electric vehicles and rooftop solar) on various feeders will allow planners to get ahead of potential cost increases driven by unplanned growth and apply NWAs as a solution. Experience from other states with higher penetration of DERs has shown that adoption will be uneven, with “clustering” of high adoption pockets. The methodologies for DER forecasting and the software tools to support these models are still evolving. While such tools were not available for this pilot, Xcel

Energy received recent approval from the Minnesota PUC to spend $4 million for an advanced planning tool, Load SEER (Xcel Energy 2019).

Several of the above points call for improved data in the planning process. However, forecasts of load and DER growth will be inherently uncertain. Investing in better detail given the uncertainties inherent in the task will have diminishing returns. This pilot clearly demonstrated this inherent uncertainty created by the unplanned-for addition of 30 MW of community solar in the project area, which changed the site needs drastically between the time of site identification and evaluation of pilot results. Yet despite the caveats about more data, there are tangible improvements to how forecasting is done today that can be geared toward helping design more accurate and fitting NWAs. These improvements can be captured by the use of scenarios in planning, and by forecasting using more detailed load data, not just the peak and how it has grown over time.

Identification of Costs and Benefits

Non-wires alternatives need to provide the same or better functionality as would have been provided by a traditional utility solution. Determining if NWAs have the potential to provide comparable functionality at a lower cost depends on where the NWAs are placed on the grid, as well as the timing, duration, and reliability provided by the DER technologies. Understanding the relative costs and benefits of non-wires alternatives versus a traditional investment requires a methodology to assess all of these attributes, and states have devoted extensive work to designing an appropriate methodology, reflective of their energy policies.

Methodologies for determining the value of a particular NWA application that include valuations for grid location, timing, and quality and duration of the resource are being worked on in many states. Often this work has been derived from cost–benefit methodologies that have been part of the standard practice tests used for energy efficiency. To the extent possible, these include distribution-level components of avoidable costs and are assigned locational values. These location-specific methods are still in the early stages. California has done the most to develop its locational net benefits analysis tool, although this tool is undergoing continual improvement as data quality improves. Avoided distribution costs have historically tended to be relatively small compared to avoided costs for energy, production capacity, and environmental impacts.

Pilot Takeaways: From the perspective of this pilot, identifying the traditional project cost was relatively straightforward. While the costs of traditional solutions will vary year to year, identifying those costs is a standard part of distribution planning that gets updated on an annual basis. The experience from this pilot does not call for a more robust or detailed quantitative assessment of those costs. However, we did experience the variability of traditional costs, especially since the project was more than three years into the future. Experience with this pilot indicates that avoided cost values are dynamic and challenging to forecast beyond one or two years. Our experience also indicates that quantifying the timing and duration of the need, wholly critical for NWAs, is an emerging practice.

This pilot also highlighted the policy need to clarify the method for identifying the present value of a project deferral. While we used the discrete valuation approach aligned with CIP valuation,[26] other avoided cost approaches should be explored. In addition, this project focused on deferral of an upgrade, but utilities should also consider whether a project can be avoided altogether.

Disclosure of Grid Needs, Locational Value, and Data Sharing

As noted above, defining grid needs well enough to design alternate solutions requires significant data, and a key policy question is whether and how that data should be shared externally. Data needs for designing NWAs include planning and system information such as circuit topology, circuit loading, voltage, reliability, hosting capacity, and preexisting DER installations. Information on equipment ratings, settings, and expected life as well as the area served by this equipment is also helpful to designing solutions to address grid needs. However, many of these data would be considered confidential by a utility. Disclosure of grid data must balance security and privacy with the value that transparency brings to NWAs.

As noted earlier, New York, California, and Rhode Island all have requirements that utilities provide a data access portal.[27] The primary goal of providing this data is to help developers and customers pursue NWA and DER projects at specific locations that will be cost-effective alternatives to traditional investment as well as avoid additional strain on a grid location. Some states have shared the sentiment that while the data portals are useful for transparency and understanding the potential for projects, developers are also driving business based on other factors, and they don't always align with areas of highest value.[28] Across several states, the jury remains out on whether these data portals have delivered on their intended value.

Pilot Takeaways: While this pilot worked only with limited data set for one project, it was a significant portion of the planning effort to identify which data to provide in what format as well as to keep the data current given the changing site needs. In our experience, limiting the available data to projects identified via screening, rather than for distribution circuits not being targeted for projects, would be sufficient.

Once a site or sites have been identified, sharing system needs in more detail will be critical to identify appropriate solutions. Whether this is shared publicly or made available under confidentiality agreements with prospective implementers is a decision that will need to be

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[26] The discrete valuation approach "looks at T&D investments with and without the energy efficiency impacts on the T&D system. The differences in those costs are totaled and divided by the amount of the EE impacts" (Xcel Energy et al. 2017).
[27] New York heat maps, California Grid Needs Assessment, and Rhode Island's Distribution System Data Portal.
[28] Minnesota does not have an equivalent data portal for distribution projects; however, the hosting capacity analysis work by Xcel Energy has been underway for about three years. Stakeholders are pressing the Commission to require more frequent and useful updates than are currently filed (MN PUC 2017b).

made, weighing the value of transparency versus security. From our experience, the primary importance is that the information be made available to those who need to design and evaluate projects. Feeder-level data at 15-minute intervals was sufficient to design an overall solution. In Minnesota, these data should also include historic production from any community solar garden that impacts the net load at the site, noting that this information is generally held by solar garden operators, not the utility.

Since this pilot focused on energy efficiency and demand response, it was also important to have customer-level data available to design community-specific solutions. In general, if working within existing programs, this information should be available to program providers under existing program contracts and data security agreements. Given the sensitivity of customer-specific energy use, it is difficult to justify that information being made available to only prospective implementers without a direct application and data security in place. That said, some types of aggregated data that would prove useful as solutions are being designed include:

- Total customer count and aggregated monthly electricity use by segment
- Previous demand side management program participation or current enrollment
- If monthly data are not available, the ratio of summer to shoulder season electricity use by segment (for this summer-peaking system)

As discussed previously, this pilot was designed with only monthly billing data available. Time-interval data, available with the rollout of AMI, will bring highly valuable yet sensitive information to segment and triage customers for more effective program marketing. Similar to monthly data, it is difficult to justify providing that data to prospective implementers without a contract in place.

Investment in Grid Modernization Technologies

Grid modernization technologies encompass a suite of investments from metering to communications, and many can support the evaluation and adoption of non-wires alternatives. While NWAs are not a primary motivation for grid modernization in other states, there is an explicit link to grid modernization and DERs in their regulatory processes. New York regulators required utilities to file a grid modernization plan to advance the use of DERs. Rhode Island is currently considering a proposal for AMI deployment. California utilities have brought forward multibillion dollar grid modernization investment plans, with the vision that once the suite of these technologies are fully deployed, the distribution grid will become a seamless platform for the deployment of a myriad of DERs.

One of the major benefits of grid modernization for NWAs comes from more granular customer load data from advanced metering infrastructure. AMI will enable more accurate load forecasts, improve management of DERs, and enable verification of NWAs that are deployed on customer side of the meter. Capacity needs are very time sensitive, and AMI can assure that the NWAs' load reduction or generation is happening when it is needed. Accurate compensation for NWA resources is based on the ability to measure whether capacity was available as planned, and AMI meters will improve the accuracy of that measurement and, therefore, the accuracy of compensation.

Pilot Takeaways: This pilot was conducted without the availability of grid modernization technologies. Advanced customer meters have not been widely deployed in Minnesota, but some utilities are planning to implement rollout of AMI across service territories in the next four years. As shown from this pilot and other states, it is possible to gather and evaluate customer data needed to deploy non-wires alternatives without AMI. The process to do so, however, is much more time intensive, and outcomes are less certain.

The availability of SCADA at the feeder level was essential and was a requirement for picking a pilot site. Currently in Minnesota, some substations do not have SCADA, which limits the ability of utilities to efficiently collect feeder data that is necessary for accurate planning and control. While SCADA is a basic element of an advanced grid, other grid sensing and control technologies will likely be deployed in the coming years that can play the same role for non-wires evaluation as SCADA did for this one.

Certain features of grid modernization would improve the functionality of a pilot such as this across planning, deployment, and evaluation. In particular, the availability of data and communication platforms may have allowed for:

- Finer representation of the frequency, timing, and duration of peak events at the feeder level;
- Better identification of the customer end uses that contribute to peak load during initial project planning;
- Increased certainty in deploying demand side solutions, for example, knowing that customer cooling loads are "on" when planning for a peak event;
- Automated call of demand response resources on a local level; and
- Improved evaluation of pilot effectiveness and attribution of savings, especially in real-time.

These may be important future areas to test to streamline the cost and increase the certainty of non-wires alternatives for distribution planners and operators.

Acquisition of DER Through Third Parties

As mentioned above, policies in New York, California, and Rhode Island are designed explicitly to encourage competitive proposals of DERs by parties other than the utility. The motivation underlying the use of competitive third-party solicitations can be to encourage technology-neutral packages of DERs, to ensure costs are reasonable and transparent, and to support nascent markets for clean energy. The sourcing for DER technologies generally occurs either through competitive solicitations, through the utilities' own programs, or through special tariffs. In New York, California, and Rhode Island, all three approaches (procurement, programs, and pricing) have been used to acquire NWAs. There are also hybrid approaches that rely on utility and third-party cooperation.

In this geotargeting pilot, competitive procurement and special tariffs were not realistic given the project timeline, especially without an approved regulatory framework to define the benefit of distribution deferrals. We exclusively used the program approach and either augmented Xcel Energy's existing energy efficiency and demand response programs to achieve the additional 500 kW savings, or in the case of smart thermostats, leveraged pilots to recruit additional customers. The pilot delivery therefore worked through existing third-party program vendors (who compete for program contracts), but the NWA was not specially procured through a competitive process. This was fitting for several reasons:

- The project size was small, and likely too small for most vendors to bother with as a one-off project.
- The pilot's learning objectives did not include procurement.
- Without an approved regulatory framework to value distribution deferrals, we determined that utility spending on pilot solutions should come from existing cost-effective programs (i.e., the existing energy efficiency and demand response portfolio).
- Our demand response solutions were a test of *existing* resources, controlled and deployed by utility operators.

To this final point, the large additions of community solar also changed the site's peak timing and duration needs. In this case, it would be more straightforward to adapt utility-operated load management to fit with new site needs. This flexibility to adapt to new conditions at minimal additional cost would be important to include in performance requirements for third-party load-management delivery as well.

Based on comments in Minnesota's IDP process, requiring competitive procurement of NWAs to allow third parties to package proposed solutions may have benefits, but would be a significant change in utility policy in Minnesota. Xcel Energy's 2019 IDP also contemplates the use of an RFP process when it discusses the amount of lead time needed to bring NWAs forward in time to meet a grid need, so this issue will receive further evaluation in the future.

However, given our findings for Minnesota's statewide technical potential, the typical project is most likely under 1 MW, with achievable cost savings in the order of 5%–20%. Given the overhead time to run an RFP process and manage contracts, third-party procurement may not be necessary to achieve optimal outcomes, especially when solutions might be available with demand side measures from existing program portfolios.[29] But for larger projects, or perhaps for an aggregated project portfolio, a utility could decide to use a competitive RFP to help identify innovative technical solutions and ensure cost prudency. Below are considerations for when a utility could decide that competitive procurement of NWAs may be valuable:

- When the individual or aggregated project size is larger than 1 MW;
- When project timeframes are at least two years into the future and project need is certain; and

[29] Minnesota does not rely on substantial third-party demand response programs to meet its goals, as some other states do.

- When contracts can include payments in anticipation of delivered capacity and payments for actual performance, therefore cementing accountability for both on the part of the third party.

Finally, deploying a disparate set of DERs from third parties would require standardization of communications between and among devices, standardized control platforms across various technology types, and development of cybersecurity protocols. While grid modernization will better allow coordination, many utilities do not yet have standardized systems in place. RFPs need to include the requirements (and therefore costs) for full integration with data systems and operations.

Utility Incentive Mechanisms Versus Mandates

Non-wires alternatives can be more complex than wires solutions, and utilities have a financial disincentive in that they lose out on a return on capital investment. Regulatory commissions have used two main approaches to better align utility and ratepayer interests and to drive acquisition of NWA: mandates and incentives. Mandates require utilities to consider NWA for needs that meet screening criteria, and they have been applied in the distribution planning process. California, New York, and other states have also experimented with incentives for NWAs that include a higher rate of return for expenditures and a shared savings incentive, which allows utilities to earn a percentage of the savings achieved by the NWA project:

- The **rate of return adder** on NWA expenditures can overcome utility preference for investment in capital projects that earn a rate of return on the traditional rate base. A draw back to the rate of return adder is that utilities could be motivated to maximize spending on NWA projects and not pursue the most cost-effective solutions.
- The **shared savings incentive** focuses the utility on maximizing savings from the NWA project and could spur utilities to search comprehensively for innovative solutions. This is the model for energy efficiency incentives in Minnesota as well, where utilities earn an incentive based on a percentage of net benefits achieved by energy efficiency programs. Some drawbacks to the shared savings incentive approach is that there is a risk that utilities will only pursue the projects with the greatest level of savings. Additionally, determining the utility's share of the savings can be a lengthy, involved process. Minnesota's energy efficiency incentive design is a standardized formula and this approach could be tailored to apply to NWAs as well.

Minnesota has models for pursuing clean energy through both incentives and mandates. The IDP requires a utility to assess non-wires options when projects exceed $2 million. While this pilot was not launched through the IDP process, it would have been included given that threshold. This requirement is consistent with Minnesota's least-cost planning principles that underpin many electric utility regulations such as energy efficiency and integrated resource planning. At present, there are not direct incentives associated with the acquisition of NWA in Minnesota. However, the Minnesota PUC, at the request of CEE, has recently ordered Xcel

Energy to design a performance incentive associated with the procurement of demand response resources as part of the performance-based incentives docket.

This pilot encountered one potential opportunity for how NWA may integrate with existing incentives. Energy efficiency has a robust policy framework in Minnesota, where utilities have shared savings incentives for meeting annual goals. Given that the pilot goals for energy efficiency were small compared to the whole program portfolio, there was little motivation for programs to spend the additional resources required to increase participation in a particular geographic location. If non-wires options are constructed using existing utility programs, as this experience indicates they should be, then an additional incentive is needed to motivate action in one location over another. This may come in the form of specific goals for NWAs, or in recalculating the shared incentive value to include the specific non-wires deferral.

Some additional opportunities to work incentives or mandates for non-wires projects into Minnesota's existing frameworks are discussed in more detail in the policy recommendations below.

Stakeholder Engagement

In states with robust NWA policies, stakeholder engagement is a central component of the utilities' NWA programs. In some cases, stakeholder groups have been instrumental in establishing methodologies and policy recommendations to the Commission, such as with California's locational net benefits methodologies. In some states, stakeholders are involved in the development of competitive solicitations for NWAs.

Stakeholders can also be instrumental in identifying roadblocks or operational challenges that impede development of NWAs, particularly if these stakeholders are developers of DERs and have good familiarity with the utility's distribution grid and interconnection processes. In some states, independent engineers have been hired to support the stakeholder process, given the very technical nature of the NWA space. Independent facilitators have also been used to ensure objective processes.

Some key takeaways from stakeholder engagement for NWAs:

- Effective stakeholder engagement requires sharing system data, but utilities are cautious about ensuring physical security and cybersecurity. This is an area of active debate in many states, and Minnesota will need to determine what data is appropriate to share and what should be kept trade secret.
- Stakeholder processes can be resource intensive, and NWAs require an active group of representative interests with expertise to devote to the process. However, informed stakeholders can provide new and different perspectives on grid designs and needs, and may have expertise that is outside utilities' purview, such as data analytics and software development.

Pilot Takeaways: While stakeholder engagement is a robust part of the IDP process, we did not conduct stakeholder input during this pilot. Once the framework for NWAs has been established, there is less need for stakeholder engagement at the individual project level. However, stakeholder input at the portfolio level remains valuable. This input can help to judge whether there are a sufficient number of non-wires projects given: (1) current system conditions; (2) the variety of DERs proposed and methods for evaluating them; and (3) results of project effectiveness and benefits.

A broader definition of stakeholder input includes community partners, which were central to the success of this pilot. Especially in the case where new projects are proposed, working with communities on clean solutions will be a part of the project process.

These takeaways are summarized in the table below.

Table 13: Summary of policy building blocks and corresponding pilot lessons

State Policy Building Blocks	Corresponding Pilot Lessons
Integrated Distribution Planning	• Project screening should identify and prioritize potential projects, given desired outcomes. • Forecasting should incorporate historical load data to forecast the timing, duration, and frequency of peak capacity needs. • Expand the use of scenario planning to identify likely DER futures, including additions of large-scale community solar and electric vehicles.
Identification of costs and benefits	• Produce location-specific avoided costs for distribution deferrals, and include cost ranges or uncertainty for projects more than two years into the future. • Clarify and formalize the method for quantifying the present value of grid deferrals.
Disclosure of grid needs, locational values, and data access	• Disclose grid needs for projects selected through screening, rather than for the whole system. • De-emphasize access to locational values that change frequently, especially if there is no near-term project identified. • Include developer data from solar garden production if a garden exists at the site. • Provide aggregate customer data that aligns with data privacy guidelines.

State Policy Building Blocks	Corresponding Pilot Lessons
Investment in grid modernization technologies to support deployment.	• Improve project planning with more granular representation of peak events at the feeder level and better identification of the customer end uses that contribute to peak load during initial project planning. • Increase certainty and automation in deploying demand side solutions at a local scale. • Improve real-time evaluation of pilot effectiveness and attribution of savings.
Acquisition of DER through third parties	• Competitive procurement may be cost prohibitive for smaller projects, especially when solutions can be delivered through existing programs. • Demand response and other active technologies may need nimble dispatch protocols as site conditions change. • For larger projects or aggregate sets of projects, a utility could decide to solicit bids from third-party vendors. If so, RFPs should include communication and data integration needs.
Utility incentives versus mandates	• Continue to use integrated distribution planning to identify non-wires alternatives as part of least-cost planning framework. • For existing DER programs, consider enhancing financial incentives to motivate implementation in a particular location.
Stakeholder engagement	• Stakeholders offer valuable insight into NWAs at the portfolio level and should continue to review projects as part of distribution plans. • External stakeholders with technical expertise on the grid offer value in reviewing eligible projects and determining the societal benefit of proposed solutions. • Once policies are established, stakeholder engagement should include community partners that will help facilitate and promote local implementation.

Minnesota Policy Recommendations

This section provides specific policy recommendations for Minnesota stakeholders and regulators to advance the use of non-wires alternatives. These recommendations build on existing regulatory frameworks rather than suggesting new ones.

Existing Minnesota Regulatory Pathways

As mentioned above, Minnesota has strong foundational policy requirements to advance clean energy and incentivize utilities under the shared benefits model. In addition to Minnesota's integrated distribution planning requirements, there are well established Conservation Improvement Programs, integrated resource planning, and emerging performance-based incentives. Most, if not all, NWA tools can be integrated into these platforms.

Conservation Improvement Programs

Minnesota's Conservation Improvement Program requirements establish the framework for energy efficiency and certain demand response programs. CIP establishes the program structure, the measurement and verification requirements, avoided cost methodology, and the incentive structure for utilities. NWAs intersect with CIP very directly in this pilot, as existing utility energy efficiency and demand response programs were augmented to achieve peak demand savings to defer the distribution grid need.

The pilot identified that having existing programs in place helps to launch expanded efforts more quickly for a targeted NWA. Prior experience with customer communication and incentive levels reduces guess work as to how customers will respond to augmented programs. Additionally, Xcel Energy's programs are trusted by customers, and uptake is likely higher as a result. Given Minnesota's strong track record of energy efficiency and utilities' broad technology portfolios, CIP is a fitting place to further encourage cost-effective NWA projects.

However, the current CIP framework also imposes constraints on how efficiency and demand response can be deployed as an NWA. Program targets and budgets are established on a yearly basis, and ramping up budgets may require program modification approval, as well as reduce the program cost-effectiveness. Currently, benefits include the distribution deferral benefits of CIP, but only on a system average basis. NWA locations will likely have higher benefits than this system average. However, should these higher benefits be claimed within CIP based on specific locations, then the system-wide average values applied to all CIP measures would effectively double count some of these benefits, and thus would need to be adjusted. Further, CIP currently restricts some load-management opportunities from being included that could be valuable for NWA projects.

We recommend two possible approaches to modify the CIP structure to better align existing customer load programs with NWA efforts:

1. **Create a localized distribution value for cost–benefit tests.** This would augment each program's benefits with a local distribution deferral value for projects in a certain

region, and also include any bonus rebates (if applicable) in the program costs. Deferral would be a near-term benefit and not spread over the project lifetime. These additions could be considered at either the program or measure level. A downside to this approach is its potential complexity. Each chosen NWA location would have a different deferral value and a different coincidence factor that would need to be applied across each program. If this approach was taken, it would supplant the current system-wide value for all measures for distribution and transmission deferral.

2. **Ask utilities to propose a portfolio of NWA projects in CIP plans, with a bundled cost-effectiveness adjustment for the suite of measures that will be given enhanced promotion in the area.** Similar to how this pilot was structured, this approach would plan for a bundle of measures that would address the specific peak needs for a distribution project area. This NWA-enhanced delivery would have an increased overall project budget less than the deferral value of the project. In theory, this bundled approach could include piloting of additional measures beyond approved programs, provided their costs fall below the cost-effective budget. The effort of this approach scales with the number of proposed non-wires projects. The cost-effectiveness adjustment could be calculated as an average or deemed value for NWA projects, which would reduce the administrative burden of having to calculate this on an individual project basis. Similar to the first approach, if enhanced benefits were claimed for targeted NWA projects, the system-wide calculation of benefits would need to be adjusted or eliminated to avoid double-counting. Utilities could potentially opt-in to this approach, in return for being allowed to use deemed T&D benefits for NWA areas.

If NWA programs are conducted as part of CIP, it would be possible to count the spending, the savings, and potentially the net benefits of the NWA as a component of CIP. Utilities would need to create systems to identify, track, and report all NWA measures as separate from their other CIP measures. The existing incentive structure, based on shared net benefits, could be expanded to include net benefits or savings from the NWA, with appropriate measures taken to avoid the double counting of benefits that have already been attributed to CIP programs. This likely means that any system-wide calculation of distribution benefits would be eliminated and replaced by a targeted approach to claiming these benefits. Transmission benefits, which spread out over a wider area, could potentially remain as system-wide benefits of CIP.

However, if should be noted that some potential non-wires alternatives are not compatible with current CIP policies, such as battery storage, or rate structures that shift consumption to other times of the day.[30] Therefore, encouraging NWAs through CIP will not address the full suite of potential solutions.[31]

Integrated Distribution Planning Enhancements

State IDP requirements were established in 2018. Apart from Xcel Energy, which has filed two IDPs, other rate-regulated utilities filed their first IDP in 2019. Utilities are gaining experience meeting the planning requirements and stakeholders and regulators are identifying possible refinements. Given the relatively new planning requirements, large reforms to the IDP do not appear warranted at this time. However, the IDP is an important building block for non-wires projects. There are some incremental changes that the Commission could consider to expand and support a more robust analysis of NWAs.

1. **Expand screening criteria:** While the IDP requires that utilities complete an NWA analysis for distribution projects that will exceed $2 million in investment, Xcel Energy has been asked to apply additional screens to refine which distribution projects warrant consideration of NWAs. These screens have excluded projects based on mandates, asset health, and reliability, as well as limited consideration to projects planned for two to three years in the future. The use of additional screening criteria is consistent with practices in other states that use more than just a financial threshold to screen for NWA potential. However, some stakeholders assert that excluding asset health and reliability projects leaves potentially viable projects off the table.

There are other project categories that warrant consideration for NWAs. These include **expansion and new business** in which the utility is building out the grid to accommodate a new load (e.g., a new subdivision). While an NWA would not defer spending, it has the potential to lower the capacity need of the new load. As mentioned above, over the next five years, Minnesota's four rate-regulated utilities plan to spend $206 million on capacity-related projects and $268 million on new customer and new revenue projects (per their 2019 IDPs). In addition to these applications, NWAs could support the grid with **better integration and optimization of DERs** such as solar generation and EV charging. These technologies have the potential to create localized strains on the grid that can be mitigated with targeted load management.

2. **Require a more comprehensive assessment of potential NWAs:** NWAs can be composed of many different types of distributed energy resources. A complete NWA analysis would investigate a compliment of resources and select the best combination that meets the needs of the particular grid constraint. To ensure that a full suite of resources is considered for an NWA, the IDP requirements could be augmented to

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[30] However, battery storage is not currently a cost-effective approach for managing peak demand that occurs for only a small percentage of hours in the year, and rate structures that only apply to a small percentage of customers present their own challenges to implement.
[31] Note that one potential remedy for this was discussed at the Minnesota Legislature, proposed as HF 4502 and SF 4409 (Stephenson et al. 2020). This bill would allow a broader range of demand response measures, if bundled together with energy efficiency measures.

require that utilities explicitly examine resources including energy efficiency, demand response, tariffs and rates, solar and other distributed generation, storage, and grid management technologies.

3. **Explore competitive procurement:** Many states use RFPs to generate the most cost-effective NWAs and to take advantage of technical capabilities that reside in the market. While utility programs and tariffs can be a source of NWA resources, utilities could use competitive procurement processes to allow non-utility providers that have expertise to propose technologies or combinations of DERs that could prove to be a cost-effective solution. Competitive procurement can also establish performance requirements so that utilities can count on the procured resources to solve the grid constraints. As part of IDP filings, utilities could report on progress with competitive procurement to test the marketplace for innovative solutions.[32]

Integrated Resource Planning

Like distribution planning, integrated resource planning (IRP) results in a coordinated, least-cost path to meet customers' energy and capacity needs. Resource planning also requires that utilities consider the potential for DERs to meet energy and capacity needs, and compare the costs and benefits with more traditional resource additions like generating plants or power purchase contracts (Minnesota Statutes 2019). However, the time frames of the two processes are very different, as distribution planning extends out to five years, while the IRP results in a five-year action plan but examines the type, timing, and size of resource additions as far out as 20 years into the future. In addition, the distribution planning process is focused on locational needs of the distribution grid, not resource additions.

That said, there is the opportunity for the IDP and IRP to be linked and coordinated. While the analytical link between IDP and IRP is primarily conceptual at this point, energy resources that connect to the distribution grid can offset the need, or create additional need, for new energy and capacity. For example, a community solar project that reduces load may obviate the need for a distribution upgrade, as well as contribute to energy and capacity requirements for the utility. Another opportunity is to coordinate consistent forecasting between a utility's IRP and IDP, such as consistent customer load and DER forecasting methodologies. Resource planning relies on sophisticated optimization models for future scenarios, which can help improve scenario assumptions in the IDP.

Performance Incentive Mechanisms

The Minnesota Public Utilities Commission has established a framework for instituting performance metrics and possible incentives for Xcel Energy (MN PUC 2017a). This process includes a number of sequential steps to identify and establish metrics, followed by an explanation of how to calculate, verify, and report on these metrics. Xcel Energy is working with

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[32] For an example, Dakota Electric Association's 2019 Integrated Distribution Plan included extensive documentation of a vendor request for information on non-wires alternatives that was used to test the marketplace (Dakota Electric Association 2019).

stakeholders to refine how the various metrics are calculated, verified, and reported and will report on the performance metrics annually.

The work to establish any financial incentives or penalties for performance has not yet begun, with the exception of the Commission's recent decision that requires Xcel Energy to work with stakeholders and the Department of Commerce to develop a demand response financial incentive and to file a proposal by the end of the first quarter of 2021 (MN PUC 2020). While the performance incentive framework is still untested, it provides an opportunity to design a performance incentive for acquisition of NWAs. Metrics to consider for NWA performance include cost-effective alignment of generation and load, affordability, reliability, and environmental performance. In addition, demand response metrics could include the value of using load management to defer local distribution projects and mitigate additional grid costs of DER expansion.

The Commission could set guiding parameters for an incentive and ask the utility to file an incentive proposal as part of the performance-based ratemaking docket or as part of the IDP docket. Commissions in other states have invited incentive proposals as part of utility filings on NWA projects. Any incentive based on shared savings will require a methodology for determining net benefits of the NWA. As acknowledged in other states and in Minnesota, the full suite of net benefits for NWA projects has not yet been monetized, which can make a complete determination of net benefits a challenge. However, key variables can be monetized, such as the deferred cost of a project, and as such, should be included. Projects that entirely avoid a distribution upgrade will likely produce greater net benefits than a project that defers an upgrade for a period of years. A well-designed incentive could focus utilities' efforts on projects that avoid, as well as projects that defer, a grid investment.

Other Policy Opportunities

Based on the lessons of this geotargeting pilot and the review of regulatory policies in other states, this chapter concludes with some recommended steps on other policy opportunities for Minnesota.

Grid Modernization Investments

Minnesota's utilities presently operate a very safe and reliable grid. Grid modernization technologies are improving the functionality of this grid, though utilities in Minnesota are at different stages with respect to investments in the newest generation of grid control and communication technologies. Some of Minnesota's utilities are still installing SCADA at substations, others are beginning a more comprehensive rollout of AMI, while still others are planning for deployment of technologies that will enable more services for customers. The challenge for the Commission is determining which investments should advance and at what pace.

With respect to NWAs, the constraints of current planning tools and limited grid data of sufficient granularity limits the consideration and implementation of NWAs. The lack of clarity about the shape, timing, and location of customer loads and other demand side behaviors constrains the evaluation and design of NWAs. Planning tools need to plan far enough into the future, with sufficient accuracy, to get NWA projects ready to meet the grid needs. As such, the Commission should recognize that without grid advancements and new planning tools, the study and application of NWA will be constrained and, to some degree, inefficient and imprecise. The Commission should consider the expanded analysis and implementation of NWAs as one benefit associated with the investment of significant grid modernization capital.

Pilot Projects

The Minnesota Commission has approved a number of pilots that are exploring how grid modernization, time varying rates, and new technologies will function for customers and the utility's system. These include pilots on residential time of use rates, electric vehicle charging and rate design, and public EV charging. While the pilots underway are not explicitly NWA pilots, each has elements that will provide lessons with respect to the distribution grid and customers' interaction with new technologies and rates. These technologies and rate structures may influence the design of future NWA projects.

This pilot offered many lessons, as articulated in the previous sections. Dynamic grid conditions, changing customer loads, the introduction of distribution generation, and uptake of augmented energy efficiency offerings were just some of the variables that provided insights into how an NWA can work in the "real world."

Other states that have initiated NWA policies have required utilities to start working on these important lessons by implementing at least one pilot NWA project in their service territories. This requirement advances the understanding of the opportunities and challenges presented by an NWA project; allows communication and collaboration with stakeholders; and exposes what additional regulatory approaches, planning methodologies, and grid investments may be needed to improve success.

While each utility's IDP examines whether there are candidate distribution projects that could be deferred or avoided by NWAs, no NWA projects have come forward out of the IDPs for any of the Minnesota utilities to date.[33] The Commission should consider whether requiring a pilot NWA project from each utility could advance the planning and implementation of NWA projects in constructive ways, much as this geotargeting pilot did for Xcel Energy.

Data Access

Data access and security is a complex topic, but fundamental to a modernized grid with full DER compatibility. As states advance NWA projects, making some level of grid and system data

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[33] In their comments on Xcel Energy's 2019 IDP, the City of Minneapolis (Attachment A page 9 Xcel Energy Reply comments) requested an NWA pilot proposal by November 2020 (City of Minneapolis 2020). In response, Xcel Energy recently filed a pilot concept proposal as part of the company's utility stimulus proposal. The project proposal is targeting the planned METRO Blue Line Extension (Bottineau) light rail transit.

available to stakeholders and DER providers will be a key ingredient for robust projects. Ideally, developers and customers could bring forward solutions to grid constraints if these constraints were identified and defined in ways that were useful for analysis of alternatives. Data system portals that other states require are one vehicle to make useful data accessible for grid solutions. However, it is unclear if such system-wide (versus project-specific) data are necessary.

At present, there are no clear determinations as to what grid data would be public. It has been at the discretion of the utility to determine which data can be publicly shared and which cannot. Typically, utilities err on the side of caution to ensure both physical security and cybersecurity. The Commission has taken recent steps to evaluate public access to grid data. In Xcel Energy's hosting capacity docket (19-685), the Commission's July 2020 Order requires Xcel Energy to "further explore and explain issues related to whether the result of Xcel Energy's hosting capacity analysis should be redacted for… privacy and security concerns."[34] The Commission took the additional step of seeking public comments and discussion on "grid and customer security issues related to public display or access to grid data which includes, but is not limited to distribution grid mapping, aggregated load data, and critical infrastructure." These initial efforts will help advance the policies regarding data availability as well as the format and timing of data updates. These Commission actions are a necessary step to ensure an interactive, dynamic, and efficient grid. Given the complexity of data security and access and the importance of this data to the efficient development of NWAs, these efforts will need to continue as data collection, analysis, and reporting tools improve.

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[34] Hosting capacity analysis is performed by the utility to identify locations on the distribution grid where there is sufficient grid capacity to accept new distributed energy projects. This data is used by developers and customers to place these projects in optimal locations.

CONCLUSION

Non-wires alternatives are a cost-effective tool to increase the use of clean electricity technologies while reliably deferring investments in grid expansion. While Minnesota has relatively low distribution grid expenditures today, peak demand is predicted to increase due to population growth, electrification of end uses like transportation and space heating, and warmer temperatures. This pilot demonstrated that adopting longer time horizons and multiple scenarios for planning forecasts will allow distribution planners to integrate non-wires alternatives, therefore saving money and advancing clean energy throughout the state.

Demand side NWAs are feasible within reasonable budgets and timescales. This pilot tested a small scale NWA application, and successfully saved 576 kW of peak electricity across two small communities, higher than the pilot goal of 500 kW. This was the result of enhanced incentives, increased and geotargeted marketing, as well as a higher than average baseline participation in commercial lighting programs. Participation was also boosted by smart thermostat incentives which were available upon enrollment in a demand management program. The pilot cost came to $163,000, within the estimated range of a one-year deferral.

Our pilot found that the incentive value of approximately $300 per kW was enough to drive needed participation within the project timeframe. However, more work is needed to test the effectiveness of different incentive levels along with other motivating factors. In addition, 11-12% of incentives went to participants on circuits outside the at-risk area. Project sites that don't overlay cleanly with jurisdictional boundaries will need to apply more stringent eligibility criteria and consider the implications for marketing and customer satisfaction.

Demand response is a valuable resource when better integrated with distribution operations. In addition to energy efficiency achievements, the pilot site had enough existing residential enrollment in demand response to avoid the need for a capacity upgrade entirely. We found that while demand response appears valuable as an existing resource to lower distribution demand peaks, work is needed to integrate with the system-wide deployment and ensure customers remain satisfied with program participation.

In addition, demand response has a role in integrating local solar. The addition of 30 MW of community solar at the pilot site had a very dramatic impact on the net load profile of these local circuits. It lowered the load at risk, but also shifted the peak to later in the day and created additional variability, especially during the dynamic weather events that followed hot weather. Demand response can help smooth the loss of solar output during a weather event, but more work is needed to integrate and test the real-time interaction across this bundle of DERs.

Distribution planners need more tools to accurately model non-wires resources in their forecasts. This pilot helped illuminate existing barriers to integrating NWAs into distribution planning. One current challenge is the lack of granularity of the timing and duration of localized peaks, as well as the characteristics of DER solutions at the scale of distribution planning. As loads aggregate over more and more transformers and substations, they mirror system peaks.

However, at the feeder level, loads often closely reflect the underlying customer mix. This barrier will be reduced as advanced metering increases availability of interval data.

In addition, distribution planners need realistic models for the time horizons required to stand up non wires solutions. This pilot used existing “off the shelf” energy efficiency and demand response combined with a territory-wide pilot for smart thermostats, which compressed the time needed for upfront planning. Even as such, the pilot timeline was extended from six months to one-year. Other types of DERs, such as solar or storage, can scale more quickly but may face additional planning barriers like siting and interconnection. A two-year cycle to identify needs and deploy solutions is more feasible.

Minnesota has a modest technical potential, but this is expected to increase. With current growth forecasts and distribution system expenditures, we calculated a low to modest potential for non-wires alternatives in Minnesota, estimated at between one and four million dollars per year. That said, there are large investments on the horizon to manage peak demand from new loads, such as those from the electrification of heating and transportation. Currently, these costs are not in distribution budgets. As distribution planners move toward more proactive consideration of end-use electrification, NWA should be considered as a tool to mitigate costs.

Minnesota has numerous existing policy frameworks that can support the use of cost-effective non-wires technologies. Many states, including Minnesota, have established regulatory policies to advance the use of NWAs as cost-effective solutions to distribution system constraints. This progress with deploying NWAs demonstrates that in many jurisdictions, the fundamental building blocks for efficient study and use of NWAs are being put in place and improving with time. These building blocks are coincident with many other advancements that are occurring in the distribution space: advanced planning requirements and tools; grid technologies that improve understanding of grid needs with respect to time and location; sophisticated tariffs and price signals that shape customer behavior; deployment of a variety of DERs; and grid data that can inform investments to improve reliability and resiliency.

Minnesota’s regulatory framework contains the essential elements to advance the study and use of NWAs. In particular, the IDP requirements are the principal vehicle for how NWAs will be considered alongside traditional distribution system investments. Conservation Improvement Programs offer a customer participation and utility incentive framework to apply more targeted use of energy efficiency and demand response specifically. And the performance incentive process offers room to encourage the use of NWAs based on their net benefits.

The driver for non-wires alternatives in the distribution system of today is not wholly to reduce costs, which are comparable to what would be required for a wires investment. Instead, a core benefit is to leverage existing spending to grow solutions that further enhance customer benefits. It is also to increase familiarity with DER solutions should more expensive investments be needed in the future. Minnesota’s utilities can increase their experience implementing non-wires alternatives to be ready when larger projects come across the wire.

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