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Xcel Energy		Information Request No. 1
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP).

Request:
Please provide Xcel Energy's response to any and all information requests pertaining to the above referenced filing. This is an ongoing request.

Response:
Please see Attachment A to this response. Attachment A contains the only Information Request (IR) we have responded to in this docket to date (MPUC IR No. 1). Moving forward, the Company will include Fresh Energy on all of our IR submittals in this docket.

Preparer:	Amber Hedlund
Title:	Regulatory Case Specialist
Department:	Regulatory Affairs
Telephone:	612.337.2268
Date:	January 23, 2020

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Xcel Energy		Information Request No. 1
Docket No.:	E002/M-19-666	
Response To:	Minnesota Public Utilities Commission	
Requestor:	Michelle Rosier	
Date Received:	December 16, 2019	

<u>Question:</u>
a. Please provide additional detail and context on the Company's belief that the certification request should be considered in a Commission process that resembles a resource acquisition proceeding[1], including which type of resource acquisition process, proposed process steps, and justification for finding the proposed process as the most reasonable.

b. Provide an update on any stakeholder input or involvement received in development of the proposed deadlines, process steps, and procedural schedule.

c. Given the 2020 MYRP is to be withdrawn in Docket No. E002/GR-19-564[2], what is the Company's proposed timeline and process for Commission review of the Advanced Grid Intelligence and Security (AGIS) certification request? Please address how the proposal is consistent with Minn. Stat. §216B.2425.

<u>Response:</u>
For context for this response, we note that we view Commission certification as providing the Company with assurance that it can proceed with the certified project(s) and seek recovery under the Transmission Cost Recovery (TCR) Rider. The Commission would additionally have the opportunity to review actual costs and expenditures as part of the Company's subsequent TCR or general rate case filings, when the Company seeks cost recovery for the projects.

a. Minn. Stat. § 216B.2425 sets forth the broad parameters for scheduling certification requests, namely that requests be submitted by "November 1 of each odd-numbered year," and that the Commission "certify, certify as modified, or deny certification" by "June 1 of each even-numbered year." No Minnesota statute, rule, or regulation sets out a more specific process for reviewing certification requests. We believe that the appropriate process for a given certification request may depend on the scope of the specific investment for which certification is requested. For example, the Company's 2019 Integrated

Distribution Plan (2019 IDP) was submitted concurrent with a multi-year rate case in which the Company also sought cost recovery for its advanced grid investments.

Under normal circumstances, and given the general seven-month statutory timeline, we believe a process that resembles the procedure established by the Commission for some of the Company's recent proposed acquisitions of generating facilities (e.g., *Acquisition of 302.4 MW Wind Generation*, Docket No. E002/M-17-694, *Petition for Approval of the Acquisition of the Mankato Energy Center (MEC)*, Docket No. IP6949,E002/PA-18-702) would be appropriate. Although each of those proposed acquisitions was governed by a separate statute (Minn. Stat. § 216B.2422 and Minn. Stat. §216B.50, respectively), they both were miscellaneous filings under Minn. R. 7829.1300. The Commission set out comment periods in both that would have allowed the proposals to be reviewed by parties and set for hearing in less than seven months, with more time however, than the default 30 days for initial Comments and 10 days for Reply Comments as provided by Minn. R. 7829.1400 (Commission Action on Miscellaneous Filings; Comments).

We recognize, however, that the scope of the Advanced Grid Intelligence and Security (AGIS) investments proposed in the 2019 IDP may require analysis that goes beyond the normal seven-month timeframe. That is why we have offered to work with the Commission and stakeholders to set an appropriate deadline and procedural schedule to facilitate the consideration of these investments.

b. We have shared our perspective on the procedural timeline and our offer to waive the June 1st statutory deadline to perhaps the September timeframe with the following stakeholders: Minnesota Department of Commerce, Minnesota Office of the Attorney General, Center for Energy and Environment, Fresh Energy, and IPS Solar. The feedback we received either supported a longer procedural timeframe for a certification determination or was indifferent as to the procedural details.

c. Although the Company plans to withdraw its 2020 multi-year rate plan request, we continue to believe the timeline and process for Commission review of our AGIS certification request should be set after consultation with stakeholders and the Commission, so that parties are provided an appropriate amount of time to review and comment on the proposed investments. Since the June 1, 2020 date required under Minn. Stat. § 216B.2425 might be hard to meet, the Company is open to waiving enforcement of this deadline to facilitate appropriate review and suggests three additional months, or a decision by September 1, 2020.

We believe that the June 1 deadline provided in Minn. Stat. § 216B.2425, subd. 3, with respect to certification of grid modernization projects like AGIS is designed to be a utility protection, allowing utilities to timely recover grid modernization investments through the TCR Rider pursuant to Minn. Stat. § 216B.16, subd. 7b. It is, therefore, the Company's right to waive this deadline. Under Minnesota law, statutory deadlines may be waived by a party for whom the deadlines are designed to protect. *See In re Commitment of Giem*, 742 N.W.2d 422, 431 (Minn. 2007). Consistent with this principle, the Commission has a longstanding practice of accepting utilities' offers to waive the ten-month review period under Minn. Stat. 216B.16, subd. 2, and its historical analogs. *See In the Matter of Northwestern Bell Telephone Company's Proposed Tariff to Discontinue Operator Services to Local Exchange Carriers*, Order Accepting Waiver of Statutory Review Period and Granting Extension of Time for Parties' Reports, Docket No. P-421/M-87-815 (March 18, 1988); *In the Matter of the Application by CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Minnesota Gas, for Authority to Increase Natural Gas Rates in Minnesota*, Order Accepting Filing, Suspending Rates, and Extending Timeline, Docket No. G-008/GR-19-524 (Dec. 18, 2019). We believe the Company's offer to waive the June 1 deadline under Minn. Stat. § 216B.2425, subd. 3, is lawful and consistent with Commission precedent.

Preparer:	Bria Shea
Title:	Director, Regulatory & Strategic Analysis
Department:	Regulatory Affairs
Telephone:	612.330.6064
Date:	December 23, 2019

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Xcel Energy		Information Request No. 2
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

<u>Question:</u>
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) page 30.

Request:
Please provide all data, analysis, studies, reports, or spreadsheets with all formulas and links intact supporting the claim that "additional investment is needed" in the form of the ISI initiative.

<u>Response:</u>

Northern States Power Company objects to this Request as overly broad and unduly burdensome. Subject to the foregoing objection, we respond as follows:

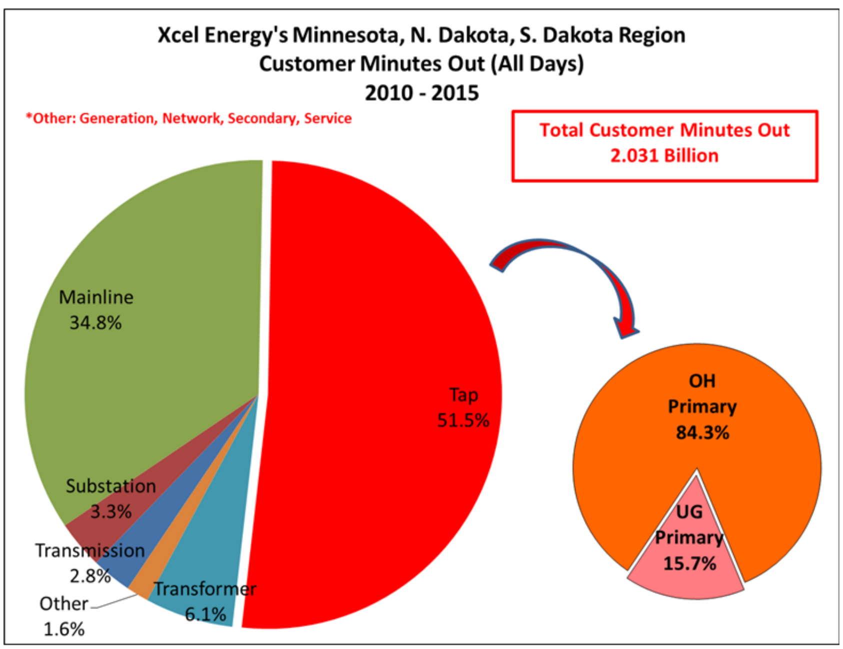
We believe that, within the next five years, we will need to focus capital on our distribution system to improve the experience of the average distribution customer by addressing aging infrastructure, better preparing the system for increased levels of Distributed Energy Resources (DER) and electric vehicles (EV), and improve its overall resilience.

There is no particular study or report that was used to develop the Incremental System Investment (ISI) initiative. Rather, the ISI was conceptualized by those familiar with the distribution system and the issues that commonly affect the system and our service to customers. The proposed ISI programs are informed by the impact various assets may have on reliability and the customer experience, through frequent and/or long-duration interruptions of service.

Since 2012, the Company has been funding asset health at an increased level to improve the life cycle replacement on seven key assets on our system: transmission, substations, mainline, overhead primary, underground primary, taps, and transformers. However, over this period of time, we also have seen an increase in other projects that demand funding, including required relocation projects and other emergent system needs, and required the Company to reprioritize a portion of these asset-health investments to timely address the emergent system needs. ISI seeks to restore the attention and focus to asset health, and do so with consideration of beneficial new programs and customer experience improvements, and specifically does so in years three to five of our five-year budgets. Other utilities are undertaking similar types of resilience-focused initiatives, including Duke/Dominion's targeted undergrounding programs.[1]

With that context, we outline some of the data underlying the major investment categories contemplated in our current ISI plan, starting with a Figure [FE-2] 1 below, which portrays our reliability from the perspective of our customers' experience.

Figure [FE-2] 1: NSPM Customer Minutes Out – Major System Component (All-Day) 2010-2015



This presentation of the customers' reliability experience by major system component is not a traditional industry reliability standard, such as System Average Interruption Duration Index (SAIDI) or Customer Average Interruption Duration Index (CAIDI), as these are not representative of the individual customer experience because they are presented as "storm-normalized." This removes the effects of major weather events, and is intended to isolate the portion of reliability performance within the utility's

[1] https://www.duke-energy.com/our-company/future/targeted-undergrounding

control, but removing the major weather events does not reflect the customers' actual experience. Also viewing reliability from this non-normalized, or "all day" reliability perspective helps to identify potential new programs that may be necessary to ensure we are addressing the experience of our customers, and not just those associated with high profile events.

Substation Programs

The objective of the ISI Substations program is to improve the reliability and resiliency of the Company's Minnesota substations. Substation transformers are fundamental to the reliability of our distribution system, and – while the failure of substation transformers is not a common occurrence – when it happens, the consequences are high and result in a significant number of customers losing service.

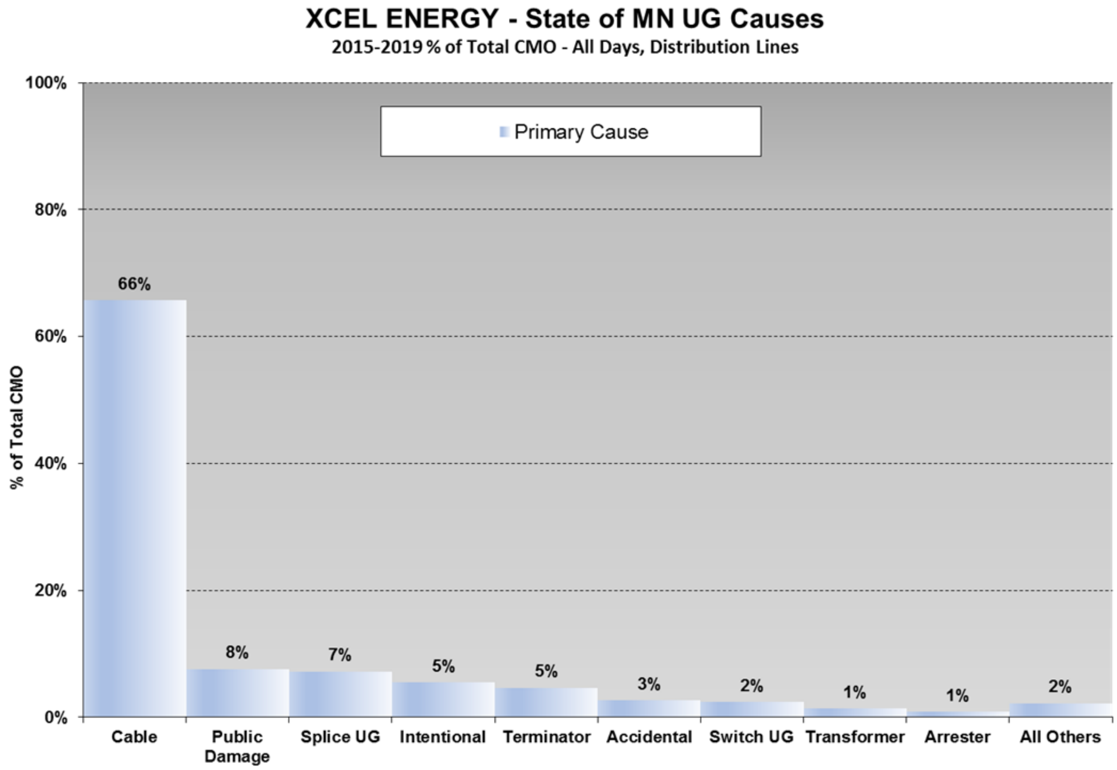
As can be seen in Figure 1 above, substation level outages, as designed and intended, is a small percentage of the overall customer minutes out (CMO) experienced on the system. A single substation can serve upwards of 45,000 customers – and as such, because of the high-impact an outage would have on our customers and our system, we design and build our substations to minimize the potential of failure. We also develop programs to further minimize the potential for failure by proactively identifying when a failure is likely to occur, so that we may preemptively replace equipment. The Substation ISI programs would increase the rate at which we replace our substation transformers.

Underground Programs

As outlined in the IDP, the ISI Underground program is composed of seven components, including replacement of different types of cable.[2] Underground cable is resistant to many environmental issues, but outages due to degraded cable can be lengthy. Programs to identify and replace degraded cable before it actually fails reduces the probability of lengthy outages. The below Figure portrays outages on underground portions of our system by cause – showing the predominant cause is cable failure, with approximately 70 percent of the CMO.

[2] ISI Underground Programs include: (1) mainline cable replacement, (2) underground residential distribution (URD) cable replacement, (3) cable asset life extension, (4) network monitoring, (5) St. Paul tunnel work (6) feeder exit capacity work, and (7) tools and equipment.

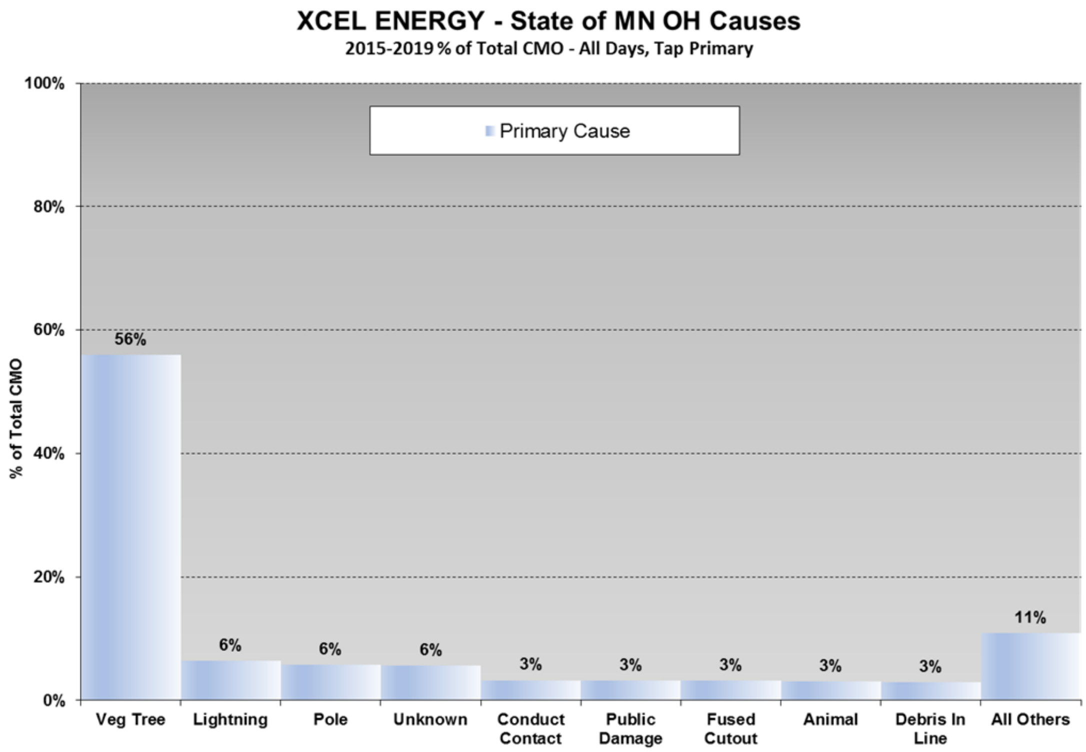
Figure [FE-2] 2: State of Minnesota Underground Outages by Cause 2015 to 2019



Overhead Tap Programs

As noted in the IDP, the primary goal of the overhead tap program is to improve reliability and resiliency of our distribution system through a series of six programs focused on overhead tap lines throughout our Minnesota service area. The overhead tap system is the single largest contributor to customer outages. The overhead system is generally older than the underground system and is subjected to many environmental factors including trees, wind, lightning, public damage and ice. Unlike the underground system, typically mitigating any one equipment failure cause type will not drastically change the performance of an overhead tap; strengthening the system against vegetation impacts however, can reduce the number and length of outages. Our current vegetation program is robust in that it typically results in 90 percent of the vegetation outages to be considered non-preventable. In developing this part of our ISI initiative, we identified programs that could reduce outages, number of customers impacted and length of outages based on several causes for the overhead system with a focus on minimizing outages on stormy days. We provide a view of overhead tap outages by cause in the below Figure.

Figure [FE-2] 3: State of Minnesota Overhead Outages by Cause 2015 to 2019

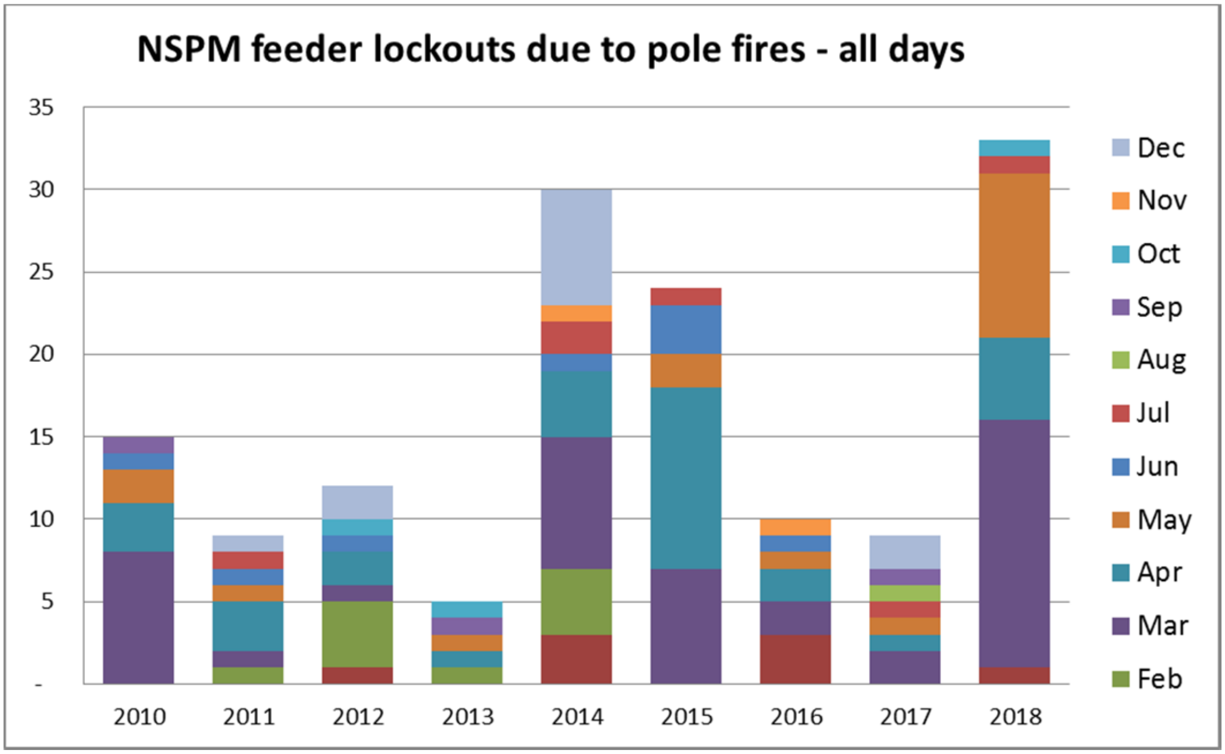


Overhead Mainline Programs

The ISI Overhead Mainline programs targets overhead mainline feeders that are the larger capacity lines found along major roadways, and that then branch off into smaller overhead tap lines and then to service laterals that connect to homes and businesses. Similar to the overhead tap system, the overhead mainline system has many different causes of events. Singling out mitigation opportunities can be difficult, but we have identified two areas of initial focus: (1) pole fire mitigation; and (2) lightening arrestor replacement. As shown in Figure 4 below, pole fires are trending upward, and tend to be some of the longest to repair due to the extensive work that typically is required.[3]

[3] Pole fires are typically caused by road salt contamination on insulators and most typically occur on older poles in higher speed traffic corridors with multiple insulators.

Figure [FE-2] 4: State of Minnesota Feeder Lockouts – Pole Fire 2015 to 2019



The particular investments we believe are necessary and have budgeted for each of these program areas are set forth in Attachment A to our response to Fresh Energy Information Request No. 8, and the need for each of these investments is laid out in the Direct Testimony of Ms. Kelly Bloch in Docket No. E002/GR-19-564 from pages 43 to 75.

Preparer: Molly Dimond
Title: Investment Delivery
Department: System Planning and Strategy
Telephone: 303.571.3232
Date: January 23, 2020

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Xcel Energy		Information Request No. 3
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) page 38, footnote 33.

Request:
A. Please provide a corrected link or copy of the report titled IEEE Benchmark Year 2019, Results for 2018 Data.
B. Please provide NSPM's participant code in the 2019 IEEE study.

Response:

A. The IEEE Distribution Reliability Working Group has been assigned a new link for posting working group documents beginning in 2019, which was discussed at the working group winter meeting on January 14 & 15, 2020. This volunteer group has not yet completed transfer of previous documents or posting of new documents. The link where the benchmarking reports will be posted is as follows: https://cmte.ieee.org/pes-drwg/benchmarking/

   In the interim until the reports are moved to the new location, we provide the report "IEEE Benchmark Year 2019 Results for 2018 Data" as Attachment A to this response.

B. We cannot provide any of the participant codes of the utilities that participate in the IEEE benchmarking study, including the Company. Participants in the IEEE benchmark study are anonymous, and sharing of a participant code outside of the participating organization is not allowed. We note that important information on the benchmarking study background and results interpretation is included on slides 2 and 3 of the study report. While the results will likely be different, we note that utilities self-report their reliability index values to the U.S. Energy Information Administration, which can be accessed at: https://www.eia.gov/electricity/data/eia861/ We note, however, these are self-calculated results, which are not necessarily comparable to each other or the IEEE results. The IEEE results are the only standard industry benchmark for utility reliability results; the utilities provide granular data including daily summary totals for the number of outage events, the number of customers interrupted, and the number of customer minutes interrupted and IEEE calculates the performance using standardized techniques and protocols.

Preparer:	John Ainscough
Title:	Principal Engineer
Department:	Electric Distribution System
Telephone:	303-571-3552
Date:	January 23, 2020

IEEE Benchmark Year 2019
Results for 2018 Data

2019 General Meeting
Distribution Reliability Working Group
Atlanta, Georgia

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Background to IEEE DRWG Benchmark Study

1. *Initiated in 2003, conducted annually*
2. *Participants are anonymous with key identifier to retain anonymity*
3. *Participation list is not revealed to anyone*
4. *Each participant can choose to share their results*
5. *No inference is made about good or bad reliability*
6. *Intended to provide information for users to assess their performance relative to peers*
7. *Called the 2019 Study (for 2018 Results)*

Benchmarking

- Using annual key metrics (SAIDI, SAIFI and CAIDI) to assess performance of a system may be useful, however, needs to be tempered
- DRWG Study attempts to identify various aspects that could cause a difference in reported metrics
- Data may not be directly comparable, since
  - Data collection & system differences exist
  - Certain exclusion differences can occur, although we strive to have the differences minimized
- IEEE 1366-2003/2012
  - addresses data issues by clearly defining the rules (i.e. what data should be excluded)
  - It DOES NOT address the data collection issues
  - Companies may not report all forms of outages, due to data collection issues or other reasons

Regions represented by the participants 2019 Benchmark Study

Region 0: Spans States or Unknown

Region 1: Northeast

Region 2: Mid-Atlantic

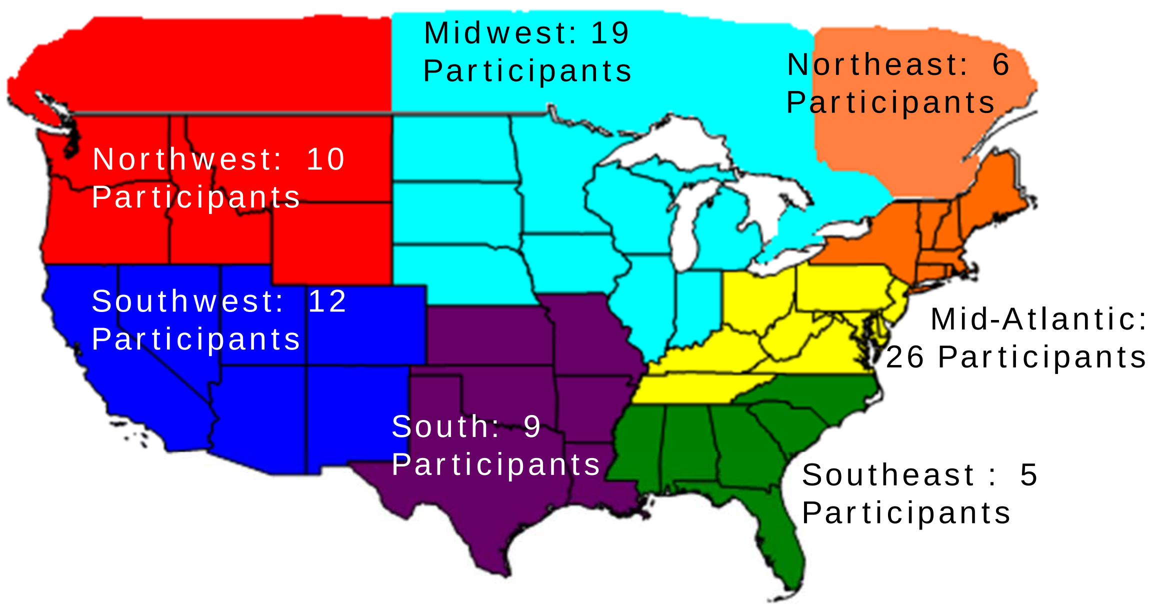
Region 3: Southeast

Region 4: Midwest

Region 5: Southwest

Region 6: South

Region 7: Northwest



Spans States or Other: 3

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Classification of Respondents

- 85,258,061 customers represented in North America
- 2019 Survey
  - 7 Small (=< 100,000 customers)
  - 56 Medium (>100,000 and <1,000,000 customers)
  - 32 Large (>= 1M customers)

Respondents

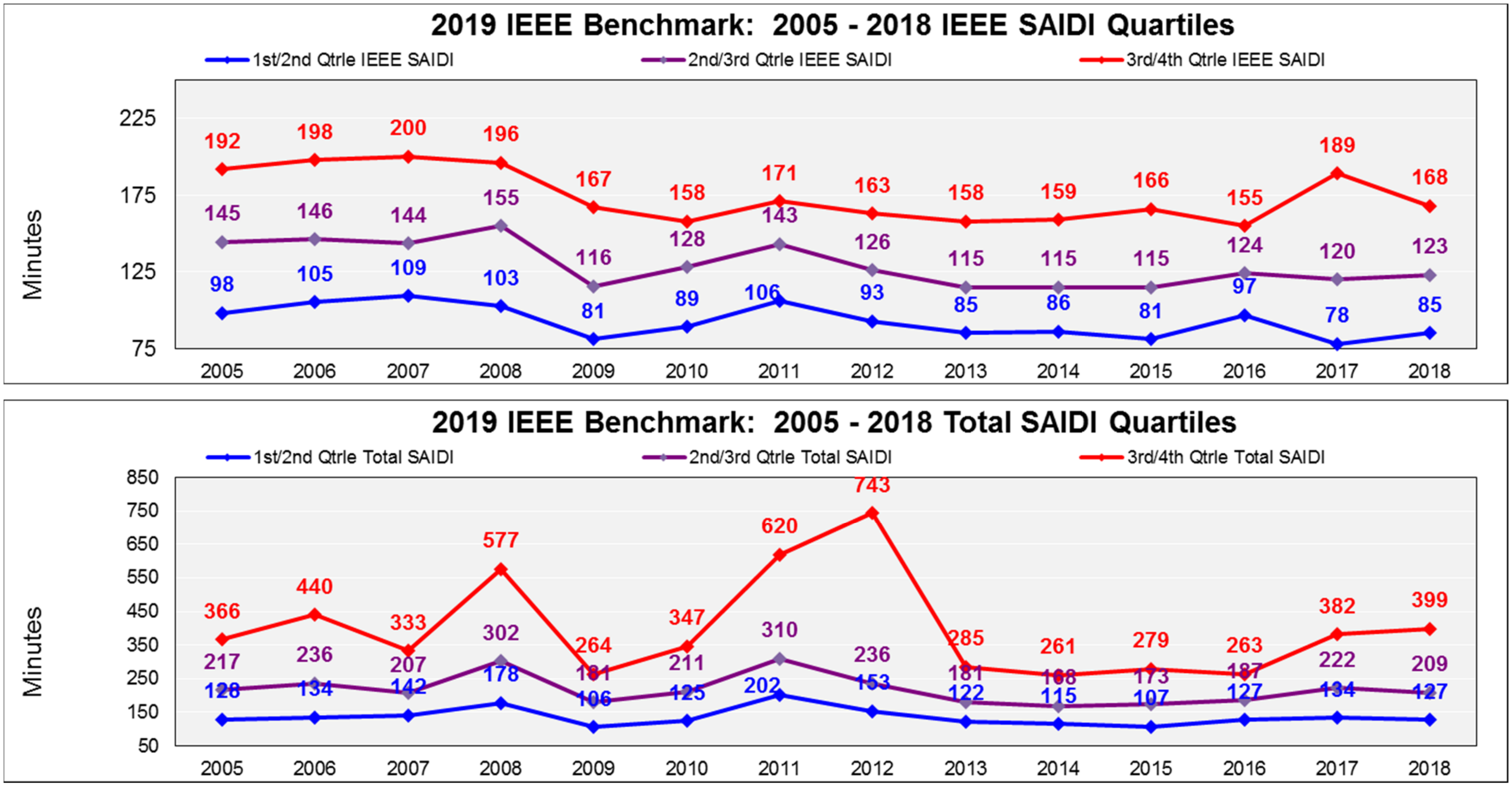
- About 250 companies have responded at some time
- 2019 Survey: 90 entries responded

All Participants	90	SAIDI ALL	SAIDI IEEE	SAIDI WOF	SAIDI WOP	SAIFI ALL	SAIFI IEEE	SAIFI WOF	SAIFI WOP	CAIDI ALL	CAIDI IEEE
0	MIN	31	28	28	28	0.4	0.3	0.3	0.3	62	62
1	Q1	127	85	83	75	1.1	0.9	0.8	0.7	117	95
2	MEDIAN	209	123	110	102	1.4	1.1	0.9	0.8	162	109
3	Q3	399	168	150	145	1.7	1.4	1.1	1.0	251	133
4	MAX	3444	535	500	463	3.4	2.5	2.5	1.8	1177	247

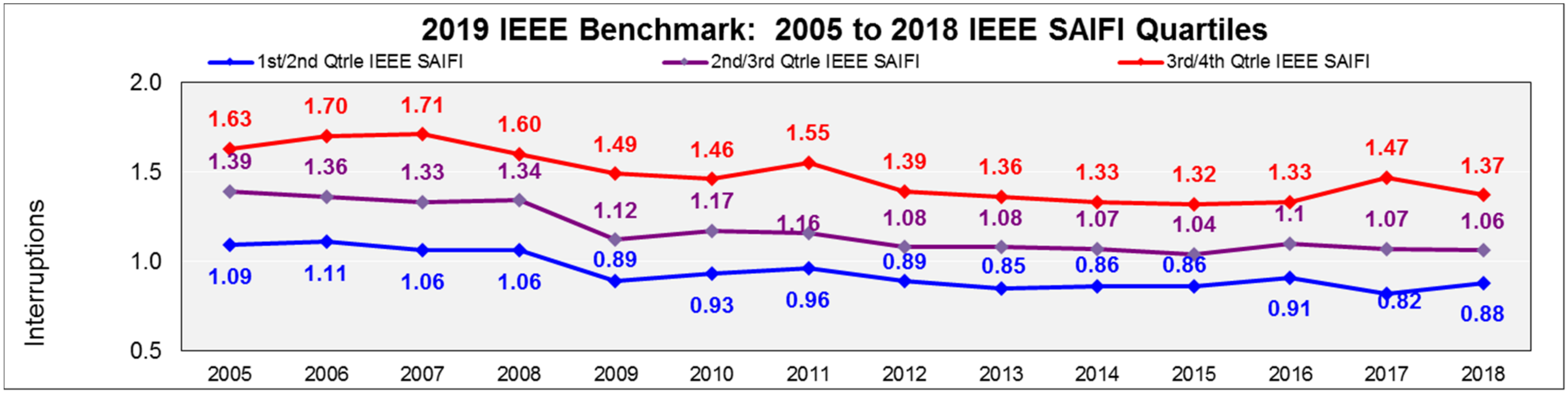
Respondents by Utility Size

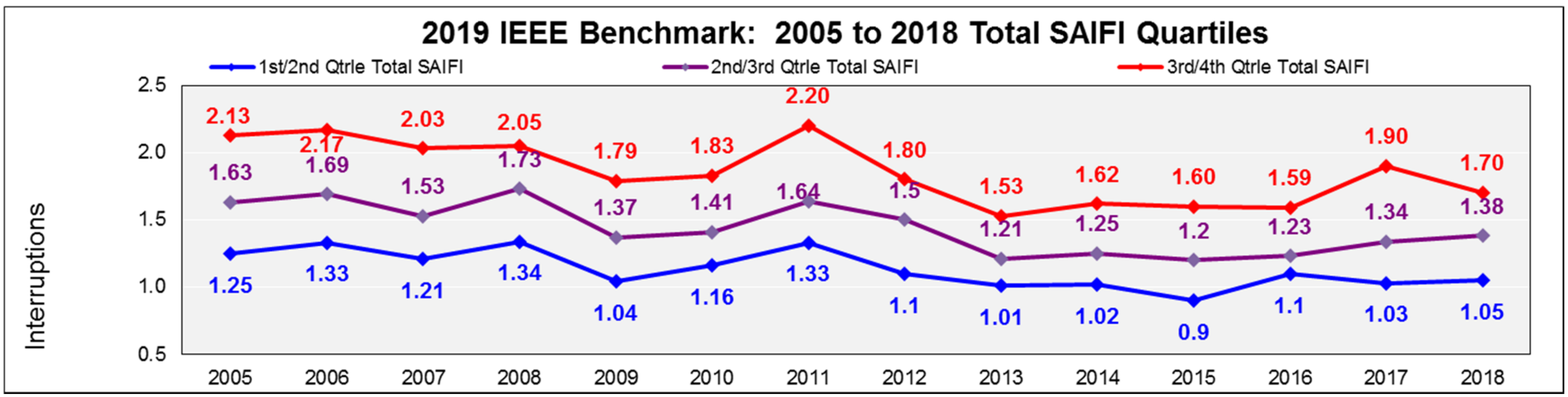
Quartile Small	7	SAIDI ALL	SAIDI IEEE	SAIDI WOF	SAIDI WOP	SAIFI ALL	SAIFI IEEE	SAIFI WOF	SAIFI WOP	CAIDI ALL	CAIDI IEEE
0	MIN	52	29	30	29	0.8	0.4	0.6	0.4	68	66
1	Q1	75	62	59	54	0.9	0.8	0.8	0.6	82	72
2	MEDIAN	113	98	70	58	1.3	1.1	0.8	0.8	94	85
3	Q3	331	167	135	100	1.9	1.4	1.0	0.8	135	110
4	MAX	367	190	157	148	3.0	2.4	1.2	1.1	220	134
Quartile Medium	56	SAIDI ALL	SAIDI IEEE	SAIDI WOF	SAIDI WOP	SAIFI ALL	SAIFI IEEE	SAIFI WOF	SAIFI WOP	CAIDI ALL	CAIDI IEEE
0	MIN	31	28	28	28	0.4	0.3	0.3	0.3	62	62
1	Q1	125	88	84	78	1.1	0.9	0.8	0.7	115	95
2	MEDIAN	184	133	111	106	1.4	1.1	0.9	0.9	157	109
3	Q3	338	162	145	144	1.7	1.5	1.1	1.1	236	134
4	MAX	3444	484	466	400	2.9	2.3	2.2	1.8	1177	207
Quartile Large	32	SAIDI ALL	SAIDI IEEE	SAIDI WOF	SAIDI WOP	SAIFI ALL	SAIFI IEEE	SAIFI WOF	SAIFI WOP	CAIDI ALL	CAIDI IEEE
0	MIN	49	49	49	48	0.5	0.5	0.5	0.5	102	69
1	Q1	170	86	84	76	1.1	0.8	0.8	0.8	144	100
2	MEDIAN	282	112	106	96	1.4	1.0	0.9	0.8	181	114
3	Q3	501	170	154	147	1.7	1.3	1.1	1.0	363	136
4	MAX	1292	535	500	463	3.4	2.5	2.5	1.8	595	247

Historic SAIDI-IEEE & Total



Historic SAIFI-IEEE & Total





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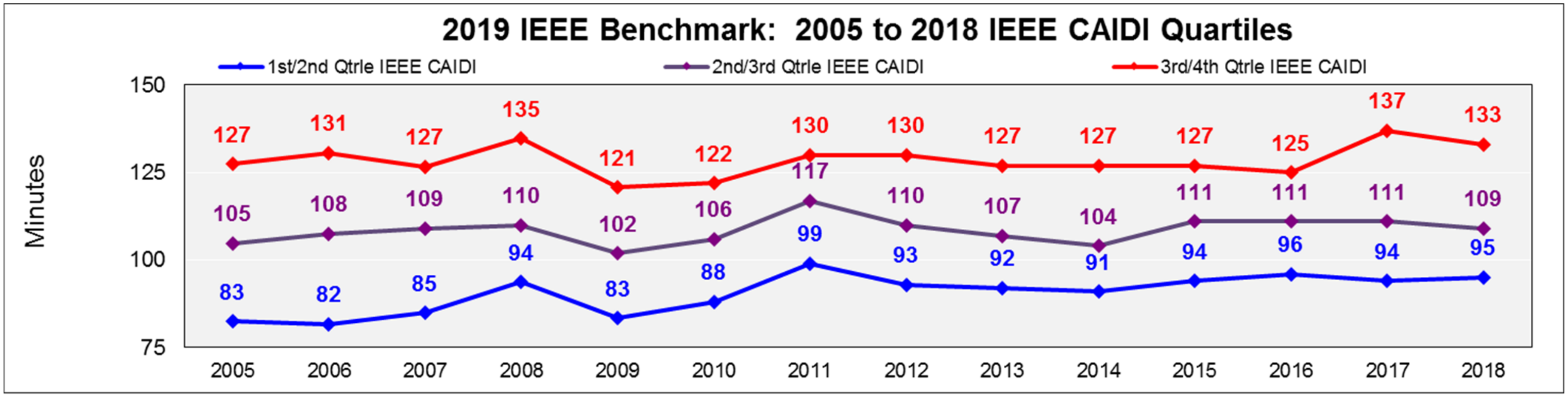
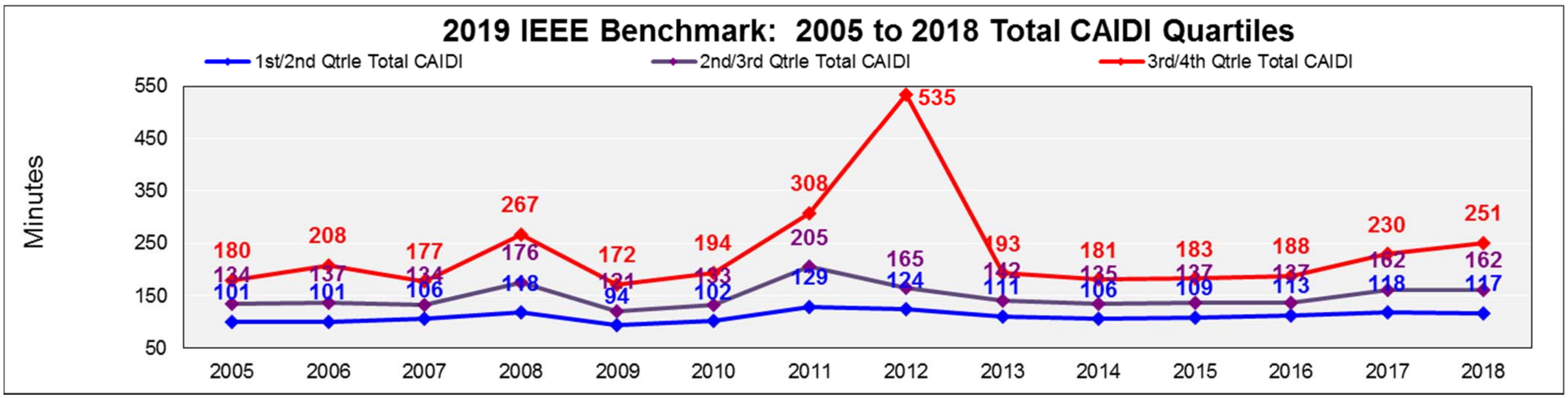
Historic CAIDI-IEEE & Total





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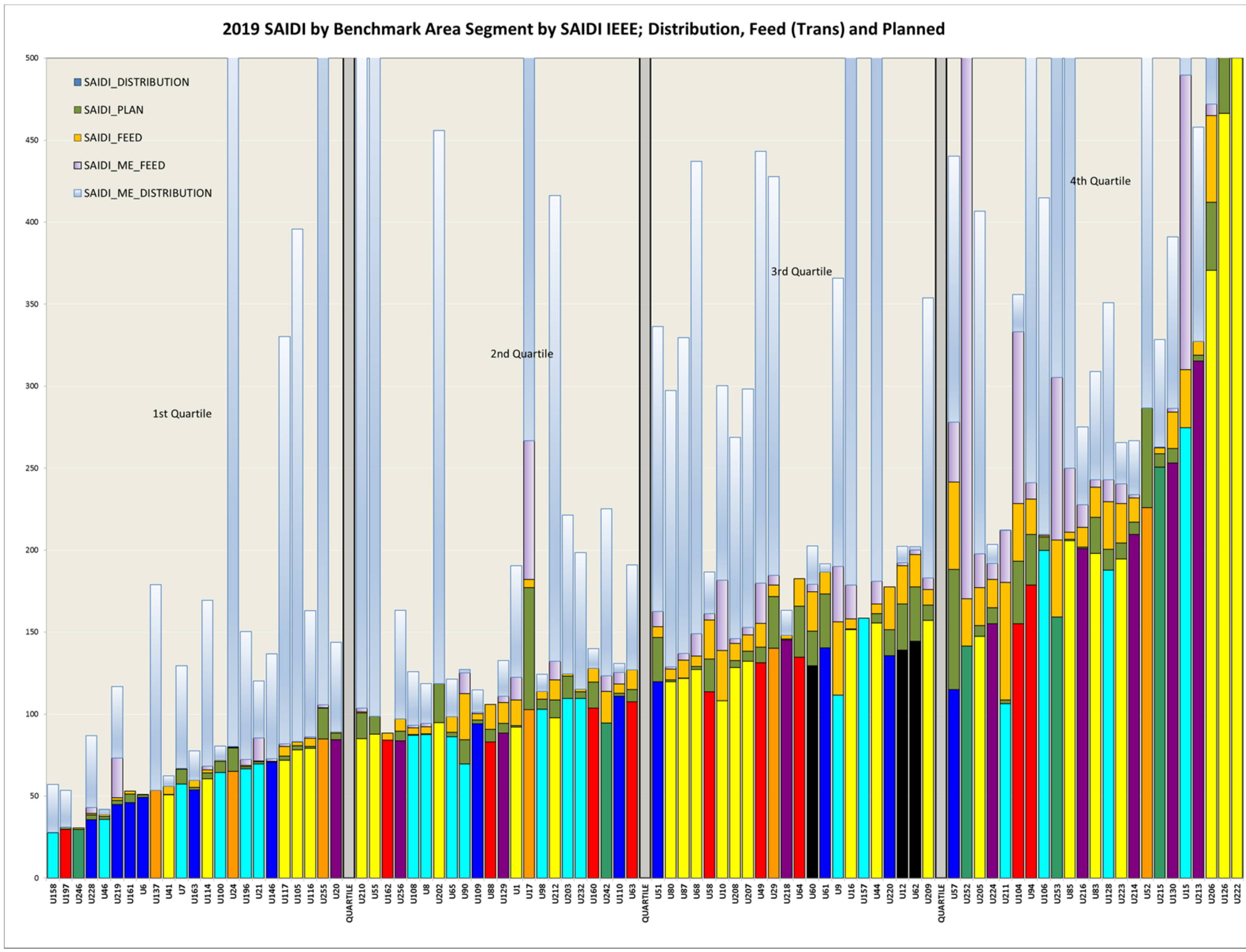
2019 SAIDI

Ordered by IEEE w/ME, Feed & Plan



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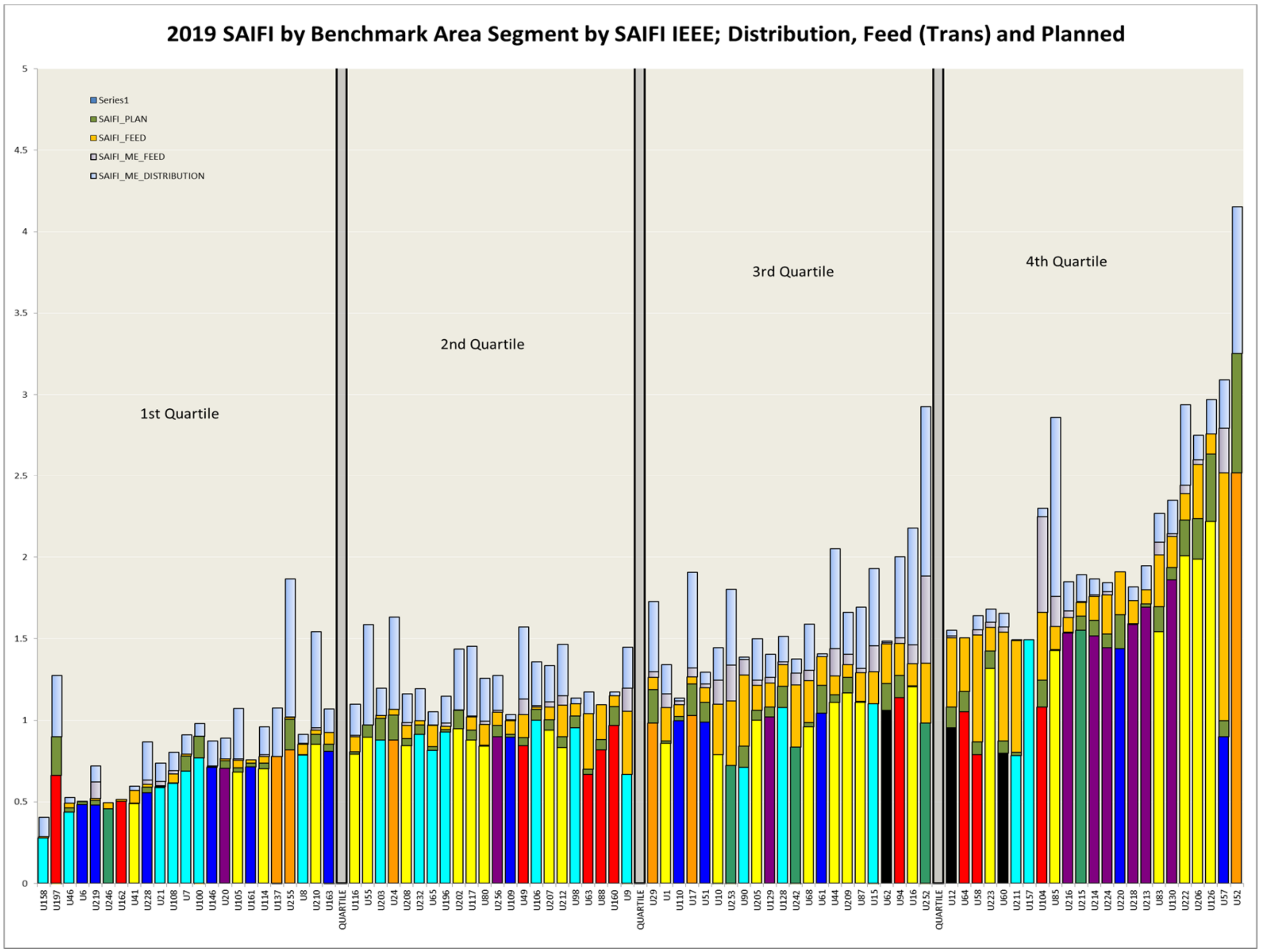
2019 SAIFI

Ordered by IEEE w/ME, Feed & Plan



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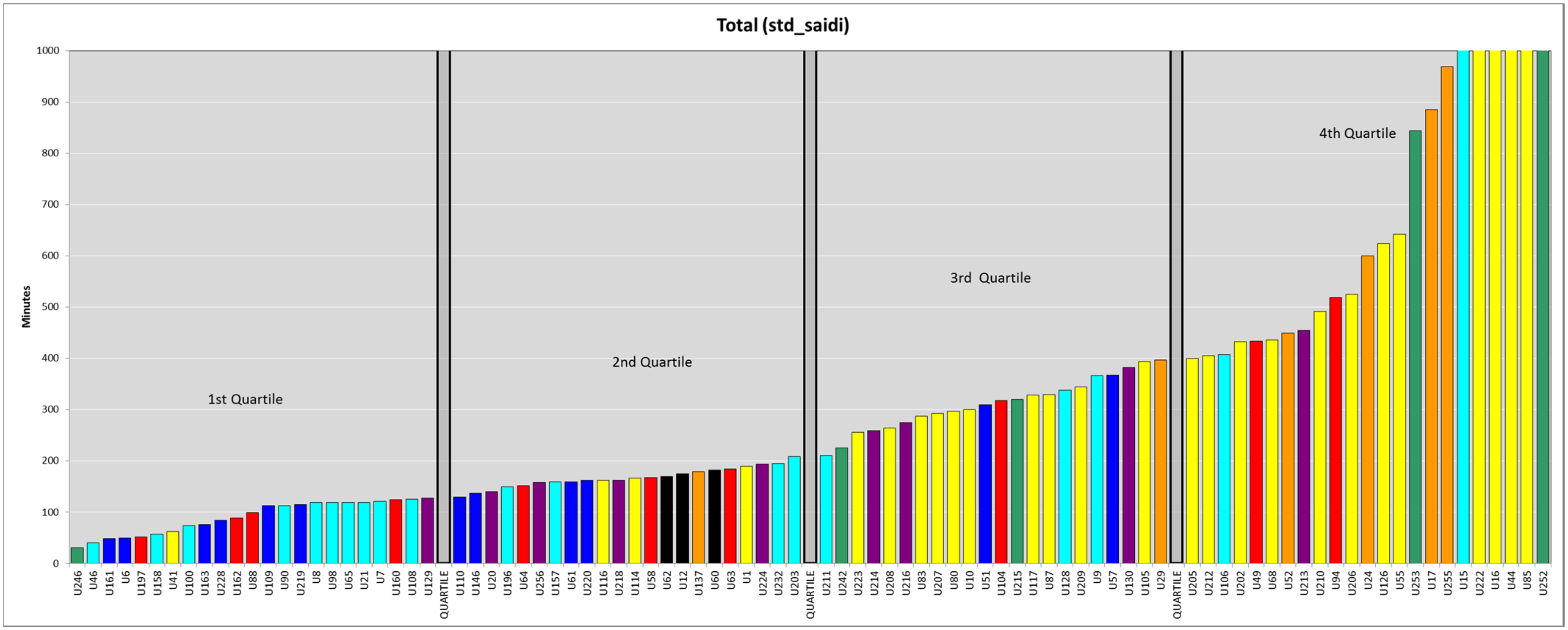
Total (STD) SAIDI 2019



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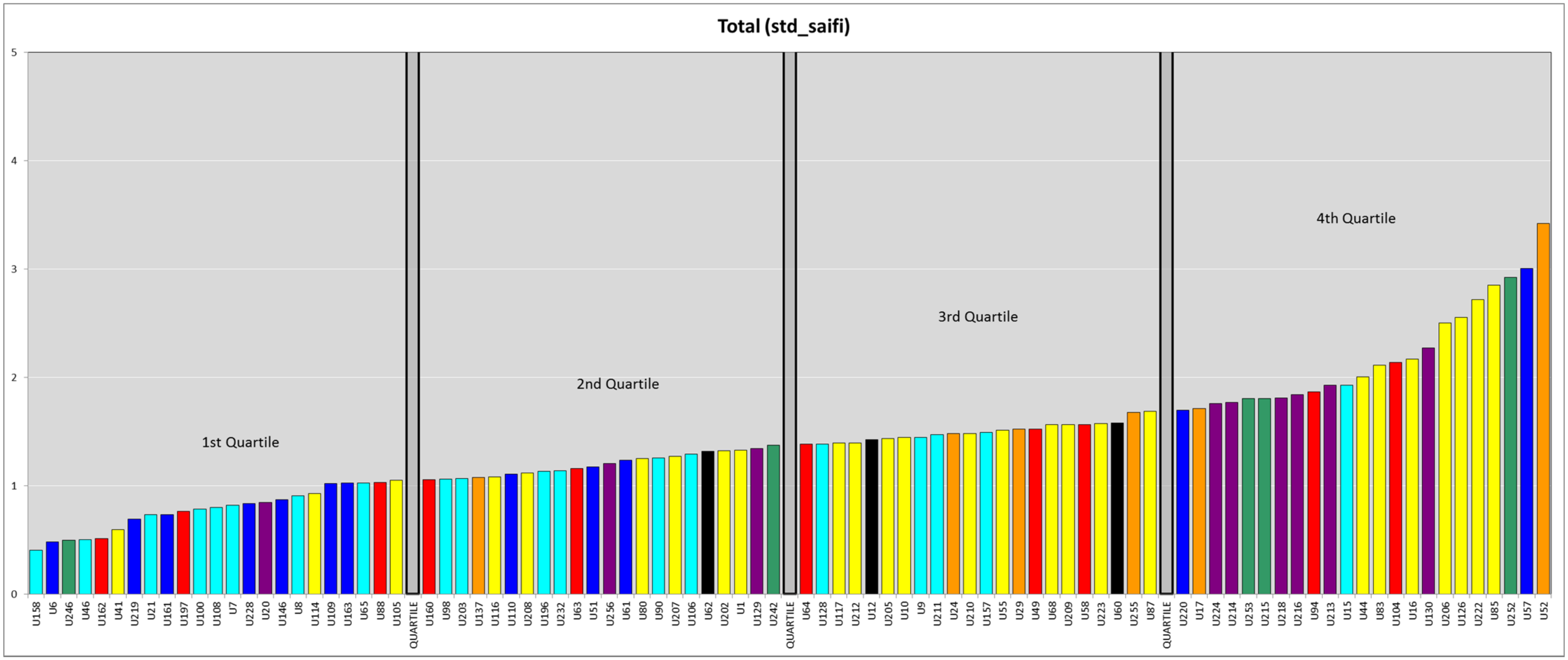

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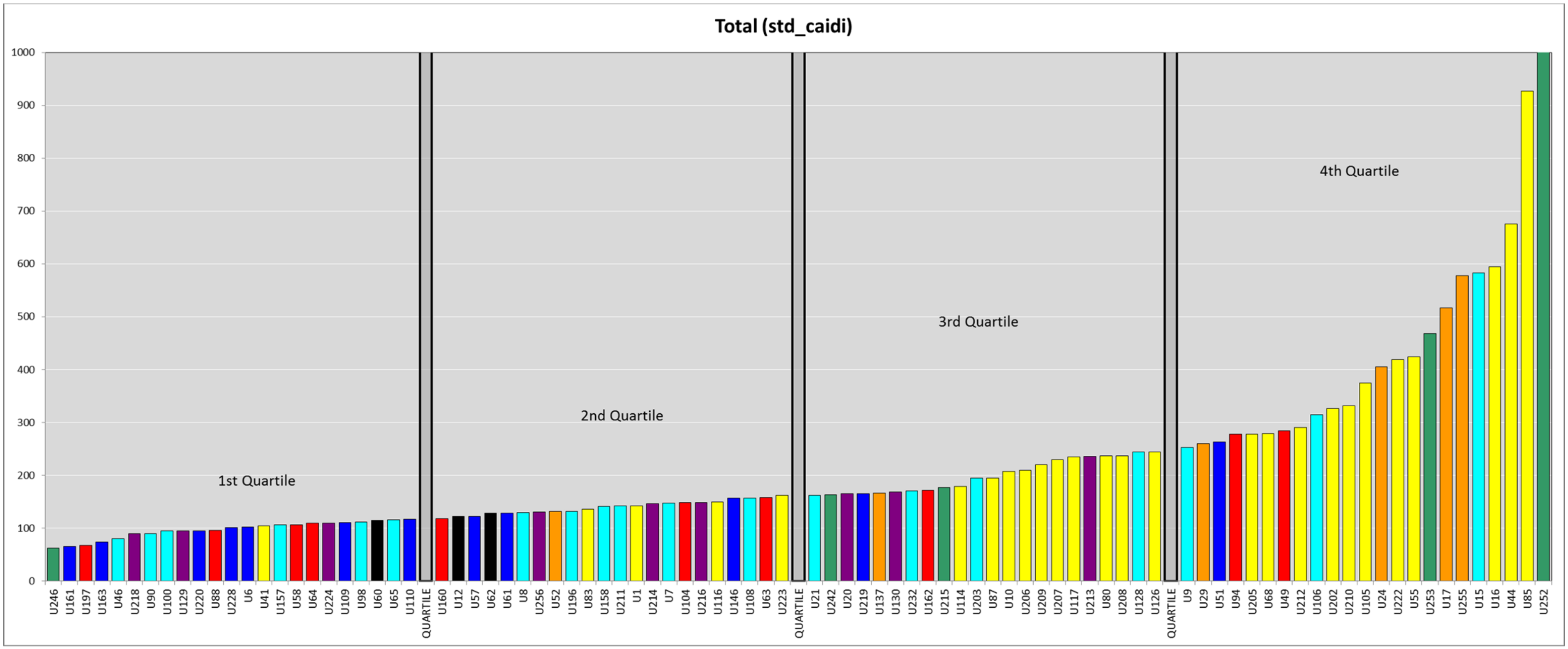

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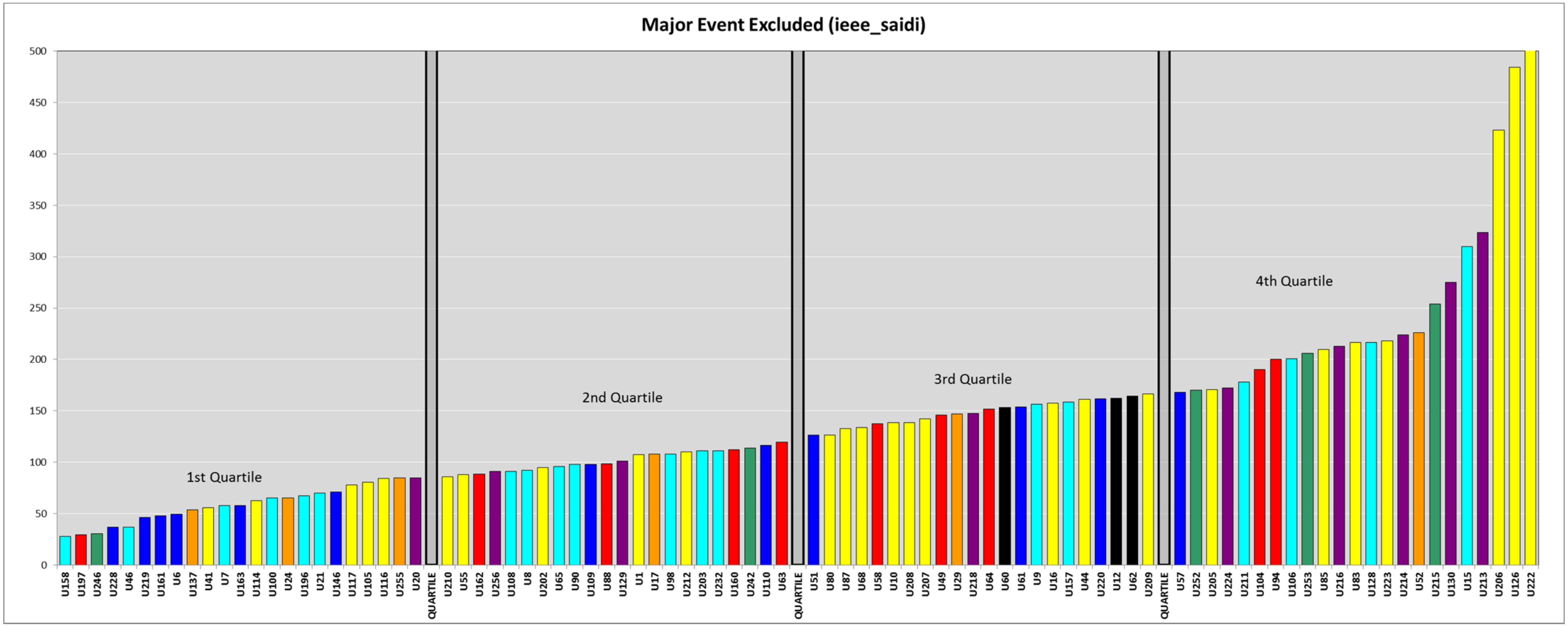
Major Event Excluded (IEEE SAIDI 2019)



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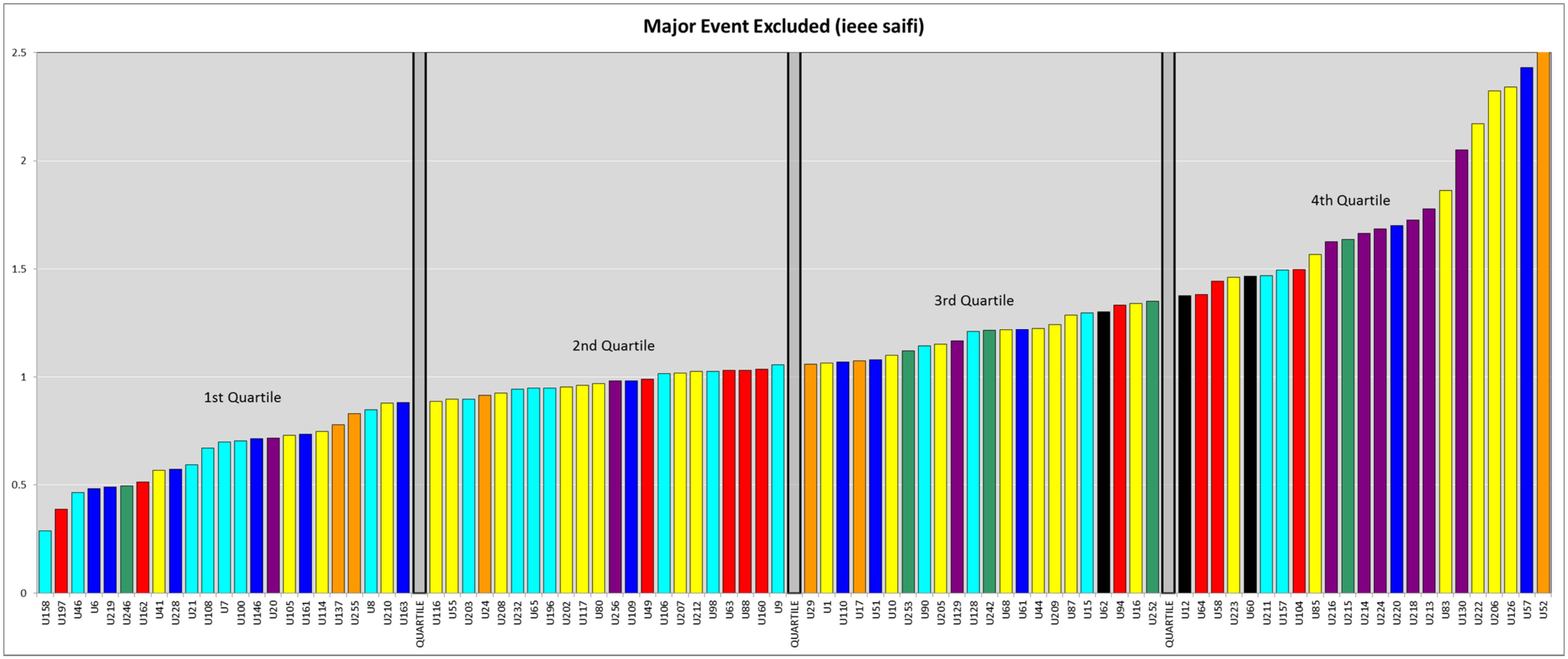
Major Event Excluded (IEEE SAIFI 2019)



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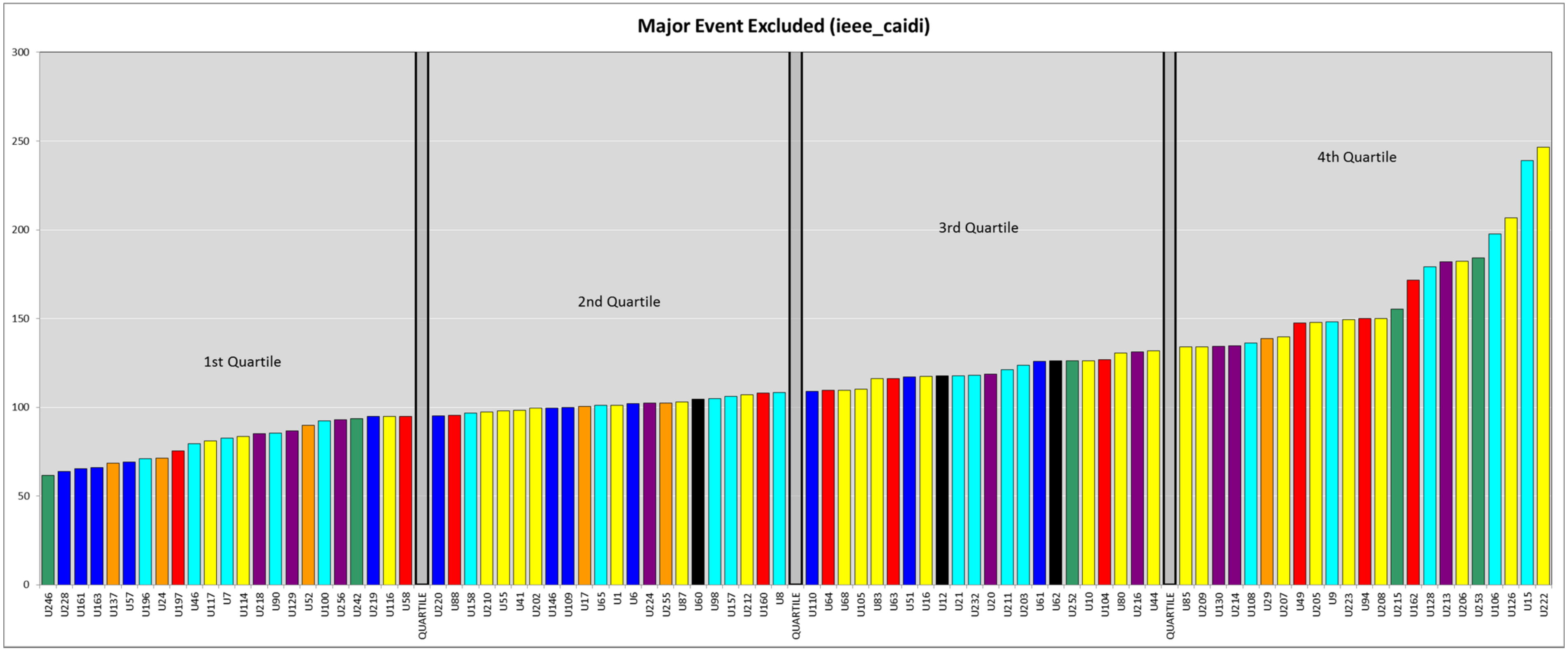
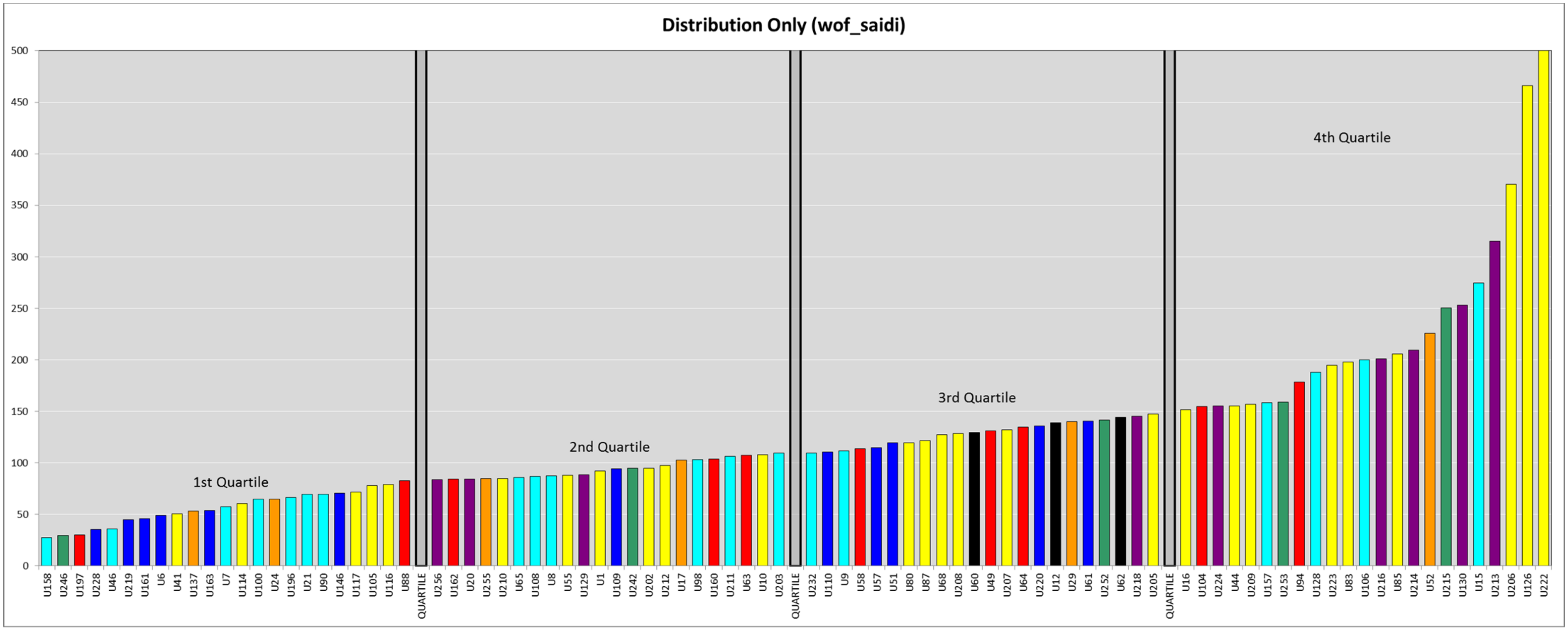
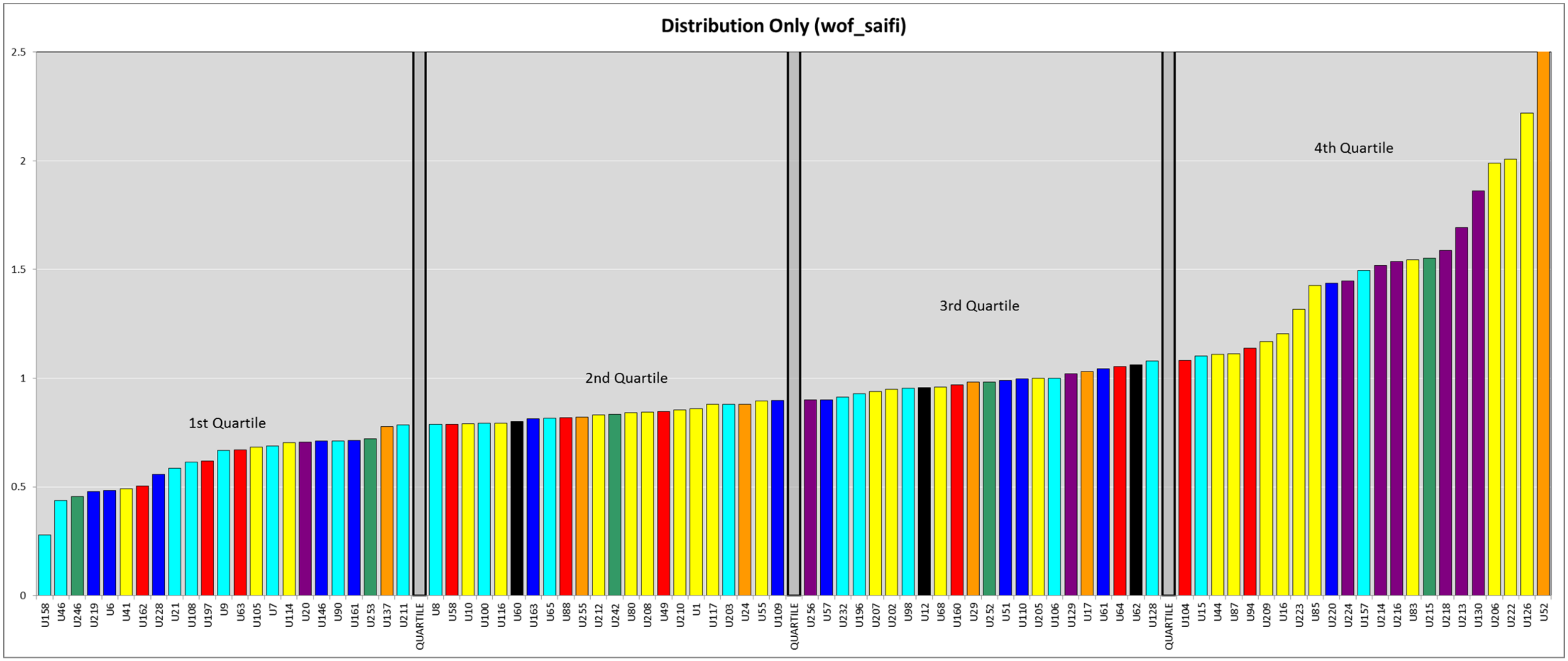


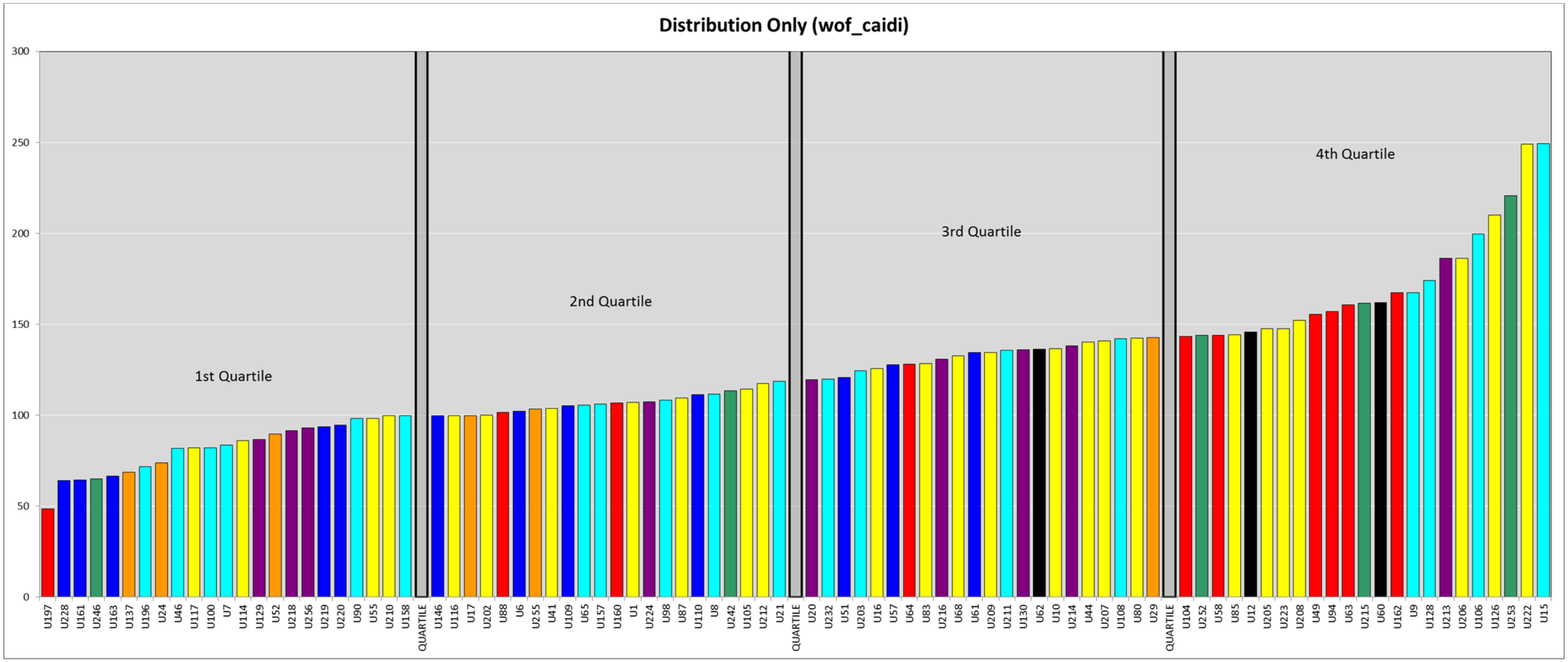
Distribution Only (WOF) SAIDI 2019



Distribution Only (WOF) SAIFI 2019



Distribution Only (WOF) CAIDI 2019



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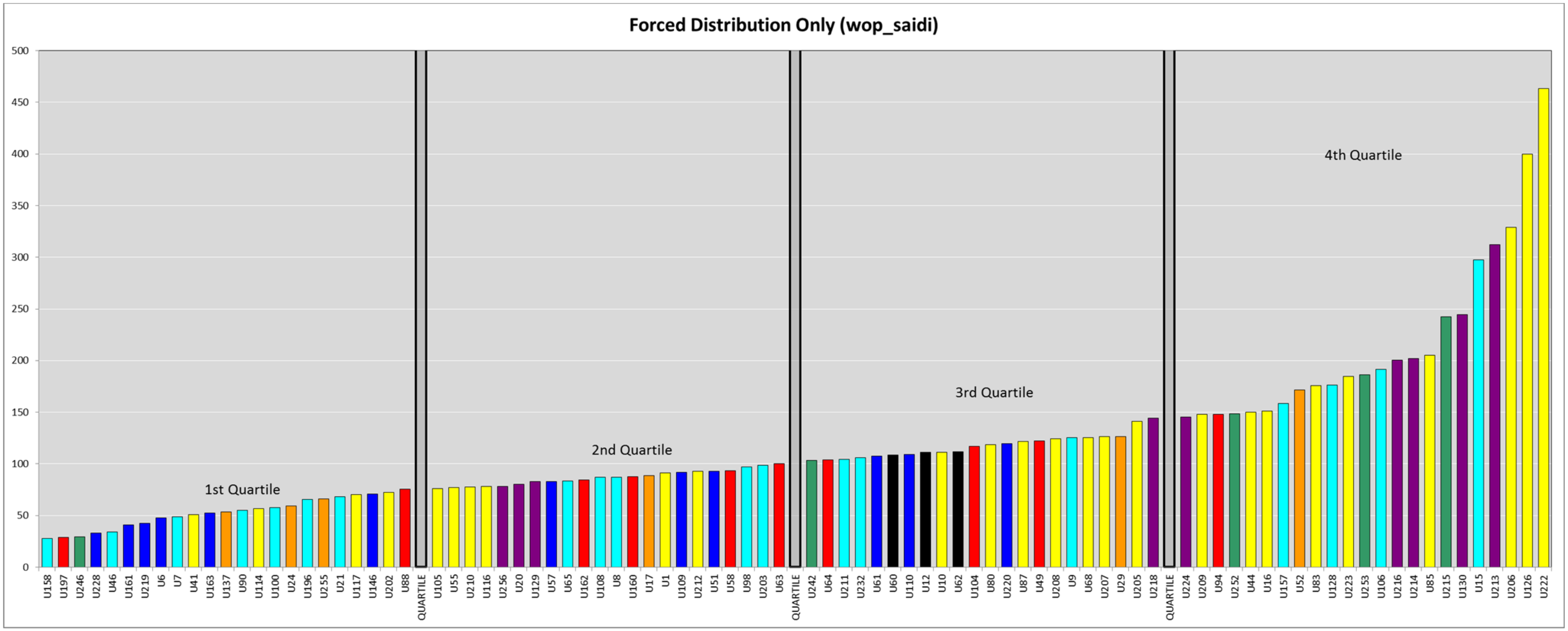
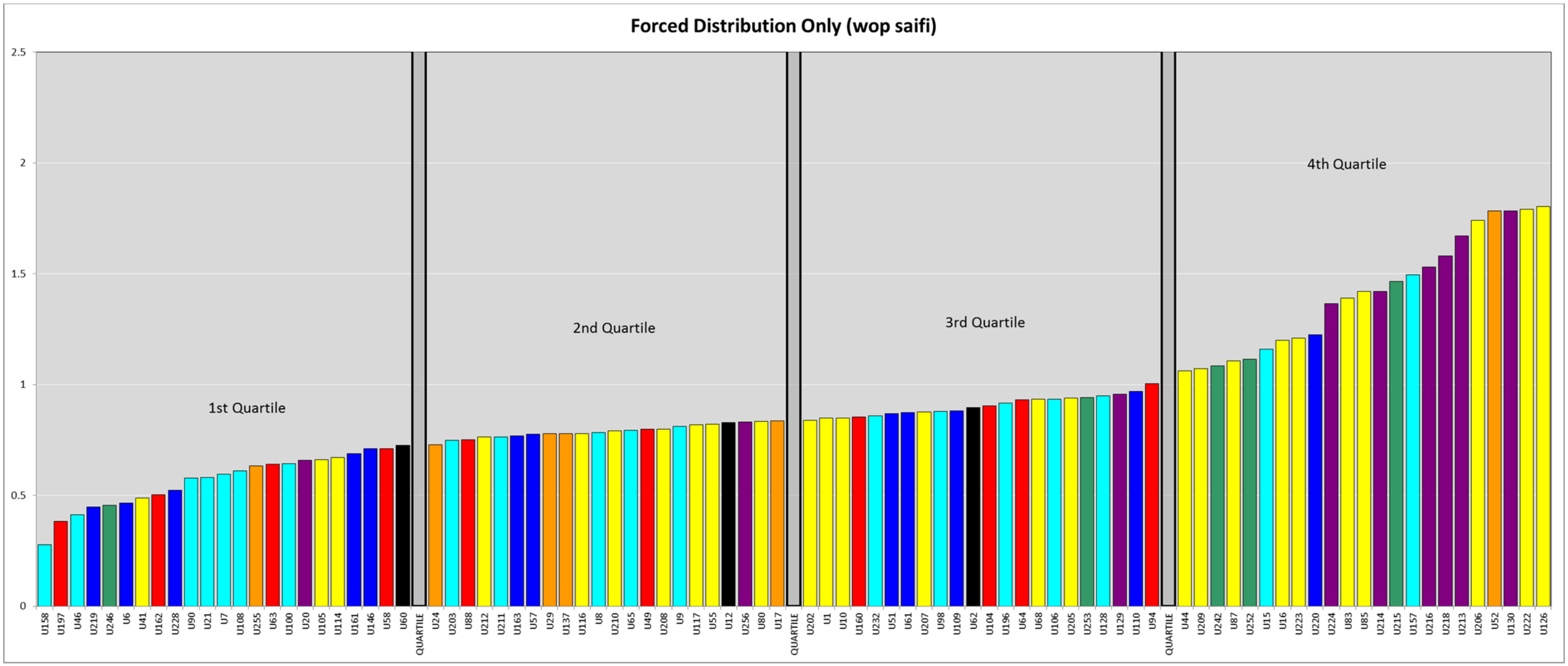
Forced Distribution Only (WOP) SAIDI 2019



Forced Distribution Only (WOP) SAIFI 2019



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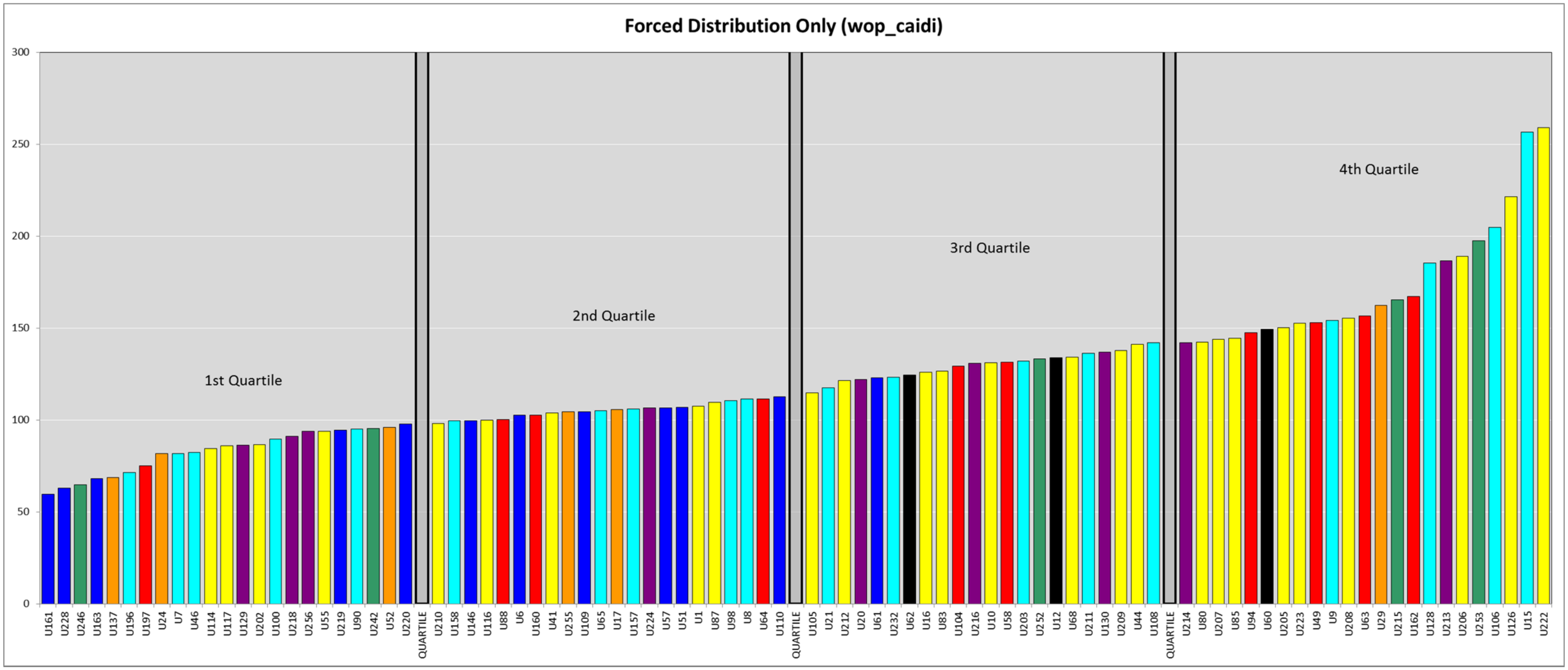

Questions

25

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☒ **Public Document**

Xcel Energy Information Request No. 4

Docket No.:	E002/M-19-666
Response To:	Fresh Energy
Requestor:	Isabel Ricker
Date Received:	January 13, 2020

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) page 75.

Request:
Fresh Energy understands that Synergi offers an Incremental Hosting Capacity Analysis (IHCA) tool and that Xcel would not have incremental or additional technology costs if it used Synergi to complete the hosting capacity analysis. Please explain why Xcel Energy continues to use DRIVE instead of the Synergi IHCA tool for its hosting capacity analysis.

Response:

Questions about hosting capacity analysis are best addressed in Docket No. E002/M-19-685. The Integrated Distribution Plan merely summarizes the Company's hosting capacity analysis, as it does for other matters that have their own regulatory docket. That said, the comments period is still open in the current hosting capacity docket, so we will provide the requested information in our January 27, 2019 Supplemental Comments in that proceeding.

Preparer:	Jody Londo
Title:	Regulatory Policy Specialist
Department:	Regulatory Affairs
Telephone:	612.330.5601
Date:	January 23, 2020

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Xcel Energy		Information Request No. 5
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) page 94.

Request:
Please provide all data, analysis, studies, reports, or spreadsheets with all formulas and links intact supporting the cost estimate of $400,000 per MWh for battery storage.

Response:

Northern States Power Company objects to this Request as overly broad and unduly burdensome. Subject to the foregoing objection, we respond as follows:

We based our $400,000 per MWh battery storage cost estimate on industry estimates. A public study we relied on is the November 2018 NREL Technical Report, NREL/TP-6A20-71714, provided as Attachment A to this response.

Preparer:	Luther Miller
Title:	Distribution Planning Engineer
Department:	System Planning
Telephone:	763-493-1893
Date:	January 23, 2020

2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark

Ran Fu, Timothy Remo, and Robert Margolis

National Renewable Energy Laboratory

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
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Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-6A20-71714
November 2018

2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark

Ran Fu, Timothy Remo, and Robert Margolis

National Renewable Energy Laboratory

Suggested Citation

Fu, Ran, Timothy Remo, and Robert Margolis. 2018. *2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71714. https://www.nrel.gov/docs/fy19osti/71714.pdf.

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Office of Energy Efficiency & Renewable Energy
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Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-6A20-71714
November 2018

National Renewable Energy Laboratory
15013 Denver West Parkway
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List of Acronyms

AC	alternating current
BOS	balance of system
CAES	compressed air energy storage
DC	direct current
DOE	U.S. Department of Energy
EPC	engineering, procurement, and construction
HVAC	heating, ventilating, and air conditioning
ILR	inverter loading ratio
LCOS	levelized cost of storage
Li	lithium
PV	photovoltaic(s)
SG&A	selling, general, and administrative

Executive Summary

The recent rapid growth of utility-scale photovoltaic (PV) deployment and the declining costs of energy storage technologies have stimulated interest in combining PV with energy storage to provide dispatchable energy (i.e., energy on demand) and reliable capacity (i.e., grid stability). In particular, the use of lithium-ion batteries in U.S. utility-scale applications has grown in recent years owing to the technology's favorable cost and performance characteristics. This study is our first time to use bottom-up modeling to benchmark the installed costs of various standalone lithium-ion storage (with storage connected to the grid only) and PV-plus-storage (with storage connected to PV and the grid) system configurations. The PV-plus-storage configurations include 1) co-located PV-plus-storage systems vs. PV-plus-storage systems in different locations, and 2) direct current (DC) coupled vs. alternating current (AC) coupled battery configurations for the co-located PV-plus-storage systems.

Figure ES-1 shows the modeled costs of standalone lithium-ion energy storage systems with an installed capacity of 60 MW able to provide electricity for several different durations. Assuming a constant per-energy-unit battery price of $209/kWh, the system costs vary from $380/kWh (4-hour duration system) to $895/kWh (0.5-hour duration system). The battery cost accounts for 55% of total system cost in the 4-hour system, but only 23% in the 0.5-hour system. At the same time, non-battery cost categories accounts for an increasing proportion of the system cost as duration declines.

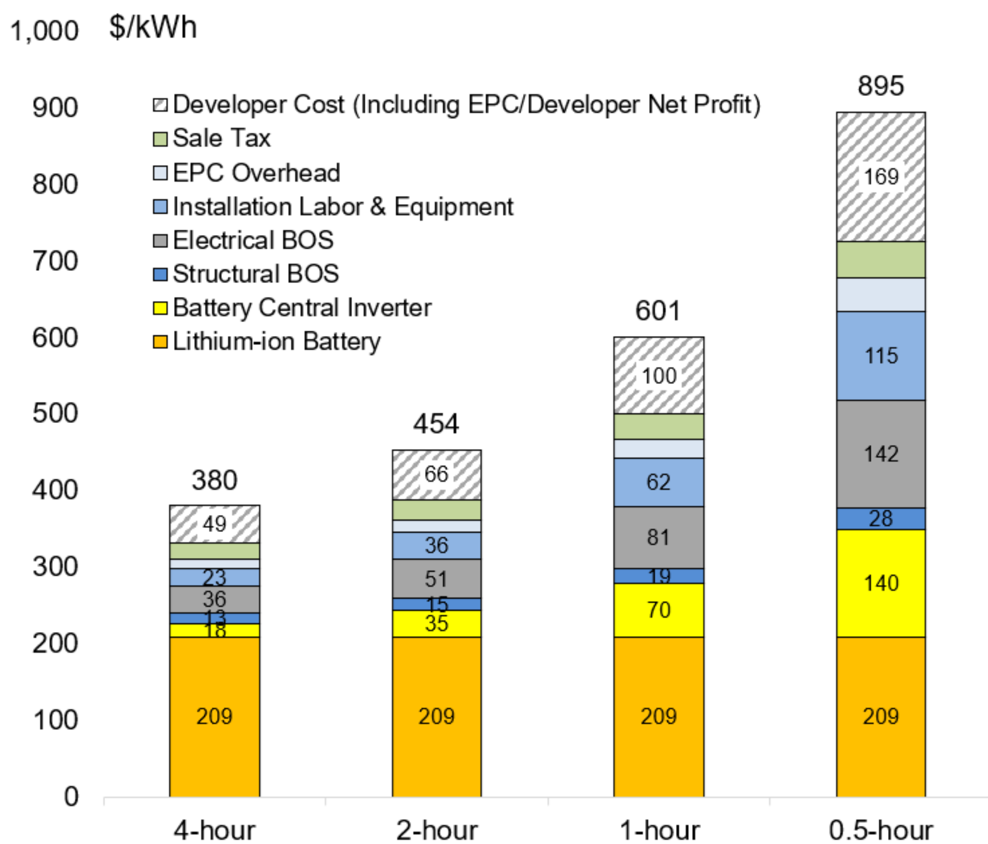

Figure ES-1. 2018 U.S. utility-scale lithium-ion standalone storage costs for durations of 0.5–4 hours (60 MW_{DC})

Figure ES-2 summarizes our PV-plus-storage model results for several system types and configurations. Each uses a 100-MW PV system and a 60-MW lithium-ion battery that provides 4 hours of storage:

- Standalone 100-MW PV system with one-axis tracking ($111 million)
- Standalone 60-MW/240-MWh, 4-hour-duration energy storage system ($91 million)
- Co-located, DC-coupled PV (100 MW) plus storage (60 MW/240 MWh, 4-hour duration) system ($186 million)
- Co-located, AC-coupled PV (100 MW) plus storage (60 MW/240 MWh, 4-hour duration) system ($188 million)
- PV (100 MW) plus storage (60 MW/240 MWh, 4-hour duration) system with PV and storage components sited in different locations ($202 million)

Co-locating the PV and storage subsystems produces cost savings by reducing costs related to site preparation, land acquisition, permitting, interconnection, installation labor, hardware (via sharing of hardware such as switchgears, transformers, and controls), overhead, and profit. The cost of the co-located, DC-coupled system is 8% lower than the cost of the system with PV and storage sited separately, and the cost of the co-located, AC-coupled system is 7% lower.

Using DC-coupling rather than AC-coupling results in a 1% lower total cost, which is the net result of cost differences between DC-coupling and AC-coupling in the categories of solar inverter, structural balance of system (BOS), electrical BOS, labor, EPC (engineering, procurement, and construction) and developer overhead, sales tax, contingency, and profit. For an actual project, however, cost savings may not be the only factor in choosing DC or AC coupling. Additional factors—such as retrofit considerations, system performance, design flexibility, and operations and maintenance—should be considered.

The benchmarked costs could facilitate PV-plus-storage project development, and the itemized cost savings could incentivize deployment of co-located PV-plus-storage systems. In addition, the model can help industry representatives evaluate the cost impacts of various battery durations for grid applications. Finally, the model can be used to estimate future potential cost-reduction opportunities for PV-plus-storage systems, helping to guide research and development aimed at advancing cost-effective system configurations.

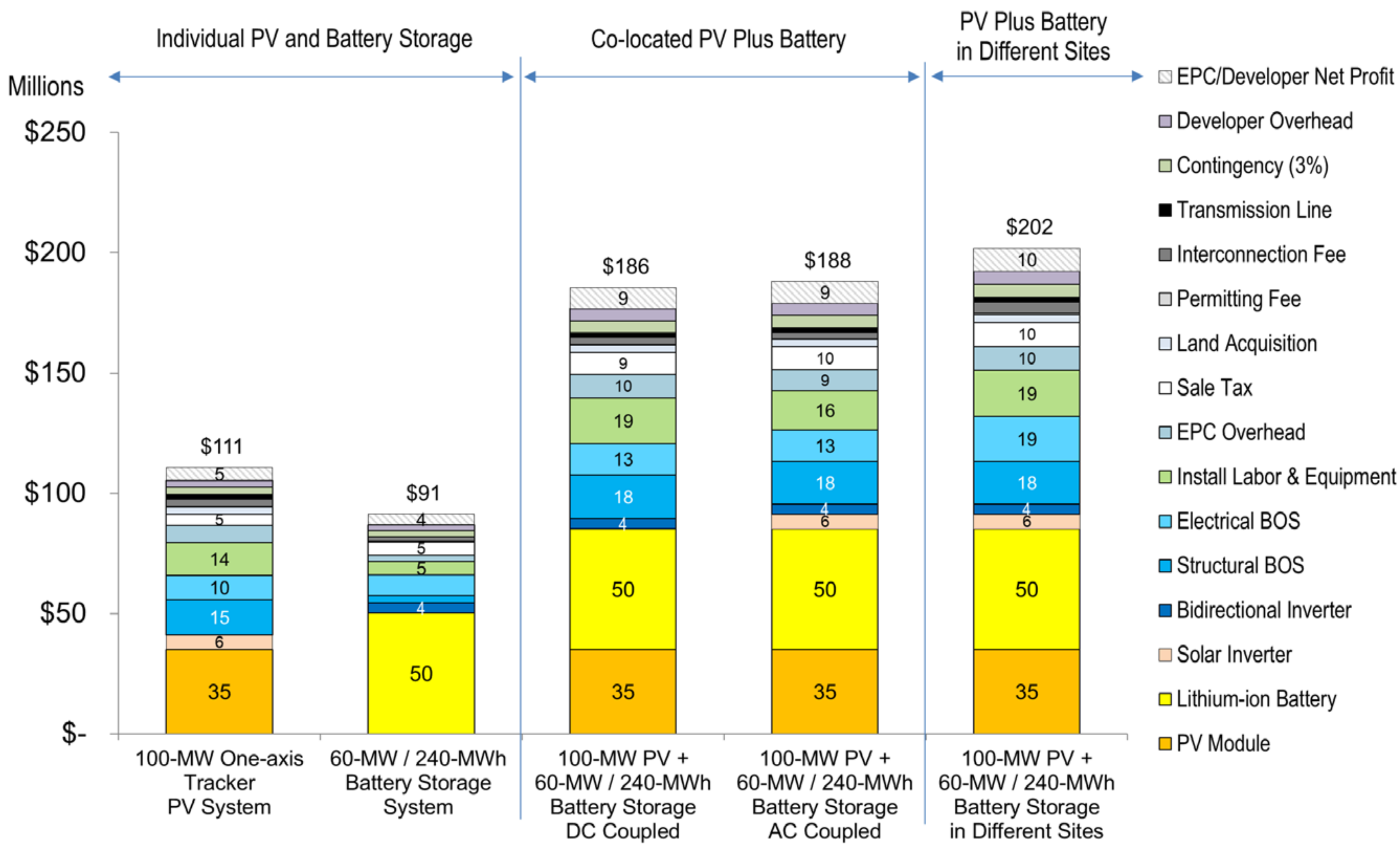

Figure ES-2. 2018 Cost benchmarks for PV-plus-storage systems (4-hour duration) in different sites and the same site (DC-coupled and AC-coupled cases)

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1 Introduction

The recent rapid growth of utility-scale photovoltaic (PV) deployment and the declining costs of energy storage technologies have stimulated interest in combining PV with energy storage to provide dispatchable energy and reliable capacity—particularly as the U.S. utility storage market has begun moving away from short-term power regulation and toward longer-term temporal shifting of renewable generation. The large-scale power interruptions caused by recent extreme weather/fire events in Puerto Rico, Houston, and California have also highlighted the need to improve the reliability and resiliency of U.S. electricity systems. The integration of renewable generation and energy storage offers a way to cost-effectively diversify and strengthen the nation's energy portfolio.

Historically, cost has been a barrier to deployment of PV and storage technologies, but improvements in both types of technologies are changing the economics rapidly. In particular, the use of lithium-ion (Li-ion) batteries in U.S. utility-scale applications has grown in recent years owing to the technology's favorable cost and performance characteristics. Still, utility-scale PV-plus-storage applications are in their infancy. The only such U.S. system recorded in the U.S. Department of Energy (DOE) Energy Storage Database is a 13-MW PV plus 52-MWh energy storage system in Kauai, Hawaii.

In order to provide a baseline for the accurate and transparent assessment of utility-scale PV-plus-storage systems, in this report we use the National Renewable Energy Laboratory's new bottom-up modeling tool to benchmark the installed costs of various standalone Li-ion storage and PV-plus-storage system configurations for utility-scale applications. Our analysis illustrates the tradeoffs between system choices including short- versus long-duration batteries, co-location versus separate location of battery and PV subsystems, and direct current (DC) versus alternating current (AC) coupling of co-located PV-plus-storage systems.

The remainder of this report is structured as follows. Section 2 provides a brief overview of energy storage technology options and deployment history. Section 3 focuses on Li-ion battery storage trends. Section 4 describes our cost models, and Section 5 shows the modeled cost results.

2 Energy Storage Technology Options and Deployment History

Numerous energy storage technologies have been deployed over the past century. Early large-scale systems typically employed physical or thermal storage media. However, widespread use of such systems has been hindered by cost, energy density, and siting disadvantages.

For example, in a pumped hydro storage system, water is pumped uphill into a reservoir and later released downhill through hydroelectric turbines to convert the stored potential energy into electricity. The first large-scale U.S. pumped hydro system was built in 1929 near New Milford, Connecticut (DOE 2018). In 1985, the country's largest pumped hydro system—with a generation capacity of 3 GW—was completed in Bath County, Virginia, after 8 years of construction (DOE 2018). Nationwide, 40 pumped hydro systems are operating today (DOE Energy Storage Database 2018). This technology typically has a roundtrip energy efficiency of 70%–80%, but siting presents major challenges. Cost-effective sites must have characteristics that enable damming of waterways to create a reservoir, usually requiring a large area remote from energy-demand centers. Even when a suitable site is identified, environmental and land-ownership considerations may hinder project approvals.

Compressed air energy storage (CAES) is another established technology that uses a physical storage mechanism. Energy is stored via air compression, and later the air is expanded to generate electricity. The lone large CAES system operating in the United States is the 110-MW plant in McIntosh, Alabama, which uses compressed air to run a natural gas turbine more efficiently (DOE Energy Storage Database 2018). CAES entails drawbacks that have hindered its deployment. Large-scale systems typically require specific geographical characteristics such as underground caverns that can be sealed to hold the compressed air. In addition, roundtrip efficiency of current technologies is only 40%–55% (Chen et al. 2013), and natural gas is consumed in the reconversion process. However, emerging CAES approaches offer higher theoretical efficiencies and generation without the need for fossil fuel combustion (Energy Storage Association 2018).

More recently, other types of energy storage have begun to be deployed at scale. Figure 1 shows the characteristics of energy storage technologies for systems built between 1958 and 2017 worldwide, categorized by storage type: electrochemical, electromechanical, thermal, and hydrogen.[1] Pumped hydro is not shown because its global capacity is much larger than the capacity of the other technologies. These technologies can be grouped into power applications (short duration or discharge time, such as Li-ion batteries) and energy applications (long duration or discharge time, such as CAES). Excluding pumped hydro, the technologies with the largest deployed capacities are molten salt thermal storage (associated with concentrating solar power plants), CAES, and Li-ion batteries.

[1] These data are from the DOE Energy Storage Database, an open-access source of energy storage project information that allows users to contribute data through a third-party vetting process; see the appendix for the figure data.

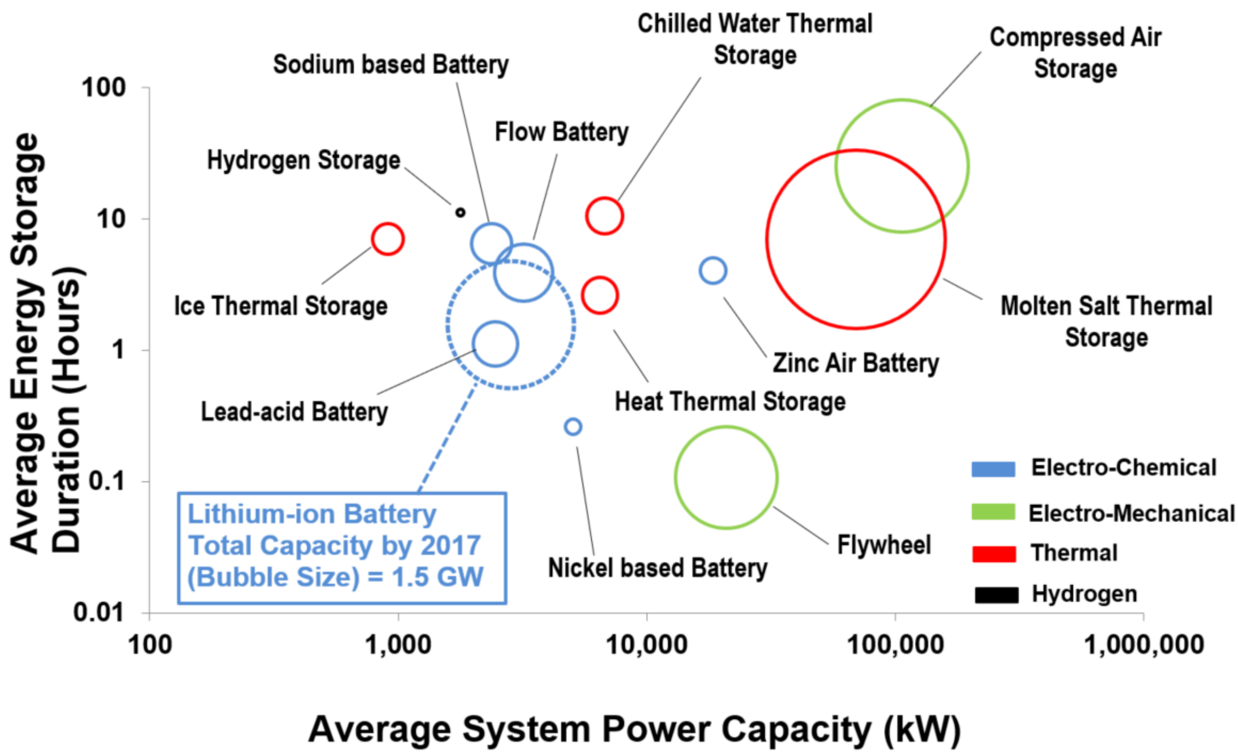


Figure 1. Average characteristics of energy storage systems built worldwide between 1958 and 2017, by technology, from the DOE Energy Storage Database (2018), sample size = 1,041 (pumped hydro not shown because of its very large global capacity)

Figure 2 shows the rapid recent growth of Li-ion energy storage. The first recorded utility-scale Li-ion project, the 1-MW Altairnano-PJM Battery Ancillary Services Demo in Pennsylvania, was built in 2008. Between 2008 and 2015, Li-ion capacity grew at a compound annual growth rate of 173% in terms of cumulative capacity, and Li-ion capacity accounted for 89% of annual energy storage capacity in 2015. The data for 2016 and 2017 are preliminary and incomplete, because some projects built in this time frame are still being verified in the database.

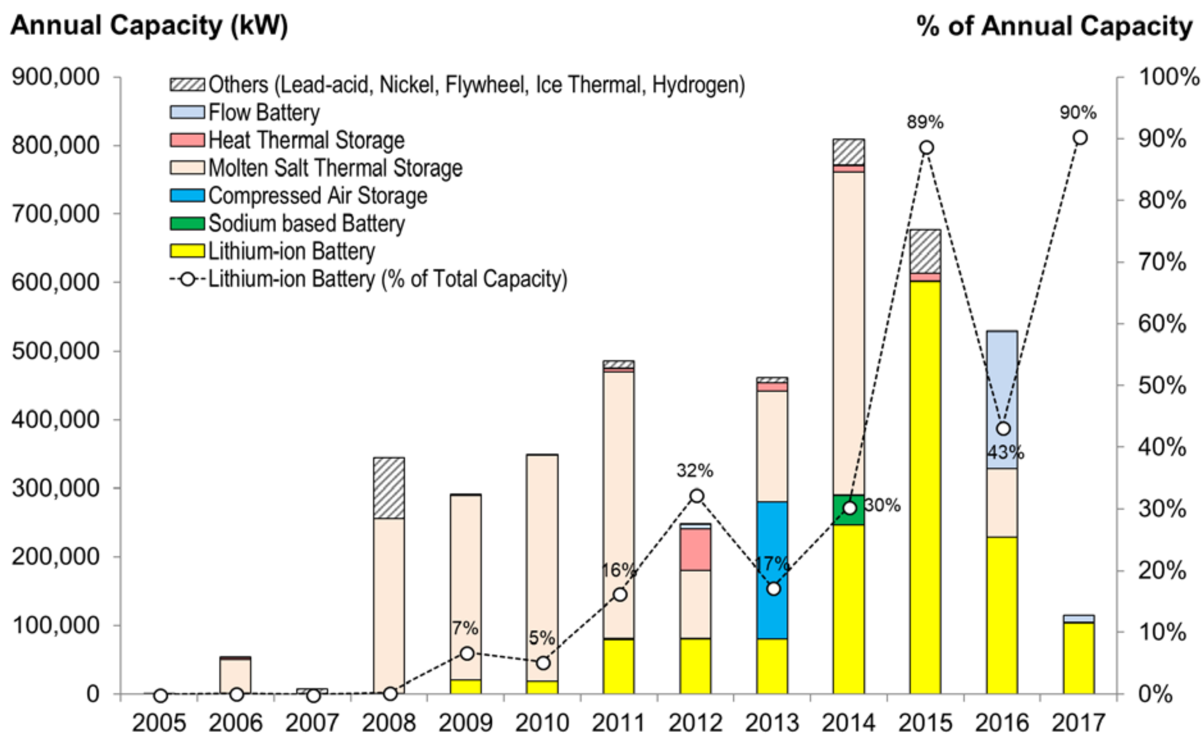


Figure 2. Annual capacities of energy storage systems built worldwide between 2005 and 2017, by technology, from the DOE Energy Storage Database (2018)[2]

[2] The data for 2016 and 2017 are preliminary and incomplete, because some projects built in this time frame are still being verified in the database.

3 Lithium-Ion Battery Storage Trends

Utilities have begun adopting Li-ion storage because of the technology's high roundtrip efficiency, high power density, ample supply chain availability, falling cell and system costs, and favorable performance metrics. Most Li-ion applications to date have provided short-duration power and grid stabilization, capturing value from various services including frequency response, voltage regulation, spinning reserves, transmission deferment, peak shaving, and demand response—and often providing a positive rate of return through this value stacking. Worldwide, Li-ion systems have an average duration of 1.6 hours and a power rating of 2.8 MW per system (Figure 1). Providing load shifting will require larger battery packs, which currently account for the largest share of system cost.

The United States is the world's leader in Li-ion storage deployment, mostly because of utility-scale storage systems. Between 2008 and 2017, it accounted for 40% of cumulative global Li-ion capacity (Figure 3). Of the U.S. Li-ion capacity through 2017, approximately 495 MW (92% of the capacity) was deployed in the utility-scale sector (systems larger than 1,000 kW), 8% in the commercial sector (systems of 10–1,000 kW), and less than 1% in the residential sector (systems smaller than 10 kW), as shown in Figure 4.

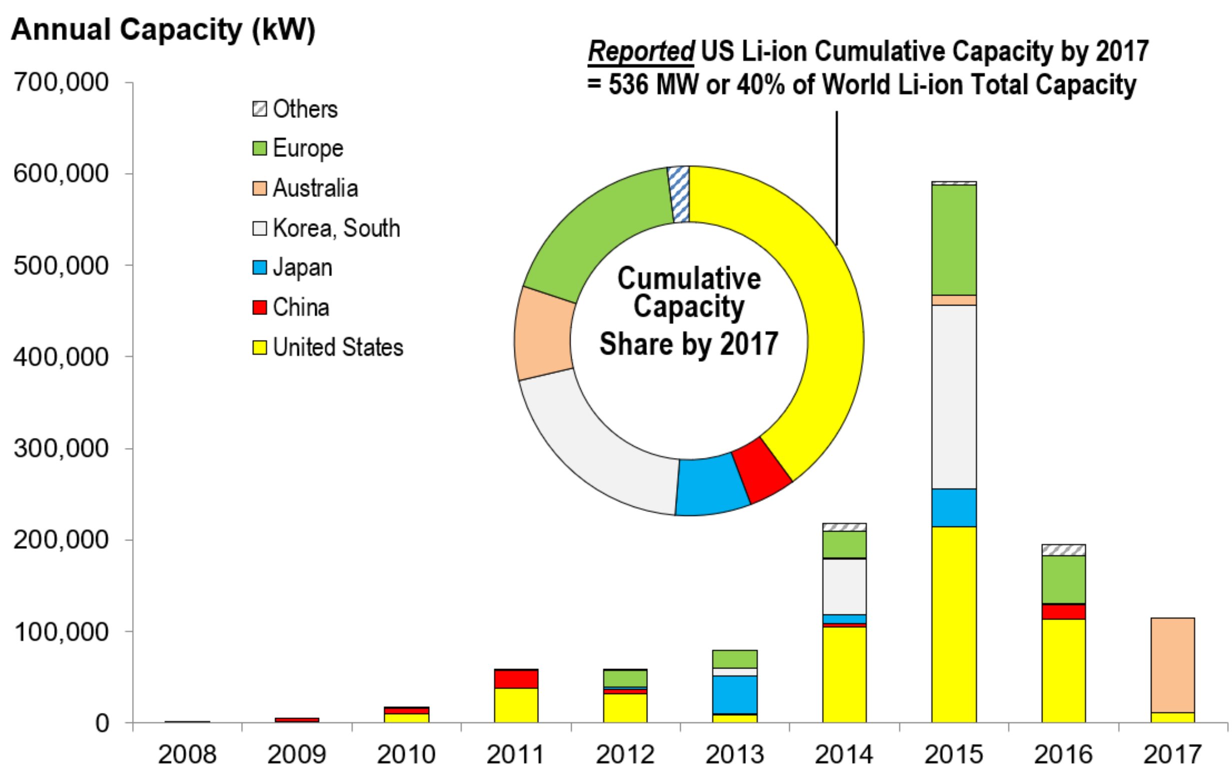


Figure 3. Li-ion storage deployment by region, 2008–2017 (DOE Energy Storage Database 2018)[3]

[3] The data for 2016 and 2017 are preliminary and incomplete owing to ongoing project verification for those years.

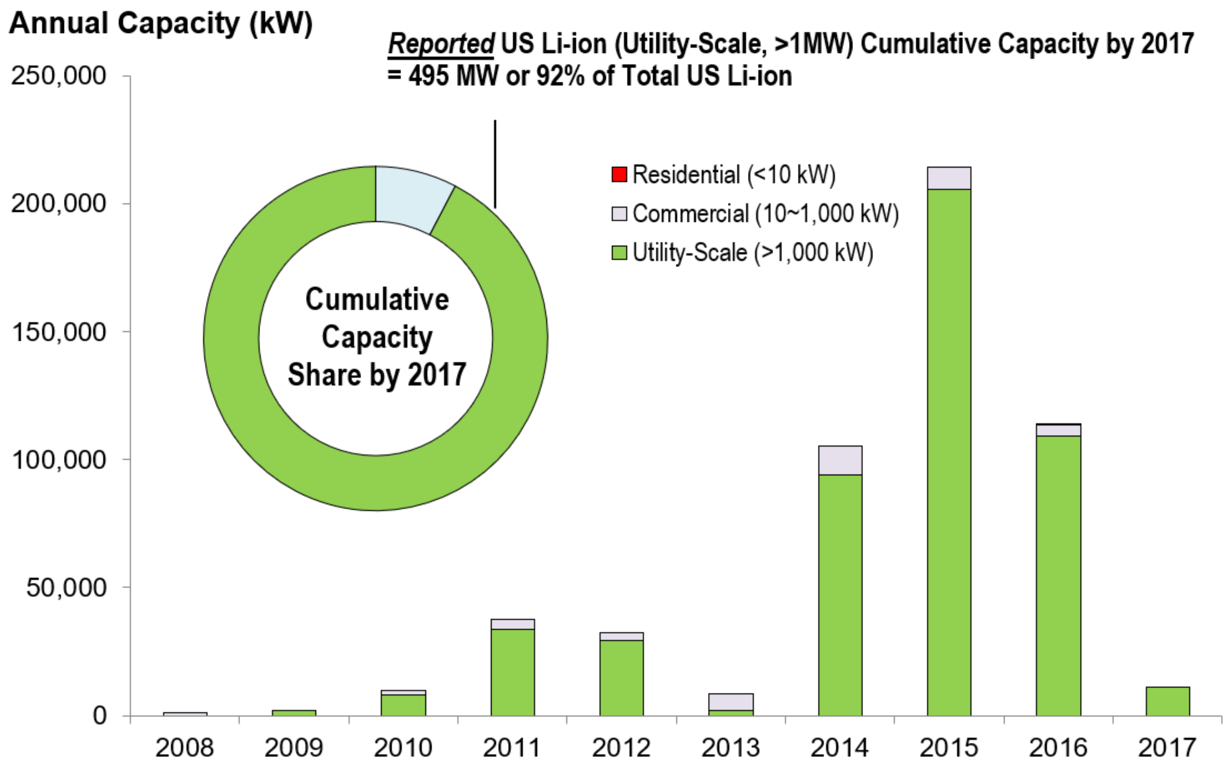


Figure 4. U.S. Li-ion energy storage by sector, 2008–2017 (DOE Energy Storage Database 2018)[4]

Figure 5 and Table 1 characterize U.S. Li-ion storage systems by sector. On average, utility-scale systems have a power rating of 9.9 MW and a duration of 1.7 hours. The utility-scale duration varies from about 0.5 to 4 hours between the 10^{th} and 90^{th} percentiles. For this reason, we model four utility-scale Li-ion storage duration cases: 0.5, 1, 2, and 4 hours. At the short end of the duration spectrum, the storage would mainly be used to maintain the real-time balance between generation and load as well as smooth short-term variations in voltage and current for frequency response. At the long end, the storage could defer transmission and distribution upgrades as well as mitigate variable energy output caused by renewable generation.

In this report, we focus on utility-scale storage systems. A previous report focused on residential storage systems (Ardani et al. 2017). For the baseline case, we use 4-hour storage according to the California Public Utilities Commission's "4-hour rule," which credits storage that can operate for 4 or more consecutive hours with the ability to provide reliable peak capacity (Denholm et al. 2017).

[4] The data for 2016 and 2017 are preliminary and incomplete owing to ongoing project verification for those years.

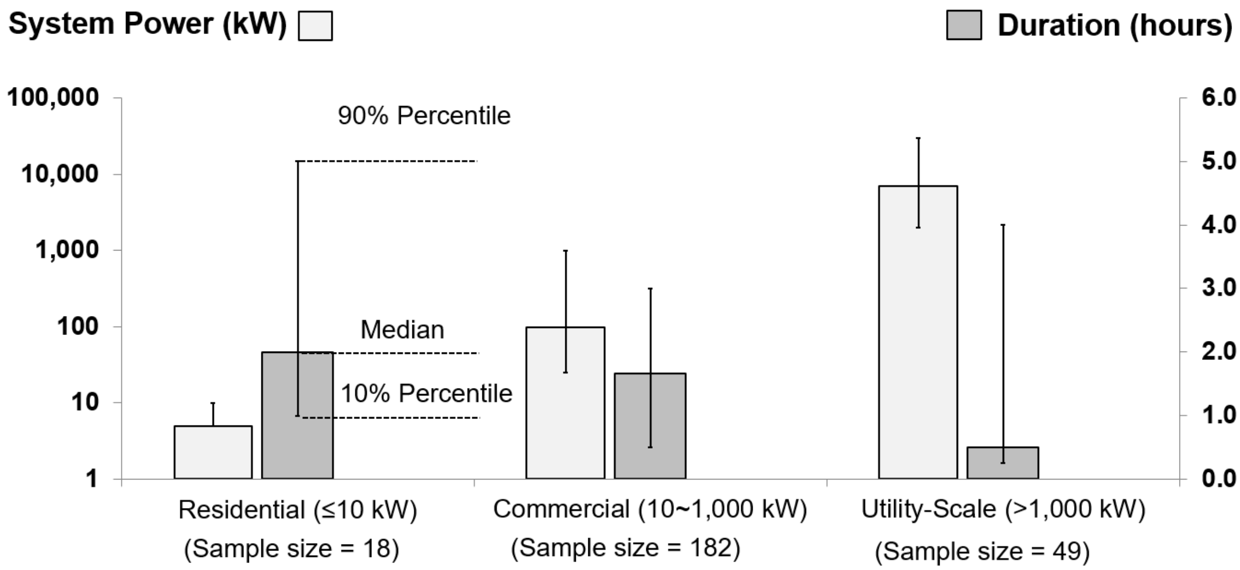


Figure 5. Distributions of U.S. Li-ion energy storage power and duration, by sector, 2008–2016 (DOE Energy Storage Database 2018)[5]

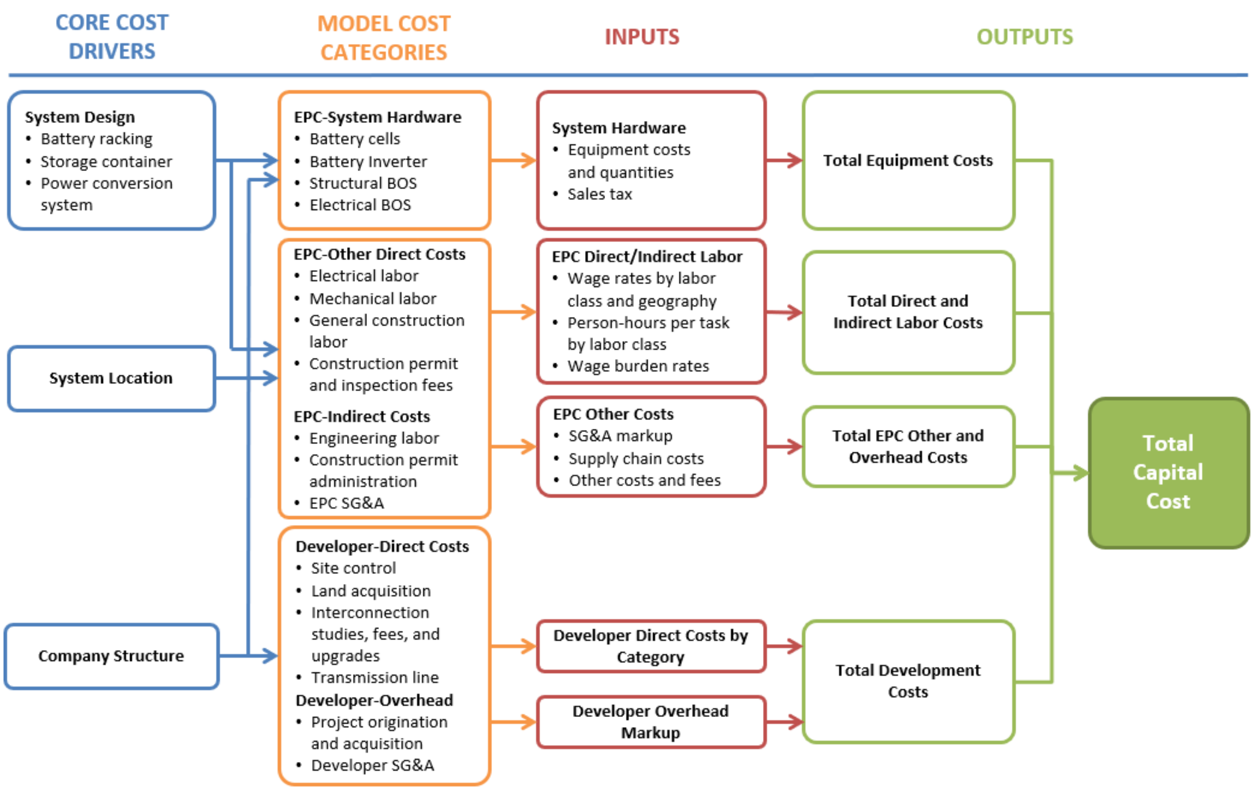
Table 1. U.S. Li-ion Energy Storage by Sector, 2008–2017 (DOE Energy Storage Database 2018)[5]

Sector	Total number of projects	Total kW	Total kWh	Average duration (hours)	Average system power rating (kW)	Average system energy (kWh)
Residential (< 10 kW)	18	116	278	2.4	6	15
Commercial (10–1,000 kW)	182	49,161	101,183	2.1	270	556
Utility-Scale (> 1,000 kW)	49	494,764	844,418	1.7	9,934	17,233
Total U.S.	**249**	**544,041**	**945,879**	**1.8**	**2,153**	**3,799**

[5] The data for 2016 and 2017 are preliminary and incomplete owing to ongoing project verification for those years.

4 Cost Models

Figure 6 shows the detailed bottom-up cost structure of our standalone storage model, which uses a similar structure to our previously developed PV cost model (Fu et al. 2015, 2016, 2017). Total system upfront capital costs are broken into engineering, procurement, and construction (EPC) costs and developer costs. EPC non-hardware or "soft" costs are driven by labor rates and labor productivities. We adapt engineering-design and cost-estimating models from RSMeans (2017) to determine the EPC hardware costs (including module/battery racking, mounting, wiring, containerization, and foundation) and related EPC soft costs (including related labor and equipment hours required in any given U.S. location). Section 4.1 presents additional detail on the Li-ion standalone storage model, and Section 4.2 shows results from the combined PV-plus-storage model.



BOS = balance of system, SG&A = selling, general, and administrative

Figure 6. Structure of the bottom-up cost model for standalone storage systems

4.1 Lithium-Ion Standalone Storage Cost Model

To reduce installation costs, some battery manufacturers may combine Li-ion battery cells, a battery management system, and the battery inverter in one compact unit (Sonnen Batterie 2018) as an AC battery. However, in this report, we focus on traditional DC batteries typically configured with the four major components shown in Figure 7 and Figure 8.

Battery cells → modules → packs → racking system (DC)

↓

Storage container
(HVAC system, thermal management, monitors and controls, fire suppression, switchgear, and energy management system)

↓

Power conversion system
(bidirectional inverter to convert AC to DC for battery charging and DC to AC for discharging)

↓

Transformer (to step up 480-V inverter output to 12–66 kV)

Figure 7. Traditional utility-scale Li-ion battery energy storage components

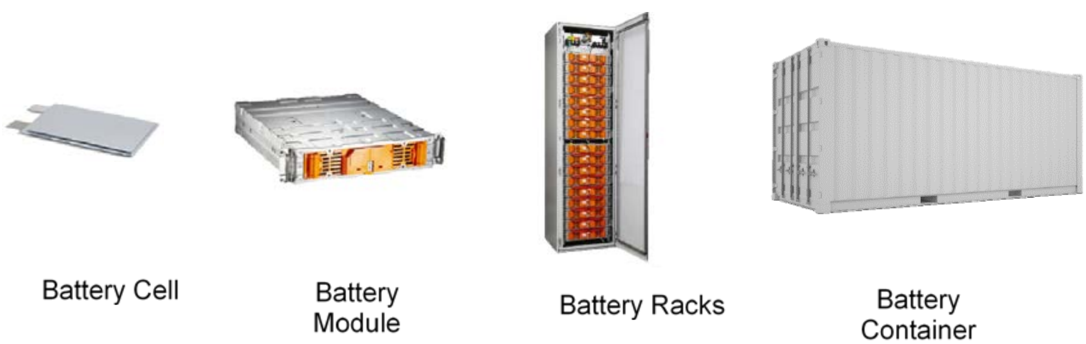


Figure 8. Battery system components (NAGF/ESIG Workshop 2018)

Table 2 lists our model inputs and assumptions for such a utility-scale energy storage system. We determined the battery size (60 MW_{DC})[6] using an inverter loading ratio (ILR) of 1.3 and an inverter/storage size ratio of 1.67, based on Denholm et al. (2017).

Table 2. Utility-Scale Li-ion Energy Storage System Model Inputs and Assumptions (NREL 2018, Fu et al. 2017, Denholm et al. 2017, Blattner Energy 2018, Escondido 2018, Curry 2017, Ortiz 2016, Gupta 2018)

Model Component	Model Input
Battery total size	60 MW DC
Battery size per container	5 MWh per 40-foot container
Number of containers	48 (if duration = 4 hours)
Li-ion battery price	$209/kWh
Duration	0.5–4 hours
Battery central inverter price	$0.07/W
Battery inverter size	2.5 MW per inverter
Number of inverters	24
Transformer price	$28,000 per transformer
Transformer size	2.5 MW per step-up transformer
Number of transformers	24
Foundation	76,800 square feet
Installation labor	Non-union at rates from Bureau of Labor Statistics survey average by state (BLS 2018)
Sales tax	7.5%
EPC overhead (% of equipment and labor costs)	8.67% for equipment and material (except for transmission line costs); 23%–69% for labor costs: varies by labor activity
Developer overhead	3% of EPC cost
Land acquisition	$250,000
Interconnection	$0.03/W
Permitting	$295,000 per system
Contingency	3% of EPC cost
EPC/developer net profit	5% of total installation cost (EPC + developer costs)

[6] For a 100-MW PV system with ILR = 1.3, the inverter size must be 77 MW AC (100 MW/1.3). Using the inverter/storage size ratio (1.67), the storage power capacity must be 46 MW AC (77/1.67). Thus, to match a 100-MW PV system, the storage power capacity must be 60 MW DC (46 × 1.3).

We use these inputs to calculate energy storage cost via the following equation[7]:

$$Energy\ storage\ installation\ cost\ \left(\frac{\$}{kWh}\right) =$$

$$Battery\ cost\ \left(\frac{\$}{kWh}\right) + \frac{Other\ cost\ components\ (\$)\ such\ as\ battery\ inverter\ and\ labor}{Storage\ system\ size\ (kW) \times Duration\ (hours)}$$

Figure 9 and Table 3 show the resulting $/kWh costs for 60-MW Li-ion energy storage systems, which vary from $380/kWh (4-hour duration) to $895/kWh (0.5-hour duration). Because the per-energy-unit battery cost remains constant at $209/kWh, the total battery cost—and the proportion of the cost attributed to the battery—decrease as system duration decreases. For example, the battery cost accounts for 55% of total system cost in the 4-hour system, but only 23% in the 0.5-hour system. At the same time, non-battery cost categories accounts for an increasing proportion of the system cost as duration declines.

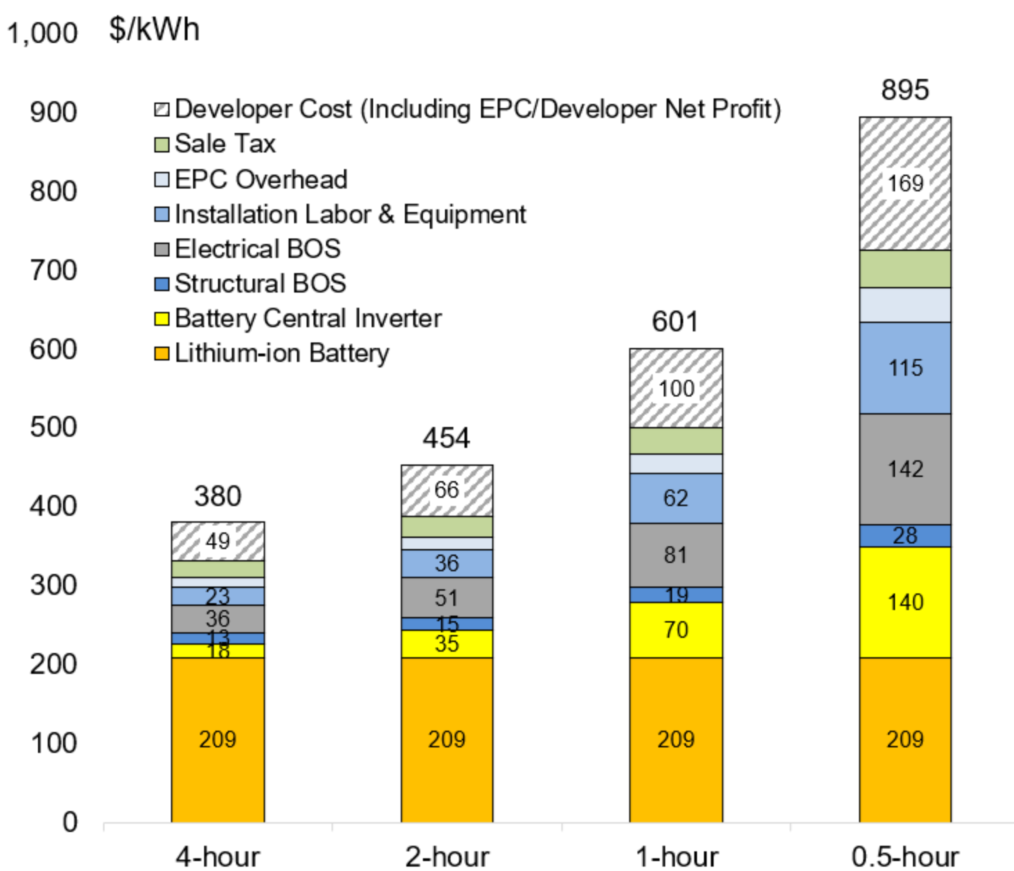


Figure 9. 2018 U.S. utility-scale Li-ion battery standalone storage costs for durations of 0.5–4 hours (60 MW_{DC})

[7] This equation is only for the energy storage installation cost calculation. For levelized cost of storage (LCOS), the equation would be different. LCOS is not covered in this report.

Table 3. Detailed Cost Breakdown for a 60-MW U.S. Li-ion Standalone Storage System with Durations of 0.5–4 Hours

	60-MW, 4-hour Duration, 240-MWh			60-MW, 2-hour Duration, 120-MWh			60-MW, 1-hour Duration, 60-MWh			60-MW, 0.5-hour Duration, 30-MWh		
Model Component	**Total Cost ($)**	**$/kWh**	**$/W**	**Total Cost ($)**	**$/kWh**	**$/W**	**Total Cost ($)**	**$/kWh**	**$/W**	**Total Cost ($)**	**$/kWh**	**$/W**
Li-ion battery	50,160,000	209	0.84	25,080,000	209	0.42	12,540,000	209	0.21	6,270,000	209	0.10
Battery central inverter	4,200,000	18	0.07	4,200,000	35	0.07	4,200,000	70	0.07	4,200,000	140	0.07
Structural BOS	3,121,131	13	0.05	1,813,452	15	0.03	1,159,612	19	0.02	832,692	28	0.01
Electrical BOS	8,602,825	36	0.14	6,119,167	51	0.10	4,877,337	81	0.08	4,256,423	142	0.07
Installation labor & equipment	5,479,149	23	0.09	4,322,275	36	0.07	3,743,838	62	0.06	3,454,619	115	0.06
EPC overhead	2,775,545	12	0.05	1,948,565	16	0.03	1,535,075	26	0.03	1,328,330	44	0.02
Sales tax	5,293,460	22	0.09	3,083,292	26	0.05	1,978,209	33	0.03	1,425,667	48	0.02
∑ EPC cost	**79,632,110**	**332**	**1.33**	**46,566,751**	**388**	**0.78**	**30,034,071**	**501**	**0.50**	**21,767,732**	**726**	**0.36**
Land acquisition	250,000	1	0.00	250,000	2	0.00	250,000	4	0.00	250,000	8	0.00
Permitting fee	295,289	1	0.00	295,289	2	0.00	295,289	5	0.00	295,289	10	0.00
Interconnection fee	1,802,363	8	0.03	1,802,363	15	0.03	1,802,363	30	0.03	1,802,363	60	0.03
Contingency	2,477,135	10	0.04	1,476,303	12	0.02	975,887	16	0.02	725,679	24	0.01
Developer overhead	2,477,135	10	0.04	1,476,303	12	0.02	975,887	16	0.02	725,679	24	0.01
EPC/developer net profit	4,346,702	18	0.07	2,593,350	22	0.04	1,716,675	29	0.03	1,278,337	43	0.02
∑ Developer cost	**11,648,623**	**49**	**0.19**	**7,893,608**	**66**	**0.13**	**6,016,101**	**100**	**0.10**	**5,077,347**	**169**	**0.08**
∑ Total energy storage system cost	**91,280,733**	**380**	**1.52**	**54,460,359**	**454**	**0.91**	**36,050,172**	**601**	**0.60**	**26,845,079**	**895**	**0.45**

4.2 PV-Plus-Storage System Cost Model

Here we combine our energy storage cost model with our PV system cost model in various configurations: 1) co-located PV-plus-storage systems vs. PV-plus-storage systems in different locations, and 2) DC-coupled vs. AC-coupled battery configurations for the co-located PV-plus-storage systems. As shown in Table 4, co-location enables sharing of several hardware components between the PV and energy storage systems, which can reduce costs. Co-location can also reduce soft costs related to site preparation, land acquisition, installation labor, permitting, interconnection, and EPC/developer overhead and profit.

Table 4. Cost Factors for Siting PV and Storage Together vs. Separately (NREL 2018, Blattner Energy 2018, Ardani et al. 2017)

Model Component	Co-located PV-Plus-Storage	PV-Plus-Storage in Different Sites
Site preparation[8]	Once	Twice
Land acquisition cost	Lower	Higher
Hardware sharing between PV and energy storage	Yes (step-up transformer, switchgear, monitor, and controls)	No
Installation labor cost	Lower (due to hardware sharing and single labor mobilization)	Higher
EPC/developer overhead and profit	Lower (due to lower labor cost, BOS, and total system cost)	Higher
Interconnection and permitting	Once	Twice

When PV and battery storage are co-located, the subsystems can be connected by a DC-coupled or AC-coupled configuration (Figure 10). A DC-coupled system needs only one bidirectional inverter, connects battery storage directly to the PV array, and enables the battery to charge and discharge from the grid. On the other hand, an AC-coupled system needs both a PV inverter and a bidirectional inverter, and there are multiple conversion steps between DC and AC to charge or discharge the battery. Also, the transmission line could be used for both PV and battery storage systems.

The advantages of the DC-coupled system include the following:

1. A DC-coupled system uses only a single bidirectional inverter (Table 5), thus reducing costs for the inverter, inverter wiring, and inverter housing.
2. Because of the extra conversion between DC and AC, an AC-coupled system may have lower roundtrip efficiency for battery charging compared with a DC-coupled system, which charges the battery directly. However, as power electronics are becoming more efficient, the actual efficiency difference is becoming smaller (Enphase 2018).

[8] Site preparation is a sub-category under labor cost, so it is not shown in the cost breakdown chart.

3. Because the battery is connected directly to the solar array, excess PV generation that would otherwise be clipped by an AC-coupled system at the inverter level can be sent directly to the battery, which could improve system economics (DiOrio 2018).

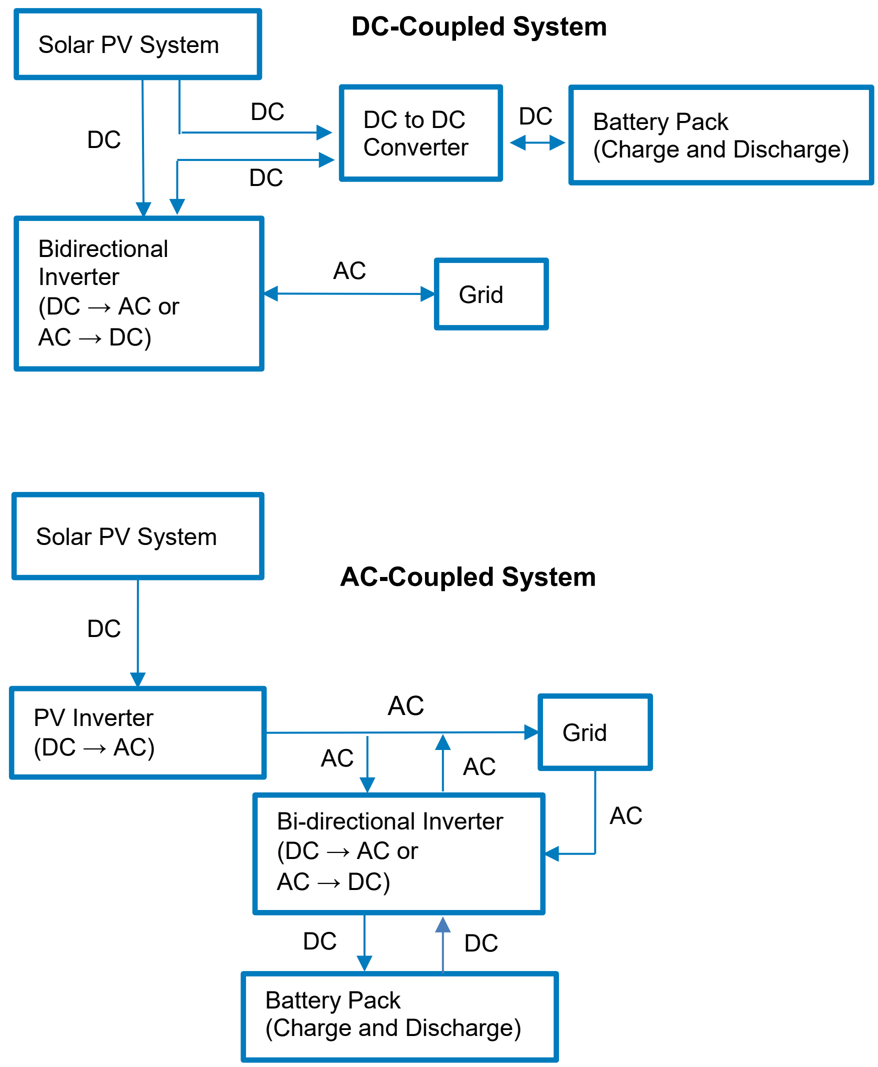


Figure 10. DC-coupled and AC-coupled PV-plus-storage system configurations

Table 5. Comparison of DC and AC Coupling for PV-Plus-Storage Systems (Denholm et al. 2017, Ardani et al. 2017, Cole et al. 2016)

Model Component	DC-Coupled Configuration	AC-Coupled Configuration
Number of inverters	1 (bidirectional inverter for battery)	2 (bidirectional inverter for battery plus grid-tied inverter for PV), resulting in higher costs for the inverter, inverter wiring, and inverter housing
Battery rack size	Smaller (because battery is directly connected to PV), resulting in more heating, ventilating, and air conditioning (HVAC) and fire-suppression systems required	Larger
Structural BOS	More (due to smaller battery rack size)	Less
Electrical BOS	Less (but needs additional DC-to-DC converters)	More (due to additional wiring for inverters)
Installation labor cost	More (due to smaller battery rack size and more skilled labor and labor hours required for DC work)	Less
EPC overhead	More (due to higher installation labor cost)	Less
Sales tax	Less	More (due to higher total hardware costs)
EPC/developer profit	Less	More (due to higher total EPC and developer costs)

The advantages of the AC-coupled system include the following:

1. Because the battery racks are not directly connected to the PV system in AC-coupled systems, these systems can use larger battery racks and thus reduce the number of HVAC and fire-suppression systems in the containers. This feature also reduces installation labor costs compared with DC-coupled systems.
2. For a retrofit (i.e., adding battery storage to an existing PV array), an AC-coupled battery may be more practical than a DC-coupled battery, because DC-coupled systems require installers to replace the existing PV inverter with a bidirectional inverter. Thus, the additional costs due to replacing the inverter and rewiring the system could make retrofit costs higher for a DC-coupled system compared with an AC-coupled system (Ardani et al. 2017). In addition, AC-coupled systems enable the option of upgrading the PV and battery separately, because these systems are independent of one another.
3. Because AC-coupled systems have separated PV and battery systems, installers have more flexibility to adjust the battery location. For instance, DC-coupled systems require batteries to be installed next to the bidirectional inverter, and the resulting need for maintenance crews to enter the PV field can make maintenance more time consuming. Because AC-coupled systems can have batteries located outside of the PV field, maintenance work can be quicker and easier.

5 Model Results and Summary

Figure 11 summarizes our model results for several system types and configurations:

- Standalone 100-MW PV system with one-axis tracking ($111 million)
- Standalone 60-MW/240-MWh, 4-hour-duration energy storage system ($91 million)
- Co-located, DC-coupled PV (100 MW) plus storage (60 MW/240 MWh, 4-hour duration) system ($186 million)
- Co-located, AC-coupled PV (100 MW) plus storage (60 MW/240 MWh, 4-hour duration) system ($188 million)
- PV (100 MW) plus storage (60 MW/240 MWh, 4-hour duration) system with PV and storage components sited in different locations ($202 million)

Table 6 shows detailed costs for the three PV-plus-storage configurations. Co-locating the PV and storage subsystems produces cost savings by reducing costs related to site preparation, land acquisition, permitting, interconnection, installation labor, hardware (via sharing of hardware such as switchgears, transformers, and controls), overhead, and profit. The cost of the co-located, DC-coupled system is 8% lower than the cost of the system with PV and storage sited separately, and the cost of the co-located, AC-coupled system is 7% lower.

Using DC-coupling rather than AC-coupling results in a 1% lower total cost, which is the net result of cost differences between DC-coupling and AC-coupling in the categories of solar inverter, structural BOS, electrical BOS, labor, EPC and developer overhead, sales tax, contingency, and profit. For an actual project, however, cost savings may not be the only factor in choosing DC or AC coupling. Additional factors—such as retrofit considerations, system performance (including energy loss due to clipping), design flexibility, and operations and maintenance—should be considered.

In summary, the National Renewable Energy Laboratory's new bottom-up cost model can be used to assess the costs of utility-scale PV-plus-storage systems using various configurations. The itemized cost savings could incentivize deployment of co-located PV-plus-storage systems. In addition, the model can help industry representatives evaluate the cost impacts of various battery durations for grid applications. Finally, the model can be used to estimate future potential cost-reduction opportunities for PV-plus-storage systems, helping to guide research and development aimed at advancing cost-effective system configurations. In the future, we will continue updating the model inputs and expand our model to cover more economic metrics, such as LCOS (Levelized Cost of Storage).

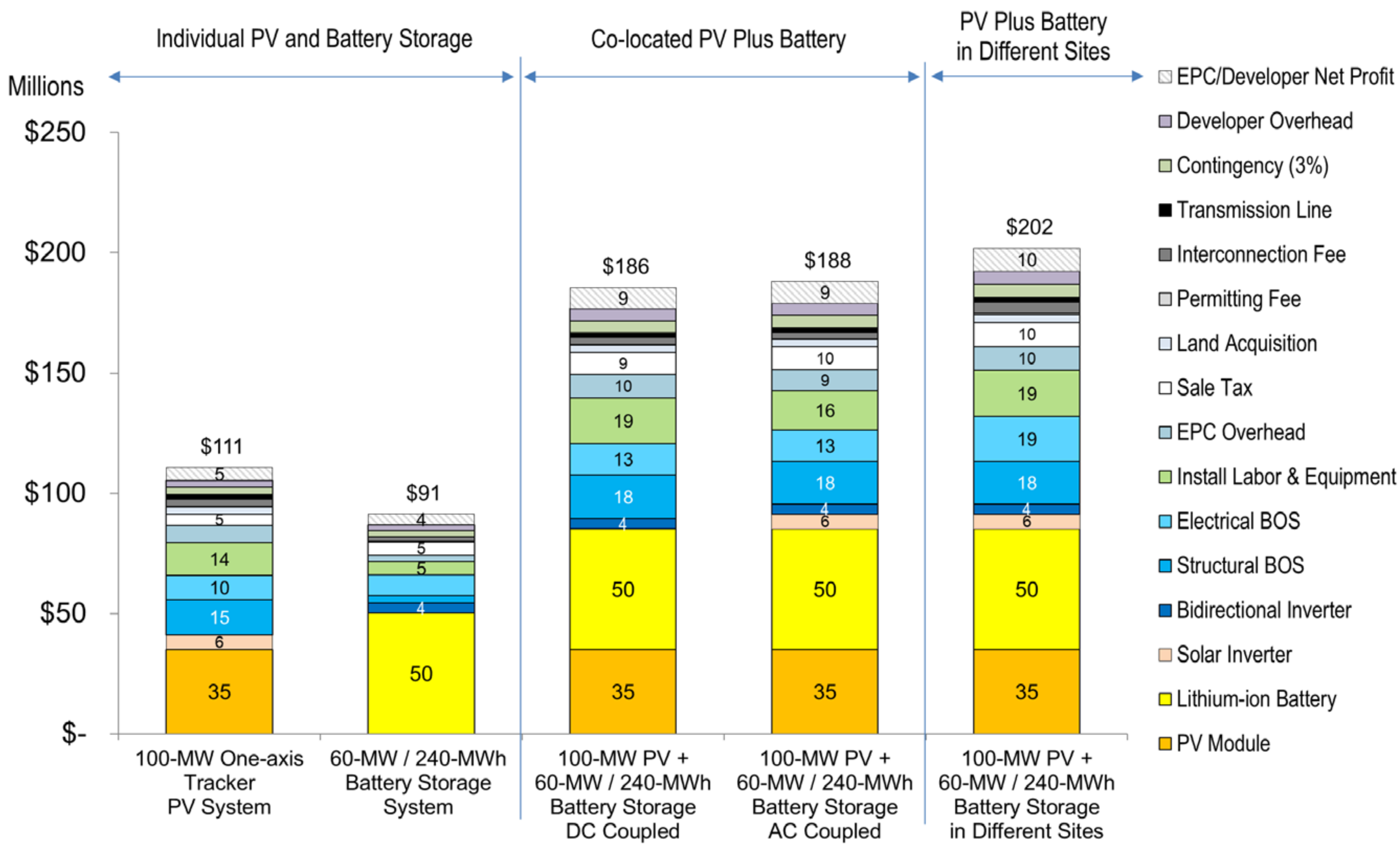


Figure 11. 2018 Cost benchmarks for PV-plus-storage systems (4-hour duration) in different sites and the same site (DC-coupled and AC-coupled cases)

Table 6. Detailed Cost Breakdown for Utility-Scale Li-ion PV-Plus-Storage Systems

Model Component	**Total Cost**		
	100-MW PV Plus 60-MW/240-MWh Battery, DC-Coupled, Co-located	**100-MW PV Plus 60-MW/240-MWh Battery, AC-Coupled, Co-located**	**100-MW PV Plus 60-MW/240-MWh Battery, In Different Sites**
PV module	$35,000,000	$35,000,000	$35,000,000
Li-ion battery	$50,160,000	$50,160,000	$50,160,000
Solar inverter	n/a	$6,153,846	$6,153,846
Bidirectional inverter	$4,200,000	$4,200,000	$4,200,000
Structural BOS	$18,346,829	$17,685,150	$17,735,564
Electrical BOS	$12,987,780	$13,115,425	$18,649,611
Installation labor & equipment	$18,863,868.05	$16,326,680.01	$19,058,910
EPC overhead	$9,879,642	$8,550,831	$9,981,792
Sales tax	$9,178,323	$9,605,687	$10,030,372
∑ EPC cost	**$158,616,442**	**$160,797,619**	**$170,970,095**
Land acquisition	$3,000,000	$3,000,000	$3,250,000
Permitting fee	$295,289	$295,289	$590,578
Interconnection fee	$2,919,545	$2,919,545	$4,721,908
Transmission line	$1,883,302	$1,883,302	$1,883,302
Contingency	$5,001,437	$5,066,873	$5,455,816
Developer overhead	$5,001,437	$5,066,873	$5,455,816
EPC/developer net profit	$8,835,873	$8,951,475	$9,616,376
∑ Developer cost	**$26,936,884**	**$27,183,357**	**$30,973,796**
∑ Total energy storage system cost	**$185,553,326**	**$187,980,975**	**$201,943,890**

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Appendix. Figure Data from DOE Energy Storage Database

Figure 1 Data

Specific Type	Category	Number of projects	Total kW	Total kWh	Average Duration (hours)	Average System Power Rating (kW)	Average System Energy (kWh)
Lead-acid Battery	Electro-chemical	79	194,300	216,578	1.1	2,459	2,741
Li-ion Battery	Electro-chemical	523	1,485,898	2,321,097	1.6	2,841	4,438
Flow Battery	Electro-chemical	101	322,702	1,251,215	3.9	3,195	12,388
Sodium-based Battery	Electro-chemical	71	168,634	1,090,820	6.5	2,375	15,364
Nickel-based Battery	Electro-chemical	6	30,385	7,925	0.3	5,064	1,321
Zinc-air Battery	Electro-chemical	4	73,750	297,008	4.0	18,438	74,252
Compressed Air Storage	Electro-mechanical	15	1,592,590	39,974,670	25.1	106,173	2,664,978
Flywheel	Electro-mechanical	46	961,435	103,414	0.1	20,901	2,248
Molten Salt Thermal Storage	Thermal	41	2,850,520	19,845,210	7.0	69,525	484,030
Heat Thermal Storage	Thermal	20	129,740	338,430	2.6	6,487	16,922
Ice Thermal Storage	Thermal	110	99,675	703,363	7.1	906	6,394
Chilled Water Thermal Storage	Thermal	20	135,206	1,421,741	10.5	6,760	71,087
Hydrogen Storage	Hydrogen	5	8,920	100,060	11.2	1,784	20,012
Total Non-Hydro Storage		1,041	8,053,755	67,671,531	8.4	7,737	65,006
Open-loop Pumped Hydro	Pumped Hydro	69	39,321,700	390,411,510	9.9	569,880	5,658,138
Closed-loop Pumped Hydro	Pumped Hydro	7	4,288,006	31,533,369	7.4	612,572	4,504,767
Total Hydro Storage (not shown in Figure 1)		76	43,609,706	421,944,879	9.7	573,812	5,551,906

Figure 2 Data

Worldwide (kW)		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Lead-acid Battery	Electro-chemical	0	16	60	0	12	1,000	44,625	445	3,010	2,114	1,050	0	0
Li-ion Battery	Electro-chemical	0	0	0	1,000	2,000	5,400	1,662	21,020	17,116	90,748	264,615	96,110	104,000
Flow Battery	Electro-chemical	0	0	100	0	0	10	800	5,190	370	30	300	200,200	10,200
Sodium-based Battery	Electro-chemical	0	1,000	0	0	0	0	1,195	298	0	44,555	10	11	800
Nickel-based Battery	Electro-chemical	0	0	0	0	0	0	0	0	0	0	0	0	0
Zinc-air Battery	Electro-chemical	0	0	0	0	0	0	0	0	0	0	62,500	0	0
Compressed Air Storage	Electro-mechanical	0	0	0	0	0	0	350	0	201,000	500	1,000	0	0
Flywheel	Electro-mechanical	1,100	0	500	0	500	500	1,600	100	2,000	290	0	0	0
Molten Salt Thermal Storage	Thermal Storage	0	49,900	0	255,720	269,900	330,000	390,000	100,000	160,000	470,000	0	100,000	0
Heat Thermal Storage	Thermal Storage	11,000	2,000	1,500	0	1,500	0	3,600	61,155	12,000	10,100	0	0	0
Ice Thermal Storage	Thermal Storage	0	0	5,320	0	375	0	0	0	1,000	0	0	0	0
Chilled Water Thermal Storage	Thermal Storage	0	0	0	90,000	0	0	0	0	0	0	0	0	0
Hydrogen Storage	Hydrogen Storage	0	0	0	0	0	0	0	0	1,320	0	0	0	0
Total Non-Hydro Storage		**12,100**	**52,916**	**7,480**	**346,720**	**274,287**	**336,910**	**443,832**	**188,208**	**397,816**	**618,337**	**329,475**	**396,321**	**115,000**

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Xcel Energy		Information Request No. 8
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

<u>Question:</u>
<u>Reference:</u>
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) page 108.

<u>Request:</u>
Please provide all data, analysis, studies, reports, or spreadsheets with all formulas and links intact supporting the values in Table 25 - ISI Capital Expenditures – Distribution.

<u>Response:</u>

Northern States Power Company objects to this Request as overly broad and unduly burdensome. Subject to the foregoing objection, we respond as follows:

Please refer to Attachment A – ISI Cost.

Preparer:	Molly Dimond
Title:	Investment Delivery
Department:	System Planning and Strategy
Telephone:	303.571.3232
Date:	January 23, 2020

OpCO	Group1	Primary Work Group	Work Description	CPU	Unit Description	2021 QTY	2022 QTY	2023 QTY	2024 QTY	2021 Spend	2022 Spend	2023 Spend	2024 Spend	Pop. +	Min Pop Qty Id 2021	Pop. +	Min Pop Qty Id 2022	Cap Adds %	CapAdds 2021	Cap Adds %	Cap Adds 2022
NSPM	Substation	Transmission	Transformer Replacement	2,000,000	Per Transformer	3	3	3	3	5,000,000	5,000,000	5,000,000	5,000,000	+2	5	+1	4	1	5,000,000	0.5	5,000,000
NSPM	Substation	Transmission	Substation Asset Renewal	20,000,000	Per 3 transformer substation	0.350	0.650	0.650	0.650	7,000,000	13,000,000	13,000,000	13,000,000	+2	2	+1	2	1	7,000,000	1	13,000,000
NSPM	Substation	Transmission	High Consequence Risks	10,000,000	Per Project	-	-	-	-	-	-	-	-	+2	2	+1	1	0.5	-	0.5	-
NSPM	Substation	Transmission	Mobile Xfmr/Gear Purchase	2,500,000	per xfmr	-	-	-	-	-	-	-	-	+1	1	+1	1	0.5	-	0.5	-
NSPM	Underground	DistOps	Mainline Cable Replacement	1,050,000	Per Mile	7	7	7	7	7,087,500	7,770,000	7,770,000	7,770,000	50%	10.13	50%	11.10	0.9	6,378,750	0.8	7,701,750
NSPM	Underground	DistOps	URD Cable Replacement	210,000	Per Mile	24	12	12	12	5,040,000	2,520,000	2,520,000	2,520,000	20%	28.80	20%	14.40	0.9	4,536,000	0.8	2,772,000
NSPM	Underground	DistOps	Cable Assessment	100,000	Per Mile	70	60	60	60	7,000,000	6,000,000	6,000,000	6,000,000	20%	84.0	20%	72.0	0.8	5,600,000	0.8	6,200,000
NSPM	Underground	DistOps	St. Paul Tunnel Work	3,500,000	annually	1	1.4	1.4	1.4	4,900,000	5,005,000	5,005,000	5,005,000		1.7		1.7	0	3,000,000	0	3,000,000
NSPM	Underground	DistOps	Feeder Exit Capacity	3,000,000	annually	1.3	1	1	1	3,750,000	3,000,000	3,000,000	3,000,000		1.5		1.2	0.8	3,000,000	0.8	3,150,000
NSPM	Underground	DistOps	Network Monitoring	1,500,000		1	2	2	2	2,025,000	2,325,000	2,325,000	2,325,000		1.6		1.9	0	-	0	1,000,000
NSPM	Underground	DistOps	Purchases / Tooling	4,500,000		1	0	0	0	4,500,000	180,000	180,000	180,000		1.2			1	4,500,000	1	180,000
NSPM	Overhead Tap	DistOps	Targeted Undergrounding	912,000	Per Mile	20	30	30	30	18,240,000	27,360,000	27,360,000	27,360,000	50%	30.00	50%	45.00	0.6	10,944,000	0.6	23,712,000
NSPM	Overhead Tap	DistOps	Low Cost Reclosers	4,200	Per Fuse	650	595	595	595	2,730,000	2,499,000	2,499,000	2,499,000	40%	910.0	40%	833.0	0.8	2,184,000	0.8	2,545,200
NSPM	Overhead Tap	DistOps	Pole Top Reinforcements	2,700	Per Pole	1,000	900	900	900	2,700,000	2,430,000	2,430,000	2,430,000	10%	1,100.0	10%	990.0	0.8	2,160,000	0.8	2,484,000
NSPM	Overhead Tap	DistOps	Transformer and Secondary Repl	15,000	Per Transformer and Secondary	165	165	165	165	2,475,000	2,475,000	2,475,000	2,475,000	20%	198.0	20%	198.0	0.8	1,980,000	0.8	2,475,000
NSPM	Overhead Tap	DistOps	High Customer Count Taps		Per Tap					3,000,000	3,000,000	3,000,000	3,000,000	20%		20%		0.8	2,400,000	0.8	3,000,000
NSPM	Overhead Mainline	DistOps	Pole Fire Mitigation	4,200	Per Pole	600	480	480	480	2,520,000	2,016,000	2,016,000	2,016,000	20%	720.0	20%	576.0	0.8	2,016,000	0.8	2,116,800
NSPM	Overhead Mainline	DistOps	Lightning Protection Replacemer	1,000	Per Location	1,000	1,000	1,000	1,000	1,000,000	1,000,000	1,000,000	1,000,000	20%	1,200.0	20%	1,200.0	0.8	800,000	0.8	1,000,000
NSPM	Overhead Mainline	DistOps	OH Rebuilds	150,000	per mile	-	-	-	-	-	-	-	-					0.8	-	0.8	-
NSPM	Overhead Tap	DistOps	Community Resiliency			TBD	TBD	TBD	TBD	2,000,000	3,000,000	3,000,000	3,000,000					0.8	1,600,000	0.8	2,800,000
										80,967,500	88,580,000	88,580,000	88,580,000								

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Xcel Energy		Information Request No. 10
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) page 111.

Request:
Please provide the average customers per mile of tap line in the proposed pilot areas for undergrounding overhead tap lines.

Response:
As discussed in our response to Fresh Energy Information Request No. 2, while we have identified areas of focus for the ISI and preliminary categories of work, we will be refining those plans to be more specific over time. As such, we have not identified specific pilot areas or created plans that are sufficiently refined to identify specific feeders, taps, etc. Therefore, we are not presently able to provide average customer counts per mile for the targeted underground program.

That said, our preliminary plans are based on areas that are served by older conductor types and are considered high-density/single family residences. We will continue our analysis of performance and reliability results, equipment and asset age, and type and construction method to identify the areas where we believe we will achieve the greatest positive impacts for customers and system resilience. After we complete this process, our operational groups will review the identified areas and plans for feasibility of system design, construction, impact to customers and impact to municipalities. Concurrent with these internal processes, we will also be factoring in external feedback from customers and the communities we serve.

Preparer:	Molly Dimond
Title:	Investment Delivery
Department:	Electric Distribution Engineering

Telephone: 303.571.3232
Date: January 23, 2020

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Xcel Energy		Information Request No. 12
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) page 113.

Request:
Please provide all data, analysis, studies, reports, or spreadsheets with all formulas and links intact supporting the Company's claim that it has 15,900 25 kVA transformers that are overloaded during peak periods and have more than 11 customers connected to them.

Response:

Northern States Power Company objects to this Request as overly broad and unduly burdensome. Subject to the foregoing objection, we respond as follows:

We used data from several of our information systems to determine the quantity of customers per transformer, size of transformers and loading on each transformer: the Customer Resource System (CRS), the Geospatial Information System (GIS), and our Itron Distribution Asset Analysis Suite (DAA). CRS associates every customer's energy usage to a particular transformer. The GIS tool can determine the number of customers on each transformer and the type of transformer associated to each customer. DAA builds transformer load profiles using a bottom-up approach to determine a peak load on each transformer, by coupling each customers' energy usage with the appropriate load profile, and summing the resulting profiles.

We analyzed the typical single phase overhead transformers sizes (25kVA, 37.5kVA, 50kVA) to start to understand the potential future overload risk. The transformers studied represent 63% of the 94,000 overhead transformers. Table [FE-12] 1 below provides counts of the transformers we analyzed by size.

Table [FE-12] 1: Transformers Analyzed

	Transformer Size (kVA)			
Total # of Overhead Single Phase Transformers	**25**	**37.5**	**50**	**Total**
94,142	33.40%	17.60%	11.90%	62.90%

Table [FE-12] 2 below outlines the customer counts and averages associated with the transformers we analyzed, along with the average loading for the group of transformers at each of the analyzed kVA levels.

Table [FE-12] 2: Transformer-Customer Association – Analyzed Transformers

Overhead Transformers		
25 kVA	# of Xfmrs	31,424
	# of Customers	195,143
	Avg Cust Per Xfmr	6.21
	Avg % Loading	127%
37.5 kVA	# of Xfmrs	16,571
	# of Customers	185,228
	Avg Cust Per Xfmr	11.18
	Avg % Loading	133%
50 kVA	# of Xfmrs	11,182
	# Of Customers	137,271
	Avg Cust Per Xfmr	12.28
	Avg % Loading	104%

Each transformer was reviewed for an estimated overload based on DAA and the associated customer count which we summarize in Table [FE-12] 3 below.

Table [FE-12] 3: Total Transformers – Peak Load at Least 100 Percent and 11 or more customers

# of Transformers	Percentage
15,837	17%

We note that Automated Metering Infrastructure (AMI) will allow for improved accuracy and understanding of existing and potential transformer overloads and customer voltage issues. Instead of coupling each customers' energy usage with the appropriate load profile, and summing the resulting profiles, we will be able to use actual coincidental customer demand data to create a transformer loading profile, with peak values – as well as a 24-hour view, including seasonal changes. We will also have the ability to flag actual voltage excursions.

Preparer: Betsy Coppock
Title: Principal Engineer
Department: Electric Distribution Engineering
Telephone: 303.571.3537
Date: January 23, 2020

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Xcel Energy		Information Request No.	13
Docket No.:	E002/M-19-666		
Response To:	Fresh Energy		
Requestor:	Isabel Ricker		
Date Received:	January 13, 2020		

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) page 122.

Request:
Please provide the total number of historical substation transformer failures, failure rate (substation transformer failures/total substation transformers in service) each year 2011-2019. For each historical substation transformer failure event, please also provide the customers interrupted and customer-minutes of outage.

Response:

Unlike the transmission system, the distribution system is not fully redundant – and so many system component failures directly impact customers. The failure of a Substation Transformer is considered a low probability but high risk event. This means that a failure is unlikely but if it does occur it will have a significant impact on the system and our customers.

As a high consequence system component, we monitor the health of Substation Transformers by performing a dissolved gas analysis (DGA) of the transformer fleet on a regular basis. Transformer readings that indicate the unit is at risk of failure may be proactively taken out of service and replaced. Another factor to consider is the asset life. The average useful life of a distribution substation transformer is 40 years; beyond 40 years, the probability of failure begins to increase. We performed our most recent asset study in 2017. At that time, the Company had 129 transformers (or 28 percent) that were older than 45 years.[1]

That said, we provide substation transformer failure information in Table [FE-13] 1

[1] As of the end of 2019, we had approximately 540 distribution substation transformers on the NSP system.

below, as follows:

- Sustained transformer failures, which are failures that resulted in customer outages. For these we also provide the associated customer minutes out,
- Momentary transformer failures, which are failures – but we were able to reconfigure the system to avoid customer outages until repairs or replacements could be made, and
- Imminent failures, which are replacements we made based on predictive signs of failure.

Table [FE-13] 1: Distribution Substation Transformer Failures – 2011 to 2019
NSPM Operating Company

	2011	2012	2013	2014	2015	2016	2017	2018	2019
Sustained Transformer Failures	2	-	1	2	3	1	1	3	-
Customers Impacted	5,293	-	477	7,043	27,426	703	860	12,357	-
Estimated CMO	914,897	-	463,644	2,945,187	4,506,707	119,510	52,460	1,054,270	-
Momentary Transformer Failures	-	-	1	-	-	1	2	1	-
Customers Impacted	-	-	8,744	-	-	7,570	20,700	1,027	-
Transformers Taken out of Service Due to Imminent Signs of Failure	1	3	3	6	4	-	-	2	-

With approximately 540 distribution substation transformers on the system as of the end of 2019, the "failure rate" of this system asset is low. However, as we discuss in our response to FE-2, we have designed a low failure rate into the system due to the high consequence of a substation level outage on our customers.

Preparer:	Molly Dimond	Betsy Coppock
Title:	Investment Delivery	Principal Engineer
Department:	System Planning and Strategy	Electric Distribution Engineering
Telephone:	303.571.3232	303.571.3537
Date:	January 23, 2020	

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Xcel Energy		Information Request No. 15
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP).

Request:
Please provide the expected improvement in SAIDI, SAIFI and CAIDI from the ISI programs, and provide all data, analysis, studies, reports, or spreadsheets with all formulas and links intact supporting the Company's estimates of the expected reliability improvement.

Response:

As we have discussed in our other responses to this group of Fresh Energy Information Requests, the details of the ISI program are still in development. As such, we have not completed any specific analyses of associated impacts to reliability metrics. As we work to refine our ISI program over time to include specific work plans, part of that work will involve developing appropriate measurements to assess the impacts of the ISI component programs. That said, we do not yet have established measures of expected benefits outside of the general benefits conveyed in the IDP.

We note generally, as also discussed in our response to FE-7, SAIDI, CAIDI and SAIFI do not fully capture the customer experience. They are more appropriate as measures of the overall reliability of our system, but even from a system performance perspective – they do not fully capture our performance.[1] For example, an individual customer that is served by an overhead tap system in a storm-prone area may experience multiple interruptions per year. Interruptions stemming from storms

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[1] For example, our proposed fault location isolation and service restoration (FLISR) advanced grid investment will primarily impact our "all-day" reliability performance, not the Company's storm-normalized performance.

would be "storm-normalized" out of the SAIDI, SAIFI, and CAIDI metrics – yet, the customer experienced (and is likely to continue experiencing) repeated outages.

The ISI program is intended to improve system resilience and the reliability and experience of our customers – both from major events, and the parts of our system that experience multiple shorter duration events. As we develop the specific ISI program details, we will be working to identify the associated qualitative and quantitative benefits, including any associated SAID/SAIFI/CAIDI benefits. We note, however, that we will not be able to determine SAIDI/SAIFI/CAIDI benefits from particular investments with accuracy for a number of years because these all-day metrics vary greatly from year to year. Creating a reasonable comparison requires at least five years of pre- and post-investment data to compare the resiliency impact of the investments.

Preparer:	Molly Dimond
Title:	Investment Delivery
Department:	System Planning and Strategy
Telephone:	303.571.3232
Date:	January 23, 2020

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Xcel Energy		Information Request No. 16
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) pages 139-142.

Request:
Please describe how the Company's distribution operations will change after implementation of the proposed AGIS investments.

Response:
As discussed in the Direct Testimony of Ms. Kelly Bloch provided with the IDP, our vision for the future distribution grid is one that utilizes advances in technology to improve our monitoring and operation of the grid for the benefit of our customers. The advanced grid intelligence and security (AGIS) initiative is a comprehensive plan to advance Xcel Energy's distribution system. This modernization will start with implementing foundational advanced grid initiatives that provide immediate benefits for customers while also enabling future systems and capabilities. AGIS will help to bring about an intelligent, automated, and interactive electric distribution system that will provide operators more visibility into the system, customers greater access to timely energy information, and enable future products and services for our customers.

Our proposed AGIS investments will provide us timely and accurate information about what is happening on all portions of the grid from our substations down to the meter at each individual customer's home and business. These investments will also have automation and intelligence to address problems quickly and efficiently. In some cases, these insights will alert us to situations likely to result in an outage (such as overloaded equipment) before an outage occurs. The increased number of field sensors and devices will also provide the Company with the necessary information to continually monitor and make the necessary adjustments to the system to support increasing amounts of distributed energy resources (DER) and other electric technologies such as electric vehicles (EVs).

The increasing sophistication of distribution grid assets means that they will serve a greater number of purposes and business areas, including forming the foundation for new programs and service offerings, enhanced billing and rate options, timely outage communications, and engaging digital experiences; it will also include security protocols that will detect and remedy cyber and physical threats to our system. These investments will greatly enhance our distribution system's performance and our ability to meet our customers' needs and expectations for their electric service provider now and in the future. As such, increased use of advanced grid equipment and capabilities will require new and different organizational and human resource skills and capabilities.

ADMS is foundational because it provides situational awareness and automated capabilities that sustain and improve the performance of an increasingly complex grid. Specifically, ADMS acts as a centralized decision support system that assists the control room, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. Distribution will operate the advanced distribution management system (ADMS) and its applications such as fault location isolation and service restoration (FLISR) and integrated volt-var optimization (IVVO). Specifically, Distribution operates the associated equipment for these applications, such as switches, reclosers, and capacitors. The Distribution Control Center will be the primary users of the ADMS, with a recently-created Grid Management team ensuring its accuracy, availability, and effectiveness. Our Grid Management team will monitor system performance and data integrity to ensure the improvements made to GIS data continue to provide accurate ADMS solutions.

The Distribution business unit will also provide maintenance for the field-based equipment. When possible, maintenance activities such as firmware upgrades will be performed remotely. However, some of the advanced equipment will reside on poles in the "power zone," and require the specialized skills of qualified line workers to access. Field personnel may need enhanced communications and information technology skills. For example, repairing communications equipment not previously used in distribution activities will require field personnel to develop an entirely new skill set.

Related, the Information Technology (IT) function will require more resources and skills to support new types of computerized field devices. For example, traditionally, Transmission and Distribution Control Center staffs are in regular contact to achieve operational tasks; IT serves as a support function for both. The advancements of grid technology will require a more integrated IT role, including in troubleshooting advanced grid technologies in the field and back office.

In addition to field and IT capability enhancements, Distribution Control Center personnel will also need to acquire new skills as the management of grid operations becomes more complex. For example, where Dispatchers have traditionally instructed field crews to make on-location changes, advanced grid technologies will allow them to perform some such actions remotely, or perhaps simply monitor automated system instructions. Some of this transition is underway as we have been incrementally advancing grid assets and customer-owned distributed energy resources (DER) has grown. However, the distribution of power beyond the substation has historically been unidirectional. As penetrations of DER get higher, Dispatchers will have to manage multidirectional power flow that is more like what Transmission operators do currently.

Advanced systems and tools will play a pivotal role in helping business areas and personnel manage practical issues and maximize the value of available data. Other functional areas and personnel will also require new systems and tools to maximize the value of data and capabilities made available by the advanced grid. Even Customer Care Center skill sets may need to change. In an advanced grid scenario, the nature of support customers may want is likely to change. As just one example, access to more detailed usage information from Advanced Metering Infrastructure (AMI) is likely to prompt customer questions on how to interpret the information, how to identify the drivers of home energy consumption, and how best to save money on time-differentiated rates. These types of calls will require new skills and competencies from Call Center agents. The advanced grid will also change the types of Demand Side Management (DSM) programs we offer, the features and capabilities of such programs, and the manner in which DSM programs will be promoted – requiring more sophisticated data analysis to develop meaningful programs and/or rates – and leveraging available technologies to maximize customer participation and thus customer and grid benefits.

We expect the impacts of advancing the grid on the Distribution and IT functions to be particularly acute during the transition period. Advanced grid upgrades take years to complete, or even decades, depending on the approach. This means that, in addition to advanced grid implementation activities that are taking place, employees in many business functions must manage two operating models – traditional and advanced – simultaneously.

That said, our proposed plans anticipate and include change management and training to ensure an effective implementation and transition.

Preparer:	Kelly Bloch
Title:	Regional Vice President
Department:	Distribution Operations
Telephone:	651-229-2435
Date:	January 23, 2020

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Xcel Energy		Information Request No. 17
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) page 180.

Request:
Fresh Energy understands that the output from community solar gardens and distribution-connected utility-scale solar serves the load of customers closest to the solar facilities, thereby reducing the need for centralized generation to serve this load.

A. Does the Company agree with Fresh Energy's understanding? If not, please explain.
B. If the Company agrees with Fresh Energy's understanding, please explain the statement on p. 180 of the IDP that "The sales and peak demand forecasts are not adjusted for community solar gardens or distribution-connected utility-scale solar because these do not affect customers' loads."

Response:

A. The Company agrees in part. Electricity generation from solar gardens and distribution-connected utility-scale solar is capable of serving some of the load of customers within the same part of the distribution system where the distributed generation is located. This may or may not include the load of customers located closest to the solar facilities.

   The Company also partially agrees that the output from community solar gardens and distribution-connected utility-scale solar reduces some of the need for other generation to serve that load. However, although it may reduce the need for other generation to serve some load while the distributed resource is generating, it does not eliminate the need. The Company continues to have an overarching obligation to serve that requires the Company to provide energy and capacity to meet customer needs regardless of whether the distributed resource is generating.

B. The sales and peak demand forecasts are estimates of customers' expected energy and load requirements. Community solar gardens or distribution-connected utility-scale solar generation are sources of energy supply the Company uses to meet the expected load requirements. Because these sources of energy supply are not behind the customers' meters, they do not directly reduce customers' expected load and energy requirements in our sales and peak demand forecasts. In other words, we count these resources as additions to the supply-side, rather than offsets to the load-side of the equation.

Preparer:	Luke Jaramillo
Title:	Senior Energy Forecasting Analyst
Department:	Sales, Energy and Demand Forecasting
Telephone:	303-571-6239
Date:	January 23, 2020

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Xcel Energy		Information Request No. 18
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) page 180.

Request:
Please provide all data, analysis, studies, reports, or spreadsheets with all formulas and links intact explaining how the Company extracts the impacts of customer-sited behind-the-meter solar installations in the NSP System peak demand forecast.

Response:

Northern States Power Company objects to this Request as overly broad and unduly burdensome. Subject to the foregoing objection, we respond as follows:

Please refer to our November 1, 2019 Integrated Distributed Plan on pages 178-180 for a discussion of the development of the Company's peak demand forecast and the associated adjustments for behind-the-meter solar installations on pages 178-180. Attachment A to this response includes the calculation of how behind-the-meter solar generation is extracted from the Company's 2020-2024 peak demand forecast.

Preparer:	Luke Jaramillo
Title:	Senior Energy Forecasting
Department:	Sales, Energy and Demand
Telephone:	303-571-6239
Date:	January 23, 2020

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Xcel Energy		Information Request No. 19
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) page 187.

Request:
Please provide updated values for Table 49 as of December 2019.

Response:

Table [FE-19] 1: Minnesota Distribution-Connected Distributed Energy Resources – Interconnected Resources
(As of December 2019)

	Completed Projects		Queued Projects	
	MW/DC	# of Projects	MW/DC	# of Projects
Small Scale Solar PV				
Rooftop Solar	80	5,200	58	967
RDF Projects[1]	19	25	1	2
Wind	16	61	<1	9
Storage/Batteries[2]	N/A	48	N/A	31

	Completed Projects		Queued Projects	
	MW/AC	# of Projects	MW/AC	# of Projects
Large Scale Solar PV				
Community Solar	656	268	241	226
Grid Scale	100	16	80[3]	1

---

[1] No change since July 2019
[2] All current battery projects within our DER process are associated with other generation projects, such as solar. As such the application does not capture gen. MW as it is accounted for in other categories.
[3] Xcel Energy Petition Approval of Solar Energy Purchase Agreement with Elk Creek Solar, LLC for 80 MW Solar Generation, Docket No. E002/M-19-568. *Pending Decision*

Revised Response:

In our original response to this Information Request, we inadvertently included 80 MW of queued grid scale solar for our pending Petition for Approval of the Solar Energy Purchase Agreement with Elk Creek Solar, LLC (Docket No. E002/M-19-568). This project is transmission interconnected, not distribution connected, and has therefore been removed from the table below. The Storage/Batteries row has also been adjusted to correctly show 47 completed projects.

Table [FE-19 Revised] 1: Minnesota Distribution-Connected Distributed Energy Resources – Interconnected Resources
(As of December 2019)

	Completed Projects		Queued Projects	
	MW/DC	# of Projects	MW/DC	# of Projects
Small Scale Solar PV				
Rooftop Solar	80	5,200	58	967
RDF Projects[1]	19	25	1	2
Wind	16	61	<1	9
Storage/Batteries[2]	N/A	47	N/A	31

	Completed Projects		Queued Projects	
	MW/AC	# of Projects	MW/AC	# of Projects
Large Scale Solar PV				
Community Solar	656	268	241	226
Grid Scale	100	16	0	0

Preparer: Jessica Peterson
Title: Sr. Regulatory Analyst
Department: Customer Solutions
Telephone: 612.330.6850
Date: January 23, 2020 **Revised**: February 5, 2020

[1] No change since July 2019
[2] All current battery projects within our DER process are associated with other generation projects, such as solar. As such the application does not capture gen. MW as it is accounted for in other categories.

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Xcel Energy		Information Request No. 20
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) page 257.

Request:
Please provide all data, analysis, studies, reports, or spreadsheets with all formulas and links intact supporting the Company's assumption of a 0.8% CAGR in NSP peak demand from 2019-2036.

Response:

Northern States Power Company objects to this Request as overly broad and unduly burdensome. Subject to the foregoing objection, we respond as follows:

Please refer to FE-20 Attachment A for the calculation of the 0.8% CAGR in the NSP System peak demand forecast for the 2019-2036 period. The corporate load forecast used for the growth assumptions beyond the distribution planning period was developed in the Fall of 2019.

Preparer:	Luke Jaramillo
Title:	Senior Energy Forecasting
Department:	Sales, Energy and Demand
Telephone:	303-571-6239
Date:	January 23, 2020

NSP System Peak Demand Forecast, MW
2019 Fall forecast release

	Peak Demand Forecast
2019	9,054
2020	9,058
2021	9,028
2022	9,066
2023	9,097
2024	9,108
2025	9,154
2026	9,219
2027	9,313
2028	9,396
2029	9,409
2030	9,480
2031	9,546
2032	9,634
2033	9,830
2034	10,033
2035	10,179
2036	10,330

2019-2036 CAGR	**0.8%**

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Xcel Energy — Information Request No. 21

Docket No.: E002/M-19-666
Response To: Fresh Energy
Requestor: Isabel Ricker
Date Received: January 13, 2020

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment D1.

Request:
A. Please provide the name of the selected APT vendor and software platform.
B. Please provide the names of existing APT customers that the Company interviewed.

Response:
A. The vendor we selected for our Advanced Planning Tool is Willdan Group Inc.'s Integral Analytics. The software platform is LoadSEER.
B. The Company met with Seattle City Light and Pacific Gas & Electric for customer references on the LoadSEER tool.

Preparer: Brian Monson
Title: Distribution Planning Engineer
Department: System Planning and Strategy
Telephone: 763-493-1811
Date: January 23, 2020

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Xcel Energy		Information Request No. 22
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment E.

Request:
Please provide all data, analysis, studies, reports, or spreadsheets with all formulas and links intact explaining the conversion factor and algorithm used by the Company to convert the reliability benefit to a financial value.

Response:
Northern States Power Company objects to this Request as overly broad and unduly burdensome. Subject to the foregoing objection, we respond as follows:

Attachment E to our 2019 IDP is our Risk Scoring Methodology that is part of our annual system planning process. We provide the requested information as Attachments A, B and C to this response, as follows:

Non-Public Attachment A – Risk Scoring_Electric. This document outlines the investment appraisal methodology and the reliability calculations used to capture an electric project's benefit.

Non-Public Attachment B – CMO-ICE_Calculator. This spreadsheet provides the calculation for the cost per Customer Minute Outage (CMO) used for the reliability benefit.

Non-Public Attachment C – IDP Projects_Score Breakdown. This spreadsheet is the listing of all scored projects, showing the reliability and financial benefits along with the annualized cost, all used for the benefit over cost ratio that becomes the project score. The reliability benefit is specifically broken down for two projects showing the specific calculations used to determine the CMO's for overload and contingency risks mitigated by the project.

Attachment A to this response is a Company work product. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Additionally, some data contained within the work product is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use, and/or contains proprietary customer and system data.

Please note Attachment A is marked as "Non-Public" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, we provide the following description of the excised material:

1. **Nature of the Material:** The Investment Appraisal Methodology developed by the Company.
2. **Authors:** Risk Analytics
3. **Importance:** The Company work product is proprietary to the Company.
4. **Date the Information was Prepared:** January 2019.

Attachment B contains 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 C also 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.

One tab included in Attachment C 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 the value of Customer Minutes Out
2. **Authors:** Risk Analytics
3. **Importance:** The Company work product is proprietary to the Company.
4. **Date the Information was Prepared:** January 2019

Attachment C contains 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 C also 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.

One tab included in Attachment C 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:

5. **Nature of the Material:** Scored projects, showing the reliability and financial benefits along with the annualized cost
6. **Authors:** Electric Systems Performance and the Risk Analytics Department.
7. **Importance:** Key values to determine the potential reliability of certain projects.
8. **Date the Information was Prepared:** January 2020

Preparer:	Steve Rohlwing
Title:	Manager, Asset Risk Management
Department:	Risk Analytics
Telephone:	303-571-7392
Date:	January 23, 2020

Mitigation No.	Mitigation Title	Jurisdiction	Lifespan of Project	Total Annualized Costs ($M's)	Reliability Benefit - CMO (Electric)	Financial Benefit	Reliability Benefit	Financial Benefit	Total Weighted Benefit	Project Score
					[PROTECTED DATA BEGINS					
E144.018970	Reinforce Medford Junction MDF TR1	NSPM - ED	40	$0.158						114.9
E147.019893	Install Switch Coon Creek CNC073	NSPM - ED	40	$0.002						52.9
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	NSPM - ED	40	$0.086						49.7
E143.016730	Install Feeder Tie Wilson WIL081	NSPM - ED	40	$0.020						34.8
E147.017741	Reinforce Osseo OSS062	NSPM - ED	40	$0.013						33.1
E150.018967	Extend Red Rock RRK063	NSPM - ED	40	$0.007						18.1
E144.017637	Load Transfer ESW062 to SMT061	NSPM - ED	40	$0.007						15.0
E141.017739	Extend Main Street MST074	NSPM - ED	40	$0.020						14.3
E143.016724	Reinforce Westgate WSG Feeders	NSPM - ED	40	$0.036						10.8
E141.019911	Reinforce Medicine Lake MEL074	NSPM - ED	40	$0.033						10.6
E141.019924	Install Hiawatha West HWW Feeder	NSPM - ED	40	$0.079						10.3
E141.019929	Install Midtown MDT Feeder	NSPM - ED	40	$0.125						9.5
E141.019957	Extend Saint Louis Park SLP085	NSPM - ED	40	$0.010						8.4
E147.015637	Install Feeder Tie Osseo OSS063	NSPM - ED	40	$0.007						8.0
E150.019910	Load Transfer CGR062 to CGR071	NSPM - ED	40	$0.063						7.7
E141.010910	Install Wilson WIL TR4 & Feeders	NSPM - ED	40	$0.970						7.6
E143.019055	Reinforce Savage SAV063 & SAV067	NSPM - ED	40	$0.072						7.1
E156.010177	Install Kohlman Lake KOL Feeder	NSPM - ED	40	$0.103						6.9
E150.010914	Install Stockyards STY TR3 & Feeders	NSPM - ED	40	$0.263						6.3
E156.015749	Install Baytown BYT Feeders	NSPM - ED	40	$0.268						6.2
E154.016772	Install Fiesta City FIC Feeder	NSPM - ED	40	$0.066						6.0
E141.019930	Install Feeder Tie SOU083 to MDT074	NSPM - ED	40	$0.007						5.4
E141.019954	Reinforce Saint Louis Park SLP087	NSPM - ED	40	$0.010						5.2
E141.019928	Extend Saint Louis Park SLP092	NSPM - ED	40	$0.040						4.8
E154.018960	Reinforce Glenwood GLD Sub Equip	NSPM - ED	40	$0.046						4.6
E144.002712	Install Goodview GVW Feeder	NSPM - ED	40	$0.072						4.0
E150.015662	Install Chemolite CHE065 Feeder	NSPM - ED	40	$0.095						3.9
E156.011061	Install Wyoming WYO Feeder	NSPM - ED	40	$0.165						3.9
E143.016727	Install Feeder Tie EBL064	NSPM - ED	40	$0.010						3.7
E147.019056	Reinforce Basset Creek BCR062	NSPM - ED	40	$0.016						3.7
E141.019958	Reinforce Moore Lake MOL071	NSPM - ED	40	$0.036						3.1
E151.012409	Install Western WES TR3 & Feeders	NSPM - ED	40	$0.493						2.8
E144.013436	Reinforce Kasson KAN TR1 & Feeders	NSPM - ED	40	$0.188						2.8
E147.012463	Install Feeder Tie Crooked Lake CRL033	NSPM - ED	40	$0.073						2.6
E154.010157	Install Albany ALB TR	NSPM - ED	40	$0.194						2.1
E141.019956	Reinforce Terminal TER073	NSPM - ED	40	$0.072						1.8
E150.012576	Install South Washington ERU Sub	NSPM - ED	40	$0.361						1.9
E144.018971	Reinforce Veseli VES TR1 & Feeder	NSPM - ED	40	$0.171						1.8
E141.019955	Extend Terminal TER064	NSPM - ED	40	$0.010						1.7
E144.010920	Reinforce Burnside BUR TR2	NSPM - ED	40	$0.172						1.6
E143.019054	Reinforce Edina EDA062	NSPM - ED	40	$0.033						1.3
E147.014465	Reinforce Brooklyn Park BRP062	NSPM - ED	41	$0.012						1.2
E144.000793	Install Zumbrota ZUM TR & Feeder	NSPM - ED	42	$0.189						1.2
E144.016592	Reinforce Sibley Park SIP Sub Equip	NSPM - ED	43	$0.006						1.1
E143.017702	Install Viking VKG Feeder	NSPM - ED	44	$0.165						1.0
E150.010904	Install Rosemount RMT TR2 & Feeder	NSPM - ED	45	$0.358						1.0
E142.011721	Install Orono ORO TR2 & Feeder	NSPM - ED	46	$0.274						0.9
E156.007927	Install Goose Lake GLK TR3 & Feeders	NSPM - ED	47	$0.333						0.8
E144.008708	Install Cannon Falls Trans CTF TR2 & Fdr	NSPM - ED	48	$0.124						0.7
E147.013379	Install West Coon Rapids WCR TR	NSPM - ED	49	$0.244						0.7
E156.011752	Install Lindstrom LIN Feeder	NSPM - ED	50	$0.043						0.7
E143.019908	Install Hyland Lake HYL TR3 & Feeder	NSPM - ED	51	$0.291						0.6
E156.011764	Reinforce Tanners Lake TLK Sub Equip	NSPM - ED	52	$0.013						0.6
E156.015811	Reinforce Oakdale OAD073 & OAD075	NSPM - ED	53	$0.018						0.5
E151.018961	New MPK075-GPH061 Feeder Tie	NSPM - ED	54	$0.016						0.5
E144.013520	Install East Winona EWI TR2 & Feeder	NSPM - ED	55	$0.218						0.4
E153.010999	Install Louise LOU TR2 & Feeders	NSPM - ED	56	$0.332						0.4
E141.009146	Install Hiawatha West HWW TR2	NSPM - ED	57	$0.092						0.1
E154.015728	Reinforce St Cloud SCL TR2	NSPM - ED	58	$0.160						0.1
E141.009145	Install Midtown MDT TR2	NSPM - ED	59	$0.093						0.1

PROTECTED DATA ENDS]

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☐ **Public Document – Not Public Data Has Been Excised**
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Xcel Energy		Information Request No. 23
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment G1.

Request:
Please provide a spreadsheet containing the data used by the Company to create Figures 1 and 2.

Response:
Attachment G1 is the Company's State of Minnesota Electric Jurisdiction capital profile trend for the 2014 to 2024 period, with Figures 1 and 2 portraying the IDP categories, as follows:

Figure 1
- New customer Projects and New Revenue
- Metering
- System Expansion or Upgrades for Capacity
- Grid Modernization and Pilot Projects

Figure 2
- Projects Related to Local (or other) Government Requirements
- Age-Related Replacements and Asset Renewal
- Other
- System Expansion or Upgrades for Reliability and Power Quality

We provide the requested information as Attachment A.

Preparer:	Shannon Robin
Title:	Manager, Investment Delivery
Department:	System Planning and Strategy North
Telephone:	651-229-2261
Date:	January 23, 2020

IDP Categories	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2014-2018	2019-2024
Age-Related Replacements and Asset Renewal	$39.6	$48.1	$59.4	$56.7	$65.5	$72.5	$87.2	$79.5	$78.3	$79.7	$81.0	$269.4	$478.2
System Expansion or Upgrades for Capacity	$33.3	$21.3	$23.3	$16.4	$15.1	$19.5	$44.4	$40.1	$32.3	$32.9	$37.9	$109.4	$207.1
Projects related to Local (or other) Government-Requirements	$15.2	$19.6	$30.2	$13.7	$28.8	$31.3	$28.9	$29.4	$28.5	$29.0	$29.2	$107.4	$176.3
Metering	$4.8	$5.2	$5.1	$6.8	$5.9	$6.7	$5.5	$4.3	$3.5	$2.3	$2.3	$27.7	$24.6
New Customer Projects and New Revenue	$26.4	$30.2	$32.4	$45.0	$41.6	$34.8	$35.6	$39.3	$39.3	$39.4	$39.4	$175.7	$227.7
Non-Investment	($3.2)	($5.6)	$4.7	$4.7	($15.5)	($4.9)	($3.7)	($3.7)	($3.8)	($3.8)	($3.8)	($14.9)	($23.8)
Other (includes Fleet add in)	$25.3	$32.4	$30.9	$35.0	$39.3	$26.7	$38.3	$39.7	$43.2	$35.4	$35.1	$162.8	$218.3
System Expansion or Upgrades for Reliability and Power Quality	$14.4	$15.6	$20.2	$22.8	$24.4	$19.8	$21.5	$114.7	$117.4	$117.3	$117.3	$97.4	$508.0
Grid Modernization and Pilot Projects	$0.0	$0.0	$0.0	$0.0	$0.4	$4.6	$19.9	$49.3	$141.7	$152.4	$76.7	$0.4	$444.6
	$155.7	$166.7	$206.2	$201.0	$205.6	$210.9	$277.5	$392.6	$480.3	$484.6	$415.2	$935.3	$2,261.1

IDP Category	Mitigation Number	Mitigation Name	2014 Expenditures
Age-Related Replacements and Asset Renewal			
	E114.006616	MN Replace/Reinforce Non-Compliant Poles	5,602,656
	E114.005559	MN Major Storm Recovery BlanketMN	3,885,299
	E103.012612	ELR MN Sub TRs	2,404,986
	E103.014456	Replace 5 distribution breakers at Merriam Park	2,291,856
	E103.004666	Hollydale - Replace Failed 69kV/13.	2,022,002
	E103.011423	RCSII Replacement Project - NSPM	1,894,812
	E141.013426	LaSalle Paving Project	1,793,870
	E154.011354	Install Cottonwood stepdowns to enable retirement of sub	1,511,143
	E141.001141	Mpls-OH Rebuilds	1,459,982
	E141.013910	St. Anthony Falls Hydro 15kV Cable Replacement	1,350,698
	E143.014668	WIL086 OH to UG Conversion	1,346,695
	E151.016150	Hamline Station	981,499
	E151.013595	SSI: Convert St Clair 4kV to 13.8kV	957,944
	E151.012282	Reconductor RAM73 Mainline	918,667
	E103.014355	Rewind failed 115KV - 13.8KV 70MVA transformer	816,306
	E103.009150	SPCC NSPM Oil Spill Prevention	731,800
	E144.013060	M&R Dairy Rebuild	723,884
	E147.004711	Funding for CO109 Gravel Pit phase	713,162
	E154.012309	Remove Eden Valley to Watkins line	648,212
	E143.013748	SAV River Crossing	602,051
	E153.012431	Convert SOS 4kV to 13.8kV	596,249
	E141.013429	Hwy 7 and Louisiana OH to UG Relocate	570,794
	E142.009661	OH Rebuild Mtka increase	559,804
	E150.013542	Woodbury Drive Road Move 3000ft Feeder at Bailey	554,279
	E156.001292	White Bear-OH Rebuilds	502,240
	E143.014769	Savage, Replace failed TR2	486,449
	E147.001209	Maple Grv-OH Rebuilds	461,085
	E147.015160	Replace failed PKL TR3	435,543
	E142.004727	Co Rd 109, Phase 2-UG Conv	373,268
	E141.014168	OH to UG County Rd 9 - Xerxes to France	354,049
	E141.001664	ELR MPLS Vault Tops	286,484
	E154.013609	SSI: Add 3 phase line on east ALB22	251,464
	E156.008247	WBL Tap Cables	247,555
	E151.013631	Replace Network Protectors - STP	235,831
	E141.015088	Chicago Ave and 4th St Conversion	203,396
	E151.013639	ELR STP Vault Tops	202,398
	E150.014414	Replace Koch TR16 with reserve	184,678
	E103.011891	ELR MN Sub Switches	169,135
	E147.002745	RM: Relocate OH mainline for Hwy 241 from Co Rd 19 to McIver Ave NE: St Michael MN: LAP311	148,229
	E141.010286	Replace Dustproof protectors	144,820
	E103.013521	ELR MN Sub RTUs	113,103
	E103.013804	Upgrade fence at Buffalo Lake	96,361
	E154.011251	Sauk Rapids OH to UG 2010	92,688
	E151.012985	SSI: Conv 4kV btwn Holly and Ashland	87,841
	E150.003703	Woodbury Lakes OH to UG conversion	83,918
	E142.013678	Sparrow Rd, City of Minnetonka, OH to UG	80,975
	E154.014732	Sauk Rapids overhead to underground	59,495
	E154.008992	SSI: Osakis Conversion from 4kV to 12.5kV	30,363
	E103.012839	Tap Cable Injection	22,218
	E144.013597	Byron Frontage Road - OH to UG	16,804
	E103.012603	ELR MN Sub Regulators	15,955
	E141.012673	Replace Fifth Street FST Switchgear	3,066
	E144.015240	Replace Jordan Sub's Aging Equipment	957
	E103.013059	Purchase 50 MVA reserve transformer	820
	E154.013988	T: Annandale Town Rebuild	524
	E154.013611	SSI: Convert Echo 4kV to 23.9kV	407
	E103.013576	reserve 70 MVA 115/13.8 kV transformer	290
	E103.007227	NSPM Dist Line Parent for CRFS Tracker Work Orders	(74)
	NA	1997 PRIVATE PARTY FORCED RECO	(539)
	NA	2000 Electric Reconstruction -	(3,659)
	E143.014095	Shady Oak OH to UG Conversion	(79,230)
	E151.014770	Lillydale UG Conversion	(226,982)
	E142.014722	County Road 101 OH-UG	(440,707)
System Expansion or Upgrades for Capacity			
	E141.007514	Oakland Install 13.8kV #1#2 50MVA 8 fdrs	5,090,844
	E147.002788	Install Basset Creek BCRTR2 50MVA	4,943,663
	E150.010916	Convert Chemolite to 13.8kV	3,356,768
	E144.013396	Add 28MVA WASTR3 and 1 fdr	2,632,033
	E141.007874	Inst 13.8kV Hiawatha #1 50MVA	2,434,649
	E144.010890	Reinforce Lake Emily TR1 to 14MVA	1,598,876
	E154.012597	Upgrade Freeport substation to 12.5kV	1,290,644
	E144.013502	Reinforce 3 miles of SMT082	1,057,039
	E147.013543	Install BCR new feeder at Basset Creek	1,004,077
	E153.012465	Install tie for SOS062	949,596
	E141.002682	Replace Failed Network Protectors on FST Network	931,156

IDP Category	Mitigation Number	Mitigation Name	2014 Expenditures
	E144.013934	Reinforce 3.5 miles of LAE061	857,469
	E141.017361	JAPS-OLSON 7500 Excelsior Blvd	699,339
	E154.008992	SSI: Osakis Conversion from 4kV to 12.5kV	664,296
	E151.011613	Rebuild Public Health Vault	547,683
	E144.012835	Reconductor 2 mi SCH211 feeder.	499,371
	E141.014051	Velo Residental Building - Vault	468,906
	E150.012453	Replace RRK TR1 with 50MVA and add one feeder	414,082
	E156.010172	Install new feeder at RAM	401,266
	E154.006387	New First Lake substation in Monticello, MN	298,659
	E151.011622	Rebuild Shaft Hole & Replace Cables	297,480
	E156.008860	Install switches on OAD075 and transfer load to relieve NOL	285,179
	E141.014356	Hampton Inn Ductline	242,525
	E141.014357	Hampton Inn Vault	235,289
	E151.010808	Install DBL082 feeder	234,634
	E141.014950	4 Marquette Ave - New Vault	222,233
	E143.001172	Edina-OH Reinforcements	197,716
	E151.002440	Extend MPK66 to US Bank east, ATO	168,936
	E141.015808	Cascade load relief to MDT	153,422
	E154.007052	Extend 3 phase to new development in Sartell - 50th st	145,532
	E147.001219	Maple Grv-UG Reinforcements	142,359
	E150.008740	Reconductor & Reinsulated CGR71 to AFT322	129,763
	E151.011161	New Ductline on 5th btwn Broadway & Robert	128,483
	E141.011698	Indiana-IDA064 new reinforce	117,796
	E141.014961	401 Nicollet - New Vault	109,829
	E151.012435	Reinforce DBL062	91,828
	E154.012593	Reinforce SDX TR1	81,406
	E150.014028	Flint Hills Refinery New 34.5kV Primary Service off RMT311, to be paid by customer.	64,208
	E156.007929	Install #2 at Long Lake normal load serving	63,239
	E156.012599	Install new fder tie for KOL64	62,869
	E103.008083	Environmental Work NSPM-EL	61,873
	E142.011357	Convert Orono to 115 kV	59,892
	E143.010967	Viking new sub 4 fdrs	56,667
	E114.015137	Aldrich - PT Addition - Parent already created	55,808
	E151.012987	SSI: Convert STR006	54,076
	E151.001248	St Paul-OH Reinforcements	52,595
	E150.012312	Replace PMC on CGR64 with PMH-9	47,181
	E147.011058	Plymouth-Area Power Grid Upgrades	43,478
	E150.010914	Install Stockyards STY TR3 & Feeders	39,373
	E144.001187	Southeast-UG Reinforcements	39,037
	E144.012984	SSI: Convert Waldorf Distribution	32,862
	E143.013500	Extend WSG062 to relieve WSG072	27,033
	E144.013448	SSI: Add 2nd 23.9kV Transformer and feeder at Waterville	26,356
	E141.013735	Nicollet Residence	25,678
	E142.014709	T: High side rebuild at BLC due to SWTC	22,649
	E142.004532	Chaska Sub FDR61 - Reinforcement Pr	21,796
	E147.012675	HOL061 3 Phase Upgrade	19,748
	E141.014694	U of M CHP Express Feeders	19,601
	E142.009045	Install Bluff Creek 115/13.8kV 50MVA TR#3-CANCELLED	15,315
	E141.014517	New ELP feeder	7,200
	E144.012973	Install Cap Bank at Crystal Foods	1,731
	E141.013130	Whole Foods - 222 Hennepin	1,567
	E144.010887	Install Dundas TR2 28MVA 69/13.8kV	1,304
	NA	Misc Tools and Equipment	1,061
	NA	Substation Land - ND	626
	NA	RESTORATION FOR ALL METR	409
	E141.013905	Construct ductline along Portland from MDT Sub to 27th	199
	E141.013010	New Feeder to UofM Fulton Switchstation	128
	E144.012111	Upgrade Buffalo Lake sub from 4kV to 15kV	31
	NA	Whole Foods - 222 Hennepin	19
	E103.013568	Rewind 69/12.5 kV 28 MVA	7
	E142.009048	Rebuild Chaska substation	(106)
	E156.010207	Install new HUG312 fdr at Hugo	(199)
	E142.011133	Transfer Plato load	(300)
	E141.010254	Marshall-RIV062 Convert4kV	(1,993)
	NA	Install two Ald fds	(3,949)
	E154.001282	Northwest-UG Reinforcement	(9,018)
	E142.013189	Bluff Creek reinf LV bushings on TR1 and TR2	(10,919)
	E143.007500	Install new feeder from East Bloomington Substation to the HHH Terminal @ MSP Airport	(16,167)
	E147.010067	Install Elm Creek TR#3 (115/13.8kV)	(45,209)
	E143.013101	United Health Shady Oak Road Project	(68,286)
	E103.012099	Capitalized-MN-Sales Tax Rfd - Elec	(572,872)
Projects related to Local (or other) Government-Requirements			
	E141.013815	Centerpoint 2nd St N Relocation	1,903,144
	E151.015043	Snelling Bridge Relocation	1,292,236
	E156.013070	St Croix River Bridge	1,259,015
	E150.014165	Hwy 149 & 55 Road Move Eagan Relocate 6 feeders	1,231,203
	E156.014239	RAM071 - Cty Rd B Road Work Maplewood	872,471

IDP Category	Mitigation Number	Mitigation Name	2014 Expenditures
	E144.012864	County Road 20 Road Move	752,438
	E143.014406	Shady Oak Conversion 212 Crossing	703,151
	E154.007065	Hwy 101 and County Rd 36 Overhead Relocation	605,602
	E141.015206	St. Anthony Bridge Relocation	575,776
	E103.011368	NSPM facility transfers from 3rd Party Owned Poles	481,344
	E144.013680	Dresbach I-90 Re-Route 3 Mi OH	433,975
	E142.008544	County Rd 17, Delano, Road Move	415,801
	E154.014754	County Rd 3 Sauk Rapids	406,157
	E143.005672	EDP/ANDERSON LAKES & HWY 169/RELOCA	375,768
	E151.016971	White Bear Ave Relocation	356,980
	E144.001189	Southeast-UG Relocations	344,628
	E154.014057	Rogers Hwy 101 Relocation	337,144
	E143.013003	Hwy 5 and Hwy 13 Relocations	298,305
	E147.004557	Medina-Hwy 101 Overhead Fdr-RM	295,633
	E143.000159	Road Widening Minnetonka CR5 and CR73	244,673
	E141.002215	Mpls-UG Service Conv	195,634
	E142.011113	Required distribution move due to phase I SWTC transmission rebuild	172,780
	E150.009111	Relc TLK77 OH on Century for Cty Rd Widening	168,727
	E151.001251	St Paul-UG Relocations	166,901
	E147.001221	Maple Grv-UG Relocations	154,367
	E141.016028	5601 Lake St PMH Relocation	144,937
	E142.001160	Mntka-UG Relocations	139,404
	E143.002217	Edina-UG Service Conv	132,003
	E151.002224	St Paul-UG Service Conv	121,229
	E151.012334	35E Relocation	114,317
	E150.013029	Cedar Grove PKWY Relocate 5000ft of 750AL	100,581
	E156.002218	White Bear-UG Service Conv	93,480
	E154.001284	Northwest-UG Relocations	91,470
	E143.010876	Hwy 494/169 Interchange rebuild	83,368
	E143.013104	MOA Relocation	78,375
	E142.002216	Mntka-UG Service Conv	65,760
	E156.001296	White Bear-UG Relocations	59,749
	E151.014237	Saints Ballpark OH-UG DBL063	46,617
	E150.002222	Newport-UG Service Conv	31,581
	E147.002219	Maple Grv-UG Service Conv	28,430
	E154.002220	Northwest-UG Service Conv	24,675
	E144.002223	Southeast-UG Service Conv	23,401
	E156.014013	Arsenal removal and relocation of facilities. AHI024	4,566
	E144.014340	Morton County Road 2 Relocation	151
	E144.013661	West Concord CSAH 24 3-mile road grade	(818)
	E150.013782	Hastings Hwy 61 Bridge Replacement	(1,141)
	NA	Lrt - Dist Work	(4,771)
	E151.007769	Relocate for LRT in St Paul	(5,597)
	E141.013428	Relocate Ductline for New Viking Stadium	(16,664)
	E150.011418	Hastings Bridge Re-route ductbank for pier #5 Hwy 61	(46,947)
	E151.008736	RM- Relocate Feeders Rice St	(151,286)
Metering			
	E103.001040	MN-Electric Meter Blanket	4,770,055
New Customer Projects and New Revenue			
	E150.005996	Newport-UG Extensions	2,917,400
	E147.014741	Olympus Technologies Service	1,982,014
	E141.017362	365 Nicollet Construction Power	1,806,914
	E144.003805	Wanamingo - Pine Ridge development 82 units	1,742,497
	E156.001299	White Bear-UG Extensions	1,732,704
	E143.002572	Install Feeder tie to eliminate N-1 on WIL86 4.9 MVA	1,333,016
	E156.001288	White Bear-UG Services	1,241,904
	E150.001226	Newport-UG Services	1,120,037
	E142.010321	New Germany Trophy Lake 45 lot URD	965,900
	E154.001271	Northwest-UG Extensions	896,149
	E142.001152	Mntka-New UG Services	718,541
	E144.001179	Southeast-UG Services	694,270
	E154.001277	Northwest-New UG Services	688,333
	E142.014619	Woodland Cove JT Devlopment, Minnetrista, MN	682,566
	E151.015041	Port Authority Barge Road	612,764
	E147.001214	Maple Grv-New Elec UG Services	605,802
	E143.001169	Edina-New UG Street Lights	513,642
	E141.017364	1910 Queen Ave N Extension	481,446
	E156.001286	White Bear-OH Extension	469,811
	E141.001135	Mpls-OH Services	465,044
	E144.002761	Switch load to new Summit Ave Bank #2 Feeder	419,758
	E143.001167	Edina-UG Services	382,522
	E141.010560	Serve Children's Hospital Addition (ATO and Pri Svc)	373,181
	E150.001229	Newport-UG Streetlights	308,194
	E154.011195	Paynesville Mastermark Plastic NB Convert to 35kV	262,554
	E144.001181	Southeast-OH Streetlights	262,291
	E144.001182	Southeast-UG Streetlights	258,214
	E141.001138	Mpls-New OH Street Lights	251,827

IDP Category	Mitigation Number	Mitigation Name	2014 Expenditures
	E156.001290	White Bear-UG Street Lts	249,983
	E142.014720	Wayzata Bay Development	182,952
	E147.014733	Oxbow Cove Development	168,216
	E156.001555	Upgrade feeder exit with 1000 Al and reactor	158,590
	E144.001178	Southeast-OH Services	152,366
	E151.001240	St Paul-OH Services	137,536
	E154.001274	Northwest-New OH Street Lights	135,961
	E156.001287	White Bear-OH Services	122,417
	E151.001243	St Paul-OH Streetlights	110,857
	E141.001139	Mpls-New UG Street Lights	109,071
	E150.014745	Dakota Aggregate-RMT312 Extend OH 5500ft	105,549
	E147.001215	Maple Grv-New UG Street Lights	104,971
	E154.001276	Northwest-New OH Services	97,268
	E142.001150	Mntka-OH Extension	93,754
	E143.001166	Edina-New OH Services	92,070
	E147.014055	Highgrove 3rd Addition	91,770
	E150.001225	Newport-OH Services	79,817
	E154.001278	Northwest-New UG Street Lights	76,297
	E141.000640	Install a new tie to PKL85 to eliminate N-1 on MEL65	71,015
	E143.002573	Install switches to eliminate N-1 on WIL77 4 MVA	57,974
	E151.001241	St Paul-UG Services	47,109
	E156.001289	White Bear-OH Street Lights	46,908
	E150.001228	Newport-OH Streetlights	44,600
	E142.001151	Mntka-OH Services	42,388
	E143.001168	Edina-New OH Street Lights	41,811
	E147.001213	Maple Grv-OH Services	29,739
	E147.001211	Maple Grv-New OH Street Lights	28,924
	E142.001153	Mntka-New OH Street Lights	24,836
	NA	North Dakota/MN - UG Extension	12,486
	E151.001244	St Paul-UG Street Lights	2,530
	NA	1999 ELECTRIC NEW BUSINESS - N	(1,232)
	E141.003614	Street Lighting,Poles,Luminair	(1,714)
	NA	2-NEW SOU FDRS-DIST WORK	(10,491)
	NA	2000 Electric New Business - S	(10,719)
	E142.001154	Mntka-New UG Street Lights	(20,292)
	E143.013750	MAC Dual Source HHH Term	(30,124)
	E143.013752	MAC NE Vault	(111,904)
	E141.015202	500 and 600 4th St S Extension to Wells Fargo	(282,093)
Non-Investment			
	E114.010645	Clearing WO for CRS credits	270,630
	NA	Misc Non-Investment	48,244
	E143.001170	Electric New Construction Contributions in Aid	(76,588)
	E154.001279	Electric New Construction Contributions in Aid	(131,627)
	E151.001245	Electric New Construction Contributions in Aid	(188,939)
	E144.001183	Electric New Construction Contributions in Aid	(233,800)
	E142.001155	Electric New Construction Contributions in Aid	(246,271)
	E156.001291	Electric New Construction Contributions in Aid	(352,141)
	E147.001216	Electric New Construction Contributions in Aid	(367,591)
	E150.001230	Electric New Construction Contributions in Aid	(480,775)
	E141.001140	Electric New Construction Contributions in Aid	(1,486,094)
Other			
	E103.001041	MN-New Bus Transformer	20,505,396
	NA	Fleet Purchases	4,285,240
	E103.010660	VAR System Project	773,836
	E103.011405	Install feeder load monitoring at selected subs	472,543
	E103.001738	MN Subs tools & equip	398,535
	E103.002265	Capitalized Locating Costs-Elec UG MN	337,870
	E103.010365	NSPM General Equipment - Communications	299,216
	E141.001133	Mpls-Electric Tools & Equip	159,388
	E114.006438	Intelliteam SG Rollout	146,712
	E103.002100	2002 Spec Cnstr - Sm Tool/Equipment Blanket for NSPM	135,640
	E103.013581	Remote Fault Indication and Load Monitors	119,417
	C103.002113	Tools & Equipment-Transportation Blanket	117,139
	E103.001739	MN Subs Constr tools	115,260
	E154.001273	Northwest-Elec Tools/Equip	84,198
	NA	Misc Tools and Equipment	79,274
	C103.013336	Tools and Equipment - Locating	70,795
	E144.001190	Southeast-Elec Tools & Equip	66,505
	C115.006786	Logistics-NSPM Tools Blanket	65,633
	E151.001252	St Paul-Elec Tools & Equip	63,878
	E153.001257	SD-Tools & Equip	53,803
	E147.001210	Maple Grv-Electric Tools & Equip	49,405
	E103.002099	NSPM Metering Sys-Tools & Equipment Blanket	34,898
	E145.001206	ND-Electric Tools & Equip	34,209
	E141.003695	Univ of MN Lease for Ductline/Reimbursement	28,848
	E143.001164	Edina-Elect Tool/Equip	26,222
	E150.001223	Newport-Elec Tool/Equip	25,418

IDP Category	Mitigation Number	Mitigation Name	2014 Expenditures
	E156.001297	White Bear-Electric Tools & Eq	25,203
	E103.013567	Install feeder load monitoring at selected subs	18,442
	E103.011254	Substation Asset Sales for NSM	18,000
	E103.001040	MN-Electric Meter Blanket	13,697
	E103.013585	Substation new RTU and FLM	12,237
	E103.012825	Electric Franchise Renewal	12,211
	E142.001149	Mntka-Elec Tools/Equip	9,297
	NA	Misc Non-Investment	7,076
	E103.012099	Capitalized-MN-Sales Tax Rfd - Elec	(3,390,290)
System Expansion or Upgrades for Reliability and Power Quality			
	E103.003453	Tap Cable Replacement 2nd Tier Minnesota	11,644,908
	E103.003452	Mainline Cable Replacement - Reactive - NSPM	1,406,697
	E114.007693	Reliability Monitoring System (REMS): MN	514,700
	E114.013511	Install Automated Switches to Improve Performance - MN	400,239
	E103.001044	NSPM-Poor Performing Fdr Blanket	236,476
	E103.009970	Mainline Cable Replacement - Proactive 2nd Tier - NSPM	106,728
	E142.012191	Reliability Upgrades (REMS) to BLC063 feeder	95,176
Grand Total			**155,747,681**

IDP Category	Mitigation Number	Mitigation Name	2015 Expenditures
Age-Related Replacements and Asset Renewal			
	E114.006616	MN Replace/Reinforce Non-Compliant Poles	8,301,322
	E114.005559	MN Major Storm Recovery BlanketMN	6,572,816
	E103.004666	Hollydale - Replace Failed 69kV/13.	3,072,366
	E147.004711	Funding for CO109 Gravel Pit phase	2,470,468
	E103.014456	Replace 5 distribution breakers at Merriam Park	2,227,623
	E141.013910	St. Anthony Falls Hydro 15kV Cable Replacement	1,984,266
	E154.011354	Install Cottonwood stepdowns to enable retirement of sub	1,493,469
	E141.001141	Mpls-OH Rebuilds	1,474,723
	E151.012282	Reconductor RAM73 Mainline	1,449,388
	E103.013576	reserve 70 MVA 115/13.8 kV transformer	1,320,329
	E103.012612	ELR MN Sub TRs	1,104,591
	E153.012431	Convert SOS 4kV to 13.8kV	1,091,565
	E103.014355	Rewind failed 115KV - 13.8KV 70MVA transformer	1,054,910
	E142.009661	OH Rebuild Mtka increase	980,025
	E151.013631	Replace Network Protectors - STP	867,073
	E143.014668	WIL086 OH to UG Conversion	826,619
	E103.011423	RCSII Replacement Project - NSPM	820,598
	E151.013595	SSI: Convert St Clair 4kV to 13.8kV	739,079
	E147.001209	Maple Grv-OH Rebuilds	703,410
	E154.012309	Remove Eden Valley to Watkins line	701,990
	E151.016150	Hamline Station	694,531
	E103.009150	SPCC NSPM Oil Spill Prevention	687,821
	E150.003703	Woodbury Lakes OH to UG conversion	657,074
	E103.015161	Purchase 50 MVA reserve transformer	649,558
	E156.001292	White Bear-OH Rebuilds	576,102
	E154.015412	Franklin TR4 Replacement	563,179
	E143.013748	SAV River Crossing	541,815
	E144.013060	M&R Dairy Rebuild	534,740
	E103.012603	ELR MN Sub Regulators	489,492
	E150.013542	Woodbury Drive Road Move 3000ft Feeder at Bailey	472,377
	E154.013608	SSI: Convert Spicer area from 12.5kV to 34.5kV	427,741
	E141.015959	Apache TR 1 Emergency Replacement	364,389
	E103.015305	7 MVA Spare	312,197
	E142.004727	Co Rd 109, Phase 2-UG Conv	278,938
	E141.001664	ELR MPLS Vault Tops	225,286
	E147.002745	RM: Relocate OH mainline for Hwy 241 from Co Rd 19 to McIver Ave NE: St Michael MN: LAP311	222,067
	E103.013521	ELR MN Sub RTUs	216,983
	E103.011891	ELR MN Sub Switches	215,798
	E144.015240	Replace Jordan Sub's Aging Equipment	182,303
	E103.013804	Upgrade fence at Buffalo Lake	178,524
	E151.013639	ELR STP Vault Tops	137,659
	E141.015353	Replace Failed WRR TR3	135,415
	E141.010286	Replace Dustproof protectors	121,122
	E156.008247	WBL Tap Cables	108,843
	E151.016446	Jackson St Rebuild	65,459
	E145.019635	ND Substation Fence Improvement	62,129
	E103.013059	Purchase 50 MVA reserve transformer	56,742
	E147.015160	Replace failed PKL TR3	25,440
	E143.014769	Savage, Replace failed TR2	24,607
	E141.012673	Replace Fifth Street FST Switchgear	21,174
	E103.016067	New 70 MVA reserve TR 115/13.8 kV	2,854
	E103.007227	NSPM Dist Line Parent for CRFS Tracker Work Orders	74
	E150.014414	Replace Koch TR16 with reserve	63
	E103.012839	Tap Cable Injection	(347)
	E151.012985	SSI: Conv 4kV btwn Holly and Ashland	(415)
	NA	Re route main St Ductline to v	(1,901)
	E154.014732	Sauk Rapids overhead to underground	(40,973)
	E154.016227	Freeport to Black Oak Rebuild	(339,524)
System Expansion or Upgrades for Capacity			
	E154.006387	New First Lake substation in Monticello, MN	6,469,203
	E154.002521	Install second bank at Fiesta City	1,866,061
	E156.010172	Install new feeder at RAM	1,865,055
	E144.013445	Add 50MVA Eastwood TR3 and feeders	1,708,296
	E153.012465	Install tie for SOS062	967,668
	E141.002682	Replace Failed Network Protectors on FST Network	739,305
	E142.013447	Install TR at new Hazeltine sub	674,232
	E141.016066	Minnehaha Ductline Extension	669,824

IDP Category	Mitigation Number	Mitigation Name	2015 Expenditures
	E151.012407	Transfer Load from DBL067	637,184
	E144.013438	Reinforce Sibley Park Feeder Exits	480,251
	E141.011698	Indiana-IDA064 new reinforce	402,799
	E141.013905	Construct ductline along Portland from MDT Sub to 27th	395,967
	E147.002788	Install Basset Creek BCRTR2 50MVA	393,782
	E151.011161	New Ductline on 5th btwn Broadway & Robert	306,817
	E141.014517	New ELP feeder	303,967
	E147.013543	Install BCR new feeder at Basset Creek	303,492
	E141.007874	Inst 13.8kV Hiawatha #1 50MVA	294,764
	E154.014561	Remove and Retire Empire Park substation	263,581
	E150.008740	Reconductor & Reinsulated CGR71 to AFT322	240,698
	E141.017361	JAPS-OLSON 7500 Excelsior Blvd	231,506
	E151.011613	Rebuild Public Health Vault	229,562
	E154.015394	Install new feeder MNI073	229,085
	E141.014950	4 Marquette Ave - New Vault	222,041
	E150.010906	Vermillion River 63	203,379
	E141.014961	401 Nicollet - New Vault	202,145
	E150.010916	Convert Chemolite to 13.8kV	193,467
	E151.002440	Extend MPK66 to US Bank east, ATO	190,062
	E156.008860	Install switches on OAD075 and transfer load to relieve NOL	189,108
	E103.008083	Environmental Work NSPM-EL	158,782
	E151.001248	St Paul-OH Reinforcements	124,843
	E154.012597	Upgrade Freeport substation to 12.5kV	119,453
	E103.014467	Sub Fiber Communication Cutover	111,858
	E142.014709	T: High side rebuild at BLC due to SWTC	104,672
	E150.012453	Replace RRK TR1 with 50MVA and add one feeder	95,568
	E154.007052	Extend 3 phase to new development in Sartell - 50th st	82,910
	E144.012835	Reconductor 2 mi SCH211 feeder.	77,533
	E144.001187	Southeast-UG Reinforcements	68,480
	E156.012599	Install new fder tie for KOL64	67,104
	E142.009045	Install Bluff Creek 115/13.8kV 50MVA TR#3-CANCELLED	47,939
	E150.012312	Replace PMC on CGR64 with PMH-9	33,485
	E143.001172	Edina-OH Reinforcements	33,229
	E143.010967	Viking new sub 4 fdrs	30,995
	E141.015808	Cascade load relief to MDT	24,483
	E141.016015	Add LTC Control at 5th St. Sub	22,921
	E147.012675	HOL061 3 Phase Upgrade	22,601
	E141.014356	Hampton Inn Ductline	21,481
	E142.004532	Chaska Sub FDR61 - Reinforcement Pr	19,018
	E147.011058	Plymouth-Area Power Grid Upgrades	12,614
	E143.013101	United Health Shady Oak Road Project	12,115
	E147.001219	Maple Grv-UG Reinforcements	10,936
	E154.001282	Northwest-UG Reinforcement	10,562
	E144.012984	SSI: Convert Waldorf Distribution	10,452
	E143.013500	Extend WSG062 to relieve WSG072	5,733
	E141.016335	Block 69 Residential Vault Ryan Co	5,249
	E141.014357	Hampton Inn Vault	3,467
	E151.010808	Install DBL082 feeder	2,973
	E144.012111	Upgrade Buffalo Lake sub from 4kV to 15kV	2,956
	E156.002804	Add 2nd bank at Baytown to eliminate N-1 risk	1,852
	E154.008992	SSI: Osakis Conversion from 4kV to 12.5kV	1,492
	E154.012593	Reinforce SDX TR1	1,491
	E147.010067	Install Elm Creek TR#3 (115/13.8kV)	676
	E144.010890	Reinforce Lake Emily TR1 to 14MVA	451
	E144.013934	Reinforce 3.5 miles of LAE061	387
	E142.011357	Convert Orono to 115 kV	82
	E103.013568	Rewind 69/12.5 kV 28 MVA	(7)
	E151.011622	Rebuild Shaft Hole & Replace Cables	(19)
	NA	Substation Land - ND	(626)
	E144.012973	Install Cap Bank at Crystal Foods	(1,831)
	E141.014051	Velo Residental Building - Vault	(5,772)
	E144.013502	Reinforce 3 miles of SMT082	(13,845)
	E141.013735	Nicollet Residence	(16,363)
	E144.013448	SSI: Add 2nd 23.9kV Transformer and feeder at Waterville	(26,356)
	E141.014694	U of M CHP Express Feeders	(28,570)
	E150.010914	Install Stockyards STY TR3 & Feeders	(39,373)
	E141.010254	Marshall-RIV062 Convert4kV	(48,671)
	E144.013396	Add 28MVA WASTR3 and 1 fdr	(75,171)
	E141.007514	Oakland Install 13.8kV #1#2 50MVA 8 fdrs	(239,806)

IDP Category	Mitigation Number	Mitigation Name	2015 Expenditures
	E103.012099	Capitalized-MN-Sales Tax Rfd - Elec	(438,115)
Projects related to Local (or other) Government-Requirements			
	E142.013864	T: Rebuild head end of WSG362 due to SWTC T-line project	1,341,157
	E142.014709	T: High side rebuild at BLC due to SWTC	1,078,380
	E156.014239	RAM071 - Cty Rd B Road Work Maplewood	1,019,907
	E142.014722	County Road 101 OH-UG	1,001,648
	E144.012864	County Road 20 Road Move	812,776
	E141.015303	SLP Reroute	805,775
	E141.013426	LaSalle Paving Project	789,928
	E147.014690	Hwy 610 Extension	740,829
	E144.014340	Morton County Road 2 Relocation	602,720
	E143.005672	EDP/ANDERSON LAKES & HWY 169/RELOCA	569,787
	E150.009111	Relc TLK77 OH on Century for Cty Rd Widening	562,063
	E147.015783	Vicksburg OH-UG	546,743
	E141.015300	4th St S Ductline Relocation	530,874
	E150.015957	Robert Street Relocation W St Paul	521,201
	E154.007065	Hwy 101 and County Rd 36 Overhead Relocation	507,148
	E141.016028	5601 Lake St PMH Relocation	507,021
	E144.014112	Madison Ave Manholes Mankato	495,114
	E141.015206	St. Anthony Bridge Relocation	476,712
	E151.015043	Snelling Bridge Relocation	410,900
	E151.001251	St Paul-UG Relocations	404,483
	E142.008544	County Rd 17, Delano, Road Move	403,461
	E142.015919	OH-UG Minnetonka Hwy 101 and Excelsior	382,116
	E144.015769	Winona Hwy 43 Bridge Ductline Re-route	370,457
	E143.014095	Shady Oak OH to UG Conversion	366,347
	E143.015886	City of Richfield OH-UG	306,658
	E103.011368	NSPM facility transfers from 3rd Party Owned Poles	304,266
	E156.014240	OAD075 OH-UG 10th St. 694 to Hadley. City of Oakdale	290,310
	E141.014169	OH-UG Cnty 9 - France to Hwy 81	275,099
	E156.015411	HUG311/312 Centerville Road Centerville	270,022
	E144.015314	CAPX 2020 OH-UG in Zumbrota	268,186
	E141.002215	Mpls-UG Service Conv	257,366
	E143.000159	Road Widening Minnetonka CR5 and CR73	253,482
	E142.001160	Mntka-UG Relocations	248,486
	E144.015253	Mankato Downtown Civic Center Project	241,831
	E151.014770	Lillydale UG Conversion	238,297
	E141.015301	Douglas Dr OH-UG Conversion	233,192
	E147.004557	Medina-Hwy 101 Overhead Fdr-RM	188,973
	E151.002224	St Paul-UG Service Conv	183,965
	E144.013680	Dresbach I-90 Re-Route 3 Mi OH	166,550
	E143.002217	Edina-UG Service Conv	156,670
	E142.002216	Mntka-UG Service Conv	147,399
	E141.013428	Relocate Ductline for New Viking Stadium	122,382
	E150.011418	Hastings Bridge Re-route ductbank for pier #5 Hwy 61	115,939
	E154.013988	T: Annandale Town Rebuild	113,577
	E156.015407	OAD071 Frost Ave Maplewood	103,575
	E156.002218	White Bear-UG Service Conv	97,069
	E144.001189	Southeast-UG Relocations	95,094
	E154.001284	Northwest-UG Relocations	63,825
	E144.002223	Southeast-UG Service Conv	58,992
	E147.002219	Maple Grv-UG Service Conv	51,277
	E154.002220	Northwest-UG Service Conv	33,727
	E150.002222	Newport-UG Service Conv	27,200
	E147.001221	Maple Grv-UG Relocations	25,550
	E156.001296	White Bear-UG Relocations	25,080
	E143.014406	Shady Oak Conversion 212 Crossing	10,030
	E141.015088	Chicago Ave and 4th St Conversion	7,727
	E156.013070	St Croix River Bridge	4,120
	E141.016274	Nicollet Mall Street Scape	2,376
	E151.014237	Saints Ballpark OH-UG DBL063	560
	E156.014013	Arsenal removal and relocation of facilities. AHI024	537
	E150.014165	Hwy 149 & 55 Road Move Eagan Relocate 6 feeders	444
	E154.014754	County Rd 3 Sauk Rapids	3
	E150.013029	Cedar Grove PKWY Relocate 5000ft of 750AL	0
	E141.013815	Centerpoint 2nd St N Relocation	(40,513)
	E141.014168	OH to UG County Rd 9 - Xerxes to France	(134,544)
	E151.012334	35E Relocation	(245,531)
	E151.016971	White Bear Ave Relocation	(260,654)

IDP Category	Mitigation Number	Mitigation Name	2015 Expenditures
Metering			
	E103.001040	MN-Electric Meter Blanket	5,162,884
New Customer Projects and New Revenue			
	E141.015298	900 5th St S FST087 - FST077 Extension	2,337,740
	E156.001299	White Bear-UG Extensions	2,292,064
	E150.005996	Newport-UG Extensions	2,002,824
	E141.017362	365 Nicollet Construction Power	1,913,269
	E147.014741	Olympus Technologies Service	1,793,734
	E141.015202	500 and 600 4th St S Extension to Wells Fargo	1,637,408
	E156.001288	White Bear-UG Services	1,370,480
	E144.003805	Wanamingo - Pine Ridge development 82 units	1,283,957
	E143.002572	Install Feeder tie to eliminate N-1 on WIL86 4.9 MVA	1,168,601
	E142.010321	New Germany Trophy Lake 45 lot URD	1,015,284
	E141.015296	700 4th St S Extension MSFA	849,592
	E141.016332	Block 75 Residential Vault Project	825,259
	E150.001226	Newport-UG Services	805,380
	E144.002761	Switch load to new Summit Ave Bank #2 Feeder	755,589
	E154.001271	Northwest-UG Extensions	730,846
	E142.001152	Mntka-New UG Services	702,096
	E144.001179	Southeast-UG Services	670,001
	E143.001169	Edina-New UG Street Lights	610,582
	E154.001277	Northwest-New UG Services	574,040
	E147.001214	Maple Grv-New Elec UG Services	548,460
	E141.001135	Mpls-OH Services	449,571
	E141.010560	Serve Children's Hosiptal Addition (ATO and Pri Svc)	381,557
	E151.015041	Port Authority Barge Road	336,350
	E151.001240	St Paul-OH Services	323,994
	E154.011195	Paynesville Mastermark Plastic NB Convert to 35kV	311,124
	E142.014720	Wayzata Bay Development	305,977
	E156.001286	White Bear-OH Extension	288,901
	E141.017364	1910 Queen Ave N Extension	287,906
	E143.001167	Edina-UG Services	287,302
	E144.001181	Southeast-OH Streetlights	276,113
	E141.001138	Mpls-New OH Street Lights	250,431
	E141.015299	900 5th St S ELP064 - ELP071 Extension	246,941
	E142.014619	Woodland Cove JT Devlopment, Minnetrista, MN	236,946
	E144.001178	Southeast-OH Services	205,945
	E151.015233	The Vintage	167,156
	E150.014745	Dakota Aggregate-RMT312 Extend OH 5500ft	166,097
	E154.001278	Northwest-New UG Street Lights	160,733
	E142.001150	Mntka-OH Extension	156,443
	E156.001555	Upgrade feeder exit with 1000 Al and reactor	149,675
	E154.001276	Northwest-New OH Services	127,673
	E154.001274	Northwest-New OH Street Lights	123,664
	E156.001287	White Bear-OH Services	120,186
	E151.001243	St Paul-OH Streetlights	107,088
	E141.001139	Mpls-New UG Street Lights	95,914
	E147.001215	Maple Grv-New UG Street Lights	95,840
	E143.001166	Edina-New OH Services	94,364
	E143.001168	Edina-New OH Street Lights	81,097
	E142.001154	Mntka-New UG Street Lights	67,734
	E144.001182	Southeast-UG Streetlights	64,790
	E151.001241	St Paul-UG Services	62,778
	E156.001289	White Bear-OH Street Lights	50,633
	E142.001151	Mntka-OH Services	48,480
	E143.002573	Install switches to eliminate N-1 on WIL77 4 MVA	47,582
	E147.001211	Maple Grv-New OH Street Lights	44,652
	E150.001228	Newport-OH Streetlights	43,785
	E156.001290	White Bear-UG Street Lts	30,519
	E147.001213	Maple Grv-OH Services	29,723
	E150.001225	Newport-OH Services	28,646
	E142.001153	Mntka-New OH Street Lights	24,841
	E141.000640	Install a new tie to PKL85 to eliminate N-1 on MEL65	12,166
	E143.013752	MAC NE Vault	6,502
	E151.001244	St Paul-UG Street Lights	7
	NA	Misc UG Extension	(13)
	E150.001229	Newport-UG Streetlights	(51,339)
Non-Investment			
	E150.016123	Aurora Solar Project NPT	104,111

IDP Category	Mitigation Number	Mitigation Name	2015 Expenditures
	E103.016168	Aurora Solar Sub Comm	5,535
	E154.016124	Aurora Solar Project NW	4,943
	E144.016140	Aurora Solar Project SE	295
	E156.016141	Aurora Solar Project WBL	245
	E144.015449	Southeast Solar Garden Extensions	(2,675)
	NA	Misc Non-Investment	(182,077)
	E151.001245	Electric New Construction Contributions in Aid	(184,861)
	E154.001279	Electric New Construction Contributions in Aid	(215,120)
	E144.001183	Electric New Construction Contributions in Aid	(222,435)
	E142.001155	Electric New Construction Contributions in Aid	(232,004)
	E147.001216	Electric New Construction Contributions in Aid	(342,609)
	E156.001291	Electric New Construction Contributions in Aid	(386,011)
	E143.001170	Electric New Construction Contributions in Aid	(523,179)
	E150.001230	Electric New Construction Contributions in Aid	(590,303)
	E114.010645	Clearing WO for CRS credits	(754,145)
	E141.001140	Electric New Construction Contributions in Aid	(2,062,292)
Other			
	E103.001041	MN-New Bus Transformer	19,064,093
	NA	Fleet Purchases	8,610,813
	E103.010365	NSPM General Equipment - Communications	1,852,210
	E103.010660	VAR System Project	848,596
	E141.001133	Mpls-Electric Tools & Equip	667,744
	E103.014464	Replace Frame Relays in NSPM	462,460
	E103.001738	MN Subs tools & equip	343,553
	E103.002099	NSPM Metering Sys-Tools & Equipment Blanket	322,057
	E103.002265	Capitalized Locating Costs-Elec UG MN	320,145
	E103.014467	Sub Fiber Communication Cutover	286,564
	C103.002113	Tools & Equipment-Transportation Blanket	280,087
	E103.011405	Install feeder load monitoring at selected subs	250,892
	NA	Misc Tools and Equipment	209,449
	E103.002100	2002 Spec Cnstr - Sm Tool/Equipment Blanket for NSPM	141,428
	NA	NSM Vegetation Mgmt MDT	132,993
	E154.001273	Northwest-Elec Tools/Equip	122,159
	E103.001739	MN Subs Constr tools	111,531
	E151.001252	St Paul-Elec Tools & Equip	106,624
	E144.001190	Southeast-Elec Tools & Equip	82,737
	E141.003695	Univ of MN Lease for Ductline/Reimbursement	79,089
	C115.006786	Logistics-NSPM Tools Blanket	78,840
	E114.006438	Intelliteam SG Rollout	72,562
	E142.001149	Mntka-Elec Tools/Equip	53,935
	C103.013336	Tools and Equipment - Locating	53,130
	E147.001210	Maple Grv-Electric Tools & Equip	51,540
	E156.001297	White Bear-Electric Tools & Eq	51,253
	E103.013567	Install feeder load monitoring at selected subs	47,766
	E143.001164	Edina-Elect Tool/Equip	45,950
	E145.001206	ND-Electric Tools & Equip	45,521
	E153.011934	Logistics-NSPM Tools Blanket - SD	39,513
	E145.013434	ND-Dist Sub Communication Equipment	39,329
	E103.013585	Substation new RTU and FLM	36,057
	E153.001257	SD-Tools & Equip	35,415
	E103.013581	Remote Fault Indication and Load Monitors	29,419
	E150.001223	Newport-Elec Tool/Equip	24,011
	NA	Misc Non-Investment	(5,871)
	E103.012099	Capitalized-MN-Sales Tax Rfd - Elec	(2,638,022)
System Expansion or Upgrades for Reliability and Power Quality			
	E103.003453	Tap Cable Replacement 2nd Tier Minnesota	10,956,911
	E103.003452	Mainline Cable Replacement - Reactive - NSPM	2,204,089
	E103.001044	NSPM-Poor Performing Fdr Blanket	1,539,791
	E103.009970	Mainline Cable Replacement - Proactive 2nd Tier - NSPM	463,177
	E114.007693	Reliability Monitoring System (REMS): MN	389,797
	E142.012191	Reliability Upgrades (REMS) to BLC063 feeder	30,692
	E114.013511	Install Automated Switches to Improve Performance - MN	22,722
Grand Total			**166,748,452**

IDP Category	Mitigation Number	Mitigation Name	2016 Expenditures
Age-Related Replacements and Asset Renewal			
	E114.005559	MN Major Storm Recovery BlanketMN	19,643,365
	E114.006616	MN Replace/Reinforce Non-Compliant Poles	6,554,500
	E151.016446	Jackson St Rebuild	6,407,862
	E103.004666	Hollydale - Replace Failed 69kV/13.	2,267,382
	E103.014456	Replace 5 distribution breakers at Merriam Park	1,897,840
	E154.011354	Install Cottonwood stepdowns to enable retirement of sub	1,613,100
	E143.014668	WIL086 OH to UG Conversion	1,450,890
	E103.016067	New 70 MVA reserve TR 115/13.8 kV	1,307,595
	E141.013910	St. Anthony Falls Hydro 15kV Cable Replacement	1,260,398
	E103.009150	SPCC NSPM Oil Spill Prevention	1,150,833
	E141.001141	Mpls-OH Rebuilds	1,149,938
	E147.004711	Funding for CO109 Gravel Pit phase	1,135,644
	E150.013542	Woodbury Drive Road Move 3000ft Feeder at Bailey	891,443
	E151.012282	Reconductor RAM73 Mainline	849,204
	E151.013595	SSI: Convert St Clair 4kV to 13.8kV	840,680
	E143.013748	SAV River Crossing	832,481
	E103.015161	Purchase 50 MVA reserve transformer	788,077
	E141.010286	Replace Dustproof protectors	667,093
	E156.001292	White Bear-OH Rebuilds	637,910
	E142.009661	OH Rebuild Mtka increase	634,621
	E151.016150	Hamline Station	616,406
	E150.003703	Woodbury Lakes OH to UG conversion	567,705
	E103.011423	RCSII Replacement Project - NSPM	537,487
	E141.017360	Chicago - Washington Relocation	523,522
	E103.012612	ELR MN Sub TRs	509,618
	E147.001209	Maple Grv-OH Rebuilds	507,272
	E144.013060	M&R Dairy Rebuild	452,867
	E141.017359	MPLS UG Network Vault Blanket	448,746
	E156.008247	WBL Tap Cables	424,931
	E142.004727	Co Rd 109, Phase 2-UG Conv	382,196
	E154.012309	Remove Eden Valley to Watkins line	337,041
	E153.012431	Convert SOS 4kV to 13.8kV	302,874
	E154.016227	Freeport to Black Oak Rebuild	257,960
	E151.016970	MLS stadium OH/UG Relocation	245,358
	E151.016697	STP UG Network Vault Blanket	220,646
	E103.011891	ELR MN Sub Switches	211,833
	E141.001664	ELR MPLS Vault Tops	165,192
	E147.002745	RM: Relocate OH mainline for Hwy 241 from Co Rd 19 to McIver Ave NE: St Michael MN: LAP311	157,545
	E103.014355	Rewind failed 115KV - 13.8KV 70MVA transformer	104,731
	E141.012673	Replace Fifth Street FST Switchgear	96,389
	E114.017864	MN/Capital Pole Inspections	95,654
	E145.019635	ND Substation Fence Improvement	68,286
	E103.013804	Upgrade fence at Buffalo Lake	60,716
	E151.013631	Replace Network Protectors - STP	57,148
	E144.015240	Replace Jordan Sub's Aging Equipment	54,149
	E141.015959	Apache TR 1 Emergency Replacement	42,451
	E103.013521	ELR MN Sub RTUs	32,573
	E103.013576	reserve 70 MVA 115/13.8 kV transformer	1,916
	E103.012603	ELR MN Sub Regulators	1,614
	E103.015305	7 MVA Spare	1,335
	E103.016670	Purchase reserve transformer 14 MVA 69- 13.8 KV	635
	E151.013639	ELR STP Vault Tops	86
	E147.015160	Replace failed PKL TR3	4
	E154.015412	Franklin TR4 Replacement	2
	E154.014732	Sauk Rapids overhead to underground	(22,329)
System Expansion or Upgrades for Capacity			
	E142.013447	Install TR at new Hazeltine sub	7,535,079
	E144.013445	Add 50MVA Eastwood TR3 and feeders	2,708,703
	E153.012465	Install tie for SOS062	2,323,379
	E154.002521	Install second bank at Fiesta City	2,004,092
	E156.002804	Add 2nd bank at Baytown to eliminate N-1 risk	1,914,037
	E141.016992	CABLE DUCT Millwright Bldg 321 5th Av	947,218
	E141.002682	Replace Failed Network Protectors on FST Network	944,666
	E147.014686	Reconfigure ties on TWL feeders	475,018
	E141.016015	Add LTC Control at 5th St. Sub	466,330
	E141.014517	New ELP feeder	437,836
	E147.016782	Extend IDA064 to relieve TWL064	391,292

IDP Category	Mitigation Number	Mitigation Name	2016 Expenditures
	E154.006387	New First Lake substation in Monticello, MN	370,057
	E144.012835	Reconductor 2 mi SCH211 feeder.	356,724
	E141.016335	Block 69 Residential Vault Ryan Co	326,510
	E142.014709	T: High side rebuild at BLC due to SWTC	321,076
	E147.014478	Reconfigure ties for TWL079	301,034
	E141.016991	NTWK TRs Millwright Bldg 321 5th Ave S	227,917
	E151.011613	Rebuild Public Health Vault	220,886
	E141.016333	Block 75 Residential Vault Project	199,998
	E154.007052	Extend 3 phase to new development in Sartell - 50th st	185,066
	E141.015808	Cascade load relief to MDT	166,054
	E103.014467	Sub Fiber Communication Cutover	140,079
	E103.008083	Environmental Work NSPM-EL	134,063
	E151.001248	St Paul-OH Reinforcements	133,632
	E156.008860	Install switches on OAD075 and transfer load to relieve NOL	122,378
	E147.014468	Install tie for BRP063	114,780
	E147.001219	Maple Grv-UG Reinforcements	114,140
	E150.008740	Reconductor & Reinsulated CGR71 to AFT322	91,016
	E151.002440	Extend MPK66 to US Bank east, ATO	90,488
	E150.012453	Replace RRK TR1 with 50MVA and add one feeder	72,566
	E142.014829	Install 2nd feeder at Plato	63,072
	E142.004532	Chaska Sub FDR61 - Reinforcement Pr	60,729
	E141.014694	U of M CHP Express Feeders	54,827
	E142.009045	Install Bluff Creek 115/13.8kV 50MVA TR#3-CANCELLED	52,419
	E144.001187	Southeast-UG Reinforcements	44,330
	E156.012599	Install new fder tie for KOL64	35,870
	E147.012675	HOL061 3 Phase Upgrade	22,252
	E143.013500	Extend WSG062 to relieve WSG072	22,069
	E142.011006	SSI: Install Waconia TR2	15,760
	E154.014561	Remove and Retire Empire Park substation	13,464
	E141.014961	401 Nicollet - New Vault	13,382
	E141.011698	Indiana-IDA064 new reinforce	11,957
	E151.010808	Install DBL082 feeder	7,545
	E143.001172	Edina-OH Reinforcements	6,813
	E147.002788	Install Basset Creek BCRTR2 50MVA	5,095
	E156.010172	Install new feeder at RAM	4,020
	E147.011058	Plymouth-Area Power Grid Upgrades	4,014
	E141.007514	Oakland Install 13.8kV #1#2 50MVA 8 fdrs	3,847
	E141.014950	4 Marquette Ave - New Vault	2,013
	E154.001282	Northwest-UG Reinforcement	1,066
	E144.013396	Add 28MVA WASTR3 and 1 fdr	1,033
	E151.012407	Transfer Load from DBL067	377
	E141.007874	Inst 13.8kV Hiawatha #1 50MVA	348
	E144.012973	Install Cap Bank at Crystal Foods	239
	E154.015394	Install new feeder MNI073	65
	E144.010890	Reinforce Lake Emily TR1 to 14MVA	11
	E144.013438	Reinforce Sibley Park Feeder Exits	4
	E153.007944	Install 14 MVA Pipestone sub, convert from 4 kV	(72)
	E150.010906	Vermillion River 63	(512)
	E150.012312	Replace PMC on CGR64 with PMH-9	(21,216)
	E141.017361	JAPS-OLSON 7500 Excelsior Blvd	(25,018)
	E154.012597	Upgrade Freeport substation to 12.5kV	(54,572)
	E103.012099	Capitalized-MN-Sales Tax Rfd - Elec	(861,748)
Projects related to Local (or other) Government-Requirements			
	E141.016274	Nicollet Mall Street Scape	14,682,021
	E141.014116	Washington Ave Relocation - Hennipin to 5th Ave	3,103,615
	E156.014239	RAM071 - Cty Rd B Road Work Maplewood	1,721,310
	E141.015301	Douglas Dr OH-UG Conversion	1,218,429
	E151.016971	White Bear Ave Relocation	877,760
	E144.012864	County Road 20 Road Move	772,040
	E154.007065	Hwy 101 and County Rd 36 Overhead Relocation	700,449
	E141.015206	St. Anthony Bridge Relocation	572,890
	E143.000159	Road Widening Minnetonka CR5 and CR73	538,997
	E154.016854	2nd St N Relocation Project	519,297
	E156.015408	LEX61/71/73 Road Recon	465,240
	E103.011368	NSPM facility transfers from 3rd Party Owned Poles	459,576
	E150.009111	Relc TLK77 OH on Century for Cty Rd Widening	428,861
	E150.015957	Robert Street Relocation W St Paul	428,025
	E143.016745	Normandale Blvd - Relocate UG facilities for road widening	395,791
	E141.013426	LaSalle Paving Project	313,745

IDP Category	Mitigation Number	Mitigation Name	2016 Expenditures
	E141.016028	5601 Lake St PMH Relocation	290,991
	E151.001251	St Paul-UG Relocations	286,538
	E141.014169	OH-UG Cnty 9 - France to Hwy 81	242,478
	E141.002215	Mpls-UG Service Conv	216,723
	E143.005672	EDP/ANDERSON LAKES & HWY 169/RELOCA	213,783
	E144.001189	Southeast-UG Relocations	203,569
	E142.014722	County Road 101 OH-UG	189,823
	E142.008544	County Rd 17, Delano, Road Move	155,401
	E147.004557	Medina-Hwy 101 Overhead Fdr-RM	146,350
	E150.011418	Hastings Bridge Re-route ductbank for pier #5 Hwy 61	136,266
	E142.013864	T: Rebuild head end of WSG362 due to SWTC T-line project	120,718
	E154.001284	Northwest-UG Relocations	112,546
	E144.002223	Southeast-UG Service Conv	111,520
	E154.013988	T: Annandale Town Rebuild	111,012
	E144.014112	Madison Ave Manholes Mankato	93,661
	E151.002224	St Paul-UG Service Conv	90,813
	E156.002218	White Bear-UG Service Conv	84,144
	E144.013680	Dresbach I-90 Re-Route 3 Mi OH	77,549
	E142.002216	Mntka-UG Service Conv	72,598
	E156.001296	White Bear-UG Relocations	68,579
	E147.001221	Maple Grv-UG Relocations	65,690
	E142.001160	Mntka-UG Relocations	50,689
	E143.002217	Edina-UG Service Conv	44,463
	E154.002220	Northwest-UG Service Conv	35,265
	E150.002222	Newport-UG Service Conv	34,107
	E151.012334	35E Relocation	29,272
	E147.002219	Maple Grv-UG Service Conv	28,420
	E142.015919	OH-UG Minnetonka Hwy 101 and Excelsior	19,840
	E147.014690	Hwy 610 Extension	18,818
	E143.014095	Shady Oak OH to UG Conversion	9,043
	E144.015253	Mankato Downtown Civic Center Project	4,164
	E144.014340	Morton County Road 2 Relocation	2,597
	E142.014709	T: High side rebuild at BLC due to SWTC	1,144
	E143.015886	City of Richfield OH-UG	997
	E141.015303	SLP Reroute	372
	E144.015769	Winona Hwy 43 Bridge Ductline Re-route	28
	E156.015407	OAD071 Frost Ave Maplewood	(3)
	E144.015314	CAPX 2020 OH-UG in Zumbrota	(7)
	E156.013070	St Croix River Bridge	(3,813)
	E147.015783	Vicksburg OH-UG	(125,422)
	E156.014240	OAD075 OH-UG 10th St. 694 to Hadley. City of Oakdale	(273,345)
Metering			
	E103.001040	MN-Electric Meter Blanket	5,090,194
New Customer Projects and New Revenue			
	E114.015600	MN LED Streetlight Program	4,604,306
	E156.001299	White Bear-UG Extensions	2,541,607
	E150.005996	Newport-UG Extensions	1,937,722
	E141.017362	365 Nicollet Construction Power	1,927,601
	E141.016332	Block 75 Residential Vault Project	1,756,897
	E147.014741	Olympus Technologies Service	1,742,158
	E156.001288	White Bear-UG Services	1,637,500
	E154.001271	Northwest-UG Extensions	1,309,363
	E144.002761	Switch load to new Summit Ave Bank #2 Feeder	1,222,288
	E144.003805	Wanamingo - Pine Ridge development 82 units	947,585
	E150.001226	Newport-UG Services	947,317
	E142.010321	New Germany Trophy Lake 45 lot URD	840,766
	E141.010560	Serve Children's Hospital Addition (ATO and Pri Svc)	835,975
	E144.001179	Southeast-UG Services	835,680
	E142.001152	Mntka-New UG Services	808,069
	E154.001277	Northwest-New UG Services	763,292
	E143.002572	Install Feeder tie to eliminate N-1 on WIL86 4.9 MVA	751,791
	E147.001214	Maple Grv-New Elec UG Services	530,866
	E156.001290	White Bear-UG Street Lts	511,663
	E143.001169	Edina-New UG Street Lights	462,347
	E141.001135	Mpls-OH Services	461,619
	E141.001138	Mpls-New OH Street Lights	430,595
	E151.001240	St Paul-OH Services	400,159
	E154.011195	Paynesville Mastermark Plastic NB Convert to 35kV	369,478
	E151.015041	Port Authority Barge Road	358,220

IDP Category	Mitigation Number	Mitigation Name	2016 Expenditures
	E150.001229	Newport-UG Streetlights	337,921
	E147.001215	Maple Grv-New UG Street Lights	321,044
	E144.001181	Southeast-OH Streetlights	284,088
	E141.001139	Mpls-New UG Street Lights	252,842
	E144.001178	Southeast-OH Services	228,558
	E156.001555	Upgrade feeder exit with 1000 Al and reactor	211,029
	E143.001167	Edina-UG Services	209,625
	E144.001182	Southeast-UG Streetlights	178,433
	E156.001286	White Bear-OH Extension	174,847
	E141.015298	900 5th St S FST087 - FST077 Extension	151,552
	E142.001154	Mntka-New UG Street Lights	144,950
	E154.001274	Northwest-New OH Street Lights	120,247
	E142.001150	Mntka-OH Extension	117,017
	E151.001241	St Paul-UG Services	112,768
	E141.017364	1910 Queen Ave N Extension	105,559
	E156.001287	White Bear-OH Services	97,557
	E150.001228	Newport-OH Streetlights	88,045
	E151.001243	St Paul-OH Streetlights	80,947
	E154.001276	Northwest-New OH Services	70,135
	E143.001166	Edina-New OH Services	60,657
	E156.001289	White Bear-OH Street Lights	54,679
	E147.001211	Maple Grv-New OH Street Lights	52,730
	E143.001168	Edina-New OH Street Lights	52,172
	E142.014619	Woodland Cove JT Devlopment, Minnetrista, MN	50,883
	E150.001225	Newport-OH Services	48,145
	E142.001153	Mntka-New OH Street Lights	43,267
	E150.014745	Dakota Aggregate-RMT312 Extend OH 5500ft	40,301
	E143.002573	Install switches to eliminate N-1 on WIL77 4 MVA	39,719
	E147.001213	Maple Grv-OH Services	27,481
	E151.001244	St Paul-UG Street Lights	24,883
	E142.001151	Mntka-OH Services	23,970
	E141.000640	Install a new tie to PKL85 to eliminate N-1 on MEL65	13,096
	E141.015296	700 4th St S Extension MSFA	462
	NA	Misc UG Extension	(6,866)
	E153.001259	SD-UG Extension	(13,490)
	E154.001278	Northwest-New UG Street Lights	(20,980)
	E141.015202	500 and 600 4th St S Extension to Wells Fargo	(277,212)
Non-Investment			
	E103.016480	Solar Garden Sub Work	8,997,405
	E103.016168	Aurora Solar Sub Comm	3,010,991
	E154.015448	Northwest Solar Garden Extensions	2,825,738
	E150.015447	NSPM Solar Gargen Extensions	2,653,371
	E156.015451	NSPM Solar Garden Extensions	1,534,322
	E114.010645	Clearing WO for CRS credits	858,983
	E142.015450	NSPM Solar Garden Extensions	754,181
	E103.016887	Solar Garden Communication Line Equip	365,233
	E142.016122	Geronimo Aurora Solar Projects	357,719
	E103.016481	Solar Garden Sub COMM	308,963
	E154.016124	Aurora Solar Project NW	195,751
	E150.016123	Aurora Solar Project NPT	193,277
	E103.016885	Aurora Solar - Business Systems Comm Related	177,445
	E143.015445	NSPM Solar Garden Extensions	115,208
	E141.016062	Solar Garden Ext - Mpls	4,567
	E156.016141	Aurora Solar Project WBL	(34,982)
	E144.016140	Aurora Solar Project SE	(97,286)
	E144.001183	Electric New Construction Contributions in Aid	(106,705)
	E147.001216	Electric New Construction Contributions in Aid	(113,155)
	E142.001155	Electric New Construction Contributions in Aid	(151,050)
	E154.001279	Electric New Construction Contributions in Aid	(195,266)
	E150.001230	Electric New Construction Contributions in Aid	(285,960)
	E143.001170	Electric New Construction Contributions in Aid	(379,290)
	E151.001245	Electric New Construction Contributions in Aid	(593,834)
	E156.001291	Electric New Construction Contributions in Aid	(668,703)
	E141.001140	Electric New Construction Contributions in Aid	(2,629,488)
	E144.015449	Southeast Solar Garden Extensions	(12,402,871)
Other			
	E103.001041	MN-New Bus Transformer	19,956,260
	NA	Fleet Purchases	3,179,201
	E114.017857	MN Elec Mixed Work Adjustment	6,450,994

IDP Category	Mitigation Number	Mitigation Name	2016 Expenditures
	E103.014464	Replace Frame Relays in NSPM	2,632,923
	E103.002265	Capitalized Locating Costs-Elec UG MN	548,815
	E141.003695	Univ of MN Lease for Ductline/Reimbursement	525,786
	E103.001738	MN Subs tools & equip	448,968
	E103.011405	Install feeder load monitoring at selected subs	364,830
	E151.001252	St Paul-Elec Tools & Equip	315,196
	E103.014467	Sub Fiber Communication Cutover	174,083
	E103.013581	Remote Fault Indication and Load Monitors	159,194
	E103.002100	2002 Spec Cnstr - Sm Tool/Equipment Blanket for NSPM	152,215
	C115.006786	Logistics-NSPM Tools Blanket	125,423
	E103.013567	Install feeder load monitoring at selected subs	116,193
	E154.001273	Northwest-Elec Tools/Equip	103,396
	C103.013336	Tools and Equipment - Locating	96,322
	E103.013585	Substation new RTU and FLM	94,971
	E114.006438	Intelliteam SG Rollout	90,574
	C103.002113	Tools & Equipment-Transportation Blanket	64,844
	E147.001210	Maple Grv-Electric Tools & Equip	60,216
	E145.001206	ND-Electric Tools & Equip	57,928
	E153.001257	SD-Tools & Equip	57,747
	E103.010660	VAR System Project	57,176
	NA	Elec Dist Communications Softw	51,638
	NA	Misc Tools and Equipment	41,998
	E103.002099	NSPM Metering Sys-Tools & Equipment Blanket	40,243
	E144.001190	Southeast-Elec Tools & Equip	39,685
	E150.001223	Newport-Elec Tool/Equip	22,934
	E103.001739	MN Subs Constr tools	21,887
	E118.017461	Land for Turkey Ridge Radio Tower	19,572
	E156.001297	White Bear-Electric Tools & Eq	15,284
	E143.001164	Edina-Elect Tool/Equip	9,165
	E142.001149	Mntka-Elec Tools/Equip	5,939
	E145.013434	ND-Dist Sub Communication Equipment	608
	E141.001133	Mpls-Electric Tools & Equip	(22,171)
	E103.010365	NSPM General Equipment - Communications	(182,557)
	E103.012099	Capitalized-MN-Sales Tax Rfd - Elec	(5,017,837)
System Expansion or Upgrades for Reliability and Power Quality			
	E103.003453	Tap Cable Replacement 2nd Tier Minnesota	16,979,613
	E103.003452	Mainline Cable Replacement - Reactive - NSPM	2,008,082
	E114.007693	Reliability Monitoring System (REMS): MN	575,948
	E103.001044	NSPM-Poor Performing Fdr Blanket	381,334
	E103.009970	Mainline Cable Replacement - Proactive 2nd Tier - NSPM	175,816
	E142.012191	Reliability Upgrades (REMS) to BLC063 feeder	61,398
Grand Total			**206,212,951**

IDP Category	Mitigation Number	Mitigation Name	2017 Expenditures
Age-Related Replacements and Asset Renewal			
	E114.005559	MN Major Storm Recovery BlanketMN	15,096,531
	E114.006616	MN Replace/Reinforce Non-Compliant Poles	5,911,259
	E141.012673	Replace Fifth Street FST Switchgear	3,711,133
	E103.014456	Replace 5 distribution breakers at Merriam Park	3,563,505
	E154.011354	Install Cottonwood stepdowns to enable retirement of sub	2,118,614
	E103.004666	Hollydale - Replace Failed 69kV/13.	1,786,417
	E141.013910	St. Anthony Falls Hydro 15kV Cable Replacement	1,675,075
	E114.018129	MN - Pole Replacement Blanket	1,311,348
	E143.017843	CSAH 53 OH to UG	1,261,813
	E103.012612	ELR MN Sub TRs	1,238,820
	E147.004711	Funding for CO109 Gravel Pit phase	1,210,912
	E114.018176	MN - OH Rebuild Tap/Backbone/Sec Blkt	1,193,195
	E103.009150	SPCC NSPM Oil Spill Prevention	857,665
	E114.018274	MN - UG Conversion/Rebuild Blanket	851,719
	E150.013542	Woodbury Drive Road Move 3000ft Feeder at Bailey	823,257
	E151.016697	STP UG Network Vault Blanket	768,309
	E141.001141	Mpls-OH Rebuilds	756,579
	E151.012282	Reconductor RAM73 Mainline	728,210
	E151.016150	Hamline Station	723,329
	E147.001209	Maple Grv-OH Rebuilds	620,345
	E142.004727	Co Rd 109, Phase 2-UG Conv	599,485
	E143.014668	WIL086 OH to UG Conversion	592,893
	E151.013595	SSI: Convert St Clair 4kV to 13.8kV	542,181
	E144.013060	M&R Dairy Rebuild	536,346
	E141.017359	MPLS UG Network Vault Blanket	533,544
	E142.009661	OH Rebuild Mtka increase	531,154
	E114.018174	MN - OH Reloc All Other Type Blkt	513,757
	E103.011423	RCSII Replacement Project - NSPM	511,432
	E103.014355	Rewind failed 115KV - 13.8KV 70MVA transformer	491,427
	E154.012309	Remove Eden Valley to Watkins line	468,741
	E114.018275	MN - UG Services Renewal Blanket	461,337
	E150.003703	Woodbury Lakes OH to UG conversion	449,901
	E103.016670	Purchase reserve transformer 14 MVA 69- 13.8 KV	416,799
	E156.001292	White Bear-OH Rebuilds	412,511
	E143.013748	SAV River Crossing	358,918
	E103.013804	Upgrade fence at Buffalo Lake	357,058
	E103.013521	ELR MN Sub RTUs	354,839
	E147.017834	Bass Lake Road OH-UG	334,691
	E153.012431	Convert SOS 4kV to 13.8kV	324,254
	E147.002745	RM: Relocate OH mainline for Hwy 241 from Co Rd 19 to McIver Ave NE: St Michael MN: LAP311	313,506
	E151.013639	ELR STP Vault Tops	285,533
	E141.010286	Replace Dustproof protectors	278,260
	E103.011891	ELR MN Sub Switches	262,081
	E150.018675	Replace Afton TR2 with System Reserve	260,008
	E114.018177	MN - OH Rebuild All Other Type Blkt	245,981
	E141.017360	Chicago - Washington Relocation	217,408
	E141.001664	ELR MPLS Vault Tops	88,117
	E114.017864	MN/Capital Pole Inspections	61,669
	E151.016970	MLS stadium OH/UG Relocation	38,451
	E114.018178	MN - OH Services Renewal Blanket	35,021
	E156.008247	WBL Tap Cables	14,472
	E103.016931	Battery Upgrade for Frame Relay Replacements - NSPM	7,389
	E103.009312	SSI: MN Infrastructure Investment	1,518
	E103.017653	ELR MN Sub Batteries	104
	E103.013576	reserve 70 MVA 115/13.8 kV transformer	5
	E151.013631	Replace Network Protectors - STP	5
	E103.015161	Purchase 50 MVA reserve transformer	2
	E103.015305	7 MVA Spare	2
	E103.016067	New 70 MVA reserve TR 115/13.8 kV	2
	E154.016227	Freeport to Black Oak Rebuild	(7,839)
	E145.019635	ND Substation Fence Improvement	(12,842)
	E151.016446	Jackson St Rebuild	(413,423)
System Expansion or Upgrades for Capacity			
	E156.002804	Add 2nd bank at Baytown to eliminate N-1 risk	4,689,485
	E142.011006	SSI: Install Waconia TR2	2,762,123
	E153.012465	Install tie for SOS062	1,631,786
	E141.002682	Replace Failed Network Protectors on FST Network	1,127,290

IDP Category	Mitigation Number	Mitigation Name	2017 Expenditures
	E154.002523	Reinforce Lowry TR and replace regulators	1,071,323
	E144.016597	Add Crystal Foods 62 Feeder	952,225
	E147.011058	Plymouth-Area Power Grid Upgrades	501,197
	E142.014829	Install 2nd feeder at Plato	498,707
	E147.013375	Reconfigure feeder ties CNC073	411,159
	E141.016992	CABLE DUCT Millwright Bldg 321 5th Av	406,837
	E143.018586	Health Partners ATO 8170 33RD AVE S	385,774
	E141.017363	365 Nicollet Residential Tower	383,626
	E150.012576	Install South Washington ERU Sub	367,662
	E156.008860	Install switches on OAD075 and transfer load to relieve NOL	356,948
	E142.013447	Install TR at new Hazeltine sub	268,564
	E151.011613	Rebuild Public Health Vault	253,209
	E144.014347	Add Dundas 072 Feeder	249,143
	E144.012835	Reconductor 2 mi SCH211 feeder.	208,432
	E103.008083	Environmental Work NSPM-EL	197,039
	E141.017361	JAPS-OLSON 7500 Excelsior Blvd	141,077
	E143.001172	Edina-OH Reinforcements	125,058
	E114.018279	MN - UG Reinforce Blkt Tap/Back/Sec	89,402
	E154.001282	Northwest-UG Reinforcement	76,274
	E151.001248	St Paul-OH Reinforcements	64,340
	E144.013445	Add 50MVA Eastwood TR3 and feeders	59,342
	E143.013500	Extend WSG062 to relieve WSG072	56,833
	E154.007052	Extend 3 phase to new development in Sartell - 50th st	51,014
	E147.001219	Maple Grv-UG Reinforcements	42,453
	E144.016590	Belle Plaine Battery plus Solar Project	42,219
	E114.018280	MN - UG Reinforce Blkt All Other	37,085
	E147.016782	Extend IDA064 to relieve TWL064	32,441
	E142.004532	Chaska Sub FDR61 - Reinforcement Pr	18,954
	E141.014517	New ELP feeder	16,107
	E114.018181	MN - OH Reinforce Blkt Tap/Back/Sec	15,966
	E150.008740	Reconductor & Reinsulated CGR71 to AFT322	13,862
	E114.018182	MN - OH Reinforce Blkt All Other	12,741
	E141.014694	U of M CHP Express Feeders	11,103
	E156.012599	Install new fder tie for KOL64	10,688
	E147.012675	HOL061 3 Phase Upgrade	8,415
	E154.002521	Install second bank at Fiesta City	7,977
	E154.010161	Install 2nd tansformer at Sauk River	5,636
	E141.015808	Cascade load relief to MDT	5,549
	E141.016335	Block 69 Residential Vault Ryan Co	5,547
	NA	Reinforce GNL072 equipment in sub	5,313
	E114.018342	MN - New Business Network Blanket	3,750
	E150.012453	Replace RRK TR1 with 50MVA and add one feeder	3,046
	E150.012312	Replace PMC on CGR64 with PMH-9	2,886
	E144.001187	Southeast-UG Reinforcements	1,908
	E103.014467	Sub Fiber Communication Cutover	1,463
	E151.002440	Extend MPK66 to US Bank east, ATO	88
	E151.010808	Install DBL082 feeder	50
	E144.012973	Install Cap Bank at Crystal Foods	(50)
	E142.014709	T: High side rebuild at BLC due to SWTC	(335)
	E147.014686	Reconfigure ties on TWL feeders	(454)
	E141.016991	NTWK TRs Millwright Bldg 321 5th Ave S	(18,925)
	E154.006387	New First Lake substation in Monticello, MN	(35,067)
	E154.014561	Remove and Retire Empire Park substation	(77,959)
	E147.014478	Reconfigure ties for TWL079	(212,090)
	E154.012597	Upgrade Freeport substation to 12.5kV	(339,199)
	E103.012099	Capitalized-MN-Sales Tax Rfd - Elec	(646,973)
Projects related to Local (or other) Government-Requirements			
	E141.015301	Douglas Dr OH-UG Conversion	1,820,948
	E141.017519	35W Relocation 40th to Franklin	1,763,659
	E144.012864	County Road 20 Road Move	1,754,536
	E156.014239	RAM071 - Cty Rd B Road Work Maplewood	960,452
	E114.018271	MN - UG Reloc Tap/Backbone/Sec Blkt	763,820
	E150.009111	Relc TLK77 OH on Century for Cty Rd Widening	689,419
	E143.016745	Normandale Blvd - Relocate UG facilities for road widening	587,997
	E114.018173	MN - OH Reloc Tap/Backbone/Sec Blkt	535,199
	E103.011368	NSPM facility transfers from 3rd Party Owned Poles	525,644
	E143.000159	Road Widening Minnetonka CR5 and CR73	490,053
	E151.001251	St Paul-UG Relocations	434,686
	E141.015206	St. Anthony Bridge Relocation	430,838

IDP Category	Mitigation Number	Mitigation Name	2017 Expenditures
	E143.005672	EDP/ANDERSON LAKES & HWY 169/RELOCA	399,518
	E114.018273	MN - UG Service Conversion Blanket	344,969
	E114.018272	MN - UG Reloc All Other Type Blkt	302,726
	E141.014116	Washington Ave Relocation - Hennipin to 5th Ave	278,029
	E142.008544	County Rd 17, Delano, Road Move	253,580
	E154.007065	Hwy 101 and County Rd 36 Overhead Relocation	240,626
	E142.018619	Co Rd 30 Road Move	236,611
	E150.011418	Hastings Bridge Re-route ductbank for pier #5 Hwy 61	234,674
	E156.001296	White Bear-UG Relocations	233,492
	E144.002223	Southeast-UG Service Conv	193,231
	E151.016971	White Bear Ave Relocation	192,130
	E141.016028	5601 Lake St PMH Relocation	177,639
	E141.002215	Mpls-UG Service Conv	163,014
	E142.001160	Mntka-UG Relocations	145,162
	E144.001189	Southeast-UG Relocations	118,871
	E147.004557	Medina-Hwy 101 Overhead Fdr-RM	73,985
	E154.001284	Northwest-UG Relocations	54,567
	E156.002218	White Bear-UG Service Conv	53,567
	E151.002224	St Paul-UG Service Conv	47,709
	E142.002216	Mntka-UG Service Conv	45,472
	E147.002219	Maple Grv-UG Service Conv	37,155
	E147.001221	Maple Grv-UG Relocations	28,844
	E150.002222	Newport-UG Service Conv	22,706
	E154.002220	Northwest-UG Service Conv	17,240
	E143.002217	Edina-UG Service Conv	16,980
	E114.018174	MN - OH Reloc All Other Type Blkt	14,153
	E151.017153	Rosedale Mall Relocation	6,850
	E154.013988	T: Annandale Town Rebuild	5,641
	E103.002265	Capitalized Locating Costs-Elec UG MN	4,296
	E114.018479	MN - Pole Transfer 3rd Party Blanket	1,055
	E118.017461	Land for Turkey Ridge Radio Tower	437
	E147.014690	Hwy 610 Extension	325
	E150.015957	Robert Street Relocation W St Paul	285
	E144.014340	Morton County Road 2 Relocation	58
	E141.013426	LaSalle Paving Project	9
	E144.015253	Mankato Downtown Civic Center Project	(161)
	E156.013070	St Croix River Bridge	(190)
	E144.014112	Madison Ave Manholes Mankato	(1,302)
	E142.013864	T: Rebuild head end of WSG362 due to SWTC T-line project	(1,544)
	E141.016274	Nicollet Mall Street Scape	(61,308)
	E143.017171	MSP Airport - Relocate 3 Feeders for MSP	(86,250)
	E147.015783	Vicksburg OH-UG	(162,178)
	E141.014169	OH-UG Cnty 9 - France to Hwy 81	(204,531)
	E154.016854	2nd St N Relocation Project	(534,902)
Metering			
	E103.001040	MN-Electric Meter Blanket	6,773,097
New Customer Projects and New Revenue			
	E114.015600	MN LED Streetlight Program	12,376,276
	E114.018268	MN - UG Extension Blanket	5,646,295
	E141.001135	Mpls-OH Services	2,410,719
	E150.005996	Newport-UG Extensions	2,107,931
	E114.018269	MN - UG New Services Blanket	1,760,262
	E156.001299	White Bear-UG Extensions	1,670,388
	E141.010560	Serve Children's Hosiptal Addition (ATO and Pri Svc)	1,625,431
	E141.017362	365 Nicollet Construction Power	1,550,971
	E147.014741	Olympus Technologies Service	1,533,634
	E156.001288	White Bear-UG Services	1,137,102
	E154.001271	Northwest-UG Extensions	1,074,666
	E142.010321	New Germany Trophy Lake 45 lot URD	1,010,138
	E114.018171	MN - OH Extension Blanket	769,883
	E144.003805	Wanamingo - Pine Ridge development 82 units	719,257
	E144.002761	Switch load to new Summit Ave Bank #2 Feeder	718,211
	E142.001152	Mntka-New UG Services	695,530
	E144.001179	Southeast-UG Services	536,634
	E150.001226	Newport-UG Services	525,627
	E154.011195	Paynesville Mastermark Plastic NB Convert to 35kV	518,507
	E154.001277	Northwest-New UG Services	516,418
	E143.002572	Install Feeder tie to eliminate N-1 on WIL86 4.9 MVA	464,875
	E150.014745	Dakota Aggregate-RMT312 Extend OH 5500ft	449,224

IDP Category	Mitigation Number	Mitigation Name	2017 Expenditures
	E151.015041	Port Authority Barge Road	448,176
	E114.018046	MN - UG New Street Light Blanket	426,284
	E141.017364	1910 Queen Ave N Extension	361,160
	E141.001138	Mpls-New OH Street Lights	333,753
	E147.001214	Maple Grv-New Elec UG Services	308,226
	E151.001240	St Paul-OH Services	279,935
	E142.001150	Mntka-OH Extension	278,673
	E143.001169	Edina-New UG Street Lights	276,855
	E144.001181	Southeast-OH Streetlights	219,066
	E114.018355	MN - UG Street Light Rebuild Blanket	180,121
	E143.001167	Edina-UG Services	173,110
	E114.018172	MN - OH New Services Blanket	169,007
	E156.001286	White Bear-OH Extension	165,836
	E144.001178	Southeast-OH Services	164,469
	E141.016332	Block 75 Residential Vault Project	133,639
	E151.001241	St Paul-UG Services	113,573
	E150.001229	Newport-UG Streetlights	113,359
	E156.001555	Upgrade feeder exit with 1000 Al and reactor	102,124
	E156.001287	White Bear-OH Services	97,204
	E154.001274	Northwest-New OH Street Lights	83,046
	E154.001278	Northwest-New UG Street Lights	75,778
	E114.018045	MN - OH New Street Light Blanket	71,957
	E144.001182	Southeast-UG Streetlights	71,054
	E156.001290	White Bear-UG Street Lts	69,187
	E154.001276	Northwest-New OH Services	65,414
	E147.001215	Maple Grv-New UG Street Lights	56,376
	E143.002573	Install switches to eliminate N-1 on WIL77 4 MVA	51,125
	E156.001289	White Bear-OH Street Lights	48,258
	E143.001166	Edina-New OH Services	48,187
	E151.001243	St Paul-OH Streetlights	47,511
	E114.018354	MN - OH Street Light Rebuild Blanket	45,488
	E150.001228	Newport-OH Streetlights	41,453
	E147.001211	Maple Grv-New OH Street Lights	37,016
	E142.001153	Mntka-New OH Street Lights	31,510
	E143.001168	Edina-New OH Street Lights	26,098
	E150.001225	Newport-OH Services	24,810
	E142.001151	Mntka-OH Services	16,943
	E141.000640	Install a new tie to PKL85 to eliminate N-1 on MEL65	14,194
	E151.001244	St Paul-UG Street Lights	12,016
	E147.001213	Maple Grv-OH Services	7,955
	E142.001154	Mntka-New UG Street Lights	(5,632)
	E141.001139	Mpls-New UG Street Lights	(73,080)
Non-Investment			
	E154.015448	Northwest Solar Garden Extensions	5,151,639
	E156.015451	NSPM Solar Garden Extensions	1,840,205
	E103.016480	Solar Garden Sub Work	1,836,106
	E141.001140	Electric New Construction Contributions in Aid	1,657,734
	E142.015450	NSPM Solar Garden Extensions	1,625,901
	E103.016887	Solar Garden Communication Line Equip	1,058,420
	E144.016140	Aurora Solar Project SE	820,212
	E150.015447	NSPM Solar Gargen Extensions	778,408
	E154.016124	Aurora Solar Project NW	152,189
	E114.010645	Clearing WO for CRS credits	82,085
	E156.016141	Aurora Solar Project WBL	32,482
	NA	Misc Solar	15,579
	E141.016062	Solar Garden Ext - Mpls	262
	E143.001170	Electric New Construction Contributions in Aid	(31,354)
	E147.001216	Electric New Construction Contributions in Aid	(69,585)
	E103.016481	Solar Garden Sub COMM	(70,611)
	E154.001279	Electric New Construction Contributions in Aid	(87,746)
	E151.001245	Electric New Construction Contributions in Aid	(108,332)
	E156.001291	Electric New Construction Contributions in Aid	(168,128)
	E103.016885	Aurora Solar - Business Systems Comm Related	(176,952)
	E143.015445	NSPM Solar Garden Extensions	(194,320)
	E150.016123	Aurora Solar Project NPT	(206,134)
	E142.016122	Geronimo Aurora Solar Projects	(219,192)
	E142.001155	Electric New Construction Contributions in Aid	(243,987)
	E150.001230	Electric New Construction Contributions in Aid	(295,170)
	E144.001183	Electric New Construction Contributions in Aid	(800,664)

IDP Category	Mitigation Number	Mitigation Name	2017 Expenditures
	E103.016168	Aurora Solar Sub Comm	(1,856,755)
	E144.015449	Southeast Solar Garden Extensions	(5,777,385)
Other			
	E103.001041	MN-New Bus Transformer	16,884,576
	NA	Fleet Purchases	14,450,660
	E114.017857	MN Elec Mixed Work Adjustment	1,790,556
	E103.010660	VAR System Project	660,807
	E103.014464	Replace Frame Relays in NSPM	583,709
	E103.002265	Capitalized Locating Costs-Elec UG MN	488,411
	E103.010365	NSPM General Equipment - Communications	365,585
	E141.001133	Mpls-Electric Tools & Equip	348,912
	E103.011405	Install feeder load monitoring at selected subs	310,754
	E151.001252	St Paul-Elec Tools & Equip	287,385
	E103.002100	2002 Spec Cnstr - Sm Tool/Equipment Blanket for NSPM	270,784
	C103.002113	Tools & Equipment-Transportation Blanket	240,970
	E144.001190	Southeast-Elec Tools & Equip	237,064
	E103.013581	Remote Fault Indication and Load Monitors	194,632
	E154.001273	Northwest-Elec Tools/Equip	178,413
	E103.013585	Substation new RTU and FLM	171,677
	E142.001149	Mntka-Elec Tools/Equip	152,329
	E103.001738	MN Subs tools & equip	143,693
	E103.002099	NSPM Metering Sys-Tools & Equipment Blanket	102,484
	C115.006786	Logistics-NSPM Tools Blanket	97,537
	E153.001257	SD-Tools & Equip	79,656
	E145.013434	ND-Dist Sub Communication Equipment	77,872
	E150.001223	Newport-Elec Tool/Equip	68,553
	E143.001164	Edina-Elect Tool/Equip	55,012
	NA	Replace Frame Relays in NSPM	53,369
	E103.014467	Sub Fiber Communication Cutover	44,550
	E156.001297	White Bear-Electric Tools & Eq	43,504
	E147.001210	Maple Grv-Electric Tools & Equip	29,680
	C103.013336	Tools and Equipment - Locating	29,180
	E103.001739	MN Subs Constr tools	28,722
	E103.013567	Install feeder load monitoring at selected subs	26,237
	E145.001206	ND-Electric Tools & Equip	15,270
	NA	Elec Dist Communications Softw	6,948
	E118.017461	Land for Turkey Ridge Radio Tower	2,052
	E114.006438	Intelliteam SG Rollout	985
	E141.003695	Univ of MN Lease for Ductline/Reimbursement	(187,304)
	E103.012099	Capitalized-MN-Sales Tax Rfd - Elec	(3,345,196)
System Expansion or Upgrades for Reliability and Power Quality			
	E103.003453	Tap Cable Replacement 2nd Tier Minnesota	14,950,947
	E114.018277	MN - URD Cable Replacement Blanket	3,378,027
	E114.018471	MN - Feeder Cable Repl Blanket Proactive	1,758,968
	E114.018278	MN - Feeder Cable Replacement Blanket	947,270
	E103.001044	NSPM-Poor Performing Fdr Blanket	870,082
	E114.007693	Reliability Monitoring System (REMS): MN	337,083
	E103.009970	Mainline Cable Replacement - Proactive 2nd Tier - NSPM	188,932
	E103.003452	Mainline Cable Replacement - Reactive - NSPM	160,891
	E114.018343	MN - Network Renewal Blanket	136,012
	E142.012191	Reliability Upgrades (REMS) to BLC063 feeder	62,962
	E114.018179	MN - REMS Blanket	8,731
Grand Total			**201,022,444**

IDP Category	Mitigation Number	Mitigation Name	2018 Expenditures
Age-Related Replacements and Asset Renewal			
	E114.018129	MN - Pole Replacement Blanket	9,453,931
	E114.005559	MN Major Storm Recovery BlanketMN	9,370,453
	E114.018176	MN - OH Rebuild Tap/Backbone/Sec Blkt	7,433,326
	E114.018274	MN - UG Conversion/Rebuild Blanket	5,979,740
	E114.018275	MN - UG Services Renewal Blanket	5,105,975
	E141.012673	Replace Fifth Street FST Switchgear	3,584,104
	E114.018177	MN - OH Rebuild All Other Type Blkt	3,302,804
	E142.011006	SSI: Install Waconia TR2	1,919,754
	E103.011959	MN Mobile TR/Subs Reserve Capacity	1,769,535
	E114.018355	MN - UG Street Light Rebuild Blanket	1,717,940
	E103.004666	Hollydale - Replace Failed 69kV/13.	1,645,482
	E103.014456	Replace 5 distribution breakers at Merriam Park	1,581,129
	E103.016837	MN Failed Sub TR Replacement	1,432,352
	E141.018795	ELR MPLS Network Protectors	1,047,189
	E103.009150	SPCC NSPM Oil Spill Prevention	1,003,013
	E114.018354	MN - OH Street Light Rebuild Blanket	962,893
	E154.017782	Convert load and remove Industrial sub for city	892,520
	E151.016697	STP UG Network Vault Blanket	677,514
	E103.013521	ELR MN Sub RTUs	645,165
	E141.017924	Golden Valley Road OH to UG	610,668
	E114.017857	MN Elec Mixed Work Adjustment	592,897
	E103.011423	RCSII Replacement Project - NSPM	504,775
	E103.012603	ELR MN Sub Regulators	456,883
	E103.011891	ELR MN Sub Switches	453,314
	E103.017653	ELR MN Sub Batteries	446,865
	E103.009312	SSI: MN Infrastructure Investment	442,975
	E103.013804	Upgrade fence at Buffalo Lake	439,597
	E151.013639	ELR STP Vault Tops	397,206
	E144.017589	Rebuild Yellow Medicine YLM211 & YLM212	389,654
	E154.013611	SSI: Convert Echo 4kV to 23.9kV	340,676
	E141.017359	MPLS UG Network Vault Blanket	302,999
	E103.016931	Battery Upgrade for Frame Relay Replacements - NSPM	301,810
	E144.018871	PIP090 Interset Poles	289,865
	E150.018675	Replace Afton TR2 with System Reserve	283,794
	E103.016671	Purchase reserve transformer 7 MVA 69- 12.5 KV	216,699
	E153.012431	Convert SOS 4kV to 13.8kV	208,481
	E114.018479	MN - Pole Transfer 3rd Party Blanket	203,168
	E114.017864	MN/Capital Pole Inspections	172,496
	E114.018178	MN - OH Services Renewal Blanket	162,256
	E144.018411	Rebuild Clara City CLC221	101,496
	E150.013542	Woodbury Drive Road Move 3000ft Feeder at Bailey	76,024
	E141.019319	Relocation 4th Street Road Project	74,142
	E103.014355	Rewind failed 115KV - 13.8KV 70MVA transformer	42,132
	E144.013060	M&R Dairy Rebuild	34,258
	E151.018796	ELR STP Network Protectors	33,593
	E141.013910	St. Anthony Falls Hydro 15kV Cable Replacement	29,500
	E150.018891	Replace Linde LND TR1	13,064
	E147.017834	Bass Lake Road OH-UG	8,179
	E103.019028	Reserve Transformer 70MVA at 115-34.5kV	4,617
	E103.016670	Purchase reserve transformer 14 MVA 69- 13.8 KV	2,727
	E147.004711	Funding for CO109 Gravel Pit phase	606
	E156.008247	WBL Tap Cables	24
	E114.006616	MN Replace/Reinforce Non-Compliant Poles	(398)
	E151.016970	MLS stadium OH/UG Relocation	(1,225)
	E141.001664	ELR MPLS Vault Tops	(1,756)
	E151.016150	Hamline Station	(1,910)
	E142.004727	Co Rd 109, Phase 2-UG Conv	(3,366)
	E151.016446	Jackson St Rebuild	(3,950)
	E141.017360	Chicago - Washington Relocation	(4,409)
	E143.014668	WIL086 OH to UG Conversion	(5,919)
	E103.012612	ELR MN Sub TRs	(6,688)
	E154.011354	Install Cottonwood stepdowns to enable retirement of sub	(8,026)
	E142.009661	OH Rebuild Mtka increase	(11,233)
	E151.012282	Reconductor RAM73 Mainline	(17,953)
	E154.012309	Remove Eden Valley to Watkins line	(34,389)
	E147.001209	Maple Grv-OH Rebuilds	(49,455)
	E156.001292	White Bear-OH Rebuilds	(62,039)

IDP Category	Mitigation Number	Mitigation Name	2018 Expenditures
	E150.003703	Woodbury Lakes OH to UG conversion	(63,741)
	E141.001141	Mpls-OH Rebuilds	(226,848)
	E143.013748	SAV River Crossing	(234,906)
	E150.019520	Flint Hills Vessel Relocation	(258,314)
	E147.002745	RM: Relocate OH mainline for Hwy 241 from Co Rd 19 to McIver Ave NE: St Michael MN: LAP311	(261,846)
	E141.010286	Replace Dustproof protectors	(378,829)
System Expansion or Upgrades for Capacity			
	E154.010161	Install 2nd tansformer at Sauk River	2,183,735
	E154.003375	Install 35KV transformer at Salida Crossing	1,494,443
	E144.013448	SSI: Add 2nd 23.9kV Transformer and feeder at Waterville	1,447,111
	E144.013445	Add 50MVA Eastwood TR3 and feeders	1,375,271
	E103.018426	SUB MN Feeder Load Monitoring	1,182,687
	E114.018181	MN - OH Reinforce Blkt Tap/Back/Sec	975,268
	E114.018344	MN - Network Reinforcement Blanket	854,861
	E153.012465	Install tie for SOS062	854,421
	E114.018279	MN - UG Reinforce Blkt Tap/Back/Sec	771,673
	E142.016725	Reinforce GNL072 feeder capacity	611,297
	E114.018280	MN - UG Reinforce Blkt All Other	575,271
	E143.016728	Reinforce HYL feeder exits	555,134
	E154.002523	Reinforce Lowry TR and replace regulators	500,587
	E141.010910	Install Wilson WIL TR4 & Feeders	426,607
	E144.014347	Add Dundas 072 Feeder	326,933
	E114.018182	MN - OH Reinforce Blkt All Other	297,731
	E114.018342	MN - New Business Network Blanket	212,314
	E142.011017	Reinforce GSL65 feeder ties	165,639
	E154.018812	Atwater Replace ATW062 Breaker	156,118
	E150.012576	Install South Washington ERU Sub	154,724
	E150.014325	Extend ALK064	153,605
	E143.018586	Health Partners ATO 8170 33RD AVE S	135,358
	E141.017363	365 Nicollet Residential Tower	95,287
	E154.006387	New First Lake substation in Monticello, MN	58,219
	E150.019265	Upgrade Capacity CHE62/72 for 3M	41,654
	E141.017687	Load Transfer TER065 to TER073, TER085	19,496
	E141.017671	MEL073,Cut load to MEL065	9,193
	E154.015728	Reinforce St Cloud SCL TR2	3,833
	E142.014829	Install 2nd feeder at Plato	3,049
	E147.011058	Plymouth-Area Power Grid Upgrades	3,049
	E150.015662	Install Chemolite CHE065 Feeder	2,306
	E156.002804	Add 2nd bank at Baytown to eliminate N-1 risk	1,828
	E154.013633	SSI: Convert Hector 4kV to 13.8kV	1,766
	E144.012835	Reconductor 2 mi SCH211 feeder.	1,475
	E144.016597	Add Crystal Foods 62 Feeder	987
	E141.014517	New ELP feeder	(0)
	E144.016590	Belle Plaine Battery plus Solar Project	(37)
	E141.016992	CABLE DUCT Millwright Bldg 321 5th Av	(472)
	E144.001187	Southeast-UG Reinforcements	(1,905)
	E151.011613	Rebuild Public Health Vault	(2,785)
	E141.002682	Replace Failed Network Protectors on FST Network	(3,889)
	E141.017361	JAPS-OLSON 7500 Excelsior Blvd	(4,074)
	E154.002521	Install second bank at Fiesta City	(5,841)
	E147.013375	Reconfigure feeder ties CNC073	(7,553)
	E154.012597	Upgrade Freeport substation to 12.5kV	(55,400)
	E141.018733	Reinforce Daytons Vault 3	(61,628)
	E141.014694	U of M CHP Express Feeders	(66,873)
	E142.013447	Install TR at new Hazeltine sub	(72,763)
	E141.018732	Reinforce Daytons Vault 2	(298,646)
Projects related to Local (or other) Government-Requirements			
	E114.018173	MN - OH Reloc Tap/Backbone/Sec Blkt	6,120,312
	E141.018906	8th Street Relocation Hennepin to Chicago	5,640,318
	E114.018271	MN - UG Reloc Tap/Backbone/Sec Blkt	3,910,646
	E114.018174	MN - OH Reloc All Other Type Blkt	3,472,963
	E143.017843	CSAH 53 OH to UG	2,942,293
	E114.018272	MN - UG Reloc All Other Type Blkt	1,276,821
	E150.018807	Hwy 95 Reconstruction (Manning)	864,758
	E141.017519	35W Relocation 40th to Franklin	780,342
	E114.018273	MN - UG Service Conversion Blanket	621,821
	E143.019229	Hopkins OH-UG 325 Blake Road N	553,126
	E114.018479	MN - Pole Transfer 3rd Party Blanket	522,941
	E154.019018	Sartel Pinecone Road Elec Reloc	450,641

IDP Category	Mitigation Number	Mitigation Name	2018 Expenditures
	E151.018808	McKnight Ave OH Feeder Relocation	449,138
	E144.019239	County 18 Relocation Project	368,466
	E154.018868	SCL 33rd South Improvements	328,050
	E142.018619	Co Rd 30 Road Move	282,905
	E144.019253	RDW 301 Potter St Relocation	242,115
	E141.016028	5601 Lake St PMH Relocation	109,915
	E143.019345	Relocation Hwy 35 106th St to Cliff Rd	63,356
	E142.018744	MTK-Woodhill Road-OH to UG	56,180
	E151.001251	St Paul-UG Relocations	8,740
	E142.001160	Mntka-UG Relocations	4,482
	E143.016745	Normandale Blvd - Relocate UG facilities for road widening	4,101
	E143.005672	EDP/ANDERSON LAKES & HWY 169/RELOCA	3,601
	E141.002215	Mpls-UG Service Conv	1,724
	E142.002216	Mntka-UG Service Conv	1,510
	E141.014116	Washington Ave Relocation - Hennipin to 5th Ave	546
	E143.000159	Road Widening Minnetonka CR5 and CR73	6
	E156.002218	White Bear-UG Service Conv	5
	E156.001296	White Bear-UG Relocations	4
	E143.002217	Edina-UG Service Conv	(16)
	E151.016971	White Bear Ave Relocation	(27)
	E147.001221	Maple Grv-UG Relocations	(466)
	E156.014239	RAM071 - Cty Rd B Road Work Maplewood	(470)
	E144.012864	County Road 20 Road Move	(799)
	E147.004557	Medina-Hwy 101 Overhead Fdr-RM	(1,107)
	E150.011418	Hastings Bridge Re-route ductbank for pier #5 Hwy 61	(1,634)
	E141.016274	Nicollet Mall Street Scape	(1,865)
	E147.014690	Hwy 610 Extension	(12,443)
	E141.015301	Douglas Dr OH-UG Conversion	(38,692)
	E142.008544	County Rd 17, Delano, Road Move	(38,931)
	E154.007065	Hwy 101 and County Rd 36 Overhead Relocation	(40,555)
	E142.018982	VCR 1670 Stieger Lake Lane OH to UG	(98,074)
Metering			
	E103.001040	MN-Electric Meter Blanket	5,889,493
New Customer Projects and New Revenue			
	E114.018268	MN - UG Extension Blanket	20,129,145
	E114.018269	MN - UG New Services Blanket	7,958,387
	E114.015600	MN LED Streetlight Program	5,492,183
	E114.018792	MN LED Post Top Conversion	2,798,071
	E114.018171	MN - OH Extension Blanket	2,383,602
	E114.018046	MN - UG New Street Light Blanket	1,313,558
	E114.018172	MN - OH New Services Blanket	722,793
	E114.018045	MN - OH New Street Light Blanket	471,974
	E142.019281	Woodland Cove JT Extension	299,988
	E142.001154	Mntka-New UG Street Lights	86,416
	E144.001181	Southeast-OH Streetlights	36,504
	E144.003805	Wanamingo - Pine Ridge development 82 units	34,757
	E156.001299	White Bear-UG Extensions	28,833
	E150.005996	Newport-UG Extensions	24,947
	E141.017364	1910 Queen Ave N Extension	20,815
	E147.001215	Maple Grv-New UG Street Lights	18,623
	E144.001178	Southeast-OH Services	15,671
	E151.001240	St Paul-OH Services	5,198
	E147.014741	Olympus Technologies Service	4,761
	E143.002572	Install Feeder tie to eliminate N-1 on WIL86 4.9 MVA	4,408
	E156.001286	White Bear-OH Extension	3,262
	E142.001152	Mntka-New UG Services	2,463
	E143.001168	Edina-New OH Street Lights	1,889
	E144.002761	Switch load to new Summit Ave Bank #2 Feeder	1,545
	E141.010560	Serve Children's Hospital Addition (ATO and Pri Svc)	1,019
	E143.002573	Install switches to eliminate N-1 on WIL77 4 MVA	727
	E147.001214	Maple Grv-New Elec UG Services	648
	E154.001276	Northwest-New OH Services	234
	E154.011195	Paynesville Mastermark Plastic NB Convert to 35kV	195
	E142.010321	New Germany Trophy Lake 45 lot URD	27
	E151.015041	Port Authority Barge Road	4
	E141.001135	Mpls-OH Services	(40)
	E156.001287	White Bear-OH Services	(64)
	E142.001150	Mntka-OH Extension	(68)
	E151.001241	St Paul-UG Services	(115)

IDP Category	Mitigation Number	Mitigation Name	2018 Expenditures
	E156.001555	Upgrade feeder exit with 1000 Al and reactor	(374)
	E154.001277	Northwest-New UG Services	(426)
	E143.001167	Edina-UG Services	(498)
	E150.014745	Dakota Aggregate-RMT312 Extend OH 5500ft	(554)
	E150.001226	Newport-UG Services	(2,263)
	E144.001179	Southeast-UG Services	(2,545)
	E141.001139	Mpls-New UG Street Lights	(4,236)
	E141.001138	Mpls-New OH Street Lights	(4,771)
	E154.001274	Northwest-New OH Street Lights	(6,432)
	E143.001169	Edina-New UG Street Lights	(9,133)
	E150.001229	Newport-UG Streetlights	(19,577)
	E156.001288	White Bear-UG Services	(20,973)
	E154.001278	Northwest-New UG Street Lights	(21,161)
	E147.019271	Takeda UG Extension and ATO	(29,595)
	E154.001271	Northwest-UG Extensions	(34,445)
	E156.001290	White Bear-UG Street Lts	(49,242)
	E141.017362	365 Nicollet Construction Power	(62,717)
Non-Investment			
	E144.015449	Southeast Solar Garden Extensions	5,863,042
	E154.016124	Aurora Solar Project NW	519,414
	E147.017018	Solar Garden Ext - Maple Grove	362,619
	E143.015445	NSPM Solar Garden Extensions	96,675
	E141.016062	Solar Garden Ext - Mpls	62,565
	E156.001291	Electric New Construction Contributions in Aid	51,626
	E142.001155	Electric New Construction Contributions in Aid	30,243
	E150.001230	Electric New Construction Contributions in Aid	28,337
	E143.001170	Electric New Construction Contributions in Aid	11,254
	E144.001183	Electric New Construction Contributions in Aid	4,438
	E147.001216	Electric New Construction Contributions in Aid	2,481
	E103.016885	Aurora Solar - Business Systems Comm Related	(2)
	E156.016141	Aurora Solar Project WBL	(245)
	E151.001245	Electric New Construction Contributions in Aid	(3,509)
	E114.010645	Clearing WO for CRS credits	(3,992)
	NA	Misc Solar	(15,181)
	E154.001279	Electric New Construction Contributions in Aid	(18,890)
	E150.016123	Aurora Solar Project NPT	(102,871)
	E103.016481	Solar Garden Sub COMM	(132,495)
	E103.016887	Solar Garden Communication Line Equip	(137,318)
	E142.016122	Geronimo Aurora Solar Projects	(150,712)
	E144.016140	Aurora Solar Project SE	(411,808)
	E142.015450	NSPM Solar Garden Extensions	(1,163,374)
	E103.016168	Aurora Solar Sub Comm	(1,209,139)
	E156.015451	NSPM Solar Garden Extensions	(1,489,607)
	E150.015447	NSPM Solar Gargen Extensions	(1,853,493)
	E141.001140	Electric New Construction Contributions in Aid	(4,225,196)
	E154.015448	Northwest Solar Garden Extensions	(4,596,081)
	E103.016480	Solar Garden Sub Work	(7,017,039)
Other			
	E103.001041	MN-New Bus Transformer	27,142,933
	NA	Fleet Purchases	9,537,459
	C103.002113	Tools & Equipment-Transportation Blanket	652,303
	E103.011405	Install feeder load monitoring at selected subs	474,221
	E145.013434	ND-Dist Sub Communication Equipment	340,682
	E103.001738	MN Subs tools & equip	232,431
	E151.001252	St Paul-Elec Tools & Equip	151,061
	E114.018047	MN - Communication Equipment Blanket	136,429
	E141.001133	Mpls-Electric Tools & Equip	129,499
	C115.006786	Logistics-NSPM Tools Blanket	123,632
	E103.018427	COMM MN Feeder Load Monitoring	121,393
	E145.001206	ND-Electric Tools & Equip	85,479
	E103.010660	VAR System Project	83,303
	E103.013567	Install feeder load monitoring at selected subs	83,163
	E103.010365	NSPM General Equipment - Communications	78,865
	E154.001273	Northwest-Elec Tools/Equip	77,181
	E154.003375	Install 35KV transformer at Salida Crossing	52,401
	E103.013585	Substation new RTU and FLM	50,615
	E153.001257	SD-Tools & Equip	46,017
	E142.001149	Mntka-Elec Tools/Equip	39,624
	E103.002100	2002 Spec Cnstr - Sm Tool/Equipment Blanket for NSPM	34,931

IDP Category	Mitigation Number	Mitigation Name	2018 Expenditures
	E144.001190	Southeast-Elec Tools & Equip	30,517
	E143.001164	Edina-Elect Tool/Equip	25,865
	C103.013336	Tools and Equipment - Locating	21,088
	E150.001223	Newport-Elec Tool/Equip	17,458
	E103.014464	Replace Frame Relays in NSPM	13,496
	E103.014467	Sub Fiber Communication Cutover	8,221
	E156.001297	White Bear-Electric Tools & Eq	5,050
	NA	Scrap Sale Credit Com Gen NSP-	(221)
	E103.013581	Remote Fault Indication and Load Monitors	(1,360)
	E103.002099	NSPM Metering Sys-Tools & Equipment Blanket	(1,362)
	E103.002265	Capitalized Locating Costs-Elec UG MN	(198,310)
	E141.003695	Univ of MN Lease for Ductline/Reimbursement	(248,379)
System Expansion or Upgrades for Reliability and Power Quality			
	E114.018277	MN - URD Cable Replacement Blanket	19,735,436
	E114.018180	MN - FPIP Blanket	1,454,793
	E114.018278	MN - Feeder Cable Replacement Blanket	1,195,085
	E114.018343	MN - Network Renewal Blanket	898,220
	E114.018471	MN - Feeder Cable Repl Blanket Proactive	745,732
	E114.018179	MN - REMS Blanket	490,462
	E103.001044	NSPM-Poor Performing Fdr Blanket	(3,831)
	E103.009970	Mainline Cable Replacement - Proactive 2nd Tier - NSPM	(10,615)
	E103.003453	Tap Cable Replacement 2nd Tier Minnesota	(142,582)
Grid Modernization and Pilot Projects			
	NA	AGIS	429,193
Grand Total			**205,565,102**

IDP Category	Mitigation	Mitigation Name	2019 Expenditures
Age-Related Replacements and Asset Renewal			
	E114.018129	MN - Pole Replacement Blanket	$16,187,637
	E114.018176	MN - OH Rebuild Tap/Backbone/Sec Blkt	$11,018,414
	E114.018275	MN - UG Services Renewal Blanket	$6,723,445
	E114.005559	MN Major Storm Recovery BlanketMN	$6,406,731
	E114.017857	MN Elec Mixed Work Adjustment	$5,014,909
	E114.018274	MN - UG Conversion/Rebuild Blanket	$4,114,972
	E141.012673	Replace Fifth Street FST Switchgear	$3,496,946
	E114.018355	MN - UG Street Light Rebuild Blanket	$2,933,310
	E144.013448	SSI: Add 2nd 23.9kV Transformer and feeder at Waterville	$2,257,112
	E103.001736	MN Failed Sub Equip Replacement	$2,255,898
	E150.018891	Replace Linde LND TR1	$1,008,523
	E141.018795	ELR MPLS Network Protectors	$1,003,478
	E103.009150	SPCC NSPM Oil Spill Prevention	$990,666
	E103.019028	Reserve Transformer 70MVA at 115-34.5kV	$971,677
	E144.019617	Rebuild Sacred Heart SCH211	$800,001
	E144.018411	Rebuild Clara City CLC221	$738,489
	E150.019520	Flint Hills Vessel Relocation	$733,666
	E154.019464	T Rebuild West St Cloud to Millwood	$700,000
	E151.018796	ELR STP Network Protectors	$631,458
	E144.017589	Rebuild Yellow Medicine YLM211 & YLM212	$614,615
	E141.019939	Replace Fifth Street Fire Suppression System	$550,000
	E103.011890	ELR MN Sub Feeder Breakers	$513,004
	E114.018354	MN - OH Street Light Rebuild Blanket	$481,490
	E151.019642	2235 Highland - Duct Rebuild	$414,870
	E103.016837	MN Failed Sub TR Replacement	$378,762
	E142.019346	2440 Plymouth Rd OH-UG Conversion	$359,995
	E103.019030	Reserve Transformer 14MVA at 69-13.2kVA	$350,603
	E143.019819	France Ave OH-UG	$314,920
	E103.012586	ELR MN Sub Relays	$301,464
	E103.012603	ELR MN Sub Regulators	$298,816
	E103.006458	ELR MN Sub Retirements	$289,552
	E103.012606	ELR MN Sub Fences	$270,267
	E141.019578	Update HVAC System in 5th St. Sub	$225,000
	E151.013639	ELR STP Vault Tops	$193,123
	E103.017653	ELR MN Sub Batteries	$180,622
	E141.019522	FST - Replace Lighting System	$151,340
	E114.018178	MN - OH Services Renewal Blanket	$137,446
	E103.013521	ELR MN Sub RTUs	$125,157
	E154.013611	SSI: Convert Echo 4kV to 23.9kV	$105,973
	E103.011891	ELR MN Sub Switches	$99,234
	E103.010754	NSM - Pole Trussing	$89,990

IDP Category	Mitigation	Mitigation Name	2019 Expenditures
	E103.011959	MN Mobile TR/Subs Reserve Capacity	$76,368
	E103.011423	RCSII Replacement Project - NSPM	$65,402
	E151.013595	SSI: Convert St Clair 4kV to 13.8kV	$53,517
	E144.018871	PIP090 Interset Poles	$38,101
	E141.017360	Chicago-Washington Relocation OH/UG Conv	$11,075
	E103.009312	SSI: MN Infrastructure Investment	$7,551
	E114.017864	MINNESOTA POLE INSPECTIONS	$3,956
	E103.016671	Purchase reserve transformer 7 MVA 69- 12.5 KV	$3,612
	E150.018675	Replace Afton TR2 with System Reserve	$1,729
	E114.018276	MN - Line Asset Health WCF Blanket	$1,638
	E142.011006	SSI: Install Waconia TR2	$1,537
	E103.019429	Reserve TR 115/13.8 kV 70 MVA	$1,445
	NA	Mpls-Oh Rebuilds	$641
	NA	Replace 7 CM2 Network Protecto	$395
	NA	Maple Grv-Oh Rebuilds	$37
	E147.017834	Bass Lake Road OH-UG	($5,108)
	E141.017359	MPLS UG Network Vault Blanket	($39,839)
	E151.016697	STP UG Network Vault Blanket	($125,047)
	E142.001156	Mntka-UG Conversion/Rebuild	($259,758)
	E141.017924	Golden Valley Road OH to UG	($277,121)
	E154.017782	Convert load and remove Industrial sub for city	($1,469,055)
System Expansion or Upgrades for Capacity			
	E154.003375	Install 35KV transformer at Salida Crossing	$3,747,739
	E114.018344	MN - Network Reinforcement Blanket	$2,969,789
	E154.010161	Install 2nd tansformer at Sauk River	$2,363,307
	E141.010910	Install Wilson WIL TR4 & Feeders	$1,705,650
	E154.015728	Reinforce St Cloud SCL TR2	$1,405,981
	E114.018279	MN - UG Reinforce Blkt Tap/Back/Sec	$1,194,816
	E147.011058	Plymouth-Area Power Grid Upgrades	$1,043,598
	E144.014347	Add Dundas 072 Feeder	$940,919
	E144.018970	Reinforce Medford Junction MDF TR1	$935,737
	E103.018426	SUB MN Feeder Load Monitoring	$852,208
	E150.012576	Install South Washington ERU Sub	$744,278
	E114.018181	MN - OH Reinforce Blkt Tap/Back/Sec	$552,846
	E114.018342	MN - New Business Network Blanket	$434,013
	E150.011740	Add feeder WBP062	$352,000
	E156.014539	Reinforce Tanners Lake TLK077	$300,000
	E151.017618	Transfer WES062 load to WES063	$200,000
	E156.017629	Reinforce RAM071 BCT	$183,488
	E150.019059	T Reinforce Red Rock RRK TR2	$175,000
	E150.010904	Install Rosemount RMT TR2 & Feeder	$120,000
	E150.014325	Extend ALK064	$62,242
	E154.014561	Remove and Retire Empire Park substation	$60,000

IDP Category	Mitigation	Mitigation Name	2019 Expenditures
	E141.014694	U of M CHP Express Feeders	$9,912
	E103.001735	MN-Sub Capacity Reinforcement	$8,128
	E142.013447	Install new sub Lake Bavaria	$5,177
	E150.019265	Upgrade Capacity CHE62/72 for 3M	$1,480
	E142.011017	Reinforce GSL65 feeder ties	$1,166
	E143.016728	Reinforce HYL feeder exits	$723
	E141.016992	CABLE DUCT Millwright Bldg 321 5th	($183)
	NA	Mpls- New Ug Network	($226)
	E154.013633	SSI: Convert Hector 4kV to 13.8kV	($1,766)
	E141.001143	Mpls-UG Reinforcement	($2,026)
	E141.018733	Reinforce Daytons Vault 3	($12,935)
	E151.019521	United Hospital SG Replacement	($26,798)
	E142.016725	Reinforce GNL072 feeder capacity	($29,837)
	E147.016782	Extend IDA064 Feeder	($34,450)
	E114.013397	Substation Land - MN	($41,780)
	E156.002804	Inst BYT#2 28 MVA	($43,556)
	E154.018812	Atwater Replace ATW062 Breaker	($168,562)
	E143.018586	Health Partners ATO 8170 33RD AVE S	($544,608)
Projects related to Local (or other) Government-Requirements			
	E141.018906	8th Street Relocation Hennepin to Chicago	$8,128,273
	E114.018271	MN - UG Reloc Tap/Backbone/Sec Blkt	$7,384,515
	E114.018173	MN - OH Reloc Tap/Backbone/Sec Blkt	$6,932,293
	E141.019412	Relocation Hennepin Ave Road Project	$3,423,108
	E141.019192	Relocation MPLS SWLRT Road Project	$1,145,076
	E142.019440	Hwy 101 Bridge Relocation	$929,122
	E150.018807	Hwy 95 Reconstruction (Manning)	$899,347
	E156.019826	Rice St & 694 Roundabout Recon	$810,706
	E150.019563	Oakdale and Marie Trl Relocation	$565,559
	E150.019641	County Road 8-Wentworth Ave	$547,507
	E114.018273	MN - UG Service Conversion Blanket	$535,333
	E114.018479	MN - Pole Transfer 3rd Party Blanket	$507,573
	E144.019772	Madison Ave & Haefner Dr Relocation	$417,912
	E150.019616	Dakota County Hwy 50 Relocation	$330,022
	E154.018868	SCL 33rd South Improvements	$289,921
	E141.019422	Relocation Hennepin Ave Road Project	$134,999
	E150.019919	Wescott Relocation	$74,000
	E141.019319	Relocation 4th Street Road Project	$73,262
	E143.013574	Relocation EDINA SWLRT Road Project	$57,369
	E141.019410	COMP Relocation MPLS SWLRT Road Project	$52,645
	E143.019409	COMP Relocation EDINA SWLRT Road Project	$46,112
	E151.018808	McKnight Ave OH Feeder Relocation	$20,788
	E154.016854	2nd St N UG Relocation Project	$19,656
	E142.018619	Co Rd 30 Road Move	$19,085

IDP Category	Mitigation	Mitigation Name	2019 Expenditures
	E154.019018	Sartel Pinecone Road Elec Reloc	$4,497
	E142.018982	VCR 1670 Stieger Lake Lane OH to UG	$3,965
	NA	St Croix River Bridge	$1,142
	E141.015301	Douglas Dr OH-UG Conversion	$640
	E143.016745	Normandale Blvd - Relocate UG facil	$299
	E103.011368	NSPM facility transfers from 3rd Party Owned Poles	($5,800)
	E142.018744	MTK-Woodhill Road-OH to UG	($15,343)
	E143.019345	Relocation Hwy 35 106th St to Cliff Rd	($164,900)
	E143.019229	Hopkins OH-UG 325 Blake Road N	($292,834)
	E143.017843	CSAH 53 OH to UG	($331,212)
	E141.017519	35W Relocation 40th to Franklin	($1,266,448)
Metering			
IDP Metering	E103.001040	MN-Electric Meter Blanket	$6,705,021
New Customer Projects and New Revenue			
	E114.018268	MN - UG Extension Blanket	$20,372,262
	E114.018269	MN - UG New Services Blanket	$6,890,975
	E114.015600	MN LED Streetlight Program	$3,566,878
	E114.018171	MN - OH Extension Blanket	$2,902,571
	E114.018172	MN - OH New Services Blanket	$690,152
	E114.018045	MN - OH New Street Light Blanket	$399,026
	E114.018046	MN - UG New Street Light Blanket	$129,222
	NA	Mpls-OH Extension	$12,068
	E141.001138	Mpls-New OH Street Lights	$11,913
	E142.019281	Woodland Cove JT Extension	$5,727
	NA	Mpls-New UG Extension	$5,722
	E147.019271	Takeda UG Extension and ATO	$3,418
	E141.001135	Mpls-OH Services	$2,506
	NA	Maple Grv- Elec Ug Extension	$64
	E141.001139	Mpls-New UG Street Lights	($121)
	E141.001131	Mpls-New UG Extension	($1,182)
	NA	Southeast-Ug Services	($4,459)
	E141.001136	Mpls-New UG Services	($5,941)
	E114.018792	MN LED Post Top Conversion	($150,402)
Non-Investment			
	E144.015449	SE Solar Garden Extensions - E	$4,875,487
	E154.016124	Extend facilities to serve NW	$410,727
	E103.016481	MN-Solar Garden Sub Comm	$166,670
	E142.015450	Solar Garden Ext - Shorewood	$123,448
	E143.015445	Solar Garden Ext - Edina	$33,886
	E144.016140	Aurora Solar Project SE	$24,025
	E103.016168	Aurora Solar Sub Reinforcement	($6,830)
	E141.016062	Solar Garden Ext - MPLS	($47,699)
	E103.016480	MN-Solar Garden Sub Work	($301,772)
	E147.017018	Solar Garden Ext - Maple Grove	($373,096)

IDP Category	Mitigation	Mitigation Name	2019 Expenditures
	E103.016887	Solar Gardens Communications - CSG	($492,110)
	E156.015451	Solar Garden Ext - WBL	($1,341,847)
	E150.015447	Solar Garden Ext Newport - Ext	($1,619,282)
	E154.015448	Northwest Solar Gardens Ext	($1,995,134)
	E141.001140	Electric New Construction Contributions in Aid	($4,377,979)
Other			
	E103.001041	MN-New Bus Transformer	$18,373,346
	NA	Fleet Purchases	$5,847,873
	E103.002100	2002 Spec Cnstr - Sm Tool/Equipment Blanket for NSPM	$872,092
	E103.002265	Capitalized Locating Costs-Elec UG MN	$451,142
	NA	NSPM Week4 SES Accrual	$412,000
	E103.018427	COMM MN Feeder Load Monitoring	$392,308
	E103.001738	MN Subs tools & equip	$233,309
	E153.001257	SD-Tools & Equip	$76,707
	C115.006786	Logistics-NSPM Tools Blanket	$73,590
	E145.013434	ND-Dist Sub Communication Equipment	$73,077
	E103.011405	Install feeder load monitoring at selected subs	$59,140
	E145.001206	ND-Electric Tools & Equip	$48,678
	E103.010660	VAR System Project	$35,047
	E144.013448	SSI: Add 2nd 23.9kV Transformer and feeder at Waterville	$34,822
	E103.002099	NSPM Metering Sys-Tools & Equipment Blanket	$34,822
	C103.002113	Tools & Equipment-Transportation Blanket	$34,462
	E114.018047	MN - Communication Equipment Blanket	$27,061
	E103.010365	NSPM General Equipment - Communications	$3,340
	E145.019571	ND Office Furniture and Equipment	$3,025
	E103.014467	Sub Fiber Communication Cutover	$2,134
	NA	Frame Relay Replacement - SD	$903
	E103.014464	Frame Relay Replacement - NSPM	$15
	NA	NSPM- MN Comm Equip - Dist Lin	($18)
	NA	Scrap Sale Credit Com Gen NSP-	($31)
	NA	NSPM - SD Comm Equip - Dist Li	($2,915)
	NA	SD-Dist Fleet New Unit Purchase El Ops	($8,231)
	E141.003695	Scrap Sale Credits-MN	($135,336)
	E103.003619	MN-Dist Transportation Blanket Elec	($238,641)
System Expansion or Upgrades for Reliability and Power Quality			
	E114.018277	MN - URD Cable Replacement Blanket	$15,372,251
	E114.018471	MN - Feeder Cable Repl Blanket	$2,623,246
	E114.018180	MN - FPIP Blanket	$1,205,062
	E114.018179	MN - REMS Blanket	$404,205
	E144.020026	Porcelain Cutout Replacement	$100,000
	E114.018343	MN - Network Renewal Blanket	$55,430
	E103.003453	NSPM-Accelerated URD Cable Rep	($646)
Grid Modernization and Pilot Projects			
	E114.020058	MN Electric Vehicle Program	$812,000

IDP Category	Mitigation	Mitigation Name	2019 Expenditures
	NA	AGIS	$3,757,031
Grand Total			**210,912,522**

IDP Category	Mitigation	Mitigation Name	2020	2021	2022	2023	2024
Grid Modernization and Pilot Projects							
	NA	AGIS	$10,350,543	$41,211,082	$131,903,272	$140,519,221	$61,990,821
	E114.020058	MN Electric Vehicle Program	$9,528,000	$8,082,000	$9,815,000	$11,862,000	$14,759,000
Age-Related Replacements and Asset Renewal							
	E114.017857	MN Elec Mixed Work Adjustment	$9,099,917	$11,829,996	$11,829,996	$11,829,996	$11,829,996
	E114.018176	MN - OH Rebuild Tap/Backbone/Sec Blkt	$9,912,000	$10,142,000	$10,377,000	$10,618,003	$10,864,003
	E114.018178	MN - OH Services Renewal Blanket	$103,000	$105,003	$107,000	$109,000	$112,000
	E114.018354	MN - OH Street Light Rebuild Blanket	$822,000	$844,000	$865,000	$888,000	$888,000
	E114.018274	MN - UG Conversion/Rebuild Blanket	$6,758,000	$6,915,009	$7,075,009	$7,239,009	$7,407,009
	E114.018275	MN - UG Services Renewal Blanket	$2,903,009	$2,970,002	$3,039,009	$3,110,002	$3,182,000
	E114.018355	MN - UG Street Light Rebuild Blanket	$788,000	$809,002	$830,000	$852,000	$852,000
	E141.017359	MPLS UG Network Vault Blanket	$492,000	$504,000	$516,000	$516,000	$516,000
	E151.016697	STP UG Network Vault Blanket	$244,000	$250,004	$256,000	$256,000	$256,000
	E103.001736	MN Failed Sub Equip Replacement	$2,300,000	$2,300,000	$2,300,000	$2,300,000	$2,300,000
	E103.016837	MN Failed Sub TR Replacement	$800,000	$1,600,000	$1,600,000	$1,600,000	$1,600,000
	E103.019429	Reserve TR 115/13.8 kV 70 MVA	$552,000				
	E103.013577	Reserve TR 115/34.5 kV 70 MVA	$800,000				
	E103.012618	Reserve TR 69/13.8 kV 28 MVA			$550,000		
	E103.017653	ELR MN Sub Batteries	$54,000	$306,000	$180,000	$180,000	$180,000
	E103.011890	ELR MN Sub Feeder Breakers	$449,998	$2,550,000	$1,500,000	$1,500,000	$1,500,000
	E103.012606	ELR MN Sub Fences	$75,008	$425,008	$250,000	$250,000	$250,000
	E103.012603	ELR MN Sub Regulators	$60,000	$340,000	$200,000	$200,000	$200,000
	E103.012586	ELR MN Sub Relays	$90,000	$510,000	$300,000	$300,000	$300,000
	E103.006458	ELR MN Sub Retirements	$60,000	$340,000	$200,000	$200,000	$200,000
	E103.013521	ELR MN Sub RTUs	$31,340	$177,594	$104,467	$104,467	$104,467
	E103.011891	ELR MN Sub Switches	$30,000	$170,000	$100,000	$100,000	$100,000
	E103.012612	ELR MN Sub TRs			$2,000,004	$2,000,004	$2,000,004
	E141.018795	ELR MPLS Network Protectors	$250,004	$750,004	$1,000,000	$1,000,000	$1,000,000
	E141.001664	ELR MPLS Vault Tops		$1,000,000	$500,000	$1,000,000	$1,000,000
	E151.018796	ELR STP Network Protectors	$250,004	$750,004	$1,000,000	$1,000,000	$1,000,000
	E151.013639	ELR STP Vault Tops	$799,999	$700,006	$500,002	$1,000,000	$1,000,000
	E114.018129	MN - Pole Replacement Blanket	$28,900,000	$17,700,000	$17,700,000	$17,700,000	$17,700,000
	E103.009150	SPCC NSPM Oil Spill Prevention	$700,000				
	E144.013600	Convert Butterfield BTF 4kV			$100,000	$2,700,000	
	E144.013622	Convert Lafayette LAF 4kV				$100,000	$1,950,000
	E144.018411	Rebuild Clara City CLC221	$800,001	$599,999			
	E144.019617	Rebuild Sacred Heart SCH211	$1,400,000				
	E144.017589	Rebuild Yellow Medicine YLM211 & YLM212	$1,450,000	$1,450,000	$1,400,000		
	E141.017906	Replace Fifth Street FST Network RTU	$200,000				
	E141.012673	Replace Fifth Street FST Switchgear	$2,470,001				
	E150.018891	Replace Linde LND TR1	$1,100,000				
	E154.019464	T Rebuild West St Cloud to Millwood	$1,500,000	$2,500,000	$900,000		
	E114.018276	MN - Line Asset Health WCF Blanket	$11,000,000	$11,000,000	$11,000,000	$11,000,000	$12,700,000
System Expansion or Upgrades for Capacity							
	E114.018342	MN - New Business Network Blanket	$1,282,000	$1,313,000	$1,345,001	$1,345,001	$1,345,001
	E114.018181	MN - OH Reinforce Blkt Tap/Back/Sec	$883,002	$883,002	$883,002	$883,002	$883,002
	E114.018279	MN - UG Reinforce Blkt Tap/Back/Sec	$460,000	$460,000	$460,000	$460,000	$460,000
	E103.001735	MN-Sub Capacity Reinforcement	$100,000	$100,000	$100,000	$100,000	$100,000
	E103.018426	SUB MN Feeder Load Monitoring	$880,000	$2,020,000	$2,500,000	$2,500,000	$3,750,000
	E147.011058	Plymouth-Area Power Grid Upgrades	$8,000,000	$7,900,000			
	E150.019059	T Reinforce Red Rock RRK TR2	$670,003				
	E150.019885	Install Jamaica JAM Area Sub	$2,800,000				
	E144.018970	Reinforce Medford Junction MDF TR1	$1,700,000				
	E147.019893	Install Switch Coon Creek CNC073	$30,000				
	E144.007793	Reinforce Fair Park FAP TR1 & Fdr	$1,300,000				
	E143.016730	Install Feeder Tie Wilson WIL081	$300,000				
	E147.017741	Reinforce Osseo OSS062	$200,000				
	E150.018967	Extend Red Rock RRK063	$100,000				
	E144.017637	Load Transfer ESW062 to SMT061	$100,000				
	E141.017739	Extend Main Street MST074	$300,000				
	E143.016724	Reinforce Westgate WSG Feeders	$550,000				
	E141.019911	Reinforce Medicine Lake MEL074	$500,000				
	E141.019924	Install Hiawatha West HWW Feeder	$1,200,000				

IDP Category	Mitigation	Mitigation Name	2020	2021	2022	2023	2024
	E141.019929	Install Midtown MDT Feeder		$1,900,000			
	E141.019957	Extend Saint Louis Park SLP085	$150,000				
	E147.015637	Install Feeder Tie Osseo OSS063	$100,000				
	E150.019910	Load Transfer CGR062 to CGR071	$950,000				
	E141.010910	Install Wilson WIL TR4 & Feeders	$6,850,000	$7,950,000			
	E143.019055	Reinforce Savage SAV063 & SAV067	$1,100,004				
	E156.010177	Install Kohlman Lake KOL Feeder	$1,000,000	$600,000			
	E150.010914	Install Stockyards STY TR3 & Feeders		$4,000,000	$3,500,000		
	E156.015749	Install Baytown BYT Feeders		$2,100,000	$2,100,000		
	E154.016772	Install Fiesta City FIC Feeder		$1,000,000			
	E141.019930	Install Feeder Tie SOU083 to MDT074		$100,000			
	E141.019954	Reinforce Saint Louis Park SLP087		$150,000			
	E141.019928	Extend Saint Louis Park SLP092		$600,000			
	E154.018960	Reinforce Glenwood GLD Sub Equip		$700,000			
	E144.002712	Install Goodview GVW Feeder		$1,100,000			
	E150.015662	Install Chemolite CHE065 Feeder		$1,440,000			
	E156.011061	Install Wyoming WYO Feeder		$2,500,000			
	E143.016727	Install Feeder Tie EBL064		$150,000			
	E147.019056	Reinforce Basset Creek BCR062		$250,000			
	E141.019958	Reinforce Moore Lake MOL071		$550,000			
	E151.012409	Install Western WES TR3 & Feeders		$100,000	$5,300,000		
	E144.013436	Reinforce Kasson KAN TR1 & Feeders			$2,850,002		
	E147.012463	Install Feeder Tie Crooked Lake CRL033			$1,250,000		
	E154.010157	Install Albany ALB TR		$100,000	$2,800,000		
	E141.019956	Reinforce Terminal TER073			$1,100,000		
	E150.012576	Install South Washington ERU Sub	$5,670,002				
	E144.018971	Reinforce Veseli VES TR1 & Feeder		$100,000	$2,650,004		
	E141.019955	Extend Terminal TER064				$150,000	
	E144.010920	Reinforce Burnside BUR TR2			$100,000	$2,600,000	
	E143.019054	Reinforce Edina EDA062				$500,000	
	E147.014465	Reinforce Brooklyn Park BRP062				$200,000	
	E144.000793	Install Zumbrota ZUM TR & Feeder			$100,000	$2,950,002	
	E144.016592	Reinforce Sibley Park SIP Sub Equip				$100,000	
	E143.017702	Install Viking VKG Feeder				$2,500,000	
	E150.010904	Install Rosemount RMT TR2 & Feeder	$4,400,008				
	E142.011721	Install Orono ORO TR2 & Feeder			$100,000	$4,000,000	
	E156.007927	Install Goose Lake GLK TR3 & Feeders				$700,000	$4,000,000
	E144.008708	Install Cannon Falls Trans CTF TR2 & Fdr				$100,000	$1,895,003
	E147.013379	Install West Coon Rapids WCR TR			$99,996	$1,979,996	
	E156.011752	Install Lindstrom LIN Feeder					$650,008
	E143.019908	Install Hyland Lake HYL TR3 & Feeder				$100,000	$4,600,000
	E156.011764	Reinforce Tanners Lake TLK Sub Equip					$200,000
	E156.015811	Reinforce Oakdale OAD073 & OAD075					$275,004
	E151.018961	New MPK075-GPH061 Feeder Tie					$250,002
	E144.013520	Install East Winona EWI TR2 & Feeder				$100,000	$3,100,000
	E153.010999	Install Louise LOU TR2 & Feeders			$100,000	$3,480,000	
	E141.009146	Install Hiawatha West HWW TR2	$1,400,000				
	E154.015728	Reinforce St Cloud SCL TR2	$1,400,002				
	E141.009145	Install Midtown MDT TR2				$100,000	$1,400,000
	E103.006881	Dist Subs Carryover-NSPM		$1,500,000	$3,999,996	$5,100,000	$9,999,996
	E114.018281	MN - Line Capacity WCF Blanket		$500,000	$1,000,000	$3,000,000	$4,999,992
Projects related to Local (or other) Government-Requirements							
	E114.018173	MN - OH Reloc Tap/Backbone/Sec Blkt	$8,468,000	$8,468,000	$8,468,000	$8,468,000	$8,468,000
	E114.018271	MN - UG Reloc Tap/Backbone/Sec Blkt	$5,408,000	$5,408,000	$5,408,000	$5,408,000	$5,408,000
	E114.018273	MN - UG Service Conversion Blanket	$649,009	$649,009	$649,009	$649,009	$649,009
	E114.018479	MN - Pole Transfer 3rd Party Blanket	$500,000	$500,000	$500,000	$500,000	$500,000
	E143.019409	COMP Relocation EDINA SWLRT Road Project	($457,997)	($582,993)	($462,998)		
	E141.019410	COMP Relocation MPLS SWLRT Road Project	($458,008)	($582,991)	($463,007)		
	E141.018907	Relocation 4th Street Road Project	$249,999	$300,001			
	E141.019319	Relocation 4th Street Road Project	$3,577,000	$3,795,000			
	E143.013574	Relocation EDINA SWLRT Road Project	$908,002	$908,002	$259,998		
	E141.019412	Relocation Hennepin Ave Road Project (LINES)	$3,033,000	$2,983,000	$1,061,000		
	E141.019422	Relocation Hennepin Ave Road Project (VAULTS)	$615,000				

IDP Category	Mitigation	Mitigation Name	2020	2021	2022	2023	2024
	E143.019345	Relocation Hwy 35 106th St to Cliff Rd		($250,002)			
	E141.019192	Relocation MPLS SWLRT Road Project	$908,000	$908,000	$260,000		
	E114.018175	MN - Mandate WCF Blanket	$3,400,001	$4,345,999	$3,653,000	$3,933,000	$4,217,001
	E141.017929	MPLS Mandates WCF	$2,075,006	$2,597,000	$9,142,000	$10,000,000	$10,000,000
Metering							
	E103.001040	MN-Electric Meter Blanket	$5,484,000	$4,290,000	$3,454,000	$2,338,000	$2,338,000
New Customer Projects and New Revenue							
	E114.018171	MN - OH Extension Blanket	$3,290,000	$3,651,000	$3,651,000	$3,651,000	$3,651,000
	E114.018172	MN - OH New Services Blanket	$2,511,000	$2,788,000	$2,788,000	$2,788,000	$2,788,000
	E114.018045	MN - OH New Street Light Blanket	$352,000	$362,000	$371,000	$380,000	$380,000
	E114.018268	MN - UG Extension Blanket	$19,387,000	$21,499,000	$21,499,000	$21,499,000	$21,499,000
	E114.018269	MN - UG New Services Blanket	$8,330,000	$9,247,000	$9,247,000	$9,247,000	$9,247,000
	E114.018046	MN - UG New Street Light Blanket	$728,000	$747,000	$767,000	$787,000	$787,000
	E114.018792	MN LED Post Top Conversion	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000
Non-Investment							
	E141.001140	Electric New Construction Contributions in Aid	($3,733,000)	($3,702,000)	($3,813,000)	($3,813,000)	($3,813,000)
Other							
	E103.002100	2002 Spec Cnstr - Sm Tool/Equipment Blanket for NSPM	$789,595	$1,169,167	$1,169,167	$1,169,167	$1,169,167
	E103.002265	Capitalized Locating Costs-Elec UG MN	$400,000	$400,000	$400,000	$400,000	$400,000
	C115.006786	Logistics-NSPM Tools Blanket	$167,359	$247,850	$252,632	$252,632	$252,632
	E153.011934	Logistics-NSPM Tools Blanket - SD	$3,482	$4,353	$4,353	$4,353	$4,353
	E103.001738	MN Subs tools & equip	$233,309	$501,441	$501,441	$501,441	$501,441
	E103.001041	MN-New Bus Transformer	$21,537,000	$23,114,000	$22,104,000	$22,774,000	$23,431,000
	E145.001206	ND-Electric Tools & Equip	$53,105	$70,518	$70,518	$70,518	$70,518
	E103.002099	NSPM Metering Sys-Tools & Equipment Blanket	$34,822	$69,645	$69,645	$69,645	$69,645
	E153.001257	SD-Tools & Equip	$76,609	$101,855	$101,855	$101,855	$101,855
	C103.002113	Tools & Equipment-Transportation Blanket	$30,284	$90,055	$90,055	$90,055	$90,055
	NA	Fleet Purchases	$9,637,809	$12,797,349	$17,093,422	$9,095,459	$7,701,612
	E103.018427	COMM MN Feeder Load Monitoring	$348,223	$696,445	$870,557	$870,557	$1,305,835
	E114.018553	AGIS - Planning and Forecasting Tool - MN	$4,000,000				
	E150.012576	Install South Washington ERU Sub	$87,056				
	E103.014467	Sub Fiber Communication Cutover	$435,278	$435,278	$435,278		
	E144.019891	T Revenue Metering Mapleton	$215,898				
	E144.019892	T Revenue Metering Minnesota Lake	$205,451				
System Expansion or Upgrades for Reliability and Power Quality							
	E114.018471	MN - Feeder Cable Repl Blanket	$5,000,000	$5,000,000	$5,000,000	$5,000,000	$5,000,000
	E114.018180	MN - FPIP Blanket	$600,000	$1,400,000	$1,500,000	$1,500,000	$1,500,000
	E114.018179	MN - REMS Blanket	$510,000	$1,190,000	$850,000	$850,000	$850,000
	E114.018277	MN - URD Cable Replacement Blanket	$15,400,000	$26,100,000	$22,000,000	$22,000,000	$22,000,000
	E114.019275	MN Incremental System Investment		$80,999,901	$88,000,000	$87,999,933	$87,999,944
Grand Total			**$277,487,137**	**$392,612,596**	**$480,287,683**	**$484,566,325**	**$415,216,373**

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Xcel Energy Information Request No. 25

Docket No.:	E002/M-19-666
Response To:	Fresh Energy
Requestor:	Isabel Ricker
Date Received:	January 13, 2020

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment H, p. 19.

Request:
Please explain the approach the Company used to scale historical 2018 peak days to 2022 forecast peak values.

Response:
The process we use to scale historical peak days to forecast peak values begins with extracting hourly SCADA data within the historical peak day timeframe. We take the ratio of the forecasted peak value to the peak hour within the SCADA data and assume that the general load curve for the historical peak day will also scale in the same proportion. We complete the process by scaling up all hours of the historical SCADA data to make the historical load curve shape reflect the forecasted peak.

Preparer:	Paul Vaynshenk
Title:	Distribution Planning Engineer
Department:	Distribution System Planning
Telephone:	763.493.1683
Date:	January 23, 2020

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Xcel Energy		Information Request No. 26
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

<u>Question:</u>
<u>Reference:</u>
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment K.

<u>Request:</u>
For each planning area, please provide the actual 2019 sums of feeder and bank demand and compare with the forecasted 2019 values shown in the Attachment.

<u>Response:</u>
Attachment K is the planning area load growth charts that are part of our system planning process. We provide the requested information as Attachment A to this response.

We note that each of the planning regions represented in Attachment K to our 2019 IDP consist of many substations, transformers, and feeders that are forecasted individually based on a variety of factors including: known load changes, physical feeder and load reconfigurations, historical peak events, and weather impacts. Due to these factors, and in an effort to ensure system reliability and adequate capacity for our customers, our forecasted demands tend to be on the conservative side. The actual peak values are a result of real weather and economic impacts. If those variables were to reoccur in future periods, it is reasonable to expect that they would produce similar values, barring any known changes.

Finally, we note that there are eight substations that are part of the Sioux Falls, South Dakota planning area that are geographically located within Minnesota. In responding to this Information Request, we realized they were not included in Attachment K to our November 1, 2019 IDP. We have included the requested information for the Sioux Falls-MN Planning Region in this response, and will additionally include an update in our Reply Comments in the IDP docket.

Preparer:	Kody Kamunen
Title:	Distribution Engineer
Department:	System Planning and Strategy
Telephone:	763.493.1579
Date:	January 23, 2020

	Northwest		Maple Grove	
Year	**Feeders**	**Bank**	**Feeders**	**Bank**
2019 - Forecast	794304	752433	908695	784007
2019 - Actual	733812	684524	803183	691677
Percent Difference	-7.6%	-9.0%	-11.6%	-11.8%

	Edina		Minneapolis	
Year	**Feeders**	**Bank**	**Feeders**	**Bank**
2019 - Forecast	1103081	951552	1882355	1557924
2019 - Actual	972599	826294	1719655	1469697
Percent Difference	-11.8%	-13.2%	-8.6%	-5.7%

	Newport		St Paul	
Year	**Feeders**	**Bank**	**Feeders**	**Bank**
2019 - Forecast	1083849	962764	842741	713671
2019 - Actual	1030280	912284	784972	665870
Percent Difference	-4.9%	-5.2%	-6.9%	-6.7%

	White Bear Lake		Minnetonka	
Year	**Feeders**	**Bank**	**Feeders**	**Bank**
2019 - Forecast	903720	787058	467402	427972
2019 - Actual	816041	714459	448235	407463
Percent Difference	-9.7%	-9.2%	-4.1%	-4.8%

	Keystone		Hiawatha	
Year	**Feeders**	**Bank**	**Feeders**	**Bank**
2019 - Forecast	635943	583055	240619	218854
2019 - Actual	592299	535610	230766	199841
Percent Difference	-6.9%	-8.1%	-4.1%	-8.7%

	Sioux Falls - MN	
Year	**Feeders**	**Bank**
2019 - Forecast	45750	40673
2019 - Actual	42783	41048
Percent Difference	-6.5%	0.9%

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Xcel Energy		Information Request No. 27
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment M1.

Request:
Please explain the inconsistency between the $524 million AGIS capital cost at p. 20 of 301, line 23, and the sum of values at p. 21 of 301, line 11 totaling $581.9 million.

Response:
The difference between the two sums is the level of presentation. The $524 million stated on page 20 of 301 is representative of the capital expenditures specific to the State of Minnesota electric jurisdiction. The $581.9 million presented in Table 2 on page 21 of 301 is representative of capital expenditures for the Electric portion of the NSP Minnesota operating company, which also includes the North Dakota and South Dakota electric operations.

Preparer:	Nick Paidosh
Title:	Principal Rate Analyst
Department:	Regulatory Affairs
Telephone:	612-342-9034
Date:	January 23, 2020

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Xcel Energy		Information Request No. 28
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment M1, p. 90 of 301.

Request:
Please provide the customer energy savings and peak demand reduction percentages achieved by the SVC implementation in Xcel Energy's Colorado service territory.

Response:

Due to the number of integrated technologies contributing to energy reduction and peak load reduction achieved by Integrated Volt Var Optimization (IVVO), the Company does not have a method for calculating the actual incremental benefits associated with Static Var Compensators (SVC). For additional information regarding the theory and estimated incremental benefits provided by SVCs, please refer to the Direct Testimony of Chad S. Nickell in Colorado proceeding 16A-0588E, which can be accessed at https://www.dora.state.co.us/pls/efi/EFI_Search_UI.search.

Preparer:	Andrew Wilson
Title:	IVVO Engineer
Department:	GV&C Delivery Team
Telephone:	303-571-3533
Date:	January 23, 2020

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Xcel Energy		Information Request No. 29
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment M1, p. 91 of 301.

Request:
Please explain why the Company is planning to limit the implementation of IVVO to 189 feeders.

Response:
Our IVVO proposal of 189 feeders is focused on feeders where we believe we will be able to maximize benefits in relation to the level of investment. For example, where substation communications and control equipment are already capable or can be modified at moderate cost, where substation transformers serve an average or above average number of feeders, and where the ADMS deployment will first occur. We then examined these locations to consider the likelihood of achieving benefits, which assumed that the probability for benefits is greater for systems with shorter feeders combined with higher customer density.

We believe our proposed deployment (13 substations with 189 feeders serving 224,000 customers) at a cost of $26.6M is an appropriate deployment proposal. As we have stated in Attachment M2 of the Company's November 1, 2019 IDP filing (p. 262), as we learn more about the benefits and costs from this deployment on our NSP system, we will be better equipped to consider a broader implementation of IVVO in the future.

Preparer:	Brian D. Amundson
Title:	Director, Advanced Grid
Department:	Distribution Electric Engineering

Telephone: 715-737-4645
Date: January 23, 2020

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Xcel Energy		Information Request No. 30
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment M1, p. 179 of 301.

Request:
Please explain what levels of cost contingencies are included in the Company's AGIS bill impact analysis.

Response:
The Company included capital and O&M contingencies in our overall bill impact analysis to the extent they are included in the AGIS project budgets within the capital budget window (2019 through 2024). However, we did not specifically break out the capital contingency amount in calculating the bill impacts. That said the best method of understanding contingency in the bill impact would be to take the percentages of capital contingency in Table 9 on p. 161 of Attachment M1 and applying them to each respective project's capital addition.

Project capital contingencies are discussed at length in Attachments M1 p. 158-162, M2 p. 86-89, and M3 p. 77-81. Additionally, O&M contingency dollars are displayed in Attachments O2-O4 on the "SummaryCosts" tabs as stand-alone line-items.

Preparer:	Nick Paidosh
Title:	Principal Rate Analyst
Department:	Regulatory Affairs
Telephone:	612-342-9034
Date:	January 23, 2020

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Xcel Energy		Information Request No. 31
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

<u>Question:</u>
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment M2, p. 73 of 202, lines 10-19.

Request:
A. Please provide screenshots of the inputs to and outputs from the LBNL ICE Calculator used for the referenced calculations.
B. Please provide a spreadsheet with all formulas and links intact containing the referenced calculations.

<u>Response:</u>
The calculation of reliability benefits on page 73 of Attachment M2 is related to improved identification of nested outages during storm events.

A. We are not able to provide screen shots of the LBNL ICE calculator because we used an internally-developed tool, the Customer Minute Out (CMO) calculator, which for this set of reliability benefits, is rooted in the 2015 LBNL ICE calculator. We provide the LBNL study as Attachment A to this response, and our CMO Calculator as Attachment B. We note that we made corrections to the original LBNL study values in our Calculator, by making a final impact correction after taxes (especially influenced by the C&I customers), , which shows a CAIDI of 572 minutes, resulting in a CMO value of $0.65.
B. See Attachment C to this Reply.

In light of the series of Information Requests asking for CMO calculations, we note that we calculated the reliability benefits associated with different pieces of our proposal at different points in time. For example, the benefits for nested outages requested in this response used the 2015 LBNL study results. We have since updated our CMO calculator, which was a result of new information provided by LBNL and

NEXANT. The updated version is based on the ICE online calculator values instead of the study; we used this later version for the FLISR benefit calculations as provided in our response to Fresh Energy Information Request Nos. 35 and 45.

Attachment B to this response is a Company work product that includes proprietary methods for calculating the value of customer minutes out. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Additionally, some data contained within the work product is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use, and/or contains proprietary customer and system data.

Please note Attachment B is marked as "Non-Public" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, we provide the following description of the excised material:

1. **Nature of the Material:** Model to determine value of Customer Minutes Out
2. **Authors:** Electric Distribution Engineering Department
3. **Importance:** The Company work product includes proprietary methods for calculating the value of customer minutes out.
4. **Date the Information was Prepared:** June 2018

Attachment C to this response is a Company work product. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Additionally, some data contained within the work product is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use, and/or contains proprietary customer and system data.

Please note Attachment C is marked as "Non-Public" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, we provide the following description of the excised material:

1. **Nature of the Material:** Calculates benefits to customer for install of Advanced Metering Infrastructure
2. **Authors:** Electric Distribution Engineering Department
3. **Importance:** The Company work product is proprietary to the Company.
4. **Date the Information was Prepared:** June 2018

Preparer:	Betsy Coppock
Title:	Principal Engineer
Department:	Electric Distribution Engineering
Telephone:	303.571.3537
Date:	January 23, 2020

LBNL-6941E

ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States

Principal Authors
Michael J. Sullivan, Josh Schellenberg, and Marshall Blundell
Nexant, Inc.

January 2015

The work described in this report was funded by the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

Disclaimer

Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States

Michael J. Sullivan, Josh Schellenberg, and Marshall Blundell
Nexant, Inc.
101 Montgomery Street, 15th Floor
San Francisco, CA

The work described in this report was funded by the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

Acknowledgments

The work described in this report was funded by the Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The authors thank Joseph Paladino of the DOE Office of Electricity Delivery and Energy Reliability, and Joseph H. Eto of the Lawrence Berkeley National Laboratory for support and guidance in the development of this research. We would also like to thank Emily Fisher, Gary Fauth, Peter Larsen, Kristina Hamachi-LaCommare, Peter Cappers, and Julia Frayer for their careful reviews and comments on the earlier drafts of this report. Their comments were extremely thoughtful and useful.

Abstract

This report updates the 2009 meta-analysis that provides estimates of the value of service reliability for electricity customers in the United States (U.S.). The meta-dataset now includes 34 different datasets from surveys fielded by 10 different utility companies between 1989 and 2012. Because these studies used nearly identical interruption cost estimation or willingness-to-pay/accept methods, it was possible to integrate their results into a single meta-dataset describing the value of electric service reliability observed in all of them. Once the datasets from the various studies were combined, a two-part regression model was used to estimate customer damage functions that can be generally applied to calculate customer interruption costs per event by season, time of day, day of week, and geographical regions within the U.S. for industrial, commercial, and residential customers. This report focuses on the backwards stepwise selection process that was used to develop the final revised model for all customer classes. Across customer classes, the revised customer interruption cost model has improved significantly because it incorporates more data and does not include the many extraneous variables that were in the original specification from the 2009 meta-analysis. The backwards stepwise selection process led to a more parsimonious model that only included key variables, while still achieving comparable out-of-sample predictive performance. In turn, users of interruption cost estimation tools such as the Interruption Cost Estimate (ICE) Calculator will have less customer characteristics information to provide and the associated inputs page will be far less cumbersome. The upcoming new version of the ICE Calculator is anticipated to be released in 2015.

Table of Contents

List of Figures and Tables

Acronyms and Abbreviations

AIC	Akaike's Information Criterion
C&I	Commercial and Industrial
GLM	Generalized Linear Model
ICE	Interruption Cost Estimate
MAE	Mean Absolute Error
OLS	Ordinary Least Squares
RMSE	Root Mean Square Error

Executive Summary

In 2009, Freeman, Sullivan & Co. (now Nexant) conducted a meta-analysis that provided estimates of the value of service reliability for electricity customers in the United States (U.S.). These estimates were obtained by analyzing the results from 28 customer value of service reliability studies conducted by 10 major U.S. electric utilities over the 16-year period from 1989 to 2005. Because these studies used nearly identical interruption cost estimation or willingness-to-pay/accept methods, it was possible to integrate their results into a single meta-dataset describing the value of electric service reliability observed in all of them. The meta-analysis and its associated econometric models were summarized in a report entitled "Estimated Value of Service Reliability for Electric Utility Customers in the United States,"[1] which was prepared for Lawrence Berkeley National Laboratory (LBNL) and the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy (DOE). The econometric models were subsequently integrated into the Interruption Cost Estimate (ICE) Calculator (available at icecalculator.com), which is an online tool designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements (also funded by LBNL and DOE).

Since the report was finalized in June 2009 and the ICE Calculator was released in July 2011, Nexant, LBNL, DOE, and ICE Calculator users have identified several ways to improve the interruption cost estimates and the ICE Calculator user experience. These improvements include:

- Incorporating more recent utility interruption cost studies;
- Enabling the ICE Calculator to provide estimates for power interruptions lasting longer than eight hours;
- Reducing the amount of detailed customer characteristics information that ICE Calculator users must provide;
- Subjecting the econometric model selection process to rigorous cross-validation techniques, using the most recent model validation methods;[2] and
- Providing a batch processing feature that allows the user to save results and modify inputs.

These improvements will be addressed through this updated report and the upcoming new version of the ICE Calculator, which is anticipated to be released in 2015. This report provides updated value of service reliability estimates and details the revised econometric model, which is based on a meta-analysis that includes two new interruption cost studies. The upcoming new version of the ICE Calculator will incorporate the revised econometric model and include a batch processing feature that will allow the user to save results and modify inputs.

[1] Sullivan, M.J., M. Mercurio, and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States.* Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

[2] For a discussion of these methods, see: Varian, Hal R. "Big Data: New Tricks for Econometrics." *Journal of Economic Perspectives.* Volume 28, Number 2. Spring 2014. Pages 3–28. Available here: http://pubs.aeaweb.org/doi/pdfplus/10.1257/jep.28.2.3

Updated Interruption Cost Estimates

For each customer class, Table ES-1 provides the three key metrics that are most useful for planning purposes. These metrics are:

- Cost per event (cost for an individual interruption for a typical customer[3]);
- Cost per average kW (cost per event normalized by average demand); and
- Cost per unserved kWh (cost per event normalized by the expected amount of unserved kWh for each interruption duration).

Cost per unserved kWh is relatively high for a momentary interruption because the expected amount of unserved kWh over a 5-minute period is relatively low.

In general, even though the econometric model has been considerably simplified, it produces similar estimates to those of the 2009 model. As in the 2009 study, medium and large C&I customers have the highest interruption costs, but when normalized by average kW, interruption costs are highest in the small C&I customer class. On both an absolute and normalized basis, residential customers experience the lowest costs as a result of a power interruption.

Table ES-1: Estimated Interruption Cost per Event, Average kW and Unserved kWh (U.S.2013$) by Duration and Customer Class

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Medium and Large C&I (Over 50,000 Annual kWh)						
Cost per Event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
Cost per Average kW	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per Unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7
Small C&I (Under 50,000 Annual kWh)						
Cost per Event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per Average kW	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per Unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0
Residential						
Cost per Event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per Average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3

Table ES-2 shows how customer interruption costs vary by season and time of day, based on the key drivers of interruption costs that were identified in the model selection process. For medium and large C&I customers, interruption costs only meaningfully vary by season (summer vs. non-summer). For medium and large C&I customers, the cost of a summer power interruption is

[3] The interruption costs in Table ES- 1 are for the average-sized customer in the meta-database. The average annual kWh usages for the respondents in the meta-database are 7,140,501 kWh for medium and large C&I customers, 19,214 kWh for small C&I customers and 13,351 kWh for residential customers.

around 21% to 43% higher than a non-summer one, depending on duration (the percent difference lowers as duration increases). For small C&I customers, the seasonal pattern is the opposite, with the cost of summer power interruptions lower by around 9% to 30%, depending on duration, season, and time of day. Small C&I interruption costs also vary by time of day, with the highest costs in the afternoon and morning. In the evening and nighttime, small C&I interruption costs are substantially lower, which makes sense given that small businesses typically operate during daytime hours. For residential customers, interruption costs are generally higher during the summer and in the morning and night (10 PM to 12 noon). The table also includes a weighted-average interruption cost estimate (equal to the cost per event estimates in Table ES-1), which is weighted by the proportion of hours of the year that each interruption scenario represents, depending on season and time of day. This weighted-average interruption cost estimate is most appropriate to use for planning purposes, unless the distribution of interruptions by season and time of day is known and accounted for in the analysis.

Table ES-2: Estimated Customer Interruption Costs (U.S.2013$) by Duration, Timing of Interruption and Customer Class

Timing of Interruption	% of Hours per Year	Interruption Duration					
		Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Medium and Large C&I							
Summer	33%	$16,172	$18,861	$21,850	$46,546	$96,252	$186,983
Non-summer	67%	$11,342	$13,431	$15,781	$35,915	$77,998	$154,731
Weighted Average		*$12,952*	*$15,241*	*$17,804*	*$39,458*	*$84,083*	*$165,482*
Small C&I							
Summer Morning	8%	$461	$569	$692	$1,798	$4,073	$7,409
Summer Afternoon	7%	$527	$645	$780	$1,954	$4,313	$7,737
Summer Evening/Night	18%	$272	$349	$440	$1,357	$3,518	$6,916
Non-summer Morning	17%	$549	$687	$848	$2,350	$5,592	$10,452
Non-summer Afternoon	14%	$640	$794	$972	$2,590	$5,980	$10,992
Non-summer Evening/Night	36%	$298	$388	$497	$1,656	$4,577	$9,367
Weighted Average		*$412*	*$520*	*$647*	*$1,880*	*$4,690*	*$9,055*
Residential							
Summer Morning/Night	19%	$6.8	$7.5	$8.4	$14.3	$24.0	$42.4
Summer Afternoon	7%	$4.3	$4.9	$5.5	$9.8	$17.1	$31.1
Summer Evening	7%	$3.5	$4.0	$4.6	$9.2	$17.5	$34.1
Non-summer Morning/Night	39%	$3.9	$4.5	$5.1	$9.8	$17.8	$33.5
Non-summer Afternoon	14%	$2.3	$2.7	$3.1	$6.2	$12.1	$23.7
Non-summer Evening	14%	$1.5	$1.8	$2.2	$5.0	$10.8	$23.6
Weighted Average		*$3.9*	*$4.5*	*$5.1*	*$9.5*	*$17.2*	*$32.4*

Study Limitations

As in the 2009 study, there are limitations to how the data from this meta-analysis should be used. It is important to fully understand these limitations, so they are further described in this section and in more detail in Section 6. These limitations are:

- Certain very important variables in the data are confounded among the studies we examined. In particular, region of the country and year of the study are correlated in such a way that it is impossible to separate the effects of these two variables on customer interruption costs;
- There is further correlation between regions and scenario characteristics. The sponsors of the interruption cost studies were generally interested in measuring interruption costs for conditions that were important for planning their specific systems. As a result, interruption conditions described in the surveys for a given region tended to focus on periods of time when interruptions were more problematic for that region;
- A further limitation of our research is that the surveys that formed the basis of the studies we examined were limited to certain parts of the country. No data were available from the northeast/mid-Atlantic region, and limited data were available for cities along the Great Lakes;
- Another caveat is that around half of the data from the meta-database is from surveys that are 15 or more years old. Although the intertemporal analysis in the 2009 study showed that interruption costs have not changed significantly over time, the outdated vintage of the data presents concerns that, in addition to the limitations above, underscore the need for a coordinated, nationwide effort that collects interruption cost estimates for many regions and utilities simultaneously, using a consistent survey design and data collection method; and
- Finally, although the revised model is able to estimate costs for interruptions lasting longer than eight hours, it is important to note that the estimates in this report are not appropriate for resiliency planning. This meta-study focuses on the direct costs that customers experience as a result of relatively short power interruptions of up to 24 hours at most. For resiliency considerations that involve planning for long duration power interruptions of 24 hours or more, the nature of costs change and the indirect, spillover effects to the greater economy must be considered.[4] These factors are not captured in this meta-analysis.

[4] For a detailed study and literature review on estimating the costs associated with long duration power interruptions lasting 24 hours to 7 weeks, see: Sullivan, Michael and Schellenberg, Josh. *Downtown San Francisco Long Duration Outage Cost Study*. March 27, 2013. Prepared for Pacific Gas & Electric Company.

1. Introduction

In 2009, Freeman, Sullivan & Co. (now Nexant) conducted a meta-analysis that provided estimates of the value of service reliability for electricity customers in the United States (U.S.). These estimates were obtained by analyzing the results from 28 customer value of service reliability studies conducted by 10 major U.S. electric utilities over the 16-year period from 1989 to 2005. Because these studies used nearly identical interruption cost estimation or willingness-to-pay/accept methods, it was possible to integrate their results into a single meta-dataset describing the value of electric service reliability observed in all of them. Once the datasets from the various studies were combined, a two-part regression model was used to estimate customer damage functions that can be generally applied to calculate customer interruption costs per event by season, time of day, day of week, and geographical regions within the U.S. for industrial, commercial, and residential customers. The meta-analysis and its associated econometric models were summarized in a report entitled "Estimated Value of Service Reliability for Electric Utility Customers in the United States,"[5] which was prepared for Lawrence Berkeley National Laboratory (LBNL) and the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy (DOE). The econometric models were subsequently integrated into the Interruption Cost Estimate (ICE) Calculator (available at icecalculator.com), which is an online tool designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements (also funded by LBNL and DOE).

Since the report was finalized in June 2009 and the ICE Calculator was released in July 2011, Nexant, LBNL, DOE, and ICE Calculator users have identified several ways to improve the interruption cost estimates and the ICE Calculator user experience. These improvements include:

- Incorporating more recent utility interruption cost studies;
- Enabling the ICE Calculator to provide estimates for power interruptions lasting longer than eight hours;
- Reducing the amount of detailed customer characteristics information that ICE Calculator users must provide;
- Subjecting the econometric model selection process to rigorous cross-validation techniques, using the most recent model validation methods;[6] and
- Providing a batch processing feature that allows the user to save results and modify inputs.

These improvements will be addressed through this updated report and the upcoming new version of the ICE Calculator, which is anticipated to be released in 2015. This report provides updated value of service reliability estimates and details the revised econometric model, which is based on a meta-analysis that includes two new interruption cost studies. The upcoming new

[5] Sullivan, M.J., M. Mercurio, and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

[6] For a discussion of these methods, see: Varian, Hal R. "Big Data: New Tricks for Econometrics." *Journal of Economic Perspectives*. Volume 28, Number 2. Spring 2014. Pages 3–28. Available here: http://pubs.aeaweb.org/doi/pdfplus/10.1257/jep.28.2.3

version of the ICE Calculator will incorporate the revised econometric model and include a batch processing feature that will allow the user to save results and modify inputs.

1.1 Recent Interruption Cost Studies

Since conducting the meta-analysis in 2009, there have been two large interruption cost surveys in the U.S., one in the southeast and another in the west. The 2011 study in the southeast involved a systemwide interruption cost survey of over 3,300 residential and small/medium business customers and nearly 100 in-person interviews of large business customers. The 2012 study in the west involved a systemwide interruption cost survey of nearly 2,700 residential and small/medium business customers and 210 in-person interviews of large business customers. Although the basic survey methodology is similar to previous work, the 2012 interruption cost study in the west featured several noteworthy methodological improvements. In particular, a dynamic survey instrument design for that study produced interruption cost estimates from 5 minutes to 24 hours, for weekdays and weekends and across many different times of the day (morning, afternoon, evening and night). As such, incorporating the 2012 data and re-estimating the underlying econometric models will enable the ICE Calculator to estimate costs for interruptions lasting longer than 8 hours, which will address one of the improvements above.

Table 1-1 provides an updated inventory of interruption cost studies that are included in the meta-dataset. The number of observations for each study is provided along with the minimum and maximum duration of power interruption scenarios in each study. Altogether, the meta-dataset now includes 34 different datasets from surveys fielded by 10 different utility companies between 1989 and 2012, totaling over 105,000 observations.[7] Some of the utilities surveyed all three customer types – medium and large commercial and industrial (C&I), small C&I, and residential – while others did not. In some cases there was only one dataset for C&I customers, in which case they were sorted into medium and large C&I or small C&I according to electricity usage. The split between small C&I and medium/large C&I is at 50,000 annual kWh. In total, the meta-dataset includes 44,328 observations for medium and large C&I customers, 27,751 observations for small C&I customers and 34,212 observations for residential customers. Each observation corresponds to a response for a single power interruption scenario. The surveys usually included four to six power interruption scenarios.

Table 1-1: Updated Inventory of Interruption Cost Studies in the Meta-dataset

Utility Company	Survey Year	Number of Observations			Min. Duration (Hours)	Max. Duration (hours)
		Medium and Large C&I	Small C&I	Residential		
Southeast-1	1997	90			0	1
Southeast-2	1993	3,926	1,559	3,107	0	4
	1997	3,055	2,787	3,608	0	12
Southeast-3	1990	2,095	765		0.5	4

[7] To the knowledge of the authors, this dataset includes nearly all large power interruption cost studies that have been conducted in the US. Some studies may not have been included for data confidentiality reasons.

Utility Company	Survey Year	Number of Observations			Min. Duration (Hours)	Max. Duration (hours)
		Medium and Large C&I	Small C&I	Residential		
	2011	7,941	2,480	3,969	1	8
Midwest-1	2002	3,171			0	8
Midwest-2	1996	1,956	206		0	4
West-1	2000	2,379	3,236	3,137	1	8
West-2	1989	2,025	5		0	4
	1993	1,790	825	2,005	0	4
	2005	3,052	3,223	4,257	0	8
	2012	5,342	4,632	4,106	0	24
Southwest	2000	3,991	2,247	3,598	0	4
Northwest-1	1989	2,210		2,126	0.25	8
Northwest-2	1999	7,091		4,299	0	12

= Recently incorporated data

Prior to adding the 2012 West-2 survey, the meta-dataset included power interruption scenarios with durations of up to 12 hours. However, the 2009 model for each customer class estimated interruption costs that reached a maximum at 8 hours, and then the estimated interruption costs would decrease, which indicated that the prior model clearly did not provide reliable predictions beyond 8 hours (i.e., it is unreasonable that a 9-hour power interruption would cost less than an 8-hour one). As discussed in Sections 3 through 5, for interruptions from 8 to 16 hours, the new model produces estimates that are more reasonable and show gradually increasing costs up to 16 hours. This improvement in model performance is attributed to the addition of the 24-hour interruption scenarios (2012 West-2) and to the much simpler model specification that resulted from the rigorous selection process.

Although the revised model is able to estimate costs for interruptions lasting longer than 8 hours, it is important to note that the estimates in this report are not appropriate for resiliency planning. This meta-study focuses on the direct costs that customers experience as a result of relatively short power interruptions of up to 24 hours at most. In fact, the final models and results that are presented in Sections 3 through 5 truncate the estimates at 16 hours, due to the relatively few number of observations beyond 12 hours (scenarios of more than 12 hours account for around 2% to 3% of observations for all customer classes). For resiliency considerations that involve planning for long duration power interruptions of 24 hours or more, the nature of costs change and the indirect, spillover effects to the greater economy must be considered.[8] These factors are not captured in this meta-analysis.

[8] For a detailed study and literature review on estimating the costs associated with long duration power interruptions lasting 24 hours to 7 weeks, see: Sullivan, Michael and Schellenberg, Josh. *Downtown San Francisco Long Duration Outage Cost Study*. March 27, 2013. Prepared for Pacific Gas & Electric Company.

As discussed in Section 6, another caveat is that this meta-analysis may not accurately reflect current interruption costs, given that around half of the data in the meta-database is from surveys that are 15 or more years old. To address this issue, the 2009 study included an intertemporal analysis, which suggested that interruption costs did not change significantly throughout the 1990s and early 2000s. However, during the past decade in particular, technology trends may have led to an increase in interruption costs. For example, home and business life has become increasingly reliant on data centers and "cloud" computing, which may have led to an increase in interruption costs for both producers and consumers of these services. Therefore, the outdated vintage of the data presents concerns that underscore the need for a coordinated, nationwide effort that collects interruption cost estimates for many regions and utilities simultaneously, using a consistent survey design and data collection method.

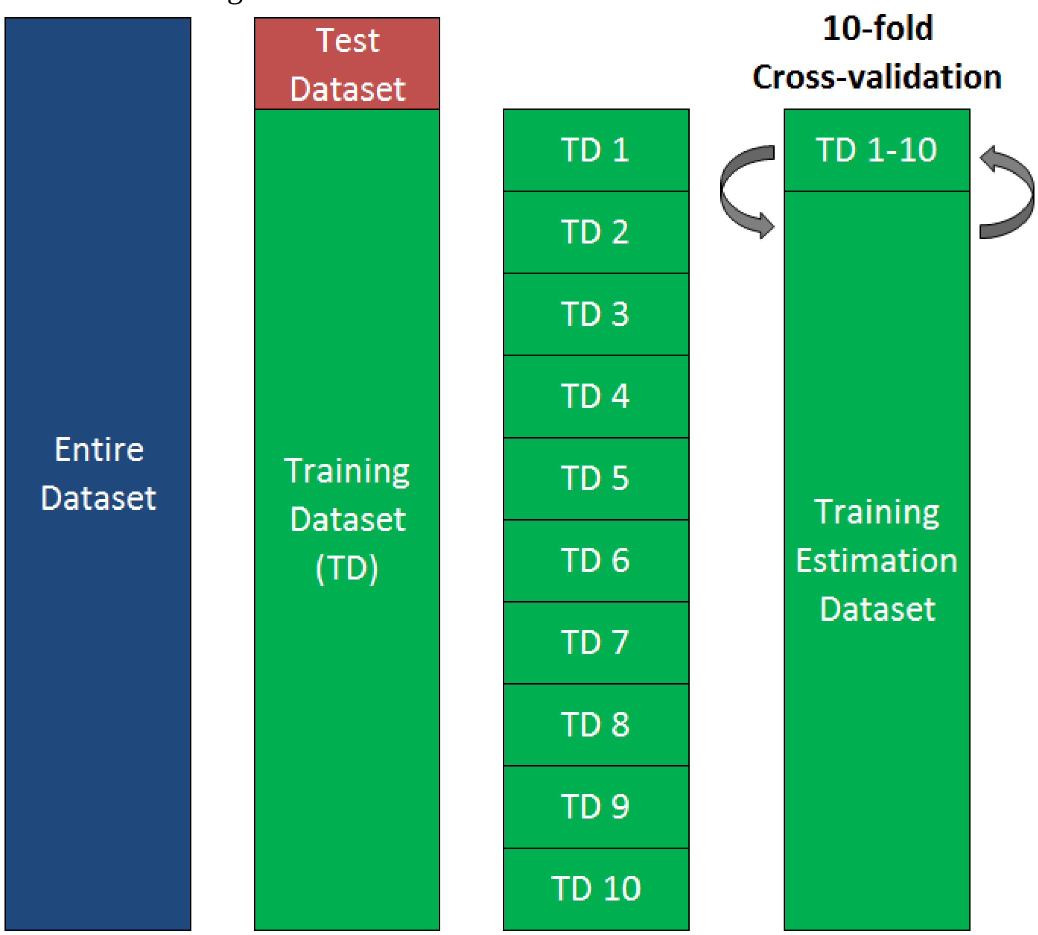
1.2 Re-estimating Econometric Models

Using the new meta-dataset, Nexant re-estimated the econometric models that relate interruption costs to duration, customer characteristics such as annual kWh, and other factors. Nexant then compared the results of the original model specification to those of several alternatives that included a reduced number of variables. This model selection process addressed another ICE Calculator improvement – reducing the amount of detailed customer characteristics information that ICE Calculator users must provide, which has been a significant barrier to the tool's use. When the econometric models were originally estimated in 2009, statistical significance was the focus of the analysis and, due to the large number of observations in the meta-dataset, many of the customer characteristics variables were statistically significant in the model, even if the marginal effect of the variable was negligible and/or collinear with other variables. Basically, many of the variables in the original specification were statistically significant, but not practically significant. In re-estimating the models, Nexant focused on the practical significance of each variable by conducting sensitivity tests to determine which variables have a substantive impact on the interruption cost estimates. Nexant also employed more recent model selection methods that have been developed since 2009, which significantly improved the rigor with which variables were selected for the model. This process led to a more parsimonious model that only included key variables. In turn, ICE Calculator users will have less customer characteristics information to provide and the associated inputs page will be far less cumbersome.

1.3 Overview of Model Selection Process

Figure 1-1 provides an overview of the model selection process. The entire dataset of interruption cost estimates for each customer class is first randomly divided into a test dataset (10% of the entire dataset) and a training dataset (the remaining 90%). The training dataset is used to train the model, which refers to the process of selecting variables for the final specification. The test dataset is excluded from the model training process so that it can be used as a test of the final model performance on unseen data, which refers to data that is completely separate from the model training process. Next, the training dataset is randomly divided into 10 equally sized parts. Then, each candidate model specification is estimated on nine of 10 parts of the training dataset. The estimated coefficients for each candidate model specification are subsequently used to predict interruption costs on the tenth part of the training dataset. This process, which is referred to as 10-fold cross-validation, is repeated nine times while withholding one of the remaining nine parts of the training dataset each time. Relevant accuracy metrics for each model specification are computed for each of the 10 parts of the training dataset. Those accuracy metrics are ranked to determine the final model specification through a backwards stepwise selection process. Next, the final model specification is run on the entire training dataset and the estimated coefficients are used to predict interruption costs for the test dataset. Relevant accuracy metrics for the test dataset are also computed. If model performance on the test dataset is similar, the final specification is then estimated on the entire dataset and those estimated coefficients make up the final model. This process is conducted for each of the three customer classes separately.

Figure 1-1: Overview of Model Selection Process



1.4 Variable Definitions and Units

There are many variables that are common among customer classes, so all variable definitions and units are provided in this section. Table 1-2 provides the units and definitions of variables that are used in the models for all customer classes.

Table 1-2: Units and Definitions of Variables for All Customer Classes

Variable Name	Variable Definition	Units
annual MWh	Annual MWh of customer	MWh
duration	Duration of power interruption scenario	Minutes
time of day	Time of day of power interruption scenario	Categorical – Morning (6 AM to 12 PM); Afternoon (12 to 5 PM; Evening (5 to 10 PM); Night (10 PM to 6 AM)
weekday	Time of week of power interruption scenario	Binary – Weekday = 1; Weekend = 0
summer	Time of year of power interruption scenario	Binary – Summer = 1; Non-summer = 0
warning	Whether power interruption scenario had advance warning	Binary – Warning = 1; No warning = 0

Table 1-3 provides the units and definitions of variables that are used in the models for both the small and medium/large C&I customer classes. For both C&I customer classes, the model selection process begins with separate variables for all eight of the industry groups in the table, with Agriculture, Forestry & Fishing as the reference category by default. However, given that each industry group is tested separately for inclusion in the model, only one or two industry variables may remain in the final model, in which case the dropped industry variables are relegated to the reference category. Within the reference category, there may be multiple industries with presumably varying interruption costs, but if the model selection process has shown that there are not any meaningful differences within the industries in the reference category, those industry variables will be grouped together. The same logic applies for other categorical variables.

Table 1-3: Units and Definitions of Variables for C&I Customers

Variable Name	Variable Definition	Units
industry	Customer business type, based on NAICS or SIC code	Categorical – Agriculture, Forestry & Fishing; Mining; Construction; Manufacturing; Transportation, Communication & Utilities; Wholesale & Retail Trade; Finance, Insurance & Real Estate; Services; Public Administration; Unknown
backup equipment	Presence of backup equipment at facility	Categorical – None; Backup Gen or Power Conditioning; Backup Gen and Power Conditioning

Finally, Table 1-4 provides the units and definitions of variables that are only used in the residential customer models.

Table 1-4: Units and Definitions of Variables for Residential Customers

Variable Name	Variable Definition	Units
household income	Household income	$
medical equip.	Presence of medical equipment in home	Binary – Medical equipment = 1; No medical equipment = 0
backup generation	Presence of backup generation in home	Binary – Backup = 1; No backup = 0
outage in last 12 months	Interruption of longer than 5 minutes within past year	Binary – Yes = 1; No = 0
# residents X-Y	Number of residents in home within X-Y age range	Number of people
housing	Type of housing	Categorical – Detached; Attached; Apartment/Condo; Mobile; Manufactured; Unknown

1.5 Report Organization

The remainder of this report proceeds as follows. Section 2 summarizes the regression modeling methodology and selection process that applies to all three customer classes – medium and large C&I, small C&I and residential. This is followed by three sections that describe the final model selection and provide the final regression coefficients for each customer class. Finally, Section 6 describes some of the study's limitations.

2. Methodology

This section summarizes the study methodology, including the regression model structure and selection process.

2.1 Model Structure

A two-part regression model was used to estimate the customer interruption cost functions (also referred to as customer damage functions). This is the same class of model used in the previous meta-study. The two-part model assumes that the zero values in the distribution of interruption costs are correctly observed zero values, rather than censored values. In the first step, a probit model is used to predict the probability that a particular customer will report any positive value versus a value of zero for a particular interruption scenario. This model is based on a set of independent variables that describe the nature of the interruption as well as customer characteristics. The predicted probabilities from this first stage are retained. In the second step, using a generalized linear model (GLM), interruption costs for only those customers who report positive costs are related to the same set of independent variables used in the first stage. Predictions are made from this model for all observations, including those with a reported interruption cost of zero. Finally, the predicted probabilities from the first part are multiplied by the estimated interruption costs from the second part to generate the final interruption cost predictions.

The functional form for the second part of the two-part model must take into account that the interruption cost distribution is bounded at zero and extremely right skewed (i.e. it has a long tail in the upper end of the distribution). Ordinary least squares (OLS) is not an appropriate functional form given these conditions. A simple way to define the customer damage function given the above constraints is to estimate the mean interruption cost, which is linked to the predictor variables through a logarithmic link function using a GLM.

The parameter values in the two-part model cannot be directly interpreted in terms of their influence on interruption costs because the relationships are among the variables in their logarithms. However, the estimated model produces a predicted interruption cost, given the values of variables in the models. To analyze the magnitude of the impact of variables in the model on interruption cost, it is necessary to compare the predictions made by the function under varying assumptions. For example, it is possible to observe the effect of duration on interruption cost by holding the other variables constant at their sample means. In this way one can predict average customer interruption costs of varying durations holding other factors constant statistically.

For a more detailed discussion of the two-part model, its functional form and the reasons why it is most appropriate for this type of data, refer to the methodology section of the 2009 report.

2.2 Summary of Model Selection Process

Nexant aimed to estimate a more parsimonious model that only included key predictor variables. This facilitates interruption cost estimation by simplifying the ICE Calculator interface and reducing the burden that ICE Calculator users face in providing numerous, accurate customer characteristics information. This section first outlines the steps involved in the model selection process that Nexant undertook, followed by a more detailed exposition of the problem at hand, and a justification for the method.

To select a more parsimonious model, Nexant conducted the following steps for each of the three customer classes:

1. Randomly sample 10% of the data and hold it out as the test dataset (assign other 90% as the training dataset);
2. Split training dataset into 10 randomly assigned, equally sized parts;
3. Start with the original specification (the global model) and identify model variables that are candidates for removal (all variables except ineligible lower power terms);
4. Remove one of the eligible model variables to yield a new model;
5. Estimate model on nine of 10 parts of the training dataset and retain estimates;
6. Use retained estimates from step 5 to predict on the tenth part of the training dataset, computing relevant accuracy metrics;
7. Repeat steps 5 and 6, cycling over each of the remaining 9 parts of the training dataset;
8. Take the average and standard deviation of the accuracy metrics from the predictions for each of 10 parts of the training dataset;
9. Repeat steps 4 through 8, for each possible candidate variable for removal;
10. Use saved accuracy metrics to rank models;
11. Exclude from the global model the variable, which when dropped, produced estimates that outperformed the rest;
12. Repeat steps 2 through 11 until only a constant remains;
13. Inspect results and select model that is parsimonious, yet sufficiently accurate according to the out-of-sample accuracy metrics described above; and
14. Test final model against the original global model using the test dataset to estimate model's performance on unseen data (ensures that the model predicts well for data that was not included in the model training process).

As discussed in Section 1, this model selection process draws from the recent model selection methods that have been developed since 2009,[9] which significantly improves the rigor with which variables are selected for the model. The remainder of this section describes this process in more detail.

[9] For a discussion of these methods, see: Varian, Hal R. "Big Data: New Tricks for Econometrics." *Journal of Economic Perspectives*. Volume 28, Number 2. Spring 2014. Pages 3–28. Available here: http://pubs.aeaweb.org/doi/pdfplus/10.1257/jep.28.2.3

2.3 Details of Model Selection Process

A model selection problem involves choosing a statistical model from a set of candidate models, given some data. In this case, the data were the pre-existing set of interruption cost surveys for each customer class. Nexant selected a candidate set of models that included the original model specification from the 2009 study, henceforth referred to as the global model, as well as all models that were nested in the global model, that is to say all models that occur when removing one of more predictor variables from the global model. This candidate set is appropriate for several reasons. First of all, nearly all of the variables that were available in the meta-dataset were already included in the global model. Secondly, all the variables in the global model are plausibly related to interruption costs, and are not simply spuriously correlated. For example, it is reasonable to conclude that a resident with medical equipment that requires a power supply would be willing to pay more to avoid a power interruption than a resident without such medical equipment. Similar conclusions can be made for the other predictor variables in the global model, across sectors, making all of them viable to include in candidate models. Furthermore, to introduce candidate models that feature predictors not already included in the global model, such as new characteristics or higher power terms, would make the task of selecting a more parsimonious model significantly more challenging. Adding new predictors to candidate models not only increases the complexity of those candidate models, but the number of candidate models increases exponentially, making selecting among them computationally challenging.[10] It therefore makes practical sense to limit the predictors used in candidate models to those used in the global model. Also in the interest of simplifying the selection process, Nexant restricted the specifications of the probit and GLM models to be identical. This was the same form that the original regression model took.

Nexant developed an iterative process to choose among the candidate set of models. This is a backwards stepwise selection method that parses down the global model one variable at a time. At each step of the process, a variable is removed from the prior model (the global model in the first step) and the resulting model is evaluated in out-of-sample tests using a variety of metrics. This is performed for all possible variables that can be excluded, and the model that performs best on average across the various metrics is retained, or rather its exclusion is retained, and becomes the prior model in the next step of the process. (Alternatively, one can consider the excluded variable as that which diminished the performance of the global model the least, relative to the other possible exclusions, although it was often the case that the performance improved.) The outcome at each step is carefully examined to determine whether an acceptably parsimonious model has been selected, and whether excluding a particular variable will severely diminish the model's predictive power, in which case that variable is retained in the final model.

The selection process uses rigorous out-of-sample testing to evaluate the performance of various models and ensure that the final model is not over-fitted.[11] Nexant divided the sample into a training dataset, used to fit models; a validation dataset, used to compare models; and a test

[10] It can be shown that a global model with n predictors has $2^n - 1$ possible nested models. Furthermore, when m new predictors are added to the global model, the number of possible nested models increases by $(2^m - 1)2^n$.

[11] Over-fitting occurs when a model describes random variation in the data. The problem manifests itself through good predictive performance on the fitted data, but poor predictive performance on unseen data that the model was not fitted to.

dataset, used as a final independent test to show how well the selected model will generalize to unseen data. The test dataset comprised 10% of the sample, and was "held out" throughout the model fitting and selection process. At each step of the selection process, the models were compared using 10-fold cross-validation. Ten-fold cross-validation divides the remaining sample data into ten equal size subsamples. Nine of those subsamples are used as the training dataset to fit the model, and the tenth is used to validate the performance of that fitted model and choose among models. This process is repeated ten times with each of the subsamples used once to validate the fitted model. This method reduces the likelihood of over-fitting the model by using unseen data in the validation step; models that generalize well to new data will be selected over those that do not. Furthermore, by "folding" the data and iterating over subsamples, each observation is used exactly once in the validation step, so all of the available data (other than the 10% in the test dataset) are used to select models.

Rather than rely on a single metric to select a model, Nexant computed several metrics, ranked models by each of these metrics, then averaged the ranks to give an overall rank across metrics. Root-mean-square error (RMSE), mean absolute error (MAE), and the coefficient of determination (R-squared) are computed in out-of-sample tests. RMSE measures the average prediction error of a model. The differences between observed and predicted values are computed, squared, and then averaged before the square root is taken to correct the units. Because errors are squared before the average, RMSE penalizes larger errors more than smaller errors. MAE also measures the average prediction error of a model. The differences between observed and predicted values are computed, their absolute value is taken, and then the absolute errors are averaged. Errors of every magnitude are penalized equally. In the case of both RMSE and MAE, values range from zero to infinity, and smaller values are preferred. R-squared measures the fraction of variation of the dependent variable that is explained by a model. Its values range from 0 to 1, and a larger value is preferred. At each step, an information theoretic approach is also used to produce a fourth ranking of models that is incorporated into the average. This ranking uses Akaike's Information Criterion (AIC), which is an estimate of the expected, relative distance between the fitted model and the unknown true mechanism that generated the observed data. It is a measure of the information that is lost when a model is used to approximate the true mechanism. A thorough exposition of the relative advantages and disadvantages of these different metrics is beyond the scope of this report. That said, by averaging the ranks obtained from each metric and choosing an overall winner, Nexant does not prioritize minimizing one kind of error over another, but rather adopts a holistic approach.

3. Medium and Large C&I Results

This section summarizes the results of the model selection process and provides the model coefficients for medium and large C&I customers, which are C&I customers with annual usage of 50,000 kWh or above.

3.1 Final Model Selection

The global model for medium and large C&I customers is shown below:

$$Interruption\ Cost = f(\ln(annual\ MWH), duration, duration^2, duration \times \ln(annual\ MWh), duration^2 \times \ln(annual\ MWh), weekday, warning, summer, industry, time\ of\ day, backup\ equipment)$$

Interruption cost is expressed as a function of various explanatory variables. Note that the dependent variables differ between the probit and GLM models; hence the above equation expresses the two-part model in its most general form. Industry, time of day and backup equipment are all categorical variables, and their respective categories are shown in Table 3-1 below. As is typical in indicatory coding, the first category within each categorical variable is not included explicitly as a binary variable, but rather serves as a reference category.

Table 3-1: Breakdown of Categorical Variables Featured in Global Model – Medium and Large C&I

Variable	Categories
industry	Agriculture, Forestry & Fishing; Mining; Construction; Manufacturing; Transportation, Communication & Utilities; Wholesale & Retail Trade; Finance, Insurance & Real Estate; Services; Public Administration; Unknown
time of day	Night (10 PM to 6 AM); Morning (6 AM to 12 PM); Afternoon (12 to 5 PM); Evening (5 to 10 PM)
backup equipment	None; Backup Gen or Power Conditioning; Backup Gen and Power Conditioning

The global model was successfully parsed down to only key variables. In selecting among variables, categorical variables were not treated as a set (either all or none removed), but rather each binary variable was removed one at a time. This allowed for a particularly important category to remain, while others that might have had a smaller effect were no longer represented. Table 3-2 shows the results of each step in the process. Each iteration represents the exclusion of a variable from the global model, and the variable listed is the one that, when excluded, produces the model with the best performance across various metrics in out-of-sample tests. The model's value and rank (relative to the other possible exclusions) in the metrics is listed, along with its overall rank, which is an average of the individual ranks. Note that iteration zero represents the global model alone, so some metrics that are only meaningful when compared with other models, such as ranks and AICs, are not listed. The highlighted row shows the final exclusion that was made; the rows that follow show the variables that remain in the final model. Ultimately, interruption costs for medium and large C&I customers can be estimated relatively accurately with a few variables and interactions representing customer usage and interruption duration, along with binary variables for manufacturing customers and for power interruptions that occur during the summer. A few of the 15 excluded variables show a minor improvement in predictive accuracy, but considering how difficult it can be for ICE Calculator users to find information for some of those inputs, this minor improvement in predictive accuracy was not sufficient to justify keeping those variables in the final model.

Table 3-2: Excluded Variables and Relevant Metrics from Backwards Stepwise Selection Process – Medium and Large C&I

Iteration	Excluded Variable	RMSE		MAE		R2		AIC			Overall Rank
		Value (Thousands)	Rank	Value (Thousands)	Rank	Value	Rank	Probit Value (Thousands)	GLM Value (Thousands)	Rank	
0	-	116	-	29.6	-	0.143	-	-	-	-	-
1	*evening*	116	1	29.5	1	0.148	1	44.1	589	4.5	1.9
2	*weekday*	116	1	29.5	2	0.150	1	44.1	589	7.0	2.8
3	*morning*	116	1	29.5	2	0.151	1	44.3	589	9.5	3.4
4	*afternoon*	116	1	29.4	1	0.153	1	44.5	589	10.0	3.3
5	*wholesale & retail trade*	116	2	29.4	2	0.153	2	44.5	589	4.0	2.5
6	*backupgen and power conditioning*	116	1	29.4	3	0.155	1	44.6	589	8.5	3.4
7	*services*	116	1	29.4	1	0.155	1	44.7	589	8.5	2.9
8	*public administration*	116	3	29.5	2	0.155	3	44.7	589	2.5	2.6
9	*unknown*	116	1	29.5	3	0.155	1	44.7	590	3.0	2.0
10	*finance, insurance & real estate*	116	1	29.5	1	0.154	1	44.7	590	4.0	1.8
11	*transportation, communication & utilities*	116	1	29.5	2	0.154	1	44.7	591	4.5	2.1
12	*construction*	116	1	29.5	1	0.154	1	44.8	591	4.5	1.9
13	*mining*	116	1	29.5	1	0.153	1	44.8	591	2.5	1.4
14	*backupgen or power conditioning*	116	1	29.5	1	0.152	1	44.8	591	1.0	1.0
15	*warning*	116	1	29.6	1	0.148	1	44.9	592	2.5	1.4
16	*manufacturing*	117	1	29.9	2	0.137	1	45.0	595	2.5	1.6
17	*summer*	117	1	30.0	1	0.128	1	45.4	595	1.5	1.1
18	*duration^2 x ln(annual MWh)*	119	1	30.5	1	0.106	1	45.5	595	1.0	1.0
19	*duration x ln(annual MWh)*	120	1	30.7	1	0.096	1	45.5	595	1.0	1.0
20	*duration^2*	129	2	32.8	1	-0.054	2	46.2	598	1.0	1.5
21	*duration*	118	1	31.3	1	0.118	1	47.8	604	1.5	1.1
22	*ln(MWh annual)*	126	1	37.4	1	0.000	1	48.7	640	1.0	1.0

The final model for medium/large C&I customers is shown below:

$$Interruption\ Cost = f(\ln(annual\ MWH),\ duration, duration^2,\ duration \times \ln(annual\ MWh),\ duration^2 \times \ln(annual\ MWh),\ summer,\ industry)$$

Manufacturing is the only remaining industry category in the model. Note that as categories are removed, they are relegated to the reference category, so for example the manufacturing binary variable should now be interpreted as the average impact on interruption cost associated with being in the manufacturing industry, relative to all other industries.

To confirm that the selection process did not produce an over-fitted model, and to estimate the predictive performance of the final model when evaluated on unseen data, Nexant evaluated the final model against the global model using the test dataset, which is the 10% of data that was held out from the backwards stepwise selection process. Both models were fitted to the remaining data, and then the test dataset was used to evaluate their predictive performance.

The results are shown in Table 3-3. The final model outperforms the global model in each accuracy metric.

Table 3-3: Test Dataset Predictive Performance Metrics for Final and Initial Models – Medium and Large C&I

Model	RMSE (Thousands)	MAE (Thousands)	R-squared
Final	111	29.6	0.118
Global	111	29.8	0.115

3.2 Model Coefficients

Nexant then estimated the final two-part regression model specification on the full dataset for medium and large C&I customers. Table 3-4 describes the final probit regression model that specifies the relationship between the presence of zero interruption costs and a set of independent variables that includes interruption characteristics, customer usage, and industry designation. Although the purpose of this preliminary limited dependent variable model is only to normalize the predictions from the interruption costs regression in the second part of the two-part model, there are a few interesting results to note (these remain consistent with the original specification):

- All of the coefficients are statistically significant at a less than 1% level;
- The longer the interruption, the more likely that the costs associated with it are positive (the presence of a negative coefficient on the square of duration indicates that this effect diminishes for longer durations);
- Summer interruptions are more likely to incur costs than non-summer interruptions; and
- Manufacturing industry customers are more likely to incur costs than non-manufacturing industry customers.

Table 3-4: Regression Output for Probit Estimation – Medium and Large C&I

Variable	Coefficient	Standard Error	P-Value
Interruption Characteristics			
duration	0.005	0.000	0.000
duration^2	-2.820E-06	0.000	0.000
summer	0.410	0.023	0.000
Customer Characteristics			
ln(annual MWh)	0.118	0.006	0.000
Interactions			
duration x ln(annual MWh)	-3.416E-04	0.000	0.000
duration^2 *x ln(annual MWh)*	1.640E-07	0.000	0.000
Industry			
manufacturing	0.200	0.025	0.000
Constant	-0.958	0.047	0.000

Table 3-5 describes the final GLM regression model, which relates the level of interruption costs to customer usage and interruption characteristics as well as industry designation. A few results of note:

- The longer the interruption, the higher the interruption cost;
- Larger customers (in terms of annual MWh usage) incur larger costs for similar interruptions (however, interruption costs increase at a decreasing rate as usage increases);
- Manufacturing industry customers incur larger costs for similar interruptions than equivalent non-manufacturing customers;
- The difference between summer and non-summer interruption costs is statistically insignificant (all other coefficients are statistically significant).

Table 3-5: Customer Regression Output for GLM Estimation – Medium and Large C&I

Variable	Coefficient	Standard Error	P-Value
Interruption Characteristics			
duration	0.006	0.001	0.000
duration^2	-3.260E-06	0.000	0.000
summer	0.113	0.060	0.058
Customer Characteristics			
ln(annual MWh)	0.495	0.016	0.000
Interactions			
duration x ln(annual MWh)	-1.882E-04	0.000	0.047
duration^2 x ln(annual MWh)	1.480E-07	0.000	0.028
Industry			
manufacturing	0.823	0.069	0.000
Constant	5.292	0.127	0.000

Finally, Table 3-6 shows the average values of the regression inputs for medium and large C&I customers, which are useful for modeling purposes and for assessing marginal effects. Other descriptive statistics are also provided.

Table 3-6: Descriptive Statistics for Regression Inputs – Medium and Large C&I

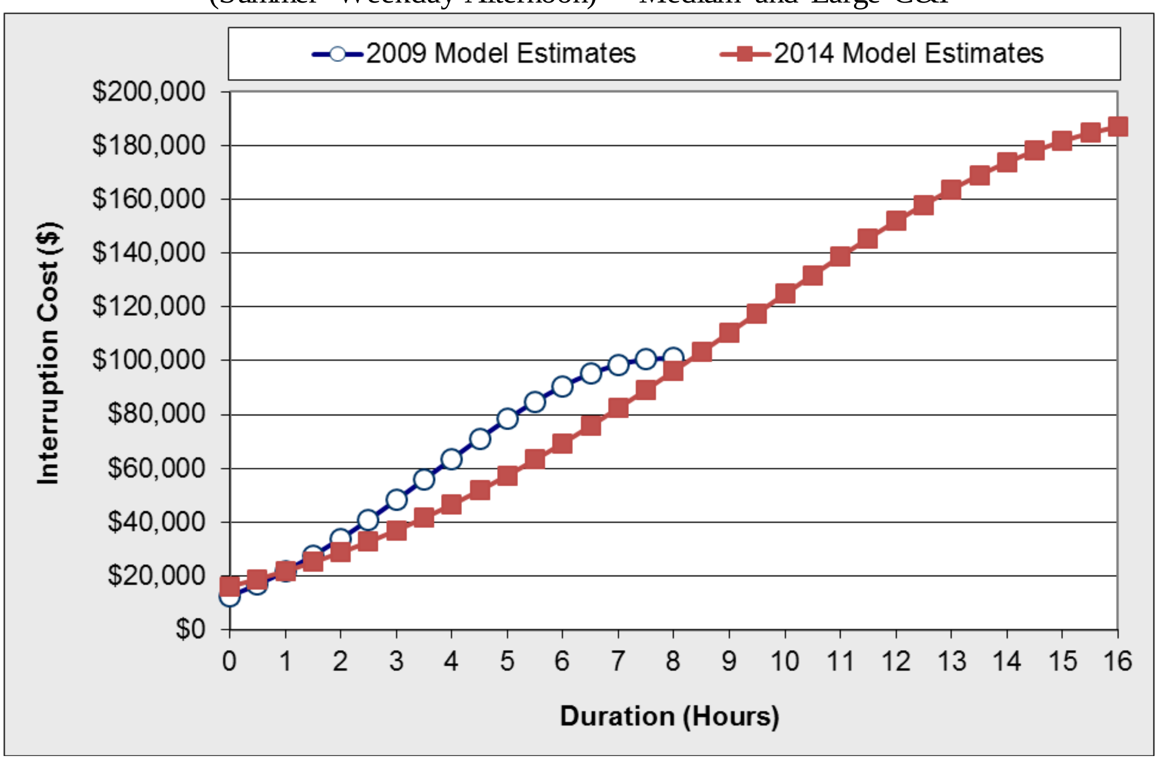
Variable	N	Average	Minimum	25th Percentile	Median	75th Percentile	Maximum
Interruption Characteristics							
duration	44,328	162	0	60	60	240	1,440
duration^2	44,328	82,724	0	3,600	3,600	57,600	2,073,600
summer	44,328	86.5%	0%	100%	100%	100%	100%
Customer Characteristics							
ln(annual MWh)	44,328	6.6	3.9	4.9	6.2	7.9	13.9

Variable	N	Average	Minimum	25th Percentile	Median	75th Percentile	Maximum
Interactions							
duration x ln(annual MWh)	44,328	1,060	0	255	437	1,327	17,064
duration^2 x ln(annual MWh)	44,328	530,872	0	14,881	26,250	317,870	24,600,000
Industry							
manufacturing	44,328	23.3%	0%	0%	0%	0%	100%

3.3 Comparison of 2009 and 2014 Model Estimates

Figure 3-1 provides a comparison of the 2009 model estimates and the 2014 model estimates by interruption duration, in 2013 dollars. The 2014 model estimates have been extended to 16 hours because the addition of data on 24-hour power interruption scenarios has allowed to model to more reliably predict costs up to 16 hours. The magnitude of the interruption cost estimates is similar between the two models, but there is a noticeable change in the functional form, which is attributable to the addition of the longer duration scenarios and to the significant change in the model specification. The functional form is more linear and no longer levels off at 8 hours, which seems more plausible.

Figure 3-1: Estimated Customer Interruption Costs (U.S.2013$) by Duration and Model (Summer Weekday Afternoon) – Medium and Large C&I



3.4 Interruption Cost Estimates and Key Drivers

Table 3-7 shows how medium and large C&I customer interruption costs vary by season. Considering that time of day and day of week were not important factors in the model for medium and large C&I customers, the only temporal variable to consider is season (summer or non-summer). The cost of a summer power interruption is around 21% to 43% higher than a non-summer one, depending on duration (the percent difference lowers as duration increases). Considering that the non-summer time period (October through May) accounts for two-thirds of the year, the weighted-average interruption cost estimate is closer to the non-summer estimate. This weighted-average interruption cost estimate is most appropriate to use for planning purposes, unless the distribution of interruptions by season is known.

Table 3-7: Estimated Customer Interruption Costs (U.S.2013$) by Duration and Timing of Interruption – Medium and Large C&I

Timing of Interruption	% of Hours per Year	Interruption Duration					
		Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Summer	33%	$16,172	$18,861	$21,850	$46,546	$96,252	$186,983
Non-summer	67%	$11,342	$13,431	$15,781	$35,915	$77,998	$154,731
Weighted Average		**$12,952**	**$15,241**	**$17,804**	**$39,458**	**$84,083**	**$165,482**

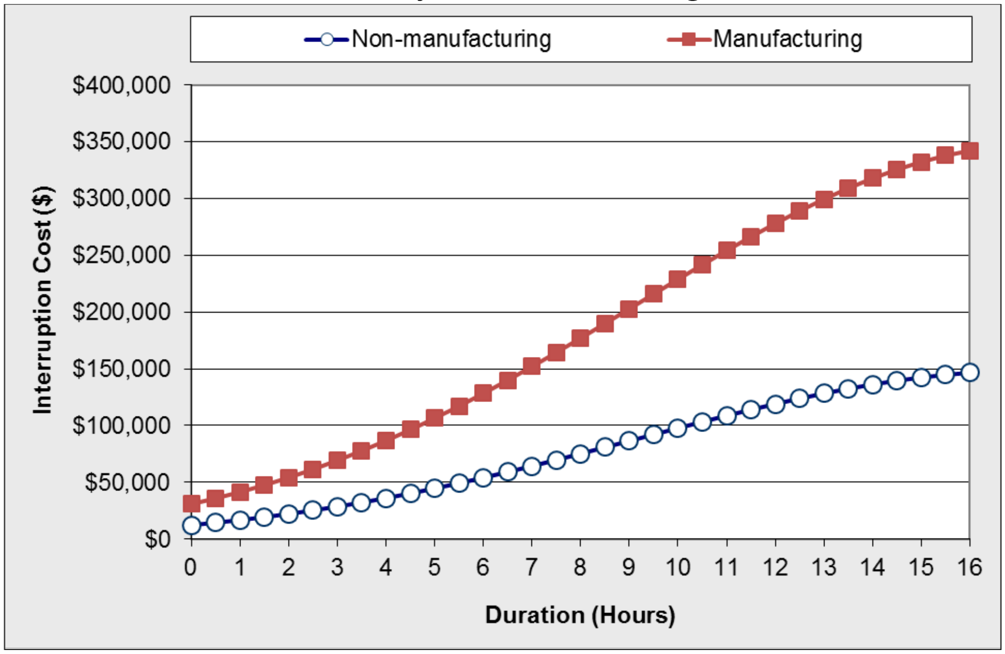
Based on the weighted-average interruption cost estimate, Table 3-8 provides cost per event (equal to the weighted-average interruption cost), cost per average kW and cost per unserved kWh for medium and large C&I customers. Cost per unserved kWh is relatively high for a momentary interruption because the expected amount of unserved kWh over a 5-minute period is relatively low.

Table 3-8: Cost per Event, Average kW and Unserved kWh – Medium and Large C&I

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Cost per Event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
Cost per Average kW	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per Unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7

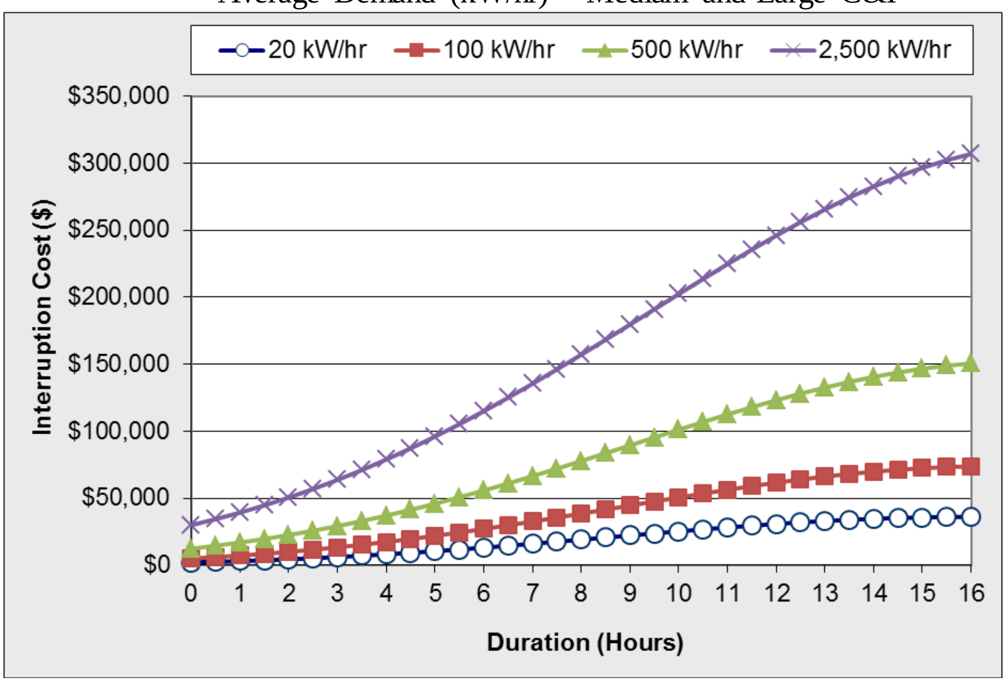
Figure 3-2 shows the medium and large C&I interruption costs in the summer for non-manufacturing and manufacturing customers. As in the 2009 model, interruption costs in the manufacturing sector are relatively high. At all durations, the estimated interruption cost for manufacturing customers is more than double the cost for non-manufacturing customers. This is a key driver to consider for planning purposes – whether the planning area of interest includes medium and large C&I customers with manufacturing facilities that may be particularly sensitive to power interruptions.

Figure 3-2: Estimated Summer Customer Interruption Costs (U.S.2013$) by Duration and Industry – Medium and Large C&I



Finally, Figure 3-3 shows the medium and large C&I interruption costs in the summer for various levels of average demand. As discussed above, medium and large C&I interruption costs increase at a decreasing rate as usage increases. This pattern is notable in the figure. Each increment in average demand represents a 5-fold increase in usage, but interruption costs only increase by a factor of 2.0 to 2.5 from one level of average demand to the next.

Figure 3-3: Estimated Summer Customer Interruption Costs (U.S.2013$) by Duration and Average Demand (kW/hr) – Medium and Large C&I



4. Small C&I Results

This section summarizes the results of the model selection process and provides the model coefficients for small C&I customers, which are C&I customers with annual usage of less than 50,000 kWh.

4.1 Final Model Selection

The global model for small C&I customers was identical to that for the medium and large C&I customers. Refer to Section 3.1 above for a discussion of the global model specification. The global model was successfully parsed down to only key variables. In selecting among variables, categorical variables were not treated as a set (either all or none removed), but rather each binary variable was removed one at a time. This allowed for a particularly important category to remain, while others that might have had a smaller effect were no longer represented. Table 4-1 shows the results of each step in the process. Each iteration represents the exclusion of a variable from the global model, and the variable listed is the one that, when excluded, produces the model with the best performance across various metrics in out-of-sample tests. The model's value and rank (relative to the other possible exclusions) in the metrics is listed, along with its overall rank, which is an average of the individual ranks. Note that iteration zero represents the global model alone, so some metrics that are only meaningful when compared with other models, such as ranks and AICs, are not listed. The highlighted row shows the final exclusion that was made; the rows that follow show the variables that remain in the final model. Ultimately, interruption costs for small C&I customers can be estimated relatively accurately with variables representing customer usage and interruption duration, along with some binary variables for customer characteristics and interruption timing. Considering how difficult it can be for ICE Calculator users to find information for some of the 12 excluded variables (especially for small C&I customers), this final model will be much easier to use.

Table 4-1: Excluded Variables and Relevant Metrics from Backwards Stepwise Selection Process – Small C&I

Iteration	Excluded Variable	RMSE		MAE		R2		AIC			Overall Rank
		Value (Thousands)	Rank	Value (Thousands)	Rank	Value	Rank	Probit Value (Thousands)	GLM Value (Thousands)	Rank	
0	-	6.17	-	1.95	-	0.044	-	-	-	-	-
1	*transportation, comunication & utilities*	6.16	1	1.94	2	0.048	1	30.6	245	8.0	3.0
2	*mining*	6.16	1	1.94	1	0.049	1	30.6	245	7.0	2.5
3	*warning*	6.16	1	1.94	3	0.049	1	30.6	245	4.5	2.4
4	*evening*	6.16	1	1.94	2	0.049	2	30.6	245	4.0	2.3
5	*duration^2 x ln(annual MWh)*	6.16	1	1.94	3	0.049	2	30.6	245	3.0	2.3
6	*finance, insurance & real estate*	6.16	2	1.94	4	0.049	2	30.7	245	5.5	3.4
7	*unknown industry*	6.16	5	1.94	2	0.049	2	30.7	245	5.5	3.6
8	*duration x ln(annual MWh)*	6.16	3	1.94	2	0.049	2	30.7	245	1.5	2.1
9	*public administration*	6.16	2	1.94	3	0.049	4	30.7	245	2.0	2.8
10	*weekday*	6.16	2	1.94	3	0.048	3	30.7	245	3.5	2.9
11	*wholesale & retail trade*	6.16	1	1.94	1	0.049	1	30.9	245	7.5	2.6
12	*services*	6.16	2	1.94	1	0.049	3	30.9	245	2.0	2.0
13	*morning*	6.16	2	1.95	2	0.048	2	31.4	245	4.5	2.6
14	*afternoon*	6.16	1	1.95	2	0.048	1	31.5	245	3.0	1.8
15	*summer*	6.17	1	1.95	1	0.047	1	31.8	245	4.5	1.9
16	*ln(annual MWh)*	6.17	1	1.96	3	0.045	1	32.0	245	3.0	2.0
17	*backupgen and power conditioning*	6.19	2	1.97	1	0.041	1	32.1	246	2.5	1.6
18	*backupgen or power conditioning*	6.20	1	1.98	1	0.036	1	32.1	246	2.0	1.3
19	*manufacturing*	6.22	1	2.00	2	0.029	1	32.1	246	1.5	1.4
20	*construction*	6.24	1	2.01	1	0.023	1	32.2	247	1.0	1.0
21	*duration^2*	6.52	1	2.16	1	-0.089	1	32.8	248	1.0	1.0
22	*duration*	6.32	1	2.13	1	-0.001	1	34.2	251	1.0	1.0

The final model for small C&I customers is shown below:

$$Interruption\ Cost = f\left(\ln(annual\ MWH), duration, duration^2, summer, industry, backup\ equipment, time\ of\ day\right)$$

Industry, backup equipment and time of day are the only categorical variables remaining, and many of the categories were removed. Note that as categories are removed, they are relegated to the reference category, so for example the construction binary variable should now be interpreted as the average impact on interruption cost associated with being in the construction industry, relative to all industries other than manufacturing, which is the only other industry that was retained as a binary variable. The categories that remain in the final model are shown in Table 4-2 below.

Table 4-2: Breakdown of Categorical Variables Featured in Final Model – Small C&I

Variable	Categories
industry	Other; Construction; Manufacturing
backup equipment	None; Backup Gen or Power Conditioning; Backup Gen and Power Conditioning
time of day	Other (5 PM to 6 AM); Morning (6 AM to 12 PM); Afternoon (12 to 5 PM)

To confirm that the selection process did not produce an overfitted model, and to estimate the predictive performance of the final model when evaluated on unseen data, Nexant evaluated the final model against the global model using the test dataset, which is the 10% of data that was held out from the backwards stepwise selection process. Both models were fitted to the remaining data, and then the test dataset was used to evaluate their predictive performance. The results are shown in Table 4-3. Note that while the global model outperforms the final model in each metric, the differences between the values are very small. The final model offers a much simpler solution with comparable performance to the global model.

Table 4-3: Test Dataset Predictive Performance Metrics for Final and Initial Models – Small C&I

Model	RMSE (Thousands)	MAE (Thousands)	R-squared
Final	5.50	1.82	0.045
Global	5.49	1.82	0.048

4.2 Model Coefficients

Nexant then estimated the final two-part regression model specification on the full dataset for residential customers. Table 4-4 describes the final probit regression model that specifies the relationship between the presence of zero interruption costs and a set of independent variables that includes interruption characteristics, customer characteristics, and industry designation. Although the purpose of this preliminary limited dependent variable model is only to normalize the predictions from the interruption costs regression in the second part of the two-part model, there are a few interesting results to note (these remain consistent with the original specification):

- All of the coefficients are statistically significant at a less than 1% level;
- The longer the interruption, the more likely that the costs associated with it are positive (the presence of a negative coefficient on the square of duration indicates that this effect diminishes for longer durations);
- Summer interruptions are more likely to incur costs than non-summer interruptions;
- Afternoon interruptions are more likely to incur costs than any other time of day; and
- Manufacturing and construction customers are more likely to incur costs than customers in other industries.

Table 4-4: Customer Regression Output for Probit Estimation – Small C&I

Variable	Coefficient	Standard Error	P-Value
Interruption Characteristics			
duration	0.003	0.000	0.000
duration^2	-1.780E-06	0.000	0.000
summer	0.215	0.030	0.000
morning	0.537	0.022	0.000
afternoon	0.664	0.029	0.000

Variable	Coefficient	Standard Error	P-Value
Customer Characteristics			
ln(annual MWh)	0.124	0.013	0.000
backupgen or power conditioning	0.082	0.025	0.001
backupgen and power conditioning	0.272	0.059	0.000
Industry			
construction	0.261	0.054	0.000
manufacturing	0.176	0.042	0.000
Constant	-1.332	0.048	0.000

Table 4-5 describes the final GLM regression model, which relates the level of interruption costs to customer and interruption characteristics as well as industry designation. A few results of note:

- The longer the interruption, the higher the interruption cost;
- Larger customers (in terms of annual MWh usage) incur larger costs for similar interruptions (however, interruption costs increase at a decreasing rate as usage increases);
- Manufacturing and construction industry customers incur larger costs for similar interruptions than equivalent customers in other industries; and
- Summer interruptions incur lower interruption costs than other times of the year.

Table 4-5: Customer Regression Output for GLM Estimation – Small C&I

Variable	Coefficient	Standard Error	P-Value
Interruption Characteristics			
duration	0.004	0.000	0.000
duration^2	-2.160E-06	0.000	0.000
summer	-0.384	0.073	0.000
morning	-0.057	0.070	0.413
afternoon	-0.032	0.083	0.701
Customer Characteristics			
ln(annual MWh)	0.069	0.035	0.046
backupgen or power conditioning	0.308	0.058	0.000
backupgen and power conditioning	0.538	0.129	0.000
Industry			
construction	0.786	0.153	0.000
manufacturing	0.587	0.104	0.000
Constant	7.000	0.135	0.000

Finally, Table 4-6 shows the average values of the regression inputs for small C&I customers, which are useful for modeling purposes and for assessing marginal effects. Other descriptive statistics are also provided.

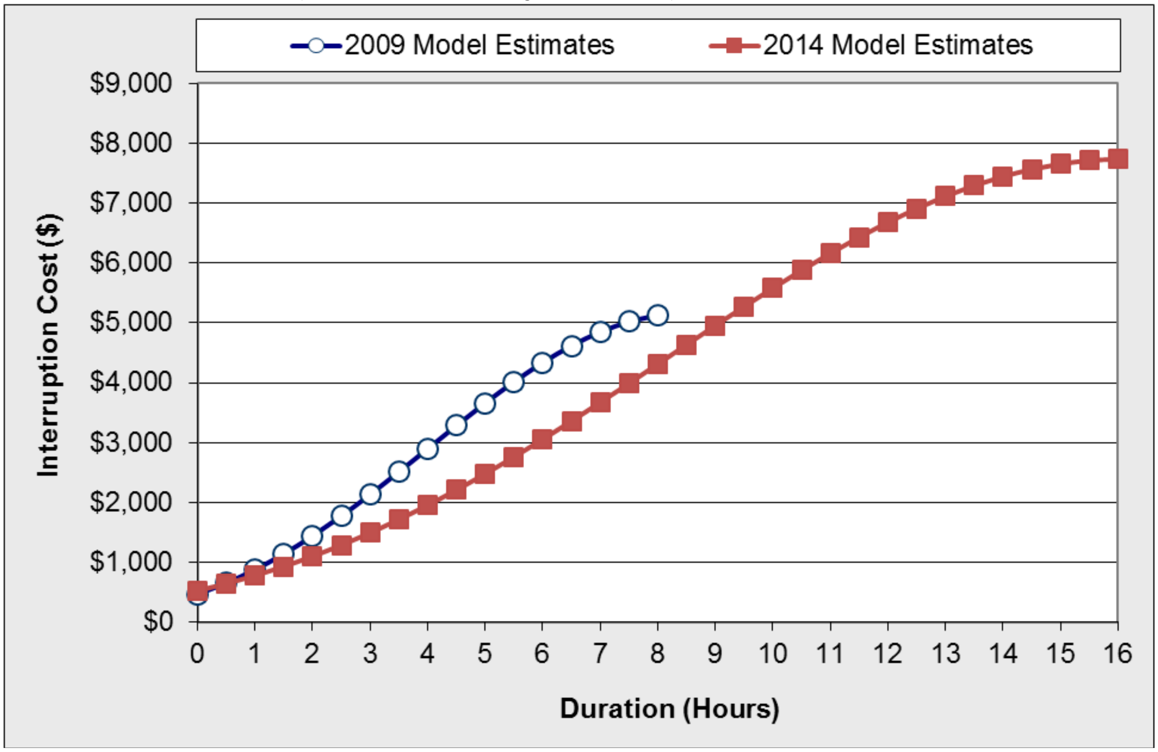
Table 4-6: Descriptive Statistics for Regression Inputs – Small C&I

Variable	N	Average	Minimum	25th Percentile	Median	75th Percentile	Maximum
Interruption Characteristics							
duration	27,751	191	0	60	60	240	1,440
duration^2	27,751	107,425	0	3,600	3,600	57,600	2,073,600
summer	27,751	89.3%	0%	100%	100%	100%	100%
morning	27,751	45.5%	0%	0%	0%	100%	100%
afternoon	27,751	37.6%	0%	0%	0%	100%	100%
Customer Characteristics							
ln(annual MWh)	27,751	2.6	-2.0	2.2	2.8	3.3	3.9
backupgen or power conditioning	27,751	27.1%	0%	0%	0%	100%	100%
backupgen and power conditioning	27,751	3.5%	0%	0%	0%	0%	100%
Industry							
construction	27,751	4.6%	0%	0%	0%	0%	100%
manufacturing	27,751	7.8%	0%	0%	0%	0%	100%

4.3 Comparison of 2009 and 2014 Model Estimates

Figure 4-1 provides a comparison of the 2009 model estimates and the 2014 model estimates by interruption duration, in 2013 dollars. The 2014 model estimates have been extended to 16 hours because the addition of data on 24-hour power interruption scenarios has allowed to model to more reliably predict costs up to 16 hours. As with medium and large C&I customers, the magnitude of the interruption cost estimates is similar between the two small C&I models, but there is a noticeable change in the functional form. This change is attributable to the addition of the longer duration scenarios and to the significant change in the model specification. The functional form is more linear and no longer levels off at 8 hours, which seems more plausible.

Figure 4-1: Estimated Customer Interruption Costs (U.S.2013$) by Duration and Model (Summer Weekday Afternoon) – Small C&I



4.4 Interruption Cost Estimates and Key Drivers

Table 4-7 shows how small C&I customer interruption costs vary by season and time of day. The cost of a summer power interruption is around 9% to 30% lower than a non-summer one, depending on duration, season, and time of day. Interestingly, this is opposite the pattern of medium and large C&I customers, which experience higher interruption costs during the summer. As for how interruption costs vary by time of day, costs are highest in the afternoon and are similarly high in the morning. In the evening and nighttime, small C&I interruption costs are substantially lower, which makes sense given that small businesses typically operate during daytime hours. Considering that the evening/night time period (5 PM to 6 AM) accounts for a majority of the hours of the day, the weighted-average interruption cost estimate is closer to the evening/night estimates. This weighted-average interruption cost estimate is most appropriate to use for planning purposes, unless the distribution of interruptions by season and time of day is known.

Table 4-7: Estimated Customer Interruption Costs (U.S.2013$) by Duration and Timing of Interruption – Small C&I

Timing of Interruption	% of Hours per Year	Interruption Duration					
		Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Summer Morning	8%	$461	$569	$692	$1,798	$4,073	$7,409
Summer Afternoon	7%	$527	$645	$780	$1,954	$4,313	$7,737
Summer Evening/Night	18%	$272	$349	$440	$1,357	$3,518	$6,916
Non-summer Morning	17%	$549	$687	$848	$2,350	$5,592	$10,452
Non-summer Afternoon	14%	$640	$794	$972	$2,590	$5,980	$10,992
Non-summer Evening/Night	36%	$298	$388	$497	$1,656	$4,577	$9,367
Weighted Average		**$412**	**$520**	**$647**	**$1,880**	**$4,690**	**$9,055**

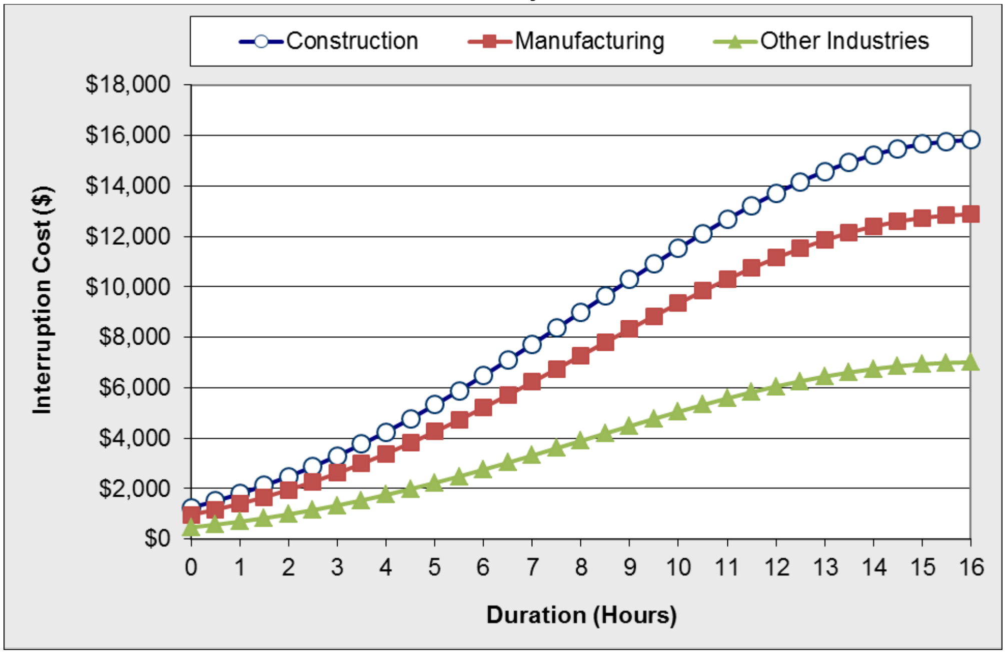
Based on the weighted-average interruption cost estimate, Table 4-8 provides cost per event (equal to the weighted-average interruption cost), cost per average kW, and cost per unserved kWh for small C&I customers. Cost per unserved kWh is relatively high for a momentary interruption because the expected amount of unserved kWh over a 5-minute period is relatively low.

Table 4-8: Cost per Event, Average kW and Unserved kWh – Small C&I

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Cost per Event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per Average kW	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per Unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0

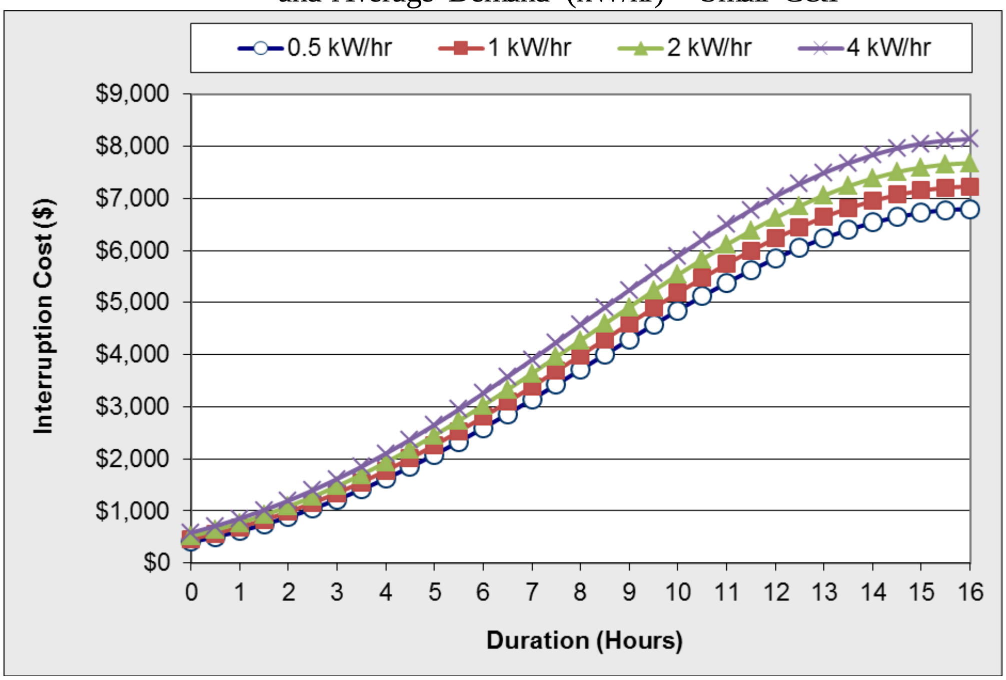
Figure 4-2 shows the small C&I interruption costs in the summer afternoon by industry. As in the 2009 model, interruption costs in the manufacturing and construction sectors are relatively high. At all durations, the estimated interruption cost for manufacturing and construction customers is around double or more the cost for customers in other industries. As in the medium and large C&I customer class, this is a key driver to consider for planning purposes – whether the planning area of interest includes small C&I customers with manufacturing or construction facilities that may be particularly sensitive to power interruptions.

Figure 4-2: Estimated Summer Afternoon Customer Interruption Costs (U.S.2013$) by Duration and Industry – Small C&I



Finally, Figure 4-3 shows the small C&I interruption costs in the summer afternoon for various levels of average demand. Small C&I interruption costs are not highly sensitive to the average demand of a customer. In the figure, each increment in average demand represents a 2-fold increase in usage, but interruption costs only increase by around 10% from one level of average demand to the next.

Figure 4-3: Estimated Summer Afternoon Customer Interruption Costs (U.S.2013$) by Duration and Average Demand (kW/hr) – Small C&I



5. Residential Results

This section summarizes the results of the model selection process and provides the model coefficients for residential customers.

5.1 Final Model Selection

The global model for residential customers is shown below:

Interruption Cost = f(ln(annual MWh), duration, duration², household income, medical equip., backup generation, summer, weekday, outage in last 12 months, # residents 0-6, # residents 7-18, # residents 19-24, # residents 25-49, # residents 50-64, # residents over 64, time of day, housing)

Interruption cost is expressed as a function of various explanatory variables. Note that the dependent variables differ between the probit and GLM models; hence the above equation expresses the two-part model in its most general form. Time of day and housing are categorical variables, and their respective categories are shown in Table 5-1 below. As is typical in indicatory coding, the first category within each categorical variable is not included explicitly as a binary variable, but rather serves as a reference category.

Table 5-1: Breakdown of Categorical Variables Featured in Global Model – Residential

Variable	Categories
time of day	Morning (6 AM to 12 PM); Afternoon (12 to 5 PM); Evening (5 to 10 PM); Late Evening/Early Morning
housing	Detached; Attached; Apartment/Condo; Mobile; Manufactured; Unknown

The global model was successfully parsed down to only key variables. In selecting among variables, categorical variables were not treated as a set (either all or none removed), but rather each binary variable was removed one at a time. This allowed for a particularly important category to remain, while others that might have had a smaller effect were no longer represented. Table 5-2 shows the results of each step in the process. Each iteration represents the exclusion of a variable from the global model, and the variable listed is the one that, when excluded, produces the model with the best performance across various metrics in out-of-sample tests. The model's value and rank (relative to the other possible exclusions) in the metrics is listed, along with its overall rank, which is an average of the individual ranks. Note that iteration zero represents the global model alone, so some metrics that are only meaningful when compared with other models, such as ranks and AICs, are not listed. The highlighted row shows the final exclusion that was made; the rows that follow show the variables that remain in the final model. Ultimately, interruption costs for residential customers can be estimated relatively accurately with variables representing customer usage, household income, and interruption duration, along with some binary variables for interruption timing. A few of the 16 excluded variables show a minor improvement in predictive accuracy, but considering how difficult it can be for ICE Calculator users to find information for some of those inputs, this minor improvement in predictive accuracy was not sufficient to justify keeping those variables in the final model.

Table 5-2: Excluded Variables and Relevant Metrics from Backwards Stepwise Selection Process – Residential

Iteration	Excluded Variable	RMSE		MAE		R2		AIC			Overall Rank
		Value	Rank	Value	Rank	Value	Rank	Probit Value (Thousands)	GLM Value (Thousands)	Rank	
0	-	16.6	-	8.50	-	0.145	-	-	-	-	-
1	*late evening/early morning*	16.5	1	8.49	1	0.147	1	37.3	126	9.5	3.1
2	*mobile housing*	16.5	3	8.48	2	0.148	3	37.3	126	3.5	2.9
3	*outage in last 12 months*	16.5	1	8.48	1	0.149	1	37.3	126	9.5	3.1
4	*# residents 7-18 years old*	16.5	1	8.48	5	0.149	1	37.3	126	6.0	3.3
5	*# residents 25-49 years old*	16.5	2	8.48	3	0.149	2	37.3	126	6.5	3.4
6	*# residents 50-64 years old*	16.5	2	8.48	2	0.149	2	37.3	126	1.0	1.8
7	*manufactured housing*	16.5	2	8.48	2	0.149	2	37.3	126	4.0	2.5
8	*weekday*	16.5	1	8.48	2	0.149	1	37.3	126	5.5	2.4
9	*attached housing*	16.5	1	8.48	1	0.149	1	37.4	126	5.5	2.1
10	*apartment/condo*	16.5	3	8.48	2	0.149	3	37.4	126	1.0	2.3
11	*# residents 19-24 years old*	16.5	1	8.48	2	0.149	1	37.4	126	3.5	1.9
12	*backup generation*	16.5	1	8.48	1	0.149	1	37.4	126	4.0	1.8
13	*# residents 0-6 years old*	16.5	2	8.48	2	0.149	2	37.4	126	1.5	1.9
14	*unknown housing*	16.5	2	8.49	1	0.148	2	37.4	126	1.5	1.6
15	*medical equipment*	16.5	1	8.49	2	0.148	1	37.5	126	2.5	1.6
16	*# residents 65 and over*	16.6	1	8.49	1	0.146	1	37.5	126	2.5	1.4
17	*household income*	16.6	1	8.53	1	0.140	1	37.5	127	2.5	1.4
18	*evening, 5 pm to 8 pm*	16.7	1	8.61	2	0.133	1	38.7	127	3.0	1.8
19	*afternoon, 12 noon to 4 pm*	16.7	1	8.63	1	0.127	1	38.9	127	2.0	1.3
20	*summer*	16.8	1	8.71	1	0.119	1	39.7	127	2.0	1.3
21	*ln(annual MWh)*	17.0	1	8.82	1	0.098	1	39.7	128	1.5	1.1
22	*duration^2*	17.3	1	8.95	1	0.072	1	39.9	128	1.0	1.0
23	*duration*	17.9	1	9.44	1	0.000	1	41.6	130	1.0	1.0

The final model for residential customers is shown below:
Interruption Cost = f(ln(annual MWh), duration, duration^2, household income, summer, time of day)

To confirm that the selection process did not produce an over-fitted model, and to estimate the predictive performance of the final model when evaluated on unseen data, Nexant evaluated the final model against the global model using the test dataset, which is the 10% of data that was held out from the backwards stepwise selection process. Both models were fitted to the remaining data, and then the test dataset was used to evaluate their predictive performance. The results are shown in Table 5-3. Note that while the global model outperforms the final model in each metric, the differences between the values are very small. The final model offers a much simpler solution with comparable performance to the global model.

Table 5-3: Test Dataset Predictive Performance Metrics for Final and Initial Models – Residential

Model	RMSE	MAE	R-squared
Final	17.5	8.34	0.148
Global	17.3	8.28	0.165

5.2 Model Coefficients

Nexant then estimated the final two-part regression model specification on the full dataset for residential customers. Table 5-4 describes the final probit regression model that specifies the relationship between the presence of zero interruption costs and a set of independent variables that includes interruption characteristics and customer characteristics. Although the purpose of this preliminary limited dependent variable model is only to normalize the predictions from the interruption costs regression in the second part of the two-part model, there are a few interesting results to note (these remain consistent with the original specification):

- All of the coefficients are statistically significant at a less than 5% level;
- The longer the interruption, the more likely that the costs are positive (the presence of a negative coefficient on the square of duration indicates that this effect diminishes for longer durations);
- Customers are less likely to have a positive cost for an afternoon or an evening interruption versus any other time of day.

Table 5-4: Regression Output for Probit Estimation – Residential

Variable	Coefficient	Standard Error	P-Value
Interruption Characteristics			
duration	0.003	0.000	0.000
duration^2	-1.130E-06	0.000	0.000
summer	0.541	0.019	0.000
afternoon	-0.266	0.026	0.000
evening	-0.755	0.024	0.000
Customer Characteristics			
ln(annual MWh)	0.038	0.018	0.035
household income	9.660E-07	0.000	0.004
Constant	-0.266	0.051	0.000

Table 5-5 describes the final GLM regression model which relates the level of interruption costs to customer and interruption characteristics. A few results of note:

- All of the coefficients are statistically significant at a less than 5% level;
- The longer the interruption, the higher the interruption cost;

- Customers have lower interruption costs for afternoon and evening interruptions than for those that occur at other times of day;
- Customers experience higher costs for summer interruptions than for non-summer interruptions; and
- Larger customers (in terms of annual MWh usage) have a higher cost for similar interruptions than otherwise equivalent, smaller customers.

Table 5-5: Regression Output for GLM Estimation – Residential

Variable	Coefficient	Standard Error	P-Value
Interruption Characteristics			
duration	0.002	0.000	0.000
duration^2	-9.450E-07	0.000	0.000
summer	0.161	0.029	0.000
afternoon	-0.282	0.041	0.000
evening	-0.095	0.047	0.044
Customer Characteristics			
ln(annual MWh)	0.249	0.028	0.000
household income	1.850E-06	0.000	0.000
Constant	1.379	0.080	0.000

Finally, Table 5-6 shows the average values of the regression inputs for residential customers, which are useful for modeling purposes and for assessing marginal effects. Other descriptive statistics are also provided.

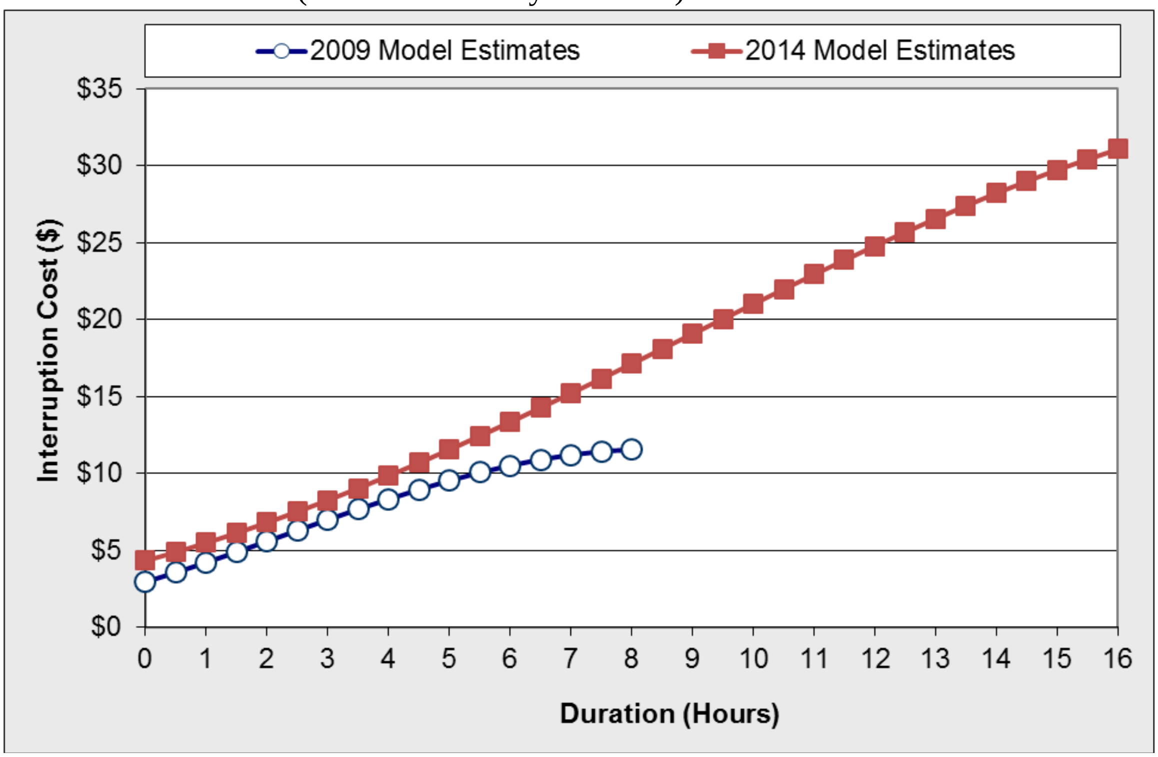
Table 5-6: Descriptive Statistics for Regression Inputs – Residential

Variable	N	Average	Minimum	25th Percentile	Median	75th Percentile	Maximum
Interruption Characteristics							
duration	34,212	168	0	60	60	240	1,440
duration^2	34,212	82,198	0	3,600	3,600	57,600	2,073,600
summer	34,212	73.4%	0%	0%	100%	100%	100%
afternoon	34,212	48.8%	0%	0%	0%	100%	100%
evening	34,212	29.1%	0%	0%	0%	100%	100%
Customer Characteristics							
ln(annual MWh)	34,212	2.4	0.3	1.9	2.4	2.9	4.4
household income	34,212	69,243	5,076	36,846	63,445	97,618	173,611

5.3 Comparison of 2009 and 2014 Model Estimates

Figure 5-1 provides a comparison of the 2009 model estimates and the 2014 model estimates by interruption duration, in 2013 dollars. The 2014 model estimates have been extended to 16 hours because the addition of data on 24-hour power interruption scenarios has allowed to model to more reliably predict costs up to 16 hours. As with C&I customers, the magnitude of the interruption cost estimates is similar between the two small C&I models, but there is a noticeable change in the functional form. This change is attributable to the addition of the longer duration scenarios and to the significant change in the model specification. The functional form is more linear and no longer levels off at 8 hours, which seems more plausible.

Figure 5-1: Estimated Customer Interruption Costs (U.S.2013$) by Duration and Model (Summer Weekday Afternoon) – Residential



5.4 Interruption Cost Estimates and Key Drivers

Table 5-7 shows how residential customer interruption costs vary by season and time of day. The cost of a summer power interruption is substantially higher than a non-summer one, for all durations, seasons, and times of day. As for how interruption costs vary by time of day, costs are highest in the morning and night (10 PM to 12 noon). The weighted-average interruption cost estimate is most appropriate to use for planning purposes, unless the distribution of interruptions by season and time of day is known.

Table 5-7: Estimated Customer Interruption Costs (U.S.2013$) by Duration and Timing of Interruption – Residential

Timing of Interruption	% of Hours per Year	Interruption Duration					
		Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Summer Morning/Night	19%	$6.8	$7.5	$8.4	$14.3	$24.0	$42.4
Summer Afternoon	7%	$4.3	$4.9	$5.5	$9.8	$17.1	$31.1
Summer Evening	7%	$3.5	$4.0	$4.6	$9.2	$17.5	$34.1
Non-summer Morning/Night	39%	$3.9	$4.5	$5.1	$9.8	$17.8	$33.5
Non-summer Afternoon	14%	$2.3	$2.7	$3.1	$6.2	$12.1	$23.7
Non-summer Evening	14%	$1.5	$1.8	$2.2	$5.0	$10.8	$23.6
Weighted Average		**$3.9**	**$4.5**	**$5.1**	**$9.5**	**$17.2**	**$32.4**

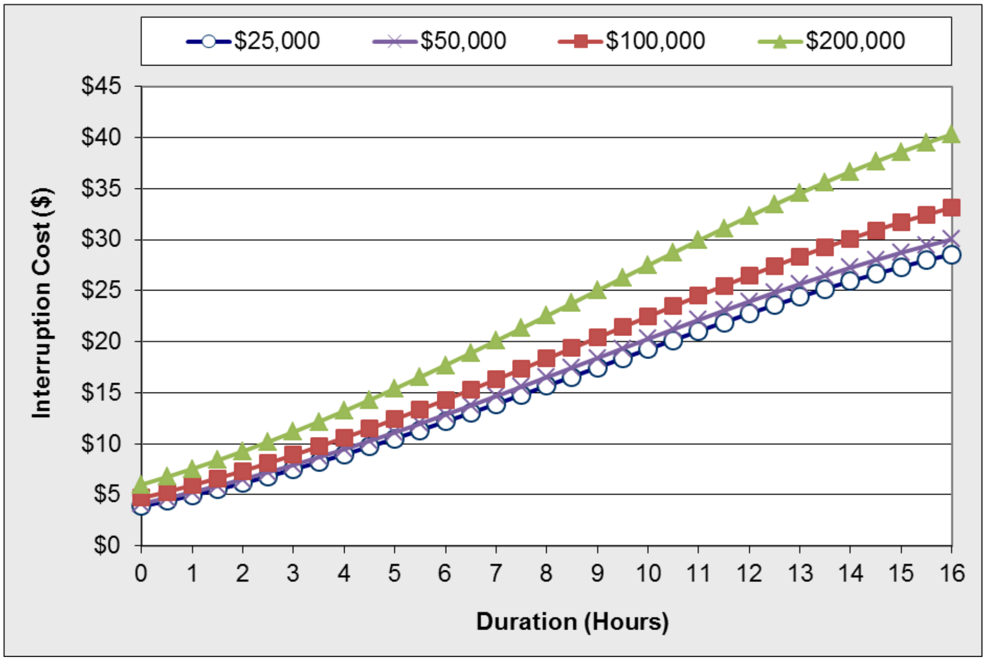
Based on the weighted-average interruption cost estimate, Table 5-8 provides cost per event (equal to the weighted-average interruption cost), cost per average kW, and cost per unserved kWh for residential customers. Cost per unserved kWh is relatively high for a momentary interruption because the expected amount of unserved kWh over a 5-minute period is relatively low.

Table 5-8: Cost per Event, Average kW and Unserved kWh – Residential

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Cost per Event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per Average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3

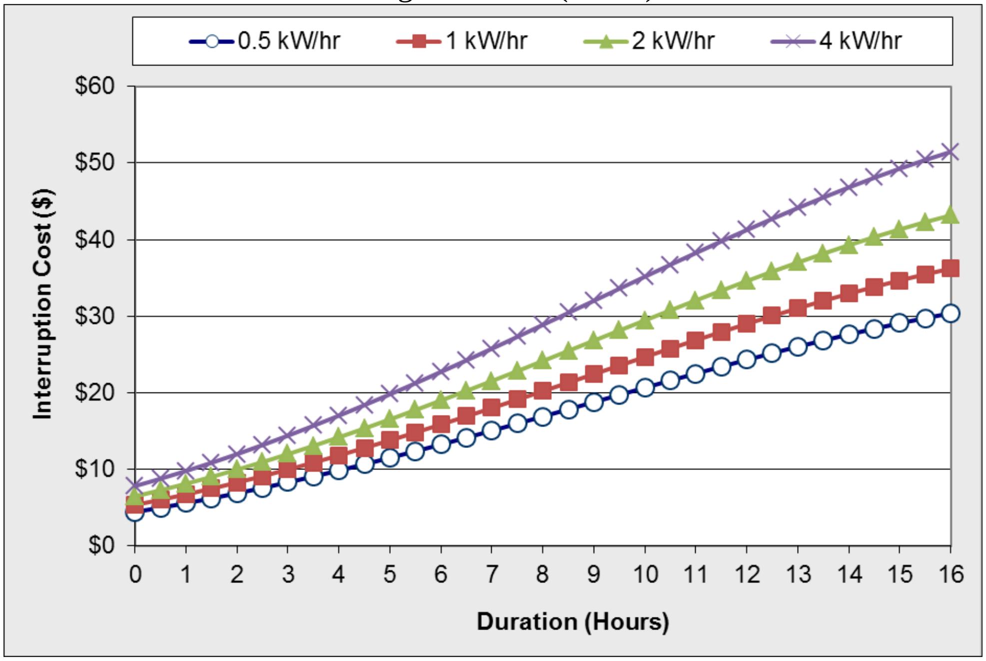
Figure 5-2 shows the residential interruption costs in the summer afternoon by levels of household income. Household income has a relatively modest impact on interruption costs. Between a household income of $50,000 and $100,000, the difference in interruption costs is only around 10% for all durations.

Figure 5-2: Estimated Summer Afternoon Customer Interruption Costs (U.S.2013$) by Duration and Household Income – Residential



Finally, Figure 5-3 shows the residential interruption costs in the summer afternoon for various levels of average demand. Residential interruption costs are not highly sensitive to the average demand of a customer. In the figure, each increment in average demand represents a 2-fold increase in usage, but interruption costs only increase by around 20% from one level of average demand to the next.

Figure 5-3: Estimated Summer Afternoon Customer Interruption Costs (U.S.2013$) by Duration and Average Demand (kW/hr) – Residential



6. Study Limitations

As in the 2009 study, there are limitations to how the data from this meta-analysis should be used. It is important to fully understand these limitations, so they are further described in this section. First, certain very important variables in the data are confounded among the studies we examined. In particular, region of the country and year of the study are correlated in such a way that it is impossible to separate the effects of these two variables on customer interruption costs. Thus, for example, it is unclear whether the higher interruption cost values for the southwest are purely the result of the hot summer climate in that region or whether those costs are higher in part because of the particular economic and market conditions that prevailed during the year when the study for that region was done. The same logic applies to the 2012 west study, which was the only survey to include power interruption scenarios of more than 12 hours, which makes it difficult to separate the effect of region and year from the effect of the relatively long interruption duration.

There is further correlation between regions and scenario characteristics. The sponsors of the interruption cost studies were generally interested in measuring interruption costs for conditions that were important for planning for their specific systems. As a result, interruption conditions described in the surveys for a given region tended to focus on periods of time when interruptions were more problematic for that region. Unfortunately, the time periods when the chance of interruptions is greatest are not identical for all sponsors of the studies we relied upon, so interruption scenario characteristics tended to be different in different regions. Fortunately, most of the studies we examined included a summer afternoon interruption, so we could compare that condition among studies.

A further limitation of our research is that the surveys that formed the basis of the studies we examined were limited to certain parts of the country. No data were available from the northeast/mid-Atlantic region, and limited data were available for cities along the Great Lakes. The absence of interruption cost information for the northeast/mid-Atlantic region is particularly troublesome because of the unique population density and economic intensity of that region. It is unknown whether, when weather and customer compositions are controlled, the average interruption costs from this region are different than those in other parts of the country.

Another caveat is that around half of the data from the meta-database is from surveys that are 15 or more years old. Although the intertemporal analysis in the 2009 study showed that interruption costs have not changed significantly over time, the outdated vintage of the data presents concerns that, in addition to the limitations above, underscore the need for a coordinated, nationwide effort that collects interruption cost estimates for many regions and utilities simultaneously, using a consistent survey design and data collection method.

Finally, as described in Section 1, although the revised model is able to estimate costs for interruptions lasting longer than 8 hours, it is important to note that the estimates in this report are not appropriate for resiliency planning. This meta-study focuses on the direct costs that customers experience as a result of relatively short power interruptions of up to 24 hours at most. In fact, the final models and results that are presented in Sections 3 through 5 truncate the estimates at 16 hours, due to the relatively few number of observations beyond 12 hours (scenarios of more than 12 hours account for around 2% to 3% of observations for all customer classes). For resiliency considerations that involve planning for long duration power interruptions of 24 hours or more, the nature of costs change and the indirect, spillover effects to the greater economy must be considered.[12] These factors are not captured in this meta-analysis.

[12] For a detailed study and literature review on estimating the costs associated with long duration power interruptions lasting 24 hours to 7 weeks, see: Sullivan, Michael and Schellenberg, Josh. *Downtown San Francisco Long Duration Outage Cost Study*. March 27, 2013. Prepared for Pacific Gas & Electric Company.

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Xcel Energy		Information Request No. 32
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment M2, p. 74 of 202, lines 7-16.

Request:
A. Please provide screenshots of the inputs to and outputs from the LBNL ICE Calculator used for the referenced calculations.
B. Please provide a spreadsheet with all formulas and links intact containing the referenced calculations.

Response:
The calculation of reliability benefits on page 74 of Attachment M2 is related to the reduction in response time for single customer events.

For both parts A and B, please see our response to Fresh Energy Information Request No. 31. Please also see Attachment A to this response, which is the 2015 version of the CMO calculator showing a CAIDI of 184 minutes resulting in a CMO value of $0.75.

Attachment A to this response is a Company work product that includes proprietary methods for calculating the value of customer minutes out. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Additionally, some data contained within the work product is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use, and/or contains proprietary customer and system data.

Please note Attachment A is marked as "Non-Public" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, we provide the following description of the excised material:

1. **Nature of the Material:** Model to determine value of Customer Minutes Out
2. **Authors:** Electric Distribution Engineering Department
3. **Importance:** The Company work product includes proprietary methods for calculating the value of customer minutes out.
4. **Date the Information was Prepared:** June 2018

Preparer:	Betsy Coppock
Title:	Principal Engineer
Department:	Electric Distribution Engineering
Telephone:	303.571.3537
Date:	January 23, 2020

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☒ **Public Document – Not Public Data Has Been Excised**
☐ **Public Document**

Xcel Energy		Information Request No. 33
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

<u>Question:</u>
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment M2, p. 75 of 202, lines 4-14.

Request:

A. Please provide screenshots of the inputs to and outputs from the LBNL ICE Calculator used for the referenced calculations.
B. Please provide a spreadsheet with all formulas and links intact containing the referenced calculations.

<u>Response:</u>
The calculation of reliability benefits on page 75 of Attachment M2 is related to a faster response to tap level events.

For both parts A and B, please see our response to Fresh Energy Information Request No. 31. Please also see Attachment A to this response, which is the 2015 version of the CMO calculator showing a CAIDI of 271 minutes resulting in a CMO value of $0.70.

Attachment A to this response is a Company work product that includes proprietary methods for calculating the value of customer minutes out. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Additionally, some data contained within the work product is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use, and/or contains proprietary customer and system data.

Please note Attachment A is marked as “Non-Public” in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, we provide the following description of the excised material:

1. **Nature of the Material:** Model to determine value of Customer Minutes Out
2. **Authors:** Electric Distribution Engineering Department
3. **Importance:** The Company work product includes proprietary methods for calculating the value of customer minutes out.
4. **Date the Information was Prepared:** June 2018

Preparer:	Betsy Coppock
Title:	Principal Engineer
Department:	Electric Distribution Engineering
Telephone:	303.571.3537
Date:	January 23, 2020

☐ **Not Public Document – Not For Public Disclosure**
☐ **Public Document – Not Public Data Has Been Excised**
☒ **Public Document**

Xcel Energy		Information Request No. 34
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment M2, p. 75 of 202, lines 18-21.

Request:
Please provide a spreadsheet with all formulas and links intact containing the referenced calculations.

Response:
The referenced calculation of reliability benefits is the sum of the benefits in Fresh Energy Information Request Nos. 31through 33. Please see our response to Fresh Energy Information Request No. 31, Attachment C.

Preparer:	Betsy Coppock
Title:	Principal Engineer
Department:	Electric Distribution Engineering
Telephone:	303.571.3537
Date:	January 23, 2020

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☐ **Public Document**

Xcel Energy		Information Request No. 35
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment M2, p. 126 of 202, lines 19-24.

Request:
Please provide a spreadsheet with all formulas and links intact supporting the potential for a 21.3 minute SAIDI reduction from FLISR.

Response:
This question references how the Company determined the feeder locations for our proposed FLISR deployment and the associated potential SAIDI reduction. Please see Attachment A to this response. Attachment A contains notes in the cells regarding derived formulas and other contextual information. We note that cell I209 contains the formula to derive the 21.3 minutes SAIDI reduction from FLISR; it is the sum of All Days CMO savings divided by the total customers of Minnesota. The number of Minnesota customers we used in this calculation was 1,257,548.

Attachment A is a portion of the Company's AGIS CBA executable model, and represents Company work product. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Additionally, some data contained within the model is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use, and/or contains proprietary customer and system data. This additional trade secret data includes negotiated pricing (including labor, materials, technology, and services) and contract terms; internal labor rates; number of customers per feeder; and device retirement and failure rates.

Please note the CBA is marked as "Non-Public" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, we provide the following description of the excised material:

1. **Nature of the Material:** A portion of the Cost Benefit Analysis Model developed by the Company.
2. **Authors:** Risk Analytics
3. **Importance:** The Company work product is proprietary to the Company.
4. **Date the Information was Prepared:** The CBA Model was created in the third quarter of 2019.

Preparer:	Thanh Huynh
Title:	Staff Engineer
Department:	Electric Distribution Engineering
Telephone:	303.571.3544
Date:	January 23, 2020

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Xcel Energy		Information Request No. 36
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:

Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment M2, p. 133 of 202, lines 15-19.

Request:

A. Please provide screenshots of the inputs to and outputs from the LBNL ICE Calculator used for the referenced calculations.
B. Please provide a spreadsheet with all formulas and links intact containing the referenced calculations.
C. Please explain how the Company accounted for the impact of increased momentary interruptions from FLISR when using the ICE Calculator.

Response:

This question refers to how the Company calculated the value of a reduction in CMO associated with its FLISR proposal.

A. As discussed in our response to Fresh Energy Information Request No. 31, we developed and used the CMO calculator based on the LBNL ICE calculator to calculate benefits. The newer CMO calculator was used to calculate the CMO benefit at an individual feeder level. The CMO values differed for each feeder based on the individual feeders commercial and residential split. Each individual worksheet was not saved.
B. See Fresh Energy Information Request No. 35 Attachment A. We derived a weighted average CMO value for each feeder. The calculation is based on the customer count of each feeder multiplied by the CMO value of the feeder and then divided by the total customer count of the sample (1,085,115). The weighted feeder average was calculated to produce a CMO value of $0.72.
C. The Company did not take into account the impact of increased momentary interruptions from FLISR in lieu of a sustained interruption.

Preparer: Thanh Huynh
Title: Staff Engineer
Department: Electric Distribution Engineering
Telephone: 303.571.3544
Date: January 23, 2020

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Xcel Energy		Information Request No. 37
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment M2, p. 134 of 202.

Request:
Please explain what the "Scale Factor" is in Figure 16.

Response:
The term "Scale Factor" is an expected reduction in benefits due to FLISR unavailability as discussed in Attachment M2, p. 134 lines 15-17. In other documents, the term derated or deration may be substituted.

Preparer:	Betsy Coppock
Title:	Principal Engineer
Department:	Electric Distribution Engineering
Telephone:	303.571.3537
Date:	January 23, 2020

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Xcel Energy		Information Request No. 38
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

<u>Question:</u>
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment M2, p. 136 of 202, lines 4-5.

Request:
A. Please provide screenshots of the inputs to and outputs from the LBNL ICE Calculator used for the referenced calculations.
B. Please provide a spreadsheet with all formulas and links intact containing the referenced calculations.

<u>Response:</u>
As explained in our response to Fresh Energy Information Request No. 31, we used our internal CMO calculator to estimate the reliability benefits associated with the reduction in patrol time.

A. We derived a CMO value for each feeder using the calculator, using a CAIDI value of 163.06 minutes for all calculations. With the proposed FLISR scheme, a section of the feeder will still experience an outage, but the duration will be shortened since patrol will only be required on the section that is experienced the outage; we assumed a ten minute reduction for this benefit.
B. See Fresh Energy Information Request No. 35 Attachment A. Tab "FLISRBenefits," column K shows the calculations for CMO reduction due to decreased patrol time. Columns AC to AS show the CMO value benefits through 2038.

Preparer:	Thanh Huynh
Title:	Staff Engineer
Department:	Electric Distribution Engineering

Telephone: 303.571.3544
Date: January 23, 2020

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Xcel Energy		Information Request No. 39
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment M2, p. 171 of 202, lines 4-10.

Request:
A. Please provide screenshots of the inputs to and outputs from the LBNL ICE Calculator used for the referenced calculations.
B. Please provide all data, analysis, studies, reports, or spreadsheets with all formulas and links intact supporting the avoided Transmission, Distribution, and Generation capacity values used in the referenced calculations.

Response:
This question refers to a projected reduction in the NSP System peak demand from IVVO.

A. We did not use the LBNL ICE Calculator to estimate this benefit. The LBNL ICE Calculator is appropriate for calculating reliability benefits; it is not appropriate for calculating benefits associated with energy savings.

B. We provide the requested information with all formulas, links, and calculations in the live file entitled "19-0666 CUB-002_CBA IVVO_MN_Electric_Filed_M-19-666 TRADE SECRET IN ENTIRETY.xlsx," and provided as Attachment A to this response. We note that the DSM values are those approved by the Commission in Docket No. E999/CIP-16-541. Attachment A is provided as a live file only.

Attachment A to this response is a Company work product. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Additionally, some data contained within the work product is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use, and/or contains proprietary customer and system data.

Please note Attachment A is marked as "Non-Public" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, we provide the following description of the excised material:

1. **Nature of the Material:** The Cost Benefit Analysis Model developed by the Company.
2. **Authors:** Risk Analytics
3. **Importance:** The Company work product is proprietary to the Company.
4. **Date the Information was Prepared:** The CBA Models were created in the third quarter of 2019.

Preparer:	Travis Majors/ Pablo Martinez	/Nick Paidosh
Title:	Sr Engineer/ Risk Analyst	/ Principal Rate
Department:	Dist Elec Eng/ Risk Mgmt	/ Regulatory
Telephone:	303-571-3817/ 303-571-7639	/ 612-342-9034
Date:	January 23, 2020	

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Xcel Energy		Information Request No. 40
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment M2.

Request:
A. Please provide spreadsheet versions of Schedules 4-9 with all formulas and links intact.
B. Please provide all data and analysis in spreadsheet format with all formulas and links intact supporting the values in Schedule 8.

Response:

For all requested Schedules, please refer to the live Cost-Benefit Analyses workbooks previously provided by the Company (Attachments O2-O4) as part of the non-public materials. Schedules 4-9 are individually selected lines from the "SummaryCost" and "SummaryBenefits" tabs in Attachments O2-O4. These selected lines were broken into smaller schedules based on the business area so they could be supported by the correct witnesses' rate case testimony.

Preparer:	Nick Paidosh
Title:	Principal Rate Analyst
Department:	Regulatory Affairs
Telephone:	612-342-9034
Date:	January 23, 2020

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Xcel Energy		Information Request No. 41
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment M4, p. 18 of 50, lines 7-10.

Request:
A. Please explain the Company's plans for transitioning from Cellnet gas meters.
B. Please explain if and how the Company's proposed FAN could support future AMI for gas.

Response:
The Company is presently reviewing a strategy to transition from Cellnet for meter reading our gas customers. One of the options that we are exploring is to utilize the electric Advanced Metering Infrastructure (AMI) wireless mesh and its headend software for our gas meter reading/informational needs. In order to use the existing AMI headend, we would need to install modules on the gas meters that can communicate gas usage data through the Field Area Network (FAN) to the AMI headend. The AMI headend software would need to be updated to the correct functional version in order to accommodate the specific gas meter information. If we take this approach, we anticipate that we would leverage the existing FAN in areas where we have both gas and electric customers. In areas where we have gas-only customers, we are exploring options, including building additional FAN infrastructure for the gas meters to communicate with the AMI headend.

Preparer:	Jim Lash
Title:	AGIS Strategic Planning Director
Department:	AGIS
Telephone:	651-639-4421
Date:	January 23, 2020

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Xcel Energy		Information Request No. 42
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

<u>Question:</u>
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment M5.

Request:
Please provide the assumed future customer participation rates in TOU and CPP programs used in the Company's CBA.

<u>Response:</u>

The TOU and CPP participation rates used in our analysis are estimates from the Brattle Group Study, *The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory*, and included as Schedule 6 of Attachment M5, of the Integrated Distribution Plan.

Preparer:	Nick Paidosh/Pablo Martinez
Title:	Principal Rate/ Risk Analyst
Department:	Regulatory/ Risk Management
Telephone:	612-342-9034/303-571-7639
Date:	January 23, 2020

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Xcel Energy — Information Request No. 43

Docket No.:	E002/M-19-666
Response To:	Fresh Energy
Requestor:	Isabel Ricker
Date Received:	January 13, 2020

<u>Question:</u>
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP) Attachment N1.

Request:
Please provide the selected APT vendor's RFI responses to questions 7.22, 7.23, 7.24, and 10.6.3.

<u>Response:</u>
We provide the requested information in Table [FE-43] 1 below.

Table [FE-43] 1: Selected Advanced Planning Tool Vendor Responses to Requested RFI Questions

Question	Question	Vendor Response
		[Trade Secret Begins]
7.22	Does your solution utilize hosting capacity information? If yes, describe your methodology.	
7.23	Can your solution be integrated with EPRI's DRIVE hosting tool without custom code?	
7.24	Which other hosting tool(s) does your solution integrate with?	
10.63	Please provide details of previous successful implementations with other clients.	
		[Trade Secret Ends]

Please note that portions of our response are marked as "Not Public." Certain data is considered to be "not public data" pursuant to Minn. Stat. §13.02, Subd.9, and is "Trade Secret" information pursuant to Minn. Stat. §13.37, subd. 1(b) as this data derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.

Preparer:	Brian Monson
Title:	Distribution Planning Engineer
Department:	System Planning and Strategy
Telephone:	763-493-1811
Date:	January 23, 2020

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Xcel Energy — Information Request No. 44

Docket No.: E002/M-19-666
Response To: Fresh Energy
Requestor: Isabel Ricker
Date Received: January 13, 2020

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP), Attachment O2 (AMI CBA) workpapers, tab 'RATIOOut'.

Request:
A. Please confirm that the formula in cell C7 is incorrect, the formula should be **[Trade Secret Begins]**

[Trade Secret Ends]

B. If the formula in cell C7 is incorrect, please provide corrected versions of all affected spreadsheets, testimony, and attachments reflecting the correct CBA results.

Response:

A. We confirm that the formula in cell C7 is applied correctly. To clarify, it is referring to avoided capital investment of $190 million. The $221 million represents the sum of both avoided capital investment ($190Million) and capital gains (=$31.5 million). The capital gains amount benefit ($31.5 million) has already been included into the Benefit/Cost Ratio, in a form of revenue requirements reductions (a cost reduction in the ratio) in cell C10. Capital Gains is defined as efficiency gains and other avoided CAP purchases, and thus applied as revenue requirement reduction. Therefore, CAP benefit to be utilized in in the ratio is $190 million not $221 million, so as not to double count the $31.5 million of capital gains benefit.
B. The formula is correct.

Please note that portions of this information request and response are marked as "Not Public." Certain data is considered to be "not public data" pursuant to Minn. Stat. §13.02, Subd.9, and is "Trade Secret" information pursuant to Minn. Stat. §13.37, subd. 1(b) as this data is derived from the Company's AGIS CBA executable model and represents Company work product. The Company maintains this information as trade secret pursuant to Minn. Stat. § 13.37(1)(b) based on its economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.

Preparer:	Pablo Martinez
Title:	Sr Principal Risk Analysist
Department:	Risk Management
Telephone:	303-571-7639
Date:	January 23, 2020

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Xcel Energy		Information Request No. 45
Docket No.:	E002/M-19-666	
Response To:	Fresh Energy	
Requestor:	Isabel Ricker	
Date Received:	January 13, 2020	

Question:
Reference:
Xcel's November 1, 2019 Integrated Distribution Plan (IDP), Attachment O3 (FLISR CBA) workpapers, tab 'CMOFeeder'.

Request:
A. Please explain what "normalized days" are.
B. Please provide screenshots of the inputs to and outputs from the LBNL ICE Calculator used to calculate the values in column AV.
C. Please provide a spreadsheet with all formulas and links intact supporting the calculation of the values in columns AX, AY, AZ, BA, and BC.

Response:
A. Normalized Days is a term commonly used in reliability reporting to separate out days that experience large Customer Minutes Out (CMO) from "normal" days that experience a more normal amount of outages/CMO. The calculation defining normalized days and non-normalized days can be found in IEEE-1366.
B. As discussed in our response to Fresh Energy Information Request No. 31, we use an internally-developed CMO calculator that relies on LBNL ICE data. Please see FE-31, Attachment A). Specific to this response, we derived a CMO value for each feeder using a CAIDI value of 163.06 minutes for all calculations.
C. See FE-35 Attachment A. In tab "CMOFeeder," cell AX4, AY4, AZ4, BA4, and BC4 have notes describing the column and how the calculation was derived.

Preparer:	Thanh Huynh
Title:	Engineer
Department:	Electric Distribution Engineering
Telephone:	303.571.3544
Date:	January 23, 2020