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February 25, 2019

Mr. Daniel Wolf, Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

Re: ***In the Matter of Distribution System Planning Requirements for Xcel Energy***
Docket No. E002/CI-18-251

Dear Mr. Wolf:

Enclosed and e-filed in the above-referenced matter please find *Corrected Comments of the Office of the Attorney General*.

These Corrected Comments address several minor changes to the February 22, 2019 Comments filed by the OAG in this docket. In particular, the February 22 Comments did not include responses to information requests that were referenced in the Comments and were intended to be attached as exhibits to the Comments. These Corrected Comments include as exhibits these responses to information requests; and the numbering of these exhibits has been added to the footnotes. In addition, several minor typographical errors have been corrected.

These Corrected Comments are late-filed under Minn. R. § 7829.0420, but the OAG respectfully requests that the Commission accept this addition to the record. First, the Corrected Comments provide additional information into the record, in the form of responses to information requests, from which all parties can benefit. Second, no party has been prejudiced because the OAG has made no material changes to the February 22 Comments.

Sincerely,

s/ **Joseph A. Dammel**

JOSEPH A. DAMMEL
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Re: ***In the Matter of Distribution System Planning Requirements for Xcel Energy***
Docket No. E002/CI-18-251

STATE OF MINNESOTA)
) ss.
COUNTY OF RAMSEY)

I hereby state that on 25th day of February, 2019, I filed with eDockets ***Corrected Comments of the Office of the Attorney General—Residential Utilities and Antitrust Division*** and served the same upon all parties listed on the attached service list by e-mail, and/or United States Mail with postage prepaid, and deposited the same in a U.S. Post Office mail receptacle in the City of St. Paul, Minnesota.

s/ Judy Sigal
Judy Sigal

Subscribed and sworn to before me
this 25th day of February, 2019.

s/ Patricia Jotblad
Notary Public

My Commission expires: January 31, 2020.

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CORRECTED

STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

Dan Lipschultz	Vice Chair
Matt Schuerger	Commissioner
Katie Sieben	Commissioner
John Tuma	Commissioner

In the Matter of Distribution System Planning Requirements for Xcel Energy

E002/CI-18-251

COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL

The Office of the Attorney General—Residential Utilities and Antitrust Division ("OAG") submits the following Comments in response to Northern States Power Company's ("Xcel" or "the Company") 2018 Integrated Distribution Plan ("IDP"). These Comments provide a series of recommendations for the Commission to consider for future IDP filings. They are presented individually by topic, and then presented in summary in the conclusion.

INTRODUCTION

The Commission explained the objectives of the IDP process in its August 30, 2018 Order Approving Integrated Distribution Planning Filing Requirements for Xcel Energy. The IDP is intended to:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products and services, with opportunities for adoption of new distributed technologies; and,
- Ensure optimized use of electricity grid assets and resources to minimize total system costs.

The IDP does not, on its own, achieve any of these goals. What the IDP *does* do is provide the Commission and other parties with information that is necessary to move forward on those goals.

It is sometimes difficult to see what specific use the IDP information can be put to, but at the very least it provides benefit by increasing the level of information shared between the utility, the Commission, and other parties. For example, the IDP filing has helped OAG staff familiarize themselves with more aspects of how Xcel develops budgets and plans distribution investments. The IDP similarly provides information about Xcel's plans to expand distributed resource forecasting, and develop new grid technologies and software solutions. This information may be of specific use in future proceedings, but even if it is not, the regulatory system benefits by increasing the knowledge base of those who participate. As the electric industry becomes more complex and interconnected, it will be necessary for regulators and parties, like the OAG, to keep pace by deepening their understanding of the utility. The IDP is a tool that can be put towards that objective.

In 2016, ICF International presented a report to the Commission about distribution planning in Minnesota.[1] The ICF report suggested using walk, jog, run framework to think about distribution planning. The "walk" phase, associated with low distributed energy resource ("DER") adoption, would focus on refreshing aging infrastructure and integrating it with advanced grid technologies. The "jog" phase would be integrating and optimizing more DERs, and developing more distribution platform capabilities. The "run" phase would involve multi-party transactions and market functionalities for DERs. Minnesota is in the early stages of both integrated distribution planning and DER adoption, and the appropriate focus in these early

[1] ICF INTERNATIONAL, INTEGRATED DISTRIBUTION PLANNING, PREPARED FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION 2, https://www.energy.gov/sites/prod/files/2016/09/f33/DOE%20MPUC%20Integrated%20Distribution%20Planning%208312016.pdf.

stages is on improving information about Xcel's efforts to refresh aging infrastructure, and developing and integrating advanced grid technologies. While it can surely be improved in the future, Xcel's IDP filing is an important step towards the future.

In the following sections, these Comments will explain why the Commission should accept the IDP filing in Section I. In Section II, these Comments will discuss the areas of the IDP that the OAG found particularly useful, and discuss a few ways that they could be enhanced in the future. Section III will briefly discuss timing issues, and Section IV will address the relationship between the IDP filing and the Biennial Grid Modernization Certification Process authorized by Minn. Stat. § 216B.2425. The Conclusion will collect all of the recommendations in these Comments in a single location for convenience.

I. THE COMMISSION SHOULD ACCEPT THE IDP WITHOUT MAKING ANY DETERMINATIONS OF PRUDENCE OR REASONABLENESS.

In general, Xcel has complied with the IDP filing requirements, and for that reason the Commission should accept the IDP filing. The Commission should specifically state, however, that it is not making any decisions about the prudence or reasonableness of Xcel's plan. Xcel will have the opportunity to present specific cost recovery requests in the future, and the Commission should explicitly reserve decisions on prudence, reasonableness, and cost recovery until that time. The OAG reserves its right to challenge any investments discussed in this IDP at a later point.

The Commission should also consider what would happen if or when investments previewed in an IDP raise concerns. If, in the future, a utility includes a planned investment in an IDP that the Commission has concerns with, it is not entirely clear what should happen. On one hand, the Commission may be inclined to withhold judgment until the utility makes its formal request for cost recovery, because the utility could assemble better information and arguments, or even take a different path entirely. On the other hand, waiting to address concerns may not be efficient. Requiring an IDP filing and identifying concerns, but only addressing them after money has been spent does not seem to be an efficient use of time or resources for anyone involved.[2] There is some merit in both of these positions, which presents a difficult question. These Comments do not offer a solution on this issue, but recommend that the Commission and its Staff consider what would happen so that expectations are set before problems arise, rather than after. The IDP brings the Commission into the utility's planning at an earlier stage than it has been in the past, and the Commission will need to decide whether and how it wishes to provide instruction in that context.

The Commission should:

- Accept the IDP filing, without any determinations as to prudence or reasonableness.

II. KEY AREAS IN THE IDP.

The IDP includes a significant amount of information and much of it is very helpful. This Section will highlight those areas that the OAG found to be most useful, and identify changes or modifications that the Commission should consider for future IDP filings.

A. DISTRIBUTION BUDGETS.

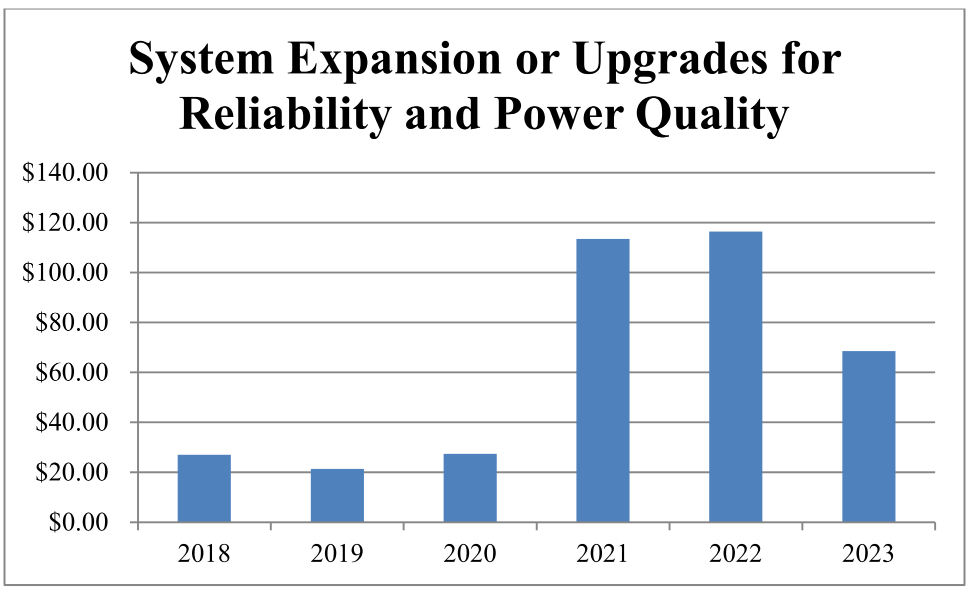
The Commission typically only receives information about utility budgets during a rate case. Even when regulated utilities file budget information, it has been the OAG's experience that the budget information included in the rate case often receives lower priority compared to reviewing specific cost recovery proposals. The IDP provides a good opportunity to learn about

[2] It is also not clear that it would make sense to "reject" an IDP filing that included concerning investments, as the IDP filing may be an accurate reflection of what the utility is planning to do, even if regulators are other parties are not satisfied with those plans.

Xcel's budgeting process and the costs it has included in the next five years of its distribution budget.

One takeaway from the Distribution Capital Expenditures Budget described on pages 14 and 15 of the IDP is that Xcel is planning a significant distribution investment in 2021 and 2022. The overall distribution budget increases from $230.3 million in 2020 to $322.3 million in 2021, and $325.1 million in 2022. The significant increase comes almost entirely from the System Expansion or Upgrades for Reliability and Power Quality category, which increases from $28 million in 2020 to $113.4 million in 2021 and $116.4 million in 2022. It then reduces to $68.4 million in 2023, but it is worth noting that this level is still more than double the average cost from 2018 to 2020.

Figure 1[3]



This increase is relatively large—the $113.4 million in 2021 represents 35 percent of the total distribution capital expenditures budget. It is also worth noting that the increase in this one cost category explains nearly all of the much larger budget projected for 2021 and 2022. The OAG

[3] IDP at 14–15.

requested additional information on this spending, which Xcel appears to refer to as the Incremental Customer Investment, but Xcel stated that it did not have any more information to share at this time.[4]

There is no indication at this time that there is anything unreasonable about Xcel's plan to increase the budget in the years it has described, but the increase is noteworthy. The Commission should request that Xcel provide an update about the purpose for the increase when more information is available. The OAG is open to suggestions on the timing or trigger for sharing such information, and requests that Xcel respond in its Reply Comments.

- Order Xcel to provide more information about the increase to System Expansion or Upgrade for Reliability and Power Quality beginning in 2021.

B. RISK EVALUATION.

While discussing its distribution budgeting process, Xcel provided information about how it identifies distribution projects on pages 52 through 65. One section of particular interest was the information about risk analysis described on pages 54 and 55. Xcel states, "One of the main deliverables of distribution planning's annual analysis includes a detailed list of all feeders and substations for which a normal overload (N-0) is a concern."[5] A normal, or N-0, overload means that the feeder has more demand than its maximum capacity under normal conditions. Xcel also creates an "N-1 Contingency Analysis."[6] N-1 identifies situations where losing one feeder could cause other overloads on another.[7] In its 2018 to 2022 planning process, Xcel identified the following risks across NSPM:

[4] Xcel Response to OAG Information Request 67, Exhibit 1.
[5] IDP at 54.
[6] *Id.* at 55.
[7] Xcel provided more explanation about N-1 capacity in response to OAG Information Request 14, which is attached as Exhibit 2.

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Table 1
Distribution Planning Risks[8]

	Feeders	Substation Transformers
N-0 Normal Overloads	70	16
N-1 Contingency Risks	408	122

Xcel further explained that its engineers develop solutions to N-0 normal overloads of greater than 106 percent, and N-1 conditions that place more than 3 Mega Volt Amps ("MVA") at risk.[9] Xcel explained that these thresholds were developed based on a variety of factors in response to OAG Information Request 16.[10]

After Xcel develops potential solutions to these risks, they are entered into a software program that creates a numerical risk-ranking for each risk. Xcel produced the risk ranking results in response to OAG Information Request 18,[11] and explained how it develops the risk ranking scores in OAG Information Request 18.1.[12] Xcel provided more information about how it uses the risk ranking to select distribution projects in OAG Information Request 68.[13] This risk-ranking should be provided in future IDP filings. It is a useful tool to better understand the risks to the distribution system, and how Xcel is responding to them.

The risk-ranking information can be even more useful when it is combined with other information. Specifically, the OAG asked Xcel to provide the load factors of its feeders and substation transformers, which are used to identify distribution system risks. Combining that information with the risk-ranking analysis, *and* identifying which feeders or substation

[8] IDP at 55; Xcel Response to OAG Information Request 69, Exhibit 3. While responding to OAG information requests, Xcel discovered that it had made some errors in the IDP filing, and updated the number of N-0 Normal Overload feeder risks from 56 to 70.
[9] MVA is a measurement of apparent power, which considers both resistive load (measured in watts), and reactive load (measured in volt amps reactive—VARs).
[10] Xcel Response to OAG Information Request 16, Exhibit 4.
[11] Xcel Response to OAG Information Request 18, Attachment A, Exhibit 5.
[12] Xcel Response to OAG Information Request 18.1, Exhibit 6. The OAG is providing only the public version of Xcel's response with these Comments.
[13] Xcel Response to OAG Information Request 68, Exhibit 7.

transformers have work planned during the planning period, would produce a useful document for tracking Xcel's distribution planning. The information could be combined in a single document similar to this example:

Figure 2
Example of Combined Distribution Feeder Information

Feeder	Forecasted Net Demand	Capacity	Forecasted Percent Load	Forecasted Load at Risk	Risk Score	$$$ Investment	Description of Investment
A							
B							
C							

A single spreadsheet including this information would work towards several of the goals of the IDP program. It would allow the Commission and parties to understand how Xcel identifies and responds to risks on its system, track the utility's performance over time, and better understand how its investment decisions are related to current capacity risks and growing distributed resource needs.[14] Xcel was able to provide the OAG with much of this information in different information requests, so it does not appear that it would be labor-intensive to combine it together for future IDP filings.[15]

Presenting this information in future IDPs would be consistent with the "walk" stage from the ICF International report presented to the Commission, which suggests gathering information about infrastructure replacement investment.[16] Obtaining information in this way will help the Commission and parties understand how Xcel makes its investment decisions, and how those decisions relate to choices about advanced grid capabilities.[17] As ICF stated,

[14] Based on information provided from Xcel, it might make more sense to use "normal loadability," instead of nameplate capacity, for the capacity in this data set in the future.
[15] The OAG has not filed the information with these comments because Xcel has marked it as Trade Secret.
[16] ICF INTERNATIONAL, INTEGRATED DISTRIBUTION PLANNING, PREPARED FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION 2, https://www.energy.gov/sites/prod/files/2016/09/f33/DOE%20MPUC%20Integrated%20Distribution%20Planning%208312016.pdf.
[17] Gathering information about which feeders require capacity upgrades and how Xcel ranks their relative risk may also assist in "locational value assessments," and identifying where NWA may be useful to address planning needs. *See id.*

"[D]istribution system planning begins with a review of current infrastructure (including prior smart grid investments) and performance."[18]

In the future, it may be possible to combine this information with more hosting capacity information, as well as information about the estimated growth of DERs. In combination, this information can identify future concerns for DER penetration, and more quickly assess how Xcel is responding to them. The Interstate Renewable Energy Council advocates a similar approach, and states:

> This data can be used in two ways. First, it can be used on an aggregate level as an input to inform the remainder of the utility's distribution planning effort, giving the utility the opportunity to identify and prioritize the possible upgrades to distribution infrastructure that would be required to accommodate anticipated DG growth . . . . Second, it can be used on a project-by-project basis to inform the interconnection screens and procedures that are applied to each facility individually.[19]

While it does not appear that Xcel's forecasting capabilities are in place yet, in the future they may be able to work towards these objectives.

The Commission should:

- Order Xcel to provide the results of its annual distribution investment risk-ranking, and a description of the risk ranking methodology, in future IDPs.

- Order Xcel to provide information on forecasted net demand, capacity, forecasted percent load, risk score, planned investment spending, and investment summary information for all feeders and substation transformers, in future IDPs.

C. LONG-RANGE AREA STUDIES.

Xcel provided information about long-range area studies on pages 58 to 59. Long-range area studies are longer-term and wider-scope mitigation plans for distribution risks. In response

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[18] *Id.* at 6.
[19] INTERSTATE RENEWABLE ENERGY COUNCIL, INTEGRATED DISTRIBUTION PLANNING CONCEPT PAPER: A PROACTIVE APPROACH FOR ACCOMMODATING HIGH PENETRATIONS OF DISTRIBUTED GENERATION RESOURCES 12 (May 2013), *available at* https://irecusa.org/regulatory-reform/grid-modernization/.

to discovery, Xcel confirmed that it has conducted three long-range studies in recent years: for Hollydale, Woodbury, and Belle Plaine.[20] Xcel confirmed to the OAG that Attachment E to the IDP is a copy of the Hollydale long-range study, which was filed by Xcel in Docket E-999/CI-15-556. It may be useful for the Commission and other parties to be kept aware of long-range studies, as they represent broader approaches to the challenges that Xcel faces along with potentially larger costs. In the future, the Commission should require Xcel to file any long-range studies that it has conducted during the year with future IDP filings. It would also be helpful if Xcel could provide more information in its Reply Comments discussing how long-range area studies are related to the non-wires analysis it is required to conduct for future IDPs.

The Commission should:

- Order Xcel to file any long-range distribution studies it had conducted in the past year in future IDPs.

D. GRID MODERNIZATION COST-BENEFIT ANALYSES.

Xcel is required to "provide a cost-benefit analysis" for "each grid modernization project in its 5-year Action Plan."[21] Xcel indicates that its 5-Year Action Plan includes projects for Advanced Metering Infrastructure ("AMI"), a Field Area Network ("FAN"), and Fault Location, Isolation, and Service Restoration ("FLISR").[22] The OAG takes no position on the merits of these investments at this time and reserves its right to do so in the future. These Comments focus on whether the cost-benefit analysis that Xcel provided satisfies the requirements of the IDP.

[20] Xcel Response to OAG Information Request 19, Exhibit 8.
[21] IDP Filing Requirements D.2.
[22] IDP at 20.

Cost-benefit analyses are very important for grid modernization proposals since the costs can be significant—it appears that Xcel is planning to invest more than $500 million in AMI, FAN, and FLISR over the next five years.

The benefits can also be difficult to measure because they depend, in part, on whether utilities operate advanced grid investments efficiently. One recent publication concluded that, "[I]t is possible to pay for the investment required to prepare the grid for future challenges out of the operational benefits and savings the smart grid can deliver," but noted that "the benefits utilities are securing from their smart grid investments are highly variable and, frankly, suboptimal in a disturbingly high percentage of deployments."[23] The author goes on to conclude that, "Investments in smart equipment do not directly create value; the amount of value customers receive is determined by how well a utility uses the data and capabilities the equipment makes available."[24] As a result, utilities may not have the incentive to maximize the potential benefits of advanced grid technologies, or to identify the possible benefits to regulators. These challenges emphasize how important it is to estimate the costs and benefits as rigorously as possible because.

Even specific components of grid modernization proposals can carry identifiable costs. For example, one publication estimates that it may cost as much as $30 to $50 to install a remote disconnection switch on each AMI meter, but that the remote disconnection capabilities would never be used on 80 percent of the meters.[25] In order to evaluate Xcel's eventual AMI proposal, each capability of the new technology should be compared to the costs for that specific capability: in this example, will the benefits of remote disconnection outweigh the costs of

[23] Paul Alvarez, Smart Grid Hype & Reality at 19.
[24] *Id.* at 239.
[25] *Id.* at 100.

installing remote disconnection switches over time? And how do those benefits compare to concerns about making it easier for utilities to disconnect customers? In order to evaluate complex investment decisions, it will be necessary to look at the details—and in order to look into details, the Commission needs detailed cost-benefit analyses.

The cost-benefit analysis that Xcel provided is located on pages 148 to 150 of the IDP filing. Xcel states that it estimates the total capital cost of AMI, FAN, and FLISR as "between $632 and $822 million."[26] Xcel further states that it estimates a "range of benefit-to-cost ratios" of 0.50 to 0.80 for AMI (and FAN, which Xcel characterizes as a component of AMI), and 2.50 to 3.00 for FLISR. Xcel states that the total cost-benefit ratio for the three projects is between 0.70 and 1.10. In addition to these figures, Xcel presents a brief list of non-quantifiable benefits that could not be captured in its cost-benefit analysis. Xcel also presents its argument that the ultimate decision for AMI, FAN, and FLISR should be based on more than a numerical cost-benefit analysis.

The OAG agrees that grid modernization plans must be evaluated on more than a numerical cost-benefit analysis, and also agrees that not all meritorious grid modernization plans will necessarily provide a numerical benefit-cost ratio greater than 1.0. That said, carefully conducted cost-benefit analyses should be a core part of any decision to move forward with grid modernization projects—it would be imprudent to make any decisions without a hard look at what the benefits and costs will be, even if some of those benefits are not quantifiable.

The two pages of explanation that Xcel provided for its cost-benefit analysis are not sufficient. Xcel did not share any supporting information for the cost estimates it provided for the grid modernization projects, or the cost-benefit ratios it reported. It did not provide

[26] IDP at 148.

explanations for any of the non-quantifiable benefits that it identified. Given the short turn-around for this first IDP filing, the OAG asked Xcel whether it intended to provide more or different information in future plans. In its response to OAG Information Request 63, Xcel stated that the IDP only requires it to discuss the issues listed in part D.2 to the extent that Xcel finds them to be appropriate, and that it did not provide more information because it was not yet seeking cost recovery for the AMI, FAN, or FLISR.[27] That position is not consistent with the intent of the IDP, which requires that cost-benefit analyses be provided for every investment included in the 5-year Action Plan.[28]

Despite its position that it only had general information for a cost-benefit analysis, Xcel was able to provide substantially more information in response to OAG discovery requests. In response to OAG Information Request 41, Xcel provided supporting information for the $632 to $822 million cost estimate, and the benefit-to-cost ratios that it provided in the IDP.[29] In regard to the cost estimates, Xcel explained that its cost estimates were based primarily on internal expertise from work done for Public Service of Colorado.[30] Xcel also broke out the cost estimates into capital and O&M categories, although did not provide more detailed cost component estimates.[31] Xcel further explained that the estimates included $153 million in contingencies in its low-end cost estimate of $636 million,[32] representing a contingency of around 25 percent on the low-end estimate. Xcel did not break out the difference between the low-end and high-end estimates, but it appears to be related to its decision to build in "$150

[27] Xcel Response to OAG Information Request 63, Exhibit 9.
[28] IDP Filing Requirements D.2.
[29] Xcel Response to OAG Information Request 41, Exhibit 10.
[30] *Id.*
[31] *Id.*
[32] It was not immediately clear why the $636 million figure reported in OAG Information Request 41 is different from the low-end estimate of $632 million included in the IDP filing, but the figures are not materially different.

million of capital and $36 million of O&M in the AMI project cost" for "emerging technology," should additional projects arise that are cost-effective.[33]

Xcel also provided more detail about its cost-benefit ratios in response to OAG Information Request 41. Xcel provided information about the AMI and FAN projects combined:

Figure 3
Xcel Cost-benefit Information on AMI/FAN[34]

Table 2: AMI/FAN Estimated Cost-Benefit NPV Ratio
(millions)

Category – Benefit/Cost	Estimated Cost/Benefit NPV
Benefits	**$403**
Operational	$134
Customer	$269
Costs	**($586)**
O&M	($168)
Change in Capital Revenue Requirement	($418)
Cost-Benefit NPV Ratio	***0.69***

Table 3: AMI/FAN – Estimated Benefits NPV
(millions)

Benefit Area	NPV
Reduction in Meter Reading Costs	$39
Reduction in Field and Meter Services	$29
Reduction in Unaccounted for Energy	$29
Improved Distribution System Spend Efficiency	$0.04
Outage Management Efficiency	$2
Customer Impacts	$303
Total Estimated Benefits NPV	***$402***

These tables indicate that Xcel estimates the Net Present Value of all benefits for AMI and FAN to be $402 million, while it estimates costs to be $586 million. It is worth noting that the vast majority of benefits are related to $303 million in "Customer Impacts," which are not defined.

[33] *Id.*
[34] *Id.*

The OAG issued supplemental discovery requesting an explanation about the "Customer Impacts" benefit category, and Xcel explained that the benefits include:

- Reduced consumption on inactive meters;
- Reduced uncollectibles / bad debt;[35]
- Reduced outage duration;
- Carbon dioxide reduction;
- Drive-by meter reading avoided cost; and,
- Critical Peak Pricing.[36]

Xcel did not provide a breakout of the estimated benefits.

In a separate discovery response, Xcel explained that the "improve distribution system spend efficiency" was related to "efficiency gains associated with managing reliability, asset health, and capacity needs" as a result of improved information from AMI.[37] Xcel did not provide an explanation about how it calculated the $0.04 million cost-benefit for the category.

Xcel also provided information about FLISR cost-benefits in response to OAG Information Request 41.[38] Xcel stated that the FLISR program would have $88 million in net present value ("NPV"), but produce $268 million in NPV benefits. Of those benefits, $251 million would be related to reduced customer minutes out—a calculation that is susceptible to many types of assumptions, and is likely to be disputed in future cost recovery filings. The information that Xcel provided is reproduced in Figure 4 for convenience:

[35] It is worth recognizing that the benefit from reduced uncollectibles would probably come from increased disconnections.
[36] Xcel Response to OAG Information Request 41.1, Exhibit 11.
[37] Xcel Response to OAG Information Request 41.2, Exhibit 12.
[38] Xcel Response to OAG Information Request 41, Exhibit 10.

CORRECTED

Figure 4
Xcel Cost-benefit Information on FLISR[39]

Table 4: FLISR Estimated Cost-Benefit NPV Ratio
(millions)

Category – Benefits/Costs	Estimated Cost/Benefits NPV
Benefits	**$268**
Operational	$17
Customer	$251
Costs	**($88)**
O&M	($6)
Change in Capital Revenue Requirement	($82)
Cost-Benefit NPV Ratio	***3.04***

Table 5: FLISR – Estimated Benefits NPV
(millions)

Benefit Area	NPV
Patrol Time Reduction	$17
Customer Minutes Out – CMO Savings	$251
Total Estimated Benefits NPV	***$268***

Xcel claims that its FLISR program would produce benefits for customers, but its calculation relies on uncertain assumptions about the value of customer minutes out.

Xcel also provided five pages of narrative description about the non-quantifiable benefits that should be considered along with its grid modernization proposals in response to OAG Information Request 42.[40] The OAG takes no position on the merits of the benefits that Xcel discusses at this time, except that it is reasonable to consider non-quantifiable benefits along with

[39] *Id.*
[40] Xcel Response to OAG Information Request 42, Exhibit 13.

a strong cost-benefit analysis, and that this discussion should have been included in the IDP filing.

All of the information that Xcel provided in response to the OAG's information requests was information that Xcel had at the time it filed the IDP. That information should have been included. Xcel correctly identifies that this proceeding does not raise cost recovery questions, and that cost-benefit analyses might change as it learns more about the projects. But Xcel should still provide the best information it has in order to comply with the IDP. The purpose of the IDP is to provide more transparency into Xcel's planning, and to ensure that Xcel is planning *reasonably*. It does not make sense for Xcel expend its ratepayer-funded resources developing projects that will not produce more benefits to ratepayers, even if non-quantifiable, than costs. Xcel should be prepared to demonstrate that it is considering costs and benefits throughout the entire life of a project, and not creating a new analysis only when it requests cost recovery. It is also somewhat concerning that Xcel appears to interpret the IDP requirements to allow it to ignore the cost-benefit analysis requirement when it wishes.

The Commission should:

- Order Xcel to provide a cost-benefit analysis for each grid modernization project in its 5 year action plan, based on the best information it has at the time and including a discussion of non-quantifiable benefits and all supporting information.

E. INTEGRATED VOLT-VAR OPTIMIZATION.

One advanced grid project that may produce customer benefits is Integrated Volt-Var Optimization ("IVVO"). Xcel has an obligation to provide its customers with service at 120 volts, plus or minus 5 percent, based on standards from the American National Standards Institute.[41] IVVO is a suite of tools that can help the utility provide this voltage more efficiently

[41] *See* Xcel Response to OAG Information Request 49, Exhibit 14.

across its system. For example, IVVO can help the utility control for voltage drop. Xcel sets an initial voltage for each feeder at the substation, but each feeder experiences some level of voltage drop—a reduction in voltage, for any number of reasons. To account for this voltage drop and ensure that every customer on a feeder receives service at a minimum of 114 volts (120 volts – 5%), Xcel sets the voltage at 123 volts.[42] Setting the voltage at a lower level could produce several system benefits, including reduced system peak demand, reduced line losses, and reduced energy consumption, as long as it still delivers service within the acceptable range. IVVO is a set of tools that can be used to control voltages in order to achieve those benefits.

IVVO has proven results. According to Greentech Media, "Peak demand reductions of 2.5 percent are common, translating into potentially significant deferred generation capacity savings."[43] The same article indicates that "line loss reductions of more than 10 percent are common," and that "annual energy reductions of . . . 1 to 3 percent are . . . typical."[44] In fact, Xcel has found that reducing the average voltage from 121 volts to 116 volts full-time would yield energy reductions of 2.7 percent on average, in its SmartGridCity study in Colorado.[45] Xcel is planning to roll out IVVO for PSCO in the near future,[46] and the Advanced Distribution Management System that Xcel has received approval to implement has the capability to operate several modes of IVVO.[47]

Despite these potential savings, Xcel indicates that it does not believe that conservation voltage reduction—a core component of IVVO—is worth pursuing in Minnesota, for several

[42] *Id.*
[43] Voltage Management: A Hidden Energy Efficiency Resource, Kelly Warner and Ron Willoughby, Greentech Media, May 7, 2013, https://www.greentechmedia.com/articles/read/voltage-management-a-hidden-energy-efficiency-resource#gs.Uwxh0c7S.
[44] *Id.*
[45] SmartGridCity Demonstration Project Evaluation Summary, Xcel Energy, Oct. 21, 2011, https://www.smartgrid.gov/files/SmartGridCity_Demonstration_Project_Evaluation_Summary_201109.pdf.
[46] IDP Filing at 168.
[47] *Id.*

reasons. Xcel states that it already performs a form of conservation voltage reduction from its SmartVAr program. In response to OAG Information Request 51, however, Xcel appears to indicate that IVVO may produce superior results.[48] In the IDP, Xcel states that differences in feeder design and climate between Minnesota and Colorado indicate that performance would not be as strong in Minnesota. In response to information requests served by the OAG, however, Xcel stated that it had not performed any studies on the impact of climate for conservation voltage reduction in response to OAG Information Request 52,[49] and that it had no direct comparison of customer density between PSCo and NSPM.[50]

Xcel should provide some more information about IVVO in its Reply Comments. Specifically, the OAG would like Xcel to discuss:

- Discuss whether it is possible to operate all four of the IVVO modes at the same time, the comparative benefits of different combinations if it is not, and what reason there would be to not activate all modes if possible;

- Provide more specific information about the timeline for investigating IVVO, along with the timeline for AMI deployment and the implementation of the ADMS system;

- Provide more specific information about the potential system benefits of IVVO tools, including specific performance information from PSCo; and,

- Provide more information about how SmartVAr compares to IVVO applications.

Depending on Xcel's responses to these questions, the Commission may wish to consider selecting a third party engineer to provide an unbiased opinion about the potential benefits of IVVO in Minnesota.[51] IVVO has the potential to reduce system peak demand, system line

[48] Xcel Response to OAG Information Request 51, attached as Exhibit 15.
[49] Xcel Response to OAG Information Request 52, attached as Exhibit 16.
[50] Xcel Response to OAG Information Request 53, attached as Exhibit 17.
[51] The Department made a similar request in Docket 17-776, in which it requested that Xcel be required to compare the costs and benefits of FLISR to IVVO before FLISR could be approved. *In the Matter of Xcel's 2017 Biennial Distribution Grid Modernization Report*, Docket No. E-002/M-17-776, DEPARTMENT COMMENTS at 8 (Feb. 5, 2018). While the two different projects may serve different purposes, Xcel's limited resources may require focus on one over the other.

losses, and system energy consumption. These improvements would be beneficial for ratepayers, but conflict with the utility's financial incentives. For example, reducing peak demand would also reduce the amount of infrastructure on which Xcel can earn a return. Because of these conflicting incentives, it may be reasonable to seek an opinion from outside the utility. An unbiased third-party could provide technical and engineering advice to the Commission without any concern for conflicting interests.

F. NON-WIRES ALTERNATIVES.

The IDP requires Xcel to conduct non-wires alternatives ("NWA") analysis for distribution projects that cost over $2 million. Xcel provided information about one NWA it investigated, the Viking Feeder Project, on pages 86 to 88 of the IDP filing. Based on its analysis, Xcel concluded that an NWA solution for the Viking Feeder Project would cost $22 million, while a traditional solution would cost only $2.5 million.

Xcel's NWA evaluation relies on a series of assumptions. For example, it appears that Xcel determined that the optimal NWA solution for the Viking Feeder Project would be to install batteries (including several very large battery installations), at an estimated cost of $600,000 per MWh of storage. The cost per MWh is an important assumption, and may be a point of contention for parties interested in energy storage. Xcel did not provide information about what it based the cost assumption on, the characteristics of the storage that it modeled (including the duration of storage), or explain why it would not combine solar with the storage. These details are important, and can have a significant impact on whether an NWA solution is cost effective or not. While Xcel did indicate that it would try to provide more information about NWA analysis in future IDP filings, it is likely that these core assumptions will be disputed in the future.

One way to get better information about NWAs would be to require Xcel to open some of its distribution projects to third parties who can provide NWA solutions. Third party developers may be able to provide storage or other solutions at prices lower than Xcel would estimate on its own, or suggest solutions that Xcel would not have considered. At this time, the OAG asks that Xcel address in its Reply Comments whether it would be possible and reasonable to open a limited amount of distribution projects for third party bids to further explore NWA development.

In its Reply Comments, Xcel should discuss:

- Whether it would be possible and reasonable to implement a limited form of third party bidding (or RFP process) for NWA projects associated with the IDP.

G. LOCATIONAL AND TEMPORAL NET BENEFITS.

One thing that the IDP does not currently require is a locational net benefits test, or any clear steps toward developing one. DERs such as solar, storage, or demand response, provide different amounts of value depending on where they are located on a utility's system.[52] For example, a solar garden located at the end of a long, sparsely-populated feeder will provide energy to the system, but it will provide as much value as the same resource located on a feeder with a demonstrated capacity need.[53] The value of DERs can also change depending on the time that they are producing power.[54] For example, the energy from a solar DER has more value during the highest days of a peak summer afternoon than the same time during the winter. In order to truly maximize Minnesota's electricity investments, these benefits should be understood. Once they are understood, compensation systems should be designed so that utilities and developers have incentives to invest efficiently. Some publications have suggested that working

[52] *See, e.g.,* ELECTRIC POWER RESEARCH INSTITUTE, TIME AND LOCATIONAL VALUE OF DER: METHODS AND APPLICATIONS (Oct. 19, 2016), *https://www.epri.com/#/pages/product/000000003002008410/?lang=en-US*; SOLAR ENERGY INDUSTRIES ASSOCIATION, GETTING MORE GRANULAR: HOW VALUE OF LOCATION AND TIME MAY CHANGE COMPENSATION FOR DISTRIBUTED ENERGY RESOURCES (Jan. 2018), https://www.seia.org/sites/default/files/2018-01/SEIA-GridMod-Series-4_2018-Jan-Final_0.pdf.

[53] There are many other examples of different valuations. DERs located in areas with sufficient hosting capacity may be cheaper (and therefore more efficient) than ones with hosting capacity limits. DERs may assist utilities with voltage concerns in specific locations.

[54] *Id.*

toward locational and temporal net benefit tests for DERs should be a goal of integrated distribution planning.[55]

It will be a difficult, technical challenge to develop systems to measure the locational and temporal benefits of DERs. California has been trying to develop a locational benefit system using a working group system for years without reaching a conclusion.[56] That does not mean, however, that it is not an important goal. The OAG requests that Xcel address, in its Reply Comments, the following topics:

- What steps, including software development, would be necessary to begin developing locational and temporal net benefit tests for DERs? Has Xcel started any of this work, or does it have a plan to do so?

- Has Xcel begun developing locational or temporal net benefit tests any of its other jurisdictions, or reviewed work done by other states or organizations? What lessons have been learned, and are they applicable in Minnesota?

- How is a location or temporal net benefits test related to the avoided distribution costs currently used in the existing Value of Solar rate?

G. XCEL SHOULD IDENTIFY-LABOR INTENSIVE PARTS OF THE IDP.

The IDP filing is a significant undertaking for Xcel. As described above, there are some areas where it would be reasonable to request more information from Xcel. It is just as likely that there are areas where Xcel is being asked to provide more information than is useful, or areas where the information is so burdensome to produce that it is not worth the effort. In its Reply Comments, Xcel should identify those areas of the IDP requirements that were the most

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[55] *See, e.g.,* INTERSTATE RENEWABLE ENERGY COUNCIL, OPTIMIZING THE GRID: A REGULATOR'S GUIDE TO HOSTING CAPACITY ANALYSES FOR DISTRIBUTED ENERGY RESOURCES 17 (Dec. 2017), *available at* https://irecusa.org/publications/optimizing-the-grid-regulators-guide-to-hosting-capacity-analyses-for-distributed-energy-resources/; ICF, THE VALUE IN DISTRIBUTED ENERGY: IT'S ALL ABOUT LOCATION, LOCATION, LOCATION (Sept. 10, 2015), *available at* https://www.icf.com/resources/white-papers/2015/value-in-distributed-energy.

[56] *See, e.g.,* Herman K. Trabish, Utility Dive, *Have California's efforts to value distributed resources hit a roadblock?* (Mar. 21, 2017), https://www.utilitydive.com/news/have-californias-efforts-to-value-distributed-resources-hit-a-roadblock/438400/; *see also* The California IDER and DRP Working Groups, https://drpwg.org/growth-scenarios/, *accessed on* Jan. 7, 2019.

labor-intensive to complete so that the Commission can evaluate whether it would be reasonable to continue those specific filing requirements in the future. This is the first-ever IDP filing in Minnesota, and it is important to recognize that the filing will evolve over time.

- Xcel should identify areas of the IDP filing that were particularly labor intensive to produce, including the amount of time or effort required, and whether there are alternative sources of similar information that would be easier to produce.

H. HELPFUL INFORMATION REQUESTS.

The OAG obtained additional information from Xcel through information requests while reviewing the IDP, and many of them provided information that others might be useful to others. To ensure that the Commission and other parties have access to this information, some of these information requests are attached to these Comments:

- OAG Information Request 6 provides information about line losses and how Xcel evaluates its performance;
- OAG Information Request 11 describes the actions that Xcel can take to increase the maximum capacity on its feeders and substation transformers;
- OAG Information Request 26 describes new demand side management programs that Xcel is considering in order to take advantage of the information that will be produced by advanced meters in the future;
- OAG Information Request 36 provides more information about the work Xcel has done to select the FAN system it is developing;
- OAG Information Request 37 provides information about the bandwidth that will be created by the FAN network;
- OAG Information Request 56 describes reverse power flow, and how it impacts Xcel's system;
- OAG Information Request 57 provides more information about Xcel's electric vehicle growth forecasts;
- OAG Information Request 59 confirms that Xcel estimates adding 492 MW of controllable demand between 2018 and 2023; and,

- OAG Information Request 61 confirms that Xcel has not yet selected the AMI meter it wants to use in the future, or the capabilities that it should have.

III. TIMING OF COMMISSION DECISION.

One important factor to consider is the timing of any Commission decisions in this docket. Xcel's next IDP filing is due on November 1, 2019. It may take several months for this proceeding to reach the Commission. It is likely that Xcel will begin working on the IDP far in advance of the November 1, 2019 deadline. If the 2018 IDP filing is not resolved in time, then Xcel may not be able to incorporate changes into the 2019 IDP filing. In effect, there would be a one-year delay in updating the filing requirements. For that reason, the OAG recommends that the Commission try to schedule the IDP matter for hearing on a timeline that will permit Xcel to incorporate any changes into the 2019 IDP filing. The OAG asks Xcel to clarify in its Reply Comments what schedule would be necessary to do so.

- Address what schedule is required to incorporate decisions on the 2018 IDP filing into the 2019 IDP filing.

IV. BIENNIAL CERTIFICATION.

Minnesota Statutes section 216B.2425 provides that any utility operating under a multi-year rate plan, which is currently only Xcel, must file a distribution grid modernization report in every odd-numbered year. Since this statute was enacted before the Commission developed the IDP filings, the Commission may wish to consider how the two concepts are related going forward.

For example, it likely does not make sense for Xcel to file an Integrated Distribution Plan, which requires a 5-year action plan identifying advanced grid investments, and a distribution grid modernization report, also identifying advanced grid investments, on the same day in different dockets. It would be repetitive and wasteful to consider the same issues in different proceedings. It would be reasonable to allow Xcel to combine the filings in odd-numbered years in the future in order to make the regulatory process more efficient.

The Commission should not, however, permit Xcel to request certification of distribution projects outside of the odd-numbered years permitted by statute. The Commission need not resolve this dispute during this proceeding, as Xcel has not requested certification at this time. These Comments raise the issue in order to clarify the OAG's position, and that the OAG continues to object to certification outside of the construct contemplated by statute, which limits certification requests to odd-numbered years.

The Commission should:

- Order Xcel to combine the IDP and distribution grid modernization report required by Minnesota Statutes section 216B.2425 in future filings during odd-numbered years.

CONCLUSION

These Comments present both requests for more information from Xcel, and recommendations for the Commission. This Conclusion will separately summarize both.

Xcel should address the following topics in its Reply Comments:

- Discuss whether it is possible to operate all four of the IVVO modes at the same time, the comparative benefits of different combinations if it is not, and what reason there would be to not activate all modes if possible;

- Provide more specific information about the timeline for investigating IVVO, along with the timeline for AMI deployment and the implementation of the ADMS system;

- Provide more specific information about the potential system benefits of IVVO tools, including specific performance information from PSCo;

- Provide more information about how SmartVAr compares to IVVO applications;

- Discuss whether it would be possible and reasonable to implement a limited form of third party bidding (or RFP process) for NWA projects associated with the IDP;

- What steps, including software development, would be necessary to begin developing locational and temporal net benefit tests for DERs? Has Xcel started any of this work, or have a plan to do so?

- Has Xcel begun developing locational or temporal net benefit tests any of its other jurisdictions, or reviewed work done by other states or organizations? What lessons have been learned, and are they applicable in Minnesota?

- How is a location or temporal net benefits test related to the avoided distribution costs currently used in the existing Value of Solar rate?

- Xcel should identify areas of the IDP filing that were particularly labor intensive to produce, including the amount of time or effort required, and whether there are alternative sources of similar information that would be easier to produce; and,

- Address what schedule is required to incorporate decisions on the 2018 IDP filing into the 2019 IDP filing.

Based on the information that Xcel provides in its Reply Comments, the OAG may provide limited supplemental comments to clarify whether it has recommendations on the issues Xcel has been asked to discuss.

The Commission should take the following actions on the IDP filing:

- Accept the IDP filing, without any determinations as to prudence or reasonableness;

- Order Xcel to provide more information about the increase to System Expansion or Upgrade for Reliability and Power Quality beginning in 2021, when its plans are more developed;

- Order Xcel to provide the results of its annual distribution investment risk-ranking, and a description of the risk ranking methodology, in future IDPs;

- Order Xcel to provide information on forecasted net demand, capacity, forecasted percent load, risk score, planned investment spending, and investment summary information for all feeders and substation transformers, in future IDPs;

- Order Xcel to file any long-range distribution studies it had conducted in the past year;

- Order Xcel to provide a cost-benefit analysis for each grid modernization project in its 5 year action plan, based on the best information it has at the time and including a discussion of non-quantifiable benefits, and including all supporting information; and,

- Order Xcel to combine the IDP and distribution grid modernization report required by Minnesota Statutes section 216B.2425 in future filings during odd-numbered years.

Dated: February 25, 2019

Respectfully submitted,

KEITH ELLISON
Attorney General
State of Minnesota

s/ **Joseph A. Dammel**

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ATTORNEYS FOR OFFICE OF THE ATTORNEY GENERAL – RESIDENTIAL UTILITIES AND ANTITRUST DIVISION

CORRECTED

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Xcel Energy		Information Request No. 67
Docket No.:	E002/CI-18-251	
Response To:	MN Office of Attorney General	
Requestor:	Ryan Barlow	
Date Received:	December 3, 2018	

Question:
Reference: Attachment D

Please provide more information about the Incremental Customer Investment for 2021–23.

Response:

Please see pages 92-93 of the IDP for more information on the Incremental Customer Investment initiative. As we noted, we are in the process of designing programs for this initiative. As our plans become more specific, we will provide more information in subsequent IDP filings.

Preparer:	Chad Nickell
Title:	Manager
Department:	System Planning and Strategy
Telephone:	303.571.3502
Date:	December 21, 2018

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Xcel Energy		
Docket No.:	E002/CI-18-251	
Response To:	Office of Attorney General	Information Request No. 14
Requestor:	Ryan Barlow	
Date Received:	November 19, 2018	

Question:
Reference: Figure 18, Page 51

Please explain the N-1 Transformer Capacity line, and how it compares to the maximum and desired utilization percentages in Figure 19.

Response:
Substation transformer N-1 loading levels for all distribution transformers of the same distribution voltage (e.g. 13.8 kV) in the same substation are addressed together, because the means to transfer large amounts of load between substation transformers for reliability purposes is built into the substation design. Substation transformer loading levels for each substation are planned for N-1 conditions based on the possibility of one transformer (the largest, if the transformers are different capacities) going out of service during a peak loading circumstance. The maximum amount of transformer capacity that can be served from all transformers grouped together in a substation under N-1 conditions is also known as substation firm capacity. To get the N-1 Transformer Capacity line shown in Figure 18, the firm capacity of each substation in the study area were added together.

By comparison, the utilization percentages shown in Figure 19 are reflective of the total substation load divided by the total N-0 capacity of the substations in the study area. In other words, the utilization percentages are the total percent loading of all the substation transformers in the study area under N-0 conditions. The maximum and desired utilization percentages are determined such that, generally speaking, if overall N-0 utilization is within those thresholds, then it might be possible to eliminate N-1 overload risks at the substation transformer level given appropriate configurations at each substation. However, similar to our 75 percent goal for loading of feeders, the desired utilization percentage is a guideline; actual N-1 overload risks need to be determined by analyzing each substation transformer on an individual basis.

CORRECTED

Preparer:	Brian Monson
Title:	Distribution Engineer
Department:	Distribution System Planning
Telephone:	763-493-1811
Date:	December 3, 2018

CORRECTED

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Xcel Energy
Docket No.: E002/CI-18-251
Response To: Office of Attorney General Information Request No. 69
Requestor: Ryan Barlow
Date Received: January 2, 2019

Question:

Reference: Page 55, OAG IR No. 10 Attach. A

How do the 56 feeder circuits with N-0 normal overloads relate or compare to the data provided in OAG IR No. 10 Attach. A? Are the N-0 normal overload feeders the same as the feeders with 2019 Forecasted Percent Load above 100%? If not, please explain the relationship and differences.

Response:

In the process of preparing our responses to this set of Information Requests, we determined that the number of feeder risks for 2019 should be 70, and not 56 as reported in our IDP filing. We also identified an error in Attachment A to our response to OAG IR No. 10. As noted in our responses to OAG IR Nos. 10.2 and 12.2, we will be supplementing our response to OAG-10 to provide a corrected Attachment A. We will note the correction to the number of feeder risks on page 55 of the IDP as part of our Reply Comments.

Upon reviewing the list of overload risks provided in OAG IR No. 10 Attachment A, we determined that some of the feeders shown as overloaded were not in fact N-0 risks, largely due to idiosyncrasies in the underlying data. For instance, in one case a feeder was forecasted to be overloaded in 2019, but a capital project completed the previous year increased the capacity of the feeder and mitigated the overload. However, since the feeder's capacity in the forecasting source system was not updated to reflect this change, the forecasting system still indicated that this feeder was an overload risk. We have identified and corrected these types of errors in conjunction with our response to OAG IR No. 10.2, and provide an updated Attachment A. We also identified a technical issue with the source data used to calculate the 56 feeders with N-0 risks on page 55 of the IDP related to one of the reported counts of feeder N-0 risks for one of the Company's Planning Areas. This issue has been corrected in the list of feeders in our forecasting system, and in Attachment A to our response to OAG IR No. 10.2. The 70 feeders shown in OAG IR 10.2 Attachment A with loading greater than or equal to capacity represent the complete set of forecasted feeder N-0 normal overload risks for 2019.

Preparer:	Brian Monson
Title:	Distribution Engineer
Department:	Distribution System Planning
Telephone:	763.493.1811
Date:	January 14, 2019

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Xcel Energy

Docket No.: E002/CI-18-251

Response To: Office of Attorney General Information Request No. 16

Requestor: Ryan Barlow

Date Received: November 19, 2018

Question:

Reference: Page 56

How did Xcel arrive at the risk thresholds described on page 56? Has Xcel used different risk thresholds in the past?

Response:

We developed the risk thresholds using multiple criteria, including both the normal and emergency ratings of substation and distribution equipment such as conductors, transformers, regulators, switches, reclosers, and breakers.

We also consider the impact of loading transformers beyond nameplate capacity levels, which shortens the life of the insulation and other components of the transformer or regulator. We have guidelines surrounding transformer loading for various situations based on the percent overload and the amount of time the transformer is overloaded. Situations will occur during normal operations that will require a higher than rated loading level be placed upon a transformer. Equipment failures, line outages, etc. require that the remaining transformation handle the resulting increased loading until the problem is fixed or is otherwise controlled.

The optimum cost/benefit loading level falls somewhere within a narrow band just above rated nameplate loading levels. We have adopted the levels as defined and recommended in IEEE Standard C57.91-2011. Given all the various factors, we developed the risk thresholds described on page 56 of our IDP.

Preparer: Mary Santori

Title: Manager

Department: System Planning and Strategy North

Telephone: 651.229.2461

Date: December 3, 2018

CORRECTED

EXHIBIT 5
Live Excel Worksheets

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Xcel Energy

Docket No.:	E002/CI-18-251	
Response To:	Office of Attorney General	Information Request No. 18.1
Requestor:	Ryan Barlow	
Date Received:	January 2, 2019	

Question:
Reference: OAG IR 18

Please answer the following questions:

1. Provide more detail about how the risk scores in Attachment A to OAG IR 18 are calculated, including the factors that go into the calculation. For all of the projects with a Risk Factor greater than 1, please provide a breakout of the calculation.

2. Explain the projects that have NA listed in the Risk Factor column.

3. Does Attachment A reflect all distribution projects included in the budget for 2019 through 2023?

4. Why is IDP Capacity the only category that has projects with a Risk Factor?

Response:
1. Risk Scores.

Xcel Energy personnel enter projects throughout the year in the Risk Register/Workbook. Along with the description of the project, the originator must identify the primary business value driving the investment, and may also enter the benefit and any associated service quality metric impacts (i.e. customer minutes out, which impacts System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI), etc.). After Distribution Operations and Risk Analytics review the projects to ensure the data is accurate, Business Area Finance sets-up all appropriate accounting structures.

Projects are then run through the risk model for scoring. This process involves a number of steps:

- A project's raw financial benefit is calculated based on a project's gross cash flow (generally, incremental revenue plus realized salvage value less incremental recurring costs, non-recurring costs (e.g. taxes), and capital expenditures) and avoided costs.
- A project's raw reliability benefit is calculated based on overload customer minutes out (considering mega volt-amperes (MVA) beyond threshold, customers per MVA, and annual hours at risk), contingency customer minutes out (considering peak load less available relief MVA, customers per MVA, time to restore, peak day hours out, and yearly failure rate of equipment at risk), and the number of customer complaints to the Commission (PUC).
- The raw reliability benefit is converted into the same metric as the raw financial benefit using a conversion factor (e.g., $0.84/customer minute out) based on an algorithm.
- Jurisdictional factors (including discount rates, income tax rates, property tax rates, inflation rates, historical Commission complaints, historical Quality of Service plan (QSP) SAIDI data, and historical transformer failure data) are then applied to the financial benefit and reliability benefit.
- A benefit:cost ratio (also known as a Risk Score) based on the jurisdictional financial and reliability benefits and annualized costs of each project is calculated.

From these calculations the projects get prioritized – and based on the capital budget, the projects that will be funded in the current 5-year budget are selected.

We discuss the Risk Score calculations in our response to Item 4 below. We provide as Attachment A to this response, a summary of the calculations, with a more detailed breakout of two example calculations as Attachment B.

2. Projects with "N/A."

Please see the response to Item 4 below.

3. Scope of Attachment A to OAG IR No. 18.

Yes, Attachment A to OAG IR No. 18 reflects all Distribution projects budgeted in the latest/most current available budget (July 2018) at the time of our IDP filing. As we discussed in the IDP filing, our budgets are formally updated annually, and rebalanced on an ongoing basis. Project scopes and/or timelines are subject to change at any time based on (but not limited to) engineering studies, area considerations, design estimates, permitting feasibility, capital target changes, and emergent circumstances.

4. Risk Scores

IDP Capacity is the only IDP category for which Risk Scores are applicable because it is the only category for which we have the ability to objectively quantify the annual risk. Capacity projects are driven by feeder and transformer risks that can be quantified in terms of increased reliability. We use the risk score to help prioritize capacity projects; however, as discussed in our IDP filing, the risk score is not the only factor used to determine budget priority. For other budget categories that may not be driven by reliability, and for which the risks may not be objectively quantifiable, we prioritize projects based on other factors:

- *Mandates*. Government- or customer-driven work that is covered by our tariffs or involves relocating our facilities in public rights of way when in conflict with road projects, for example. This work category is not negotiable and has established timelines/due dates – and some portion may additionally be emergent in the current year, potentially requiring us to reprioritize/rebalance our budgets.
- *New Business*. Customer-driven work under our tariffs, including customer requests for changes or applications for new service. Like Mandates, this work category is not negotiable, has established timelines/due dates, and some portion may additionally be emergent in the current budget year.
- *Asset Health*. Programs or projects driven by engineering analyses to address aging infrastructure and improve system resilience. Our budget benefit/cost model does not effectively capture the value that a programmatic approach to asset health provides.
- *Blankets*. Blankets fund high volume, low dollar, current year, reactive work and can contain hundreds of smaller projects and therefore does not lend itself to risk-ranking.
- *Programs*. Also see Asset Health above. Programs are funded based on identified needs or risks outside of the budget risk scoring model. Programmatic work for the current year is typically defined in-year based on equipment failures that are occurring, or after the previous year's reliability results are available and analyzed. For example, our cable replacement program is based on in-year cable failures and customer impacts, and is driven by engineering and reliability needs, not a budgeting risk model. As noted in Asset Health, our budget benefit/cost model does not effectively capture the value that a programmatic engineering approach to cable failures provides.

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Attachments A and B contain information Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service.

Attachment B contains information Xcel Energy maintains as trade secret data as defined by Minn. Stat. § 13.37, subd. 1(b). This information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use.

Attachment B is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Calculations of expected Customer Minutes Out given electric distribution asset load and failure rate data
2. **Authors:** Electric Systems Performance and the Risk Analytics Department
3. **Importance:** Key values to determine the potential reliability of certain projects
4. **Date the Information was Prepared:** January 14, 2019

Preparer:	Steven Rohlwing/ Shannon Robin
Title:	Manager, Asset Risk Management/ Manager, Investment Delivery
Department:	Risk Analytics/ System Planning & Strategy
Telephone:	303-571-7392/ 651-229-2261
Date:	January 15, 2019

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Xcel Energy
Docket No.: E002/CI-18-251
Response To: Office of Attorney General Information Request No. 068
Requestor: Ryan Barlow
Date Received: January 2, 2019

Question:
Reference: Page 55

Page 55 indicates that Xcel identified 56 feeder circuits and 16 substation transformers with N-0 normal overloads in the 2018 to 2022 period.

Please answer the following questions:

1) In general, when Xcel identifies N-0 normal overloads, does it attempt to resolve those problems in that planning cycle? What is the normal timeline to address N-0 normal overloads that are addressed?

   a) What would cause an identified N-0 normal overload to not be addressed in that planning cycle?

2) In the last three years, are there any N-0 normal overloads identified for feeder circuits or substation transformers that have not yet been addressed?

3) Please identify the N-0 normal overloads on feeder circuits and substation transformers. Recognizing that the budgeting process may not yet be complete, please describe the timeline on which Xcel plans to resolve these identified problems.

Response:
1) We forecast all feeder and substation transformer N-0 overloads as part of our system planning process. However, we do not have a prescriptive timeline to mitigate those potential future overloads. It is important to understand that our forecasted overloads represent a potential heavy load scenario, and the element of concern may not actually experience that level of loading for various reasons, such as variations in weather or customer-related factors. As stated on page 56 of the

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IDP, we do not develop projects for overloads less than 106 percent (see IR No. 16 for additional information on the 106 percent threshold). This is partially due our ability, and in some cases, the ability of the equipment, to withstand small overloads for brief periods of time – and the potential for such overloads. Our primary reason for selecting projects is based in our scoring model, which factors-in the amount and severity of multiple N-0 and N-1 risks, and the availability of funds.

a) Overloads less than 106 percent would not specifically be addressed based on that criteria alone. Also, we may not immediately address overloads greater than 106 percent depending on how it ranks in comparison with other projects and the availability of funds.

2) Yes, for reasons described above.

3) Please see Attachment A to our responses to OAG IR No. 10.2 and OAG IR No. 12.2, which indicates all forecasted feeder and transformer overloads greater than 100 percent. If there is a "Near Future Capacity Upgrade" indicated for that overload in these spreadsheets, that means we intend to address the overload within the next five years.

Preparer: Chris Punt
Title: Senior Engineer
Department: Distribution System Planning
Telephone: 763-493-1849
Date: January 14, 2019

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Xcel Energy

Docket No.:	E002/CI-18-251	
Response To:	Office of Attorney General	Information Request No. 19
Requestor:	Ryan Barlow	
Date Received:	November 19, 2018	

Question:
Reference: Page 55–60

How many "long-range area studies" have been conducted in recent years? How does the number of long-term studies compare to the list of risks described on page 55?

Response:
Generally we progress to a long-range area study when we find it is necessary to address multiple large risks for an area, coupled with the foresight to know that any potential mitigation will require more complex projects that span distribution, substation, and potentially transmission. A long-range area study may also be triggered by another group such as Transmission identifying a need to rebuild or relocate a substation, or build a new transmission line or substation. While those projects do not necessarily lead to a long-range area study, we do coordinate with transmission, assess distribution needs, and look for any synergies.

In recent years, we have conducted studies for the Hollydale area in Plymouth, which involves 17 risks in the present 5-year budget; an area in South Washington County including the Woodbury/Afton area, which involves nine risks in the present 5-year budget; and, the Belle Plaine area, for which there are no budgeted projects to address risks at this time.

Preparer:	Mary Santori
Title:	Manager
Department:	System Planning and Strategy North
Telephone:	651.229.2461
Date:	December 3, 2018

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Xcel Energy		Information Request No.	63
Docket No.:	E002/CI-18-251		
Response To:	MN Office of Attorney General		
Requestor:	Ryan Barlow		
Date Received:	December 3, 2018		

Question:
Reference: Page 231, IDP Requirement 3.D.2

This requirement directs Xcel to provide a "cost-benefit" analysis for each grid modernization project included in its 5-year Action Plan. Is this information provided only in Part IX.H, or is it also provided elsewhere? Does Xcel intend to provide more detail in future IDP filings, or is this representative of Xcel's understanding for IDP Requirement 3.D.2?

Response:

IDP Requirement 3.D.2 requires that we discuss the listed topics, as appropriate. We believe there is an important distinction between projects presented for informational purposes compared to investments for which we are seeking approval. In this case, we are not seeking approval of any specific grid modernization projects or investments, so the information we are able to provide at this point in time is more general.

Preparer:	Jody Londo
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Telephone:	612.330.5601
Date:	December 21, 2018

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Xcel Energy		Information Request No.	41
Docket No.:	E002/CI-18-251		
Response To:	MN Office of Attorney General		
Requestor:	Ryan Barlow		
Date Received:	December 3, 2018		

Question:
Reference: Page 148–149

Is there anywhere in the Plan in which Xcel has provided detailed information about the costs and benefits discussed in Section IX.H? If not, answer the following questions:

- Produce the data that supports the $632 to $822 million preliminary cost estimate for AMI, FAN, and FLISR, with as much granularity as possible. Where possible, identify whether information was obtained from benchmarking or internal expertise.

- How much contingency is included in the $632 to $822 million preliminary cost estimate?

- Produce the data that supports the preliminary benefit-to-cost ratios of 0.50 to 0.80 for AMI and FAN and 2.50-3.00 for FLISR, with as much granularity as possible.

Response:

The preliminary advanced grid cost estimates portrayed in our IDP filing reflect a thoughtful consideration of costs, but also the uncertainty associated with pending decision points around our final customer and data management strategy. We clarify that because we are continuing to actively develop our advanced grid proposals for Minnesota, the numbers that we submit in future filings in conjunction with specific advanced grid proposals will likely vary from these amounts.

Preliminary Cost Estimates

We summarize the costs of each of the AMI, FAN, and FLISR advanced grid projects as presently scoped in Table 1 below.

Table 1: AMI, FAN, FLISR Cost Estimates
Present Scope and Assumptions – December 2018
(millions)

Project/Cost Component	Cost Estimate		
	Capital	O&M	Total
AMI			
Base	$287	$54	$342
Contingency	$78	$37	$115
Total	$365	$92	$457
FAN			
Base	$64	$16	$80
Contingency	$24	$2	$27
Total	$88	$19	$107
FLISR			
Base	$60	$2	$62
Contingency	$11	$0.5	$11.5
Total	$71	$2	$73
Grand Total	$524	$113	$636

These amounts reflect the expected labor, equipment, licenses, customer education, overheads, etc. associated with the projects in absolute dollar terms. They do not reflect other costs that may be attributable to an enterprise-wide system such as allocations of shared assets, expected increases in labor rates or changes in customer growth, for example. Rather, these other types of costs are broadly reflected in the preliminary benefit-to-cost ratio (CBA) view of the projects also noted in our filing, and further discussed below.

While also noted in our IDP filing, we also clarify for purposes of this response that while these benefits and costs form the basis of our present estimates, they may not be fully reflective of the final costs and benefits contained in our AMI/FAN and or FLISR proposals.

The upper end of our estimated cost range for AMI, FAN, and FLISR is driven by emerging technology in this area (direct interaction with the customer, such as smart home and real-time pricing) – and the need to ensure that if we identify cost-effective options such as these for our customers, the capabilities needed to implement them are available. We have therefore built-in $150 million of capital and $36 million of O&M in the AMI project cost for these potential capabilities.

For each project, the Xcel Energy Business Systems area does the design, development, installation and ongoing operations of all information technology hardware and software, including the FAN. The Distribution business area is responsible for the business requirements for all aspects of the project, including sourcing, procurement, installation and ongoing operations of meters and FLISR field devices. That said, these cost ranges may also not be representative of a future cost recovery request, because the project aspects eligible for cost recovery may vary based on the proposed mechanism (i.e., base rates, rider, etc).

These estimates are based primarily on internal expertise from our related work that is underway in our Public Service of Colorado (PSCo) operating company affiliate. We clarify that the advanced grid work we have underway in PSCo was informed by benchmarking, and internal and external experience.

Contingency in the Preliminary Cost Estimate

We have included $153 million in contingency, which is informed by our work that is underway in PSCo.

Preliminary Benefit-To-Cost Ratios

While also noted in our IDP filing, we clarify for purposes of this response that while we have quantified preliminary benefits and costs to form the basis of our present estimates, they may not be fully reflective of the final costs and benefits contained in our AMI/FAN and or FLISR proposals. We further note that the cost-benefit information presented in our IDP filing (and below) reflects the net present value (NPV) of these preliminary cost and benefit estimates, which means that any changes to individual amounts – and especially their timing – will have an impact on the resulting NPV ratio, which could be significant. Finally we note that while this presents a simple cost-benefit ratio for the project, as we have noted in our other IR responses and more extensively in our Reply Comments in Docket No. E002/M-17-776,[1] we believe narrowly viewing a complex project such as AMI and FAN solely through a CBA lens is flawed. Rather, proper assessment of investment value must fit the circumstances. While we agree that CBAs can provide one helpful evaluation tool, by definition a CBA can only quantify that which is quantifiable. It may be possible to estimate the costs of a particular project (including contingencies); however, it is not possible to quantify all potential qualitative benefits. As such, over reliance on CBAs encourages overlooking other, valid considerations

That said, for AMI/FAN, Table 2 below summarizes the estimated cost-benefit NPV ratio, based on a 20-year timeframe.

[1] *See* Xcel Energy Reply Comments pages 7-10 (February 26, 2018).

Table 2: AMI/FAN Estimated Cost-Benefit NPV Ratio

(millions)

Category – Benefit/Cost	Estimated Cost/Benefit NPV
Benefits	**$403**
Operational	$134
Customer	$269
Costs	**($586)**
O&M	($168)
Change in Capital Revenue Requirement	($418)
Cost-Benefit NPV Ratio	***0.69***

Table 1 above summarizes the estimated cost stream details and Table 3 below summarizes the estimated benefits.

Table 3: AMI/FAN – Estimated Benefits NPV

(millions)

Benefit Area	NPV
Reduction in Meter Reading Costs	$39
Reduction in Field and Meter Services	$29
Reduction in Unaccounted for Energy	$29
Improved Distribution System Spend Efficiency	$0.04
Outage Management Efficiency	$2
Customer Impacts	$303
Total Estimated Benefits NPV	***$402***

For FLISR, Table 4 below summarizes the estimated cost-benefit NPV ratio – and similar to AMI/FAN above where the costs are summarized in Table 1, FLISR's estimated benefits are outlined in Table 5.

Table 4: FLISR Estimated Cost-Benefit NPV Ratio

(millions)

Category – Benefits/Costs	Estimated Cost/Benefits NPV
Benefits	**$268**
Operational	$17
Customer	$251
Costs	**($88)**
O&M	($6)
Change in Capital Revenue Requirement	($82)
Cost-Benefit NPV Ratio	***3.04***

Table 5: FLISR – Estimated Benefits NPV
(millions)

Benefit Area	NPV
Patrol Time Reduction	$17
Customer Minutes Out – CMO Savings	$251
Total Estimated Benefits NPV	***$268***

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Date: December 21, 2018

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Xcel Energy

Docket No.: E002/CI-18-251

Response To: Office of Attorney General Information Request No. 41.1

Requestor: Ryan Barlow

Date Received: January 2, 2019

Question:

Reference: OAG IR 41

Please explain "customer impacts" in Table 3. Provide a definition or explanation of what benefits are included in the category, and how the NPV estimate of $303 million was reached.

Response:

The benefits in Customer Impacts consist of the following:

- Reduced consumption on inactive meters
- Reduced uncollectibles / bad debt expense
- Reduced outage duration
- Carbon dioxide ($CO_{2)}$ reduction
- Drive-by meter reading avoided cost
- Critical Peak Pricing

We calculated the NPV by estimating the value of these benefits over a 20-year timeframe.

Preparer: William Magrogan

Title: Director

Department: AGIS Delivery Team

Telephone: 303.571.7228

Date: January 14, 2019

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Xcel Energy
Docket No.: E002/CI-18-251
Response To: Office of Attorney General Information Request No. 41.2
Requestor: Ryan Barlow
Date Received: January 2, 2019

Question:
Reference: OAG IR 41

Please explain the Improved Distribution System Spend Efficiency category in Table 3.

Response:
This category includes benefits from efficiency gains associated with managing reliability, asset health, and capacity needs on the system due to improved information from the AMI system (customer outages, voltage, etc.). The assumption is that with the increased and/or improved information, Distribution can more effectively plan system investments, thus reducing cost.

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Department: AGIS Delivery Team
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Date: January 14, 2019

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Xcel Energy — Information Request No. 42

Docket No.:	E002/CI-18-251
Response To:	MN Office of Attorney General
Requestor:	Ryan Barlow
Date Received:	December 3, 2018

Question:
Reference: Page 149–150

Xcel suggests that non-quantifiable benefits should be included, in addition to a quantified cost-benefit analysis, when considering AGIS investments. List all of the non-quantifiable benefits that should be considered for the AMI, FAN, and FLISR investments discussed in the Plan. For each benefit that is listed, explain the value provided and how it should be considered in the overall evaluation.

Response:

Generally, we believe valid considerations that cannot be quantified in investment decisions include: (1) customer satisfaction; (2) customer convenience/ inconvenience; (3) employee or customer personal safety; (4) power quality; (5) customer service risks associated with aging systems; (6) strategic advancement of the distribution system to accommodate other customer interests, such as DER; (7) maintaining favorable utility market position with respect to service to customers; and (8) overall impressions of utility service and the regulatory environment in Minnesota. This is especially true for investments in foundational capabilities that can be built-upon/further leveraged down the road – both, in ways that can be contemplated at present, and also in ways that may not be reasonably contemplated at the time of investment decision.

Fundamentally, and as discussed in our IDP filing, an important factor that needs to play into the equation for AMI and FAN is that we must take some action. The technology and support underlying our present AMR meter reading service is sunsetting – and doing nothing is not an option. While we can quantify the cost of differing approaches, the underlying need to take some action is intangible, in that it is not clear what value(s) (costs or benefits) should be applied.

That said, the non-quantifiable benefits associated with AMI, FAN, and FLISR that we have considered to-date include:[1]

- Improved customer experience leading to customer empowerment and satisfaction,
- Enhanced distributed energy resource integration,
- Environmental benefits (of enhanced energy efficiency, for example),
- Improved safety for customers and Company personnel, and
- Improvements in power quality.

Improved Customer Experience. AMI meters can be configured to measure, store and report peak demand and energy usage at selected time intervals. Together with appropriate web portals, smart phone applications, and rates and programs, this information enables customers to better understand, have greater control, and therefore make better informed decisions regarding their energy usage – leading to cost savings and increased satisfaction. AMI will also enable the Company to develop and offer additional programs and advanced rates to meet our customers' needs – and the needs of the grid.

Further, the two-way communication capabilities of AMI meters and the FAN enhance customers' experience. The Company will be able to remotely access meters to gather or provide information, reprogram or update, and otherwise address customer questions or concerns without the delay of scheduling a Company visit the customer's premise and meter. Additionally, the Company will have the ability to detect an outage and monitor system voltages, which benefit customers through improved customer service and quality.

Additionally, in the event an AMI meter experiences a failure, it will either report a diagnostic error or discontinue communicating to the head-end application. When that occurs, the Company is quickly made aware of the malfunction at a specific location, as compared to the current AMR system, which has more limited capabilities to indicate an error. This efficiency will minimize the amount of time a customer's bill may need to be estimated or retroactively adjusted – improving bill accuracy and reducing associated customer frustration.

Finally, today, the Company has no specific information when an individual customer's power has gone out, until the power outage is reported. Thus when customers report that they have experienced frequent/multiple outages, our analysis

[1] Although this list comprises the non-quantifiable benefits the Company has considered to date, we reserve the right to add to this list in the future as we learn new information.

and identification of potential solutions will be better informed because AMI meters have the ability to record the time and duration of each individual outage.

FLISR, similarly, is a reasonable means of not only reducing outage minutes and their quantifiable impact on customers, but also improving customers' satisfaction with their electric service. Absent FLISR and its interaction with ADMS and the FAN, our ability to quickly and efficiently isolate, locate, and resolve faults is limited, and will generally result in greater numbers of customers impacted by a fault – and longer outage durations for those customers that lose power because of the fault.

Although benefits such as energy savings and reduced Company service costs related to outages can be estimated in our analysis, attempting to quantify associated customer empowerment and satisfaction benefits would be fully subjective, and therefore fall into a 'non-quantifiable' benefits category.

Enhanced Distributed Energy Resource Integration. Through the FAN, AMI will provide more timely and more robust data on the flow of energy to, from, and among our customers. This capability enhances the Company's grid visibility, which has the power to inform the Company's interconnection processes – aiding customers wanting to install DER, and better ensuring grid and power quality for all customers. With this load flow information, and with voltage, current, and power quality data provided from AMI to ADMS through the FAN, system operators will be able to optimize grid performance – even with additional DER on the system. The precise benefit(s) provided by this optimization however, would be speculative and at best, difficult to estimate with any certainty.

Enhanced Energy Efficiency Opportunities. AMI enabled by the FAN is expected to result in greater energy efficiency from the both the customer and the Company perspectives. As previously noted, AMI enables the Company to provide customers more information on their energy usage. This in turn, facilitates development of additional time-based rates or other offerings that give customers a deeper understanding and more control over their energy usage and costs. Customer actions and behaviors in response to this information may reduce the need for generating resources, or more efficiently use of available generating resources (such as abundant wind in the overnight hours), leading to benefits including reduced carbon dioxide and criteria pollutant emissions. While emissions benefits can be quantified, anticipated customer behavior in connection is speculative and therefore difficult to estimate with any certainty.

Public and Worker Safety. AMI facilitated by the FAN provides remote functional capabilities that eliminate or minimize the need for Company personnel to visit the meter, which minimizes the intrusiveness to the customer. FLISR also gives the

Company increased visibility into the system, allowing us to more efficiently dispatch crews to fix faults – and in some cases, eliminates the need to dispatch a crew to a fault at all. Eliminating and improving the specificity of Company field visits also reduces employee safety risks associated with travel – and with risks associated with customers' premises, customers' pets, and traversing unfamiliar properties. We do not have the ability to quantify these safety benefits, and any attempt to estimate them would be speculative. If the Company also decides to enable remote disconnect and reconnect of the AMI meters, remote disconnect also supports customer safety by allowing the Company to disconnect in an emergency situation more quickly than dispatching a truck to perform a physical disconnection of service; it would support worker safety in similar ways as noted for other Company field visits.

Improvements in Power Quality. Through the FAN, AMI meters will monitor and provide power measurement and voltage data at more points within the distribution system than is practical today, which will be used in load flow calculations and other system planning and analyses to increase grid visibility and enable improvements in power quality. In other words, better voltage regulation reduces situations such as power flickers or non-sustained/brief power interruptions that may not amount to an "outage," but may serve to irritate customers or interfere with their home or business equipment. Additionally, timely power outage notifications will enable enhanced Company response and restoration management – and contribute to improved power quality to customers overall.

Finally, while this does not fit in any of the above categories, we expect to also realize benefits in the areas of increased interoperability through use of industry standard protocols and enhanced security that we build in at every step along the way. Again, quantifying specific benefits associated with these important principles would be speculative – but both provide obvious value to the Company and our customers.

Although these non-quantifiable benefits should be considered in any analysis of advanced grid investments, by their very nature, ascribing a particular value to them is subjective and often speculative. As a result, and at this time, we do not have specific suggestions for how these non-quantifiable benefits should be considered in the overall evaluation of the technologies. Minnesota has previously recognized that differing tools can be used to measure benefits of a given project, and has a long history of employing varying tools to evaluate the effectiveness of investments and customer programs. For example, there are several cost-effectiveness tests for utility Conservation Improvement Programs (CIP), which involve weighing benefits and program costs from the following perspectives: (1) participant, (2) ratepayer impact, (3) utility cost, (4) total resource cost, and (5) societal cost. While the program may demonstrate a cost-effective value in one test, it may not in another. Another example of varying CBA approaches are the Present Value Societal Cost (PVSC) and Present

Value Revenue Requirements (PVRR) valuations used in Integrated Resource Plans – with the PVSC considering some, less tangible, societal impacts and the PVRR representing actual expected costs.

A range of analyses may likewise need to exist for grid modernization investments. As we note above, some investments will be necessary to effectively continue carrying out our obligation to provide reliable and safe utility service to customers. The evaluation of a proposed investment must be tailored to properly consider a reasonable view of expected benefits and costs – and allow sufficient flexibility and discretion to weigh intangibles.

Preparer:	William Magrogan
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Telephone:	303.571.7228
Date:	December 21, 2018

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Xcel Energy — Information Request No. 49

Docket No.:	E002/CI-18-251
Response To:	MN Office of Attorney General
Requestor:	Ryan Barlow
Date Received:	December 3, 2018

Question:
Reference: Page 167–169

Please answer the following questions:

- Does Xcel have the capability to measure the voltage that is delivered to premises without manual reads? –
  - o If so, how?
  - o If not, what method does Xcel use to measure the voltage that is delivered to customers along a particular feeder?
    - How could Xcel obtain that information?
- How does Xcel determine what voltage a feeder should be operated at when it leaves the substation
- Does Xcel maintain a list of feeders including the voltage level at the substation, and the actual or estimated voltage that is delivered to customers along the feeder? If so, produce it. If not, explain what would be required to create such a list
- Does Xcel have the capability to locate specific areas of low voltage delivery along a feeder? If so, please describe it. If not, explain what Xcel could do to obtain better information.

Response:

We do not currently have the capability to measure the voltage that is delivered to premises without doing special manual readings of that information. Although we have some devices on the distribution grid that provide voltage data to the Company remotely, there are not enough of these devices to provide a system view. Like outages, we rely on customers to report a voltage issue. We are currently planning for Advanced Meter Infrastructure (AMI) to provide this functionality, as AMI meters have the capability to measure various aspects of power quality that they will then report through the FAN for the Company to use to identify any problems, operate the system, and proactively plan the system.

Our standard sets the substation bus at 123 Volts on a 120 Volt base, which allows for some voltage drop but still provides voltage within American National Standards Institute (ANSI) limits. Outside the substation, we deploy capacitor banks and regulators to maintain voltage within ANSI limits.

We do not have or maintain a list of feeders and actual voltage delivered to customers along the feeder. As we have explained, we do not currently have the capability to measure actual voltage at specific points on the system without doing special readings with special equipment. Our goal is to generally provide customers service at 120 Volts, consistent with the American National Standards Institute (ANSI) Voltage Range B (service voltage), which specifies a minimum voltage of 110 Volts and a maximum voltage of 127 Volts. Our service voltage objective is 120 volts plus/minus 5 percent – or a minimum of 114 volts to a maximum of 126 volts. We estimate that our service voltage is generally within the acceptable range, or we would be receiving complaints from customers of voltage-related issues in their homes and businesses.

To achieve our voltage range objective, we set the voltage at the substation bus at 123 Volts (on a 120 Volt base), which allows for some voltage drop – but still provides voltage within the ANSI limits and our internal guidelines. Outside the substation, we employ capacitor banks and, in very limited circumstances field regulators, which both act to maintain customer voltage within the established parameters. Capacitor banks do not have voltage settings; rather, they manage reactive power, which impacts voltage. In the very limited circumstances in which we employ a field regulator, which may be on a very long feeders in metro-fringe or rural areas, the voltage setting on the field regulator is dependent on the conditions and circumstances that drove the need for a regulator to be employed. We do not maintain a list of the voltage settings on the few field regulators on our Minnesota distribution system, as the list would have no bearing on overall system operations or planning. Rather, we would incorporate the existence of a field regulator, just like we would incorporate other field equipment into our planning efforts when working to resolve a problem in a focused geographic area.

As we have noted, we presently rely on customer notification to identify potential voltage issues. As reported in our 2017 Annual Electric Service Quality Report filed in Docket No. E002/M-18-239 on March 30, 2018 – during 2017, we conducted 284 voltage investigations on a Minnesota electric customer base of approximately 1.3 million. These investigations resulted in a diagnosis of a specific voltage problem in 64 of these cases. These problems are typically the result of transformer overloads or some other equipment malfunction. In all other cases, either no problem was found or the root cause was attributed to something other than voltage deviations. In cases where the Company finds the voltage to be out of the acceptable range, we take appropriate actions, including but not limited to swapping transformers, upgrading transformers, or checking capacitor banks. Today, these investigations require field visits and special readings/monitoring.

We believe AMI, FAN, and other advanced grid investments in the area of sensing and monitoring will increase our grid visibility to possibly proactively identify or anticipate voltage issues – and take action before they impact customers – or at a minimum, reduce the field visits and special monitoring associated with investigating potential voltage issues. As noted above we currently do not have the capability to broadly identify areas of low voltage through direct measurement. Where we suspect an area along a feeder may have low voltage due to load growth or some other factor, we conduct an engineering analysis and identify an appropriate remedy. We are planning on the Advanced Distribution Management System (ADMS) that we have underway to predict and report areas of low voltage; bellwether meters deployed as part of our AMI implementation would provide confirmation of actual voltage.

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Date:	December 21, 2018

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Xcel Energy — Information Request No. 51

Docket No.: E002/CI-18-251
Response To: MN Office of Attorney General
Requestor: Ryan Barlow
Date Received: December 3, 2018

Question:
Reference: Page 167–169

Please provide more detail about the SmartVAr program, how it reduces distribution losses, and how it relates to IVVO. Specifically compare the performance of the SmartVAr program in reducing losses to the potential for IVVO to reduce losses.

Response:
The SmartVAr program reduces losses by reducing the amount of reactive current required by switching capacitors on the feeder. SmartVAr measures the voltage at one point on the feeder normally near the substation. IVVO measures the voltage at several points along the feeder, and manages the voltage by controlling capacitors and regulators. More data points allow the feeder voltage profile to more effectively minimize losses while keeping the voltage within ANSI specifications.

Preparer: Joel Limoges
Title: Manager
Department: Area Engineering North
Telephone: 651.229.2316
Date: December 21, 2018

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Xcel Energy		Information Request No.	52
Docket No.:	E002/CI-18-251		
Response To:	MN Office of Attorney General		
Requestor:	Ryan Barlow		
Date Received:	December 3, 2018		

Question:
Reference: Page 167–169

Please provide more information about how the climate zone can impact CVR benefit. Is Xcel aware of any other Midwestern utilities that operate CVR? How does the climate for PSCO compare to NSPM?

Response:

PSCo and NSPM are in different climate zones, with Colorado categorized as cool-dry, and Minnesota as cold-humid. Research by the U.S. Department of Energy (DOE) reports that these two regions form different types of load characteristics and resulted in slightly different energy savings between 2013-2015.[1] We have not performed any studies involving climate zones and CVR benefits or potential and we are not aware of any research on this subject, so we are not able to translate the DOE study results to CVR. We have not reviewed any specifics on CVR use cases associated with any other Midwestern utilities.

Preparer:	Linh Nguyen
Title:	IVVO Engineer
Department:	AGIS
Telephone:	303-571-3533
Date:	December 21, 2018

[1] *See* US Department of Energy, "*Energy Saving Analysis, ANSI/ASHRAE/IES Standard 90.1-2016*," Table 10, (October 2017), and US Department of Energy, "*Evaluation of Conservation Voltage Reduction (CVR) on a National Level*" (July 2010).

CORRECTED

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Xcel Energy		Information Request No.	53
Docket No.:	E002/CI-18-251		
Response To:	MN Office of Attorney General		
Requestor:	Ryan Barlow		
Date Received:	December 3, 2018		

Question:
Reference: Page 169

Please provide information about the comparative density of the PSCO system to NSPM.

Response:
We do not have a direct comparison of customer density between PSCo and NSPM. In our related discussion beginning on page 168, we noted that in addition to the system design that uses feeders with larger conductors, the load type, customer count, distribution feeder length, voltage level at the substation, and other factors could influence benefits.

Preparer:	Linh Nguyen
Title:	IVVO Engineer
Department:	AGIS
Telephone:	303-571-3533
Date:	December 21, 2018

Xcel Energy State of Minnesota Electric Jurisdiction
2019 - 2022 Project List with Risk Score
Ranked Projects

IDP Category	Project Category	Mitigation	Mitigation Title	Risk Score	Sum of Allocated 2019	Sum of Allocated 2020	Sum of Allocated 2021	Sum of Allocated 2022	Sum of Allocated 2023
IDP Asset Health	Blanket	E114.018176	MN - OH Rebuild Tap/Backbone/Sec Blkt	NA	3,380,000	3,380,000	3,380,000	3,380,000	3,380,000
		E114.018177	MN - OH Rebuild All Other Type Blkt	NA	4,865,000	4,865,000	4,865,000	4,865,000	4,865,000
		E114.018178	MN - OH Services Renewal Blanket	NA	6,980,000	6,980,000	6,980,000	6,980,000	6,980,000
		E114.018274	MN - UG Conversion/Rebuild Blanket	NA	35,000	35,000	35,000	35,000	35,000
		E114.018275	MN - UG Services Renewal Blanket	NA	460,000	460,000	460,000	460,000	460,000
		E114.018354	MN - OH Street Light Rebuild Blanket	NA	801,000	822,000	844,000	865,000	888,000
		E114.018355	MN - UG Street Light Rebuild Blanket	NA	768,000	788,000	809,000	830,000	852,000
		E141.017359	MPLS - New UG Network	NA	480,000	492,000	504,000	516,000	516,000
		E151.016697	St. Paul UG Network	NA	238,000	244,000	250,000	256,000	256,000
	Failure	E103.001736	MN-Sub Equipment Replacement	NA	2,800,000	2,800,000	2,800,000	2,800,000	2,800,000
		E103.012618	Reserve 69/13.8 kV 28 MVA Transformer - NSPM	NA	0	0	0	550,000	0
		E103.013577	reserve 70 MVA 115/34.5 kV transformer	NA	0	800,000	0	0	0
		E103.016837	Replace Failed Substation Transformers	NA	1,500,000	2,000,000	2,000,000	3,000,000	3,000,000
		E103.019028	Reserve Transformer 70MVA at 115-34.5kV	NA	800,000	0	0	0	0
		E103.019030	Reserve Transformer 14MVA at 69-13.2kVA	NA	350,000	0	0	0	0
	Program	E103.006458	Retire 6 NSPM Abandoned Subs	NA	200,000	200,000	200,000	200,000	200,000
		E103.009150	SPCC NSPM Oil Spill Prevention	NA	1,000,000	700,000	0	0	0
		E103.011890	Feeder Breaker Replacement - NSPM	NA	1,000,000	1,000,000	2,700,000	3,250,000	3,250,000
		E103.011891	Substation Switch Replacement	NA	100,000	100,000	300,000	300,000	300,000
		E103.012586	ELR - Substation Relay Funding - NSPM	NA	300,000	300,000	750,000	1,000,000	1,000,000
		E103.012603	ELR - Substation Regulator Funding - NSPM	NA	300,000	300,000	300,000	450,000	450,000
		E103.012606	Substation Fence Improvement - NSPM	NA	250,000	250,000	750,000	750,000	750,000
		E103.012612	Substation Transformer Replacements - NSPM	NA	0	0	1,500,000	3,000,000	3,000,000
		E103.013521	ELR - NSPM RTU	NA	104,555	104,577	418,060	627,033	626,605
		E103.017653	Replace End of Life Substation Batteries	NA	180,000	180,000	780,000	780,000	780,000
		E114.018129	MN - Pole Replacement Blanket	NA	7,000,000	11,000,000	12,000,000	12,000,000	12,000,000
		E141.001664	Network Vault Top 735 marquette	NA	200,000	750,000	1,000,000	1,000,000	1,000,000
		E141.017906	FST Network RTU Replacement	NA	0	200,000	0	0	0
		E141.018795	MPLS Network Protector Replacement	NA	600,000	1,700,000	1,800,000	1,800,000	1,500,000
		E151.013639	STP Vault Top Replacement	NA	300,000	1,000,000	1,000,000	1,000,000	800,000
		E151.018796	STP Network Protector Replacements	NA	600,000	1,225,000	1,108,000	1,300,000	400,000
	Project	E141.012673	Install Fifth Street switchgear	NA	3,399,000	1,740,000	0	0	0
		E141.017673	ALD Sub, Transfer controls to Transm house	NA	1,500,000	2,500,000	2,500,000	0	0
		E144.000791	SSI: Install La Crescent TR2 13.8kV 14 MVA	NA	0	0	0	0	300,000
		E144.000793	SSI: Install 12.47kV Zumbrota #2	NA	0	0	150,000	0	0
		E144.011180	SSI: Upgrade Clark's Grove to 23.9kV	NA	0	0	0	100,000	2,000,000
		E144.013448	SSI: Add 2nd 23.9kV Transformer and feeder at Waterville	NA	1,950,000	0	0	0	0
		E144.013600	SSI: Convert Butterfield from 4kV to 13.8kV	NA	0	0	100,000	2,700,000	0
		E144.013622	SSI: Convert Lafayette 4kV	NA	0	0	100,000	1,950,000	0
		E144.017589	YLM211 and YLM212 Reinf OH lines	NA	500,000	1,450,000	1,450,000	1,400,000	0
		E144.018411	CLC221 Reinf OH Lines	NA	800,000	600,000	0	0	0
		E150.018891	Replace Linde TR1	NA	3,100,000	0	0	0	0
		E154.013603	SSI: Convert Bird Island 4kV to 13.8kV	NA	0	100,000	2,450,000	0	0
		E154.013605	SSI: Convert GLD021 4kV area to 12.5kV	NA	0	0	0	150,000	0
		E154.013611	SSI: Convert Echo 4kV to 23.9kV	NA	75,000	0	0	0	0
		E154.013613	SSI: Convert Belgrade 4kV to 13.8kV	NA	0	0	100,000	2,600,000	0
		E154.013633	SSI: Convert Hector 4kV to 13.8kV	NA	0	0	0	100,000	2,700,000
		E154.013635	SSI: Convert Sacred Heart 4kV to 23.9kV	NA	0	0	0	250,000	0
	WCF	E114.018276	MN - Line Asset Health WCF Blanket	NA	11,000,000	11,000,000	10,113,000	11,774,000	11,600,000
IDP Capacity	Blanket	E103.001735	MN-Sub Capacity Reinforcement	NA	300,000	300,000	300,000	300,000	300,000
		E114.018181	MN - OH Reinforce Blkt Tap/Back/Sec	NA	565,000	565,000	565,000	565,000	565,000
		E114.018182	MN - OH Reinforce Blkt All Other	NA	318,000	318,000	318,000	318,000	318,000
		E114.018279	MN - UG Reinforce Blkt Tap/Back/Sec	NA	184,000	184,000	184,000	184,000	184,000
		E114.018280	MN - UG Reinforce Blkt All Other	NA	276,000	276,000	276,000	276,000	276,000
		E114.018342	MN - New Business Network Blanket	NA	1,251,000	1,282,000	1,313,000	1,345,000	1,345,000
	Program	E103.018426	Feeder Load Monitoring DCP Capacity Reinforcement	NA	900,000	1,100,000	1,800,000	2,500,000	2,500,000
	Project	E141.009145	Install 13.8kV 50 MVA Midtown TR2	0.1	0	0	100,000	1,900,000	0
		E141.009146	Hiawatha West HWW TR02 install	0.1	0	100,000	1,400,000	0	0
		E141.010910	Crosstown new 13.8kv sub 2 fdrs	6.0	600,000	4,550,000	4,650,000	0	0
		E141.011164	North Main- I694 & Main St 13.8kV sub-2 Fdrs	0.3	0	0	0	100,000	3,900,000
		E141.015729	Moore Lake new feeder	2.7	0	0	0	990,000	0
		E141.015818	ELP84 - cut to HWW61	14.2	0	250,000	0	0	0
		E141.017687	TER065, extend TER073 to provide load relief	40.5	0	150,000	0	0	0
		E141.017739	MST075, Extend MST074 to relieve MST075 and TER066	10.3	0	0	300,000	0	0
		E141.017747	TER066, Extend MST074	30.3	0	350,000	0	0	0
		E142.011024	Reinf MND TRs and WWK SD	0.2	0	0	0	550,000	0
		E142.011721	Install 2nd transformer at Orono	0.3	0	0	100,000	2,900,000	0
		E143.016724	Reinforce WSG feeder capacities	8.7	0	550,000	0	0	0
		E143.016727	Install tie for EBL064	0.9	0	0	0	150,000	0
		E143.016730	Install tie for WIL081	10.5	0	0	300,000	0	0
		E143.017702	Install new VKG feeder	1.1	0	0	0	1,000,000	1,500,000
		E143.017703	Blue Lake reinforce banks to 50MVA and add feeder	0.3	0	0	0	100,000	3,100,000

		E143.019054	Upgrade EDA062 feeder capacity	2.5	0	0	0	500,000	0
		E143.019055	Upgrade SAV063 and SAV067 feeder capacities	1.4	0	100,000	1,100,000	0	0
		E144.000791	SSI: Install La Crescent TR2 13.8kV 14 MVA	0.6	0	0	0	300,000	1,610,000
		E144.000793	SSI: Install 12.47kV Zumbrota #2	3.1	0	100,000	2,020,000	0	0
		E144.002712	Add 3rd feeder to Goodview Bank #2	3.6	0	0	1,100,000	0	0
		E144.007793	Reinforce FAPTR1 69/13.8kV to 28MVA and add 1 feeder	7.0	100,000	1,600,000	0	0	0
		E144.010920	Reinforce Burnside TR2 to 28MVA	1.5	0	0	100,000	2,600,000	0
		E144.013436	Reinforce Kasson TR1 and Fdrs	2.6	0	100,000	2,050,000	0	0
		E144.013520	Add EWITR2 and one feeder	0.5	0	0	0	100,000	2,900,000
		E144.014484	Serve Essig from Local REA	1.6	0	0	0	225,000	0
		E144.016592	Upgrade Bushings and CTs on SIP TRs	0.5	0	0	0	0	100,000
		E144.017637	Transfer Load from ESW062 to SMT061	2.2	0	0	100,000	0	0
		E144.018970	Upgrade Medford Junction TR1 to 14MVA	3.8	100,000	2,200,000	0	0	0
		E144.018971	Upgrade VESTR1 and add VES022	1.7	0	100,000	2,650,000	0	0
		E147.011058	Convert Hollydale Sub to 115kV	Non-Discretionary	3,000,000	8,000,000	5,800,000	0	0
		E147.012463	Install feeder tie for CRL033	3.5	0	0	0	1,250,000	0
		E147.014465	Upgrade BRP062 feeder capacity	0.3	0	0	0	0	200,000
		E147.015637	Install tie for OSS063	12.6	0	0	100,000	0	0
		E147.016645	Install section switch for BRP072	1.3	0	0	0	50,000	0
		E147.017741	Upgrade OSS062 feeder capacity and transfer	1.3	0	0	0	200,000	0
		E147.019056	Upgrade BCR062 feeder capacity	6.4	0	0	250,000	0	0
		E150.010904	Add 70MVA 115/34.5kV Rosemount TR2	1.7	100,000	1,100,000	2,200,000	0	0
		E150.010914	Add STY TR3 and two new feeders	11.5	100,000	2,800,000	4,000,000	0	0
		E150.012576	New South Afton Substation and feeders	16.2	500,000	4,400,000	0	0	0
		E150.015662	Build New CHE065 Feeder	4.7	0	0	0	1,200,000	0
		E150.018967	Extend RRK063	4.1	0	0	0	100,000	0
		E150.019059	TAM - Upgrade RRK TR2	Non-Discretionary	50,000	670,000	0	0	0
		E151.012409	Add TR3 and feeders at WES	3.1	0	0	2,200,000	3,050,000	0
		E151.018961	New MPK075-GPH061 Feeder Tie	1.3	0	250,000	0	0	0
		E154.003375	Install 35KV transformer at Salida Crossing	625.3	2,600,000	0	0	0	0
		E154.003388	Reinforce Montrose transformer to 14 MVA	0.3	0	0	0	100,000	1,000,000
		E154.010157	Install 2nd transformer at Albany	0.6	0	0	0	100,000	2,050,000
		E154.010161	Install 2nd tansformer at Sauk River	0.4	1,545,000	0	0	0	0
		E154.015728	Reinforce SCL TR2 to 70MVA	0.1	2,000,000	0	0	0	0
		E154.016772	Install new FIC fdr to serve MTV area	6.9	0	975,000	0	0	0
		E154.018960	Reinforce Glenwood sub equipment	6.9	0	40,000	600,000	0	0
		E156.007927	Install TR3 70 MVA GLK Sub	1.1	0	0	0	1,800,000	1,800,000
		E156.010177	Install new KOL feeder to serve OAD	8.5	0	800,000	0	0	0
		E156.011061	Install new Wyoming feeder	4.6	0	0	1,650,000	0	0
		E156.011749	Reinforce LEX ties	0.3	0	0	0	0	950,000
		E156.011752	Install new LIN fdr	0.6	0	0	0	0	650,000
		E156.011764	Reinf sub equip on TLK TR1 and TR2	0.3	0	0	0	0	200,000
		E156.011874	Install new sub near Birch	1.3	0	0	0	0	1,470,284
		E156.013545	Expand AHI substation	1.8	0	0	100,000	3,500,000	3,500,000
		E156.014539	Reinforce feeder ties for TLK	0.7	0	0	0	400,000	0
		E156.015749	Add 2 New Baytown Feeders	16.8	0	1,200,000	600,000	0	0
		E156.015811	Reinforce TLK66 feeder ties to OAD	0.6	0	0	0	275,000	0
	WCF	E114.018281	MN - Line Capacity WCF Blanket	NA	0	600,000	2,000,000	4,758,000	5,000,000
IDP Mandates	Blanket	E114.018173	MN - OH Reloc Tap/Backbone/Sec Blkt	NA	3,323,000	3,323,000	3,323,000	3,323,000	3,323,000
		E114.018174	MN - OH Reloc All Other Type Blkt	NA	2,946,000	2,946,000	2,946,000	2,946,000	2,946,000
		E114.018271	MN - UG Reloc Tap/Backbone/Sec Blkt	NA	2,069,000	2,069,000	2,069,000	2,069,000	2,069,000
		E114.018272	MN - UG Reloc All Other Type Blkt	NA	887,000	887,000	887,000	887,000	887,000
		E114.018273	MN - UG Service Conversion Blanket	NA	962,000	962,000	962,000	962,000	962,000
	Program	E114.018479	MN - Pole Transfer 3rd Party Blanket	NA	500,000	500,000	500,000	500,000	500,000
	Project	E141.016840	Relocate UG and OH Facilities for Bottineau LRT - Minneapolis	NA	500,000	4,500,000	4,000,000	0	0
		E141.017519	35W Relocation 40th to Franklin	NA	(1,000,000)	0	0	0	0
		E141.018906	8th Street Relocation Hennepin to Chicago	NA	11,436,000	0	0	0	0
		E141.018907	4th St Reloc 2nd Ave N to 4th St S	NA	5,000,000	5,000,000	0	0	0
		E141.019192	Relocate UG and OH Facilities for SWLRT - Minneapolis	NA	2,600,000	1,800,000	(150,000)	0	0
		E143.013574	Relocate UG and OH Facilities for SWLRT	NA	7,800,000	5,400,000	(450,000)	0	0
		E147.016563	Relocate UG and OH Facilities for Bottineau LRT - Maple Grove	NA	500,000	4,500,000	4,000,000	0	0
	WCF	E114.018175	MN - Mandate WCF Blanket	NA	2,687,000	3,068,000	8,000,000	12,000,000	12,000,000
		E141.017929	Minneapolis Mandates	NA	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000
IDP Meters	Blanket	E103.001040	MN-Electric Meter Blanket	NA	5,885,000	5,141,000	3,904,000	3,450,000	3,142,000
IDP New Business	Blanket	E114.018045	MN - OH New Street Light Blanket	NA	343,000	352,000	362,000	371,000	380,000
		E114.018046	MN - UG New Street Light Blanket	NA	709,000	728,000	747,000	767,000	787,000
		E114.018171	MN - OH Extension Blanket	NA	2,950,000	3,032,000	3,117,000	3,203,000	3,291,000
		E114.018172	MN - OH New Services Blanket	NA	3,456,000	3,553,000	3,653,000	3,753,000	3,856,000
		E114.018268	MN - UG Extension Blanket	NA	11,736,000	12,065,000	12,403,000	12,744,000	13,094,000
		E114.018269	MN - UG New Services Blanket	NA	6,247,000	6,422,000	6,602,000	6,783,000	6,970,000
	Program	E114.018792	MN LED Post Top Conversion	NA	0	2,000,000	0	0	0
IDP Non Investment	Blanket	E141.001140	Electric New Construction Contributions in Aid	NA	(1,037,000)	(1,074,000)	(1,066,000)	(1,098,000)	(1,098,000)
		E142.001155	Electric New Construction Contributions in Aid	NA	(319,000)	(330,000)	(328,000)	(338,000)	(338,000)

		E143.001170	Electric New Construction Contributions in Aid	NA	(282,000)	(292,000)	(290,000)	(299,000)	(299,000)
		E144.001183	Electric New Construction Contributions in Aid	NA	(339,000)	(351,000)	(348,000)	(358,000)	(358,000)
		E147.001216	Electric New Construction Contributions in Aid	NA	(336,000)	(350,000)	(346,000)	(356,000)	(356,000)
		E150.001230	Electric New Construction Contributions in Aid	NA	(379,000)	(391,000)	(389,000)	(401,000)	(401,000)
		E151.001245	Electric New Construction Contributions in Aid	NA	(289,000)	(305,000)	(300,000)	(309,000)	(309,000)
		E154.001279	Electric New Construction Contributions in Aid	NA	(312,000)	(323,000)	(320,000)	(330,000)	(330,000)
		E156.001291	Electric New Construction Contributions in Aid	NA	(308,000)	(317,000)	(315,000)	(324,000)	(324,000)
IDP Other	Blanket	C115.006786	Logistics-NSPM Tools Blanket	NA	76,114	168,288	249,079	253,861	253,689
		E103.001041	MN-New Bus Transformer	NA	17,224,000	17,867,000	18,254,000	18,546,000	18,624,000
		E103.002265	Capitalized Locating Costs-Elec UG MN	NA	400,000	400,000	400,000	400,000	400,000
		E153.011934	Logistics-NSPM Tools Blanket - SD	NA	1,743	3,486	4,355	4,354	4,351
	Program	C103.002156	Transportation-NSPM Fleet Blanket	NA	2,126,000	2,386,458	1,925,959	1,810,100	1,809,126
		C145.008061	Fleet New Unit Purchase Common Ops-NSPM-North Dakota	NA	9,956	9,956	9,951	9,950	9,944
		E103.003617	Fleet New Unit Purchase El Ops-NSM	NA	4,977,514	7,819,042	15,132,744	16,220,122	6,722,391
		E103.018427	Feeder Load Monitoring COMM - Communication/Other	NA	435,644	435,739	609,671	870,880	870,284
	Project	E103.014467	Fiber Communication Cutover	NA	1,742,576	2,178,696	2,177,398	1,741,759	0
	Tool	C103.002113	Transportation-NSPM Tools	NA	80,120	160,274	240,269	240,247	240,084
		C103.013336	NSPM Locating - Tools and Equipment	NA	30,446	60,904	90,501	90,493	90,432
		E103.001738	MN-Dist Sub Tool & Equip	NA	200,396	435,739	435,480	435,440	435,142
		E103.001739	MN-Construct Dist Sub Tool & Equip	NA	33,109	66,232	66,193	66,187	66,142
		E103.002099	NSPM Metering Sys-Tools & Equip	NA	34,852	69,718	69,677	69,670	69,623
		E103.002100	EUC-Tools & Equip	NA	102,812	149,023	148,934	148,920	148,819
		E141.001133	HUGO Training Center Tools & Equip	NA	20,040	40,088	59,225	59,220	59,179
			Metro West-Electric Tools & Equip	NA	197,782	287,588	287,416	287,390	287,194
			Trouble Electric Tools & Equip	NA	133,307	196,083	195,966	195,948	195,814
		E144.001190	Southeast-Elec Tools & Equip	NA	124,594	172,553	172,450	172,434	172,316
		E145.001206	ND-Electric Tools & Equip	NA	53,149	70,590	70,548	70,541	70,493
		E151.001252	Metro East-Elec Tools & Equip	NA	147,248	219,613	219,482	219,462	219,312
		E153.001257	SD-Tools & Equip	NA	76,673	101,963	101,902	101,893	101,823
		E154.001273	Northwest-Elec Tools/Equip	NA	64,475	86,276	86,225	86,217	86,158
IDP Reliability	Program	E114.018179	MN - REMS Blanket	NA	850,000	850,000	850,000	850,000	850,000
		E114.018180	MN - FPIP Blanket	NA	1,000,000	1,000,000	1,500,000	1,500,000	1,500,000
		E114.018277	MN - URD Cable Replacement Blanket	NA	15,500,000	20,500,000	21,000,000	21,000,000	21,000,000
		E114.018471	MN - Feeder Cable Repl Blanket Proactive	NA	4,000,000	5,000,000	5,000,000	5,000,000	5,000,000
		E114.019275	MN Incremental Customer Investment	NA	0	0	85,000,000	88,000,000	40,000,000
Grand Total					199,982,105	230,325,887	322,252,485	325,100,121	261,787,204